Proceedings
Volume 2 — Oil

$20.00
CONF-790805—P2

Fifth Annual DOE Symposium

Enhanced Oil & Gas Recovery & Improved Drilling Technology



August 22, 23 & 24, 1979
Performing Arts Center
Tulsa, Oklahoma

MASTER

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UNITED STATES DEPARTMENT OF ENERGY
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A80004913

PROCEEDINGS

VOLUME 2—OIL

FIFTH DOE SYMPOSIUM ON ENHANCED OIL & GAS RECOVERY & IMPROVED DRILLING TECHNOLOGY

Tulsa, Oklahoma, August 22-24, 1979

Bill Linville, *Editor*
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BARTLESVILLE ENERGY TECHNOLOGY CENTER, BARTLESVILLE, OKLAHOMA

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Contains papers for the following sessions

Session F—Residual Oil Determination
Session G—Thermal Methods
Session H—Heavy Oil—Tar Sands
Session J—Technology Transfer
Session N—Carbon Dioxide Flooding
Session O—Carbon Dioxide Flooding (Continued)

Volume 1—Oil, contains papers from

Session A—Chemical Flooding: Surfactant-Polymer Field Projects
Session B—Chemical Flooding: Surfactant-Polymer Research
Session C—Chemical Flooding: Alkaline
Session D—Chemical Flooding: Polymer

Volume 3—Gas and Drilling, contains papers from

Session K—Natural Gas Supporting Research
Session L—Natural Gas Supporting Research (Continued)
Session M—Western Gas Sands Project
Session I—Drilling Technology
Session E—Environmental

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Publisher of the Oil & Gas Journal

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CONTENTS

SESSION F — **Residual Oil Determination**

R&D Needs in the Determination of Residual Oil — F-1
Dr. Donald C. Bond
Petroleum Consultant

Residual Oil Saturation Technology Test in a Consolidated Sandstone Reservoir, Bell Creek Field, Powder River County, Montana — F-2
F. Richard Myal
Gary Energy Corp.

Residual Oil Saturation Determination, Wilmington Micellar-Polymer Project, October 1978-May 1979 — F-3
R. C. Earlougher
Godsey-Earlougher Engineering
and
Harrison L. Staub
City of Long Beach

Measurement and Correlation of Conditions for Entrapment and Mobilization of Residual Oil — F-4
Norman R. Morrow and Boonruam Songkran
New Mexico Institute of Mining & Technology

An Investigation of Low Invasion Fluids for Pressure Coring — F-5
A. L. McFall and P. A. McGuire
Sandia Laboratories

The Single-Well Chemical Tracer Test: Direct Calculation of Residual Oil Saturation from Field Data — F-6
Harry Deans and Stephen Majoros
Rice University

SESSION G — **Oil Recovery by Thermal Methods**

Bodcau In Situ Combustion Project, Bossier Parish, Louisiana — G-1
John Garvey
Cities Service Co.

Wet Combustion Pilot, Paris Valley Field, Monterey County, California — G-2
R. G. Shipley, Jr., and J. W. Patek
Husky Oil Co.

The Lynch Canyon Thermal Drive Oil Recovery Project — G-3
R. M. Scarborough, G. V. Cady, and J. R. Stair
General Crude Oil Co.

Economic Feasibility of Steam Drive in Light Oil Reservoirs — G-4
S. R. Aydelotte and A. B. Ramesh
INTERCOMP Resource Development and Engineering, Inc.

Williams Holding Steamflood, Cat Canyon Field, California G-5
Gary R. Adamson and Edward J. Hanzlik
Getty Oil Co.

The '200' Sand Steamflood Demonstration Project G-6
Willie O. Alford
Santa Fe Energy Co.

Potential Use of Petroleum Coke and California Lignite as Fuels for Enhanced Oil Recovery G-7
Robert D. Shelton
Acurex Corp.

SESSION H **Thermal Methods—Heavy Oil & Tar Sands**

Field Testing of the Vapor Therm^{TM} Process in Eastburn (Cherokee) Field, Vernon County, Missouri H-1
John Sperry, F. S. Young, and Robert S. Poston
Carmel Energy, Inc.

Willow Draw Field, Attic Air Injection Project, Park County, Wyoming H-2
Quentin T. Wilson
Santa Fe Energy Co.

In Situ Thermal Processing H-3
A. S. Abou-Sayed, R. McCain, K. M. Wolgemuth, and A. H. Jones
Terra Tek, Inc.

Deep Steam: Development of Downhole Steam Generation Systems and Injection String Modifications for Deep Steam Injection H-4
Ronald L. Fox
Sandia Laboratories

Heavy Oil Recovery Research Program at SUPRI H-5
S. K. Sanyal, H. J. Ramey, S. S. Marsden, W. E. Brigham, A. Satman, M. Soliman, and L. Castanier
Stanford University Petroleum Research Institute

Physical Models of Steam Drive Operations H-6
W. W. Huang and T. M. Doscher
University of Southern California

The Use of Chemical Additives with Steam Injection to Increase Oil Recovery H-7
L. L. Handy, I. Ershaghi, M. Amabeoku, J. Amaefule, M. Elgassier, and V. Ziegler
University of Southern California

Coal: An Alternate Fuel for Thermal Enhanced Oil Recovery H-8
James F. Kelly
Arthur G. McKee & Co.

SESSION J — **Technology Transfer**

Determination of EOR Technology Transfer Requirements — J-1
Tom D. Wilson and John P. Scott
Spears and Associates, Inc.

Bibliographic Data Bases: Key to EOR Information — J-2
Elizabeth Mohr
Bartlesville Energy Technology Center, DOE

Information Retrieval for the Petroleum Production Industry — J-3
Samuel J. Martinez and John A. Bailey
University of Tulsa

Information Can Make a Difference — J-4
Charles E. Spath
Technical Information Center, DOE

Information Management Technology: An Integration of the Behavioral, Information, and Computer Sciences — J-5
J. K. Willoughby, D. A. Kullas, and J. A. Gardner
Science Applications, Inc.

Petroleum Data System: Scope and Applications — J-6
Patricia Tracy
University of Oklahoma

Evaluation of Target Oil in 50 Major Reservoirs in the Texas Gulf Coast for Enhanced Oil Recovery — J-7
James N. Hicks and Rhonda S. Foster
DOE Energy Information Administration
Dallas Field Office

SESSION N — **Oil Recovery by CO_2 Flooding**

Weeks Island 'S' Sand Reservoir B Gravity Stable Miscible CO_2 Displacement, Iberia Parish, Louisiana — N-1
George E. Perry and Charles M. Kidwell
Shell Oil Co.

Survey and Analysis of Corrosion Problems Caused by CO_2 Injection for Enhanced Oil Recovery — N-2
D. W. DeBerry and W. S. Clark
SumX Corp.

Recovery of CO_2 for Oil Recovery from Flue Gas Impurity Effects — N-3
J. T. Sears and A. W. Pappano
West Virginia University

The Critical Role of Reservoir Temperature in CO_2 Flooding — N-4
K. I. Kamath
Morgantown Energy Technology Center, DOE

Enhanced Oil Recovery by CO_2 Miscible Displacement in the Little Knife Field, Billings County, North Dakota N-5
Terrance M. White and Robert F. Lindsay
Gulf Oil Exploration and Production Co.

Solvent Displacement of Residual Oil N-6
S. Gharib and T. M. Doscher
University of Southern California

SESSION O **Oil Recovery by CO_2 Flooding—Continued**

A Geologic Appraisal and Economic Sensitivity Study of Drilling and Producing Naturally Occurring Carbon Dioxide for Use in Enhanced Oil Recovery O-1
F. W. Zimmerman
Gulf Universities Research Consortium

Sources and Delivery of Carbon Dioxide for Ehanced Oil Recovery O-2
M. N. Shah and A. E. Cover
Pullman Kellogg

Alternative Methods of Supplying CO_2 for Enhanced Oil Recovery O-3
Harvey J. Ford and Franklin E. Grange
Science Applications, Inc.
and
John H. Erbar
Oklahoma State University

Carbonate Target Reservoirs for CO_2 Miscible Flooding O-4
R. W. Pease, J. H. Hartsock, and E. A. Lohse
Gruy Federal, Inc.

Progress of the Pilot Carbon Dioxide Flood in the Rock Creek-Big Injun Field, Roane County, West Virginia O-5
G. P. SanFilippo and L. G. Guckert
Pennzoil Co.

Granny's Creek CO_2 Injection Project, Clay County, West Virginia O-6
W. D. Conner
Columbia Gas Transmission Corp.

SURVEY OF R & D NEEDS IN THE DETERMINATION OF RESIDUAL OIL SATURATION

Donald C. Bond
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Last year I visited 12 oil companies, 2 service companies, and 3 universities. I interviewed about 60 experts and I had informal contacts with a dozen other experts on residual oil.

The purpose of these interviews was to obtain industry opinions about research and development on ROS determination that could be—and should be—supported by DOE. In the interviews we emphasized problems that are not likely to be handled by industry in the normal course of events—that is, worthy projects that probably will not be undertaken if they do not receive support from DOE.

My recommendations about DOE funding for ROS research are given in Table 1. Recommended funding for projects related to methods of logging is about $2,400,000; note that, in part, the justification for some of these logging projects is based on benefits other than improvements in ROS determination. Recommended funding for research on log-inject-log methods is about $1,250,000. I will say a little more about this L-I-L work later.

For research on coring, a modest $400,000 is recommended. Most of the people whom I interviewed expressed great skepticism about the possibility of ever obtaining "true" samples of reservoir rock and fluid. But if any proposed system should appear to have high probability of success, an all-out effort to perfect that system would be warranted.

Recommended funding for work on the single-well tracer method is $300,000. I will say more about this tracer work later.

For the running of complete suites of ROS methods in various DOE-sponsored TOR projects, about $900,000 is recommended. Several miscellaneous projects, such as an ROS seminar, would require about $100,000.

Prepared for the Department of Energy Under Contract No. EW-78-C-19-0007

For details concerning the different projects, I suggest that you see my report on the R & D survey.* In the time that is left here, I would like to talk a little bit about several questions that still trouble me—in this business of determining residual oil saturation.

Some people say that no ROS method is applicable to a well that has been hydraulically fractured.[1] I wonder if this is true? In some cases you know that a hydra-fracked well has a single vertical fracture and you can even estimate the extent of the fracture. For example, in the study of the Willard Unit, fractured wells are shown to have a single fracture—of known orientation—that cuts through the well out to a distance of about 200 feet.[2] If you inject a limited volume of fluid into a well like that, the flow of the fluid through the rock is nearly linear. If you developed the theoretical curves for the single-well tracer technique for this case, you ought to be able to use the tracer method to determine ROS. I have talked with Harry Deans about this question; I think he agrees with me. I hope that Deans or somebody else will go ahead and look into this question of tracer tests in hydra-fracked wells.

While we are talking about tracer tests—Harry Deans says ". . . even if the strata include layers that have high oil saturation, the injection of the test fluid will reduce the oil saturation in those layers before the tracers arrive."[3] That is, Deans says that even if mobile oil is present, the mobile oil is displaced, so the tracer test tells the oil saturation in a rock that is flooded out. For a water-wet rock, this may be true. But suppose you have rock of intermediate wettability, like the one that Salathiel[4] worked on (Fig. 1). In most tracer tests, when you have produced about half of the injected tracer solution, you have produced

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*A detailed discussion of the individual projects is given in the report on this study: DOE Contract EW-78C-19-0007.

most of the alcohol tracer that you use to get an ROS value. That is, you are looking at the oil saturation in a rock that has had, on the average, about one pore volume of tracer solution pass through and displace mobile oil. If the reservoir has a saturation represented by point A, to the right, you have no problem. But suppose the existing saturation is represented by point B, on the left.

In this case the tracer solution displaces some oil, but it does not displace all of the mobile oil. The tracer test doesn't give the existing oil saturation, which is what we really want. Neither does it give an ultimate floodable residual oil saturation. It gives something in between these two. I wonder if we should be thinking more about what happens in tracer tests carried out in oil-wet or intermediate-wettability rocks.

Just because the single-well tracer test is called a tracer test, you might think that the "tracer" was present in <u>trace</u> quantities. But this is not necessarily so. Harry Deans' example in the IOCC book uses 1% ethyl acetate.[5] This gives about 0.1M ethyl acetate solution. When the ethyl acetate hydrolyzes, it forms ethyl alcohol and acetic acid. If about 10% to 50% of the ethyl acetate hydrolyzes, you get about 0.01 to 0.05M solution of alcohol and acetic acid. In theory, the acetic acid is spent by reaction on the rock. But what if the reservoir rock contains little or no acid-soluble material? What if the rock is oil-wet? Will the acetic acid react with the rock then? What is the effect of this 0.01 to 0.05M solution of acid on the wettability of the rock? And on the mobility of the oil that is present? I doubt that anyone would flood a reservoir with 0.05M acid solution without expecting some change in the residual oil saturation. I wonder if we shouldn't take a closer look at the possible effects of the acid that is formed—at least in some kinds of single-well tracer

tests. Maybe we should work with tracers—formed in situ by hydrolysis—that don't react with the rock, or change the nature of the rock surface.

You can get a pretty good idea of the wettability of a reservoir rock from imbibition tests or centrifuge tests on cores. And you can get some idea of the wettability from tests like waterfloods on cores and relative permeability of cores—because the behavior of the fluids in these tests depends, to a degree, on the wettability of the rock. But do you really need to know the wettability in order to estimate the residual oil saturation?

No, you don't have to know the wettability. You can get residual oil values from pressure cores—or from L-I-L tests—or from tracer tests—without knowing anything at all about the wettability of the rock.

But I think you ought to have some wettability information, so that you can rationalize your ROS results from various methods and understand what is going on in the reservoir during your tests.

Wettability information can put you on guard about potential problems. It might warn you about the possibilities for mobile oil, for example, especially if the rock is <u>not</u> water-wet. Or it might warn you about large capillary end effects, if the rock <u>is</u> water-wet. I think it is important for you to have a clear idea about the wettability of the rock, to help you plan your ROS tests and to help you interpret your results.

Now let's look at some of the log-inject-log techniques. Some of the logging tools that are used have pretty shallow radius of investigation. For example, they tell me that the nuclear magnetic log and the dielectric constant log penetrate only an inch or two of rock. The PNC log penetrates a few inches. There are so many things that can happen in that first inch or two of rock that I am worried about the validity of any ROS result, even though the tool itself gives an accurate reading.

—Mud filtrate can give abnormal flushing.

—Some capillary imbibition end effects must occur, especially with tight rocks.

—If you have very permeable rocks, mud particles can penetrate several inches, unless you have a perfect mud. Surely these mud particles disturb the fluid saturation to some degree.

The logging people say that they take these phenomena into account. But I wonder if there isn't room for some serious thought about some of these things that can take place near the well bore.

In the L-I-L technique, one of the fundamental assumptions that you make is that the fluid that you inject completely displaces the fluid that was around the well when you ran the first log. And you assume that you can detect the displacement of one fluid by another, by means of your logging device.

You might think that research people would have thoroughly tested this fundamental assumption, in rocks that are 100% water-saturated. Actually only one test of this kind has been run. At the Biennial SPE Oil Recovery Symposium about a year ago, you remember that Exxon reported the results of such a test in the Tar Springs Sand in the Louden Field, Illinois.[6] The Tar Springs contains no oil, but Exxon's L-I-L tests—using the PNC log—indicated up to about 60% oil saturation in the Tar Springs.

They took the usual precautions about injecting extra brine and re-running the PNC log to show that a stabilized fluid distribution existed around the well. They concluded that the anomalous "oil saturations" calculated for the Tar Springs water sand resulted from: ". . . incomplete displacement of formation fluids close to the wellbore by the injected. . . water." This is one of our most important unanswered questions: Under

various hole conditions how completely does an injected fluid displace another fluid—and how well can we measure the degree to which one fluid displaces another? Unless we are convinced that we can answer this question for L-I-L tests in water sands—which don't have all the complications caused by an oil phase—our ROS results for waterflooded oil reservoirs will always be open to question.

In the past year or so services related to ROS determination—especially pressure-coring and single-well tracer services—have been improved. You can probably obtain the information needed for TOR evaluation (a) if you are willing to spend several hundred thousand dollars, and (b) if you have access to the facilities of a major research center, staffed by people with years of experience in manipulating fluid injections in wells and obtaining information from wells. But there is still room for improvement in methods of determining ROS. Some DOE support of research on ROS determination is warranted.

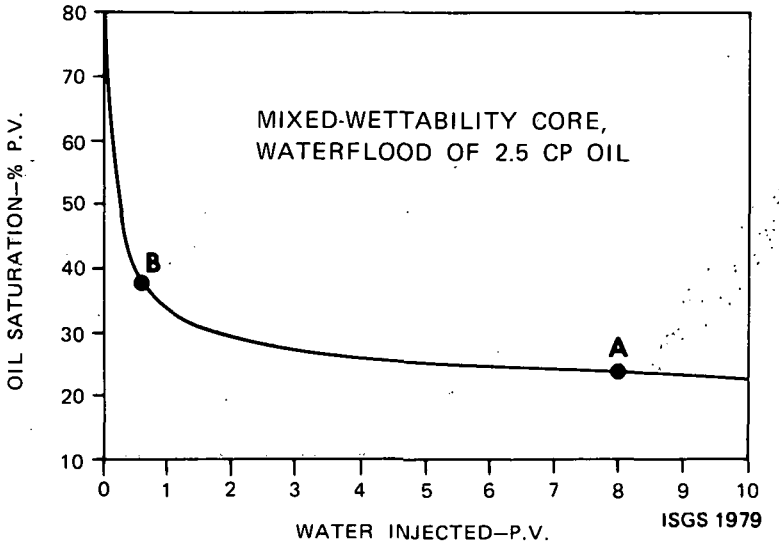


Fig. 1 - Waterflood of intermediate-wettability rock (modified from Salathiel[4]).

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TABLE 1
RECOMMENDED DOE FUNDING FOR RESEARCH PROJECTS ON ROS DETERMINATION

No.	Project	Priority A, B, C (A = highest priority)	DOE Funding Recommended, Thousands of Dollars: Amt. per Year	Years	Total	Comments
1	Log calibration and testing facilities (for logging in general as well as for ROS determination)	A	250	3	750	Includes No. 2 and No. 3. Industry should contribute reasonable part of total cost.
2	Study of neutron diffusion effects	B				Combine with No. 1.
3	Precision and accuracy of logging tools, especially PNC tools	B				Combine with No. 1.
4	Measurement of neutron capture cross-section of fluids ($\Sigma > 40$)	B			50	State-of-the-art study
5	Routine measurement of neutron capture cross-section of cores	C			25	Feasibility study
6	Precise measurement of neutron capture cross-section of pure elements (for application to all kinds of nuclear logging, with incidental application to the use of these logs in ROS determination)	C			100	
7	L-I-L in water-saturated rocks	A	250	2	500	
8	Comprehensive study of the precision of the determination of ROS by various L-I-L methods	B	150	2	300	State-of-the-art documentation and some research
9	Log-inject-log with untested combinations	B	150	3	450	
10	Design of partially-conductive casing	C	100	2	200	
11	New, or improved, pressure core barrels with:					
	—near-zero mud filtrate flushing	A	100	2	200	Desirable, but low feasibility. Run feasibility studies on novel ideas.
	—better pressure retention —higher pressure and temperature limits	B	100	2	200	Sandia to make proposal.
12	Single-well tracer method:					
	—results in stratified reservoirs —sensitivity of derived value of S_{or} to various parameters —errors in S_{or} caused by difference between the compositions of trapped oil (behind the flood front) and produced oil—effect on distribution coefficient of tracer	A				Work by Deans in progress.
	—test of method in fractured wells —test of 2-well tracer method	B	100	3	300	Additional work desirable.
13	Correlations for errors in S_{or} (derived from log and core studies) caused by high pressure gradients	B				Present effort by Morrow is about the right level.
14	Application of complete suite of methods for determination of ROS, in TOR projects that have DOE support	A	300	3	900	
15	Determination of oil saturation in the parts of a water-flooded reservoir that contain mobile oil	A	25 (250)	1 (3)	25 (750)	Study the merits of any novel proposal. (Proceed if feasible method is proposed.)
16	Rate of advance of TOR front	A	(500)	(3)	(1500)	(Amounts listed are recommended if feasible new method is proposed.)
17	Survey of Russian literature on ROS determination	C	25	1	25	Make survey of availability of Russian publications on oil production and oil recovery.
18	Seminar on ROS determination	A	25	1	25	Sponsor 1½-day seminar for 50-100 ROS experts.

RESIDUAL OIL SATURATION TECHNOLOGY TEST IN A CONSOLIDATED SANDSTONE RESERVOIR

Bell Creek Field, Powder River County, Montana

by

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ABSTRACT

Gary Energy Corporation is conducting a field test of the technology available to measure residual oil saturation, both following waterflood secondary recovery and following tertiary recovery processes. The test is being conducted in a new well drilled solely for that purpose, located immediately northwest of the Bell Creek Micellar Polymer Pilot. The area where the test is being conducted was originally drilled during 1968, produced by primary until late 1970, and was under line drive waterflood secondary recovery until early 1976, when the area was shut in at waterflood depletion.

As the test is ongoing, this paper presents only the results of testing through waterflood residual oil saturation determination. The engineering techniques used to determine the magnitude and distribution of the remaining oil saturation were both Pressure and Side Wall Cores, Conventional Well Logs (Dual Laterlog-Micro Spherically Focused Log, Dual Induction Log-Spherically Focused Log, Borehole Compensated Sonic Log, Formation Compensated Density-Compensated Neutron Log, Carbon-Oxygen Log) Dielectric Logs, the Nuclear Magnetic Log, Thermal Decay Time Logs, and a Partitioning Tracer Test.

Following completion of testing following tertiary micellar-polymer process minitest, a detailed engineering and economic analysis of the various residual oil saturation determination methods will be undertaken to ascertain the most effective combination of technology for determining residual oil saturation in a consolidated sandstone reservoir.

Prepared for DOE under Contract No. DE-AC03-78ET12366

INTRODUCTION

Gary Energy Corporation is conducting for the U. S. Department of Energy a residual oil saturation technology evaluation to demonstrate the capabilities of different techniques to measure residual oil saturation, in situ, in a semi-consolidated sandstone reservoir as the basis for selection of appropriate methods for determining oil saturation at tertiary recovery test sites. The test site is located in C SE ¼ Sec 1, T8S, R54E, immediately north of the Bell Creek Micellar-Polymer Oil Recovery Demonstration Project being conducted jointly by the Bell Creek Working Interest Owners and the U. S. Department of Energy, Contract No. DE-AC03-78QQ0182.

During the first year of the contract, September 1978 through August 1979, the test well, designated Residual Oil Saturation Well No. 1, was drilled to the casing point in the Muddy Silt at 4630 ft. KB, approximately 18 ft. above the top of the Muddy Sandstone pay. The well was logged to the surface with the Bore Hole Sonic-Gamma Ray tool and the 10 3/4" diameter casing was run to total depth and cemented. The well was then unsuccessfully pressure-cored from 4648 ft. to 4660 ft. However, sidewall core coverage was obtained through the zone of interest. Following reaming to 7" diameter, the open hole log suite, consisting of the following logs were obtained: the Dual Laterolog-Microspherically Focused Log, Dual Induction-Spherically Focused Log, Formation Compensated Density-Compensated Neutron with Gamma Ray Log, Nuclear Magnetic Resonance Log, Electromagnetic Propagation Log, the Carbon-Oxygen Log and the Dielectric Constant Log. Following completion of open hole logging, the hole was reamed to 9½" diameter and an 8 5/8" O.D. fiberglass liner was cemented in place from total depth to the tie back to the production casing at 4550 ft. KB. Four abrasijet holes per foot were then cut in the fiberglass liner over the zone of interest. Then the Formation Compensated Density-Compensated Neutron Log was obtained to determine if near well porosities were altered during installation of the liner and/or during perforation. Following installation of the fiberglass liner, the Carbon Oxygen Log, Spectralog and Thermal Decay Time Logs were run to determine waterflood residual oil saturation. To complete the waterflood residual oil saturation measurements, a Partitioning Tracer Test in conjunction with a drift test is being undertaken. A detailed description of the testing, and preliminary analysis of the data obtained, are presented herein.

DISCUSSION

Site Selection

Figure No. 1 shows the location of the Residual Oil Saturation Technology Test in C SE ¼, Sec 1, T8S, R54E, Powder River County, Montana, immediately to the north of the Bell Creek Micellar-Polymer Oil Recovery Demonstration Project. This location was selected due to the similarity of the formation in this area to the pilot area, but outside the immediate pilot boundaries so that operating in the Residual Oil Saturation Technology Test would not impinge upon operations in the pilot area, yet the injection facilities at the pilot could be used for mixing and blending of chemicals for the tertiary minitest portion of the residual oil saturation determinations, and a comparison made with the full pilot.

Drilling to the Casing Point

During late October 1978, the Residual Oil Saturation Technology Test, designated SOR Well No. 1, was drilled to the casing point in the Muddy Silt at 4632 ft. KB, approximately 16 ft. above the top of the Muddy Sandstone pay. A 20" hole was drilled to 325 ft. and 16", 65 lb/ft. H-40 casing was set at 304 ft. KB and cemented back to surface with 300 sks of 50/50 Pozmix A cement and 100 sks of Class G Regular cement. A 14 3/4" hole was then drilled to 4632' KB. The hole was then logged from 4632 ft. KB to 304 ft. KB with the Borehole Compensated Sonic-Gamma Ray tool for correlation purposes. A 10 3/4", 40.5 lb/ft. to 51.0 lb/ft. long string was then run to 4630 ft. KB and cemented with 275 sks of 50/50 Pozmix A cement As it had been decided to pressure core with a service unit following setting the long string, the drilling rig was released at 2:00 a.m. October 28, 1978. Figure No. 2 illustrates the well completion at SOR Well No. 1.

Coring Operations

Service Unit

Due to an extremely tight situation obtaining service units in the Rocky Mountain area, a service unit capable of drilling to the coring point, cutting the pressure core and drilling to total depth of 4705 ft. KB was not obtained until early December 1978. By this time winter weather had

arrived in southeastern Montana with snow and ambient temperatures including chill factors down to -88°F. The service unit selected for pressure coring was a Cooper Model 4210 rated to 12,000 ft.with 2 7/8" EUE tubing and having a draw works capacity of 250,000 lbs., a 12 ft. substructure and equipped with a power swivel.

Drilling Fluid System

The drilling fluid system selected for pressure coring was a low spurt loss (2-3 cc), low API fluid loss (5-6 cc), fresh water mud. The properties of the drilling fluid system throughout pressure coring operations are presented on Table No. 1. As the reservoir pressure in the pilot area was estimated to be approximately 1550 psi prior to pressure coring operations and the hydrostatic pressure of the mud column was estimated to be 2220 psi, it was deemed necessary to try and minimize the overbalance by nitrifying the drilling fluid. Nitrification during pressure coring operations decreased the mud column hydrostatic head by slightly more than 200 psi. Pressure coring operations were then undertaken with an operating overbalance of approximately 400 psi. To insure that the drilling fluid properties were held consistent throughout the pressure coring operations, the mud system was equipped with a two-tier shale shaker with 200 mesh screens, a desilter, and a gas buster for removal of nitrogen from the mud returns.

Pressure Core

Preparation for actual pressure coring was completed by December 9, 1978 with the drilling of 8 ft. of 9½" hole below the casing shoe (4630' KB to 4638' KB) and 3 ft. of 6½" pilot hole (4638' KB to 4641' KB) for the bit on the pressure core barrel. At this time the coring mud was mixed and the hole was displaced with approximately 450 bbls of low spurt loss, low water loss, coring mud containing 50 SCF/bbl of nitrogen to decrease the drilling fluid hydrostatic pressure and thus minimize invasion.

Actual pressure coring operations were initiated on December 12, 1978. Pressure Core Barrel No. 1, a dummy run in the Muddy Silt, was conducted to check systems and procedures prior to actual pressure coring in the Muddy Sand. The circulating rate was 94 gpm, nitrogen feed rate 50 SCF/bbl, bit weight 10,000 lbs, and rotating speed 60 RPM during the dummy run. Five feet of silt and shale

were recovered between 4641 ft. KB and 4646 ft. KB. A check on the bottom hole pressure following nitrification with 50 SCF nitrogen per bbl mud just prior to the dummy run indicated that nitrification reduced the bottom hole pressure from 2220 psi to 2015 psi. Pit gain indicated the bottom hole pressure to be reduced from 2220 psi to 2000 psi. Thus nitrification did assist in minimizing the pressure differential during pressure coring operations.

Pressure Core Barrel No. 2, the first coring run in the Muddy Sand was conducted on December 13, 1978 at a circulating rate of 94 gpm, nitrogen feed rate of 88 SCF/bbl, bit weight of 10,000 lbs. and rotating speed of 60 RPM. After 2 hours coring was terminated and the pressure core barrel surfaced. Recovery was approximately 1.3 ft. of black shale and small sand stringers from 4646 ft. KB to 4648 ft. KB. Pressure Core Barrel No. 2 was recovered with approximately 1800 psi intact at the surface.

Pressure Core Barrel No. 3, the second coring run in the Muddy Sand was conducted on December 14, 1978 at a circulating rate of 102 gpm, nitrogen feed rate of 82 SCF/bbl, bit weight of 10,000 lbs. and rotating speed of 60 RPM. After having been on bottom in excess of 7 hours, the pressure core barrel was surfaced. Five feet of interval, between 4648 ft. KB and 4653 ft. KB was pressure cored. Approximately 3.8 ft. of pressure core was obtained with approximately 2000 psi intact at the surface.

Pressure Core Barrel No. 4, the third coring run in the Muddy Sand was initiated the evening of December 14, 1978. Circulation was established and nitrification of the mud system was underway for approximately 30 minutes before a valve seat in the mud pump washed out. The core barrel was tripped out of the hole and operations suspended until the morning of December 15, 1978 when parts for the mud pump arrived and were installed. During this period of time the pressure core barrel was completely refurbished, run back to bottom, and reached total depth by 12:00 noon, December 15, 1978. Nitrification was then attempted to 80 SCF/bbl and following several hours of circulation, the problems with the mud pump returned and nitrogen gas-locked the mud pump. Problems with the pump persisted until the early hours of December 16, 1978 when it was decided to suspend nitrification and attempt to obtain a pressue core without nitrification. During the night of December 15, 1978 and early morning of December 16, 1978, temperatures

in the area fell to -30°F with a 30 mph wind or a chill factor of -88°F. Coring with Pressure Core Barrel No. 4 resumed the morning of December 16, 1978. The bottom of the hole was tagged approximately 2 ft. high and the first 1.5 ft. drilled rapidly. The circulation rate was 70 gpm, nitrogen feed rate 0 SCF/bbl, bit weight 10,000 lbs. and rotating speed was 60 RPM at the start of the run. The pump rate held constant for approximately 30 minutes and then began to decrease. It was decided at this time to continue with coring until the pump rate decreased to the point where the pressure core barrel had to be pulled. By 7:00 p.m., December 16, 1978, the pump rate had decreased to 25 gpm and it was decided to pull the pressure core barrel. The pressure core barrel was surfaced in the early morning hours of December 17, 1978. A 7 ft. interval between 4653' KB and 4660' KB was cored and the barrel was recovered with 2200 psi intact at the surface. No core was recovered over the interval of interest between 4653 ft. KB and 4660 ft. KB. This interval was later indicated, from open hole logs and side wall cores to traverse the heart of the Muddy Sand pay. Pressure coring operations were terminated at a depth of 4660 ft. KB.

We believe that several factors resulted in the inability to recover core through the Muddy Sand pay interval. The extreme friability of the Muddy Sand in this area is indicated by the need for sand screens to maintain offset wells on production. Sand friability, in conjunction with the extremely slow drilling rate and the inability to circulate at rates sufficient to move cuttings away from the bit face, all are suspected to have contributed to the inability to recover core over the interval of interest.

Sidewall Cores

Following completion of pressure coring operations, the 6½" diameter hole was reamed to 7" diameter and the well was drilled to a total depth of 4705 ft. KB. Following completion of open hole logging operations, Sidewall Core coverage was obtained over the Muddy Sand interval at one foot intervals from 4648 ft. KB to 4664 ft. KB. Sidewall Core recovery was 100% over the desired interval. Analysis of the Sidewall Cores is presented on Table No. 2.

Open Hole Logging Operations

Conventional Open Hole Logs

Schlumberger's portion of the open hole logging sequence was initiated December 19, 1978 and completed December 20, 1978. The following sequence of logs were run from total depth of 4705 ft. KB to the base of the 10 3/4" long string at 4630 ft. KB. Dual Induction Log-Spherically Focused Log, Dual Laterolog-Microspherically Focused Log, Borehole Compensated Sonic with Gamma Ray and the Formation Compensated Desnity-Compensated Neutron Log with Gamma Ray.

Preliminary analysis indicates that the average porosity and residual oil saturation over the 10 ft. pay interval from 4653 ft. to 4662 ft., from conventional log analysis, averaged 28% and 34% respectively. Analysis of all data obtained herein is ongoing.

Electromagnetic Propagation Log

The Electromagnetic Propagation Log also was run over the interval from total depth of 4705 ft. KB to the base of the 10 3/4" long string at 4630 ft. KB.

Preliminary calculations using the porosity from the open hole log sequence indicates that residual oil saturation as measured with the Electromagnetic Propagation log was approximately 28.5%. Analysis of all data obtained herein is ongoing.

Dielectric Constant Log

Gearhart Owens Dielectric Constant Log and Sidewall Neutron Porosity logging operations, originally initiated December 20, 1978, were delayed due to power supply problems and winter blizzard conditions from December 20, 1978 until December 22, 1978. Both instruments were run December 22, 1978 from total depth at 4705 ft. KB to the base of the 10 3/4" long string at 4630 ft. KB without incident.

Preliminary calculations indicate that the average porosity from the Sidewall Neutron Porosity Log and residual oil saturation from the Dielectric Constant Log are 29.7% and 29.2% respectively. Analysis of all data obtained herein is ongoing.

Nuclear Magnetic Resonance Log

Research personnel from Schlumberger's Houston, Texas Research Center assisted local Schlumberger personnel in field operation of the Nuclear Magnetic Resonance Log. While making up the coring mud, 1.75 lbs. per barrel of Na_2 EDTA and 1.00 lbs. per barrel of $MnSO_4 \cdot H_2O$ was added to the drilling fluid system to form MnEDTA (magnanous versene). The manganous versene invades the formation dissolved in the mud filtrate and supresses the formation water signal observed by the NMR tool. While conditioning the hole for logging operations, the drilling fluid was treated with 0.1 gal. per barrel of magnetized magnetite to suppress the borehole water signal from the mud filtrate. Mud filtrate samples taken several times daily on returns during coring, reaming, and hole conditioning operations just prior to the addition of magnetite indicated mud filtrate spin lattice relaxation times of 10.4. Following the addition of magnetite and conditioning the hole for logging the spin lattice relaxation time was determined to be 8.4. Five passes with the Nuclear Magnetic Resonance Log were conducted from total depth at 4705 ft. KB to the base of the 10 3/4" long string at 4630 ft. KB, to provide a statistical basis for analysis. No preliminary data analysis was available at the publication deadline.

Carbon-Oxygen Log

The Dresser Atlas Carbon-Oxygen Log was run over the interval from total depth at 4705 ft. KB to the base of the 10 3/4" long string at 4630 ft. KB. No preliminary data analysis was available at the publication deadline.

Fiberglass Liner Installation and Well Completion

Due to the necessity to run the Nuclear Magnetic Resonance Log following tertiary chemical flood minitest, and the extreme friability of the Muddy Sandstone pay interval, it was decided to equip the Residual Oil Saturation Technology Test with a non conductive fiberglass liner. An 8 5/8" O.D., 7" I.D., 0.88 wall thickness, flush joint fiberglass liner manufactured by the Fibercast Company, Sand Springs, Oklahoma, was selected. A Texas Iron Works 10 3/4" x 8 5/8" O.D. liner hanger assembly and a Texas Iron Works 8 5/8" Type A modified set shoe were selected

to tie back the liner to the long string and for landing and cementing, respectively. Prior to actual assembly, the fiberglass liner was sandblasted to provide a rough surface to improve the bond between the liner and the cement.

Following completion of open hole logging, the hole was reamed to 9½" diameter to total depth at 4705 ft. KB. The fiberglass liner was then run to 4702 ft. KB with the liner hanger assembly at 4550 ft. KB and cemented in place with 35 sks of Class G Regular Cement containing 0.75 percent CFR2, 0.4 percent Halad 9, and 3 percent KCl. Good cement returns were experienced throughout the liner cementing operation. A Cement Bond Log undertaken several weeks after liner installation indicated an excellent cement bond over the full length of the liner.

On January 13, 1979 four holes per foot were abrasi-jetted in the fiberglass liner between 4648 ft. KB and 4660 ft. KB. The well subsequently swabbed 22 bbls of water per hour with an operating fluid level at 3500 ft. from surface. Laboratory analyses indicated that the water recovered on swab test was Muddy Sandstone formation water similar in properties to waters produced at offset wells. Figure No. 3 illustrates the fiberglass liner installation in the Residual Oil Saturation Technology Test well. Due to extreme winter weather conditions, field operations were suspended following completion operations until the weather moderated in late April, 1979.

Cased Hole Logging Operations

Carbon-Oxygen Log and Spectralog

Following moderation of weather conditions, the Dresser Atlas Carbon-Oxygen Log and the Spectralog were run April 26, 1979 from plug back depth at 4683 ft. to the base of the long string at 4630 ft. KB. Data analysis problems with the Carbon-Oxygen Log run in open hole during December, 1978 prompted running the Spectralog for clay mineralogy determination. In addition the Sidewall Cores taken December 22, 1978 were spectrographically analyzed to serve as a check against the Spectralog. No preliminary data analysis was available at the publication deadline.

Thermal Decay Tracer Logs

May 2, 1979 an injection profile was run following injection of 500 bbls of fresh Madison floodwater to determine the injection profile in the Residual Oil Saturation Technology Test well prior to initiating log-inject-log operations for residual oil saturation determination. The injection profile indicated that fluid entry was distributed through the zone of interest between 4648 ft. KB and 4664 ft. KB, as would be expected from the permeability profile developed from analysis of the Sidewall Cores.

On May 8, 1979, Gearhart Owens' 40 Arm Caliper was run across the Muddy Sandstone interval to determine the exact location of the abrasijet holes in the fiberglass liner. The zone indicated to be open from the 40 Arm Caliper was between 4646 ft. and 4660 ft.

On May 12, 1979, following injection of 1195 bbls fresh water, the Schlumberger TDT-K log was run across the Muddy Sandstone interval from 4648 ft. KB to 4664 ft. KB. Five passes were made with the TDT-K tool to obtain statistically accurate information. The TDT-L tool was then run from 4648 ft. KB to 4664 ft. KB with stations obtained at one foot intervals throughout the zone of interest. Following resolution of electrical problems with the TDT-L tools and panels, logging with the TDT-L tools was completed on May 16, 1979. Total fluid injected during the fresh water phase was 1345 bbls to the end of logging operations. A one gallon sample of the 1050 ppm TDS Madison injection water was taken by Schlumberger for measurement of the fresh water phase capture cross section.

On May 20, 1979 following injection of 450 bbls of 130,000 ppm TDS salt water, the Schlumberger TDT-K log was run across the Muddy Sandstone interval from 4648 ft. KB to 4664 ft. KB. Five passes were made with the TDT-K tool to obtain statistically accurate information. The TDT-L tool was run from 4648 ft. KB to 4664 ft. KB with stations obtained at one foot intervals throughout the zone of interest. A one gallon sample of the 130,000 ppm TDS salt water was taken by Schlumberger for measurement of the brine phase capture cross section. Total fluid injected during the brine phase was 650 bbls to the end of logging operations.

All fluid injection during both phases was undertaken at injection rates below 140 bbl per day to insure that no stripping of residual oil occurred. Preliminary analysis indicates that the average residual oil saturation over the 10 ft. pay interval from 4653 ft. to 4662 ft. is 30%. Analysis of all data obtained herein is ongoing.

Partitioning Tracer Test

During June 1979 two separate drift tests were undertaken at the Residual Oil Saturation Technology Test using methyl alcohol and ethyl alcohol as tracers. In addition, bottom hole pressures were taken on the offset wells during operation of the chemically determined drift test. Both the chemical tracers and the bottom hole pressure surveys indicated drift rates of much less than 1 ft. per day in the drainage area of the Residual Oil Saturation Technology Test well. At the deadline for submission of the published text, the Partitioning Tracer Test was underway.

ACKNOWLEDGEMENT

The author wishes to acknowledge the efforts and skills of Dr. Arnold Goldburg, Manager of Enhanced Recovery; Mr. Fred A. Haddenhorst, Vice President of Production; Mr. Bill Spires, Bell Creek Field Superintendent, Mr. Dan Krause and Mr. Bill Belden, Bell Creek Field Engineers, and the Bell Creek Field Staff for their dedication to the completion of this project. The author also wishes to acknowledge the assistance of Mr. Chuck Neuman of Chevron Oilfield Research in the measurement of drilling fluid properties as they relate to the Nuclear Magnetic Resonance Log.

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TABLE NO. 1

Drilling Fluid System Properties During Pressure Coring Operations

Date	Weight	Viscosity	Plastic Viscosity	Yield Point	Water Loss	Spurt Loss	Mud Filtrate Spin Lattice Relaxation Time	Operation
12/12/78	9.4ppg	46 sec	21	6	8.6	3.0	11.1	Coring
12/13/78	9.5ppg	47 sec	26	3	6.8	1.8	NA	Coring
12/14/78	9.5ppg	47 sec	26	4	6.6	2.6	10.0	Coring
12/15/78	9.5ppg	60 sec	32	8	6.4	2.7	10.2	Coring
12/16/78	9.5ppg	60 sec	32	8	6.0	2.5	10.2	Coring
12/17/78	9.5ppg	65 sec	32	15	6.0	2.5	NA	Drilling
12/18/78	9.5ppg	83 sec	68	29	6.4	NA	10.8	Drilling
12/19/78	9.5ppg	83 sec	68	29	6.4	NA	8.4*	Logging

*NOTE: Spin Lattice Relaxation Time taken December 19, 1978 was obtained after magnetite was added to the drilling fluid.

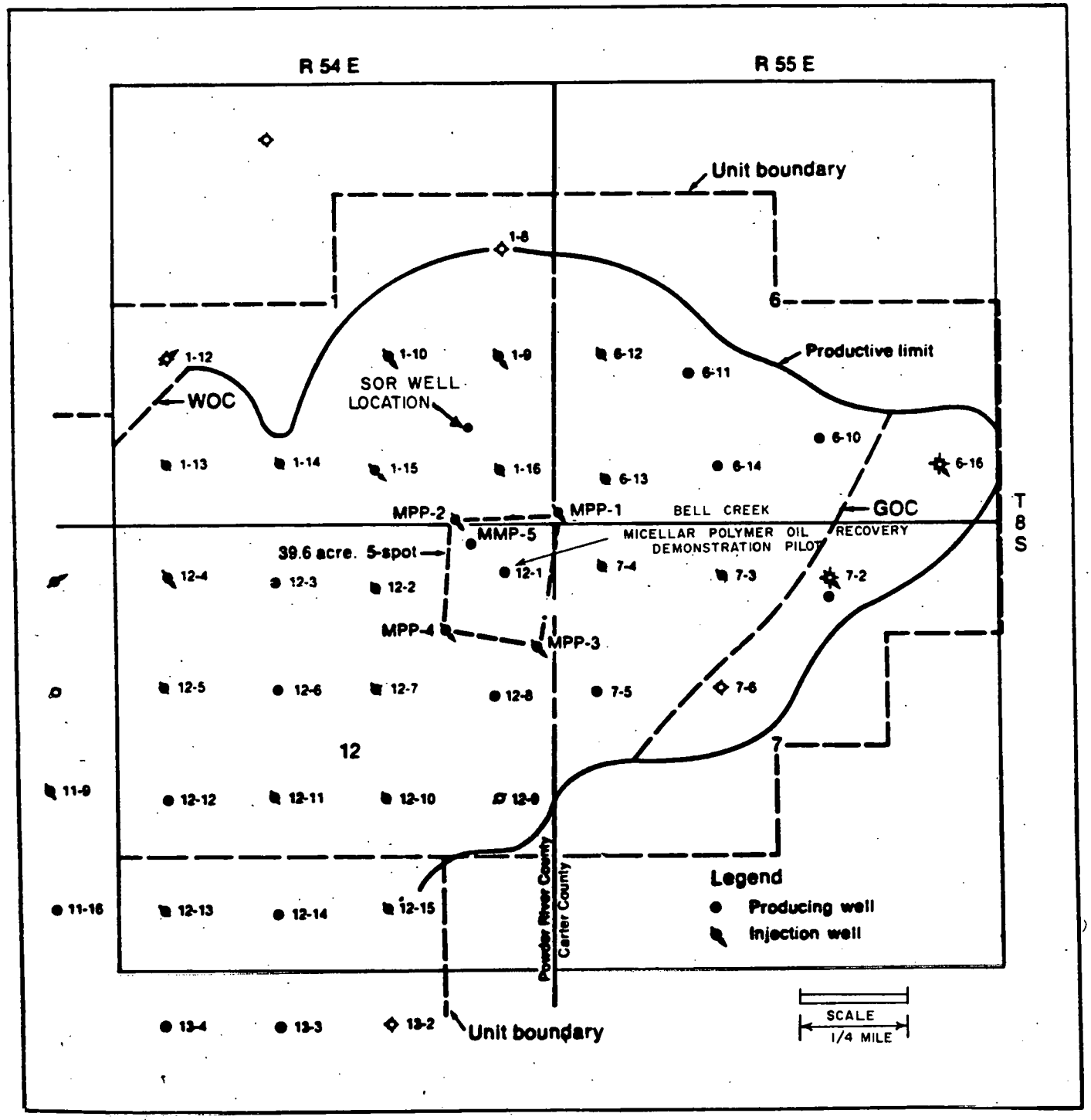
TABLE NO. 2

Sidewall Core Analysis

Depth	Porosity %	Permeability md	Water Saturation %	Oil Saturation %
4352	Shale	Shale	---	---
4653	Altered Core	Altered Core	---	---
4654	28.6	46	56	11
4655	30.4	110	53	14
4656	32.2	800	68	4
4657	22.0	34	60	6
4658	29.4	270	50	19
4659	26.8	240	61	10
4660	27.3	250	63	12
4661	30.9	234	56	14
4662	Shale	Shale	---	---
4663	31.6	735	52	21
4664	Shale	Shale	---	---

FIGURE 1

RESIDUAL OIL SATURATION EVALUATION AREA



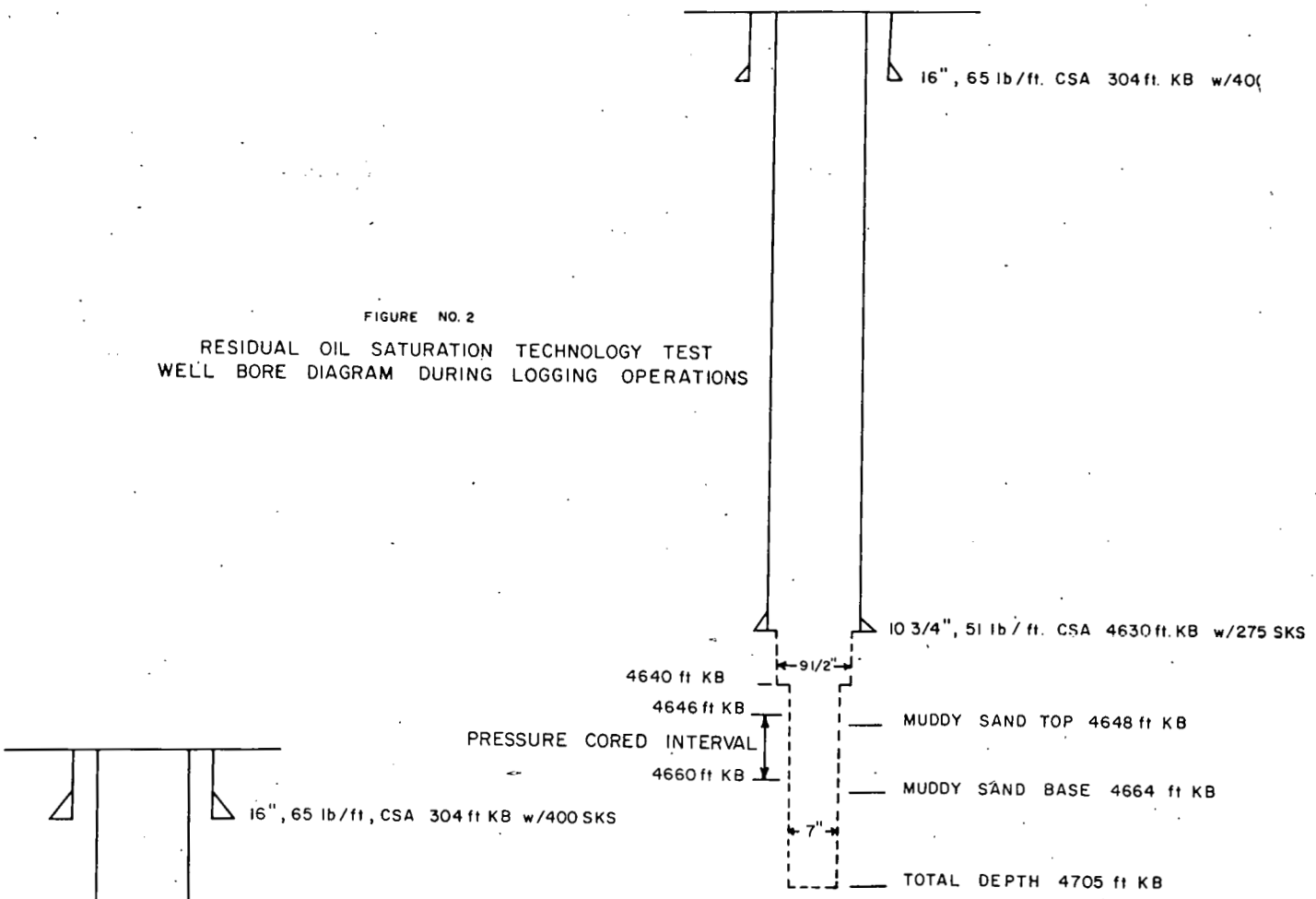


FIGURE NO. 2

RESIDUAL OIL SATURATION TECHNOLOGY TEST
WELL BORE DIAGRAM DURING LOGGING OPERATIONS

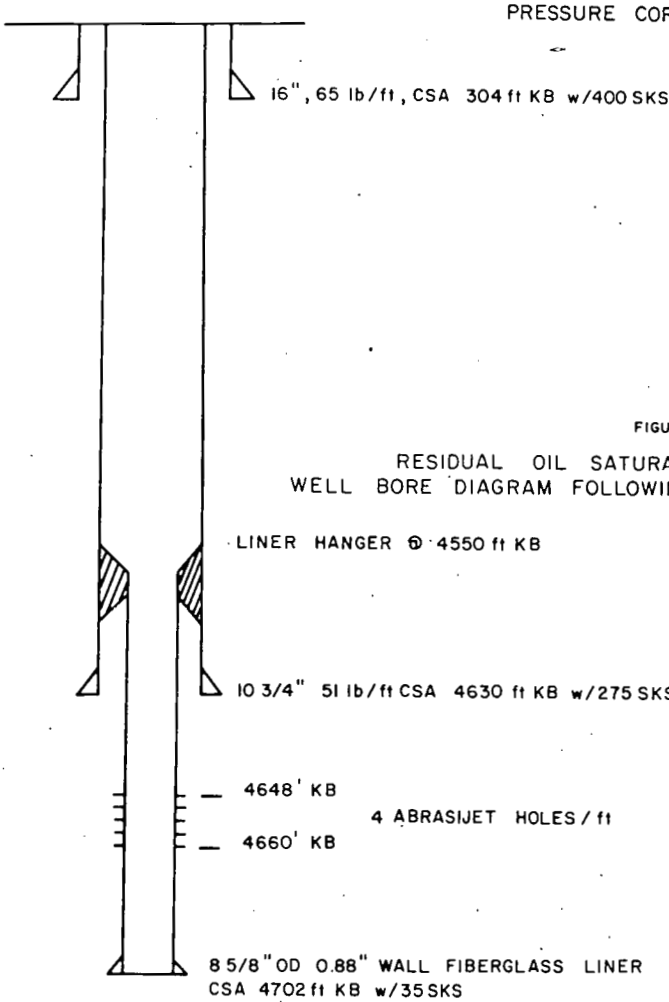


FIGURE NO. 3

RESIDUAL OIL SATURATION TECHNOLOGY TEST
WELL BORE DIAGRAM FOLLOWING FIBERGLASS LINER INSTALLATION

RESIDUAL OIL SATURATION DETERMINATION
WILMINGTON MICELLAR-POLYMER PROJECT
OCTOBER 1978-MAY 1979

BY

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ABSTRACT

The City of Long Beach, under contract with the U.S. Department of Energy, is conducting a program to obtain residual oil saturation (ROS) data in the HXa Sand, Fault Block VB, Wilmington Field, in which a micellar-polymer demonstration project is being implemented. This program utilizes many complementary techniques for determining the ROS in a watered-out unconsolidated sand, typical of many reservoirs in the California Coastal Province. This program will be performed in two stages. The first, Phase 1, is intended to determine the ROS in an area which has been flooded out during the course of a peripheral waterflood. The second stage, Phase 2 of the ROS program, is intended to measure the ROS after tertiary recovery by a micellar-polymer flood. This paper describes the diagnostic tools and techniques which have been used to establish ROS. It then presents a comparative analysis of the results obtained using the different techniques.

The methods used to obtain the excellent core recovery in this highly unconsolidated sand are described. The problems of handling and performing core analyses on these sands are detailed, along with recommendations for special handling techniques.

The values of residual oil saturation and other pertinent reservoir parameters determined by each technique are summarized. The advantages and limitations of each method relating to the results obtained are discussed.

Present oil saturation and oil content of the HXa sand in the Pilot Area is now believed to be better defined. This conclusion is supported by the agreement obtained for electrical log analysis, core analysis, and a Single-Well Tracer Survey.

PREPARED FOR THE DEPARTMENT OF ENERGY UNDER
CONTRACT NO. EF-77-C-03-1395-M001

PURPOSE

This ROS study is intended to improve the certainty of in situ values for porosity and oil saturation of the HXa sand in the Micellar-Polymer Demonstration Project (Map 1), Wilmington Field, Los Angeles County, California. Phase 1 of the study concerns the ROS after waterflooding and at the start of the Micellar-Polymer Project. Phase 2 is to be performed at the conclusion of the project to determine the residual oil after tertiary recovery.

SCOPE OF STUDY

Phase 1 includes data obtained from a special coring and core analysis program, open-hole and cased-hole electrical logs, and a Single-Well Tracer Test. The opportunity to obtain this information occurred when producer T-103 was redrilled in October 1978. Availability of these additional reservoir measurements was made possible by the U. S. Department of Energy (DOE) and provided for by Contract No. EF-77-C-03-1395-M001 of October 20, 1978 between DOE and the City of Long Beach. This report, "Residual Oil Saturation Determination For Wilmington Micellar-Polymer Project," together with core analyses from three of the other wells and open-hole electrical-log suites from five other project wells, provides the data available for estimating in situ porosity and ROS after waterflooding and at the start of the tertiary recovery project. Evaluation and/or comparison of core handling and core analysis methods is included, together with results of different electrical logs. This paper presents a summary for the first phase of this project. The forthcoming final report for Phase 1 will include a comprehensive presentation and analyses of all data obtained.

BACKGROUND INFORMATION

Prior to 1965, the accepted porosity values for the unconsolidated sands in the upper three zones (depth 2000 to 3500 feet) in the Wilmington Field were 34 to 36 percent. These values were based upon core analyses run with little to no compaction pressure. In the early drilling of the Long Beach Unit (1965 to 1966) the practice of running core analysis porosity tests with a sleeve compaction pressure of 350 psi was adopted. This pressure was chosen because it resulted in a less scattering of data points than with a sleeve pressure of 250 psi. Additional values were determined on a number of samples under a triaxial confining pressure to 1500 psi. The resulting porosity and permeability values were less than obtained with the 350-psi sleeve pressure.

In 1972, a few redrill wells in Old Wilmington were logged using the Compensated Density and Compensated Neutron logs in addition to the Dual Induction, Spontaneous Potential, Gamma Ray, and Caliper Logs. These data were computer processed by Schlumberger, using its Saraband program. The porosity values (based principally on cross-plot of the neutron and density porosity) were considerably less than 30 percent. Subsequently, old electrical logs available from aquifer water-injection wells were reviewed and porosity calculated for sands having 100-percent water saturation, using the Archie method[1]. This calculation resulted in values averaging less than 30 percent. For the HXa sand in Upper Terminal VB, the average indicated porosity was 29 percent for eight wells. Because one of the prime needs of this Micellar-Polymer Demonstration Project was (and is) to determine the current in situ values of porosity and oil saturation[2], a concerted logging and coring program has been applied.

In about 1958, Norris Johnston[3] developed a uniaxial pressure core holder and advocated the running of porosity, permeability, capillary pressure, and relative permeability tests of core samples under elevated pressures to simulate overburden load. However, such practice was not accepted by the industry. Engineers to whom such data were submitted refused to believe the lower values for permeability and for porosity.

Since 1962, a number of papers have appeared in the literature, indicating that conventional core analysis porosity values are too high and have resulted in an overestimation of oil in place[4,5,6,7,8,9,10,11 and 12].

RESERVOIR DATA

Four of the 10 wells in the Micellar-Polymer Project were cored. Special electrical logs were run in eight of the wells.

CORE DATA

The HXa sand has been cored in four wells, using a plastic-sleeve core barrel. Cores were cut into 3-foot lengths on the rig floor, quick-frozen, and then transferred to the laboratory for analysis or stored in a deep-freeze locker for later use. Following is summary of cores obtained:

		Diam. 1/	Gross Ft HX_a Sand			
Well	Date	Inches	Cored	Recovered	%	Analyzed by
FT-1	7/77	5	55	36	65	2/ & 3/
T-102	3/78	5	50	9	18	3/ & 4/
T-104	4/78	5	48	34.3	71	Stored; 2/
T-103-Rd	10/78	3.2	55	52	95	5/

1/ I.D. of plastic tube. I.D. of core head 4-3/4". Core expands to fill tube.

2/ Petroleum Testing Service, Inc., Santa Fe Springs, California.

3/ Marathon Oil Company's Denver Research Center.

4/ Core Laboratories, Inc., Long Beach Laboratory.

5/ Core Laboratories, Inc., Oklahoma City Laboratory.

The purpose of freezing the core material on the rig floor in the plastic sleeve and maintaining the core in a frozen state until it was analyzed was to minimize rearrangement of sand grains. While this procedure should minimize movement, it does not prevent movement. The fact that the formation cut with a 4-3/4-inch I.D. head expanded to fill a 5-inch I.D. tube illustrates that there was movement.

ELECTRICAL LOGS

Following is summary of logging programs including the redrill of T-103:

Well	Month	Year	Special Logs	Computer Analysis	Logging Company
Surface Redrills					
FT-1	July	1977	Yes	Saraband	Schlumberger
FT-3	Jan.	1978	Yes	Saraband	Schlumberger
T-101	Feb.	1978	Yes	Saraband	Schlumberger
T-102	March	1978	Yes	Saraband	Schlumberger
T-104	April	1978	Yes	Saraband	Schlumberger
Mill-Out Completions					
FT-2	Dec.	1977	Yes	Epilog	Dresser Atlas
FT-4	Feb.	1978	No		Schlumberger
T-100	Jan.	1978	No		Dresser Atlas
T-103	Mar.	1978	Yes	Epilog	Dresser Atlas
T-105	Apr.	1978	Yes		Dresser Atlas
Special for ROS Project					
T-103-Rd	Oct./Nov.	1978	Yes	Various	Schlumberger
				Epilog	Dresser Atlas
					GO International

Well T-103-Rd

The following logs were run in T-103-Rd:

Open-Hole Logs

(a) Micro-Spherical Focused Log (MSFL)
(b) Dual-Induction Laterolog (DIL-LLB)
(c) Bore-Hole Compensated Sonic w/Gamma Ray (BHC-GR)
(d) Formation Density-Compensated Neutron-Gamma Ray (FDC-CNL-GR)
(e) Microlaterolog (MLL)
(f) Dielectric Constant Log (DCL)

The Electro-Magnetic Propagation Tool (EPT) had been scheduled, but no tool was available.

Cased-Hole Logs

(a) Dual-Spacing Thermal Neutron Decay Time Log (TDT)
(b) Dual-Detector Neutron Lifetime Log (NLL)
(c) Carbon-Oxygen Log (C/O)

RESULTS FROM CORE ANALYSES

SUMMARY DATA

Average core analysis data by well is given in Table 1. For each well, results are presented in two general groupings, (1) data from routine core analysis, and (2) porosity and permeability values at different triaxial confining pressures. After the test results from T-103-Rd were studied, it was necessary to segregate porosity values depending on whether they resulted from a wet or a dry measurement. Early in the micellar-polymer project, a significant difference in porosity values for samples compacted dry versus samples compacted wet was apparent. Marathon's early work, using old core material which had been cleaned and dried, showed that a dry sand pack did not compact nearly as much at 1400 psi as when the pack was wet. However, for porosity values determined at low pressure, consideration was not given to there being a significant difference between helium porosity values determined on a dry sample compared with a liquid-filled sample. The fact that there is a difference, at least for the HXa sand, was not recognized until test results from T-103-Rd became available.

Figure 1-A is included to illustrate the difference in porosity values between wet and dry determinations. The average values for each of the four data sets from three wells show that the helium porosity value ranges from 0.93 to 0.97 of the liquid value, with an overall average of 0.95. Because data for wells FT-1 and T-104 are similar to T-103-Rd data, the difference is not the result of different laboratories or the capability of technicians. It is postulated that the difference is caused by clays in the matrix of the sand. Generally, in the case of consolidated sandstones, a liquid porosity value will be equal to or less than a helium porosity value.

Figure 1-B is used to show the effect that this porosity difference has on the calculated total liquid saturation of the cores from conventional analyses. The total liquid-saturation value under routine core analysis for FT-1 was 88 percent in samples analyzed in July 1977 and 82 percent for samples analyzed in September 1977. Then the average was 74 percent for samples analyzed during several months by Marathon Oil Company. At first this reduction in value for total saturation was attributed to loss of liquid from the frozen core samples with time. Then it was recognized that the principal difference between 88- and 82-percent total liquid saturation was accounted for by the difference in dry and wet porosity values. The higher dry-porosity value of 42 percent for the 57 disk samples (Table 1) was relatable to the zero psi compaction pressure, while the 39.6-percent value (dry) was for samples which had been subjected to a 200-psi sleeve pressure.

Core From Well T-103-Rd

A series of special tests were run on the cores from Well T-103-Rd. Cores were shipped to Core Laboratories, Inc. in Oklahoma City for analysis because that laboratory had special equipment not available in CLI's Long Beach laboratory. The frozen core was slabbed and then photographed, using both natural and ultraviolet light. The slabbed section was mounted in plaster of paris and returned to the Department of Oil Properties in Long Beach for detailed geological description.

Two sets of samples (A and B) were taken from each foot of core. Starting at the bottom, each of the first 10 were drilled from the frozen core, using liquid nitrogen. Because the plugs were removed from the core bit with difficulty, all subsequent

samples were taken using a cork borer after permitting the core to partially thaw. A third set of eight C samples was taken for dry compaction tests, a fourth set of D samples was taken for wet compaction tests, and a fifth set of eight E samples was taken for waterflood susceptibility tests run under a confining pressure of 1600 psi. The C, D, and E samples were taken from the same foot of core as the corresponding numeric prefixes for the A and B samples. The core contained approximately 1 foot of calcareous oil sand at a depth of 2939 to 2940 (Sample 32). Initially C, D, and E samples were taken from this foot. Subsequently, replacements for Sample 32 were secured for the C and D sample sets so that each set of eight would be more representative of the total sand section.

The A set of samples was for conventional analyses, together with permeability and porosity values under confining pressure of 1600 psi with samples compacted dry.

The B samples were to be used for determining porosity at 1600-psi confining pressure for wet compaction. The fresh core plugs were subjected to 1600 psi in the triaxial pressure cell, and volume of liquid expelled from each sample was measured and recorded. However, the procedure did not include testing for the presence of residual gas space in the sample before the sample was removed from the pressure cell. These B samples were removed from triaxial holder, vapor extracted, and dried in a non-humidity oven. Grain volume was measured next, using helium. Samples were then evacuated and saturated with brine which was then subjected to 1000 psi pressure overnight to ensure complete liquid saturation.

Summation of Permeability and Porosity Data - All Wells

Summation of all permeability and porosity data for the four cored wells at the different confining pressures are presented in Table 2. Average values by well for each pressure and number of samples are given. The porosity data are segregated between samples compacted dry and samples compacted wet. Data for the disk samples from FT-1 and T-102, analyzed by Marathon, are included.

Values averaged by well are shown in Figures 2-A and 2-B. The average permeability of 731 millidarcies at 350 psi decreased to 366 millidarcies at 2000 psi. The latter compares with values of 1000 to 1500 millidarcies for data used prior to 1960. The average porosity values at 350 psi are 36.5 and 34.7 percent for samples compacted dry and those compacted wet, respectively. These values are close to the range of accepted values prior to 1960. Under confining pressure of 1600 psi, the 39 samples compacted dry have an average porosity of 32.8 percent, whereas the average for the 21 samples compacted wet is 30.7 percent. The 73 disk samples at 1400 psi averaged 29.5 percent, or 1.2 porosity percent less than for the plug samples at 1600 psi. This difference could indicate more compaction in the disk and might be attributable to the flow of liquids through the samples, providing movement of fine particles into larger pores and, thus, tighter packing. The eight samples compacted wet with a confining pressure of 2000 psi had an average porosity of 29.2 percent compared to 31.7 percent for 39 samples compacted dry.

Core Analysis by Marathon Oil Company
Wells FT-1 and T-102

A summary of porosity and core saturation data is included in Table 1. These data were obtained during the displacement tests required for design of the micellar-polymer system. Each sample consisted of a disk 2-inches thick sawed from the frozen core. After a 1/8-inch hole had been drilled through the center of the disk, the sample

was inserted into a high-pressure core holder. A pressure of 1400 psi was then applied and maintained on the top surface. All flow tests were from the center hole to the periphery. Values shown include porosity and oil and water saturation of the frozen core, together with porosity of the compacted samples.

The 1400-psi loading pressure was specified as approximating the initial net overburden load at the top of the HXa sand. In choosing this pressure, no allowance was made for additional load caused by maximum reservoir-pressure depletion of 670 psi (1953). The maximum net-overburden load in 1953 could have been as much as 2100 psi on the HXa sand. However, if only 65 percent of the additional load was effective on the HXa, the net overburden load would have approximated 1850 psi.

The average porosity values of 30 percent for FT-1 and 29 percent for T-102 each need to be adjusted to a loading pressure of at least 1850 psi and possibly 2100 psi. First, though, there is another indeterminate factor in these values caused by the clay content of this sand. In the determination of final oil and water content, each sample was subjected to a temperature of 220 to 230°F for 36 hours while in the Dean Stark extraction unit. Following this, samples were dried in a high-vacuum oven. Temperature was only 30°C but it is not known whether or not the vacuum might have pulled off more water from the clays.

J. M. Hartshorne of Marathon Oil Company, who had done the mineralogical work on several samples of HXa sand, reports minimum clay content of 7 percent and possibly 12 to 15 percent. This means that as much as 6 cc's of water could have been given up by the minimum clay content in the extraction process, and that up to 12 cc's could have been lost with 15 percent clay[13]. Such a loss of clay water for FT-1 would mean that the porosity available for hydrocarbons and interstitial water was between 29.2 and 28.3 percent at 1400-psi confining pressure rather than 30 percent. Clay analyses are to be obtained on another group of sand samples from the core for T-103-Rd. This might help resolve the magnitude of the problem. All of the electrical log analyses indicate the presence of a substantial amount of bound clay water.

Probable Core Porosity and Oil Saturation Under Overburden Load at Maximum Pressure Depletion

As noted previously, minimum overburden load should have approximated 1850 psi and the maximum could have been as much as 2100 psi. Core porosity values for samples compacted wet at 1400 psi are available for two wells (FT-1 and T-102), at 1600 psi for two wells (T-104 and T-103-Rd), and at 2000 psi for one well (T-103-Rd). The porosity compressibility factor going from 1600 psi to 2000 psi for T-103-Rd is calculated as follows:

$$C_f = \frac{1 - 30.5/29.2}{2000 - 1600} = -111 \times 10^{-6} \text{ per psi}$$

Using this compressibility, the applicable porosity correction factors are as follows:

1400 to 1850 psi = 0.950
1400 to 2100 psi = 0.922
1600 to 1850 psi = 0.972
1600 to 2100 psi = 0.944

From these factors, the porosity values are adjusted to the higher overburden pressures as listed:

Well	Porosity (Percent) 1400 psi	1600 psi	1850 psi	2100 psi
FT-1	30		28.5	27.7
T-102	29		27.6	26.7
T-103-Rd		30.6	29.7	28.9
T-104		30.8	29.9	29.1
Average			28.9	28.1

When the above porosity values are applied to the reported core oil saturation, the equivalent reservoir oil saturation is as follows:

	Conventional Porosity Percent	Oil Sat. Percent	Reservoir Oil Saturation Percent Adjusted to Overburden Load 1850 psi	2100 psi
FT-1	39.6	21	37	38
T-102	32.1	26	35	36
T-103-Rd	39.0	21	34	35
T-104	37.7	20	29	31

The adjustments are made as follows:

$$\text{Adj. Oil Sat.} = S_{oi} \times \frac{\phi_1/\phi_2}{(1-\phi_1) \div (1-\phi_2)} \times b_o$$

where ϕ_1 = initial porosity
ϕ_2 = compacted porosity

$b_o = 1.06$

Example FT-1:

$$S_{o\ 2100} = 21 \times \frac{39.6/27.7}{(1-0.396) \div (1-0.277)} \times 1.06 = 38.1$$

Any oil lost from the core either by flushing ahead of the bit or from pressure reduction would cause the preceding reservoir numbers to be low. However, loss of oil should have been negligible because of the current stage of depletion in this sand, the expansion of the core between bottom of the hole and the surface, and the 18° API oil gravity.

RESULTS FROM ELECTRICAL LOGS

A summary of the electrical log analysis for the 10 wells in the pilot area is given in Table 3. Included are values from the Engineering Printout as well as the Customer's Listing. The average values for each well are segregated into two groups.

The first is for the six wells which were redrilled from the surface and in which open-hole logs could be run. The second group is for mill-out completions which negated the use of most open-hole logs. Initially, well T-103 was a mill-out; however, because of casing failure, the well had to be redrilled from the surface. Saraband analyses are available on all six of the surface redrills. Early in 1979, Schlumberger agreed to review and rerun the Sarabands for the purpose of a fine-tuning of the data normalization decisions and to ensure consistency in selection of the Saraband parameters. Dresser Atlas reran the Epilogs on three wells in June 1979. This applied specifically to the HXa sand.

Cased-hole logs and analyses had been run and computed for mill-out completions T-103 and T-105 by Dresser Atlas. In T-103-Rd, the Dresser Atlas (NLL and C/O) and Schlumberger's (TDT) cased-hole logs were run.

Figure 3 includes the graphical analyses for the three computed logs for well T-103-Rd. The Epilog presents oil and water saturation values based on three logging tools. These are the Neutron Lifetime Log (NLL), the Carbon/ Oxygen Log (C/O), and the Deep Induction Resistivity (Rt) obtained from open-hole log. The porosity as calculated from the Neutron log is the same for all three saturation determinations. Oil saturation is 26.1 percent for the NLL, 32.6 percent for the C/O, and 32.9 percent for the Rt. For the constant porosity of 29.0 percent, these saturation values equate to 587 and 733 barrels per acre-foot for the NLL and the C/O logs, respectively, and 740 barrels per acre-foot for the Rt.

The Saraband for T-103-Rd indicates an average porosity of 24.1 percent and an oil saturation of 39 percent for an average oil content of 729 barrels per acre-foot. The TDT cased-hole log indicates an average porosity of 23.1 percent with average oil saturation approximating 46 percent. The latter represents an oil content of 824 barrels per acre-foot. Schlumberger used its Dual Water Model to compute the TDT values.

Average values from Saraband for the six surface redrills are included in Table 3. Porosity varies from a low of 22.9 percent for T-101 to a high of 27.6 percent for T-102. The average is 25.6 percent. The oil saturation values vary from 36 percent for T-102 to 42 percent for FT-1 and FT-3. The average for the six wells is 39 percent. The calculated clay content by well varies from 11 percent to 22 percent, with an overall average of 17 percent.

Results from reprocessing the six Saraband logs and the Epilogs are compared with the former values:

	Recomputed Values, June 1979			Former Computations*		
Well	Porosity (%)	Oil Sat. (%)	B/A-Ft	Porosity (%)	Oil Sat. (%)	B/A-Ft
Saraband						
FT-1	25.6	42.0	834	27.8	35	755
FT-3	26.8	42.0	873	27.5	38	811
T-101	22.9	39.4	700	26.0	37	746
T-102	27.6	36.0	771	30.3	37	870
T-103-Rd	24.1	39.0	729	24.6	35	668
T-104	26.5	37.3	767	28.1	40	872
Average	25.6	39.3	780	27.4	37	787

Cased-Hole Logs						
T-103-Rd:						
Epilog	29.0	26.1(NLL)	587			
		32.9(Rt)	740			
		32.6(C/O)	733			
TDT	23.1	46	824			
T-103:						
Epilog	27.5	29(NLL)	619	27.0	43(NLL)	901
		33(Rt)	704		60(Rt)	1257
		39(C/O)	832		10(C/O)	209
FT-2:						
Epilog	28.8	36(NLL)	804	24.0	33(NLL)	614
		26(Rt)	581		26(Rt)	484
		32(C/O)	715		19(C/O)	354

*Reference 14

The average porosity for the six Sarabands was reduced from 27.4 to 25.6 percent, but the calculated oil saturation increased from 37 to 39 percent. This results in little change in oil content.

The NLL log for T-103-Rd gave average oil content less than that indicated by the Saraband analysis while the TDT oil content value was higher.

Values for oil content indicated by the earlier Epilogs for T-103 and FT-2 vary widely and do not agree with results for T-103-Rd. However, average porosity values are in the same range as the recomputed values for the six open-hole logs.

OIL CONTENT FROM ELECTRICAL LOGS VERSUS CORE ANALYSES

The following tabulation shows agreement in oil content between the electrical log values and core-derived values.

	Reprocessed Saraband Values			Core Analyses Values Adj to 2100 psi Overburden		
Well	Porosity (%)	Oil Sat. (%)	B/A-Ft	Porosity (%)	Oil Sat. (%)	B/A-Ft
FT-1	25.6	42.0	834	27.7	38	817
T-102	27.6	36.0	771	26.7	36	746
T-103-Rd	24.1	39.0	729	28.9	35	787
T-104	26.5	37.3	767	29.1	31	693
Average	26.0	38.6	778	28.0	35	760

The Technical Proposal dated April 1, 1976, for this Micellar-Polymer Pilot reported an estimated porosity of 28 percent for the HXa sand with an oil saturation of 36 percent and 780 barrels per acre-foot.

RESULTS FROM PARTITIONING TRACER TEST

The single-well tracer test for residual oil saturation determination--licensed by Exxon--was performed on Well T-103-Rd during February and March 1979. This work was performed by personnel from Union Oil Scientific and Technology Division and utilized their skid-mounted module for partitioning tracer testing.

Prior to testing, some concern was expressed regarding the amount of fluid drift in the HXa sand through the pilot area and the consequent effect on the test. The drift rate strongly influences the partitioning tracer test. A high drift rate would have required an ester with a high hydrolysis reaction time; e.g., propyl formate. In fact, it was considered possible that the drift rate could be high enough to negate test results.

Accordingly, a drift rate measurement test was initiated on January 29, 1979. The injection water was tagged with a methanol tracer--for the material balance--and isopropanol was injected to tag the end of the slug. After a shut-in period of about a day the well was put on production. The fluid was sampled until the concentration-production profile indicated that most of the tracer had been produced. A computer match indicated a drift rate of about 0.8 feet per day. This rate was considered acceptable and the mini-partitioning tracer test was scheduled.

The mini-test began on February 23, 1979. A 1500-barrel slug was injected at 1500 B/D. The first 375 barrels were tagged with ethyl acetate and methanol. The next 925 barrels contained only methanol. The last 200 barrels were tagged with isopropanol. The nominal tracer concentration was 5000 ppm. The actual concentration was determined by gas chromatography with a 20-minute sampling frequency. An injection profile survey was made. Subsequently, the well was shut in on February 24 for the soak period and a pressure fall-off was recorded.

After a soak period of three days, the well was placed on production at about 1500 B/D and the produced water was sampled and analyzed every 20 minutes until 2674 barrels had been produced. A production profile survey was made.

Union Research reported that "the results of the mini-test were good; however, it was noted that the reaction rate was only 1.6%/day as compared with the laboratory results of 8%/day. It was determined that one of the possible causes was the low injection water temperature of 110°F. It was decided to continue with ethyl acetate as the ester used in the Main PTT. The steps taken to help improve the reaction rate on the main test and thus obtain better results were: (a) increase the injection water temperature to 130°F; (b) shut-in the well for 7 days to give a longer reaction; (c) increase the ethyl acetate injection concentration to 6000 ppm."

The main test was initiated on March 3 after about 2000 barrels of chemical-free water had been injected. After a 2580-barrel slug of chemically tagged water was injected, the well was shut-in for a seven-day soak period, during which a pressure fall-off test was made. During the soak period an adjacent producer, Well T-100, caused a 10-psi increase in pressure in Well T-103A within one day. This upset of reservoir stability has complicated reservoir matching for the main test. Further simulation of the main test has been postponed, because the results of the mini-test are considered excellent and additional time would have been required to investigate other theories.

The conclusions of Union's Exploration and Production Research Division were that:

1. The residual oil saturation in Well T-103-Rd in the Wilmington Field is 39% ± 2%.

2. Unknown factors caused some reservoir parameters to change between the mini-partioning tracer test and the main partitioning tracer test, thus causing anomalies in the returning chemical concentration curves of the main PTT.

3. A drift rate of 0.8 ft/D was determined from the data.

4. This well would be a good candidate for a residual oil saturation after an enhanced recovery process has been used to sweep the oil from this area.

CONCLUSIONS

Several conclusions can be drawn from Phase 1 of this Residual Oil Project. While the study relates only to the Micellar-Polymer Pilot Area (HXa sand in Upper Terminal Fault Block VB), findings are applicable to other sands in the Wilmington Field. Some of the findings are pertinent to other unconsolidated oil sand reservoirs and might apply to many sandstones containing clays in their matrixes. The most important results of this study follow:

1. The estimated oil content of the HXa sand in the pilot area is close to 780 barrels per acre-foot. This estimate relates to (1) a porosity of 26 percent and oil saturation of 39 percent for Saraband logs from six wells, (2) a porosity of 28 percent and oil saturation of 35 percent derived from core analyses adjusted to 2100-psi overburden pressure for four wells, and (3) a single-well tracer test in one well which shows 39 percent oil saturation ±2 percent. This last value is independent of a porosity determination; it is applicable to whatever the in situ porosity might be.

2. Cased-hole log analysis for three wells by one set of three methods and for one well with another method do not appear to provide as consistent values for oil content as the open-hole logs.

3. These cased-hole logs may have applicability in tracking reduction in oil saturation in a tertiary project where penetrating wells are available. However, it appears that sensitivity for oil content needs to be improved.

4. Reprocessing of all six Saraband logs by one specialized analyst, having the advantage of fine-tuning the normalization of data, resulted in some change in values from well to well. However, the change in overall average oil content was negligible.

5. Alone, conventional core analyses of this unconsolidated sand with low confining pressure are of limited value. This applies to estimates of permeability, porosity, oil and water saturation, initial oil in place, and recovery efficiency.

6. Porosity and permeability of unconsolidated sands must be run under triaxial confining pressure equivalent to the net overburden load. Values for at least three different pressures are desirable. Furthermore, the samples should be compacted liquid-filled. This results in more compaction and lower porosity. No permeability data (air) were obtained for samples compacted wet.

7. Porosity compressibility between 1600 and 2000 psi for eight samples compacted wet was C_f = -111 x 10 per psi.

8. When porosity for samples compacted wet at the net overburden pressure is obtained, the conventional core-oil saturation can be converted to an in situ value. Both reduction in pore volume and in bulk volume must be accounted for.

9. Laboratory methods used for measuring porosity have significant effect on the value obtained. Helium porosity methods applied to dry samples yielded consistently lower values than the wet methods used. This difference is in reverse of that usually encountered for consolidated sand cores.

10. The clay content of the sand is postulated to be the basic cause for the higher porosity values obtained from the wet porosity methods. The degree of difference is probably affected by the method used to dry the samples. If all clay water were driven off, even the helium porosity values could be high. More laboratory work and research is needed to quantify the amount and effect of the clay minerals.

11. Excellent core recovery can be obtained from an unconsolidated sand similar to HXa using a plastic-sleeved core barrel, provided the core driller is experienced with soft formations and that core runs are six feet or less.

12. A satisfactory method for handling the core after it is removed from the barrel is to cut the plastic sleeve into 3-foot lengths, seal each end, quick-freeze on site before transporting the tubes to the laboratory. The tubes of core should be kept in a deep-freeze unit except when taking samples for analysis. Unless disk samples are required for laboratory displacement tests, core should be slabbed along one side, the slab set in toolstone, and then photographed with color and with ultraviolet light.

ACKNOWLEDGEMENTS:

The authors wish to acknowledge the assistance of the following in the preparation and analyses of the material presented in this paper:

The Department of Oil Properties, City of Long Beach, including L. W. Brock, Director, W. H. Garrison, Chief Engineer, M. E. Wright, Principal Geologist and Dennis R. Allen, Subsidence Engineer; The U.S. Department of Energy and Thomas C. Wesson, Technical Project Officer; C. E. Monson, Log Analyst and R. H. Newman, Chief Engineer of Long Beach Oil Development Company, the field contractor; Wayne R. Hause, Wayne O. Roszelle and James M. Hartshorne of Marathon Oil Company's Denver Research Center; Paul B. Mount II, Union Oil Company of California; R. M. Weinbrandt, Aminoil USA, Inc.; Ray L. Campbell and George R. Coates of Schlumberger Well Services, Houston; and J. M. Robinson, Manager of Core Analysis for Godsey-Earlougher Division of Williams Brothers Engineering Company.

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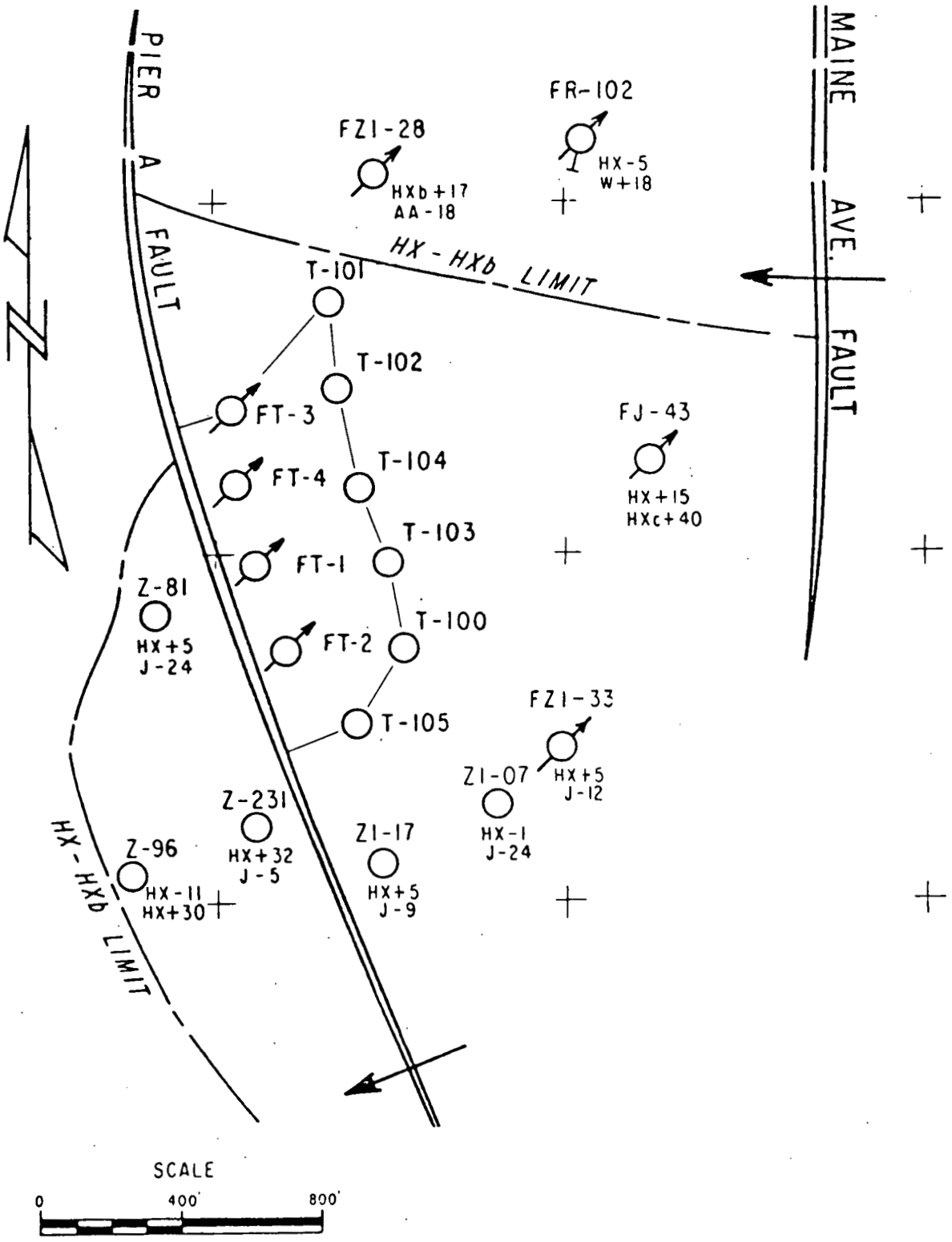
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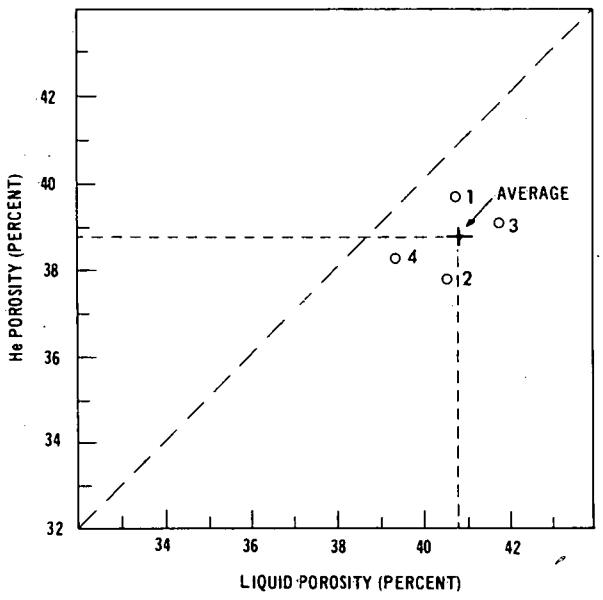
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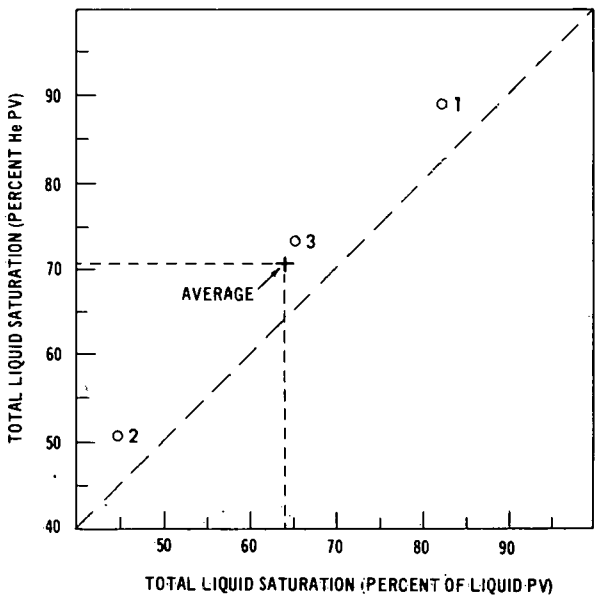


Map 1 HXa Sub Pool Upper Terminal Zone Fault Block VB
(Wilmington Oil Field)



Key	Well	No. Samples	Porosity, % Helium	Porosity, % Liquid	Ratio He/Liq.
1	FT-1	14	39.6	40.8	0.97
2	T-104	7	37.7	40.6	0.93
3	T-103 Rd	43A	39.0	41.8	0.93
4	T-103 Rd	8D	38.2	39.4	0.97
	Well Avg		38.7	40.9	0.95

Figure 1-A Effect of Porosity Method



Key	Well	No. Samples
1	FT-1	14
2	T-104	7
3	T-103 Rd	43

Figure 1-B Effect of Porosity Method on Total Liquid Saturation

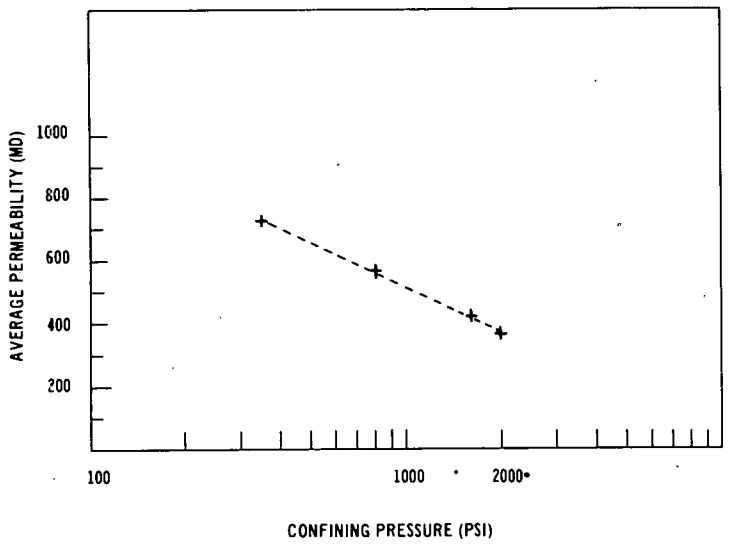


Figure 2-A Effect of Overburden Load on Permeability (Average of All Data for FT-1, T-102, T-103-Rd, and T-104)

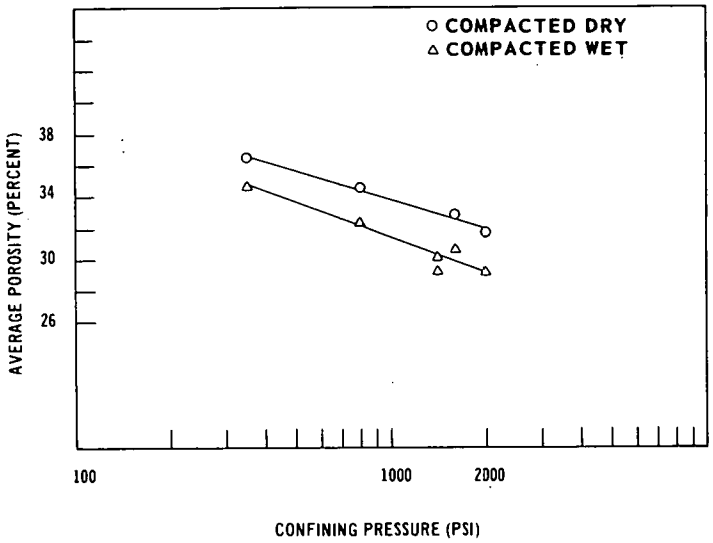


Figure 2-B Effect of Overburden Load on Porosity (Average of All Data Compacted Dry and Compacted Wet for FT-1, T-102, T-103-Rd, and T-104)

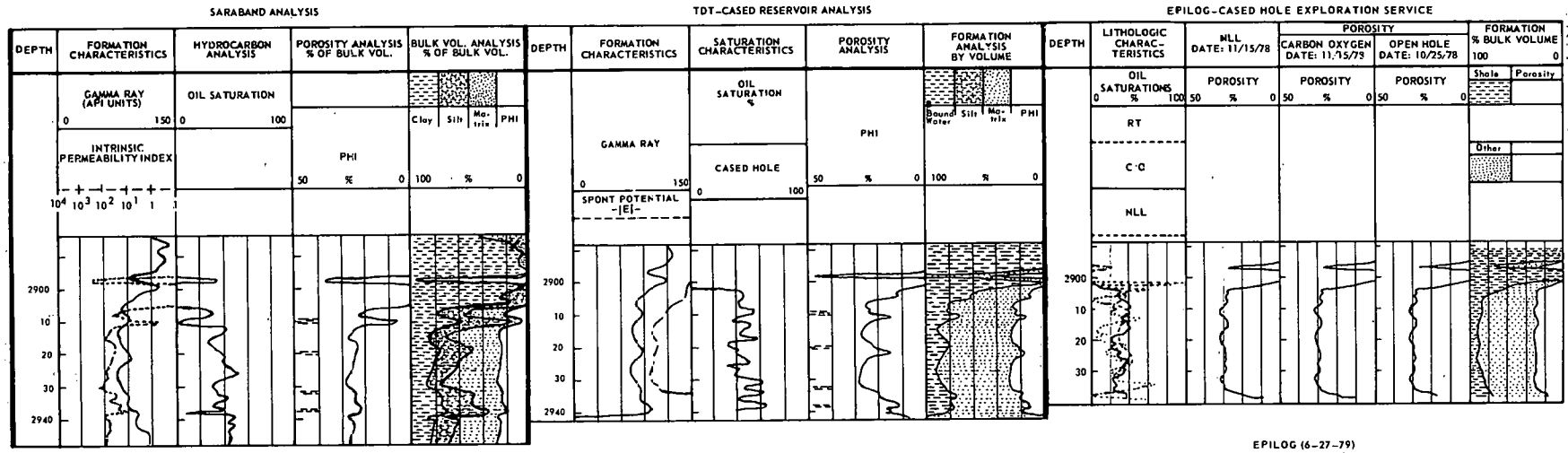


Figure 3 Electrical Log Analysis-Three Methods HX_a Sand (T-103 Rd) (Wilmington Field)

TABLE 1

AVERAGE CORE ANALYSIS BY WELL

Well No.	Month Tested	No. Samples	Sleeve Press psi	Routine Core Analysis: Porosity % He	Porosity % Wet	Perm md	Liquid Saturation % Oil	Liquid Saturation % Water	Liquid Saturation % Total	Grain Density g/cc
FT-1	7/77	14A	200	39.6		835	21.0	67.0	88.0	2.691
	9/77	14B	200		40.8	802	21.8	60.5	82.3	2.702
		57 1/	0	42.2			15.6	58.0	73.6	2.658 2/
T-102	3/78	5	750	32.1		510	26.4	68.6	95.1	2.664
		16 1/		40.9			17.9	51.9	69.8	
T-104	10/78	7	200		40.6		17.4	27.4	44.8	2.714
	10/78	7A	350	37.7		648	19.6	31.0	50.6	
T-103 Rd	12/78	43A	200		41.8	486	19.3	45.9	65.2	2.667
	12/78	43A	200	39.0		486	21.1	52.1	73.2	
	1/79	45B	1600 4/		35.2					2.68 3/
	1/79	45B	1600 4/		34.5					
	1/79	45B	1600 4/		33.9					
	2/79	8C								
	2/79									
	2/79									
	5/79									

No. Samples	Porosity and Permeability @ Different Confining Pressures, psi: Initial Por, % psi	Initial Por, % He	Initial Por, % Wet	350 psi Por	350 psi Perm	800 psi Por	800 psi Perm	1400 psi Por	1600 psi Por	1600 psi Perm	2000 psi Por	2000 psi Perm
14B dry	350	38.2		38.2	802	36.0	634		34.1	469	33.0	386
57 wet								30.0				
5 dry	750	32.1							30.5	410		
5A dry	350	33.5		33.5	612	31.3	505		29.2	383	28.2	333
16 wet								29.0				
7 wet	200		40.6						30.8			
7 dry	350	37.7		37.7	648	35.9	478		33.7	344	32.9	315
43A dry	200	39.0							33.1			
8A dry	200	38.2							33.4			
8C dry	200	37.4		36.5	862	35.0	667		33.4	501	32.7	429
8D wet 5/	0		39.4	36.1		33.8			32.0		30.8	
8D wet 6/	0	38.2		34.7		32.4			30.5		29.2	
6E wet	1600								30.7			

1/ Frozen disc core samples 12.5 cm diameter x 5 cm. Approx. 620 cc bulk volume. Porosity calculated from diameter and thickness of frozen sample less grain volume from dry weight and grain density. All other samples 1" diameter x 1 to 1-1/2" long.

2/ 31 samples.

3/ 43 samples.

4/ Samples taken from triaxial pressure cell, extracted, dried, helium grain volume measured and then saturated with brine. Porosity determined by the three following methods:
(a) Liquid pore volume and Archimedes bulk volume
(b) Liquid pore volume and helium grain volume
(c) Helium grain volume and Archimedes bulk volume

5/ Initial porosity determined by liquid pore volume and helium grain volume.

6/ Initial porosity determined by helium pore volume and helium grain volume before saturating with brine.

TABLE 2

PERMEABILITY AND POROSITY AT DIFFERENT CONFINING PRESSURES
AVERAGE VALUES BY WELLS

Well	No. Samples	Perm to Air, Millidarcies Confining Pressure, psi 350	800	1600	2000
FT-1	14	802	634	469	386
T-102	5	612	505	383	333
T-103-Rd	8C	862	667	501	429
T-104	7	648	478	344	315
Well Avg		731	571	424	366

Well	No. Samples	Porosity, Percent Confining Pressure, psi 350	800	1400	1600	2000
SAMPLES COMPACTED DRY						
FT-1	14	38.2	36.0		34.1	33.0
T-102	5A	33.5	31.3		29.2	28.2
	5				30.5	
T-103-Rd	8C	36.5	35.0		33.4	32.7
T-104	7	37.7	35.9		33.7	32.9
Well Avg		36.5	34.6		32.8	31.7
No. Wells		4	4		4	4
No. Samples		34	34		39	39
SAMPLES COMPACTED WET						
FT-1	57			30.0		
T-102	16			29.0		
T-103 Rd	8D	34.7	32.4		30.5	29.2
	6E				30.7	
T-104	7				30.8	
Well Avg		34.7	32.4	29.5	30.7	29.2
No. Wells		1	1	2	2	1
No. Samples		8	8	73	21	8

TABLE 3

SUMMARY OF ELECTRICAL LOG ANALYSIS, HX_a SAND

Well No.	Log	MW Depth (Feet) From	MW Depth (Feet) To	Net Feet of Sand MWD Log	Net Feet of Sand Official VSS 2/	Perm Index	Porosity (Percent)	Oil Sat. (Percent)	From Engineering Printout: Porosity (Percent) Neutron	Porosity (Percent) Density	Rt DIL 4/	VSH (Silt %)	VCL (Clay %)	Grain Density	BHT and Resistivity: Rw @ BHT 3/	BHT Corrected 3/	E Log BHT Max Recorded
SURFACE REDRILLS																	
FT-1	Saraband 1/	2965	3003	39	61	82	25.6	42.0	38	32	2.8	19	17	2.70	.138	137	120
FT-3	Saraband 1/	3062	3125	64	59	105	26.8	42.0	40	33	2.6	35	17	2.68	.133	143	NR
T-101	Saraband 1/	3099	3141	41	59	45	22.9	39.4	39	32	3.2	44	22	2.66	.176	105	123
T-102	Saraband 1/	3008	3050	43	60	110	27.6	36.0	37	31	2.8	23	11	2.68	.166	113	110
T-103-Rd	Saraband 1/	2906	2946	38	54	62	24.1	39.0	40	31	2.8	40	20	2.69	.137	138	119
T-104	Saraband 1/	2969	3030	61	62	102	26.5	37.3	37	31	2.6	26	13	2.68	.139	136	117
Avg (6)	Saraband 1/			48	59	84	25.6	39.3	38	32	2.8	31	17	2.68	.148	129	
T-103-Rd	TDT	2905	2939	35	54	104	23.1	45.7				14					
T-103-Rd	Epilog 7/	2904	2937	34	54	125	29.0	(NLL) 26.1 (Rt) 32.9 (C/O) 32.6				14					
MILL-OUT COMPLETIONS																	
FT-2	Epilog 7/	2930	2997	56	60	125	28.8 5/	(NLL) 36. (Rt) 26. (C/O) 32.			2.0 6/		13		.137	138	118
FT-4	DIL	2967	3034	67	58						3.0				.133	142	128
T-100	DA, DIL	2882	2952	70	53						1.9				.133	142	120
T-103	Epilog 7/	2896	2958	54	54	106	27.5 5/	(NLL) 29. (Rt) 33. (C/O) 39.			3.0		15		.137	138	130
T-105	DIL, Densilog	2947	2993	46	53					35.7	2.7				.135	140	NR
Average				59	56										.135	140	

1/ Schlumberger Saraband and Engineering Printout dated 6-14-79, except FT-1 dated 6-18-79.
2/ VSS net feet of sand is revised sand count agreed upon by M. E. Wright and C. E. Monson based on core and microlog correlation from T-103-Rd and microlog from other old wells.
3/ Corrected Rw and corrected BHT from C. E. Monson memo to R. H. Newman dated 8-11-78 based on static bottom hole temperature surveys.
4/ Rt from engineering printout for wells with Saraband and with Epilog. Values for other wells calculated from conductivity curves.
5/ Dresser Atlas Neutron log through casing.
6/ FT-2. In April 1980 Rt = 6.2.
7/ Epilog revised data 6-27-79.

MEASUREMENT AND CORRELATION OF CONDITIONS FOR ENTRAPMENT AND MOBILIZATION OF RESIDUAL OIL

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ABSTRACT

A systematic study is being made of factors which affect the entrapment and mobilization of residual oil. The project has three main parts. The first deals with the entrapment and mobilization of residual oil, and the development and testing of capillary number (ratio of viscous to capillary forces) and Bond number (ratio of gravity to capillary forces) correlations. In the second part, specific aspects of wettability, namely, the magnitude of dynamic contact angles at rough surfaces, and the problem of accounting for wettability effects in capillary number and Bond number correlations are being investigated. The third part of the project concerns the magnitude and detailed structure of residual oil saturations and the application of capillary number studies to the correction of in situ residual oil saturations determined close to the wellbore, where high pressure gradients can cause residual oil saturations to fall below their normal waterflood values.

Progress to date is summarized. The mechanism of trapping is discussed and detailed results are presented of the effect of gravity and viscous forces on the magnitude of residual saturations trapped in unconsolidated porous media. For vertical displacement, residual saturations were correlated precisely using a linear combination of capillary number and Bond number. Residual saturations showed systematic change with angle of dip, but were less than those predicted by simply resolving gravity forces according to dip angle. The results imply that buoyancy forces can have significant effect on microscopic displacement in low interfacial tension systems.

Prepared for the Department of Energy under Contract No. DE-AC03-79-ET-3251

INTRODUCTION

The entrapment and mobilization of residual saturations are pertinent to many aspects of enhanced recovery. Entrapment mechanisms determine what proportion of oil is recovered from the swept zone of a waterflood and consequently, how much oil remains for possible recovery by tertiary methods. The volume of oil remaining in swept zones and the fraction of this oil that is recovered are critical economic factors in application of enhanced recovery processes.

Conventional methods of determining residual oil by laboratory waterflood or resistivity logs are not considered to be sufficiently reliable or accurate for formation evaluation with respect to application of tertiary methods. A number of sophisticated techniques for in situ measurement of residual oil have been developed and in general, a combination of techniques is used to determine the amount and vertical distribution of residual oil. The more recently developed logging tools for in situ measurement of residual oil (pulsed neutron capture and nuclear magnetism) sample the formation for a region extending only a few inches from the wellbore. This region would likely have suffered stripping of residual oil because high pressure gradients around the wellbore may be sufficient for viscous forces to overcome the capillary retaining forces. Likewise, the residual oil in cores obtained using a pressure core barrel could also have been subjected to stripping by the drilling fluid. Improved methods of correcting for such effects are needed and require knowledge of the factors governing mobilization.

Entrapment and mobilization mechanisms at low flow rates and low interfacial tension can control the recovery obtained by tertiary methods. In micellar flooding, for example, high ratios of viscous to capillary forces arise at field flow rates when interfacial tensions are very low. Development of a continuous oil bank having significant mobility requires that discontinuous oil be mobilized to form a continuous bank which gathers more residual oil as it advances. Interfacial tension may exist or develop between the micellar bank and the oil or between the micellar fluid and the aqueous polymer bank used to push the micellar fluid. Entrapment of oil by the micellar bank or of micellar fluid by the polymer bank would eventually cause the process to fail.

Because of the many problems of mobilization and entrapment that are of importance to successful application of enhanced recovery, a general investigation of this topic has been undertaken. The first part of this paper provides a summary of the project. The second part presents detailed results of a study of the effect of viscous and gravity forces on entrapment. The results demonstrate that buoyancy forces can have an important influence on the displacement mechanism in systems where interfacial tensions have been reduced to the ultra low values needed for displacement of residual oil by viscous forces at typical field flow rates.

PART 1. SUMMARY OF PROJECT OBJECTIVES AND PROGRESS TO DATE

Objectives will be discussed with respect to six areas of investigation.

1. Capillary Number Relationships for Rock Samples

Objectives:
(a) to test the capillary number concept by comparing capillary number relationships for given rock samples when parameters (in particular, the interfacial tension) of the capillary number are varied.
(b) to measure relative permeabilities at reduced residual saturations.
(c) to obtain capillary number relationships for systems having initial oil saturations higher than residual.
(d) to obtain accurate values of residual oil and reduced residual as a function of capillary number for a wide range of rock specimens.

Laboratory studies have shown that residual oil can be recovered if the flowing phase causes viscous forces acting on the residual oil to exceed the capillary retaining forces.[1-4] The ratio of viscous to capillary forces is sometimes referred to as the capillary number expressed as $\frac{v\mu}{\sigma}$, or $\frac{v\mu}{\sigma\phi}$, where v is the fluid velocity normal to a unit area of rock, ϕ is the porosity, μ is the viscosity, and σ is the interfacial tension. The influence of capillary number on the displacement of one continuous fluid by another and loss of continuous liquid through trapping is of equal, if not greater, importance to tertiary recovery processes where, for example, a developed bank of continuous oil is displaced by micellar fluid which is, in turn, displaced by an aqueous solution of polymer. For this reason, both mobilization of residuals and trapping of continuous fluid during displacement are being investigated.

Taber[2] showed, for water-wet sandstones, that a critical value of viscous to capillary forces was required for production of residual oil. For economically significant recovery of oil, this critical value, which is an intrinsic property of a given rock, must be exceeded by a factor of about ten. Because of practical limitations on pressure drop and distances of separation between injection and producing wells, it was estimated that extremely low interfacial tensions of the order of 1/100 of a dyne/cm must be achieved for mobilization of significant quantities of residual oil.

Estimates of the reduction in interfacial tension required for tertiary oil recovery based on capillary number relationships measured at normal oil-water interfacial tensions involve the assumption that the effect of change in interfacial tension will hold for up to and more than 3 orders of magnitude change in interfacial tension. This assumption is now being tested by making interfacial tension the principal variable in capillary number measurements on a few given rock samples. Interfacial tension is being varied by using equilibrated fluid pairs formed from mixtures of 2% $CaCl_2$ brine, isooctane and isopropyl alcohol. Phase composition, surface tension, density, and viscosity data have been measured for this system.[5] Interfacial

tension can be varied from 0 to 41 dyne/cm. The form of the variation of interfacial tension with composition is such that the system is particularly well suited for obtaining tensions in the range 0.5 to 10 dyne/cm.

The viscous forces which can cause mobilization of residual oil are directly proportional to the interstitial velocity of the flowing phase. For a given pressure drop, fluid velocity is inversely proportional to the relative permeability of the flowing phase at reduced values of residual saturation. The presence of residual oil in water-wet media causes about an order of magnitude reduction in the effective permeability of the flowing phase, because residual oil tends to be trapped in the larger pore spaces. When residual oil is mobilized, oil blocking the largest pore spaces will tend to be displaced first. This is expected to result in a large increase in permeability to the flowing phase for a relatively small decrease in residual saturation. This effect is detrimental to oil recovery because viscous forces are reduced while the oil which remains will tend to be that part of the residual which is more difficult to mobilize. At present, the amount of published permeability data at reduced residuals is extremely limited. Effective permeabilities at reduced residual saturations are being measured during the course of making capillary number measurements.

Some preliminary capillary number results for interfacial tensions of 10 to 41 dyne/cm have been reported together with results for recovery when continuous oil is displaced at high capillary number.[5] For the high interfacial tension system given by oil and brine, oil was observed to be produced as a clay stabilized emulsion after the residual oil had been reduced to about 75% of its original value. Structural damage to the sandstone was indicated by permeability loss. This makes the significance of the results (in particular, the relative permeabilities) uncertain, and points to one advantage of measuring capillary number relationships at reduced interfacial tensions using brine-alcohol-oil systems so that flow rates are probably below values at which significant permeability damage will occur.

2. Residual Oil Saturations Near the Wellbore

Objective: to provide a correction to residual oil saturation measured close to the wellbore for loss of oil caused by stripping.

Accurate values of residual oil saturation are essential for economic evaluation of any tertiary oil process. Methods of determining in situ residual oil saturations have been reviewed.[6] Currently, the industry is devoting much effort to in situ measurements of residual oil by specialized logging techniques such as pulsed neutron capture and nuclear magnetic logs. Most of these measurements involve a relatively small portion of the formation near the wellbore. This region will generally have been subjected to high pressure gradients which may be sufficient to cause significant reduction in the amount of residual oil retained close to the wellbore compared to that trapped in the swept zone as a whole. Thus, logging techniques for in situ determination of residual oil may provide a conservative estimate of the residual oil with respect to application of tertiary recovery methods or an optimistic value with respect to judging the success of a secondary recovery waterflood operation. In situ residual oil saturations determined by logging techniques should, therefore, be corrected for the effect of high

flow rates around the wellbore. This requires knowledge of capillary number relationships and permeabilities to the flowing phase for a range of rocks which are typical of enhanced recovery target reservoirs. After results, as described under objective 1(d) have been obtained, techniques similar to those of Stosur and Taber[7] will be used to estimate the variation of residual oil saturation with injection rate for regions near the wellbore. This information will be of direct value in the interpretation and evaluation of results given by in situ logging and in estimating the amount of flushing that can occur during pressure coring.

3. Residual Oil Structure

Objective: to develop techniques for the study of the microscopic structure of residual oil and obtain statistics on how residual oil is distributed.

In addition to the amount of residual oil, the microscopic distribution of residual oil within the pore spaces of a reservoir rock is also important to the mechanism of tertiary recovery. For example, in modeling the recovery of residual oil, the viscous force required for mobilization is expected to be inversely porportional to ganglia length. At present, there is very little quantitative information available on structural detail of residual oil.

The technique[8] of using a nonwetting phase which will solidify is being used in this work. Displacement was first carried out using glass beads as the porous media and styrene monomer containing a hardener as the oil phase. After trapping the styrene, the bead pack was sealed and heated at 80°C for 48 hours. This was found to be sufficient time for the styrene to set up as mechanically robust blobs which could be separated by dissolving the glass beads in hydrofluoric acid and then treating the blobs with fuming sulfuric acid to remove inorganic residues. Properties of the solidified blobs are now being investigated. A similar procedure has also been applied to a Berea sandstone. Many of the blobs in the sandstone were relatively massive (up to about 50 pore diameters in width) when compared to those obtained in the bead pack (where maximum blob size was about 10 diameters). The blobs could not be completely separated from the sandstone, probably because residual styrene protected the rock within the blobs from severe chemical attack.

4. Effect of Gravity on Residual Saturation

Objective: to develop correlations which relate oil displacement to the ratio of capillary to gravity forces.

At normal oil-water interfacial tensions, capillary forces which retain residual oil far exceed buoyancy forces. However, comparatively little attention has been given to the distinct possibility that when interfacial tensions are lowered as in surfactant flooding, buoyancy forces may have significant effect on both trapping mechanisms and on mobilization.[4]

The relationship between Bond number (ratio of gravity to capillary forces) and residual saturation has been determined for trapping in sphere packs. Capillary number relationships for trapping in these systems were also determined, and an extensive series of measurements were made for a wide range of Bond and capillary numbers. For vertical displacements, all results could be correlated to give a general relationship between residual saturation and any combination of Bond number and capillary number. The effect of dip angle was also studied. Detailed results of this work are given in the second part of this paper.

5. Magnitude of Residual Oil Saturation

Objective: to determine the effect on residual oil of particle shape, size, size distribution, and other factors which represent variation in rock and fluid properties.

A critical factor in the success of a tertiary project is the amount of oil available for recovery. Residual oil saturations remaining after waterflooding can range from less than 10% to more than 50% in rocks which may be similar in porosity and permeability. In situ measurements of residual oil give values which, in general, appear to be lower than those indicated by material balance method and laboratory waterflood tests on reservoir core samples.[9] While a major effort has gone into methods of determining residual oil saturation, there is very little information available on factors which determine the magnitude of residuals.

As a step in understanding this key aspect of any tertiary project, a systematic investigation is being made of factors which might influence the magnitude of residual oil saturations. These include effect of particle shape, size, and size distribution, the inclusion of heterogenities, change in fluid properties, and initial water saturation. In recently completed displacement tests for packings formed from two sizes of particles, residual saturations were not significantly affected by aggregate composition. Changes in relative permeability at residual saturations were proportional to changes in absolute permeability for the two component systems.

6. Effects of Wettability on Capillary Number Relationships

Objectives:
(a) to advance the theory of the effect of wettability on capillary number.
(b) to investigate the effect of interface velocity on contact angle at rough surfaces for advancing and receding conditions.

At present, there is not much hard evidence as to the effect of wettability on capillary number relationships and how wettability should be taken into account in capillary number correlations. Opinions vary as to the optimum wettability conditions for both secondary and tertiary recovery. When the hydrophobicity of a porous solid is increased sufficiently, the manner in which retained oil is distributed within porous media after water-

flooding, and the behavior of retained oil with respect to recovery vs. fluid injected and response to change in flow rate are distinctly different from that for residual oil trapped in strongly water-wet media.[10]

Wetting behavior is also likely to be of significance in tertiary processes. Contact angle measurements on microemulsion systems have shown that wetting behavior can be related to interfacial tensions and hence, optimal salinity.[11] From considerations of displacement mechanism, it has been concluded, for systems which spontaneously imbibe, that it is more difficult to mobilize isolated blobs as contact angle increases, but it is less difficult to prevent entrapment of a continuous phase.[12] If the contact angle is sufficiently large (about 62°), spontaneous imbibition does not occur and there will be a distinct change in microscopic displacement mechanism.[13] Experiments designed to test these predictions are presently being carried out.

Displacement of oil by spontaneous imbibition of water can often make a significant contribution to recovery by waterflooding. The rate at which spontaneous imbibition occurs is highly dependent on wetting behavior. Under certain wettability conditions, a minor change in wettability towards increased water wettness can be expected to have dramatic effect on the extent and rate of spontaneous imbibition.

Previous studies[13] of the effect of wettability on imbibition capillary pressures and imbibition rates suggested that dynamic effects might be important in systems which are not strongly wetted, and that investigation of dynamic contact angles at rough surfaces was needed. The effect of interface velocity on contact angle has been measured using roughened low energy surfaces for which a wide range of wetting conditions can be achieved. For velocities from below to well above normal field rates, receding and advanging contact angles changed by no more than a few degrees with change in interface velocity.

PART 2. EFFECT OF GRAVITY AND VISCOUS FORCES ON TRAPPING AND MOBILIZATION

The factors which determine the microscopic mechanism of trapping are: geometry of the pore network, fluid-fluid properties such as interfacial tension, density difference, viscosity ratio, and phase behavior; fluid-rock interfacial properties which determine wetting behavior and applied pressure gradient and gravity. Results presented in this paper concern the effect of applied pressure gradient and gravity on residual nonwetting phase saturations for systems in which there is complete wetting, the fluid-fluid properties are held constant, and the porous media have geometric symmetry.

The capillary forces which cause trapping or resist mobilization can be overcome by viscous pressure gradient or buoyancy forces. The ratios of gravity to capillary forces and viscous to capillary forces are expressed as dimensionless groups, known respectively as the Bond number (N_B), and capillary number (N_{Ca}).

$$N_B = \frac{\Delta\rho g R^2}{\sigma} \qquad N_{Ca} = \frac{v\mu}{\sigma}$$

where: $\Delta\rho$ = fluid density difference (gm/cm^3)
g = acceleration due to gravity (cm/sec^2)
R = particle radius (cm)
v = displacing fluid-velocity (cm/sec)
μ = displacing fluid viscosity (poise - gm/cm-sec)
σ = interfacial tension (dyne/cm)

The particle radius R is chosen as a convenient characteristic length which is of the same order of magnitude as the pore dimensions. The main reason for using unconsolidated packings of close-sized particles is that particle radius can be varied at will to give systems of different permeabilities but essentially similar geometries which scale according to particle radius. The absolute permeability, in C.G.S. units, can be expressed in terms of particle radius by using the Kozeny Carman equation:[14]

$$k = \frac{\phi^3}{K_z(1-\phi)^2 A_s^2}$$

where: A_s = specific surface area per unit solid volume
$= \frac{3}{R}$

K_z = Kozeny constant, which by experiment has been shown to be approximately equal to 5 for well-sorted sands or sphere packings

ϕ = porosity, is usually equal to about 0.38 for random packings of equal spheres.

Substitution of these values gives an approximate relationship between permeability and particle radius for random packings of equal spheres:

$$k = 0.00317R^2$$

It follows that the relationship between the Bond number, expressed as $\Delta\rho gR^2/\sigma$, and that expressed as $\Delta\rho gk/\sigma$ can be written:

$$N_{B(k)} = 0.00317(N_{B(R^2)})$$

where k and R^2 indicate the basis of the Bond number. Unless stated otherwise, the values of Bond number, N_B, or the reciprical of the Bond number, are based on the particle radius, R.

Materials

In most of the experiments, an aliphatic oil (soltrol-130), was used as the wetting phase and air was the nonwetting phase. This choice of fluids ensured that the contact angle was zero through the oil phase for all experiments. The soltrol had a viscosity of 1.42 cp., density of 0.7484 gm/cm^3 and surface tension of 23.19 dynes/cm. All measurements were made at room temperature (23 ± 0.5°C).

Packings of close-sized glass beads were used as the porous media. The spheres were first separated into the sizes listed in Table 1.

Apparatus and Procedure

Bead packs were held in a modified burette (see Figure 1) which had a disc of fine stainless steel screen of about 450 mesh size at its base. The screen was supported in a hollow rubber plug or in a stainless steel cylinder with an o-ring which provided a seal with the inside wall of the burette. After adding oil to the burette, it was attached to a vibrator and beads were added slowly in order to avoid entrapment of air during packing. This procedure gave a reasonably dense and consistant packing which was initially 100% saturated. After adding the beads, a plastic washer was forced against the upper surface of the pack to prevent its movement during subsequent displacement tests. The oil above the bead pack was then drained to the level of the upper surface of the saturated pack and porosities were determined from subsequent weight and volumetric measurements. All weighings were made on a top loading balance having an accuracy ±0.01 gms. Errors in saturation measurement were estimated to be less than one-tenth percent of pore volume. Permeability measurements were made with equipment set up as shown in Figure 1(a). A plot of change in height, Δh, versus time, t, on a semi-logarithmic graph paper yielded a straight line relationship because pressure drop is directly proportional to Δh, and flow rate is proportional to rate of change in Δh. The permeability of the pack was determined from the overall permeability by correcting for the resistance to flow in the apparatus caused mainly by the stainless steel retaining screen.[15] After measuring absolute permeability, the oil is drained from the column into a burette connected as shown in Figure 1(b). The height, H, in Figure 1(b) is calculated to provide for drainage to the irreducible saturation of the bead pack but is kept well below the penetration pressure of the stainless steel screen. Thus, the space below the screen remains completely filled at all times.

After drainage, the oil was pumped via the screen into the burette using a variable speed syringe pump as illustrated in Figure 1(c), until oil appeared at the top of the bead pack. Capillary number was varied by changing the injection rate. Bond number was varied by changing particle radius (see Table 1). In studies of the effect of dip on trapping, the burette was set at an angle, α_d, with the horizontal, as shown in Figure 1(d). The amount of trapped nonwetting phase which remained within the packing was determined by weighing. Flow rate and pressure drop measurements were also made using the apparatus configuration shown in Figure 1(a) in order to determine permeabilities in the presence of trapped fluids.

Results

Permeability Measurements

Relative permeabilities to the wetting phase at and below residual saturation values are shown in Figure 2. All of the end point values for five sizes of sphere were in the range of 0.6 to 0.65, the average value being 0.63 with a standard deviation of 0.02. The average residual saturation obtained at low capillary number was 14.25% with a standard deviation of 0.25%. Previously reported wetting phase relative permeability data[16] for sphere packings are included in Figure 2. The end point relative permeability for these results is lower than that obtained in the present work,

being 0.45 at a saturation of 16.5%. Even though the end point relative permeabilities are not in close agreement with the previously reported value, it is clear that relative permeability at reduced residuals obtained by prevention of trapping should not be predicted by simply extrapolating the conventional relative permeability curve to 1.0 at 100% wetting phase saturation. It should also be noted that permeabilities obtained when residuals are reduced by change in entrapment mechanism do not necessarily correspond to those given when residual saturations are decreased by mobilization of trapped fluid, but data which would permit comparison do not appear to be available.

Effect of Bond Number and Capillary Number on Trapping

Results for the effect of gravity and viscous forces on trapping are given in Table 3 and are shown in Figure 3 as plots of residual saturation versus inverse Bond number with capillary number as parameter. For the type of system under study, it is estimated that no trapping will occur if the inverse Bond number is less than about 3. When the inverse Bond number is greater than about 200, buoyancy forces have no effect on the amount of trapped residual nonwetting phase saturation and residual saturation depends only on the capillary number. Above the critical capillary number and Bond number for trapping, the residual saturation depends on the combined effect of viscous and gravity forces. The plot in Figure 4 shows percent residual saturation versus capillary number, with inverse Bond number greater than 200; at capillary numbers of about 10^{-6} and lower, the trapping mechanism is dominated by capillary forces, and the residual saturation is constant.

Correlation of Combined Effect of Gravity and Viscous Forces

Attention was next turned to correlating the combined effect of gravity and viscous forces. The results presented in Figure 3 were used to obtain the plot shown in Figure 5 of capillary number versus Bond number at given residual saturations. The straight line relationships show that a given saturation can be achieved for a complete range of linear combinations of Bond and capillary numbers. Furthermore, each line in Figure 5 is parallel to any other line given by different choice of saturation. Thus, residual saturation can be correlated by simple linear combination of Bond number and capillary number as shown in Figure 6. If the capillary and Bond numbers of the system are given, the amount of nonwetting phase that is trapped can be predicted for any combination of these two numbers.

Residual saturations at various Bond numbers were also measured using water as the wetting phase and air as the nonwetting phase. The relationships between residual saturation and Bond number were in good agreement with those obtained by using air and oil. A comparison is presented in Figure 7. Attempts are now being made to reproduce these relationships using oil and water as fluid phases.

Effect of Dip Angle on Trapping

All of the experiments described so far were for vertical displacement with the more dense (wetting) fluid advancing upwards. When results are sensitive to Bond numbers, it is reasonable to expect that the amount of trapping will decrease if the angle of dip, α_d, measured from the horizontal is increased. Results for the effect of dip angle are presented in Table 4. They are plotted in Figure 8 as residual saturation versus Bond number with dip angle as parameter.

When a modified Bond number, $N_B \sin\alpha_d$, was used to allow for the effect of dip angle, the reduction in residual saturation always tended to be higher than predicted from measurements obtained for vertical displacement. Results are plotted in Figure 9 as residual saturation versus $\left[\frac{1}{N_B \sin\alpha_d}\right]$.

The results for trapping at low capillary and Bond numbers presented in the last two columns of Table 4 were obtained as a check against the possibility that the measured effect of dip angle might be an artifact of the experiment. It is seen that when capillary number and Bond number are well below their critical values so that displacement is dominated by capillary forces, residual saturations are essentially independent of dip angle.

Mobilization of Trapped Nonwetting Phase

Laboratory studies show that trapped residual oil can be recovered if the pressure difference due to viscous flow is sufficient to overcome capillary forces so that trapped blobs, or at least parts of blobs, are mobilized.[2-4] If the ratio of viscous to capillary forces is raised sufficiently, almost complete recovery of residual oil can be achieved. For packs of very coarse sand, Leverett[17] reported data which showed indications of slightly improved recovery efficiency for capillary numbers (in this case, of the form $\frac{\mu v}{\sigma \cos\theta}$) as low as 10^{-5}. In the present work, some of the systems in which trapping was measured were later subjected to high flow rate in an attempt to measure the capillary number required for mobilization of trapped nonwetting phase so that results could be compared with capillary numbers for trapping.

The amount of injected fluid (number of pore volumes) was found to have significant effect on the residual saturation (see Figure 10). It was apparent that in these experiments, results were strongly influenced by gas passing into solution because of the pressure gradient in the column. During the experiment, the residual gas appeared to develop a shock front. Behind the front, the gas saturation was very low. Ahead of the front, the gas saturation appeared to be uniform and at least as high as the normal residual values. Consideration of pressure gradients and gas solubilities shows that solution effects can reasonably account for the observed results. The severe solution effects encountered in an attempt to mobilize trapped gas by increasing the capillary number are in distinct contrast to trapping behavior where solution effects proved to be insignificant. For example,

saturations appeared uniform throughout the column and relative permeabilities at reduced residual saturations were independent of time and flow rate.

The observed solution effects present a distinct limitation of using gas-oil systems to model mobilization of completely wetted oil-water systems. However, the mobilization results obtained do at least provide a lower limit to the capillary number required for mobilizing residual fluid. The residual saturation remaining after injection of one pore volume was used to estimate a lower bound for the capillary number relationship for mobilization of residuals in sphere packs.

Oil recovery from a swept region can be expressed in terms of the ratio of oil removed to that originally in place. The ratio is the microscopic displacement efficiency, E_m,

$$E_m = \frac{1-S_{or}-S_{wi}}{1-S_{wi}}$$

where S_{or} is the residual (or reduced residual) nonwetting phase saturation and S_{wi} the initial wetting phase saturation. Results for reduction of residuals after one pore volume injection are plotted in Figure 11 as E_m versus capillary number. Previously reported typical capillary number relationships for trapping of residuals in rocks of narrow and wide pore size distributions are included in Figure 11. Work on obtaining more definitive results for mobilization of residuals from sphere packs is presently underway. With respect to the large difference in magnitude of microscopic displacement efficiency in unconsolidated media as compared to reservoir rocks, it may be noted that for recently collected measurements of in situ residual oil saturations[9], microscopic displacement efficiencies for reservoir rocks are generally higher than those indicated by results presented in Figure 11.

Discussion

Mechanism of Trapping

The results obtained for the effect of Bond numbers on residual saturation provide insight into the mechanism by which trapping occurs and how it can be avoided. Obviously, if the ratio of gravity to capillary forces is very high, for example, a trough containing blowing balls in which air is displaced by water, the interface will be essentially plane and no trapping will occur. However, for the range of Bond numbers of 0.006 to 0.35 over which residual saturation is reduced, the small changes of interface curvatures that would occur are apparent from the profiles[18] shown in Figure 12 for Bond numbers of 0,1,10,1000. Local changes in interface shape with individual pores will be small and are not likely to account for the large changes in residual saturation that were measured. It is believed that reduction in residual saturation is due to change in imbibition mechanism caused by small hydrostatic pressure differences. When capillary forces are dominant ($N_B < 10^{-6}$, $N_B < 0.0067$), potential blobs become isolated once an imbibition event occurs whereby the blob separates

from the main body of continuous fluid as illustrated in Figure 13. Each blob will have a number of pore openings across which an imbibition capillary pressure is maintained. With increase in Bond number, the tendency for imbibition to occur into the lower region of the blob before the upper region, is increased because the hydrostatic pressure between the regions is increased. If the supplementary hydrostatic pressure is sufficient to cause imbibition into the lower region first, the potential blob is recovered. A similar mechanism can be expected to apply to reduction of residual saturation by viscous forces except that the required supplement in pressure at the trailing edge of the potential blob is provided by the viscous pressure gradient. The correlation obtained between residual saturation and a linear combination of Bond number and capillary number demonstrates that the effect of viscous and gravity forces on supplementation of imbibition pressure are additive for vertical displacement, and points to the equivalence of the effect of gravity and viscous forces on the trapping mechanism. It may be noted that the proposed mechanism is distinct from pore doublet theory[1] which predicts that both the location and consequently the magnitude of trapped residual oil changes with viscous pressure gradient. For the proposed mechanism, the space occupied by reduced residual oil saturations will, in general, be a sub-set of the space occupied by residual oil under conditions where capillary forces are dominant.

When displacement was carried out with the packing set at various dip angles, α_d, the reduction in trapping was distinctly greater than that predicted by resolving gravity according to the angle of dip. This is believed to reflect the influence of the three dimensional structure of a potential blob. On a microscopic scale, gravity can supplement imbibition pressures because of local vertical height of the potential blob and this can be sufficient to cause some reduction in trapping.

Magnitude of Supplemental Imbibition Pressures

Raimondi and Torcaso[19] showed that entrapment of nonwetting phase tends to occur as the invading wetting phase approaches high saturations. From capillary pressure measurement for sphere packings[11], the imbibition pressure at 70% wetting phase saturation is given by:

$$P_{imb} = \frac{3.9\,\sigma}{R}$$

Preliminary estimates based on an examination of blobs formed in sphere packings indicates that when residual saturation is reduced to one half of its normal value of about 14%, the larger blobs will tend to be decreased in size and potential blobs will have maximum lengths of about 7R. The supplementary hydrostatic pressure, ΔP_s, which developes within a potential blob of this length is given by:

$$\Delta P_s = 7\Delta\rho g R$$

Thus, the ratio of the supplementary pressure to imbibition pressure can be expressed in terms of the Bond number as

$$\frac{\Delta P_s}{P_{imb}} = \frac{1.8\ \Delta\rho g R^2}{\sigma}$$

From the experimental results given in Figure 5, the Bond number for 50% reduction in trapping is 0.08, which gives:

$$\frac{P_s}{P_{imb}} = 0.14$$

Thus, if the imbibition pressure at the trailing edge of a potential blob is supplemented by 1/7 of the average imbibition pressure, entrapment is halved.

Comparison of Entrapment and Mobilization

The foregoing result can be used to provide a comparison of the conditions required for prevention of entrapment with those required for mobilization of trapped liquid. Movement of a trapped blob involves drainage at the leading edge of the blob and imbibition at the rear. (See Figure 14). For a completely wetted random sphere pack, the pressure drop required for mobilization, ΔP_m is given by the difference between drainage and imbibition displacement pressures.[3,12,21] At 70% water saturation, these pressure are $\frac{6.7\,\sigma}{R}$ and $\frac{3.9\,\sigma}{R}$, giving a value for ΔP_m of $\frac{2.8}{R}$. The value of ΔP_s is:

$$\frac{\Delta P_s}{P_{imb}} = 0.546\,\frac{\sigma}{R}$$

Hence, the ratio of ΔP_s to ΔP_m is 0.2. The conclusion that it is about 5 times more difficult to mobilize entrapped fluid than to prevent entrapment is in fair agreement with the experimental results presented in Figure 11. With respect to interpretation of experimental results, it would seem reasonable to expect that the correct relationship for mobilization of residuals in sphere packs will lie somewhere between the sphere pack results, which, because of solution effects represent a lower limit, and the curve obtained for rocks of narrow pore size distribution. Additional experiments are presently being carried out to obtain more reliable data on capillary number results and blob size distributions. This data will be used to further test and improve the foregoing type of analysis.

Comparative Effects of Viscous and Capillary Forces

At ordinary waterflood conditions, capillary number is about 10^{-7}. This corresponds to a flow rate of about 1 ft./day for water of one centipoise viscosity and an oil-water interfacial tension of 30 dyne/cm. The capillary number for 50% reduction of residual saturations in sphere packings is close to 10^{-4} (Figure 4) and would require that interfacial tension be reduced to 0.3 dyne/cm for the above flow rate and viscosity. For vertical displacement at very low capillary numbers, the Bond number at which saturation is reduced 50% by buoyancy forces, is about 0.08. If the fluid density difference is 0.2, the sphere radius of the packing would be 35 microns with corresponding pore radii of about 10 microns. Although the permeability

(about 4 Darcys), and porosity (about 38%) are high relative to most reservoir rocks, the pore radius of 10 microns is of the same order as that for good producing zones. With respect to the present discussion, pore size is the more relevant parameter. Results for the effect of dip angle (Figure 8) indicate that even for horizontal displacement, buoyancy forces can have a favorable effect on recovery. It follows that in any low tension displacement, the influence of buoyancy forces on the displacement mechanism may well be significant.

Conclusions

1. Relative permeabilities at less than normal residual saturations are generally higher than those predicted by extrapolating the wetting phase imbibition relative permeability curve.

2. For vertical displacement in random packings of equal spheres, Bond numbers for variation in trapping because of buoyancy forces, lie in the range of 0.00667, below which there is no effect on trapping, up to 0.35, above which there is no trapping. Capillary numbers for variation in trapping lie in the range of 10^{-6} to 10^{-3}.

3. Below Bond numbers of 0.00667, the amount of entrapped nonwetting phase saturation depends only on the capillary number, and varies from the normal value of about 14.4% for capillary numbers of less than about 10^{-6} to zero at capillary numbers of about 7×10^{-4} or higher.

4. The amount of nonwetting phase trapped for displacement within the range of Bond and capillary numbers given above can be predicted from a linear correlation of capillary number and Bond number which accounts for the combined effect of gravity and viscous forces on trapping.

5. Prevention of trapping is about 5 times easier than mobilization of residual fluid once it has become trapped.

6. The effect of buoyancy forces on prevention of trapping with change in dip angle is greater than that predicted from results for vertical displacement by resolving Bond number according to angle of dip.

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TABLE 1. Particle sizes and corresponding Bond numbers used in experimental work ($\Delta\rho$=0.748, σ=23.19 dyne/cm)

Mesh Size	Mean Dia. (mm)	Bond Number $\frac{\Delta\rho g R^2}{\sigma}$
12-14	1.55	0.1895
14-16	1.29	0.1313
16-18	1.09	0.0937
18-20	0.925	0.0675
25-28	0.655	0.0338
32-35	0.462	0.0168
42-48	0.327	0.00843
48-60	0.275	0.00595
65-80	0.191	0.00288
80-100	0.165	0.00215
100-115	0.137	0.00148

TABLE 2. Effect of nonwetting phase saturation on relative permeability

Mesh Size	$\%S_{nw}$	Relative Permeability
42-48	Run No. 1	
	3.07	0.882
	6.14	0.841
	8.51	0.768
	11.72	0.684
	13.95	0.656
	Run No. 2	
	1.70	0.963
	2.97	0.928
	4.24	0.874
	5.94	0.790
	8.77	0.726
	12.16	0.655
	14.14	0.627
48-60	Run No. 1	
	9.15	0.704
	11.75	0.671
	13.93	0.649
	Run No. 2	
	1.98	0.923
	3.40	0.904
	6.66	0.806
	8.92	0.712
	12.18	0.648
	14.59	0.623

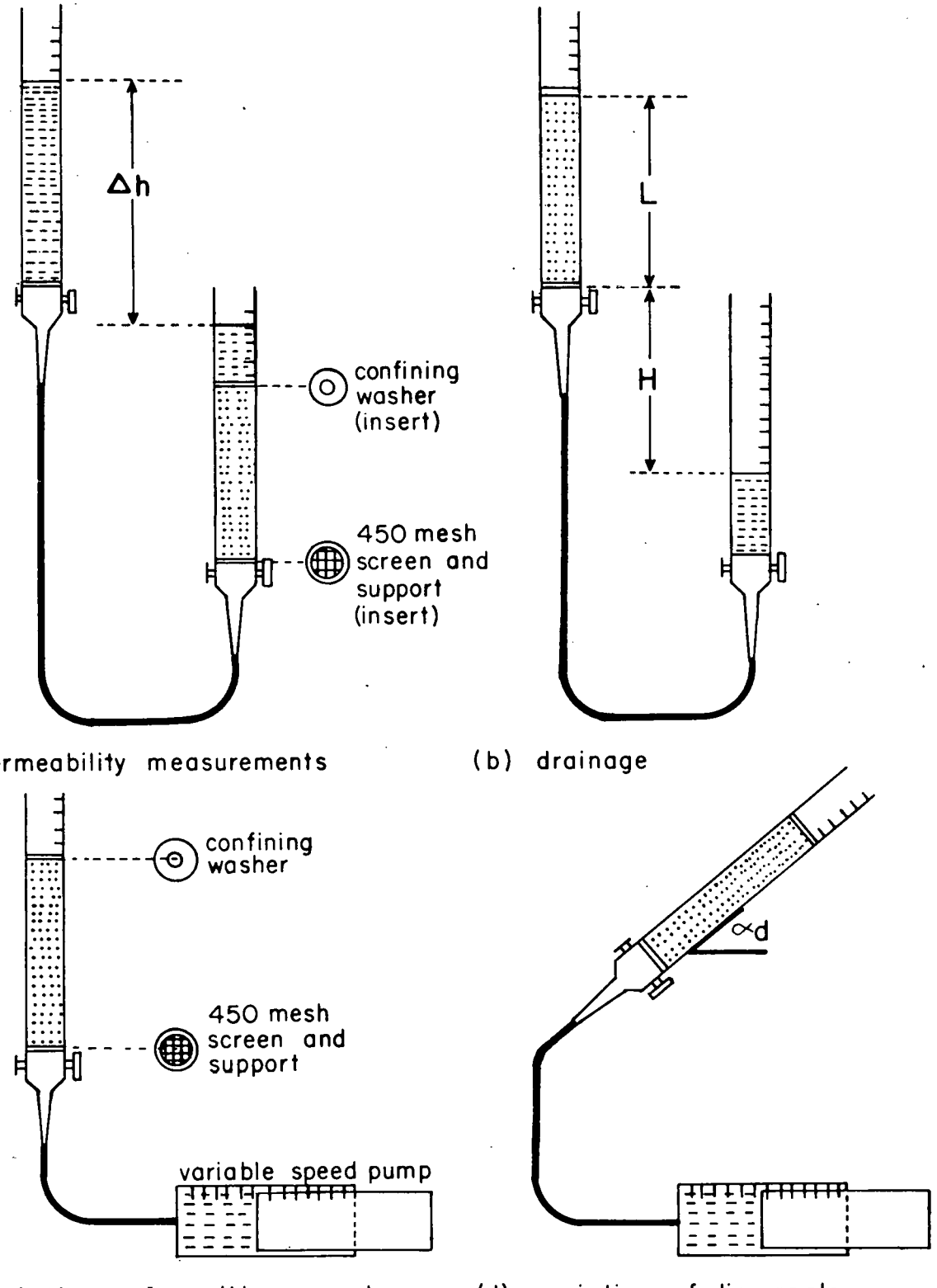
Mesh Size	$\%S_{nw}$	Relative Permeability
65-80	Run No. 1	
	2.36	0.906
	4.57	0.851
	6.78	0.799
	9.14	0.703
	12.09	0.642
	14.60	0.607
80-100	Run No. 1	
	4.05	0.916
	6.94	0.859
	9.39	0.790
	11.99	0.719
	14.31	0.600
	Run No. 2	
	3.72	0.918
	6.84	0.822
	11.90	0.676
	14.43	0.641
100-115	Run No. 1	
	6.96	0.853
	9.28	0.815
	11.88	0.726
	14.06	0.652

TABLE 3. Nonwetting phase saturations trapped at various Bond and capillary numbers.

Mesh Size	Bond Number	Inverse Bond Number	$\%S_{nw}$ at Capillary Number				
			2.82×10^{-6}	2.82×10^{-5}	7.07×14^{-5}	1.41×10^{-4}	2.82×10^{-4}
12-14	0.1895	5.277	2.97	2.56	1.90	1.62	1.21
14-16	0.1313	7.619	4.83	4.28	3.41	2.76	-
16-18	0.0937	10.671	6.31	5.22	4.35	3.37	-
18-20	0.0675	14.818	7.79	6.68	5.45	3.74	-
25-28	0.0338	29.551	10.30	9.19	6.65	4.78	2.11
32-35	0.0168	59.399	12.36	10.60	8.19	5.14	2.64
42-48	0.00843	118.568	13.95	11.72	8.51	6.14	3.07
48-60	0.00596	167.647	14.03	11.94	9.27	6.54	3.68
65-80	0.00288	347.532	14.06	11.92	9.21	6.92	4.07
80-100	0.00215	465.686	13.99	11.90	9.39	6.94	4.05
100-115	0.00148	675.492	14.06	11.88	9.28	6.96	4.06

TABLE 4. Effect of dip angle on residual nonwetting phase saturation at low capillary number (2.82×10^{-6}).

Dip Angle (Degrees)	% Residual Saturation						
	N_B 0.1895	N_B 0.1313	N_B 0.0937	N_B 0.0675	N_B 0.0338	N_B 0.00288	N_B 0.00215
90	2.97	4.75	6.31	7.68	10.20	14.45, 14.60	14.29
60	3.14	5.10	6.79	8.19	10.83	15.04	15.03
45	3.81	5.77	7.51	8.85	11.25	15.05, 14.45	14.88, 14.29
30	4.90	6.93	8.67	9.36	11.67	14.90	14.88
20	5.59	-	9.25	9.87	12.52	15.04	15.03
15	6.40	7.79	9.54	10.45	12.80	15.19	15.18
10	7.49	8.92	9.82	10.89	13.01	-	-
5	9.13	10.25	11.56	11.62	13.64	14.60	14.58, 14.43
0	-	-	-	-	-	14.60, 14.75	14.43



(a) permeability measurements

(b) drainage

(c) variation of capillary numbers

(d) variation of dip angle

Fig. 1 Apparatus

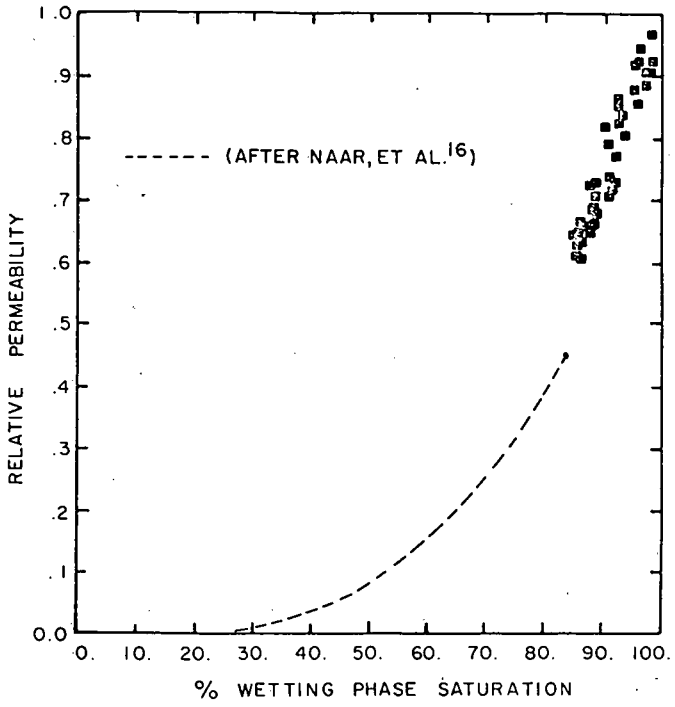


Fig. 2 Relative permeability to the wetting phase at less than normal nonwetting phase residual saturations. (Detailed results given in Table 2)

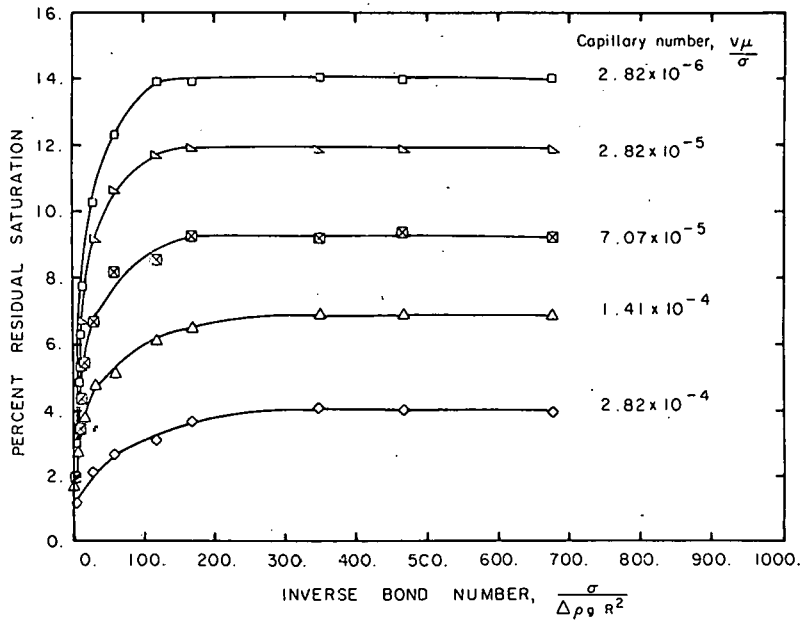


Fig. 3 Trapped residual saturation versus inverse Bond number for a range of capillary numbers

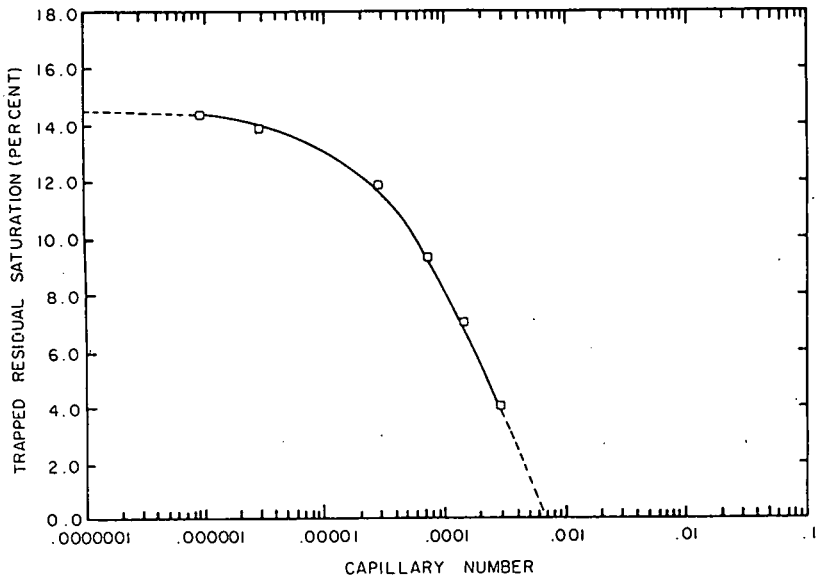


Fig. 4 Effect of capillary number on trapping of residual saturation at Bond numbers greater than 0.00667

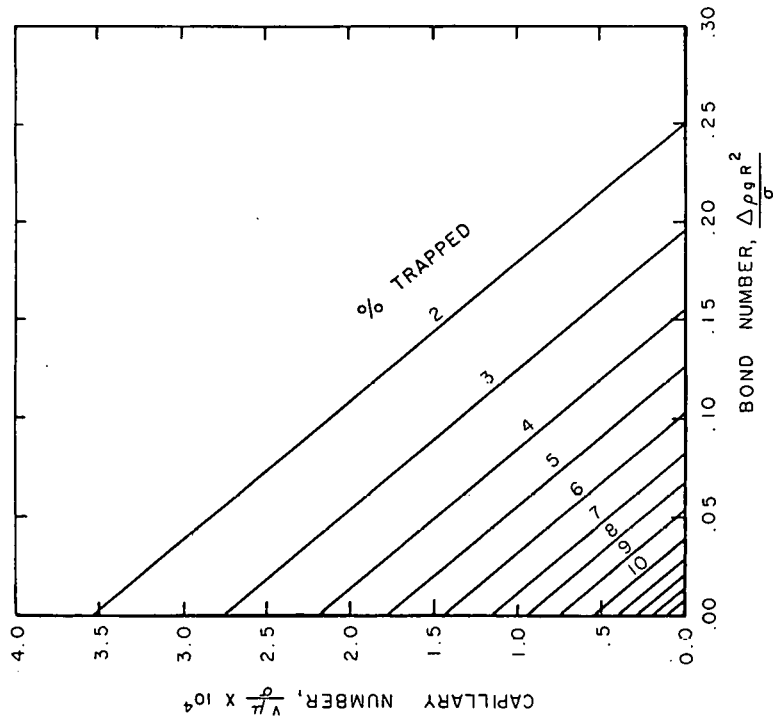


Fig. 5 Plots of capillary number versus Bond number with percent trapped residual saturation as parameter

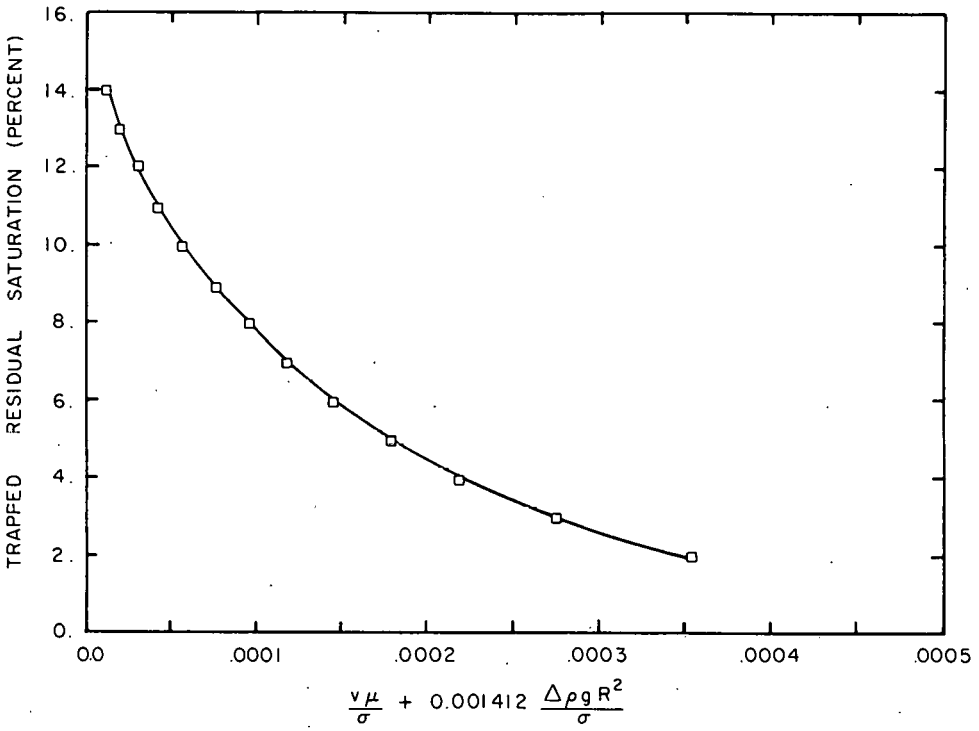


Fig. 6 General correlation of trapped residual saturation with a combined linear function of Bond number and capillary number

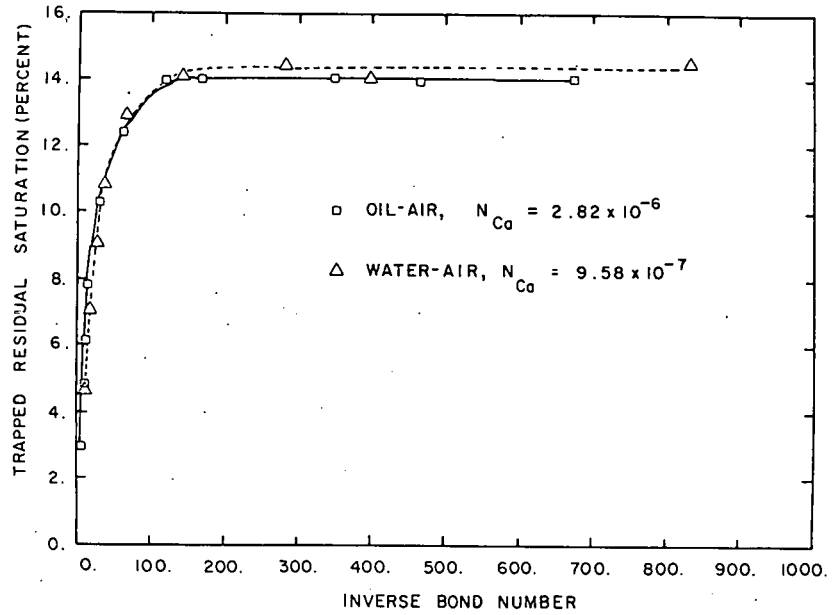


Fig. 7 Comparison of trapped residual saturation versus inverse Bond number for oil-air and water-air as fluid pairs

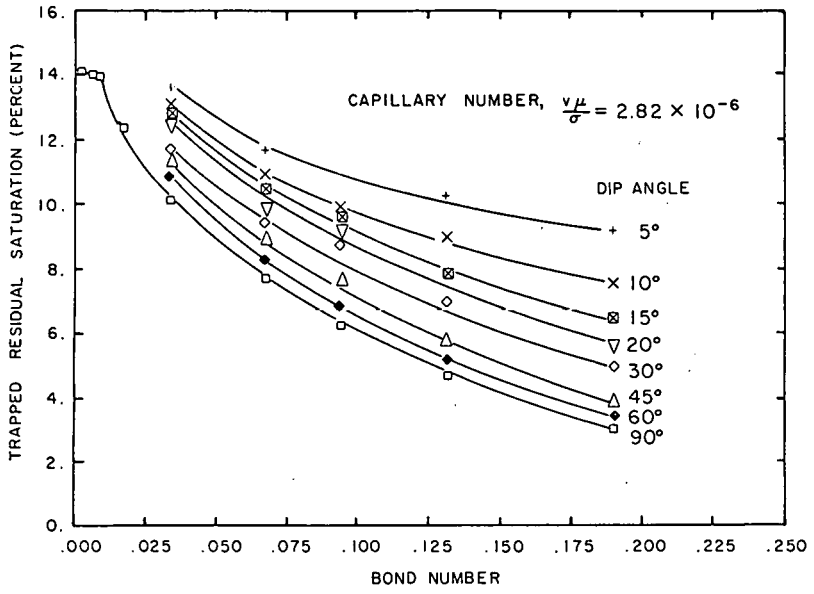


Fig. 8 Effect of Bond number on trapping of residual saturation at different dip angles ($\frac{v\mu}{\sigma} = 2.82 \times 10^{-6}$)

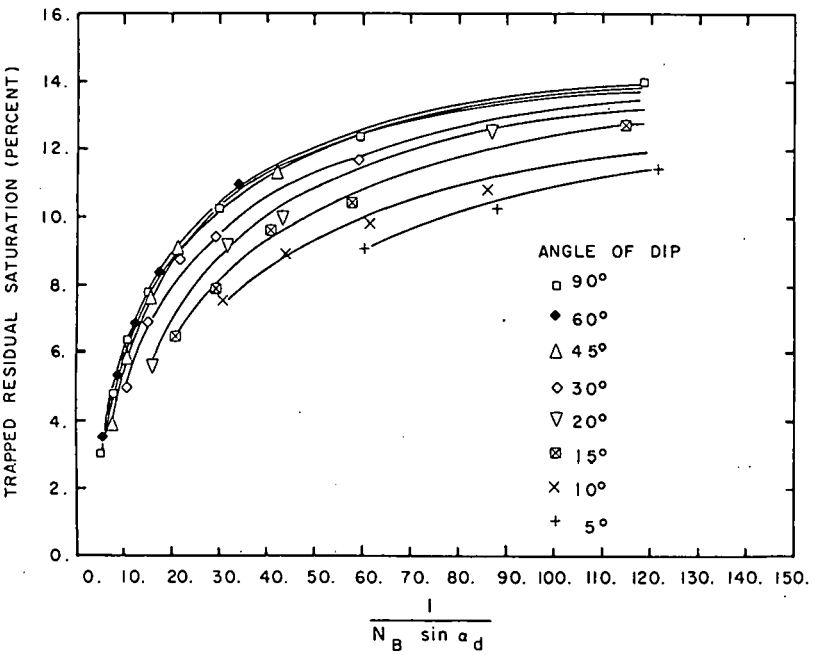


Fig. 9 Trapped residual saturation versus $\left[N_B \sin \alpha_d\right]^{-1}$

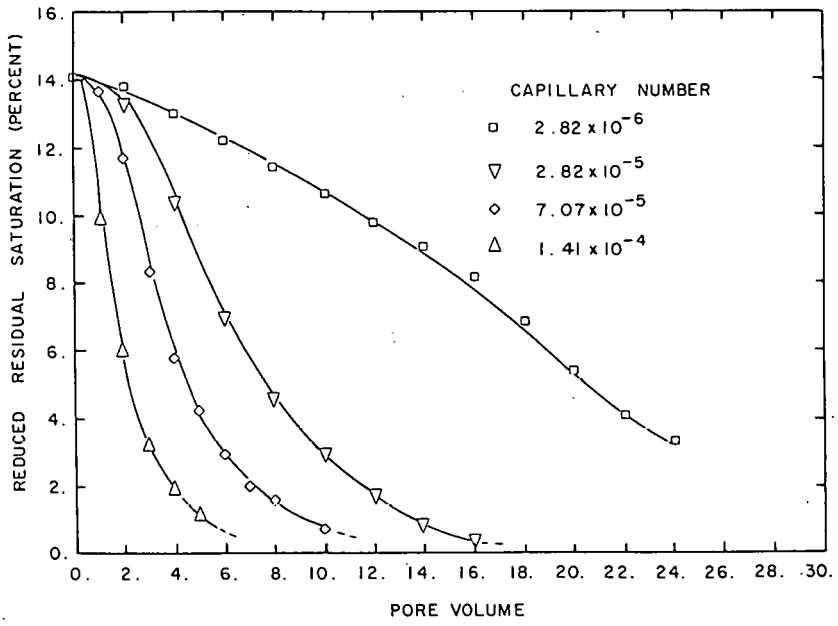


Fig. 10 Effect of amount of injected fluid on reduced residual saturation at various capillary numbers

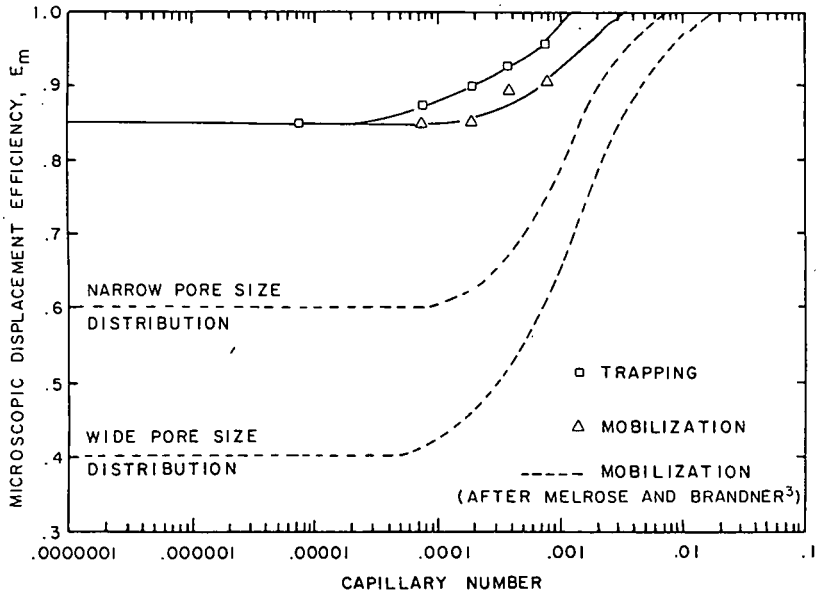


Fig. 11 Plots of microscopic displacement efficiency versus capillary number $\left[v\mu/\phi\sigma\right]$

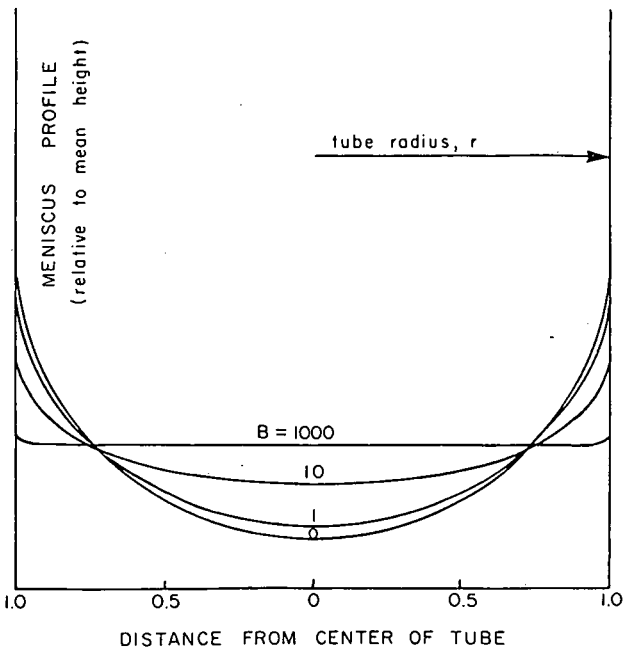


Fig. 12 Interface profile at various Bond numt (based on tube radius, r) (after Concus

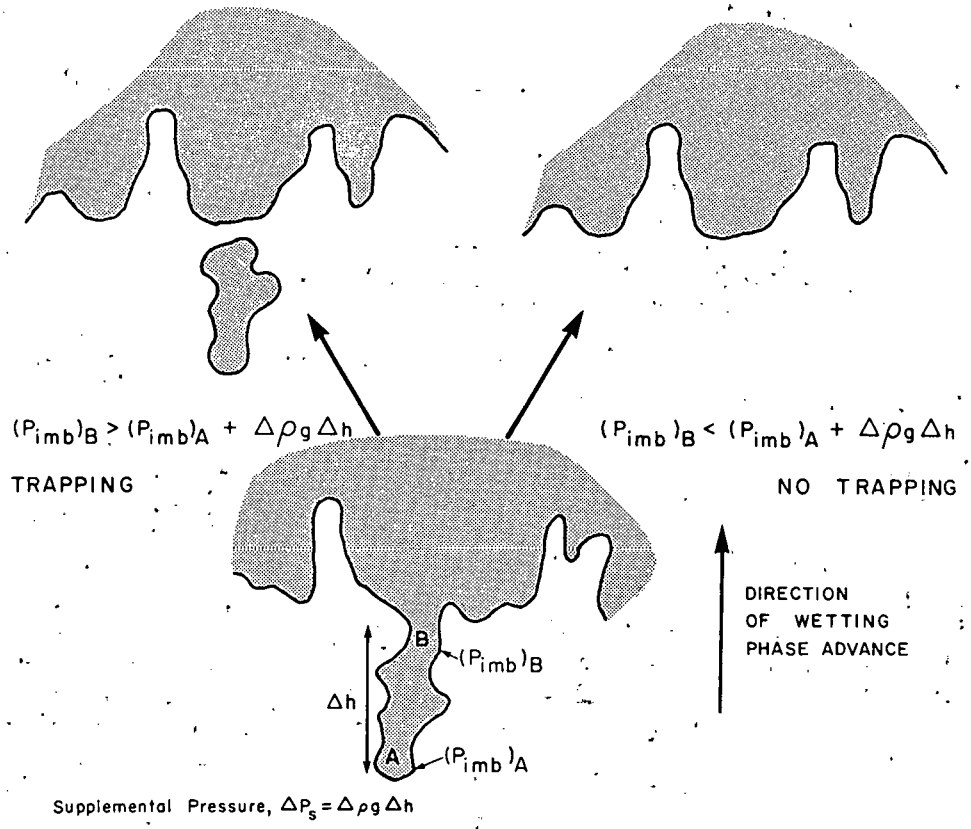
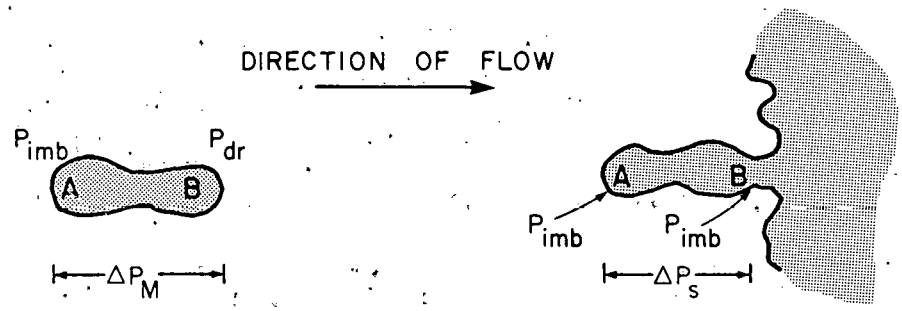


Fig. 13 Illustration of change in trapping mechanism caused by hydrostatic contribution to imbibition capillary pressure



(a) MOBILIZATION

$\Delta P_M > (P_{dr})_B - (P_{imb})_A$

(b) PREVENTION OF ENTRAPMENT

$(P_{imb})_A + \Delta P_s > (P_{imb})_B$

Fig. 14 Conditions required for (a) mobilization of a trapped blob, (b) prevention of entrapment of a potential blob

AN INVESTIGATION OF LOW INVASION FLUIDS FOR PRESSURE CORING*

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ABSTRACT

A new pressure coring system is being developed which could significantly improve the measurement of in-situ oil and gas saturations in hydrocarbon reservoirs. This improved system will incorporate a low-invasion fluid that is stored in the core retriever and is extruded to seal and protect the core. The low-invasion fluid consists of an extremely viscous, brine-based polymer system with sized calcium carbonate bridging particles to minimize invasion. This special coring fluid has been selected from several candidates that were laboratory tested at simulated downhole conditions. Both static and dynamic filtration characteristics were considered. Other important properties of this low-invasion pressure coring fluid are also discussed, including freezing point, formation damage, clay stabilization, wettability changes, and pressure buildup in the core barrel.

INTRODUCTION

Pressure coring has become a valuable tool for obtaining in-situ situations and relative permeability data for enhanced oil recovery projects. Recent improvements in core barrel design and in field operating procedures have greatly improved the reliability of taking cores under pressure. At this time, the primary limitation of pressure coring is fluid invasion of the drilling mud into the core; this can significantly reduce the oil and gas saturations in the core.[1, 2] In addition, deep invasion of particulate matter and drilling solids can cause irreversible formation damage and relative permeability changes.[3, 4]

A great deal of study has been devoted to drilling fluids, including those used in coring, and significant improvements have been made. Unfortunately, the coring fluids in use today are of necessity a compromise between low invasion, good drilling properties, and expense.[5] For example, to minimize invasion into the core, a very viscous mud with a high solids content is deisrable. This type mud would cause high bottom-hole pressures,

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*This work is supported by the U. S. Department of Energy.

low penetration rates, and high costs. In effect, a good drilling mud will be a poor coring fluid, while a good coring fluid will be completely unacceptable as a drilling mud.

To overcome these problems, Sandia Laboratories, under contract with the Department of Energy and in cooperation with industry, is developing an improved pressure coring system (See Figure 1). This new system, which is described in another paper,(6) incorporates a low-invasion fluid which is stored in the inner core barrel and is extruded to seal and protect the core. As the core is pushed up into the inner core barrel, it displaces the low-invasion fluid down the outside of the core and around the pilot bit. Conventional drilling mud is pumped down the drill pipe to the main bit for chip removal and cooling, but the core itself is drilled with the replaceable pilot bit and is contacted only by the low-invasion coring fluid.

The complete separation of the coring fluid from the conventional mud system affords a great deal of freedom in the selection of a low-invasion fluid. The coring fluid is no longer under the severe constraints of viscosity, solids content, chemical composition, or expense that limit the choice of drilling muds. Because of this greater flexibility, a wide variety of fluid types have been considered. Criteria for a low-invasion fluid compatible with the new pressure coring system were established, and all fluid candidates were evaluated on that basis. Those fluids which appeared to be promising were then laboratory tested to select the best low-invasion fluid. Laboratory testing included static filtration at simulated downhole conditions and static invasion testing in high and medium-permeability sandstones. Dynamic invasion testing under simulated drilling conditions is also planned.

CORING FLUID REQUIREMENTS

The requirements for a low-invasion coring fluid are quite different than those for a conventional coring fluid. In order to take full advantage of the improved pressure coring system, the following criteria were established for selection of the low-invasion coring fluid:

1. minimum invasion into the core to obtain accurate saturation data

2. non-reactive with reservoir rock and fluids to obtain accurate permeability and wettability data

3. good drilling properties for removing cuttings and cooling the pilot bit at the very low flow rates encountered while coring

4. stable at the high temperatures anticipated near the bit

5. low freezing temperature to allow removal of the frozen core from the inner core barrel

6. moderate viscosity to limit pressure buildup in the core barrel as the core extrudes the low-invasion fluid.

Of the criteria listed, minimizing fluid invasion and reducing damage to the core are clearly the most important. The coring fluid should also be stable at relatively high temperatures since the pilot bit will be cooled only with the fluid extruded by the core. For a 2 1/2 inch diameter core, the pilot bit will core 10 feet of formation while extruding less than three gallons of coring fluid. The most severe environment for invasion will be at the bit face, where heat generation and continuous removal of surface filter cake will occur.

It is also desirable that the low-invasion fluid have a very low freezing point to facilitate removal of the frozen core from the core barrel. Pressure cores are usually frozen with dry ice at the wellsite to immobilize the reservoir fluids and to permit safe handling of the cores. The core must be taken out of the core barrel and the coring fluid must be completely removed from the surface of the core prior to laboratory testing. It is essential that the fluids within the core remain frozen until the cleaned core can be put into the test cell where it will thaw and undergo a controlled pressure blowdown. If the freezing point of the low-invasion fluid is too high to permit thawing of the coring fluid, the inner core barrel must be milled off and the coring fluid must be carefully chipped away by hand. This is an expensive and time consuming process which should be avoided if possible.

The viscosity of the coring fluid is limited by the allowable pressure buildup in the core barrel as low-invasion fluid is extruded by the core. The maximum pressure buildup occurs when low-invasion fluid is extruded through the 0.125 inch annular gap over the entire ten-foot length of the core. Since the overbalance or differential pressure is the major factor controlling fluid invasion, the pressure buildup inside the core barrel should be kept small.

FLUID TYPES EXAMINED

Since the core retriever will contain only a few gallons of low-invasion coring fluid, the search for an acceptable fluid was not confined to conventional oil field muds. Several exotic fluids were examined before a brine-based polymer system was selected.

Dimethyl siloxane is a readily available silicone fluid used in damping and insulating electronic instruments. At a viscosity of 62,000 centipoise, this fluid showed low invasion in Berea Sandstone and was very effective in removing cuttings at low flow rates. The fluid was also non-freezing to -42°F and stable up to 600°F. Unfortunately, dimethyl siloxane is soluble in toluene and would therefore appear as increased oil saturation in a Dean-Stark core analysis. Silicone fluids also have some undesirable surfactant properties which could significantly alter the wettability of the core.

Several patents have been granted in which a liquid metal such as mercury was used to prevent flushing of the core. A liquid metal coring fluid would be non-reactive, temperature stable, and easily distinguished from both oil and water, so this possibility was examined. Two gallium/tin based low melting point alloys were considered because they were non-toxic and relatively inexpensive. However, mercury injection data on a 1550 millidarcy Brown Sandstone core showed that the mercury invaded almost 70% of the pore space with only 6 psi differential pressure. Similar invasion data from other sources eliminated liquid metals from further consideration.

Of the commonly used oilfield drilling fluids, oil-base muds generally have the lowest API filtrate losses and are stable at elevated temperatures. However, the filtrate loss becomes significant as temperature and differential pressure increase. Since the invading fluid is oil, even very limited invasion from an oil-base mud would significantly increase residual oil saturation measurements. For this reason, oil-base muds are useful in coring for interstitial water saturation, but have limited value in coring for enhanced recovery projects.

Most water-based drilling muds use bentonite, i.e. sodium montmorillinite, for increasing viscosity and reducing fluid loss. These small clay particles are very effective in sealing most rock pores and minimizing fluid invasion, but numerous studies show that bentonite particles often cause severe, irreversible formation damage.[3, 4] Bentonite particles also have a strong affinity for water, and substantial particle invasion could cause changes in the relative permeability of the core. Because of these drawbacks, water-based muds containing bentonite were considered unsuitable for pressure coring.

During recent years, water-based polymer muds have been used extensively in completion and workover operations. Polymer systems have several properties which are desirable in a low-invasion fluid. High viscosity and particle bridging of the formation pores are the major mechanisms in limiting dynamic fluid invasion of the core, and polymers can be used to develop extremely high

viscosities and to effectively suspend large concentrations of bridging particles. In addition, polymers are compatible with a wide variety of drilling fluids and mud additives. There are many polymer drilling fluids in use today, and those examined in this study included carboxymethyl cellulose (CMC), hydroxyethyl cellulose (HEC), Xantham gum (XC), guar gum, polysaccharide, and polyacrylamide.

SELECTION OF HYDROXYETHYL CELLULOSE POLYMER

A major advantage of water-based polymer fluids is the formulation of very high viscosity fluids which have low freezing points. Figure No. 2, which shows the freezing temperatures of various brine solutions, indicates that a 10.8 ppg (30% by weight) $CaCl_2$ brine is non-freezing to below -50°F. Furthermore, $CaCl_2$ brine has been shown to stabilize swelling clays and to prevent formation damage in sensitive sands. To capitalize on these properties, the polymer must be compatible with the 30% $CaCl_2$ and must itself be relatively non-damaging to the formation. Neither the CMC polymer or the polysaccharides tested were usable in this heavy calcium brine, and were therefore unsuitable for use as low-invasion fluids. Guar gum and polyacrylimide have been shown to cause severe, irreversible formation damage and were also judged unsuitable for use as coring fluids.(7)

Table No. 1 shows the API filtrate loss for several different polymer systems. The HEC polymer was clearly superior to the other polymers in reducing filtrate loss under simulated downhole environments. This was confirmed by further high pressure, high temperature testing which showed that the XC polymer and the starch began to break down at 250°F, while the HEC polymer was stable at 300°F.

The HEC polymer mud will also allow removal of a frozen core from the core barrel at very low temperatures. Laboratory tests with Mud A (see Table 1) show that when the mud is flash heated (by spraying the outside of the core barrel with water, for example), the core can easily be removed from the barrel. This extremely viscous fluid (14,000 centipoise at 196°F and 1.57 sec^{-1} shear rate) was quite "liquid" at -53°F and could be wiped off of the core with a rag at that temperature while the core remained solidly frozen.

HEC polymer fluids can develop extremely high viscosities and have low filtrate losses under simulated downhole environments. When used in 30% $CaCl_2$ brine, they are non-freezing to below -50°F and stable up to 300°F. In addition, when $CaCO_3$ bridging particles are used to minimize invasion, the coring fluid is relatively non-damaging and is completely soluble in hydrochloric acid.(7) For the above reasons, HEC polymer with $CaCO_3$ bridging particles in a 30% $CaCl_2$ brine was selected as the best low-invasion coring fluid.

CORING FLUID TESTING AND OPTIMIZATION

In order to reduce invasion while coring to a minimum, three areas need to be examined in greater detail. First, since invasion decreases as fluid viscosity increases, what is the practical upper limit on coring fluid viscosity? Second, what effects do fluid loss additives such as lignosulfonates and starches have on coring fluid invasion? Third, since invasion is a strong function of both bridging particle concentration and particle size distribution, what are the optimum bridging particle values?

The upper limit on coring fluid viscosity was chosen as that viscosity which would result in a maximum pressure buildup in the core barrel of 100 psi. In order to calculate the pressure buildup, the annular flow between the core barrel and the moving core was approximated by laminar flow between two moving plates, and the simplified momentum equations were solved using the power law shear-stress model. The power law model which best describes these highly non-Newtonian polymer systems at low shear rates is of the form $\tau = k\gamma^n$ where τ is shear stress, k is the consistency index (the absolute viscosity at $\gamma = 1\ sec^{-1}$ shear rate), and n is the power law exponent.[8] The resulting velocity profile and pressure buildup equations, which were rather complicated trancendental functions, were solved numerically on a computer and clearly demonstrated the advantages of using a shear-thinning fluid such as the HEC polymer. For example, Mud A (see Table 1) with k = 14,000 cp and n = 0.57, had a pressure buildup of only 31 psi, which is the same pressure buildup that a 3700 cp Newtonian fluid would yield. This mud was already semi-solid at rest and would not pour at room temperature, so little would appear to be gained by further increasing the viscosity.

There are a number of additives which may improve the fluid loss performance of the HEC polymer. Lignosulfonates are often used in drilling and completion fluids both to reduce viscosity and to decrease fluid loss, but because of their dispersant properties, lignosulfonates are not used in coring fluids. Starches are often used as fluid loss additives and are effective in sealing pore openings in permeable formations. Experimental data indicates that some starches cause severe formation damage, so their use in a coring fluid is questionable.[9] There are many starches and starch derivatives available today and further testing is needed to determine their usefulness in the low-invasion coring fluid. One additive which does appear to be useful in the low-invasion fluid is magnesia (MgO), a patented additive to HEC systems which reduces the filtrate loss and stabilizes the polymer at high temperatures.[10] Static filtration tests of Mud B at 300°F and 500 psi differential pressure showed that the magnesia reduced the API filtrate loss from 6.0 cc to 3.4 cc. The magnesia additive had little effect on filtration losses at lower temperatures, but it did improve the high temperature properties of HEC and was therefore included in the low-invasion coring fluid.

There are four major effects which limit drilling mud invasion; viscosity of the mud, surface tension effects between the mud and reservoir fluids, particle bridging of formation pores, and external filter cake formation on the exposed formation face. The effectiveness of both particle bridging and the filter cake in limiting invasion is a function of the particle size distribution (PSD) of the mud. Gates[11] examined filtrate losses through filter cakes and found that the optimum PSD for minimizing fluid loss was roughly 65% by weight colloids (less than 1 micron), 30% silt (1 to 74 microns), and 5% sand (larger than 74 microns). Several authors have studied the bridging of formation pores and have shown that colloidial particles are ineffective in sealing high permeability cores, and that particles in the silt range are most effective in minimizing invasion.[12, 3, 4] A general guideline which is often used says that the mud should contain at least 5% by volume of bridging particles with a median size larger than one-third of the median pore size.

None of the previously cited papers dealt with the effects of polymers on the optimum particle size distribution, so a static invasion study of five different polymer muds was made. The muds were made up by adding 25 lb/bbl of various sized $CaCO_3$ particles to a base mud consisting of 5 lb/bbl HEC polymer in 30% $CaCl_2$ brine. The tests were run in a Hassler core holder using Grey Berea Sandstone (20% porosity and 350 md permeability) and Brown Sandstone cores (22% porosity and 1550 md permeability). A pressure differential of 500 psi and hydrostatic loading of 3000 psi were used for all tests. The results are summarized in Tables 2 and 3 and in Figure 3.

Although it is difficult to draw general conclusions from such a limited number of tests, it is clear that the HEC polymer has a significant effect on the optimum PSD for minimizing invasion. Mud #1 very closely matched the one-third rule for PSD in Grey Berea Sandstone yet had much more static invasion than any of the other muds. The polymer itself appears to supply effective bridging in the smaller size range and further addition of very fine bridging particles is not effective. Mud #2, #3, and #4 varied greatly in fluid invasion despite very similar size distributions. The only major variable was the size and shape of those particles which were larger than 100 microns; Mud #2 had small, thin plate-like particles, Mud #3 had much larger plate-like particles, and Mud #4 had small, well-rounded particles. The small plate-like particles were the most effective in reducing invasion. Pore size distribution data from Table 3 shows that this is a surface filter cake phenomena which should not be a factor in dynamic invasion at the bit face.

These 100 micron and larger particles cannot enter the Brown Sandstone (45 micron mean pore throat diameter) or the Berea Sandstone (16 micron mean) and will be continuously scraped off the core by the pilot bit.

Future laboratory studies will focus on dynamic invasion of cores, and equipment is being designed to scrape the surface of the core while test fluids are circulated by the core face at simulated downhole conditions. Dynamic invasion is usually much more severe than static invasion and is limited primarily by particle bridging of the formation pores, while static filtration is limited primarily by the surface filter cake. Dynamic invasion will be examined as a function of particle size distribution in the presence of HEC polymer. In addition, field testing of the low-invasion coring fluid is planned for this summer. Fluid invasion will be measured with chamical tracers and/or radioactive tracers to evaluate the effectiveness of the low-invasion fluid in actual coring operations.

CONCLUSIONS

1) The best low-invasion coring fluid found in this study was a stabilized hydroxyethyl cellulose polymer with $CaCO_3$ bridging particles in 30% by weight $CaCl_2$ brine.

2) The recommended coring fluid exhibits very low static invasion and filtrate loss and is non-reactive with reservoir rocks and fluids, stable to 300°F, non-freezing to below -50°F, and causes little pressure buildup in the core barrel.

3) The HEC polymer changes the optimum particle size distribution and makes larger particles more effective in reducing static invasion. Thin plate-like particles form a more effective surface filter cake than well-rounded particles.

4) Further work is required to evaluate various additives which could improve the low-invasion fluid. In particular, dynamic testing under simulated drilling conditions is needed to evaluate the effects of particle concentration and particle size distribution.

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Table 1 - Filtrate Loss of Various Polymer Muds

Mud Type	API Filtrate Loss in 30 Minutes, cc. 72°F/100 psi	200°F/500 psi
A	0.4	2.4
B	0.0	2.8
C	1.0	10.4
D	3.8	10.6
E	2.5	15.8

Mud A - 100 lb/bbl lost circulation pill containing HEC, lignosulfonates, and $CaCO_3$ in 30% $CaCl_2$ brine

Mud B - 20 lb/bbl HEC with 100 lb/bbl $CaCO_3$ in 30% $CaCl_2$ brine

Mud C - 1.5 lb/bbl XC and 5 lb/bbl starch with 100 lb/bbl $CaCO_3$ in 37% $CaCl_2$ brine

Mud D - 20 lb/bbl XC with 100 lb/bbl $CaCO_3$ in 30% $CaCl_2$ brine

Mud E - 10 lb/bbl polysaccharide with 100 lb/bbl $CaCO_3$ in 25% KCl brine

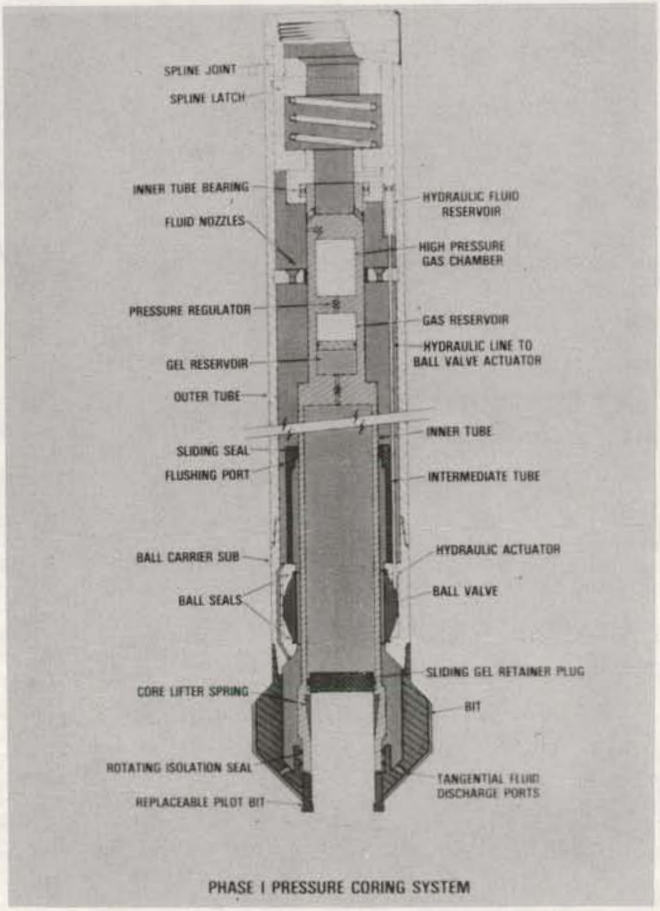


Figure 1 - Conceptual Drawing of Improved Pressure Coring System

Table 2 - Fluid Invasion and Filtrate Loss for Various Particle Size Muds, cc.

	Grey Berea Sandstone		Brown Sandstone		API Filtrate Loss	
	1 Minute	30 Minute	1 Minute	30 Minute	100 psi, 72°F	500 psi, 200°F
Mud #1	21.0	38.2	17.0	27.6	8.4	24.0
Mud #2	0.5	3.7	4.0	15.9	1.4	11.6
Mud #3	5.0	8.3	17.0	22.9	3.2	11.0
Mud #4	1.5	7.1	7.0	11.9	2.0	14.4
Mud #5	8.2	12.3	5.5	10.2	4.2	18.4

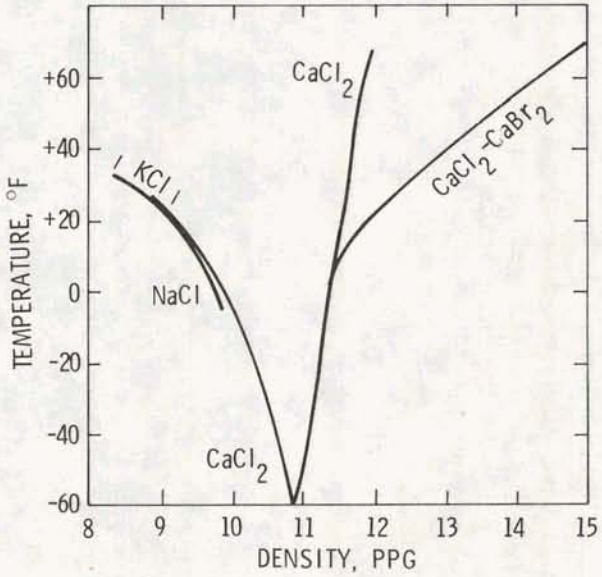


Figure 2 - Freezing Temperatures of Various Brines (13)

Table 3 - Pore Size Distribution Data

Sample Identification:	Berea Sandstone	Brown Sandstone
Vertical Permeability, md:	198	1520
Porosity, percent:	19.8	22.3
Pore Entry Radius, microns	Percent Pore Space	
35	100.0	94.8
30	100.0	77.0
25	100.0	58.1
20	99.8	40.7
15	95.1	29.6
10	69.3	24.2
8	51.3	22.2
6	38.6	20.3
4	30.7	17.9
3	26.8	16.4
2	22.9	14.4
1	17.4	11.3
0.8	16.0	10.2
0.6	14.2	9.0
0.4	11.9	7.3
0.3	10.5	6.2
0.2	8.8	4.6
0.1	6.4	3.3
0.05	4.7	2.2

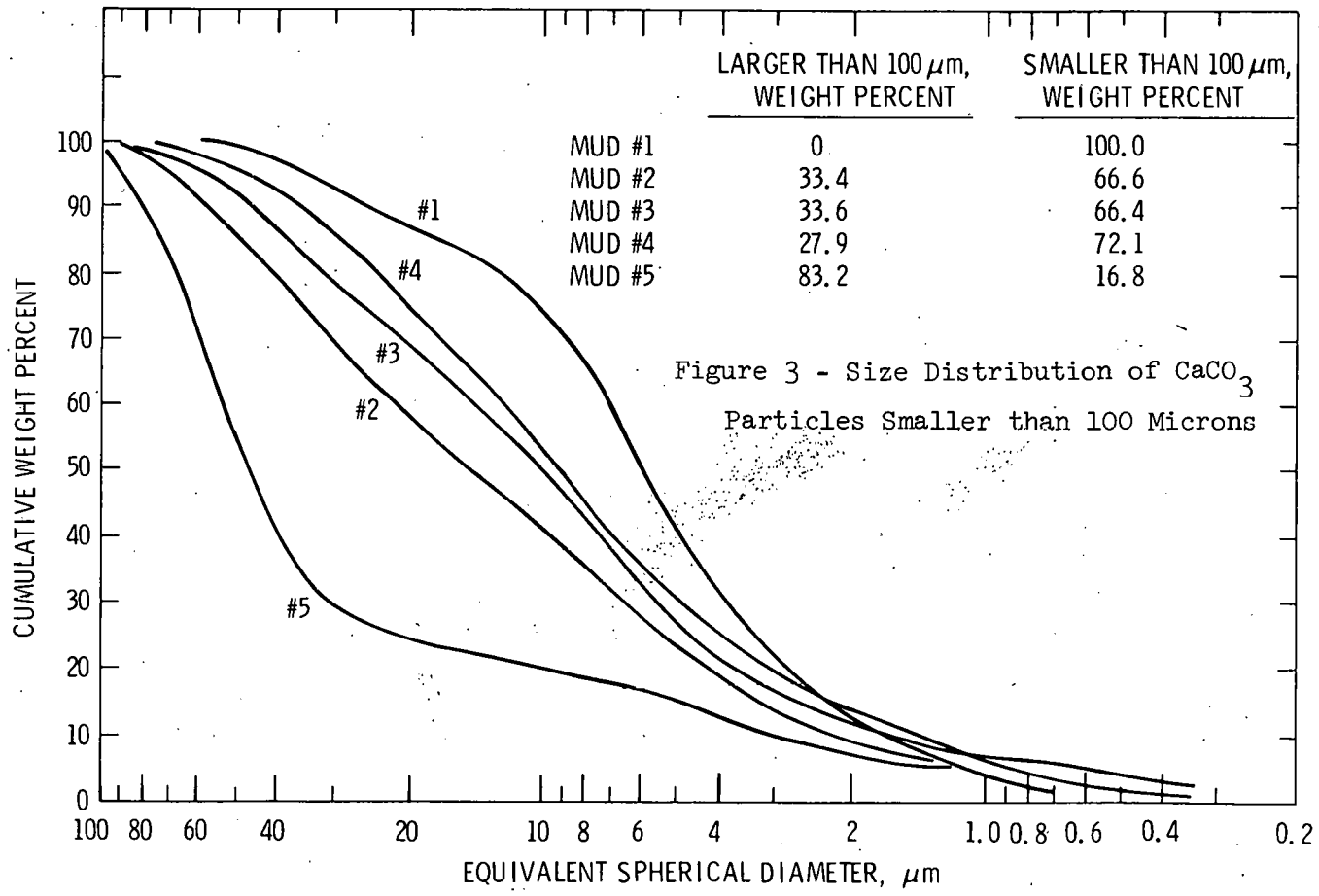


Figure 3 - Size Distribution of $CaCO_3$ Particles Smaller than 100 Microns

THE SINGLE-WELL CHEMICAL TRACER TEST; DIRECT CALCULATION OF RESIDUAL OIL SATURATION FROM FIELD DATA

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Abstract

The field data obtained in a single-well chemical tracer test are pairs of concentration profiles for primary and product tracers. These are measured values of tracer concentractions C_i as functions of produced fluid volume Q.

These data have previously been subjected to analysis by computer simulation. Input parameters to the simulator, including S_{OR}, were varied until the computer output matched the field curves as well as possible. (or practical).

In this paper, we develop a direct procedure for calculating S_{OR} from the field data. The retention volume of tracer i is defined as

$$\bar{Q}_i = \frac{\int_0^\infty c_i Q dQ}{\int_0^\infty c_i dQ}$$

which can be calculated by direct integration of the measured profiles. We show the relationship between S_{OR} and the retention volumes of primary tracer A and product tracer B. Under ideal test conditions, this is

$$S_{OR} = \frac{\bar{Q}_A - \bar{Q}_B}{\bar{Q}_A + (K_A - 1)\bar{Q}_B}$$

where K_A is the equilibrium distribution coefficient of tracer A between oil and brine. We show how this result can be corrected for the non-ideal conditions of real field tests.

The sensitivity of a single-well chemical tracer test for measuring S_{OR} is related to $\bar{Q}_B$. We show how both ideal and real tests can be designed for optimal sensitivity. Finally, we use the direct method to obtain values for S_{OR} from published test data. The results are compared to the saturations obtained by computer simulation.

Prepared for DOE under Contract No. DE-AS19-78BC20006

Direct Interpretation of Single-Well Chemical Tracer Tests

Introduction

Single-well chemical tracer tests have normally been interpreted by detailed computer simulation (1). The simulator solves the basic material balance equations numerically to predict concentration profiles during fluid production. S_{OR}, dispersion coefficient, hydrolysis rate constant, and other input variables are adjusted to obtain the "best fit" to the concentration profiles measured in the field test.

This procedure has worked well for tests which produced more or less classical Gaussian-shaped concentration profiles. In other cases, reservoir and well-bore problems have caused non-ideal shapes to appear. Layering, flow irreversibilities of various types, fractures, and fluid drift have all been encountered on various occasions.

Each of these effects can be built into the simulator at the expense of complicating the model and adding new unknown input parameters. While good fits can eventually be obtained, questions always remain as to the uniqueness of the value of S_{OR} predicted.

We have always known that detailed simulation was not essential in ideal cases of tracer flow. The basic chromatographic equation for equilibrium flow in the presence of residual oil is

$$V_i = \frac{V_{BR}}{1+\beta_i} \tag{1}$$

where: V_i = local velocity of tracer i in the pores

V_{BR} = local velocity of brine, the carrier

$\beta_i = K_i S_{OR}/(1-S_{OR})$

K_i = equilibrium distribution coefficient of tracer i, (concentration in oil/concentration in brine)

Suppose tracers A and B with different K values (hereafter we assume $K_B = 0$, for simplicity) are located at the same position in the formation at time t_o. The tracers then flow along a common path; their concentrations $C_A(Q)$ and $C_B(Q)$ are measured as they pass a remote point X_1. Q is the flow past point X_1 since t_o. If equation (1) holds, we can show that

$$\frac{\bar{Q}_A}{\bar{Q}_B} = 1+\beta_A \tag{2}$$

where the mean residence volumes are calculated by

$$\bar{Q}_i = \frac{\int_0^\infty C_i Q dQ}{\int_0^\infty C_i dQ} \tag{3}$$

The basic objective of the single-well chemical tracer test is to create the above situation in a target formation, and to do it in a manner such that the remote point X_1 is the well bore. For various practical reasons, we cannot satisfy the conditions leading to equation (2) exactly. Our method, producing tracer B from tracer A in the reservoir by chemical reaction, has an obvious limitation. Some B will be produced while we are pushing A out to the reaction location; some B will also be formed as we produce the fluid. Both of these effects are contrary to the assumption that A and B are "together" at time t_o.

This report shows how we can correct equation (2) so that it can be applied under normal field test design conditions. We will then show how the corrected equation can be used to obtain a value of S_{OR} by integrating field-measured concentration profiles according to equation (3). Finally, we will use the corrected equation to show the effect of design variables on test sensitivity for S_{OR} determination.

Single-Well Tracer Test Design

The typical single-well tracer test consists of three distinct phases:

(1) Injection - primary tracer A is injected as a dilute solution in Q_A barrels of brine; injection of brine then continues until Q_I barrels are in the formation. All injected fluid is usually tagged with a non-reactive tracer for material balance control. The total time of injection is Δt_I.

(2) Reaction (soak) phase - the well is shut in for time Δt_S; tracer A hydrolyzes to form product tracer B in the formaiton.

(3) Production - the well is back-produced by natural flow, gas-lift, or pumping as appropriate. C_A and C_B are measured as functions of Q, the barrels of brine produced from the formation. The total time to produce Q_I barrels is Δt_P.

Two of the primary design factors are thus

$$F = Q_A/Q_I \tag{4}$$

which determines the injection profile of tracer A, and

$$R = \frac{(\Delta t_I + \Delta t_P)/2}{\Delta t_S} \tag{5}$$

which determines how "ideal" the test is. The smaller R is, the less B is produced during the flow periods relative to the soak period. Both F and R can be varied within certain limits by the test designer.

The following analysis shows the relative importance of these choices.

Effect of Design & Reservoir Parameters

Using a perfectly stirred multi-cell model we have shown that equation (2) holds exactly if R=0, independent of the injection profile of tracer A and the amount of dispersion. This suggest that R is really the most critical design factor for a test. F will only matter when R > 0, which must be true in any real test.

For this real world case (R > 0) we have solved the tracer balance equations for a test with no dispersion and an impulse input of tracer A (F=0) as a function of R. Two important results are obtained from this solution:

(1) If less than half of the original A is hydrolyzed to B during the test, the results are essentially independent of the extent of hydrolysis. Almost all tracer tests run to date satisfy this condition.

(2) In this case, the corrected form of equation (2) is,

$$\frac{\bar{Q}_A}{\bar{Q}_B} = (1+\beta_A)\ \frac{1+2R}{1+2R\left(1+\frac{\beta_A}{2}\right)} = \frac{1+\beta_A}{1+\frac{R\beta_A}{1+2R}} \qquad (6)$$

This result applies for F = 0 and no dispersion, which corresponds to a mixing cell length $\Delta r=0$ in the cell model. We have developed a simulator based on the mixing cell model to extend our theoretical results to other cases, in particular, finite mixing lengths.

The simulator input includes values for β_A, F, R, Δr, and r_I, the radius of investigation. The latter is the distance away from the well-bore that tracer A reaches during injection. These are the basic design variables for a single-well tracer test in a homogeneous formation in which only radial flow occurs.

Output from the simulator is the test history, including the concentration profiles $C_A(Q)$, $C_B(Q)$. The program also computes $\bar{Q}_A$ and $\bar{Q}_B$ using equation (3) and the trapezoid rule for integration.

We have run simulations to cover the normally observed ranges of all of the tracer test design variables. These are:

(1) $0.25 \leq F \leq 0.50$ - primary tracer bank has always been between 25% and 50% of the total injected volume.

(2) $0.1667 \leq R \leq 0.50$ - the ratio of average flow time to shut-in time has approached 0.5 in certain high drift cases: values lower than 0.1667 have never been considered practical.

(3) $0 \leq \Delta r/r_I \leq 0.20$ - mixing length is related to apparent dispersion coefficient α by

$$\alpha = \frac{\Delta r}{2} \qquad (7)$$

The observed values of Δr have ranged from 0.2 to 2 feet in simulations of field tests. The usual range of radius of investigation is 10 to 20 feet.

(4) $\frac{1}{2} \leq \beta_A \leq 2$ - this has always been considered the most sensitive range of β_A for field tests. We have always tried to choose the primary tracer such that its K value and the expecte)R would cause β_A to be in this range.

The computer-preducted values of $\bar{Q}_A/\bar{Q}_B$ for 54 runs are tabulated in Table 1. It can be seen that for a given β_A the observed value of $\bar{Q}_A/\bar{Q}_B$ decreases with increasing Δr (more dispersion) and increasing R (more flow time relative to shut-in time); it is almost independent of F at constant Δr and R.

We have been able to express the dependence of $\bar{Q}_A/\bar{Q}_B$ on these design and reservoir parameters in terms of two emperical correction factors to equation (6). It was first noticed that the variation with Δr was linear, so that we could extrapolate to $\Delta r = 0$ (no dispersion) with assurance. These limiting values of $\bar{Q}_A/\bar{Q}_B$ were then correlated by the expression,

$$\left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_{\Delta r=0} \approx (1+\beta_A)\left(\frac{1+2R}{1+2R(1+\frac{\beta_A}{2})}\right)(1+.025\beta_A F) \tag{8}$$

which fits all our results within $\pm$ 0.5%. The new factor multiplying equation (6) corrects for the injection profile parameter F.

The dispersion correction was then obtained by correlating the linear Δr variations in the form

$$\frac{\bar{Q}_A}{\bar{Q}_B} = \left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_{\Delta r=0}\left(1-A\,\frac{\Delta r}{r_I}\right) \tag{9}$$

where the radius of investigation r_I is given by

$$r_I = \left[\frac{5.61 \times Q_{INJ}}{2\pi H\phi(1-S_{OR})(1+\beta_A)}\right]^{\frac{1}{2}} \tag{10}$$

and H = formation thickness

ϕ = formation porosity

When the mixing length Δr is made dimensionless in this way, the coefficient A turns out to be a surprisingly simple function of R, F and β_A. The final correction factor, again fitting the computed values within $\pm$ 0.5%, is

$$\frac{\bar{Q}_A}{\bar{Q}_B} = \left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_{\Delta r=0} \cdot \left[1-(R^{\frac{1}{2}}+.08\beta_A F)\,\frac{\Delta r}{r_I}\right] \tag{11}$$

As an example of using these corrections, consider a tracer test with the following design and reservoir prameters:

$H = 20$ feet; $\phi = 0.30$

$Q_A = 1000$ bbls; $Q_{INJ} = 2000$ bbls.

$\Delta t_I = 2$ days; $\Delta t_P = 2.5$ days; $\Delta t_S = 9$ days

$K_A = 6.7$; S_{OR}(estimated) $= 0.13$

Δr (estimated from shape of mat.bal. tracer curve) $= 1$ ft.

From these we calculate

$$\beta_A = \frac{(0.13)(6.7)}{1-0.13} = 1.0$$

$$r_I = \left(\frac{2000 \times 5.61}{2\pi(20)(0.30)(1-.20)(1+1.0)}\right)^{1/2} = 13.6 \text{ FT}$$

$$R = \frac{\frac{2+2.5}{2}}{9} = 0.25$$

$$F = \frac{1000}{2000} = 0.50$$

Using equation (8), we predict a no-dispersion value

$$\left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_{\Delta r=0} = (1+1.0)\left(\frac{1+0.5}{1+0.5(1+\frac{1.0}{2})}\right)(1+.025(1.0)(0.5)) = 1.736$$

The dispersion corrected value by equation (11) is

$$\left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_P = (1.736)\left[1-(0.5+(.08)(1.0)(.5))\frac{1}{13.6}\right]$$

$$= 1.667$$

The value predicted by the simulator (Table 1) is 1.672.

Application to Field Test Data

The above parameters are very close to the results of field test #2 reported by Bragg, et al (2). The differences, as reported in this reference, are

Δr (estimated) $= 0.6$ Ft.

$\Delta t_S = 12$ days ; $\Delta t_P = 3$ days

which leads to

$$R = \frac{2.5}{12} = 0.28 \quad ; \quad \frac{\Delta r}{r_I} = .044$$

The field-measured curves for $C_A(Q)$ and $C_B(Q)$ are shown in Figure 2 of the above reference. These data were replotted, smoothed, and integrated numerically to give the following results (see equation (3)).

$$\bar{Q}_A = 1598 \text{ BBLS}$$

$$\bar{Q}_B = 953 \text{ BBLS}$$

or

$$\left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_{OBS} = 1.678$$

From equation (8), we would predict a no-dispersion value (assuming $\beta_A = 1$)

$$\left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_{\Delta r=0} = (2)\left(\frac{1+0.42}{1+0.42(1.5)}\right)\left(1+.025(1.0)(0.5)\right)$$

$$= 1.764$$

Correcting for dispersion,

$$\left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_{PREDICTED} = 1.764\left(1-(.456+(.08)(1.0)(.5))\ \frac{.6}{13.6}\right)$$

$$= 1.725$$

This result is slightly higher than the observed value of 1.678. We now assume that the correction factors of equations (8) and (11) are essentially constant, and solve equation (6) for β_A in terms of R and $(\bar{Q}_A/\bar{Q}_B)$ corrected;

$$\beta_A = \left[\frac{1+2R}{1+R\left(2-\left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)\right)}\right]_{CORR} \cdot \left[\left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_{CORR} - 1\right]$$

where

$$\left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_{CORR} = \left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_{OBS} \Big/ (1+.025\beta_A F)\left[1-(R^{1/2}+.08\beta_A F)\frac{\Delta r}{r_I}\right]$$

$$= 1.678/(1.012)(.978) = 1.698$$

substituting,

$$\beta_A = \frac{(1+.408)}{1+.204(2-1.698)} \quad (1.698-1)$$

$$= .926$$

This gives a predicted value of S_{OR} from the definition of β_A; solving,

$$S_{OR} = \frac{\beta_A}{K_A+\beta_A} = \frac{.926}{6.7+.926} = 0.121$$

Bragg et al. report a value $S_{OR} = 0.125 \pm .015$ from direct simulation.

Applications to Design of Field Tests

The corrections given in equations (8) and (11) are relatively small in magnitude. We have apparently been fortunate in earlier tests and should not be overly concerned in future designs, provided we stay within the suggested ranges for F and $\Delta r/r_I$.

Our field test example shows the importance of R in test interpretation. We now consider how R effects field test design. We would like to know in particular if the practical limits on the size of R should effect our choice of tracers for a given reservoir.

We must first discuss the sensitivity of the single-well test, which we can define as the rate of change of $\bar{Q}_B$ with respect to S_{OR} at constant test volume;

$$S \equiv -\left(\frac{\partial \bar{Q}_B}{\partial S_{OR}}\right)_{\bar{Q}_A} \tag{12}$$

Since $\bar{Q}_B$ decreases as S_{OR} increases, we use the negative sign so that S will be positive.

For an ideal test, with R = 0, S can be obtained from equation (2);

$$S = -\bar{Q}_A \frac{\partial}{\partial S_{OR}}\left(\frac{1}{1+\beta_A}\right) = \frac{\bar{Q}_A K_A}{(1-S_{OR}+K_A S_{OR})^2} \tag{13}$$

Within limits, we are free to choose primary tracer A such as to maximize S. Differentiating equation (13) with respect to K_A,

$$\frac{\partial S}{\partial K_A} = \bar{Q}_A \frac{(1-S_{OR}+K_A S_{OR}) - 2K_A S_{OR}}{(1-S_{OR}+K_A S_{OR})^2} \quad 4)$$

Setting equation (14) equal to zero, we find that the maximum occurs when,

$$1-S_{OR} = K_A S_{OR} \tag{15}$$

We conclude from this that $\beta_A = 1$ is optimal for the single-well chemical tracer test if R = 0.

The sensitivity for a real test can be derived from equation (6) in the form,

$$\bar{Q}_B = \bar{Q}_A\left(\frac{1}{1+\beta_A} + \frac{R}{1+2R} \bullet \frac{\beta_A}{1+\beta_A}\right) \tag{16}$$

The result is,

$$S = \bar{Q}_A \frac{(1+R)}{(1+2R)} \frac{K_A}{(1-S_{OR}+K_A S_{OR})^2} \tag{17}$$

The remarkable conclusion is that $\beta_A = 1$ is still optimal, regardless of R. The test sensitivity is reduced by the factor (1+R)/(1+2R).

In summary, we want to make R as small as possible, and choose tracer A such that its K value is as close as possible to the obtimum value,

$$K_A = \frac{1-S_{OR}}{S_{OR}} \tag{18}$$

provided we have an estimate for the expected value of S_{OR}.

Correcting for Non-Ideal Fluid Flow-

Layering Effects

All reservoirs exhibit some degree of permeability stratification. Tracers injected into more permeable layers penetrate further into the formation. One of the redeeming features of a single-well test is that these tracers must return by a longer path, hence tend to be produced at the same time as tracers injected into less permeable layers.

We have evidence from various tests that this flow reversibility is not always observed. One or more strata appear to produce fluid more readily than they accepted fluid during injection. This selective plugging (check-valve effect) is sometimes caused by suspended solids in the bore-hole. Whatever the reason, the resulting tracer concentration profiles may show multiple peaks, and will generally be difficult to interpret with a conventional simulator.

We model the target formation by dividing it into N non-comunicating layers. During the injection phase of a tracer test layer i accepts the fraction f_i of the injected fluid and tracers. During production, the fraction of the total produced fluid from layer i is g_i. We insist that $g_i \neq 0$, wh means merely that any layer which will not produce fluid must be ignored. With this restriction, we

require that

$$\sum_{i=1}^{N} f_i = \sum_{i=1}^{N} g_i = 1 \tag{19}$$

We have used the impulse-input condition to derive a relatively simple correction factor to the mean residence volume for primary tracer A in this N-layer formation. The multi-layer simulator was then used to confirm and generalize the result, which is

$$(\bar{Q}_A)_N = (\bar{Q}_A)_{REV} \sum_{i=1}^{N} \frac{f_i^2}{g_i} \tag{20}$$

where $(\bar{Q}_A)_{REV}$ is the mean retention volume which would be observed for $f_i=g_i$; all i. This if of course, the reversible flow limit.

The correction factor for product tracer B has also been derived and confirmed. Referring to equation (5), we define

$$r = \Delta t_P / \Delta t_I \tag{21}$$

the ratio of production to injection times for the test. The N-layer result corresponding to equation (6) is,

$$\left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_N = (1+\beta_A) \frac{1+2R\left(\frac{1}{1+r}+\frac{r}{1+r}\sum_{i=1}^{N}\frac{f_i^2}{g_i}\right)}{1+2R\left(1+\frac{\beta_A}{2}\right)\left[\frac{1}{1+r}+\frac{r}{1+r}\left(\frac{\sum f_i^3/g_i^2}{\sum f_i^2/g_i}\right)\right]} \tag{22}$$

This result assumes that β_A is the same in all layers. For reversible flow ($f_i=g_i$), this reduces to equation (6) because of equation (19).

One interesting feature of this irreversible flow model can be seen from the extrema of equation (20) with respect to the f_i or g_i subject to equation (19). This calculation shows that

$$\bar{Q}_A \geq (\bar{Q}_A)_{REV}$$

with the equality holding for the reversible limit. Thus the observed retention volume for a primary tracer can only increase if flow irreversibility occurs. This property could be used for diagnosis of bore-hole problems independent of determining S_{OR}.

Applying equations (20) and (22) will require information about the f's and g's for a given test. In some cases, flowmeter surveys during injection and production will supply these data. In other cases, the tracer production profiles themselves will be the only indication of flow irreversibility.

We are reinterpreting several previous tests whose production profiles show multiple "bumps". Each of these curves can be decomposed into a set of individual "layer curves" with normal Gaussian shape. The f's can be obtained from the areas under each curve; the g's then follow from the individual retention volumes. If all of the tracer profiles from the test can be fit with the same set of f's and g's, the model is at least internally consistent if not unique. These results will be reported elsewhere.

Finally, we note that equation (22) can be used to evaluate the sensitivity of the test to measuring S_{OR} as in equation (17). Again, sensitivity is reduced when R>0, but the optimum choice of K_A is still that which makes $\beta_A = 1$.

Fluid Drift in the Formation:

In many tests our assumption of radial flow is not valid. Especially in fields which are still being actively produced by water flooding, there is general fluid movement the formation at the test well. Referred to as "drift", this flow field must be considered as superimposed on the radial flow of a single-well chemical tracer test.

Two-dimensional tracer simulators have been developed by Exxon Production Research Company to account for this effect. We were permitted to use one of these programs to develop correction factors to mean residence volumes for drift effects. The corrections depend on the single dimensionless parameter D defined by

$$D = \frac{(V_D \Delta t_{tot})^2 \pi (H\phi)(1-S_{OR})}{5.61 Q_{INJ}} \tag{23}$$

where
- V_D = linear drift velocity of fluid in the formation
- Δt_{tot} = $\Delta t_I + \Delta t_S + \Delta t_P$, total test time
- $H\phi$ = porosity-thickness product of the formation
- Q_{INJ} = volume of fluid injected with tracers

D is seen to be the square of the "drift" distance divided by the radius of investigation.

We have run cases to cover the expected range of the variables F and R as we did in verifying equation (6), while letting D range as high as 0.667. This produces very distorted profiles, especially for the product tracer.

Our results are correlated very well by the equations,

$$\bar{Q}_A = (\bar{Q}_A)_o \left[1 + \frac{1.15D+0.21D^2}{1+\beta_A}\right] \tag{24}$$

and

$$\bar{Q}_B = (\bar{Q}_B)_o \left[1 + \frac{\beta_A R}{1+2R} + (1.40D+0.60D^2)\right] \tag{25}$$

where $(\bar{Q}_A)_o$ and $(\bar{Q}_B)_o$ are the predicted values of mean residence volumes for R=0 and D=0. Combining these results and ignoring the small corrections for dispersion effects and F (see equations (8) and (11)),

$$\left(\frac{\bar{Q}_A}{\bar{Q}_B}\right)_D \simeq (1+\beta_A) \frac{\left(1+\frac{1.15D+0.2D^2}{1+\beta_A}\right)}{\left(1+\frac{\beta_A R}{1+2R} + (1.40D+0.60D^2)\right)} \tag{26}$$

which is identical to equation (6) when D=0.

Equation (24) and (25) are remarkable for several reasons. The drift corrections depend on β_A in a very simple way, and seem to be independent of F and R over the range investigated. The simple addition of corrections in equation (25) for non-ideal reaction period ($R \neq 0$) and drift is very surprising. The resulting structure of equation (26) allows us to predict the effect of "drift" on test sensitivity with ease. Abbreviating the functions of D by

$$f_A = 1.15D+0.21D^2 \quad (27a)$$

$$f_B = 1.40D+0.60D^2 \quad (27b)$$

we see that

$$\left(\frac{\bar{Q}_B}{\bar{Q}_A}\right)_D = \frac{1+\frac{\beta_A R}{1+2R}+f_B}{1+\beta_A+f_A} \quad (28)$$

Normalized test sensitivity S* is then defined as the negative derivitive of this ratio with respect to S_{OR}. The result is,

$$S^* = \left[(1+\beta_B) - \frac{R}{1+2R}(1+f_A)\right] \frac{K_A}{\{(1-S_{OR})(1+f_A)+K_A S_{OR}\}^2} \quad (29)$$

This result is to be compared with equation (17). Depending on the value of S_{OR}, test sensitivity can either increase or decrease with "drift," since $f_B > f_A$ Perhaps more interesting is the observation that

$$(\beta_A)_{OPT} = 1+f_A \quad (30)$$

which suggests the use of tracers with higher K values for tests with suspected "drift." Equations (28)-(30) are the basis for quantifying test design in such cases.

Equation (24) is the basis for a procedure for determining S_{OR} by a single-well test using only non-reacting tracers. The reversibility problem of the radial single-well test has been removed by the "drift" velocity. This procedure was in fact patented by Deans and Tomich on the basis of simulator demostration of the effect.

As an example, consider two non-reacting tracers A_1 and A_2 such that $K_{A_1} = 10$ and $K_{A_2} = 0$. The tracers are injected simultaneously so that $(\bar{Q}_{A_1})_o = (\bar{Q}_{A_2})_o$. D is assumed to have the value 0.667, so that $f_A = 0.86$ from equation (27b). The observed values of $\bar{Q}_{A_2}$ to $\bar{Q}_{A_1}$ as calculated by equation (3) from the field data are 1785 bbls. and 1189 bbls. respectively.

From equation (25), we predict

$$\frac{\bar{Q}_{A_2}}{\bar{Q}_{A_1}} = \frac{1+0.86}{1+\frac{0.86}{1+\beta_{A_1}}} = \frac{1785}{1189} = 1.501 \quad (31)$$

Solving for β_{A_1} and then for S_{OR},

$$\beta_{A_1} = 2.6 \; ; \; S_{OR} = \frac{\beta_{A_1}}{K_{A_1}+\beta_{A_1}} = 0.21$$

We also note that three tracers with different K values could be used in principle to determine S_{OR} and V_D. This procedure has not been evaluated in the field to date.

Summary

We feel that the direct interpretation of the field production profiles of the primary and product tracers to give values of S_{OR} is a good alternative to computer simulation. As we have shown, under ideal conditions, residual oil saturation is given simply by

$$S_{OR} = \frac{\bar{Q}_A - \bar{Q}_B}{\bar{Q}_A + (K_A - 1)\bar{Q}_B} \tag{32}$$

Real-world complications such as dispersion, non-ideal injection profiles of the primary tracer, drift, and multi-layer effects have been taken into account by appropriate correction factors. Except for conditions of very high drift, these correction factors seem to be accurate to within 1% for the range of test conditions normally found on the field.

This analysis also gives a quantitative basis for designing single-well tracer tests. The sensitivity of a test for measuring S_{OR} can now be evaluated quantitatively with respect to all important parameters.

Nomenclature

β_i	=	$\frac{K_i S_{OR}}{1-S_{OR}}$; dimensionless constant. See equ. 1.
c_i	=	concentration of tracer i
D	=	dimensionless drift parameter. See equ. 23.
f_i	=	in a multi-layer formation, the fraction of fluid accepted by layer i
F	=	the ratio of the amount of injected fluid containing primary tracer A to the total amount of fluid injected. See equ. 4.
g_i	=	in a multi-layer formation, the fraction of fluid produced by layer i
H	=	formation height
K_i	=	distribution coefficient of tracer i. See eq. 1
$\bar{Q}_i$	=	mean residence volume of tracer i. See equ. 3.
Q_{INJ}	=	total amount offluid injected (barrels)
Q_{PROD}	=	total amount of fluid produced (barrels).
r	=	ratio of production time to injection time. See equ. 21.
Δr	=	mixing length for cell model; equal to twice the dispersion coefficient α. equ. 7.

R	=	the ratio of one half of the injection plus production time to the soak time. This ratio indicates how "ideal" the test is. See equ. 5.
S	=	sensitivity factor. S is the rate of change of $\bar{O}_B$ with S_{OR}, $\bar{O}_A$ being constant. One factor to take into consideration when designing tests. See equ. 12.
Δt_I	=	duration of injection phase of test (days)
Δt_P	=	time to produce Q_{INJ} barrels (days)
Δt_S	=	duration of shut-in phase of test (days)
Δt_{TOTAL}	=	the sum of Δt_I, Δt_S and Δt_P
V_D	=	drift velocity of formation fluids
ϕ	=	porosity of test formation.

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2. Bragg, J.R., Carson, L.O., and Atterbury, J.H. "Recent Applications of the Single-Well Tracer Method for Measuring Residual Oil Saturation," SPE 5805, presented at the Improved Oil Recovery Symposium, Tulsa, Okla., March 22-24 1976.

3. Deans, H.A., Tomich, John F., U.S. Patent #3,902,362, "Method to Measure Fluid Drift and Immobile Phase Saturation", Sept. 1975.

TABLE 1 - COMPUTED VALUES OF $\bar{O}_A/\bar{O}_B$

		β = ½			β = 1			β = 2		
	Δr,ft.	½	1	2	½	1	2	½	1	2
	R = 1/6	1.399	1.384	1.351	1.763	1.739	1.687	2.381	2.333	2.230
F = 0.25	= 1/4	1.369	1.350	1.310	1.696	1.667	1.605	2.227	2.172	2.057
	= 1/2	1.311	1.285	1.234	1.574	1.537	1.462	1.966	1.905	1.708
	R = 1/6	1.397	1.382	1.351	1.769	1.745	1.695	2.406	2.359	2.256
F = 0.5	= 1/4	1.365	1.347	1.308	1.701	1.672	1.611	2.252	2.197	2.080
	= 1/2	1.302	1.277	1.227	1.573	1.536	1.461	1.981	1.919	1.790

BODCAU IN SITU COMBUSTION PROJECT
BOSSIER PARISH, LOUISIANA

by

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ABSTRACT

The Bodcau In Situ Combustion Project is a demonstration of an efficient and economical simultaneous air and water In Situ Combustion process. Production is from the Upper Cretaceous Nacatoch Sand which has produced 19° API crude since start of the combustion process in 1976 and has continued since then without interruption.

Since initiation of this jointly-funded project on June 1, 1976, production has totaled 401,646 bbls of previously unrecoverable oil thru April, 1979. Estimated recoverable reserves by means of In Situ Combustion in the project are 700,000 bbls.

Extensive field and laboratory testing is continuing to monitor the progress of the project. In addition to maintaining an efficient combustion process, costs of developing and operating are being kept in great detail to facilitate analysis of key economic factors in projects of this nature.

INTRODUCTION

The demonstration site[1] is located in the Bellevue Field, Bossier Parish, Louisiana, approximately 18 miles northeast of Shreveport, Louisiana (Figure 1). The project area is part of Cities Service Company's Bodcau Fee "B" Lease.

[1]Little, Tracy P., Bodcau In Situ Combustion Project, "Pre-Contract Work and Plan for Project Development," Cities Service Company Topical Report.

Prepared for DOE under Contract No. EY-76-C-03-1189.

Production in the Bellevue Field, discovered in 1921 and covering approximately 900 productive acres, is from the Upper Cretaceous Nacatoch Sand approximately 400 feet deep. Primary production by fluid expansion and gravity drainage caused high producing rates early in the life of the field but decreased very rapidly to only a few barrels of oil per day. Residual oil-in-place after primary techniques had ceased, was estimated at 95 percent. Various stimulation processes were attempted throughout the field but none were successful in producing the heavy 19° gravity crude until an In Situ Combustion process was enacted.

RESERVOIR CHARACTERISTICS

The Nacatoch Sand in the Bellevue Field is very unconsolidated with strings of fossiliferous lime and sandy shale. Porosity averages 33.9 percent with a water saturation of 27.4 percent. Core analysis of the formation indicated a permeability of approximately 700 millidarcies. Net pay and structure maps (Figure 2) were developed from log information to evaluate the project area. The average thickness of the formation throughout the area was determined to be 56 feet. These figures yielded a 1909 bbl/acre-foot or in excess of 2,000,000 barrels of oil-in-place in the project.

The reservoir temperature is 75° F. and the pressure is 40 psig. Viscosity of the 19° gravity crude is 670 cp at reservoir temperature but drops rapidly with an increase in temperature (Figure 3).

FACILITIES

Thirty-three producers and five injectors are included in the demonstration area at the present, with plans to drill five additional producers during mid-1979. The wells were drilled to an average of 450 feet, which was sufficient to penetrate the entire pay interval of the Upper Nacatoch Sand and 7" O.D. casing was set and cemented back to the surface using high temperature resistance materials. Production wells were selectively perforated and equipped with conventional beam pumping units. A downhole water cooling system is required in each producer to combat high temperature problems (Figure 4).

Individual flowlines carry each well's tubing production to a centralized header system. Produced fluid is then sent to the central battery facility.

Natural flow through the casing annulus is transported through an exhaust line to a concrete-lined pit. At the pits, liquids are extracted from the exhaust gas and sent to the central battery facility.

The central battery used for the storage and treatment of the production consists of a free water knockout, emulsion treater, tankage and ACT unit.

Three compressors with a combined output of 20 MMCFD at 250 psig are used to supply the air to the five injection wells. Air is delivered through a trunk system with individual metering and regulation at each injector.

OPERATIONS AND PERFORMANCE

Ignition[2] of the five inverted nine-spot patterns was accomplished between August 7 and September 24, 1976. This was accomplished by injecting approximately 600° F. air, generated by a 30 KW electrical immersion heater, into the formation (Figure 5).

To improve volumetric sweep and provide greater heat transfer ahead of the combustion zone, all five injectors were converted to simultaneous air and water injection in April, 1977. Produced water is injected down the annulus at a rate of 250 bbl/MMCF into the upper section of the zone while air is injected through tubing below a packer into the lower section of the reservoir (Figure 6).

Combustion front breakthrough has occurred at nineteen of the thirty-three producing wells thus far. With the advance of the combustion front toward producing wells, the area surrounding the well becomes thermally stimulated, causing producing rates to greatly increase as the mobility of the oil increases. Commercial producing rates cannot be obtained without this stimulation. Unfortunately, the combustion front will breakthrough, or channel, to the producer before the entire reservoir can be thermally stimulated. This breakthrough of hot gases and sands causes extreme wear of bottomhole tubulars and pumping equipment. The quench water system combats the gases and sands but eventually the problem becomes too intense.

This problem of breakthrough is eliminated by squeeze cementing the portion of the zone that is burned. These wells continue to produce following breakthrough of a front but continual operating problems, as a result of burns, limit the withdrawal capability as the combustion progresses, hampering project

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[2]Joseph, Conrad, Bodcau In Situ Combustion Project, "Ignition," Cities Service Company Topical Report.

economics both by increased operating costs and reducing income rom crude sales.

As anticipated, the problems with the treatment of the oil continues to exist. Treating these emulsions are difficult due to the amount of sand produced with the oil. Various treatment programs are being conducted at the present to minimize this problem.

Since initiation of the project, cumulative air injection through April, 1979 is 6,381,364 MCF. A total of 1,024,613 barrels of water has been injected during the simultaneous phase. Total recovery from the five patterns has been 401,646 barrels through April, 1979 (Figure 7).

MONITORING AND TESTING

Production wells are tested monthly for oil, water and gas volumes. This test is used to allocate production. Flowline temperatures are recorded daily for monitoring downhole conditions. Exhaust gas from each producer is analyzed each month for carbon dioxide, oxygen and carbon monoxide levels. Temperature profiles are run monthly in the five observation wells within the project.

Prior to ignition, pulse tests were conducted at each injector. These tests indicated areas within the project where directional permeability was higher. This was used to determine what wells in the project would recieve stimulation first.

Also, pressure falloff tests[3] were run before injectors were ignited and again before conversion to simultaneous air-water injection. From these tests, permeabilities plus wellbore damage were calculated. Average permeability, before ignition, ranged from 6 to 32 millidarcies and after six months of dry combustion the average was 112 to 544 millidarcies.

Produced oil and water samples from each well in the project has been analyzed for composition, specific gravity and viscosity. Analysis of these fluids aid in the treatment of the crude.

Twenty-five combustion tube tests[4] have been conducted to determine burn parameters and the optimum simultaneous water and air injection ratio. It was determined that during dry combustion the fuel deposit was 2.05#/ft^3 with an air requirement of

[3]Bandyopadhyay, P., and Joseph, C., Bodcau In Situ Combustion Project, "Pressure Transient Testing," Cities Service Company Topical Report.

[4]Pusch, W. H., Bodcau In Situ Combustion Project, "Combustion Tube Tests," Cities Service Company Topical Report.

17.0 MMSCF/acre-foot. By switching to the simultaneous phase and injecting at a ratio of 2.25 barrels of water per MMSCF of air the fuel deposit was reduced to 1.65#/ft^3 and the air requirement reduced to 10.6 MMSCF/acre-foot. These tests have indicated that in the Bellevue Field a simultaneous combustion phase requires approximately 37% less injected air than a dry combustion phase project.

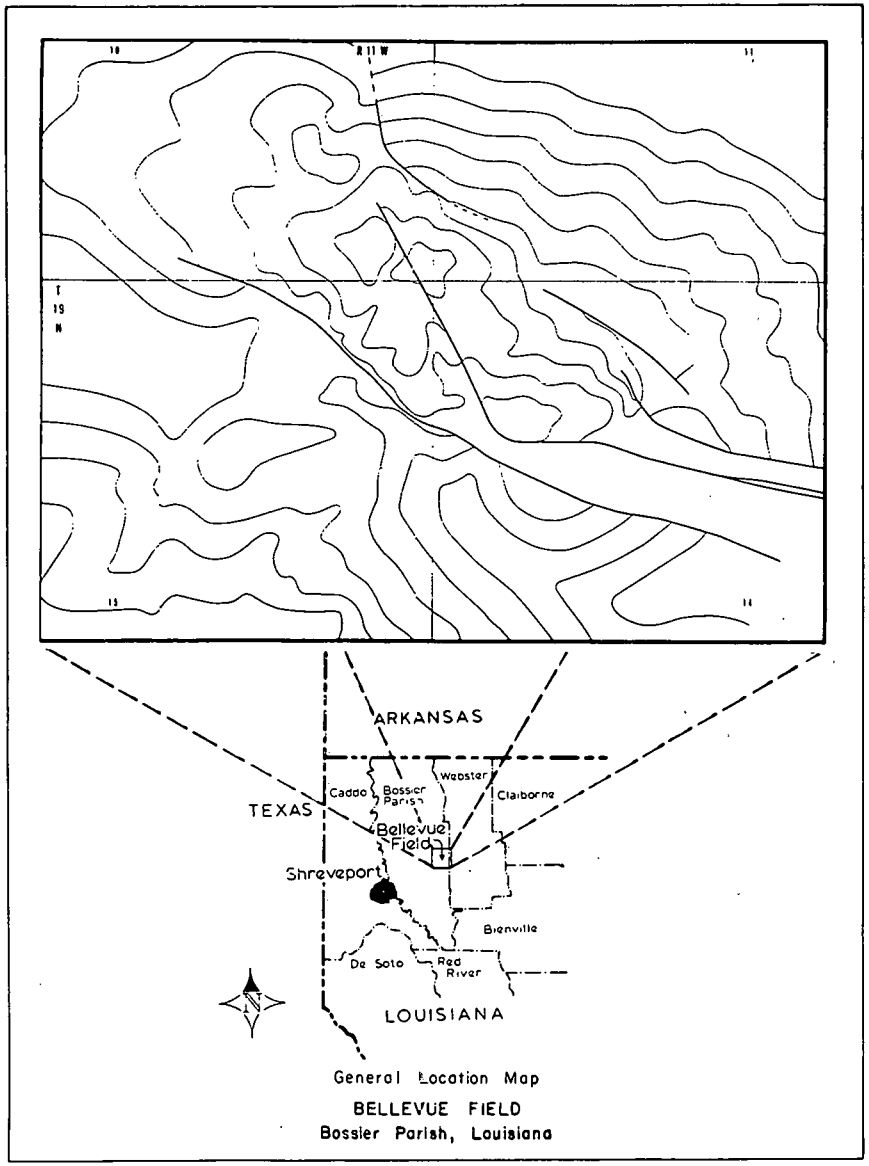
ECONOMICS

Development of a full-scale fireflood project is a costly adventure. One of the primary objectives of this contract is to demonstrate key economic factors that are involved with this project. Costs are kept in great detail to analyze all portions of development and operation of the project.

The total investment for wells and facilities has been $1,428,080. Total expenditures for operations and maintenance, research and production staff services, have been $2,312,016. Expenditures for Louisiana severance taxes has amounted to $676,498 and overhead expense was $545,354. The total project expenditure through April, 1979 was $4,961,948 (Figure 8).

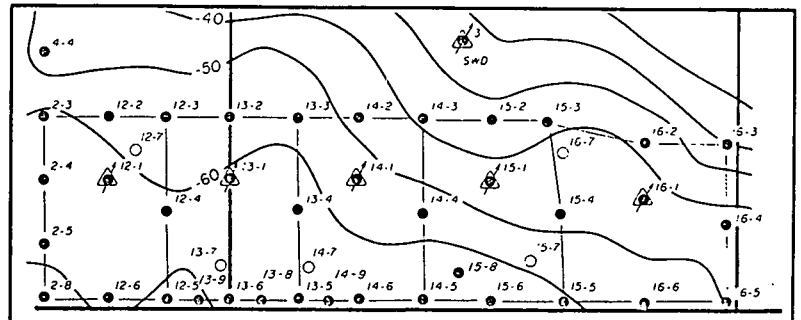
Operating expenses have been broken down into a cost per barrel of oil to even further demonstrate the economic factors in this project. Lease operation is $.99, lease maintenance is $1.82, operation of compression facilities is $2.00, Louisiana severance tax is $1.92, overhead is $1.55 and depletion and depreciation is $1.97. Total operating and maintenance expense through April, 1979 is $10.25 per barrel of oil produced.

FIGURE 1

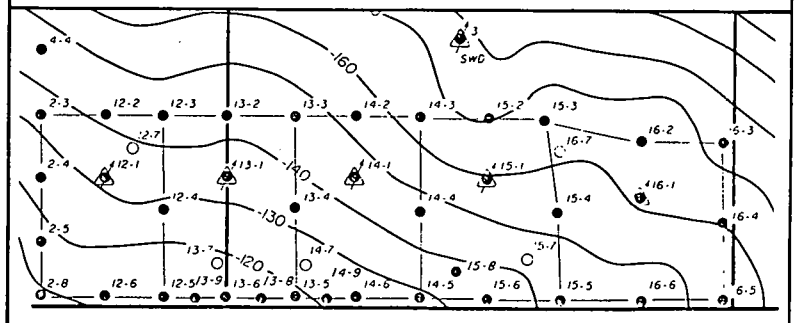


General Location Map
BELLEVUE FIELD
Bossier Parish, Louisiana

FIGURE 2

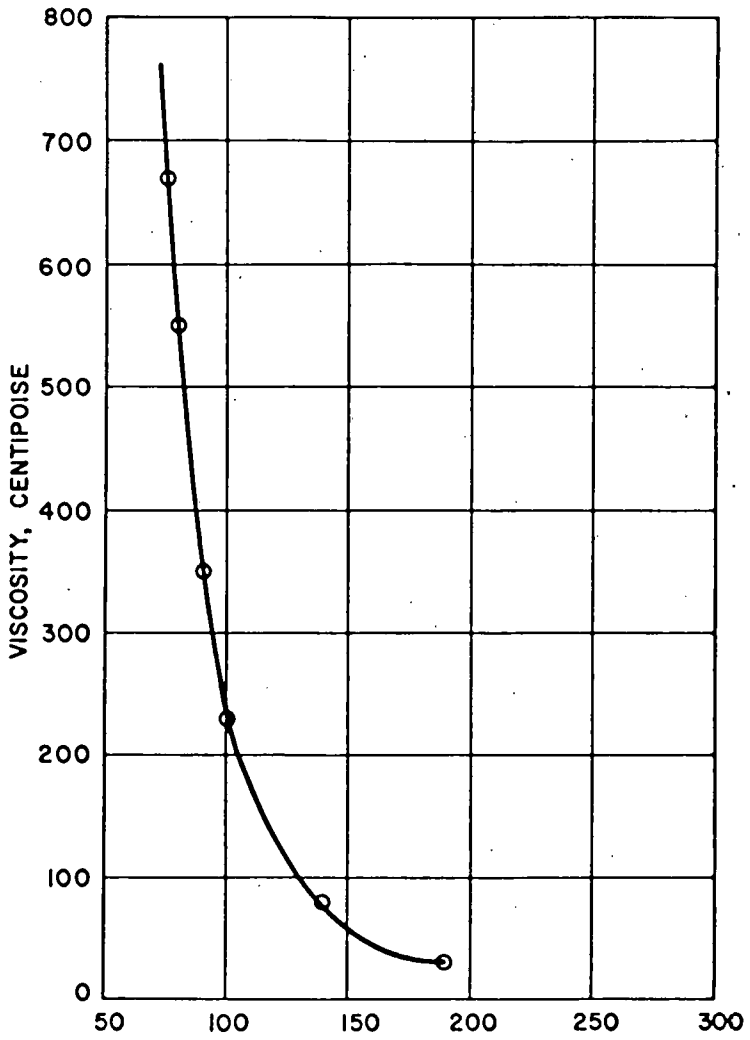


PROJECT AREA NET PAY MAP



PROJECT AREA STRUCTURE MAP
BODCAU FEE FIREFLOOD
0 200' 400' 600'

FIGURE 3



VISCOSITY-TEMPERATURE RELATIONSHIP
(19° API, BELLEVUE CRUDE)

Figure 4

Production Well Schematic

Dry & Simultaneous Burning Phases

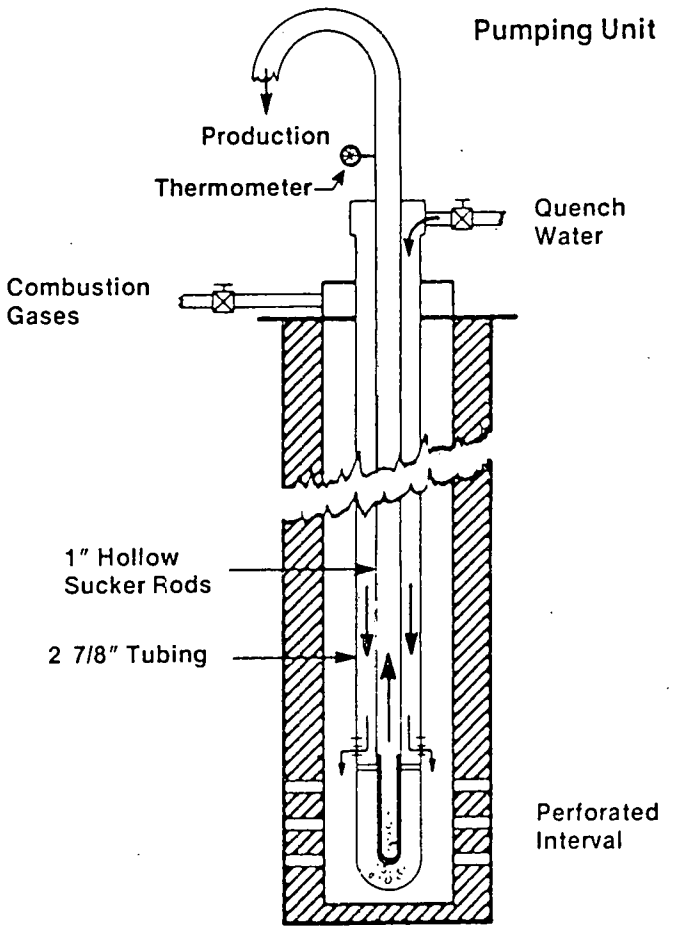


FIGURE 5
IGNITION WELL EQUIPMENT SCHEMATIC

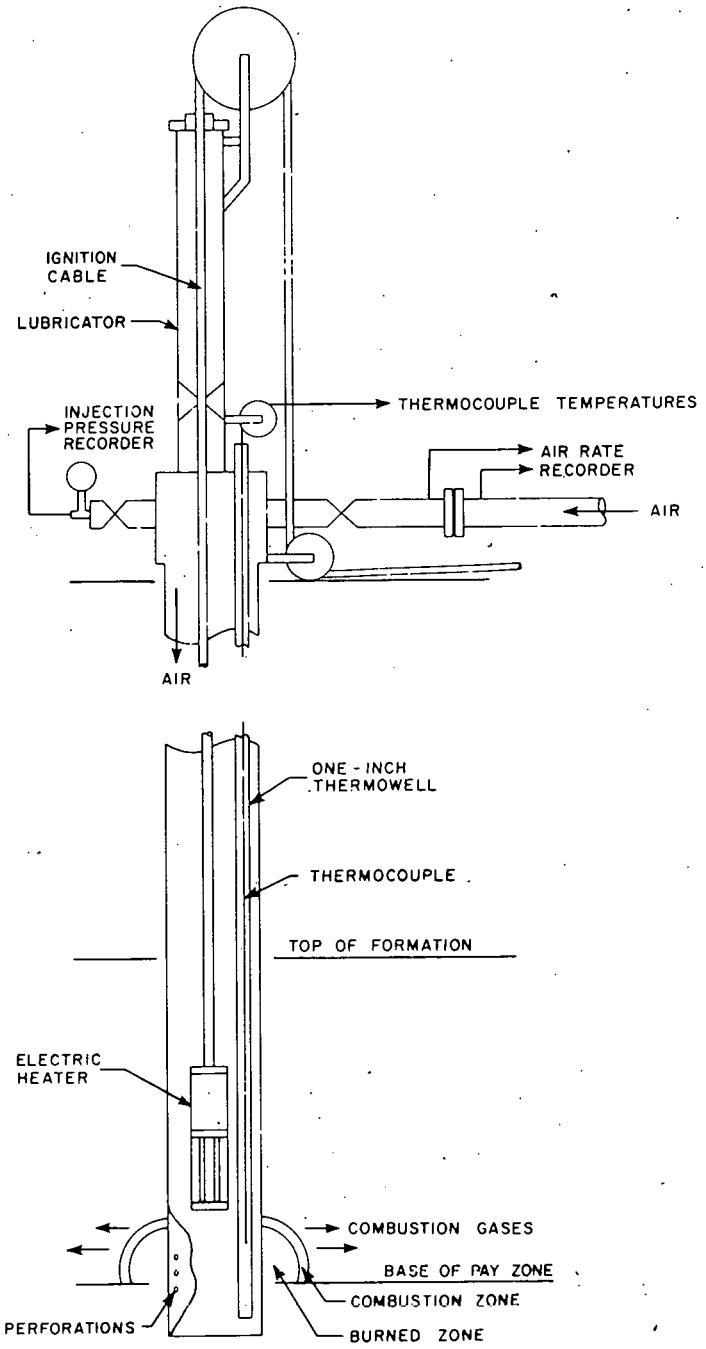


Figure 6

Injection Well Schematic

Simultaneous Injection

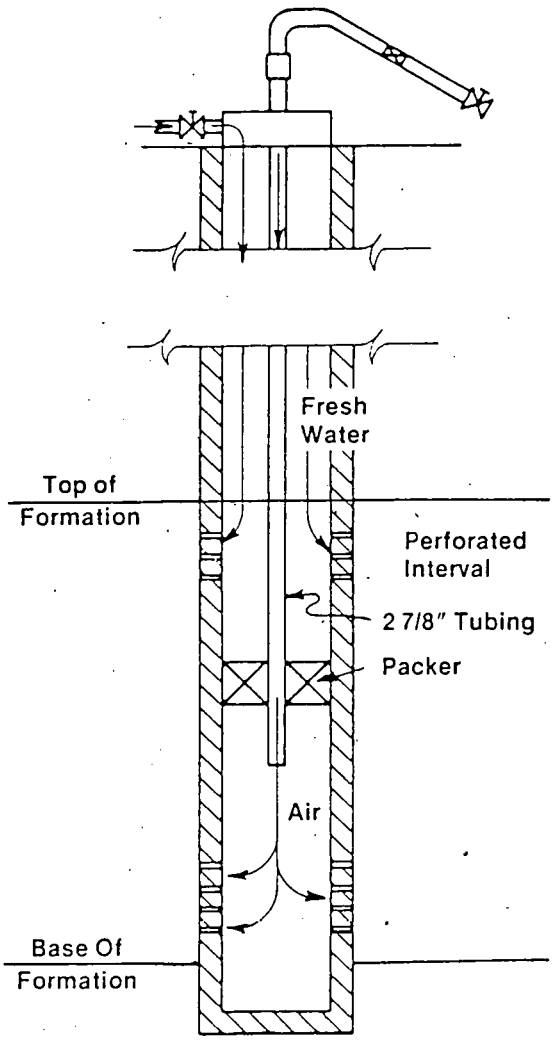
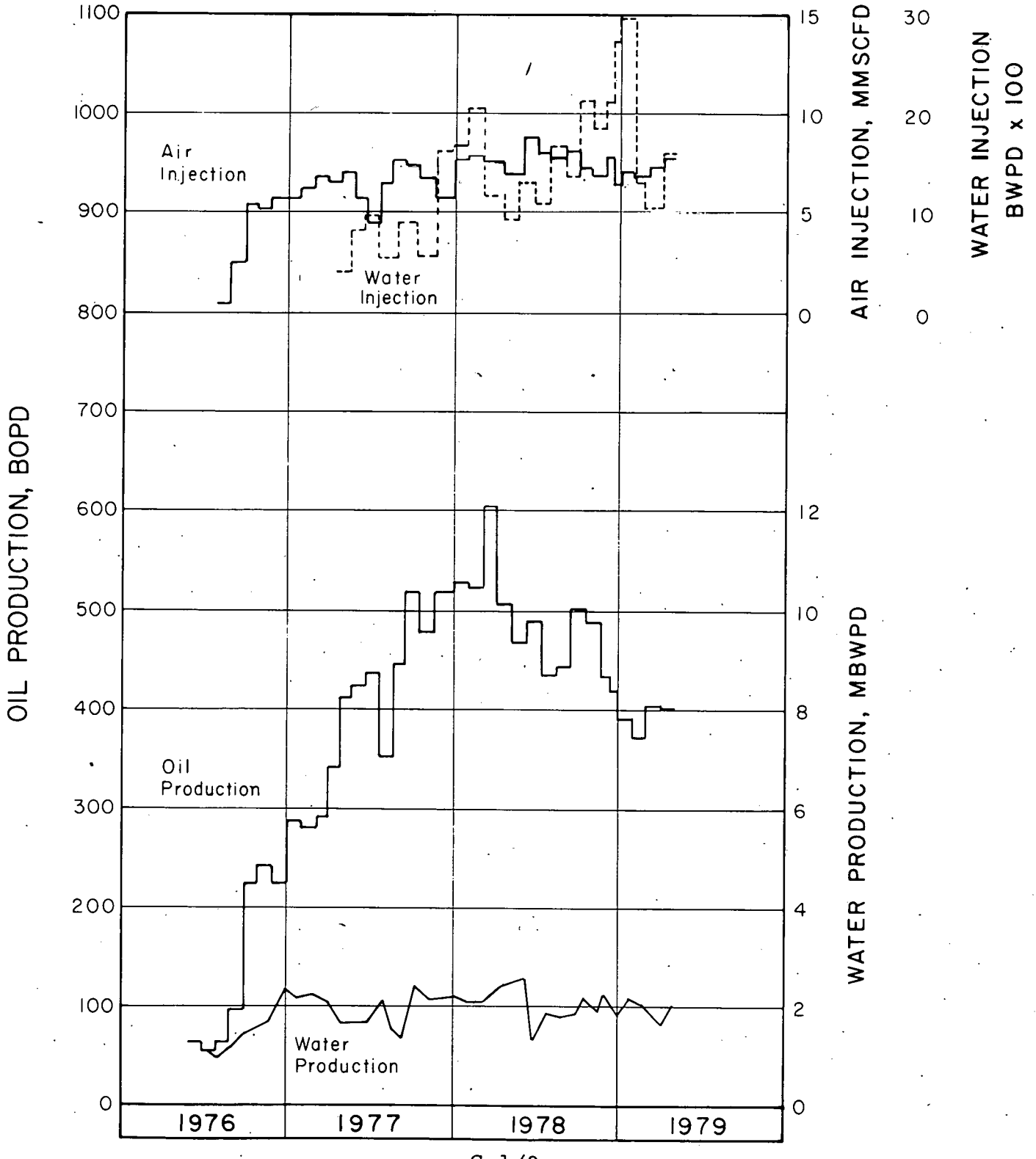


FIGURE 7

E.R.D.A. – CITIES SERVICE IN SITU COMBUSTION PROJECT

BELLEVUE FIELD, LOUISIANA

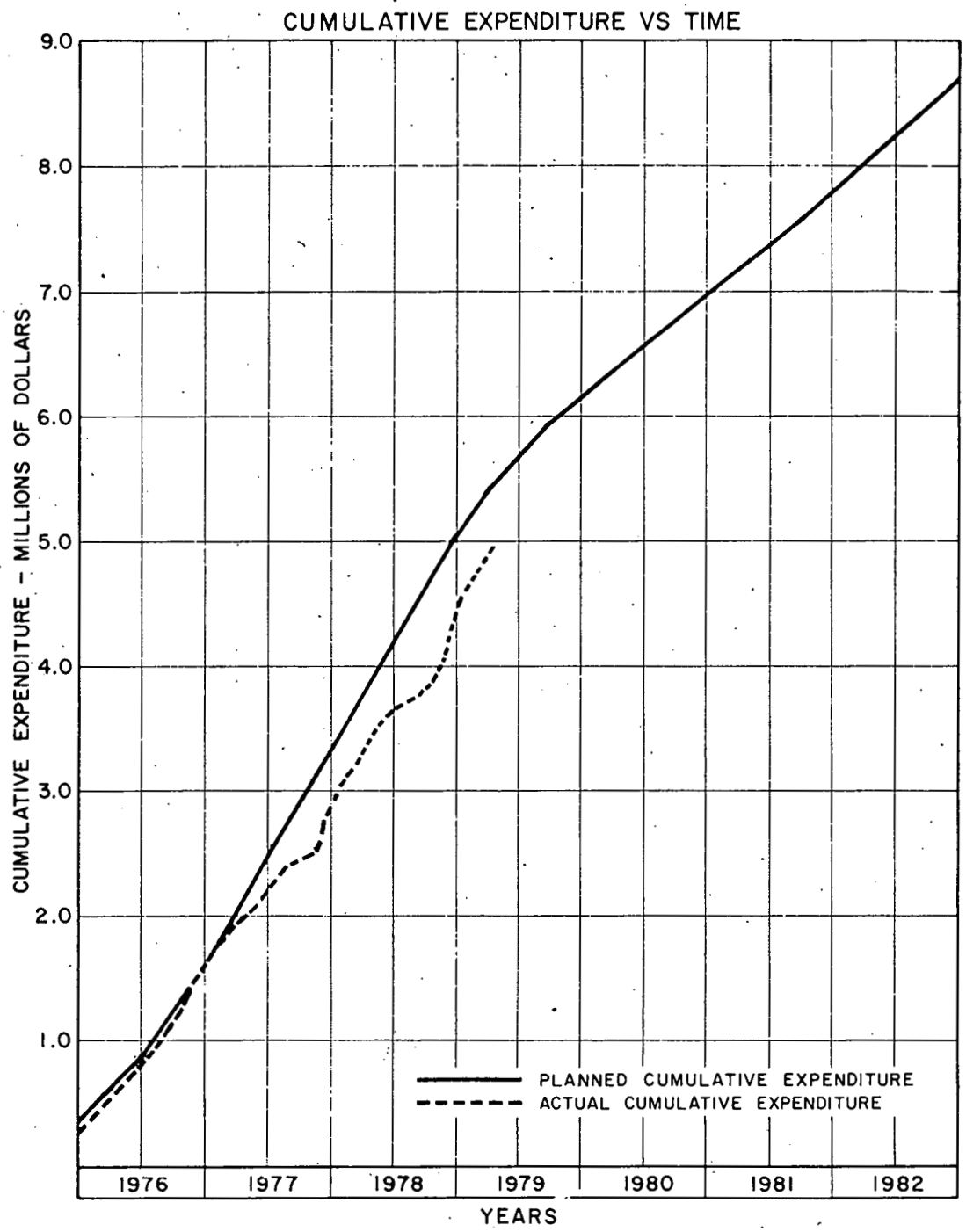
PRODUCTION AND INJECTION PERFORMANCE



G-1/9

FIGURE 8

BODCAU IN SITU COMBUSTION ERDA PROJECT



WET COMBUSTION PILOT
PARIS VALLEY FIELD
MONTEREY COUNTY
CALIFORNIA

By

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ABSTRACT

Husky Oil Company, with the support of the U. S. Department of Energy, has completed the wet combustion combined with cyclic steam pilot in the Paris Valley Field, Monterey County, California. The purpose of the test was to determine the technical and economic feasibility of these secondary recovery techniques within a reservoir containing a very viscous crude. The project was terminated during March 1979 due to adverse reservoir properties within the pilot area and the low oil production rates which did not offset the high operating costs.

Cyclic steaming has been thoroughly tested. Fifty-six steam treatments in twenty-one wells were performed during the operation of the pilot. Tests conducted to improve the performance of cyclic steaming included: varying the volume of steam injected, use of a packer to reduce heat losses, changing the location of the shoe of the injection string across the sand, the addition of compressed air with the steam and simulation studies of the cyclic steam process. Thin net pay combined with the high oil viscosity has limited the success of cyclic steaming in the pilot area.

The wet combustion process was conducted in two intervals of the Ansberry formation. Either poor air injectivity and/or severe channeling occurred within the upper interval in which air was injected. Air injected into the lower interval was unsuccessful in stimulating oil production due to bottom water entry in adjacent producing wells. Operating problems due to high combustion gas production were also encountered.

Prepared for the Department of Energy
under Contract No. EY-76-C-03-1000

Economic oil production rates were not obtained for any given month while the project was in operation. During 1978, the average cost per barrel of oil (gross) sold was $42.70. The most significant operating cost was that of air compression which increased 233% during the course of the project. The remote location of the project also added to its high operating expense.

INTRODUCTION

A wet combustion combined with cyclic steaming pilot was initiated during January 1975 by Husky Oil and the U. S. Department of Energy. The pilot was conducted in the Paris Valley Field which is approximately 160 miles south of San Francisco, California (Figure 1). The purpose of this test was to determine both the technical and economic feasibility of these Secondary Recovery Techniques in a reservoir containing a very viscous crude. Due to the adverse reservoir characteristics within the formation tested, the pilot was terminated during March 1979.

The project design and development have been discussed within the references listed at the end of this paper.[1,2,3,4] Also included within those publications are steam and combustion data obtained prior to May 1978.

This paper briefly describes the pilot and presents the performance of the project during the last eleven months it was operated. Specific reasons will be given for the failure of both steaming and combustion operations in the Paris Valley Field. The economics of conducting this test will also be presented.

PILOT DESIGN/RESERVOIR DATA

Eighteen producing wells and five air injectors were drilled during 1975 to develop the five staggered line drive patterns shown on the Structure Map in Figure 2. The air injectors were positioned downstructure in order to compensate for the expected directional permeability of air updip. During development drilling it was determined that the Lower Lobe was wet in the downstructure wells of Patterns II, III, IV, and V. Due to this condition, the wells were completed as indicated on Figure 3. The structural high southwest of Pattern I was not located until after the temperature observation wells were drilled in 1978.

The production interval was from the Ansberry Formation which averages 800 feet from surface. Oil accumulation is controlled by the faulted Ansberry Anticline which acts as a

structural trap. Within the formation, three distinct intervals were correlated and defined as the Upper, Middle, and Lower Lobes - note type log on Figure 4. The net pay ranges from 4 to 84 feet in the pilot area. Listed on Table 1 are the average rock and fluid properties of the Ansberry Formation along with data for each Lobe. Note that the permeability to air is approximately 3015 md in the Upper Lobe and 4454 md in the Lower Lobe. The viscosity at reservoir temperature averages 227,000 cp in the Upper Lobe, whereas it averages 23,000 cp in the Lower Lobe.

PROJECT UPDATE: May 1978 - March 1979

Production

Total oil produced from the operation of the pilot was 118,434 STB or 6.6% of the original oil in place within the pattern area. Of this amount, 103,080 STBO is attributed to cyclic steam response, 2,731 STBO due to combustion operations, and the remainder from primary production. Presented on Figure 5 are the production/injection curves for the project.

As the project progressed, several producing wells were shut-in due to mechanical problems. Wells 1-2 and 13-2 were shut-in because of liner failures. The liner in Well 4-2 and both the casing and liner of Well 21-2 were damaged due to combustion operations. During the first steam stimulation of Well 23-2, the casing failed. Well 7-2 was also shut-in as a result of liner damage from a high temperature stimualtion. Bottom water entry in Wells 2-3, 9-2, 16-2, and 17-2 was a constant operating problem.

During the last eleven months of the project, one of the major producing problems encountered was the inability to achieve efficient operation of the down hole pumps. Combustion gas was being produced through both the tubing/casing annulus and within the production string. Neither the installation of gas anchors nor lowering the depth of the tubing shoe were effective in increasing pump efficiencies. An attempt to flow the wells through a gas/liquid separator was also unsuccessful due to heavy oil plugging the liquid discharge of the vessel.

Cyclic-Steaming

As a result of the increase in combustion gas production combined with the unfavorable economics associated with steaming, the number of steam stimulations completed in 1978 and 1979 was limited to five cycles.

The production response to air-steam stimulations continued to be encouraging. Presented on Table 2 are the data collected from air-steam stimulations performed. As a comparison, the data prior to each air-steam stimulation

are included. Note that the incremental oil produced per cycle day was higher when air was added to steam.

Steam injection profiles were normally obtained using a liquid radioactive steam tracer. An evaluation of two types of tracers was conducted during the second air-steam stimulation of Ansberry 20-2. Both gas and liquid tracers were injected to obtain the profiles indicated on Figure 6. The profiles indicate similar steam distributions indicating that the liquid tracer mixed as effectively as the gas tracer.

Computer Modeling of Cyclic Steaming

The Intercomp thermal model was used to study cyclic steaming in the Paris Valley Field. The primary objective was to find procedures which might significantly improve performance. During the study a much better understanding of reservoir behavior and the thermal model was gained.

The study was limited to the upstructure area of the reservoir from Well 3-2 to Well 14-2 where the chance of profitable cyclic steaming or steamflooding is the greatest. Well 4-2 was selected for history matching because reservoir properties and performance were typical for the area; and because more complete test data were available.

Radial Model:

The single well radial model constructed from the estimate of Paris Valley reservoir properties is described in Table 3. The thermal model reported in 1976[5] was modified to input two oil viscosities. Oil in the Upper Lobe appears to be about ten times as viscous as oil in the Lower Lobe. The model contains seven layers with two rock types and nine rings radially. Moveable water is present so initial production is 4.5 BOPD and 29 BWPD compared to observed values of 4.3 BOPD and 43 BWPD. Parameters of greatest uncertainty included (1) the initial water saturation, (2) the vertical permeability to steam between lobes, (3) the oil viscosity of the middle layers, (4) rock compressibility, and (5) water relative permeability versus temperautre.

Figure 7 shows the actual production history of Well 4-2 and that predicted by the computer model. Variations in model producing rates from month to month, particularly in Cycle 2, result from changes in bottom hole producing pressure which were input to the model on the basis of observed fluid levels in Well 4-2. The history match was generally unsatisfactory as shown by the summary in Table 3 which includes the 3D model results discussed below. Adjustments in model properties within a reasonable range improved the agreement in oil production in a given cycle, but produced greater error in another cycle. There was no way to match observed water production in Cycle 2 and Cycle 3.

The inability to achieve a history match lead to a more detailed study of reservoir and well behavior. First, it was observed that water production increased markedly during the second or third cycle of upstructure wells. Total water production from the area by the end of 1978, 641,000 bbls., was twice the amount of water injected as steam. It appears that cyclic steaming tapped the acquifier observed in downstructure wells. Second, it was decided that observed oil rates during Cycle 2 were probably higher than actual since no water production was reported for most of the first month after steaming. Finally, high fluid levels and production increases occurred when nearby wells were steamed. For example, see the increase in Well 4-2 production rate, particularly water, in December 1976 when nearby Wells 19-2 and 20-2 were steamed. Thus, steam was channeling rather than moving out radially in the reservoir.

It is clear that the radial model does not provide an adequate description of cyclic steam behavior in the Paris Valley reservoir, so the lack of history match is not surprising.

3D Model:

Figure 8 shows the 3D r-z-Θ model constructed to include the water acquifier and interference of nearby wells. The results are summarized in Table 4. Oil production is about the same as the radial model prediction. Water production, however, agrees better with observed data. Even better agreement could be achieved with some fine tuning on the distance of the acquifier from Well 4-2. This did not seem justified since the 3D model run cost about $4,000 or 10 times a 2D radial model run.

Gas Injection With Steam:

Injecting inert gas with steam in the radial model significantly increased predicted oil recovery and reduced water production. For Cycle 3:

Amount Inert Gas SCF/Bbl. Steam	Oil Bbl.	Water Bbl.
0	6506	20,000
80	7403	17,000
320	8005	17,400

The results are in qualitative agreement with the field results reported above for Well 20-2, and suggest more consideration should be given to injecting gas when cyclic steaming viscous oil reservoirs. The gas provides energy to sustain oil production.

Wet Combustion

The cumulative air and water injected into the air injectors were 634 MMSCF and 89714 BW, respectively. Total combustion gas produced was 353 MMSCF. Throughout the wet combustion phase of the project, oxygen utilization was over 95%.

During 1978, the scope of the project for wet combustion was changed due to the low injectivities earlier experienced in the air injectors completed in the Upper Lobe which contains higher oil viscosity. Referring to Figure 2, Well 18-2 was shut-in and air was injected into Well 22-2 (Pattern IV). Due to mechanical problems with the surrounding wells in Pattern V, air was not injected into Well 8-2. Air injection into Well 12-2 was terminated because of severe channeling of combustion gas to the upstructure Well 4-2.

Three wells became hot from combustion. Elevated bottom hole temperatures of 150° F. were measured in Wells 11-2 and 14-2; however, incremental oil production from combustion was not measured. The bottom hole temperature of Well 21-2 exceeded 700° F. as heat front channeled into the well bore from Well 15-2. With an automatic cooling system installed on Well 21-2, over 100 BOPD of incremental oil production was produced at a controlled bottom hole temperature of 350° F. The 700° F. bottom hole temperature was obtained when the cooling water pump failed during the early morning hours. Severe well bore damage resulted and attempts to replace the damaged liner were unsuccessful.

Referring to Figure 3, note that the air injector 15-2 was completed in the Upper Lobe, whereas the producer 21-2 was completed in the Lower Lobe. Temperature surveys in Well 21-2 confirmed the heat front was confined to the Lower Lobe. This observation describes one of the pitfalls of the Ansberry Formation - the inability to confine air injection within the same lobe.

The air injection rates were increased during the last three months of the project in order to force a heat front into the producing wells. Combustion gas withdrawal rates increased, but the operating problem of inefficient fluid production also persisted. Air injection was terminated during February 1979 with water injection continuing for 22 days in order to scavenge heat created by combustion.

Temperature Observation Wells

Two temperature observation wells were drilled in Pattern I during May 1978. Selected temperature profiles with electric logs from each well are shown on Figures 9 and

10. Note that Well M-1 indicated the heat front to be located at the bottom of the Lower Lobe where as the maximum temperature recorded on Well M-2 was at the top of the Lower Lobe - the adjacent air injector was completed across the Lower Lobe.

TERMINATION OF THE PARIS VALLEY PROJECT

Cyclic Steaming

Cyclic steaming was not economically feasible in the pilot area due to the reservoir properties of the Ansberry Formation. Thin net pay, high viscosity of the Upper Lobe, and bottom water entry are the major factors which affected the success of steaming.

Downstructure wells completed in only the high viscosity, Upper Lobe did not respond to steaming. The lowest steam oil ratio of the seven stimulations attempted was 15.7 BW/STBO. Oil was not produced after two of the seven stimulations were completed.

Bottom water entry prevented economic response from steaming Wells 2-3 and 5-2. The average steam oil ratio of five of the cycles completed was 42.5 BW/STBO.

Incremental oil produced from selected upstructure wells was high enough to pay out the cost of the stimulations; however, capital costs for the production or steaming facilities could not be recovered.

Wet Combustion

The reservoir properties and operational difficulties in the pilot area prevented wet combustion from being a feasible secondary recovery process in the Paris Valley Field. Conditions encountered include:

A. The high viscosity of the Upper Lobe resulted in extremely low injectivities in the air injectors completed in the Upper Lobe. For example, the average injectivity of the Upper Lobe injector 18-2 prior to being shut-in was 0.27 SCF/Δ (P^2); during the same month the average injectivity in Well 6-3 (completed in the Lower Lobe) was 3.35 SCF/Δ (P^2).

B. In addition to the low injectivities in the air injectors completed in the Upper Lobe, severe channeling was experienced. Well 4-2 was damaged due to high combustion gas volumes channeling to the well bore. Because of the increased reservoir pressure from air injection, Well 4-2 could not be repaired without the adjacent air injectors shut-in for an extended period of time to vent the high pressure combustion gas stored in the formation.

C. As previously discussed, confinement of the heat front within the Upper Lobe did not occur in Pattern III. Air injected into Well 15-2 channeled into the Lower Lobe to upstructure Well 21-2. The ensuing liner and casing damage which resulted when the cooling pump failed prevented Well 21-2 from producing - $48,000 was spent in an attempt to replace the damaged liner.

D. Air injection into Well 22-2 (completed in the Lower Lobe) was unsuccessful in stimulating oil production due to bottom water entry in the Pattern Wells 14-2 and 17-2. Heat had been conducted to Well 14-2 as the bottom hole temperature increased to 150° F.; however, negligible incremental oil from combustion was produced.

E. Although higher injectivities were obtained in Pattern I, combustion operations were not successful due to the structural high southwest of the Pattern. Bottom water entry in wells 2-3 and 5-2 with accompanying high fluid levels may have forced the heat front to bypass the producing wells.

EXPENDITURES

As of April 1, 1979, the total expenditures for the Paris Valley Project was $7,028,811.87. Of this amount Husky Oil has spent $4,530,444.94 with the DOE contributing $2,498,366.93. Remaining expenditures include well abandonment and lease shutdown.

Tabulated below are the total operating costs for each complete year the project has been active. There has been no profit generated for any given month the pilot was operated. The most significant operating cost was that of electric power for air compression which increased 233% during the course of the project.

Year	1976	1977	1978
Gross Sales (STBO)	18,262	39,697	23,014
Total Operating Costs ($)	273,967	948,697	982,543
Total Operating cost/ Gross Bbl. ($/Bbl.)	15.00	23.89	42.70

ACKNOWLEDGEMENT

The author would like to express appreciation to A. J. Leighton and the U. S. Department of Energy for their support in the Paris Valley Project, and to J. W. Patek, A. S. Bakr, P. D. White, G. L. Scullin and L. A. Simmons for their assistance in preparing this paper.

K. H. Coats, Intercomp, and R. F. Meldau conducted the computer model studies reported herein.

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3. Patek, J. W. and Meldau, R. F., Wet Combustion Pilot, Paris Valley Field, California, Proceeding from the Third ERDA Symposium on Enhanced Oil, Gas Recovery, and Improved Drilling Methods August 30-31 to September 1, 1977, Vol. 1, No. D-5.

4. Shipley, R. G., Wet Combustion Pilot, Paris Valley Field California, Proceedings from the Fourth DOE Symposium on Enhanced Oil and Gas Recovery and Improved Drilling Methods, August 29-31, 1978, Vol. 1B, No. D-3.

5. Coats, K. H., "A Fully Implicit Steamflood Model," SPE 6105, New Orleans, October, 1976.

TABLE 1

AVERAGE ROCK AND FLUID PROPERTIES

Depth	800 Feet	Water Saturation	36%
Temperature	87°F.	Gas Saturation	0%
Initial Pressure	220 psig	Oil Content	1590 $\frac{\text{Bbl.}}{\text{AC-FT.}}$
Net Thickness	50 Feet		
Permeability	3750 Feet	Oil Viscosity	35,000 CP@87°F.
Dip	15°	Oil Gravity	10.5 API
Porosity	32%	Solution GOR	< 10 SCF/Bbl.
		Water Salinity	280 PPM

PROPERTIES OF INDIVIDUAL LOBES

	Upper Lobe	Middle Lobe	Lower Lobe
Oil-In-Place, MBBL	940	8	852
Avg. Net Pay, FT.	23	0.2	28
Permeability, MD	3015	3305	4454
Porosity,%	32.7	31.9	31.7
Viscosity @ 87°F., CP	227,000	-	23,000
@100°F., CP	94,000	-	11,000
@200°F., CP	340	-	120

TABLE 2

CYCLIC STEAM RESPONSE

Well Number	3-2	3-2	20-2	20-2	20-2	20-2
Air With Steam	No	Yes	No	Yes	No	Yes
Date: Start of Cycle	11-02-77	10-10-78	12-04-76	07-25-77	03-05-78	10-06-78
Cycle Number	6	7	2	3	4	5
Injection Days	13	31	45	38	21	26
Bbls. of Water Injected	8211	9213	13249	16256	15735	10452
MMBTU's Injected	2976	3140	4724	5821	5553	3570
Average Wellhead Quality,%	71	66	74	74	75	62
Average Stm. Inj. Press., psig	211	440	469	405	536	300
Cum. Air Injected, MSCF	-	3629	-	1473	-	3711
Cycle Days	309	148	202	215	225	147
Cum. Water Produced, BW	28900	3882	24639	16390	14119	11722
Peak Production, BOPD	60	141	51	81	24	38
Incremental Oil Produced, STBO	4832	4207	2384	4041	543	503
Steam Oil Ratio, BW/STBO	1.70	2.19	5.56	4.02	29.0	20.8
Incremental Oil/Cycle Day, STBO/Day	15.6	29.8	11.8	18.8	2.4	3.4

TABLE 3

RADIAL MODEL PROPERTIES

Layer Description:

Layer	Thick Ft.	Air Perm md	Porosity %	Rock Type	Oil Viscosity @ 87° F.,cp
1	12	2500	28	1	100,000
2	12	2500	28	1	100,000
3	24	500	29	2	100,000
4	12	2500	27	1	10,000
5	12	4000	26	1	10,000
6	12	4000	26	1	10,000
7	12	2500	22	1	10,000

Oil Viscosity Versus Temperature:

Temp. °F.	Oil Viscosity, cp Layers 1-3	Layers 4-7
87	100,000	10,000
100	38,000	5,000
200	320	110
400	8.0	5.3

Saturation and Relative Permeability Data:

	Type 1 87°F.	Type 1 300°F.	Type 2 87°F.	Type 2 300°F.
Saturations,% PV:				
Initial Water	32	-	58	-
Connate	25	40	33	53
Residual Oil to Waterflood	20	10	20	10
Residual Oil to Gas Flood	33	13	23	13
Relative perm to water @ residual oil.	0.1	0.05	0.1	0.05

Other Significant Properties:

1.	Number of radial rings	9
2.	Outer model radius, ft.	400
3.	Rock compressibility, psi^{-1}	400×10^{-6}
4.	Thermal conductivity, BTU/Ft-Hr-°F.	1.0
5.	Solution gas	None
6.	Initial reservoir temperature, °F.	87
7.	Initial reservoir pressure, psia	254
8.	Initial oil in place, Mbbl.	125
9.	Vertical transmissibility factor top layers 3,4,5,&7	0.02

TABLE 4

SUMMARY MODEL VERSUS OBSERVED RESULTS

	Cycle 1	Cycle 2	Cycle 3
Oil Produced, Bbl.			
Observed	2,064	6,295	9,020
Predicted Radial	3,155	2,868	6,780
Predicted 3D	3,220	3,130	6,470
Water Produced, Bbl.			
Observed	14,100	33,400	51,000
Predicted Radial	14,400	8,100	20,500
Predicted 3D	17,100	15,500	39,800
Steam-Oil Ratio, Bbl./Bbl.			
Observed	2.2	1.2	1.5
Predicted Radial	1.5	2.6	1.9
Predicted 3D	1.4	2.4	2.0

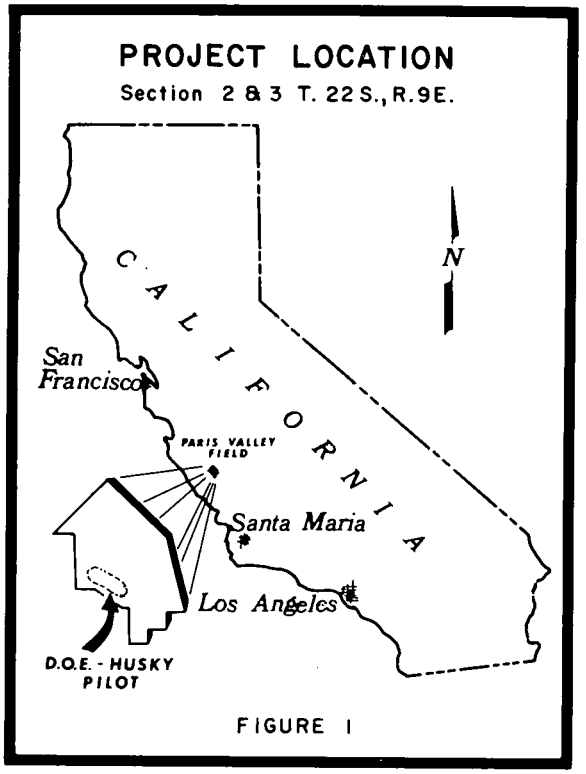


FIGURE 1

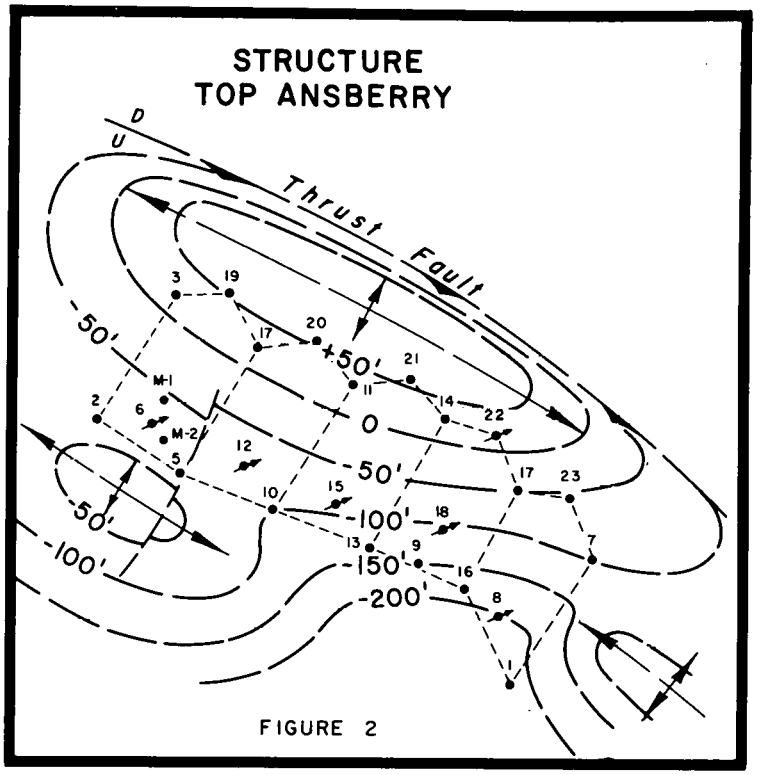


FIGURE 2

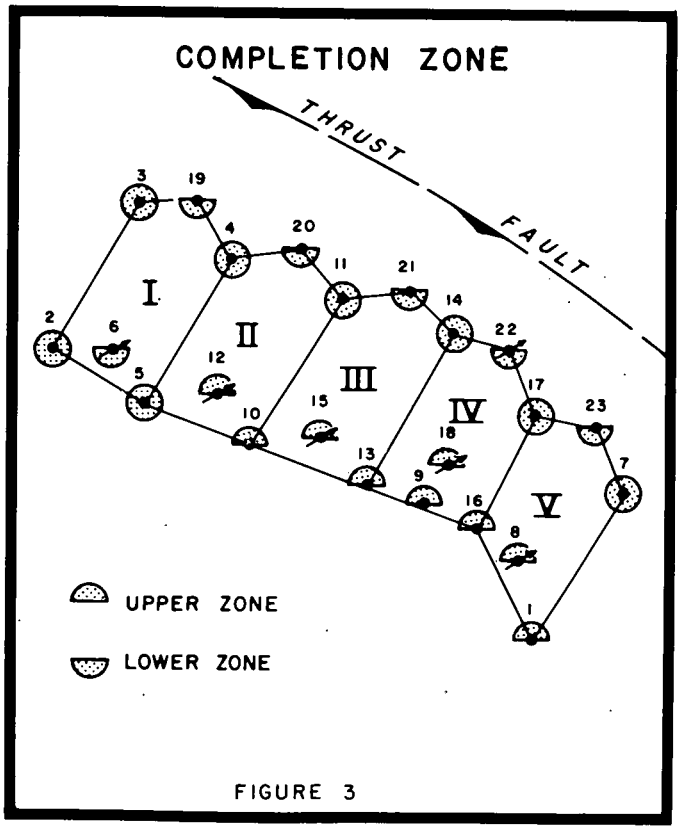


FIGURE 3

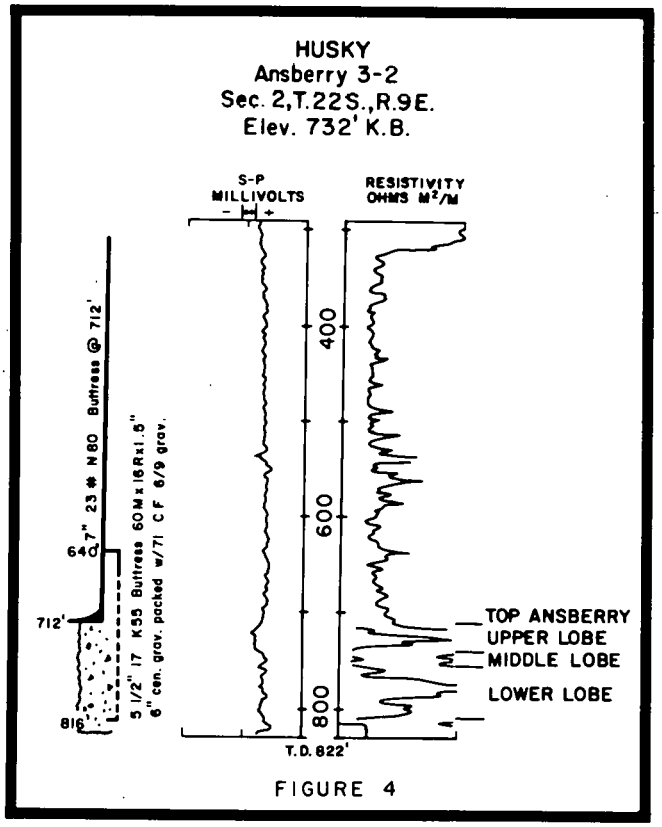


FIGURE 4

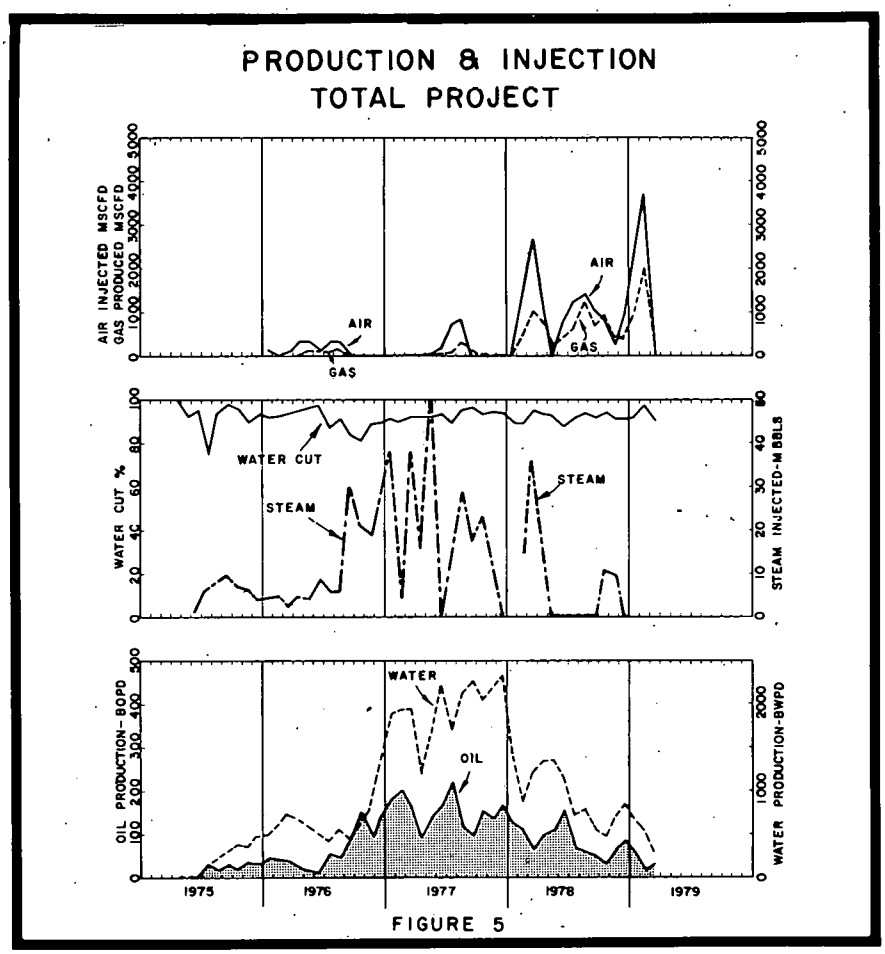


FIGURE 5

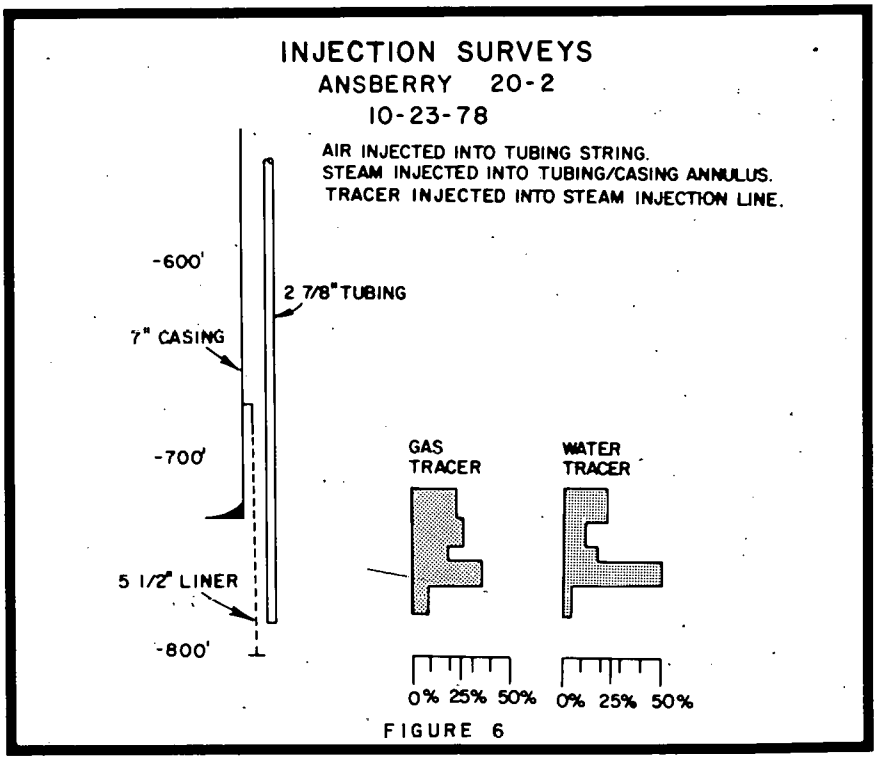
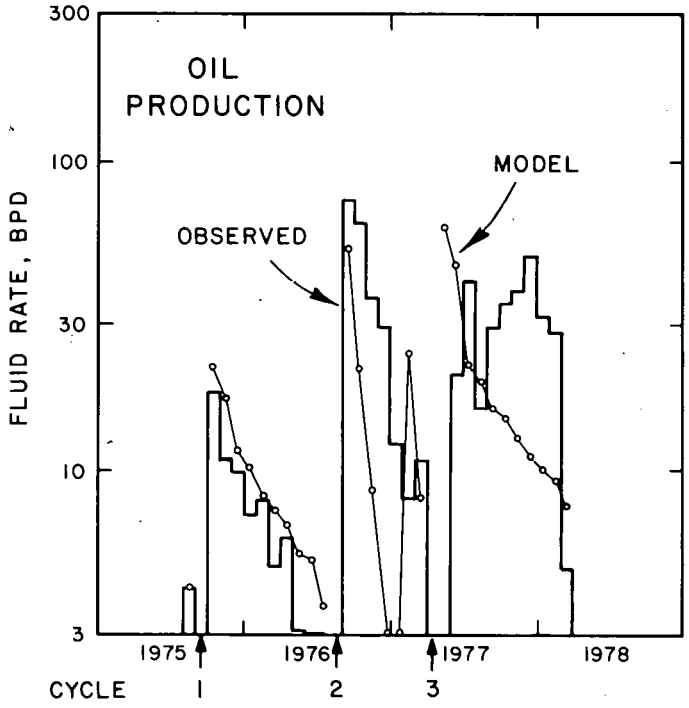
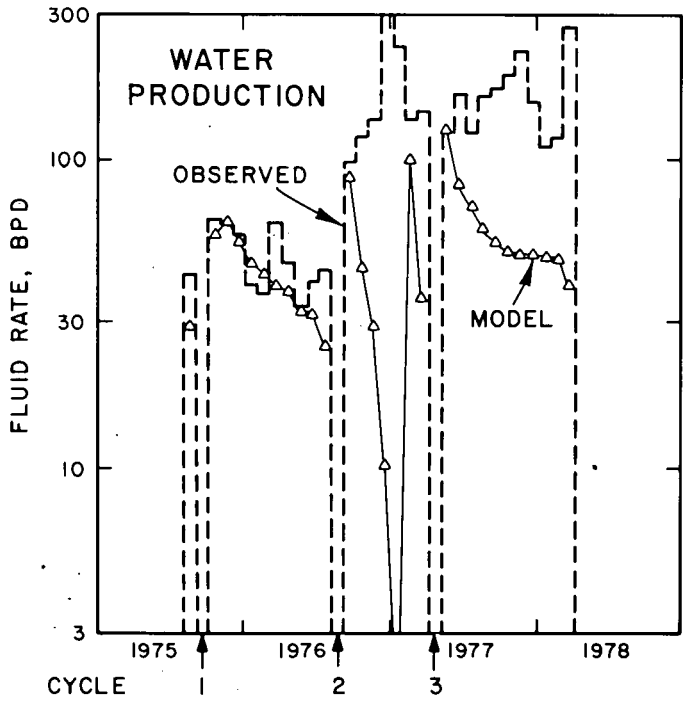


FIGURE 6

HISTORY MATCH OF WELL 4-2 CYCLIC STEAMING



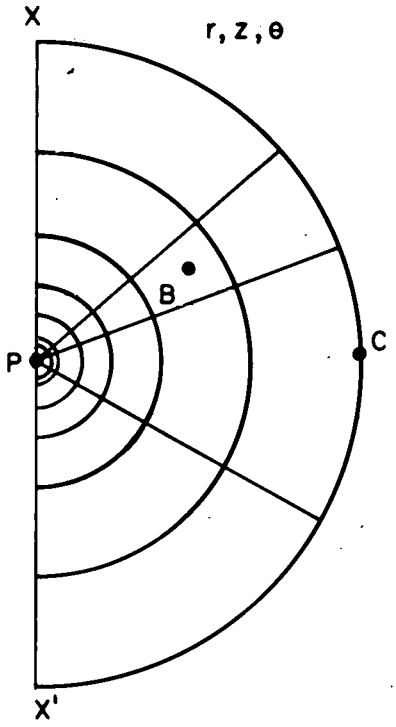


CYCLE	1	2	3
STEAM BBLS.	4400	7600	13200
HEAT MMBTU	670	2000	4300

FIGURE 7

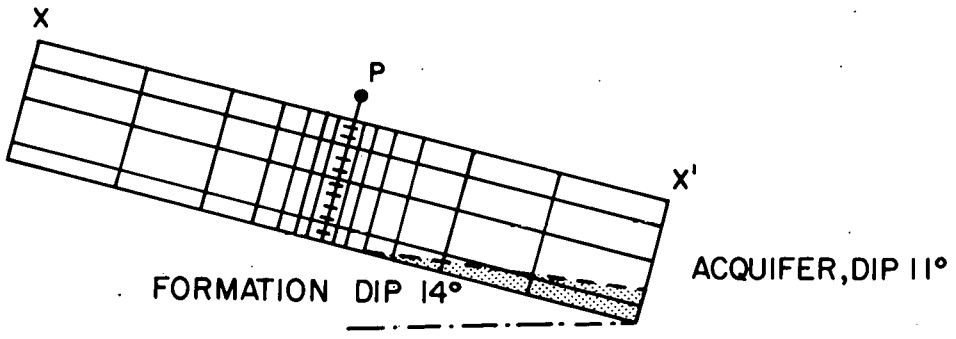
THERMAL 3D MODEL OF CYCLIC STEAMING

PARIS VALLEY WELL 4



	WELLS	
MODEL	FIELD	DISTANCE
P	4	0'
B	19+20	215'
C	3+11	381'

LAYER	THICK FT.	TYPE ROCK	OIL VIS. @87°F., cp
1	24'	1	100,000
2	24'	2	100,000
3	36'	1	10,000
4	12'	1	10,000



1. ACQUIFER CONTAINS SUPPLY WELL.
2. OTHER PROPERTIES SAME AS RADIAL MODEL, TABLE 3.

FIGURE 8

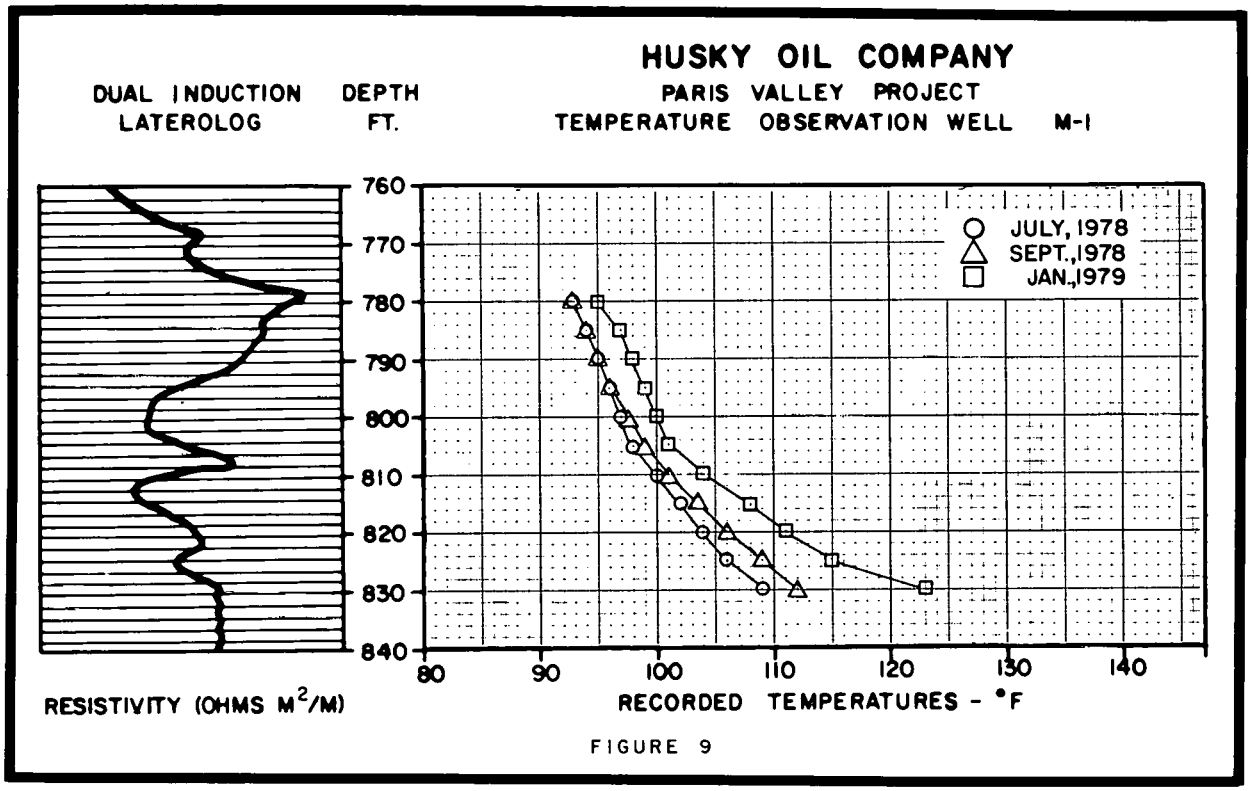


FIGURE 9

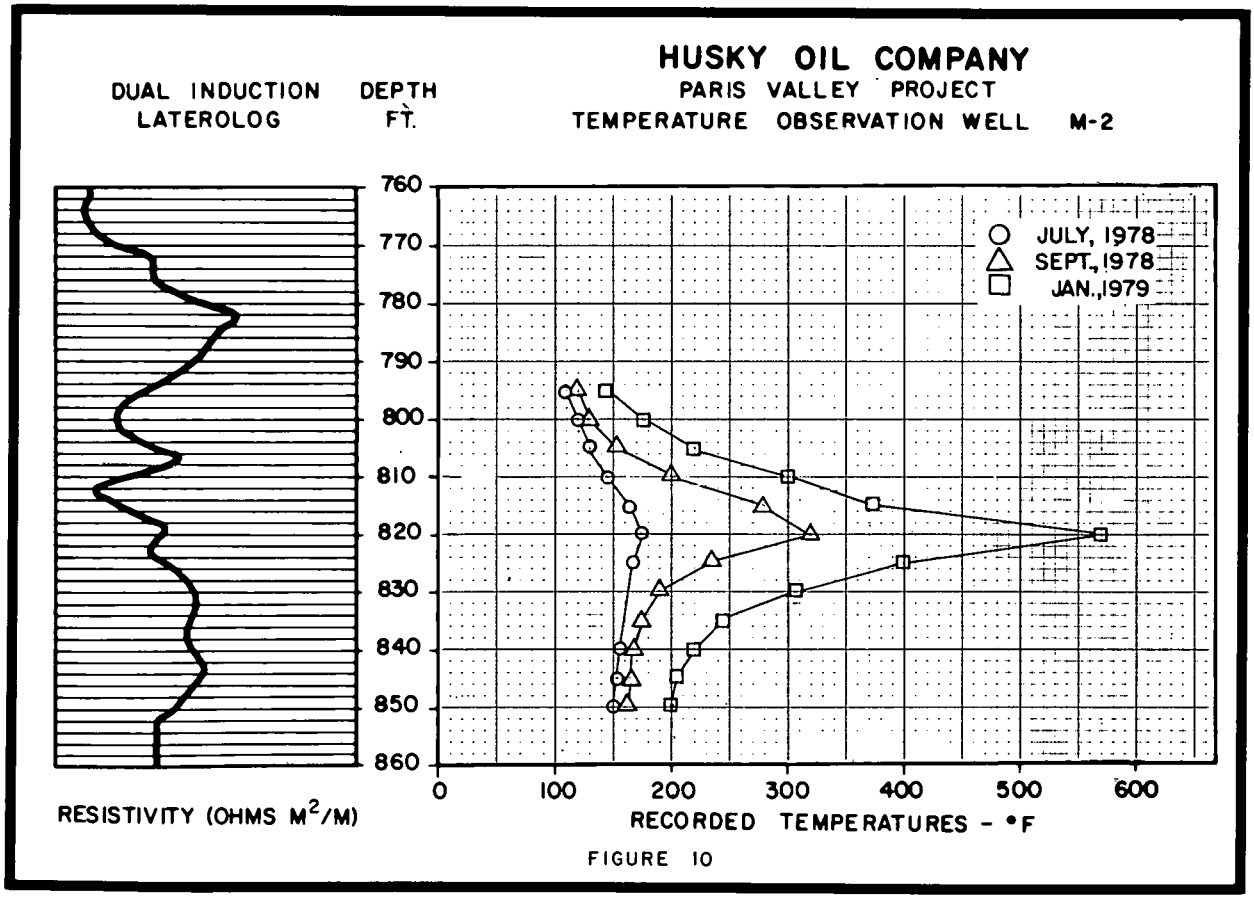


FIGURE 10

THE LYNCH CANYON THERMAL DRIVE OIL RECOVERY PROJECT

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ABSTRACT

The Lynch Canyon Oil Field is situated three miles north of the San Ardo Oil Field near San Ardo, California, approximately halfway between San Francisco and Los Angeles near Highway 101. The reservoir; in Sections 23 and 24 of Township 22 South, Range 10 East MDB&M; is the Lanigan sand which is oil bearing over approximately 500 acres and contained some 26 million barrels of oil originally in place.

The field was discovered in 1962 and underwent a brief, but intensive, development program up to 1968 when the field was abandoned. During this period, the eleven wells experienced production stimulation using 1) flowline heaters, 2) downhole electric heaters and 3) huff-and-puff steam stimulation. Even though these operations increased the average well productivity three-fold, the effect was short-lived and the field's cumulative oil production was only 111,300 barrels.

General Crude Oil Company obtained the mineral rights to the field and plans to conduct a demonstration project in conjunction with the United States Department of Energy. The proposal contains four major steps: 1) geologic study, 2) pilot test, 3) dry combustion and 4) combination thermal drive. The geo ogic study will comprise a 4 well coring-logging program to better define reservoir saturations and down-dip reservoir boundaries. Cores from these wells will be used to

Prepared for DOE under Contract No. ET-78-C-03-2096

define reservoir combustion variables using laboratory tube studies. The pilot test will include productivity testing of an isolated inverted 5-spot pattern using 1) natural reservoir energy, 2) huff-and-puff steam stimulation and 3) dry combustion. The third step includes the development and operation of a 60 acre line drive flood area involving 33 wells. After ignition and stabilization of the first 6 well injection line using dry-combustion, use of the combination thermal drive process is anticipated.

The project is expected to continue to September, 1983. The basic design rests on drilling the reservoir on a 2½ acre density and utilizing six in-line wells to establish a line drive firefront. The injection rate into the six wells will reach 6,000 MSCFD and 1,320 barrels of water per day at peak rates. The entire project life will be five years, one year for geologic study with pilot testing and four years for dry and combination thermal drive processes. At the end of this study, the variables associated with the operation of combination thermal drive process in a typical depleted heavy oil sand in California will be determined. The potential recovery, economics, operational procedures and viability of the combination thermal process using an extensive transducerized data recording system will be demonstrated.

INTRODUCTION

The Lynch Canyon Field is located at the southern end of the Salinas Valley in the foothills to the east of San Ardo, California. The field location, shown in Figure 1, is 258 miles north of Los Angeles on Highway 101 near the gigantic San Ardo Oil Field in Monterey County.

Lynch Canyon was discovered in 1962 by Moriqui Exploration Company who transferred the mineral rights to Texaco by December, 1962. Field production was plagued by heavy oil production problems which resulted in Texaco's attempt to improve the field's productivity with flowline heaters, bottom heaters and steam stimulation treatments. The stimulation treatments ultimately resulted in ruptured production strings and concurrent water production. Texaco soon quitclaimed the field in 1968 after producing 111,300 barrels of oil. The field's production history is shown in Figure 2.

General Crude Oil Company acquired the property in 1972 expressly for the application of thermal recovery methods. A technical proposal for oil recovery by combination thermal drive was submitted to ERDA in 1977. A year later, the Department of Energy requested an updated proposal for the combination thermal drive oil recovery project in the Lynch Canyon Field. The objective was not only to demonstrate the

applicability of the CTD process in heavy oil sands, but to demonstrate the usefulness of General Crude's transducerized data collecting system.

Recently, General Crude Oil Company was purchased by Mobil Oil Company, who has assumed the responsibility of the Lynch Canyon demonstration project.

GEOLOGY

Geology of the Lynch Canyon Field was presented by E. R. Wilkinson[1] in 1964. Two ancient ranges, the Gabilan to the east and San Lucia to the west, flanked an elongated synclinal depression which was faulted by the King City fault. Movement along the fault uplifted the eastern side of the trough to form the Gabilan shelf. Fine to coarse grained Miocene sands were deposited on the shelf along the ancient shoreline to form many stratigraphic traps which were destined to become oil production sands of the Monterey Formation. The Lanigan sand is an off-shore sand bar which pinches out against the Juranic basement along the shoreline. The productive area is delineated on three sides by a water table at -1072 feet subsea.

A structure map on top of the Lanigan sands shows the approximate productive up dip basement on lap and downdip shale-out limits in Figure 3. Contours on top of the Granitic basement are shown in Figure 4. Cross sections through the field are shown in Figure 5. An isopach map based on the known Lanigan sand net thickness from penetrating wells as well as the relation of the oil sand-basement structure are shown in Figure 6. Electric logs from Lanigan 102, 205 and 140-X show the down-dip shaliness, the saturation variation and the typical up dip Lanigan sand characteristic near the crest of the structure (See Figure 7). The approximate down dip shale-out limit and the oil-water contact at -1072 feet is supported by the data shown by the logs from Lanigan 102 and 205.

RESERVOIR PROPERTIES

The Lanigan sand is very fine to coarse-grained unconsolidated oil saturated formation that grades to a sand that includes pebbles, cobbles and basement detrius on bottom. Average core analysis for Wells 172, 102 and 205 are shown in Table I. The characteristic increase in the water saturation in the lower half of the Lanigan sand by the electrical surveys is reflected in the core analysis averages.

PRODUCTION HISTORY

Moriqui Exploration Company's Lanigan 172, drilled in September, 1962, was completed in 35 feet of oil sand and produced 41 BOPD of 9.7° API oil at a cut of 6.2% water. Lanigan 50 and 20 were soon drilled to further evaluate the field's potential. Only Lanigan 50 produced, since Lanigan 20 was too far down dip to be commercial. Lanigan 50 was tested at 14 BOPD of 10.7° API oil cutting 2.7% water. Production problems experienced with these wells resulted in the transfer of the mineral rights to Texaco in 1963.

Texaco completed wells 140X and 170X to find initial production rates equivalent or better than Lanigan 172. Texaco experimented with down hole electric heaters and flowline heaters through 1963 and found increases in the specific productivity index of 2 to 3 times the initial index. By October, 1963, nine wells had been completed and the field's production rate peaked at 4,000 BOPD and started a rapid decline as shown in Figure 2. The loss of Lanigan 50 and 174 in March of 1974 intensified the loss in field productivity. Texaco installed steam generation equipment and drilled two wells, Lanigan 106 and 136, in June, 1964. An intensive steam stimulation program was followed by treating the wells with 1000 to 1500 BWPD as steam for 3 to 5 days and bringing the well back on production. Specific productivity indexes for the wells varied greatly from 4.6 BOPD/ft. to 0.5 BOPD/ft. which was an eight fold increase in the best case. The high production rates following a steam job lasted for 2 to 9 months. Most wells received two to three stimulation treatments. Subsequent treatments on a well were much larger than the original 5000 barrel treatment. Second and third cycle treatments were between 15,000 and 30,000 barrels. The field's oil production increased to as high as 6000 BOPM initially, but declined throughout 1965 and 1966 to less than 200 BOPD. Four wells were lost in 1965 and three wells were lost in 1966 to high water production which was probably due to damaged casing. The field was produced only a few months in 1967 and finally abandoned in 1968 after producing a cumulative 111,300 barrels of oil.

PROPOSED RECOVERY PROCESS

The viscous nature of the oil and the benefits experienced by the application of heat indicate that a thermal recovery process should be used at Lynch Canyon. Hot water, steam or combustion displacement processes may be used in conjunction with push pull stimulation of the producing wells to increase the field's cumulative oil production.

In-situ combustion will give the highest recovery of all thermal processes when it is properly designed, controlled, and applied to a reservoir. To increase the combustion process's efficiency, the combination water-air process may be used to carry heat stored behind the fire front in normal combustion and deposit the heat ahead of the fire front. General Crude intends to use the combination thermal process (See Figure 8) in lieu of the quenched combustion process in order to maintain flame front temperatures near the dry combustion flood level. This is accomplished by close control of the water-air ratio. The injected water strips heat from the hot-dry rock behind the flame front and forms super heated steam which passes through the fire front with the injected air. After reaching the cooler rock ahead of the flame front, the steam gives up its superheat, latent heat and eventually condenses to form a hot water bank. This action experienced in the Combination Thermal Drive process greatly enhances the rate of heat front growth and allows a much earlier heat stimulation effect to aid in the flood's productivity. It is not uncommon to experience air-oil ratios as low as 5 when using the Combination Thermal Drive process.

PROJECT DESCRIPTION

The Lynch Canyon project will involve four separate phases:

Phase I Geologic and Reservoir Evaluation
Phase II Pilot Testing and Project Planning
Phase III Project Operation - Dry Combustion
Phase IV Project Operation - Combination Thermal Drive

Each phase will be separated from the following phases to present the results of the operation and recommend any improvement to the original design concept in succeeding phase operations.

Four wells (shown in Figure 9) will be drilled to evaluate the southern limits of the reservoir and prove existing geologic maps and estimated reserves. The four wells will define the down dip limits of the reservoir. Two of these wells, Lanigan 102 and 205, have been drilled and indicated an overall reduction in reservoir volume on the order of 1,316 acre feet over the original 1978 geologic interpretation. Three of the four wells drilled in Phase One will be cored for a better interpretation of reservoir properties. All wells will be logged and some wells will be specifically logged with a compensated neutron-formation density log for porosity determination. All cores taken will be tested for porosity, permeability and saturation. Some core material will specifically be used for combustion tube studies and definition of the burning characteristic of the Lanigan sand.

Phase II will proceed based on the information developed by the geologic and laboratory studies made in Phase I. Some of the four wells drilled in Phase I will be used to develop an inverted 5-acre 5-spot pilot pattern (See Figure 10). This pattern will be used to test the Lanigan sand's production characteristic and steam injection response. All five wells will be stimulated and produced to establish a preliminary state of depletion in the pilot area for an air injectivity test. Two observation wells will be used in an up dip and down dip location to measure the average rate of burning front advance in the pilot area. Subsequent to the tests, the central well will be ignited and a preliminary dry combustion project will be run to study reservoir heterogeneity.

Phase III will be the project's full size expansion to a line drive well array on a 2½ acre spacing. Five additional injection wells and twenty-one producing wells will be drilled to develop a well array as shown in Figure 11. After production testing and cleaning the drilling contaminants from the well bore area, the remaining five injection wells will be ignited to complete a 6 well line drive displacement flood. Air injection will be controlled in an attempt to balance displacement by the burning front while using cyclic steam stimulation treatments at the producing wells. The proposed air injection schedule is presented in Figure 12. Air will be injected until a heat-pad volume has been established in the reservoir around the injection well. This will occur after the cumulative air injection is between 100 and 200 MMSCF and stable burning conditions exist.

Phase IV operation will proceed after the six patterns have reached their stable burning conditions and the required heat-pad exists around each injection well. Expected water injection rates per pattern shown in Figure 13 will create a water-air ratio of approximately 220 Bbl/MMSCF. Air will be injected for six days while water will be injected on the seventh day. Air injection following the water treatment will resume and distribute the water throughout the reservoir. When the water contacts the heat-pad, it will heat and eventually vaporize. The closer the water vapor comes to the flame; the more it will super heat. After passing through the flame front, the water vapor will again reach saturation conditions and form a steam bank that drives and heats oil ahead of the displacing front. This heat bank will grow larger and larger until the heat effect improves each producing well's productivity. The cyclic steam treatments used on the producing wells will then be suspended and the productivity of the displacement will be maintained by the CTD process.

After the completion of Phase IV, continued water injection will be maintained to sweep the residual formation heat stored at

the time air injection operations terminate. This final water displacement operation will last until each well's water cut increase significantly and production economics dictate abandonment of the producing well.

PROJECT OPERATIONS

The Lynch Canyon project started September 15, 1978, when the final contract negotiations resulted in the signing of contract ET-78-C-03-2096. Even though General Crude Oil Company had prepared an environmental report and applied to the Monterey Bay Unified Air Pollution Control District as early as July, 1978, negotiation for a permit from the APCD was not complete. A new NOx standard was being adapted and the industry was being asked to meet the terms of District Rule 208 (b), which limits the total project emissions to 250 lb/day. The project will not meet this restriction unless electric drive compressors are used. The APCD finally granted a permit to construct with the restriction that the total project emissions will be less than 250 lb/day. The permit was issued in January, 1979. Plans are to continue to obtain complete project approval for the project with the use of diesel drive compressors.

Drilling operations were delayed until March, 1979, due to rains and soft terrain. Coastal Drilling finally was able to move into the field on March 26, and spud Lanigan 102. This well encountered problems at 1715 feet when the Santa Margarita zone, a pressurized water sand, began to flow. The back flow condition was complicated by loss circulation in a low pressure D-2 sand located at the top of the Lanigan sand. Mud and loss circulation material were mixed and control was finally regained. A 9-5/8 inch protector string was run to case off the Santa Margarita zone, and drilling operation continued by coring through the Lanigan sand. The well reached total depth at the top of the Jurrasic granite basement at 1829 feet and was logged. The log indicated reduced resistivity and spontaneous potential throughout the Lanigan sand. The well was then plugged in to the 9-5/8" casing and idled until further data could be obtained.

Coastal moved to the Lanigan 205 location and drilled to basement without incident. An improved mud program and drilling rate control adverted the loss circulation problem experienced with Lanigan 102. Lanigan #205 was logged and sidewall sampled. Seven inch casing was set at 1842 feet and a 5½" slotted liner and gravel pack was installed. The well was placed on production, but would not produce due to a rod hang-up problem. Plans are being made to production test this well using a cyclic steam stimulation treatment. However, environmental permits were required and have caused a month's

suspension in operations.

Coastal Drilling had committments, of which General Crude was aware, to drill several wells in April, May and June. Instead of bidding for a new contractor, General Crude asked to remain on Coastal's waiting list to complete the remaining two wells required to complete Phase I.

ACKNOWLEDGEMENTS

We thank General Crude Oil Company and International Paper Company for permission to publish this paper. In addition, we acknowledge the advice, encouragement and valuable assistance from Dr. Philip D. White and Jon T. Moss of Tejas Petroleum Engineers and TOR Development Company in the development and operation of the Lynch Canyon Project.

1. Wilkinson, E. R., "Lynch Canyon Oil Field", Summary of Operations, California Oil Fields, California State Division of Oil and Gas Publication, Vol. 50, No. 2, 1964, pg. 79.

Table I

LYNCH CANYON FIELD

Averaged Core Analysis

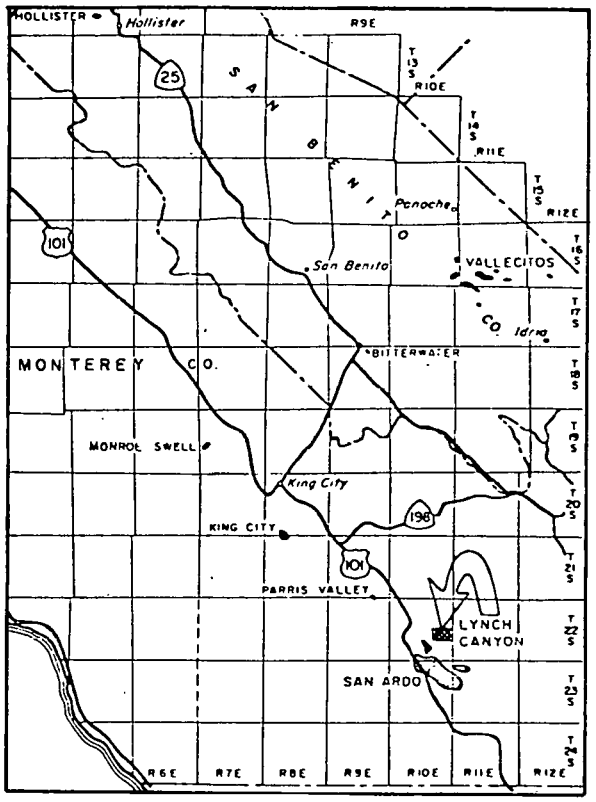
WELL	ZONE	NUMBER OF SAMPLES	INTERVAL FT. BELOW KB	PERMEABILITY md	POROSITY %	SATURATION, PERCENT OIL	SATURATION, PERCENT WATER
50	A	1	2083/2102	304	27.7	NA	NA
	B	2	2119/2129	294	31.0	NA	NA
102	A	20	1730/1755	2,804	36.4	49.7	40.4
	B	7	1755/1770	5,477	38.0	40.5	48.8
172+	A	6	1706/1726	8,916	40.6	70.8	15.2
	B	10	1726/1743	4,869	39.9	51.4	30.2
205*	A	14	1840/1860	2,037	34.3	38.3	37.8
	B	5	1860/1880	1,961	34.7	36.8	45.9
TL#1	A	1	1711/1734	9,800	41.0	50.7	34.6
	B	3	1734/1767	6,110	41.0	49.0	45.2

+ Cored in 10% Diesel Oil Mud

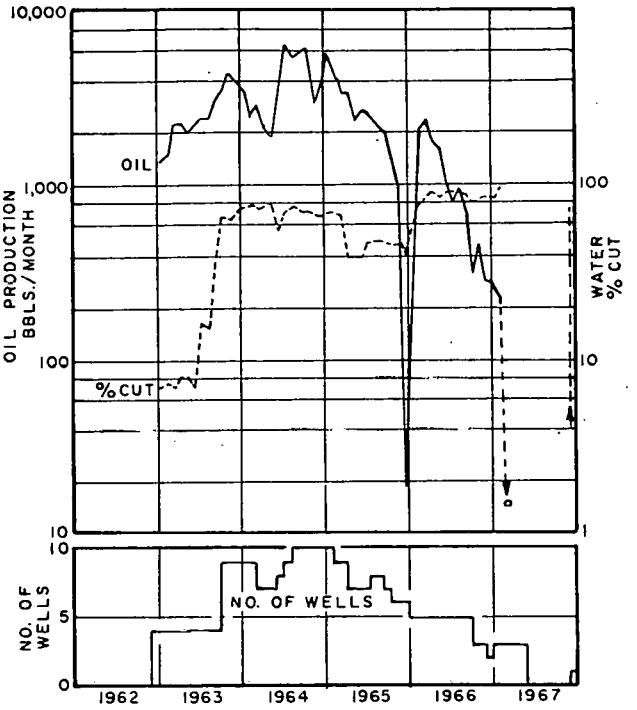
* Sidewall Sample

Average Field Core Analysis:

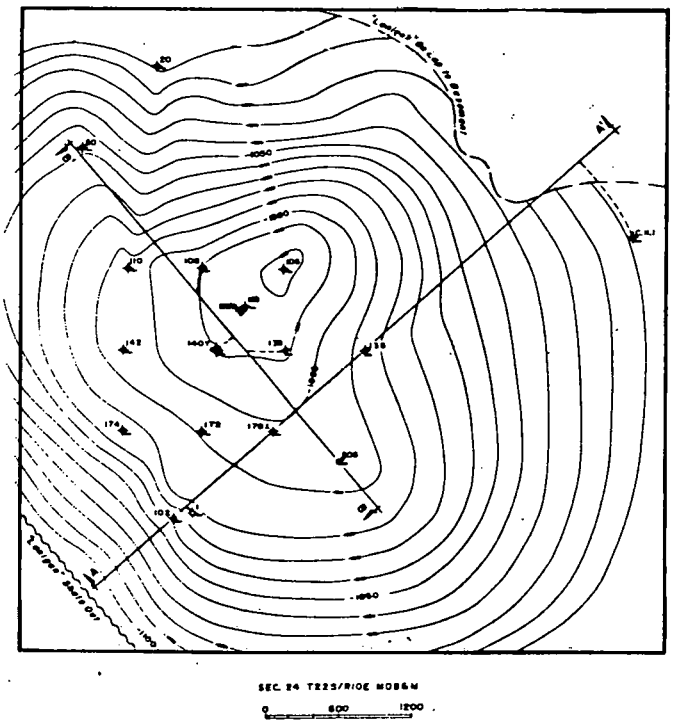
A	42	-	3,529	36.2	48.9	35.7
B	27	-	4,287	37.9	45.1	40.3



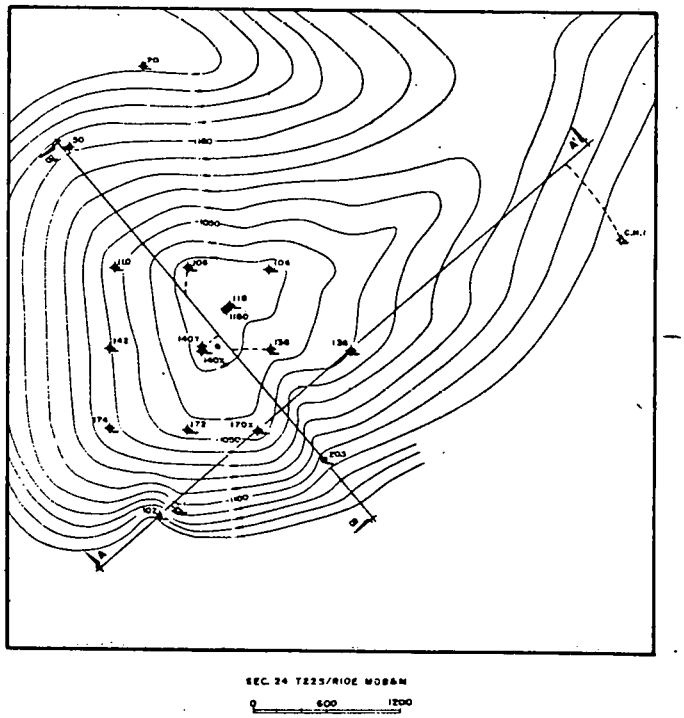
LOCATION MAP
LYNCH CANYON FIELD
Figure 1



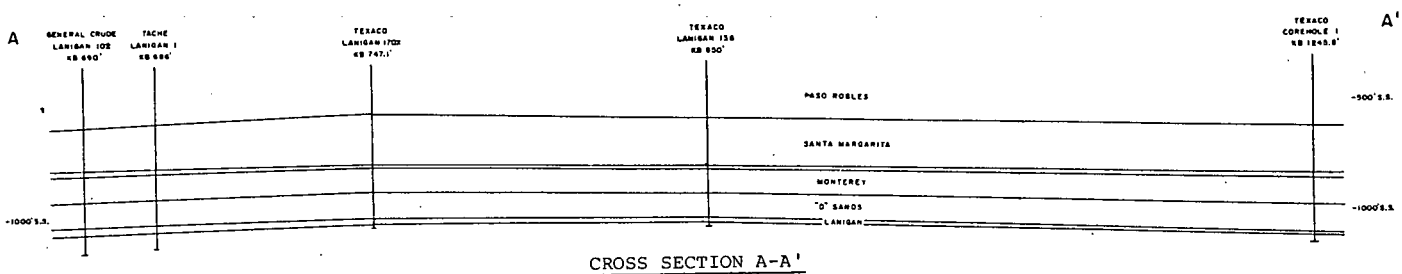
PRODUCTION HISTORY
LYNCH CANYON FIELD
Figure 2



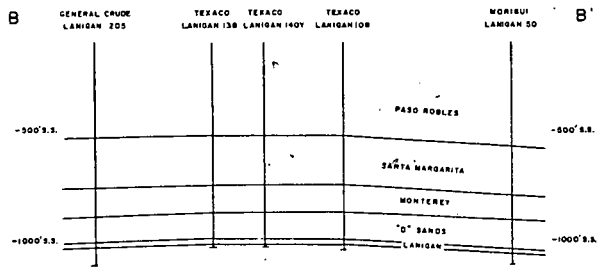
CONTOURS TOP OF
LANIGAN SAND
Figure 3



CONTOURS TOP OF
GRANITIC BASEMENT
Figure 4

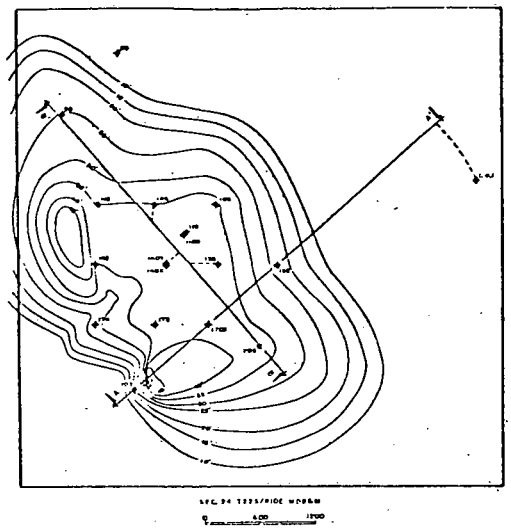


CROSS SECTION A-A'

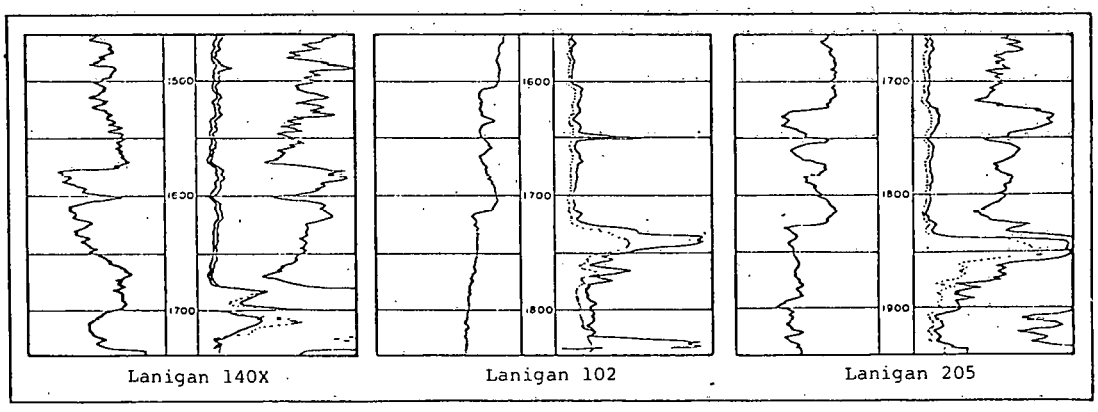


CROSS SECTION B-B'

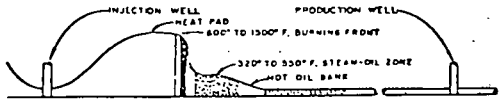
CROSS SECTIONS
LYNCH CANYON FIELD
Figure 5



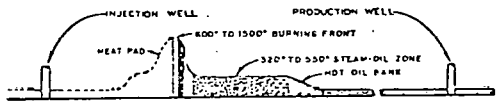
ISOPACH MAP
LANIGAN SAND
Figure 6



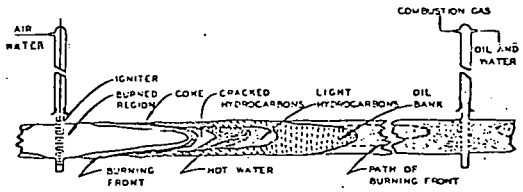
TYPICAL E-LOGS
LYNCH CANYON FIELD
Figure 7



TEMPERATURE DISTRIBUTION
DRY COMBUSTION

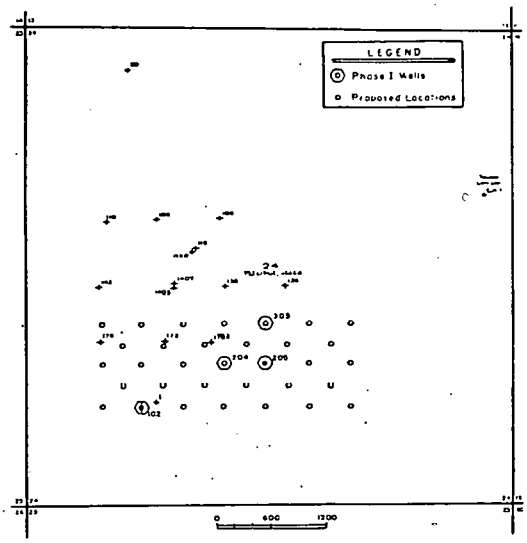


TEMPERATURE DISTRIBUTION
C.T.D. COMBUSTION

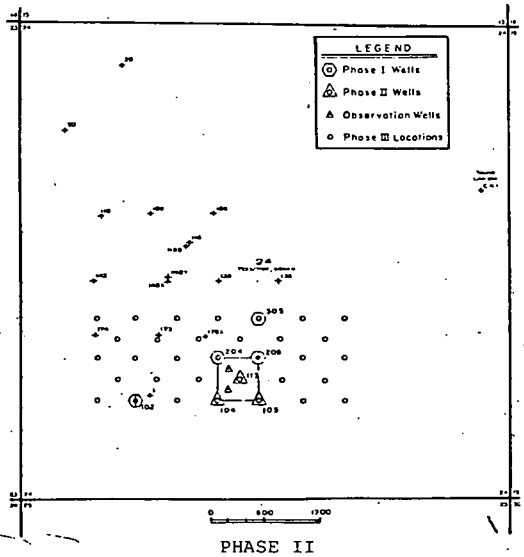


CROSS-SECTION OF FORMATION

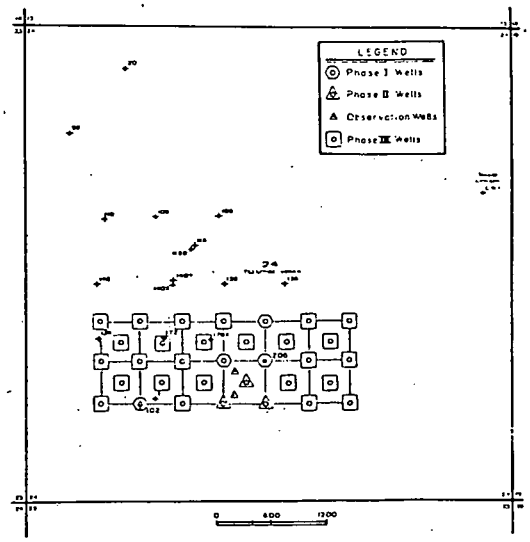
TEMPERATURE-SATURATION SECTIONS
C.T.D. COMBUSTION PROCESS
Figure 8



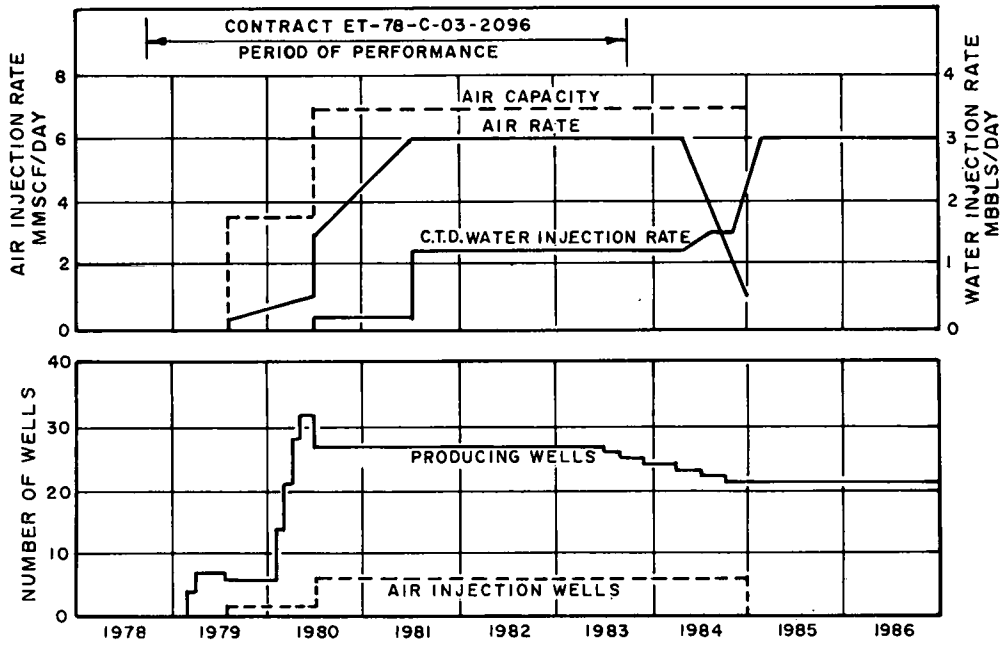
PHASE I
GEOLOGIC TEST WELLS
Figure 9



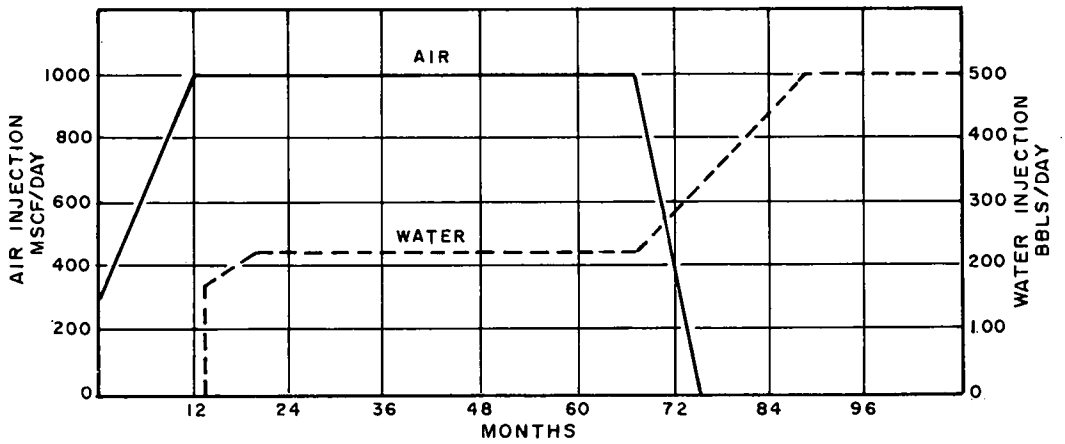
PHASE II
PILOT TEST PATTERN
Figure 10



PHASE III
DEVELOPMENT WELLS
Figure 11



PROJECT INJECTION SCHEDULE
LYNCH CANYON FIELD
Figure 12



SINGLE PATTERN
INJECTION SCHEDULE
Figure 13

ECONOMIC FEASIBILITY OF STEAM DRIVE IN LIGHT OIL RESERVOIRS

By

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ABSTRACT

This study has been performed to investigate the effects of certain reservoir parameters upon the economic feasibility of steam distillation drive in light oil reservoirs. Previous investigations have shown that steam injection into light oil reservoirs would result in high oil recovery due to very good sweep efficiency and low residual oil saturation. The model used in this study includes the viscous and gravitational forces, as well as compositional and thermal effects, which influences the multi-phase flow of steam, water, oil, and gas in porous media.

The economic feasibility of steam distillation drive in a light oil reservoir depends upon the permeability of the reservoir rock, the crude oil composition, the steam injection rate, the well pattern and spacing, and the magnitude of the start-up costs. The presence of a free gas saturation or a high water saturation is not detrimental to steam distillation drive as long as sufficient quantities of distillable oil are present in the reservoir. Steam overriding is not severe in light oil reservoirs, and very good vertical sweeps are possible in homogeneous, thin, and slightly dipping sandstone reservoirs.

The present worth before taxes of oil recovered by steam flooding a light oil reservoir with a 50% oil saturation can range from $50,000 per acre in widely spaced wells in low permeability formations with low yield oil to $250,000 per acre in close well spacings in highly permeable formations containing high yield oil.

Prepared for DOE under Contract No. DE-AC19-78-BC-00044

INTRODUCTION

In the steam distillation process, volatile components are stripped from residual oil left from steam displacement and are transported to the steam front, where they condense to form a solvent slug. As the steam zone advances, this solvent slug is displaced and redistilled to further increase oil recovery. Residual oil saturations below those obtainable by steam driving non-distillable oils are possible.[1] Other important mechanisms attendant with this process are (1) the reduction in oil viscosity, which improves oil mobility, (2) the thermal expansion of oil, and (3) gas drive from the steam vapor phase.

Previous studies of the steam distillation drive process[2,3] have used numerical models in one dimensional applications aimed at simulating experimental core flood results. In this study, a thermal-compositional model described elsewhere[2] has been used to investigate the distillation process in a series of shallow, thin reservoir prototypes. The reservoir characteristics studied included formation permeability and depth, crude oil composition, well spacing, and injection pattern. Also steam injection rate was studied indirectly, and the effects of each parameter upon the economic feasibility of the steam distillation process in the candidate reservoir prototypes were calculated.

RESERVOIR CHARACTERISTICS

The light oil reservoir prototypes which were considered for steam distillation drive were (1) depleted, watered-out, sandstone reservoirs with negligible free gas saturation, and (2) depleted sandstone reservoirs with significant free gas saturation and solution gas. Oil from the first reservoir type had been produced by solution gas drive followed by water injection or natural water influx. The residual oil saturation was assumed to be distributed homogeneously throughout the reservoir, and the free gas saturation was negligible. The second type of reservoir was produced by solution gas drive with no water influx, and the remaining free gas, solution gas, oil, and connate water were homogeneously distributed throughout the reservoir.

Reservoir Properties Both reservoir prototypes studied in this project can be described as thin, depleted sandstone reservoirs with low pressures and a 50% residual oil saturation. Reservoir depths were all from 500 to 2000 feet with net thicknesses of 50 feet, and reservoir dip was either 0^{o} or 15^{o} depending upon the injection pattern. Detailed descriptions of the two reservoir prototypes, designated as Class 1 for the watered-out reservoir and Class 2 for the depleted reservoir containing free gas, are given in Table 1.

Reservoir permeabilities and depths were varied to study the effect of these parameters upon the profitability of steam distillation drive. Permeabilities ranged from 100 millidarcies to 1000 millidarcies with an intermediate value of 316 millidarcies. Reservoir depths were specified as 500, 1000, 1500, and 2000 feet, and a maximum bottomhole injection pressure for

each depth was calculated from a 0.75 psi/foot gradient. Well spacings and the quality of the injected steam were varied with depth. "Well density" has been used to relate the depth of the well to well spacing, with high well density correpsonding to 2 1/2 acres per 1000 feet of depth. This definition was utilized to compensate for changes in injection rate with depth so that shallow wells on closer spacing received about as much steam per acre as deeper wells with the same well density. Medium density represents 5 acres per 1000 feet of depth, and low density corresponds to 10 acres per 1000 feet of depth.

The relative permeabilities used in this study were generated by an analytical relationship presented by Corey[4] for clean sandstones. These relative permeability curves were not altered by changes in reservoir temperature. Earlier investigations[2,3] have indicated that steam distillation drive is sensitive to relative permeability, but this sensitivity was not investigated in this study. Capillary forces were neglected for this study, as were changes in absolute formation permeability with temperatures.

Description of Patterns and Wells Two injection patterns were investigated in this study. The first pattern, a direct line drive pattern, is shown in Figure 1. A cross-sectional, two-dimensional grid was used to simulate this confined line drive pattern of two rows of injectors alternately drilled between three rows of producers. The cross-section was tilted at an angle of 15^{0}, and no gas-oil or oil-water contacts were encountered. The 50-foot net pay thickness was divided into six homogeneous layers which differed only in that their thickness increased with depth. In the injection wells, steam was injected into the lowest possible grid blocks while the highest possible rate was maintained. The producing wells were completed in every layer.

A no-flow boundary would normally exist between adjacent producers and injectors in a line drive pattern, and the area influenced by each well should extend to that boundary. Areal sweep for a set of wells within these boundaries would depend upon fluid mobilities and reservoir heterogeneities, and under typical reservoir conditions, the areal sweep is less than 100%. The cross-sectional grid utilized in this study, however, imposes perfect areal sweep; therefore, the pattern area simulated was reduced by half to represent a 50% areal sweep. The area modeled, illustrated in Figure 1, represented only half the pattern area. This placed an arbitrary limit on the oil available for displacement and distillation by injected steam, and created some distortion in the response times and rates for the producing wells.

The five-spot pattern used a three-dimensional grid system as described in Figure 2. Only one-eighth of the actual five spot pattern was modeled, and conditions imposed by symmetry did not allow any formation dip with this pattern. The 50-foot net pay was divided into four homogeneous layers which differed only in that their thickness increased with depth. The completion intervals were again the lowest possible grid blocks for injection wells and all grid blocks for the production wells.

For both the direct line drive and five-spot patterns, the thermal-mpositional model used in this study implicitly linked the wellbore to the injecting or producing grid block using well indices calculated from wellbore, rock, and fluid properties. No wellbore skin effects were included. The injection rates for each well were dependent upon the maximum bottomhole pressure, which was determined by depth. In general, the deeper wells had higher injection rates, and a maximum rate of 760 B/D cold water equivalent (CWE) of steam was set for each injection well.

Producing wells were allowed to produce against a constant bottomhole pressure of 30 psi. The makeup and quantity of fluids produced were determined by changes in fluid saturations, mobilities, and pressures near the producing wells. Each well produced as much fluid as possible against the 30 psi bottomhole pressure restriction.

Each simulation was run for a maximum of eight years unless the production of hydrocarbons ceased before that time. All hydrocarbon production after eight years was assumed to be uneconomical because of high replacement or repair costs to the steam generation facilities. Also, steam injection rates were not reduced at steam breakthrough at the producing wells, but were continued until hydrocarbon production ceased.

Fluid Properties The hydrocarbon fluid properties used in this study are based upon the laboratory work of Volek and Pryor[5] with Brea crude oil. They reported that, in an experimental steam flood of a 20-inch long core, the hydrocarbon components C_6 through C_{17} were practically all distilled by injected steam. To represent a distillable crude oil in this study, the hydrocarbons were divided into three components: C_1-C_5, C_6-C_{17}, and C_{18+}. The first component, C_1-C_5, represented the hydrocarbon gas found in Class 2 reservoirs, and was not present in Class 1 reservoirs. The intermediate component, C_6-C_{17}, was the distillable hydrocarbon liquid, and the heavy C_{18+} component represented the non-distillable hydrocarbon.

The two crude oil compositions investigated in this study were different in the proportions of distillable and non-distillable oil in the reservoir. The low yield crude oil sample, shown in Figure 3, represents the yield reported by Volek and Pryor, and it compares well with a Weber crude oil sample from Pennsylvania (sample no. 91 in USBM-RI 6819).[6] The high yield oil sample is richer in the distillable component, and is similar to a 5600' Frio oil sample from Texas (sample no. 566).[6] Equilibrium ratios were calculated from these yields and the other fluid property data given in Table 2.

The fluid properties of water and steam were represented as those of pure H_2O. Steam tables provided the majority of the physical and thermodynamic properties of both the liquid and gaseous H_2O component.

DISCUSSION OF RESULTS

Reservoir Type Early results of this investigation indicated that both reservoir types (Classes 1 and 2) would respond to steam injection similarly when the same quantities of distillable oil were present. The producing characteristics of the two reservoir types were very similar except for a few important differences. The Class 2 reservoir, containing free gas and a lower water saturation, produced hydrocarbons quicker and did not immediately produce water; while the Class 1 reservoir, representing a previously waterflooded formation, initially did produce water. The pressure maintenance and cold waterflooding aspects of steam distillation drive in Class 2 reservoirs account for the early production of hydrocarbons while the hydrocarbon saturation was still high around the producing well. In both cases, at water breakthrough, all the free gas had been produced or returned to solution, and hot waterflooding effects were evident as an oil bank was produced. The composition of the produced oil became richer in distillable oil as the solvent bank reached the producing well. In both reservoir types the oil bank was produced at a water-oil ratio near 10 to 1.

Present worth calculations, described later, were made comparing Class 1 and 2 reservoirs with almost identical results. For the range of permeability, spacing, depth, and crude oil composition studied, the profitability of the two reservoir types were virtually the same. The rest of this study, therefore, only considers Class 1 reservoirs, and the results can be applied to Class 2 reservoirs.

Vertical Sweep Previous studies have concluded that very high fractional oil recoveries are possible in both laboratory[1,4] and field[6] applications of steam distillation drive. One of the primary reasons for this high oil recovery has been the good sweep efficiencies. Using the cross-sectional direct line drive model to investigate vertical sweep, the effects of well position, injection rate, and formation dip were studied to determine if steam overriding appreciably influenced recoveries in thin reservoirs. The effects of layering were not considered.

Simulations were made with a modified model to represent both updip injection at a low rate and downdip injection at a high rate. For the case of downdip injection, shown in Figure 4, good vertical sweep efficiency was maintained, and about 43% of the oil in place was produced at steam breakthrough. At ultimate recovery, 87% of the oil in the swept area was produced. For the updip injection at a low rate, 51% of the oil in place was produced at steam breakthrough, and again 87% of the oil in the swept area was produced. A noticeable hot zone existed at the top of both reservoir models, and very little distillable oil was present in the models.

Areal Sweep An identical simulation to the low rate case above was made with the three-dimensional five-spot model described in Figure 2. The production from one pattern, shown in Figure 5, shows again that the produced oil became richer in distillable oil with time. At heat breakthrough 44% of the

il in place had been recovered, and 70% of the oil had been recovered at the nd of eight years. These recoveries, combined with the known vertical sweep characteristics, indicate that the areal sweep was very good for the five spot pattern.

Crude Oil Composition The two crude oil samples described earlier differed in the amount of distillable oil present in the hydrocarbon phase. The higher yield oil, being richer in the distillable component, had a greater portion of the oil distilled by steam than did the low yield oil. Properties of the distillable and non-distillable components were the same for both crudes however. The ultimate recoveries of the high yield oils were near 87% in the swept area, while 72% of the low yield crude was produced from the reservoir swept.

The effect of crude oil composition is simply that the greater the amount of distillable oil in place, the greater the oil recovery and profitability during steam flooding. The major differences between the simulations with the two oils were not in sweep efficiency or solvent bank formation, but were in the residual oil saturations behind the steam front. Figure 6 contrasts the fractional recovery from low and high yield oils for both low and high permeability sands with direct line drive pattern. For both crude oil systems, the curve shapes were the same, and the high yield oil systems produced more oil for each unit of steam injected.

Formation Permeability It is apparent from Figure 6 that formation permeability is also an important factor in steam distillation drive. The most direct effect of formation permeability was to allow higher steam injection rates which allowed shorter flood lifes and quicker oil recoveries. Even when identical injection rates were utilized with three different formation permeabilities, as in Figure 7, the higher permeability reservoirs were each swept faster, more efficiently, and with higher recoveries. The percentages of high yield oil recovered in the swept areas were 87%, 86% and 83% at the economic limits of 2.4 years, 3.1 years and 4.4 years for the high, middle and low permeability formations, respectively. The ultimate recoveries were all within 1% of each other, as ultimate recovery was mostly dependent upon crude oil composition. Therefore, formation permeability will influence the economic performance, but not the ultimate recovery during the steam distillation drive process.

Formation Depth and Well Spacing The effect of changing both formation depth and well spacing were investigated. For wells of the same density, the deeper, more widely spaced well patterns required more steam to achieve the same recoveries for both high and low yield oils. The economic limits of floods in formations of different depths but with the same well densities were virtually identical. The oil recoveries of the deeper formations were slightly higher because more pore volumes of steam swept the reservoir.

The effects of depth, and consequently injection rate, upon oil recovery for a single spacing is shown in Figure 8. With low injection rates, the shallower reservoirs were more efficiently flooded due to higher steam quality and less fingering, but the production rates were also lower. The economic oil

recovery and ultimate oil recovery fractions were not altered by changes in depth or injection rate. The percentage of injected heat lost did decrease with increasing injection rates, with losses of 55%, 39% and 31% in the 500', 1000' and 2000' reservoirs, respectively.

Changing well spacing also influenced the rate at which oil was recovered, as shown in Figure 9. The tighter well spacings were characterized by a more efficient sweep, a higher fractional recovery, and less heat loss. The injected heat lost was 34%, 43% and 55% for 1-1/4, 2-1/2 and 5 acre spacings at a 500' depth.

ECONOMIC EVALUATION

To evaluate economic performance, a set of economic parameters were estimated to describe the operational conditions of a steam distillation drive project. The factors considered in these evaluations included an escalating oil price, overhead, repair and remedial expenses, fuel costs, royalties, initial investment, and the time value of money. Some of the factors not considered include lease acquisition costs, depreciation, depletion allowances, taxes, and water acquisition, treatment, or disposal costs. A summary of these items can be found in Table 3. With this data and the results of the simulation runs, the economic analyses were performed by a comprehensive economic evaluation program known as POGO.[7]

Each simulation run was evaluated assuming that existing wells, production facilities, and injection facilities could be used without major modification, and that the only start-up costs would be for steam generators. The price of these facilities was estimated from the capacity required to inject steam at the maximum rate into each pattern. The factor used to calculate these costs was $250 per B/D (CWE) required. The inital cost of steam generators ranged from $20,000 per pattern to $380,000 per pattern.

Direct Line Drive Pattern Applying a 15% discount factor to the revenues and expenses calculated from the results of the numerical model, the present worths per acre and per acre-foot were determined. Acreage, for the direct line drive pattern, was twice the area modeled, or the actual acreage between the no-flow boundaries in Figure 1.

Both high yield oil and high formation permeability are very important factors in the profitability of steam distillation drive, as shown in Figure 10. Profitability generally increases with shallower formation depths and tighter well spacings. An exception to this is at low permeabilities and shallow depths, when not enough steam could be injected to effectively flood the reservoir. A second increase in profitability with increasing depth and spacing at high permeabilities occurred at the deepest formation and widest spacing. The rate limit of 760 B/D (CWE) did not allow higher injection rates or more expensive start-up costs for the deepest, high permeability formations simulated, and additional oil was recovered from larger patterns. This additional oil was not offset by an increased investment, and the profitability per acre increased. This suggests that with a given injection rate, there exists a well spacing which would maximize profitability.

ive Spot Pattern The results of the five spot pattern simulations, given n Figure 11, show that the profitability of the five spot pattern seems greater than the direct line drive pattern. This may be due to the imposed 50% areal sweep in the direct line drive patterns being too severe a restriction, causing the oil displaced to be too small. Therefore, a valid comparison between patterns cannot be made in this study. The shape and behavior of the calculated profitability response function for the five spot simulation does closely resemble the direct line drive results. Again, the most profitable combination of reservoir characteristics were high yield oil, high permeability, and shallow depth.

Injection Rate Figure 12 shows the effects of changing depth and injection rate upon the profitability of flooding a 5 acre, direct line drive pattern. The highest profitability exists at an injection rate less than the maximum value. This indicates that for a given spacing, an optimum rate does exist. More practical experience should be obtained before any definite conclusions about optional rates are made. This study does conclude that, in general, when nly low injection rates are possible, thighter well spacings are more profitable; while, when higher injection rates can be used, wider well spacings are desireable.

SUMMARY AND CONCLUSIONS

Utilizing a general set of economic assumptions and a thermal-compositional numerical model, the economic feasibility of the steam distillation process for certain reservoir characteristics has been estimated. Relatively thin sandstone reservoirs should be economically attractive when a 50% saturation of light, distillable oil is present. The presence of a 50% water saturation or a 20% free gas saturation does not noticeably reduce the reservoir profitability of steam distillation drive in the reservoir prototypes investigated in this study.

Steam overriding is not a severe problem in thin, light oil reservoirs, and very good vertical sweep efficiencies were predicted for every reservoir prototype simulated. Much of the distillable oil in the reservoir was recovered at steam breakthrough, and all the distillable oil was ultimately recovered. At heat breakthrough, at least 40% to 50% of the oil in place was recovered, and recoveries of 80% were calculated at the economic limit for some reservoirs.

Important characteristics of a successful steam distillation drive project were found to be first, a high formation permeability, and second, a high yield oil. The high formation permeability gave better oil recoveries and allowed higher steam injection rates. The steam distillation drive was generally most economical at high steam injection rates due to quicker oil recoveries and lower heat losses. The highest possible injection rate was not necessarily the most profitable due to a greater initial investment for steam generation facilities.

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TABLE 1 - RESERVOIR PROPERTIES

	Class 1	Class 2
WATER SATURATION	50%	30%
OIL SATURATION	50%	50%
GAS SATURATION	0%	20%
RESIDUAL WATER SATURATION	25%	25%
RESIDUAL OIL SATURATION	50%	50%
RESIDUAL GAS SATURATION	0%	5%
RESERVOIR PRESSURE, psi	250	100
SOLUTION GOR, SCF/STB	0	50
RESERVOIR TEMPERATURE, ^{o}F	175	175
k_v/k_h RATIO	0.2	0.2
POROSITY, fraction	0.23	0.23
STRUCTURAL DIP, DIRECT LINE DRIVE	15^{o}	15^{o}
STRUCTURAL DIP, FIVE SPOT	0^{o}	0^{o}
ROCK COMPRESSIBILITY, psi^{-1}	$2x10^{-4}$	$2x10^{-4}$
NET THICKNESS, ft.	50	50
RESERVOIR THERMAL CONDUCTIVITY, BTU/(FT-DAY-^{o}F)	28.8	28.8
RESERVOIR HEAT CAPACITY, BTU/(FT^3-^{o}F)	35	35
OVERBURDEN AND UNDERBURDEN THERMAL CONDUCTIVITY, BTU/(FT-DAY-^{o}F)	23	23
OVERBURDEN AND UNDERBURDEN HEAT CAPACITY, BTU/(FT^3-^{o}F)	32	32

TABLE 2 - HYDROCARBON PROPERTIES

	C_1-C_5	C_6-C_{17}	C_{18+}
MOLECULAR WEIGHT	30	156	400
CRITICAL PRESSURE, psia	708	321	196
CRITICAL TEMPERATURE, ^{o}R	550.1	1160	1730
COMPRESSIBILITY, psi^{-1}	$2x10^{-3}$	$5x10^{-5}$	$1x10^{-5}$
THERMAL EXPANSION, $^{o}F^{-1}$	0.0	$5x10^{-5}$	$34x10^{-5}$
HEAT OF VAPORIZATION, BTU/lb	210.7	110.0	0.0
STOCK TANK DENSITY, lb/ft^3	0.0	48.87	66.14
HEAT CAPACITY BTU/(lb-^{o}F)	0.41	0.41	0.44
VISCOSITY @ 175^{o}F, cp	0.013	1.0	35.0
VISCOSITY @ 600^{o}F, cp	0.018	0.045	1.6

TABLE 3 - ECONOMIC ASSUMPTIONS

I.	INITIAL INVESTMENT	
	A. LEASE PURCHASE & BONDS	NOT CONSIDERED
	B. SURFACE FACILITIES	
	1. PRODUCTION	NOT CONSIDERED
	2. INJECTION	NOT CONSIDERED
	3. STEAM GENERATION	$250/BPD CAPACITY (CWE)
II.	OPERATING EXPENSES	
	A. OVERHEAD	$0.90/BBL OIL (INC. 5% ANNUALLY)
	B. REPAIR & REMEDIAL (5 WELLS & PLANT)	$2,000/WELL/YR (INC. 5% ANNUALLY)
	C. FUEL	1 BBL OIL/13.5 BBL WATER (OIL AT PROD. OIL PRICE)
	D. WATER DISPOSAL	NOT CONSIDERED
III.	REVENUES	
	A. OIL	$15.66/STB (INC. 6% ANNUALLY)
	B. GAS	$2/MCF (INC. 6% ANNUALLY)
IV.	ROYALTIES	12.5% OF PRODUCTION
V.	DISCOUNT FACTOR	15% ANNUALLY
VI.	OTHER	PRODUCING LIFE LIMITED TO 7.67 YEARS

DIRECT LINE DRIVE
AREAL PATTERN SHOWING AREA SIMULATED

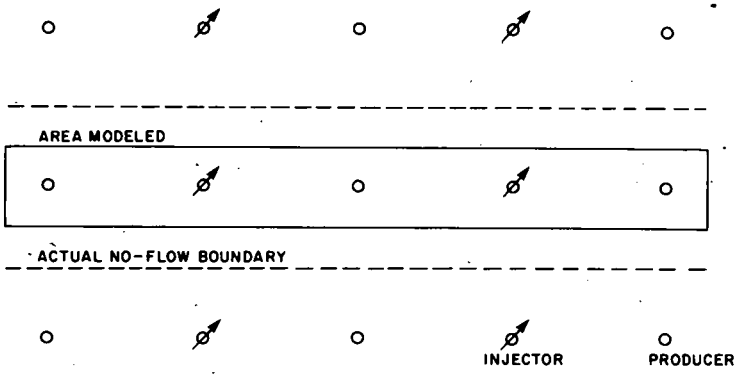


FIGURE 1

FIVE SPOT PATTERN AND AREAL GRID SYSTEM

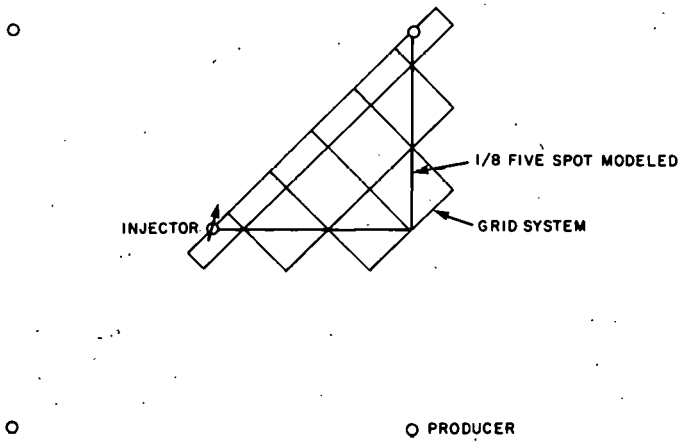
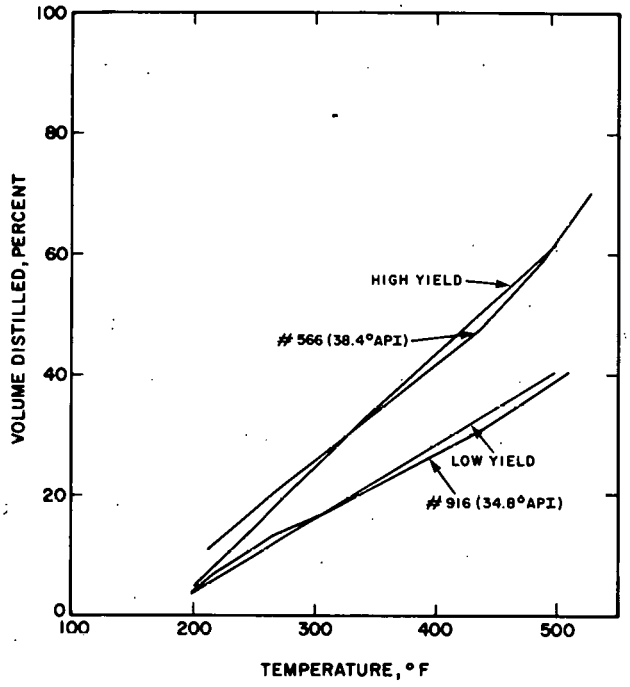


FIGURE 2

DISTILLATION YIELD OF CRUDE OIL SAMPLES



SAMPLES #27 & #566 TAKEN FROM RI 6814 "ANALYSIS OF CRUDE OILS FROM 546 IMPORTANT OILFIELDS OF THE UNITED STATES", USBM, 1966

FIGURE 3

POSITIONS OF STEAM AND CONDENSED OIL DURING DOWNDIP STEAM INJECTION

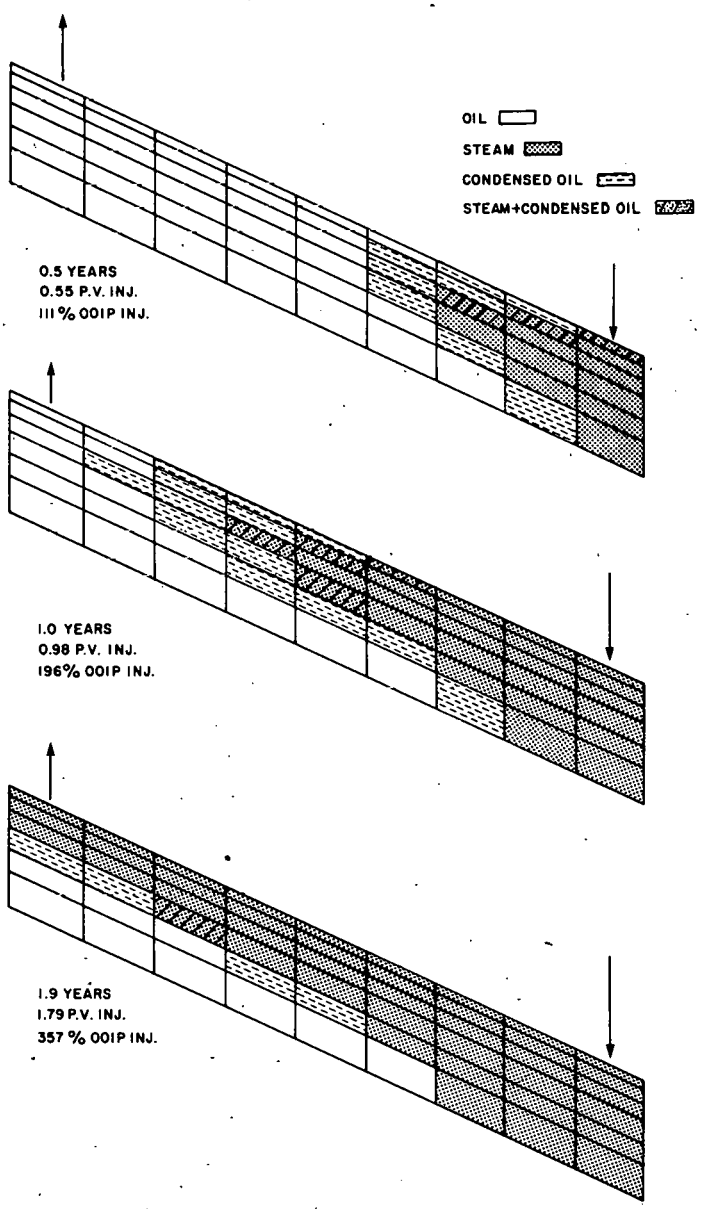


FIGURE 4

PRODUCTION FROM FIVE SPOT PATTERN IN A CLASS 1 RESERVOIR

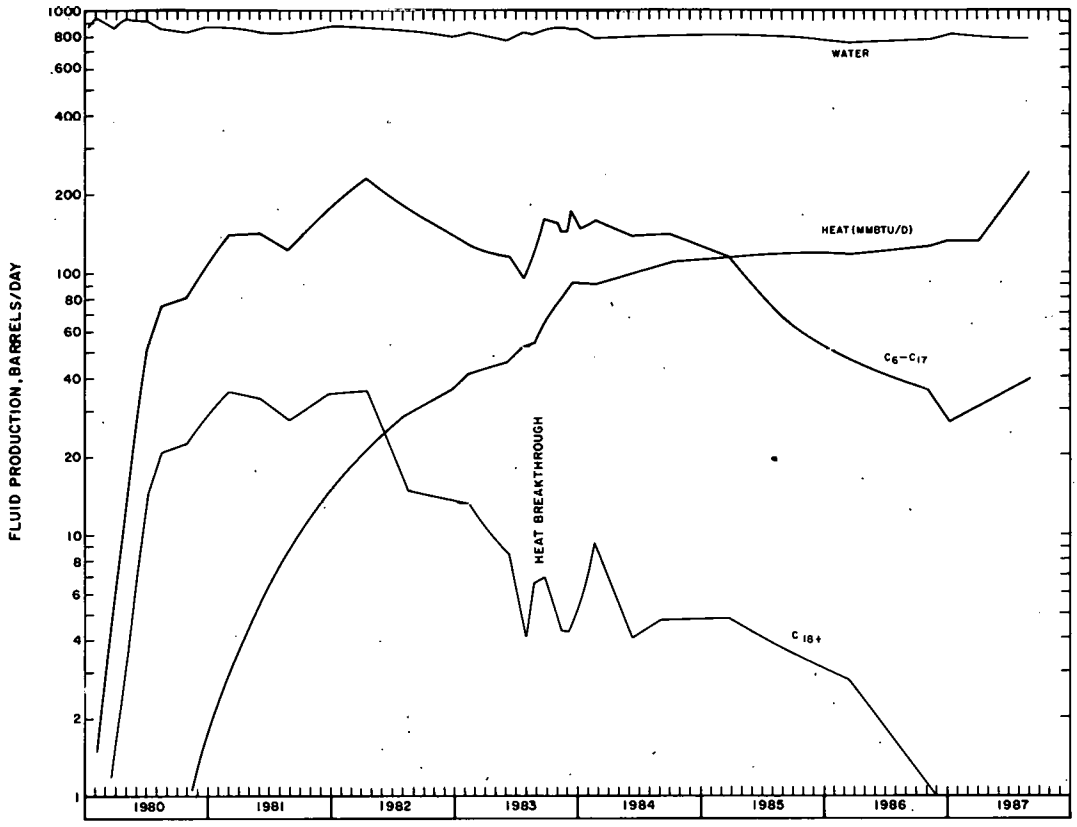


FIGURE 5

OIL RECOVERIES AS A FUNCTION OF STEAM INJECTION
FOR 1 1/4 ACRE SPACING AT 500'

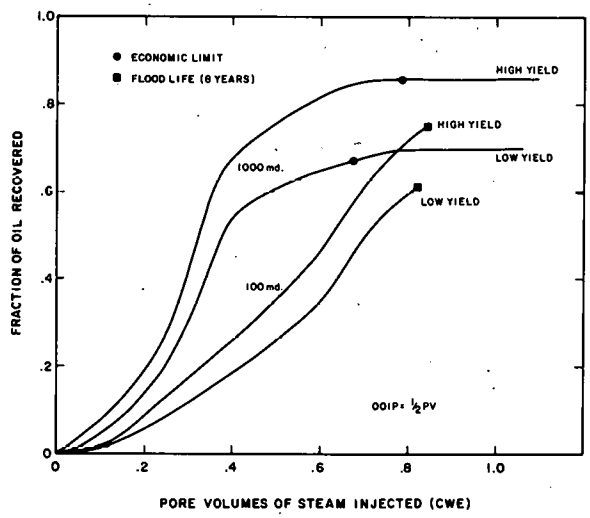


FIGURE 6

OIL RECOVERIES AS A FUNCTION OF STEAM INJECTION
FOR 5 ACRE SPACING AT 2000'

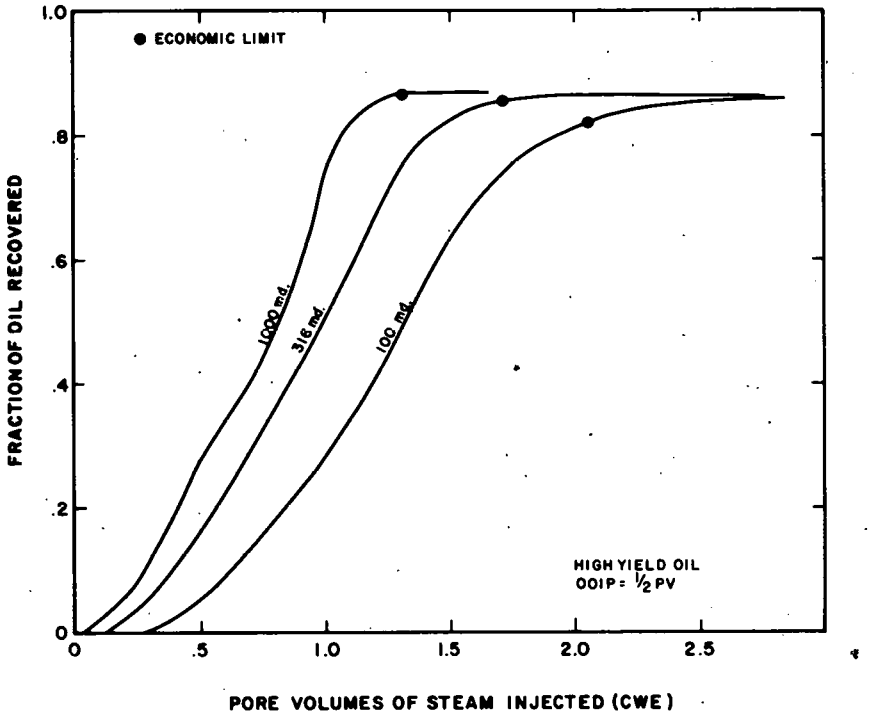


FIGURE 7

EFFECT OF DEPTH AND INJECTION RATE ON OIL RECOVERY

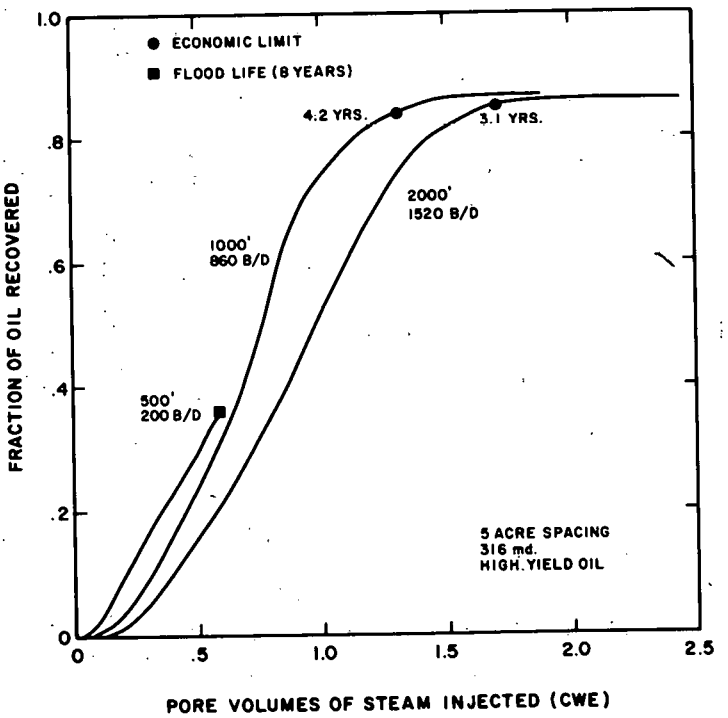


FIGURE 8

EFFECT OF WELL SPACING UPON OIL RECOVERY

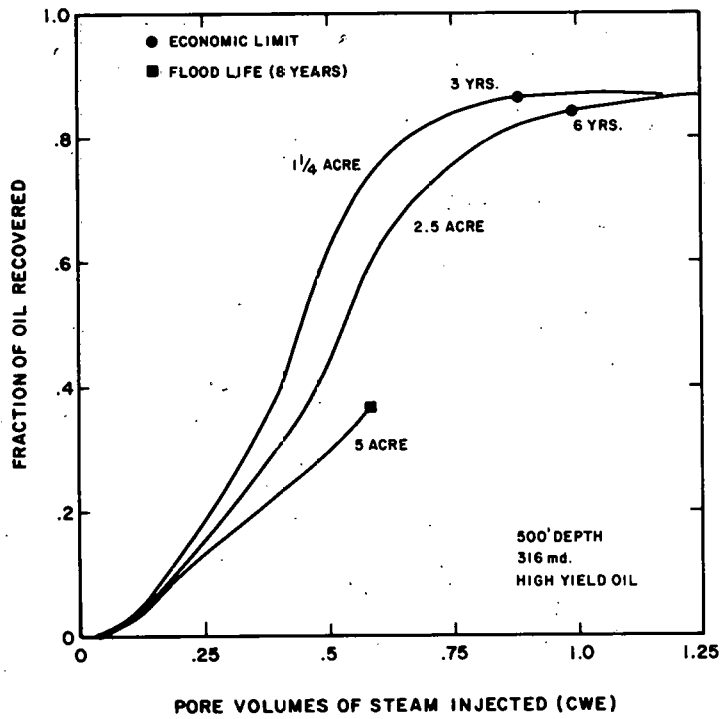


FIGURE 9

PRESENT VALUE PER PATTERN ACRE FOR HIGH DENSITY SPACING

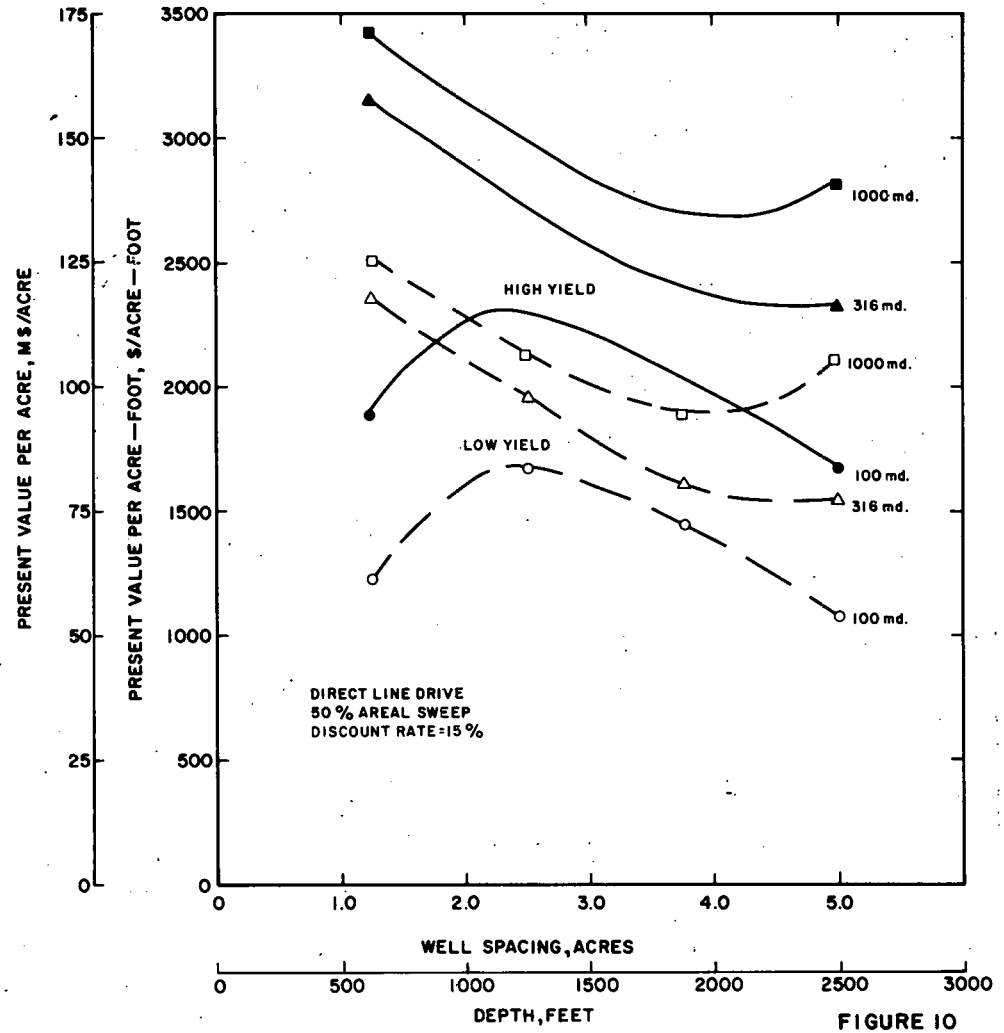


FIGURE 10

PROFITABILITY OF THE FIVE SPOT PATTERN

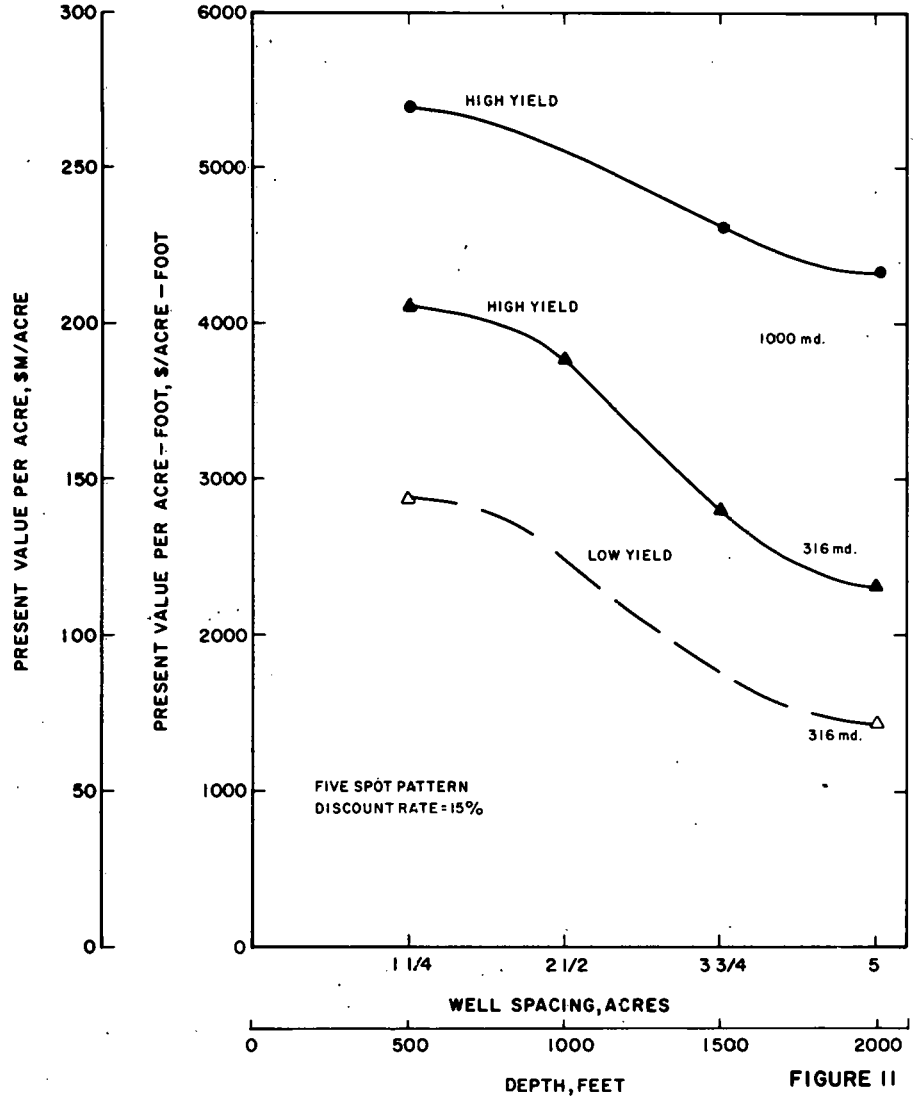


FIGURE 11

EFFECT OF DEPTH AND INJECTION RATE ON PROFITABILITY

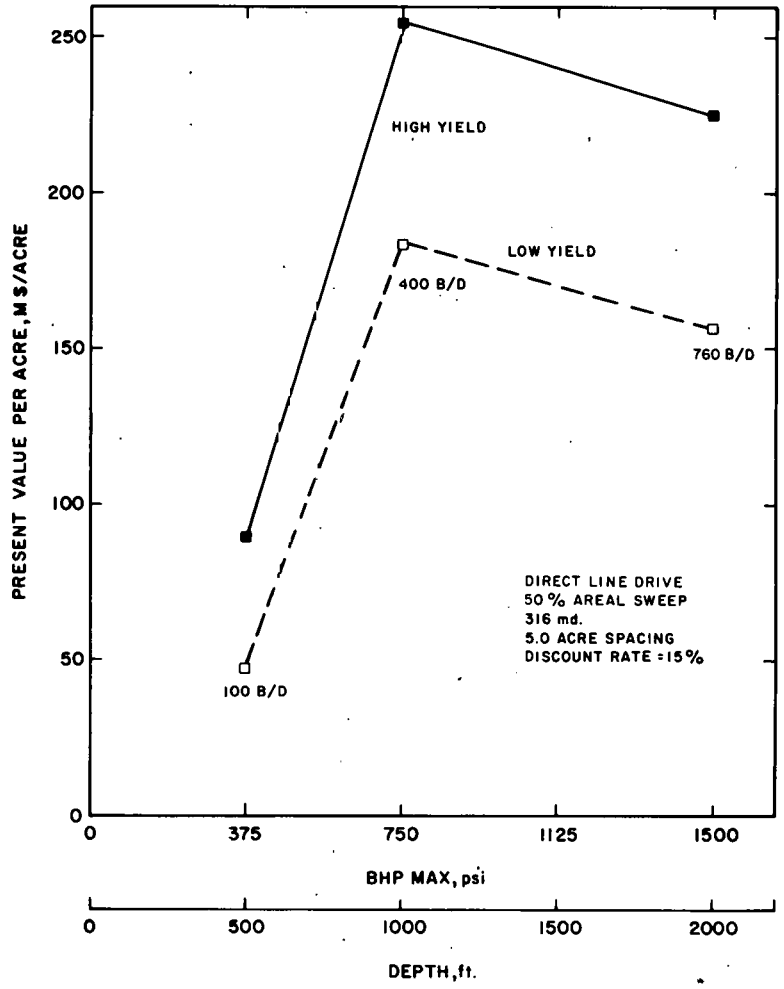


FIGURE 12

STEAMFLOOD DEMONSTRATION PILOT
WILLIAMS HOLDING LEASE, CAT CANYON FIELD
SANTA BARBARA COUNTY, CALIFORNIA

by

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ABSTRACT

A 20-acre steam displacement pilot is being conducted in the Cat Canyon Field, Santa Barbara County, California. Continuous steam injection into the four inverted five-spot patterns was initiated in April, 1977.

Significant delays were encountered during the first year of displacement operations due to a series of thermal packer failures and the necessity to replace gravel packed liners in six wells.

During the second year of continuous injection, definite displacement heat response has been noted in four of the producing wells. The high gross production rates accompanying the heat response has exceeded artificial lift capacity in the four responding wells. Current efforts are directed toward achieving heat response in the remaining five producing wells in order to balance fluid withdrawal rates in the project.

GENERAL PROJECT DESCRIPTION

The Cat Canyon Field is about eight miles southeast of Santa Maria in Santa Barbara County, California, as shown in Figure 1. The S1-B sand of Cat Canyon, shown in Figure 2, is a relatively deep, heavy crude oil reservoir found at an average depth of 2,500 feet. It produces a 9° API crude oil which has an estimated average oil viscosity of 25,000 centipoises at fully gas-saturated reservoir conditions.

Prepared for DOE under Contract No. EY-76-C-03-1188

The pilot consists of four inverted five-spot patterns on five-acre spacing. Pilot location and configuration are shown in Figures 2 and 3. Activities prior to contract inception on June 25, 1976 are reported in Topical Report I - Project Design and Development[1]. Project progress since contract initiation has been in two phases: a pre-displacement phase and a displacement phase which started in April, 1977. The pre-displacement phase included cyclic steam stimulation of the pilot producers, acquisition of steam generator operating permits, and computer simulation studies concerning pilot operations. Preliminary steam displacement operations were beset by repeated failures of the thermal packers in the steam injection wells. Early pilot operations and results are discussed in detail in the First Annual Report and Second Annual Report - Williams Holding Lease Steamflood Demonstration Project[2,3].

PROJECT PROGRESS - OPERATIONS

Initial pilot response to continuous steam injection was adversely affected by repeated failures of thermal packers in the steam injection wells. After over two months of difficulties, thermal packers were removed from three of the injectors. A packer was maintained in Williams Holding 935 to protect cement-squeezed perforations in the casing, which were made necessary by problems encountered during primary cementing operations. Sand control was lost in the four injection wells and two of the producers in late 1977. This required shutting down the steam generator twice for long periods while these wells were recompleted with new liners and gravel packs. A revised completion technique using a thicker gravel pack was used for the injectors which eliminated the sand control problems. This technique is described in detail in the Second Annual Report - Williams Holding Lease Steamflood Demonstration Project[4]. Figure 4 shows a schematic of the original and of the present mechanical condition of these wells. Additionally, a protective tubing string was cemented in place in Williams Holding 935.

By March, 1978, the packer and liner failure problems were solved and continuous steam injection was again established. Steam injection has remained continuous through the present with only short-time shutdowns for minor repairs.

[1]References, tables, and figures are given at the end of the paper.

Steam Generator Operations

The operation of the 50 MM Btu/hr displacement steam generator has been straight forward and uncomplicated by major problems. Figure 5 shows the steam generator performance since initiation of steam displacement. The down times shown in late 1977 and early 1978 were due to the well recompletion work described earlier. The dramatic improvement in steam quality achieved in late 1977 was due to the removal of the thermal packers from the injection wells. Starting with October, 1977, the steam generator did not need to be shut down every few days to replace a thermal packer. Consequently, steam generation operations improved significantly.

The injection rate was lowered in February, 1979 when injection well WH 825 was shut in to test for communication with the surrounding producers. The total injection rate remained cut back when WH 825 was returned to injection because four of the producers were shut in due to high fluid levels that could not be pumped off, as will be discussed later.

Sulfur Dioxide Removal

Getty Oil Company is testing a stack gas scrubber for the removal of sulfur dioxide from emissions resulting from burning high sulfur crude oil as steam generator fuel in a 22 MM Btu/hr generator. The original scrubber design was a disc-and-doughnut type with three sets of gas-liquid contact surfaces, using a soda ash (sodium carbonate, Na_2CO_3) solution as the absorbing material.

Testing of the initial scrubber design was significantly delayed due to the unsuitability of some components. During the first firing of the steam generator-flue gas scrubbing system, the demister pad was blown out the top of the scrubbing vessel, which required that a new demister pad be ordered and installed. Testing was then further delayed by heavy rain damage in February and March, 1978.

In April, 1978, the generator was test fired again. The new demister pad plugged in 1½ hours with fly-ash and sulfate, and was subsequently replaced with a chevron mist eliminator. The generator was fired again in July, 1978, and a cyclic steam stimulation was performed on a thermal well. Preliminary sulfur dioxide removal tests showed that the chemical efficiency of the soda ash-SO_2 reaction was not as great as predicted for the desired pH range of 6.7-7.0. A pH of approximately 9 was necessary to achieve the required degree of SO_2 removal, which would cause a scaling problem. To avoid this problem the soda-

ash was replaced with caustic soda (sodium hydroxide, NaOH) solution. The caustic solution proved to be no more efficient than the soda-ash, so it became necessary to redesign the scrubber. The disc-and-doughnut contact surface was replaced with a fluted media contact surface. The increased surface area of this contactor resulted in much greater chemical efficiency. Caustic is used as the absorbing material due to its greater ease of handling compared to soda ash. The revised scrubber system was tested in March, 1979. The test results showed that this system is very successful, with SO_2 emissions of 2.9 lb/hr and NO_2 emissions of 8.3 lb/hr compared to the EPA required maximums of 11.0 and 11.2 lb/hr, respectively. A schematic of the current scrubbing system is shown in Figure 6.

PROJECT PROGRESS - PRODUCTION

Initial pilot response to continuous steam injection was delayed by repeated failures of thermal packers and sand control problems in the steam injection wells. Pilot production and heat response has paralleled the periods of continuous steam injection since the initial problems were solved.

Production performance for the total pilot area and for the confined, central producer, Williams Holding 205, are shown in Figures 7 and 8, respectively. The effect of the steam injection is shown by the increasing gross production starting in early 1978. The effects of steam injection can also be seen by the temperature response of WH 205, as shown by Figure 9. The initial temperature response was seen in November, 1977, when the flowline temperature reached 200°F before the liner failure in December, 1977. Once continuous steam injection was resumed in March, 1978, flowline temperatures increased very rapidly until they leveled out between 320°F and 350°F in July, 1978. The flowline temperature remained at this level until WH 205 was shut-in in April, 1979, as will be explained later.

Unfortunately, the oil production response did not match the gross production response. Oil production declined from 291 BOPD in August, 1978 to 106 BOPD in March, 1979. This was due to the fact that production response was only seen in four wells (WH 25, WH 26, WH 205 and WH/RF 204), and it became impossible to keep these wells pumped off. The difficulty of pumping off these wells is increased due to the high fluid temperatures which cause very poor pump efficiency.

Previous studies[5] have shown the importance of maintaining low fluid levels in the production wells of this steamflood pilot. Field experience has confirmed that low fluid levels are critical to oil production. Wells WH 205 and WH/RF 204 have had steep oil production declines reversed when high fluid levels were pumped off.

The four wells, mentioned earlier, that were seeing fluid and temperature response were shut in in April, 1979. This was done to encourage heat breakthrough in the five wells that have not seen response. There will be two benefits if heat and fluid response can be spread to all nine producing wells. First of all, it will result in better steam sweep efficiency. Secondly, by spreading the fluid production to more wells, it will be easier to maintain low fluid levels in these wells. The four idle wells will be returned to production as soon as heat and fluid response is seen in most of the other five producers in this pilot.

PROJECT PROGRESS - ECONOMICS

Declining oil production and rising operating costs due to inflation have caused the project operating cost per barrel to rise sharply. Additionally, the repeated thermal packer failure during the initial phase of continuous steam injection and the six sand control liner failures have adversely affected the project economics. Table 1 itemizes the operating costs of the pilot from the effective date of the contract through March, 1979. The costs are given in terms of dollars per barrel of oil produced (BOP). Total operating costs for this period were $12.57/BOP. Of this amount, $1.39/BOP was due to major well workovers caused by the six liner failures.

When heat breaks through to the non-responding wells, and the idle wells are returned to production, oil production will rise which will result in a lowering of the cost per barrel of oil produced. Future projects of this type would also not have the high well workover costs due to the improved well completion techniques learned from this project. Improvements have been made through the standardized use of superior gravel, a change in the method of gravel placement, and the use of open hole packs in the injectors.

CONCLUSIONS

Initial operation of this project was troubled by excessive steam generator downtime caused by well problems. This delayed temperature and production response of the producing wells. After the initial problems were solved, steam channeling resulted in only four of the nine producing wells having temperature and production response. These wells have been shut in to force steam to move to the other five producing wells. When all of the producing wells have experienced thermal response, oil production should increase due to better areal sweep of the steam and the ability to keep low fluid levels in the producing wells.

Operating costs to date per barrel of oil have been very high. This has been due to inflation and declining oil production as well as unanticipated well workovers caused by loss of sand control. It is expected that oil production will rise in the future causing the cost per barrel to decline. Future projects will not have the high workover costs experienced by this project because of improved well completion techniques.

REFERENCES

1. Hanzlik, E.J., ed., Williams Holding Lease Steamflood Demonstration Project, Cat Canyon Field, Topical Report I, Project Design and Development.

2. Hanzlik, E.J. and Schenck, H., eds., First Annual Report, Williams Holding Lease Steamflood Demonstration Project, Cat Canyon Oil Field.

3. Hanzlik, E.J. and Schenck, H., eds., Second Annual Report Williams Holding Lease Steamflood Demonstration Project, Cat Canyon Oil Field.

4. Ibid, pp. 15-17.

5. Hanzlik, E.J. and Schenck, H., eds., Op. cit., pp. 21-23.

TABLE 1

ITEMIZATION OF ACTUAL OPERATING COSTS TO DATE

June 25, 1976 through March, 1979

($/Bbl Oil Produced)

Item	Total Cost
50 MM Btu/hr Steam Generator (excluding fuel)	$ 1.26
Steam Generator Fuel	4.55
Contract Services	2.43
Company Services	0.62
Materials and Supplies	1.07
Utilities	0.43
Central Plants	0.46
Steam Stimulation (excluding displacement)	0.81
Engineering and Supervision	0.42
Computer and Deliverables	0.09
General and Administrative	0.43
TOTAL OPERATING COST	$12.57
Major Well Workovers[1]	(1.39)
OPERATING COST EXCLUDING MAJOR WELL WORKOVERS	$11.18

[1] The major well workover costs only include the liner replacements that had to be done on WH 205, WH 36, and the four pilot steam injectors.

Figure 1

LOCATION OF CAT CANYON FIELD
SANTA BARBARA COUNTY

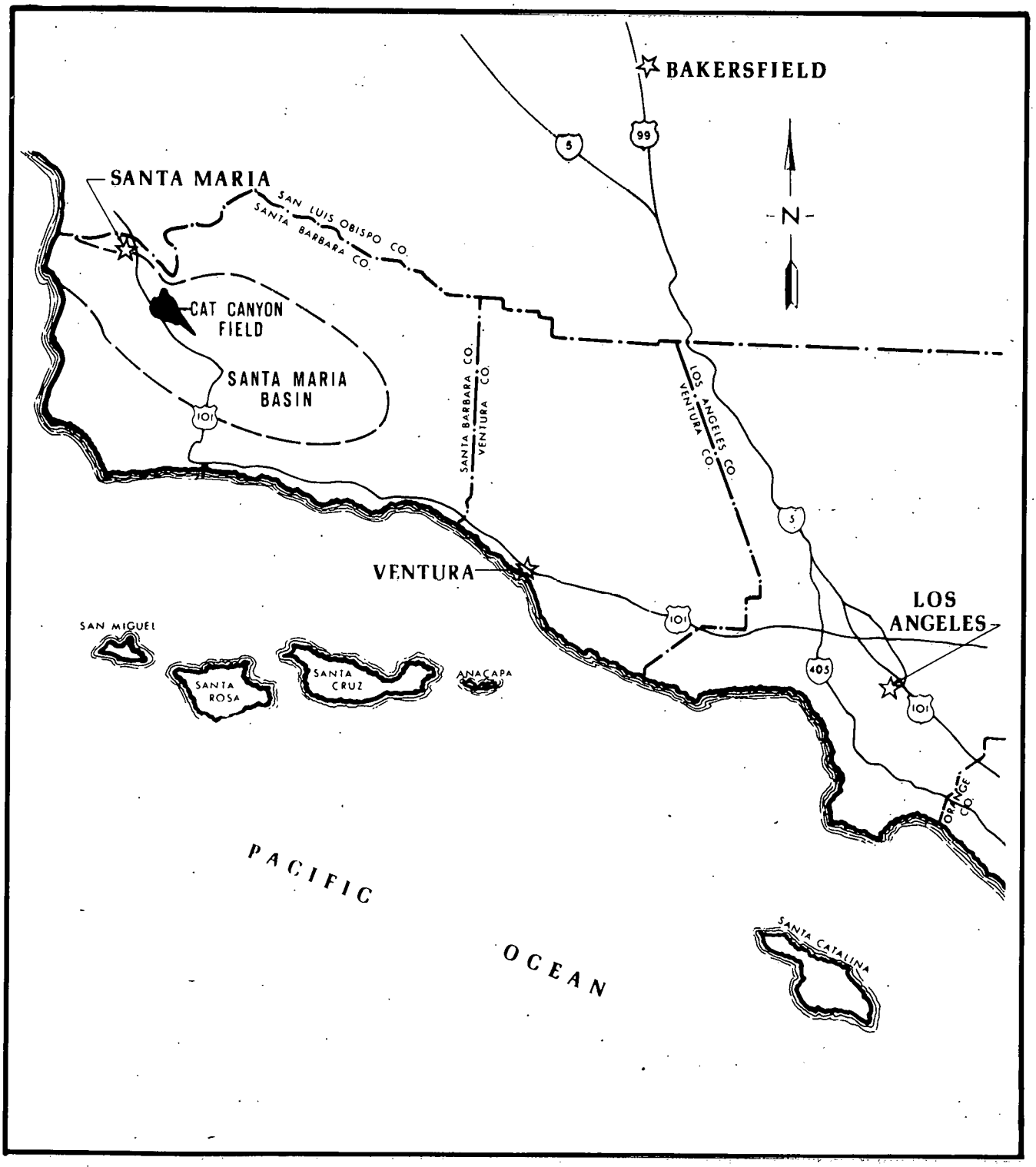


Figure 2

LOCATION OF WILLIAMS HOLDING STEAMFLOOD PILOT
CAT CANYON FIELD

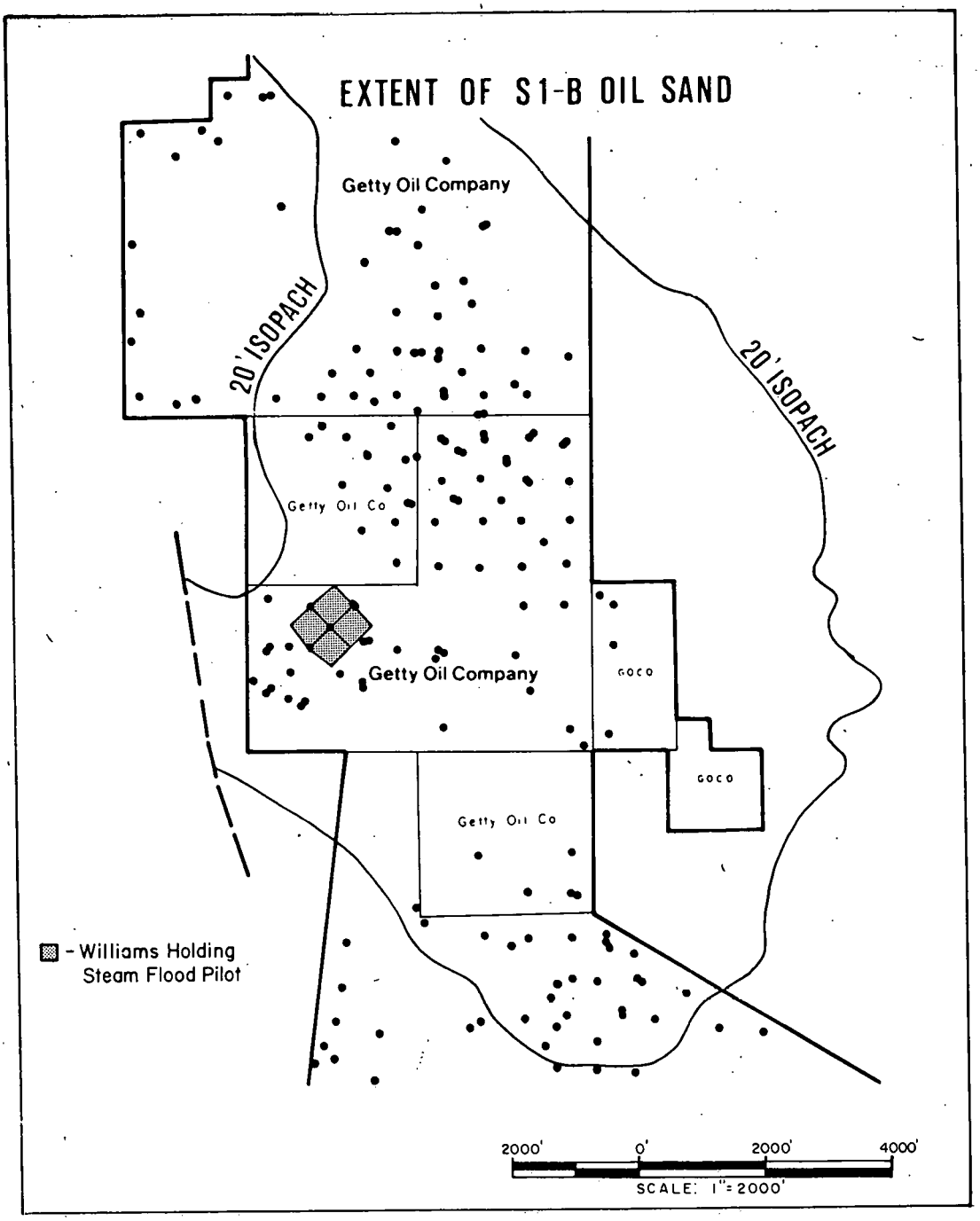


Figure 3

WILLIAMS HOLDING
STEAMFLOOD PILOT CONFIGURATION

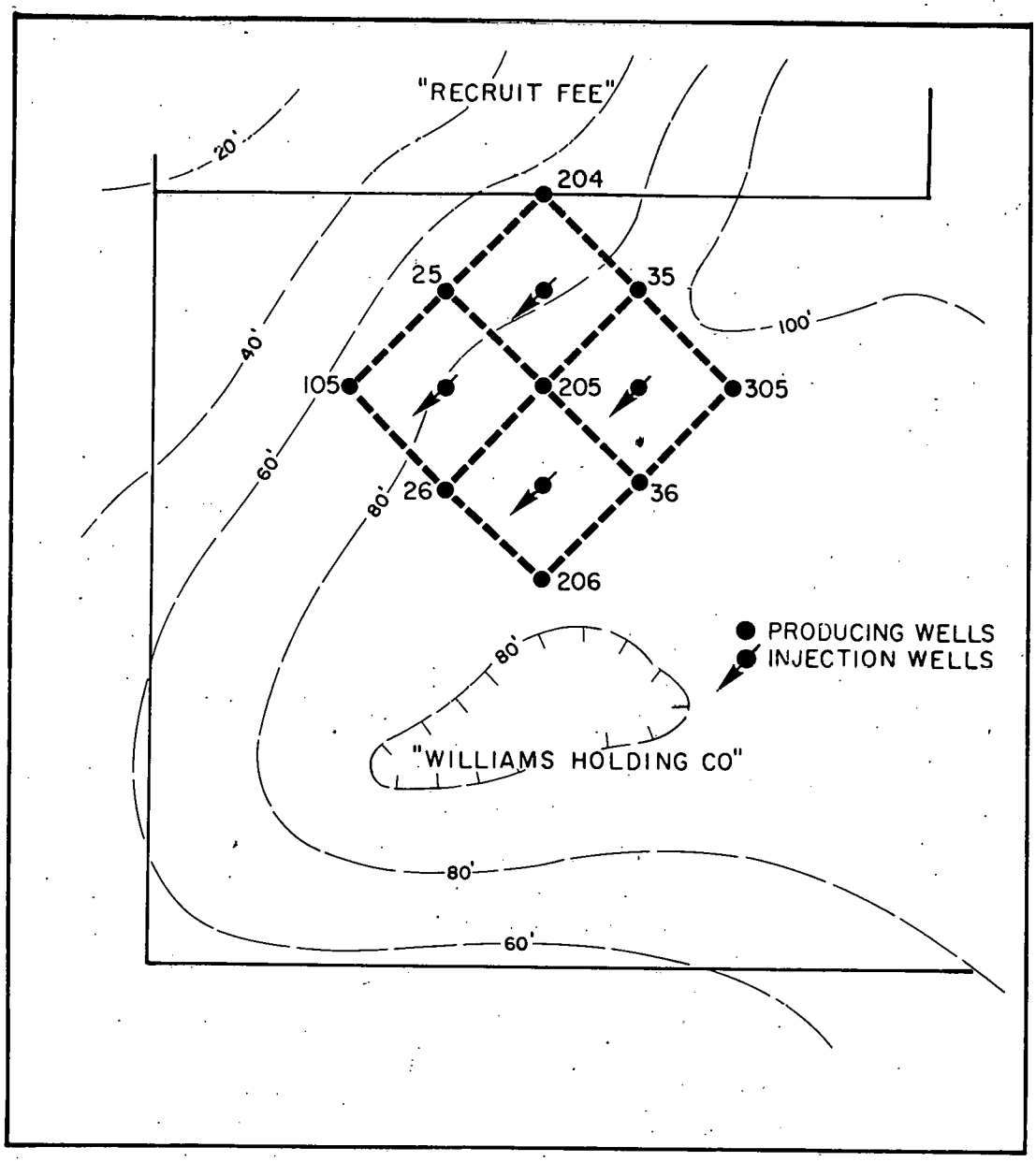


Figure 4

GENERAL SCHEMATICS OF THE STEAM INJECTOR WELL COMPLETIONS

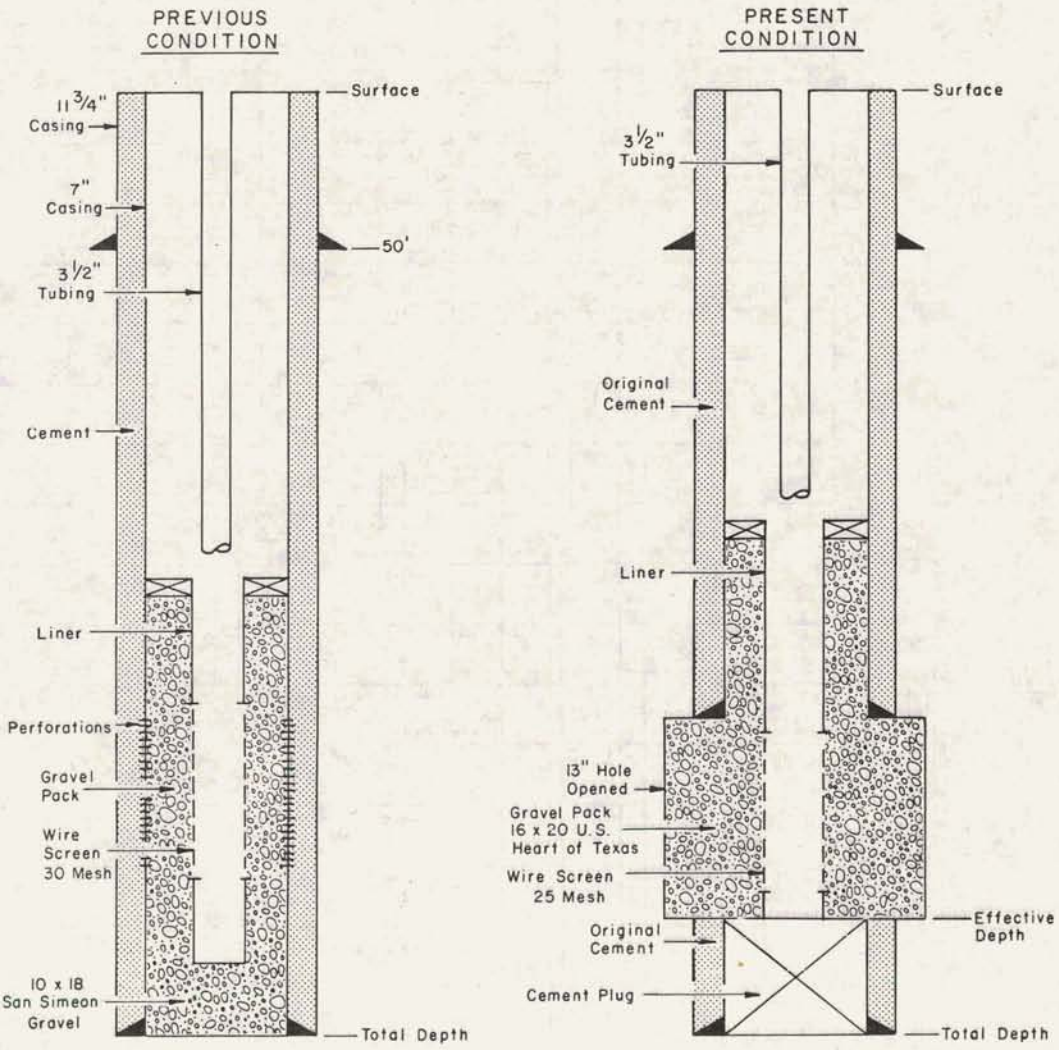


Figure 5

DISPLACEMENT STEAM INJECTION
WILLIAMS HOLDING STEAM FLOOD DEMONSTRATION PILOT

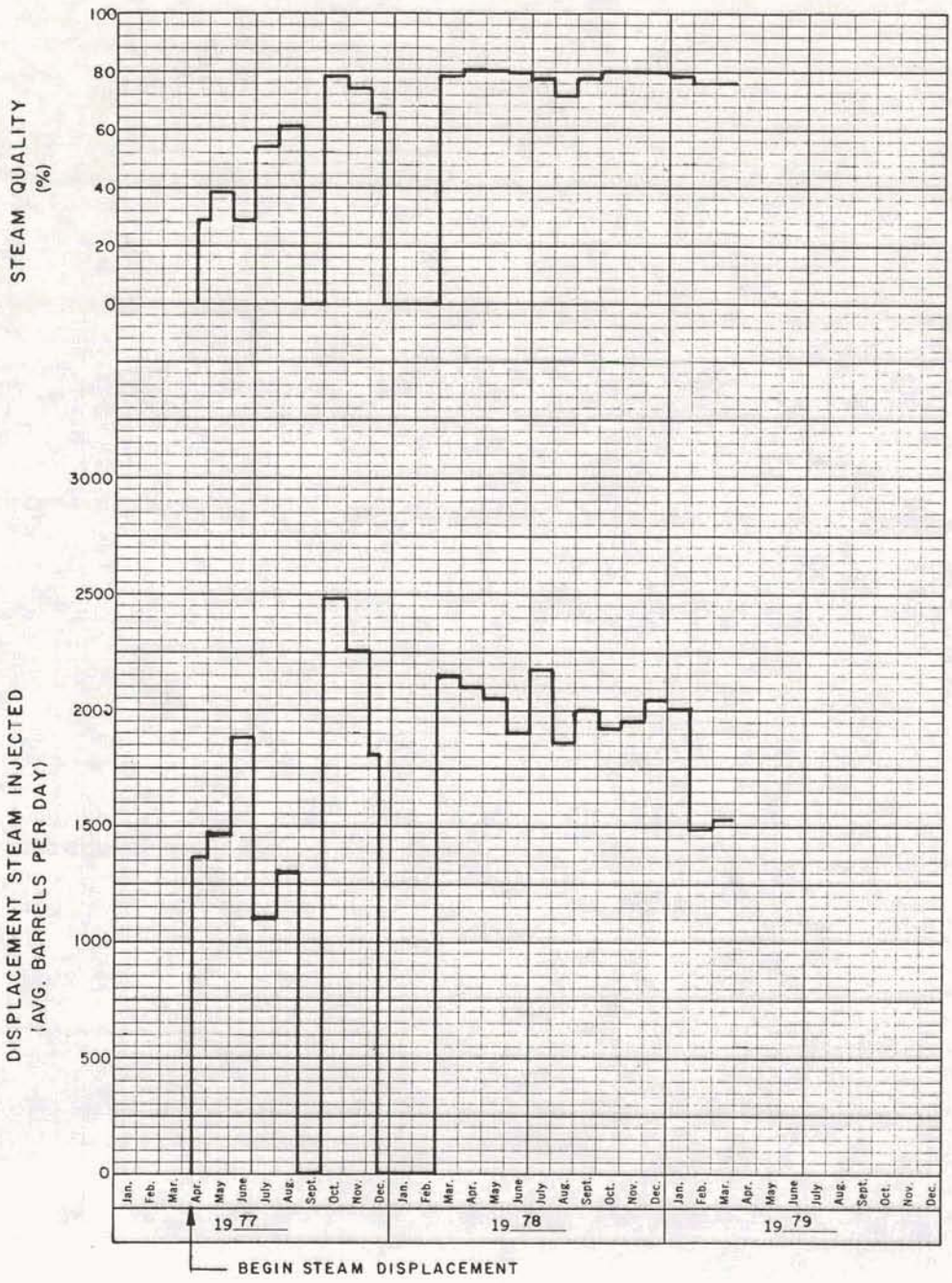


Figure 6

SCHEMATIC OF SULFUR DIOXIDE REMOVAL SYSTEM

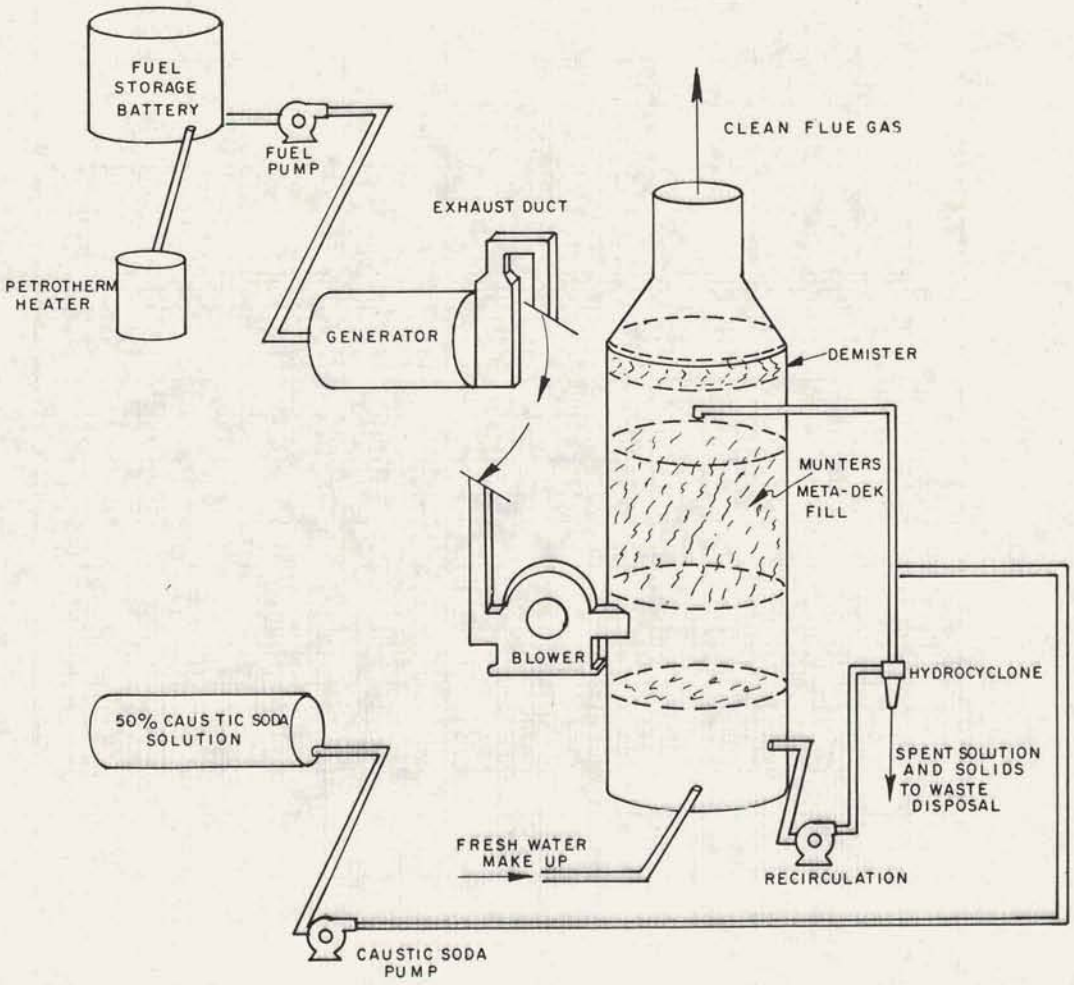


Figure 7

"WILLIAMS HOLDING"

STEAM DISPLACEMENT PILOT PRODUCTION PERFORMANCE

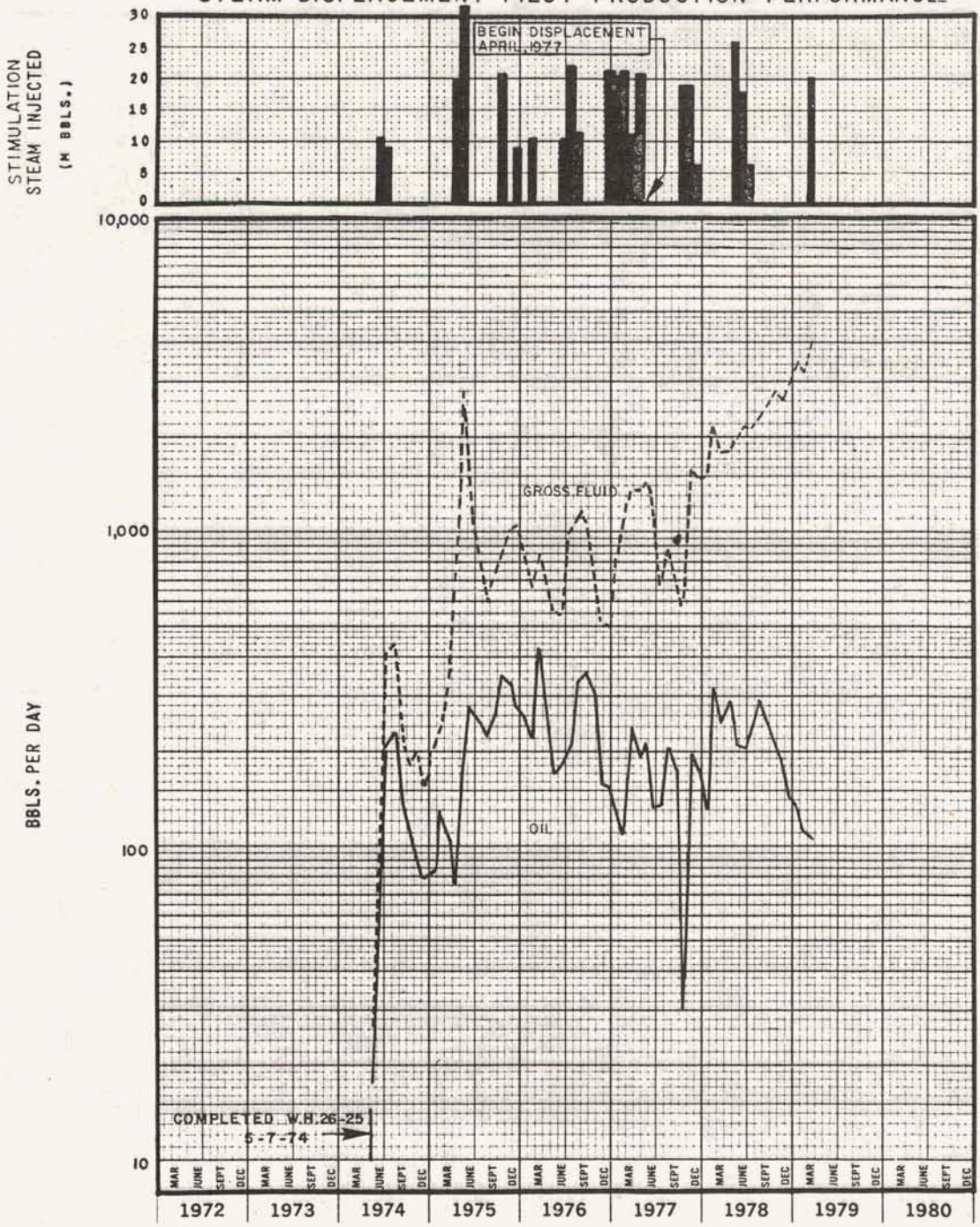


Figure 8

WILLIAMS HOLDING 205-25 PERFORMANCE

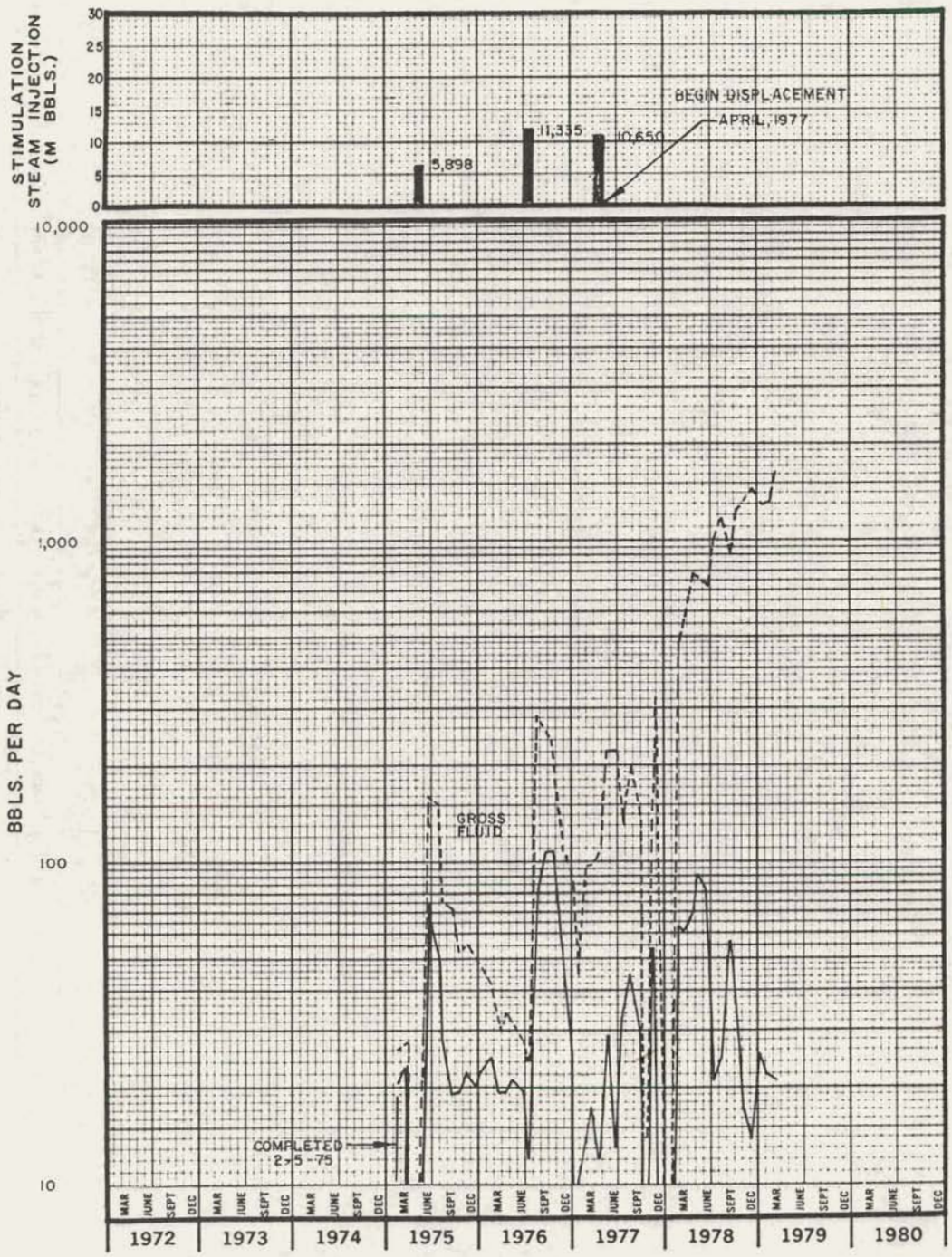
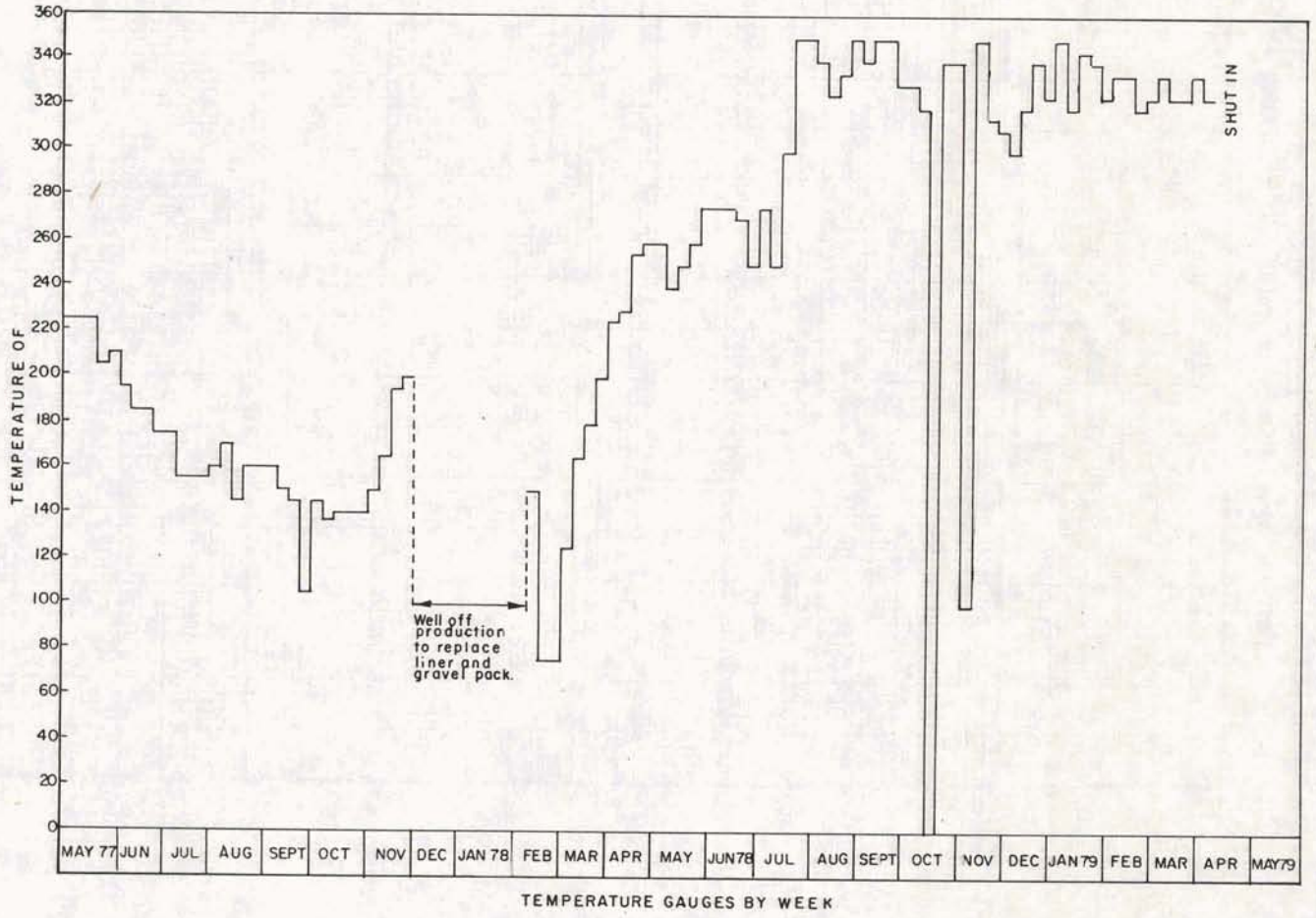


Figure 9

WILLIAMS HOLDING 205-25 FLOWLINE TEMPERATURE GAUGES



THE "200" SAND STEAMFLOOD DEMONSTRATION PROJECT

By

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ABSTRACT

The Demonstration Project was initiated in the "200" Sand Pool to demonstrate the operational, recovery, and economic aspects of steamflooding a typical heavy oil reservoir which had unfavorable response to cyclic stimulation. The test is being conducted in four 2.35 acre inverted seven-spot patterns, which are not fully developed with producers. Within the four patterns are two interior producers that will be key wells for determining production response for expanding the project.

Continuous steam injection was initiated in October, 1975, and the first significant production rate increase for the project attributed to steam drive occurred in November, 1977. Most of the response is coming from the two enclosed producers. Performance evaluation is under way to decide the merits of expanding the project to fourteen inverted seven-spot patterns.

INTRODUCTION

The project is testing an enhanced steamflood technique in the Midway-Sunset Field, Kern County, California (Figure 1). Generally, steamflooding on Santa Fe Energy Company (SFE) properties has been conducted in reservoirs which have responded favorably to cyclic steam stimulation in order to accelerate cyclic production and to increase ultimate recovery. This pool, designated the "200" Sand, made no primary production and responded poorly to cyclic steam stimulation. With the cyclic method, estimated ultimate recovery was virtually zero percent because of its ineffectiveness and unfavorable economics.

Prepared for the Department of Energy, under Contract No. EY-76-C-03-1277.
(Formerly Contract No. E(04-3) - 1277)

Pilots utilizing continuous steam have been monitored and evaluated in other parts of the field. Based on its predicted and actual performance in other heavy oil reservoirs, steamflooding is considered the most promising thermal recovery technique for this property. However, the high capital and operating costs of steamflooding made a pilot desirable to evaluate the process in this pool. Therefore, this project was initiated to demonstrate the operational, recovery, and economic aspects of steamflooding a typical heavy oil reservoir which had unfavorable response to cyclic steam stimulation.

Figure 2 shows the four - 2.35 acre inverted seven-spot drive patterns, which are not fully developed with producers. The project area consists of ten producers (exclude two stepout producers), four injectors, and two observation wells. Within the four patterns are two interior producers that will be key wells for determining production response for expanding the project.

RESERVOIR AND GEOLOGICAL DATA

The reservoir is located in Section 17, T32E, R23E, Midway-Sunset Field, Kern County, California. The Spellacy formation, designated the "200" Sand of Upper Miocene Age, contains approximately 50 million barrels of oil-in-place. The crude oil is very viscous with ambient viscosities in the range of 6500 centipoise. Relatively no gas is produced in conjunction with the crude.

The reservoir pressure in the "200" pool is very low, in the range of 20-60 psi. This kind of pressure does not provide sufficient energy for a producing mechanism. Most of the project area is located on top of an anticlinal structure where dips range from 5 to 15 degrees. With the shallow dips, gravity drainage does nor provide an effective mechanism to obtain economical production rates and effectively deplete the reservoir. Herein lies the necessity of steamflooding, to not only reduce the oil viscosity, but also increase the displacement process, so the crude can flow to the wellbore.

Based on sidewall cores, the relatively flat and moderately sorted reservoir is unconsolidated with sand, silt, and conglomerates. The sand is fine to medium grained, with scattered coarse to very coarse grains and pebbles; at some locations they are interbedded with well-cemented sandstones. They are brown and dark brown sandstone with lamallae of brown and grey silty sandstone, interbedded with silt and clay, which is contorted and powdered. Usually the sands are clean and extremely friable with the grains being held together by the heavy viscous crude.

The structure is an anticline dipping to the northwest (Figure 3), and the sands are truncated by an unconformity that produced the trap. Initial log correlations and geological study had the "200" Sand consisting of four productive sand bodies separated vertically by 5 to 20' thick siltstone intervals. Also, the siltstone barriers were believed to be

laterally continuous in order to prevent vertical fluid flow between sands. However, recently two observation wells were conventionally cored through the entire producing sand and completed in January, 1979. They are located in the only fully developed pattern between Injector 243 and Producers 231 and 254 in order to determine the degree of channeling and sweep efficiency of the pilot. To evaluate advancement of the flood front from the injector, Figure 2 shows observation Well 201 located two-thirds distance from Injector 243 to Producer 254 and observation Well 202 located one-third distance from Injector 243 to Producer 231. This information is valuable in designing injection well completion intervals to improve steamflood response. Although with little desaturation both cores showed steam migrating 35 to 50 feet above the 50' drive interval at lateral distances of 70 and 140 feet from the injection well, even though most of the steam is restricted to the bottom of the 50' zone. This seems to indicate the siltstone barriers separating the sand are competent but have limited lateral extent that does allow vertical transmissibility between zones. The Upper Miocene sands appeared to have been deposited as a series of complex submarine fan channels. Therefore additional detailed log correlations are necessary to make sure the intended zone will be driven. The wells were completed with 2-7/8" O.D. tubing cemented in the hole to observe the depletion growth and define the position of the heat front and steam and hot water zones.

The subject field trial is being conducted in the bottom sand interval, approximately the bottom 50 feet of the reservoir. Santa Fe Energy's experience to date indicated that intervals greater than 50 feet will permit steam overriding in the reservoir which results in poor vertical sweep efficiency. When the bottom interval is depleted, the upper sands will be steamflooded successively from bottom to top if the technique is successful.

The average petrophysical properties for all productive sands are 2,250 millidarcies permeability, 30 percent porosity, and an oil saturation before steamflooding of 59 percent, equivalent to an average oil content of 1,373 barrels per acre foot. Table I has a summary of reservoir data obtained from the pilot wells and surrounding core holes in Section 17, T32S, R23E.

PROJECT PERFORMANCE

Steam Injection

Injection of steam into the four input wells started in October, 1975 (Figure 4). Since startup, 1.67 million barrels of steam have been injected into the four injection wells at an average injection interval temperature and quality of 350° F and 72%, respectively. Steam at the two 20 million BTU/Hr. steam generator outlets are 420° F with 80% quality.

Due to the lag in response time, estimated at 18 to 24 months, increased injection rates the last year have been averaging 450 B/D - well. Also the project is rate sensitive, therefore, the higher the injection rate, the higher the oil production. Sensitivity can be expected in this steam drive area where the reservoir with very little dip does not allow for gravity drainage. With the low gravity oil and flat formation, the burden of displacing the crude oil to the producing wells lies primarily with the injected steam. However, there is an optimum injection rate which results in the highest oil production per dollar invested for steam injection; and seldom do the early requirements for a steamflood operation represent an optimum steam injection rate. Realizing this, the initial objectives were getting the producing formation hot and observing maximum production rate potential then optimizing the injection rate later in the project life.

No limits have been put on how high the injection rates can be. Considerations with respect to fracture gradient are not a problem, the only limitation now and foreseen are the generators' discharge pressures. The reservoir is thick, highly permeable, and unconsolidated, which makes fracture gradient determination virtually impossible. Tests have shown similar sands undergoing a plastic deformation rather than fracturing under high rate injection.

All ten pilot area producers (exclude two stepout producers) have temperature and gross fluid produced response. Five wells have moderate to good steam breakthrough, including the two enclosed producers that will be key wells for determining production response for expanding the pilot. All massive steam breakthrough will be avoided by reducing injection rates and restricting producing wells' drawdown which is discussed in the next topic.

Production

Production from the ten pilot producers (exclude two stepout producers) have averaged 136 B/D oil and 276 B/D water the last year. Several wells were given steam stimulation treatments due to decline in wellbore temperatures. Total pilot area production is shown in Figure 5. With reference to Figures 6 and 7, most of the response has been coming from the two enclosed producers, 254 and 255, and because they are the only producers surrounded by injectors, the two will be key wells for determining expansion.

Two different completions were used in producing wells 254 and 255. Well 254 is a 60 mesh slotted liner set across the entire sand. Peak production was 67 B/D oil in March, 1978 with an average production during the last year of 34 B/D oil and 33 B/D water. Well 255 reached 42 B/D oil in May, 1978. Production in the last year was 13 B/D oil and 39 B/D water. It is a cased-through completion with jet perforations in the bottom pay to confine steam in the drive interval by restricting production only to the steam drive interval. Recent temperature surveys show the steam to be limited in the drive interval. The average oil

response from the different completion methods indicates the slotted liner completion is the best in the steam drive. Two additional producers, 241 and 287, are showing favorable response from the drive (Figures 8 and 9).

One of the major limitations to the effectiveness of steam drive recovery are patterns not fully developed with producers. Fully developed patterns would have improved control of frontal movement and volumetric recovery, but capital availability did not permit additional drilling. As a result of delayed production and temperature response, the project is behind schedule. Observations from operating the pilot indicate that steam channeling from injector to producer is necessary to efficiently produce the highly viscous oil. Therefore the existing high steam injection volume will continue in the future.

Producing wells that have shown excessive steam breakthrough (channeling) have been controlled by restricting the communicating wells' drawdown. Partially shutting in the casing vents creates a back pressure which reduces the rate of frontal advance in the direction of the channel and enhances channeling to other producing wells of the patterns. Thus far, restricting responding wells' drawdown has been more advantageous than steam injection rate reduction, because the average reservoir temperature for the total pilot area is not high enough to allow a BTU input reduction.

TABLE I

SUMMARY OF RESERVOIR DATA

Depth, feet	400-700
Areal extent, acres (est.)	250
Oil gravity, °API	12
Reservoir pressure, psi (est.)	40
Reservoir temperature, °F	90
Average formation dip, degrees	12
Average gross thickness, feet	200
Average net thickness, feet	150
Permeability to air, md	1,050-3,440
Average porosity, percent	30
Average oil saturation, percent	59
Average oil content, bbl/acre-ft.	1,373
Oil viscosity @ 90°F, cp	6,500
Oil viscosity @ 212°F, cp	60

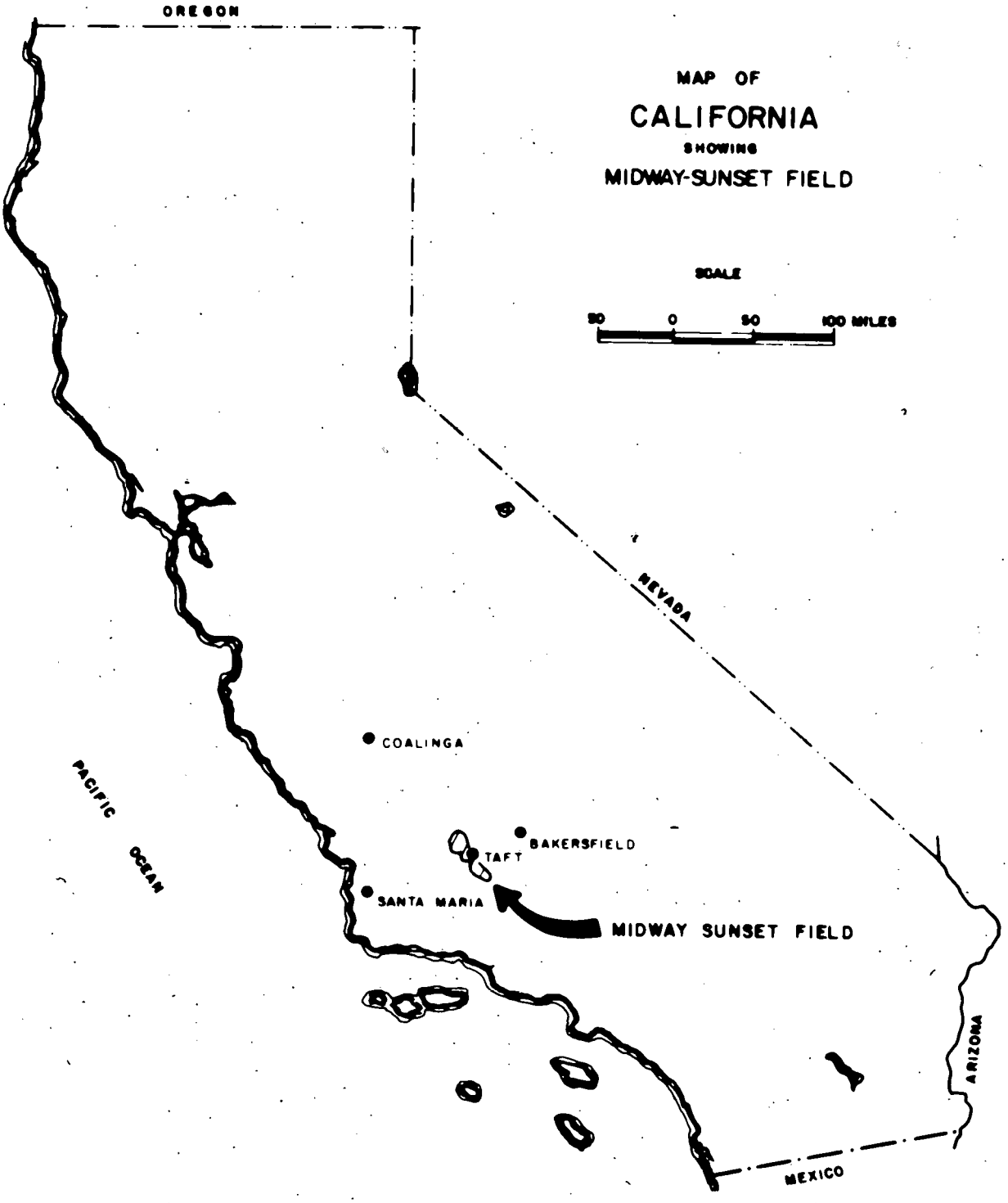
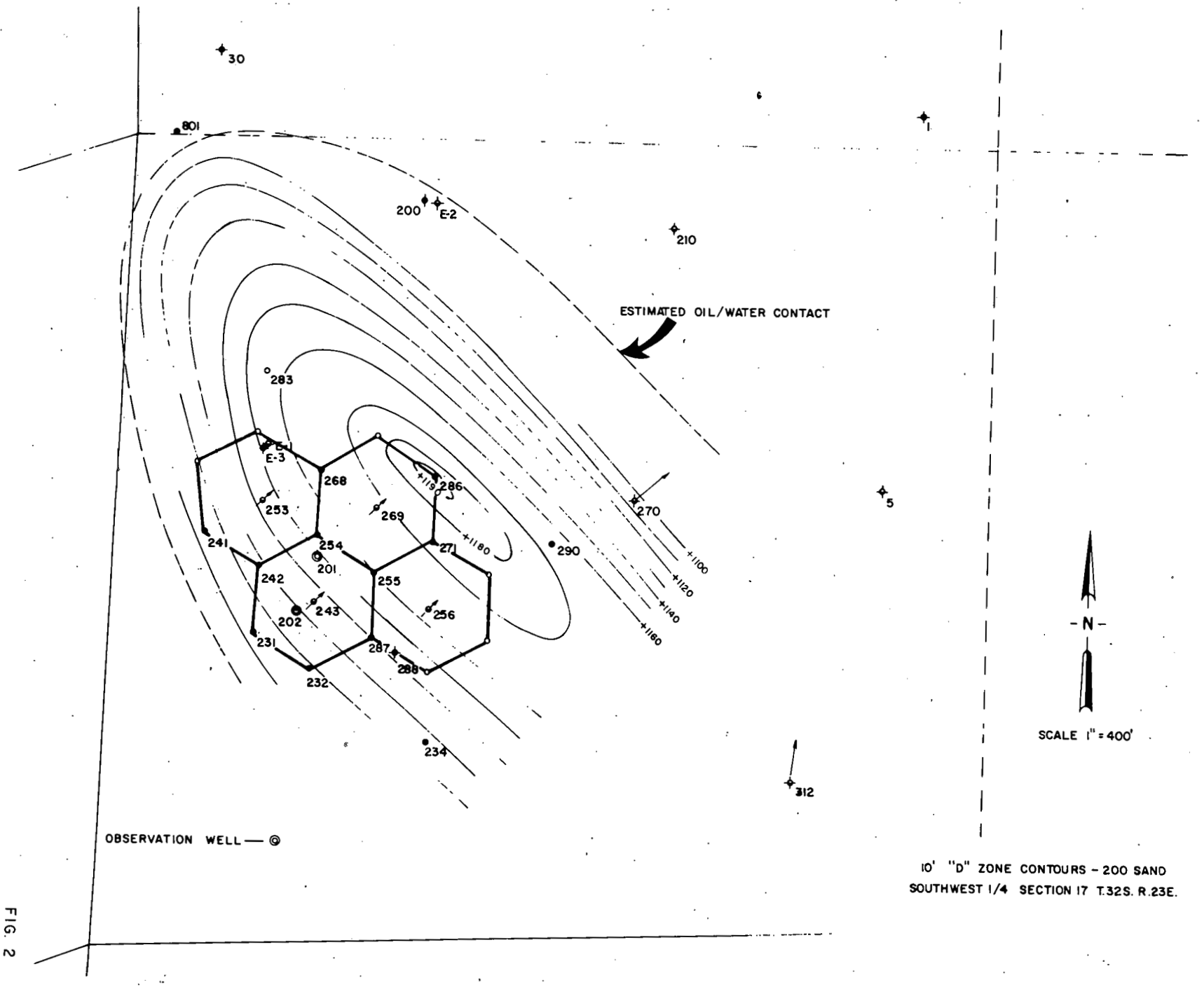

OREGON
MAP OF
CALIFORNIA
SHOWING
MIDWAY-SUNSET FIELD
SCALE
50 0 50 100 MILES
NEVADA
COALINGA
PACIFIC OCEAN
BAKERSFIELD
TAFT
SANTA MARIA
MIDWAY SUNSET FIELD
ARIZONA
MEXICO

FIG. 1



10' "D" ZONE CONTOURS - 200 SAND
SOUTHWEST 1/4 SECTION 17 T.32S. R.23E.

FIG. 2

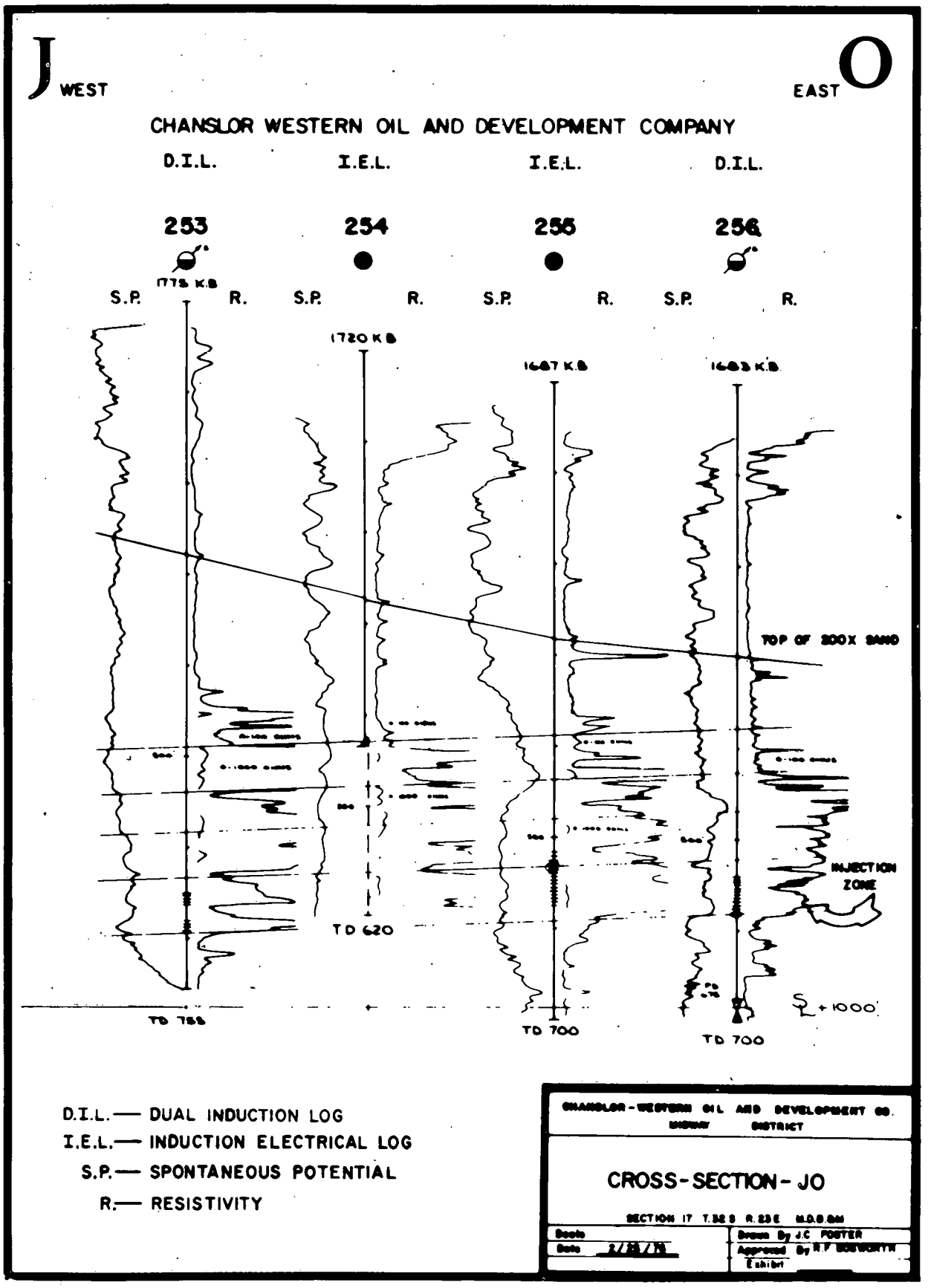

J
WEST
EAST
O
CHANSLOR WESTERN OIL AND DEVELOPMENT COMPANY
D.I.L.
I.E.L.
I.E.L.
D.I.L.
253
254
255
256
1775 K.B
1720 K.B
1687 K.B
1683 K.B
S.P.
R.
S.P.
R.
S.P.
R.
S.P.
R.
TOP OF 200X SAND
INJECTION ZONE
TD 620
TD 768
TD 700
TD 700
+1000'
D.I.L.— DUAL INDUCTION LOG
I.E.L.— INDUCTION ELECTRICAL LOG
S.P.— SPONTANEOUS POTENTIAL
R.— RESISTIVITY
CHANSLOR-WESTERN OIL AND DEVELOPMENT CO.
SIGNAL DISTRICT
CROSS-SECTION-JO
SECTION 17 T.32 S R.23 E M.D.B.&M
Scale
Date 2/28/75
Drawn By J.C. FOSTER
Approved By R.F. BOSWORTH
Exhibit

FIG. 3

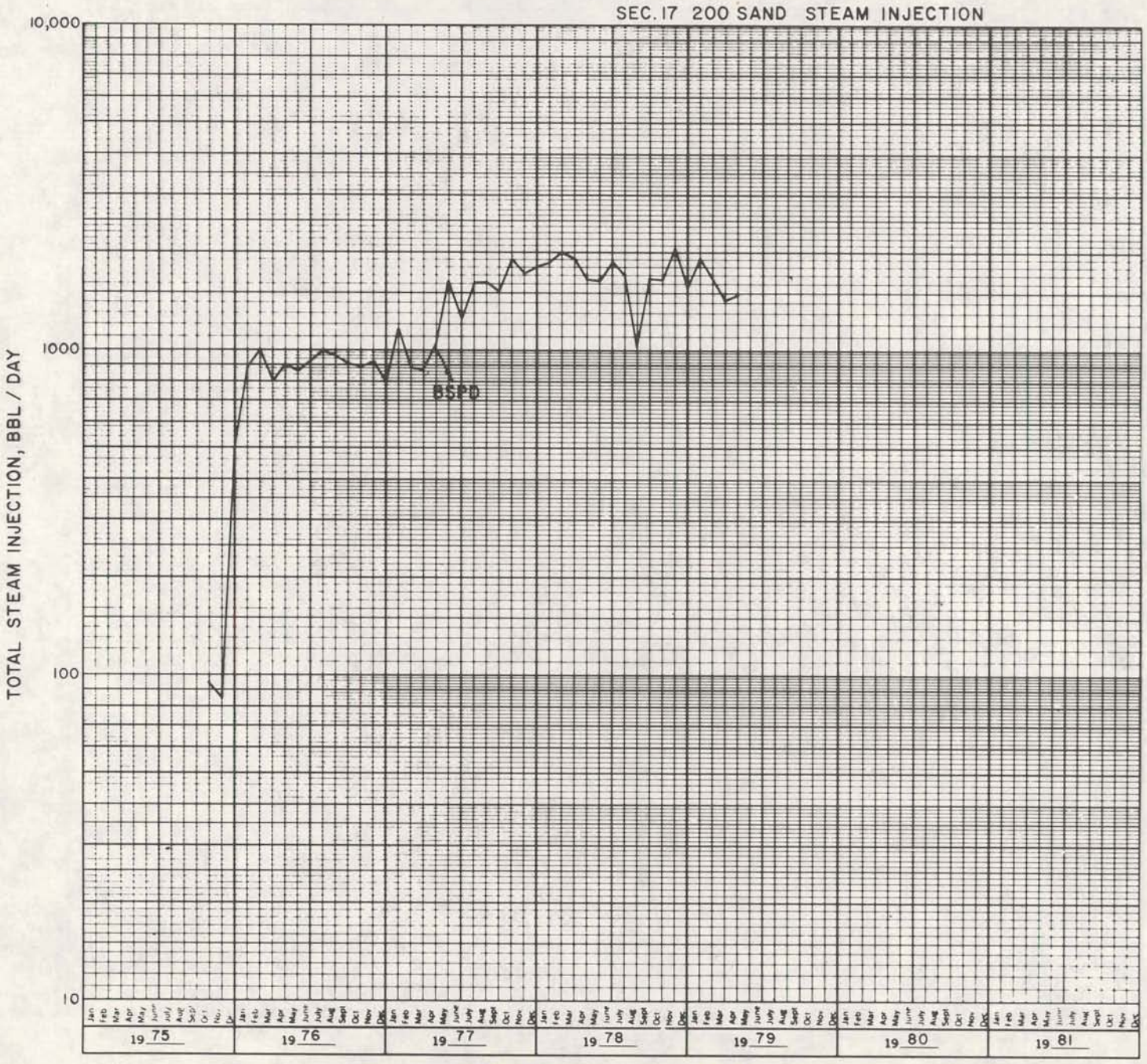

SEC. 17 200 SAND STEAM INJECTION
TOTAL STEAM INJECTION, BBL / DAY
10,000
1000
100
10
BSPD
19 75
19 76
19 77
19 78
19 79
19 80
19 81

FIG. 4

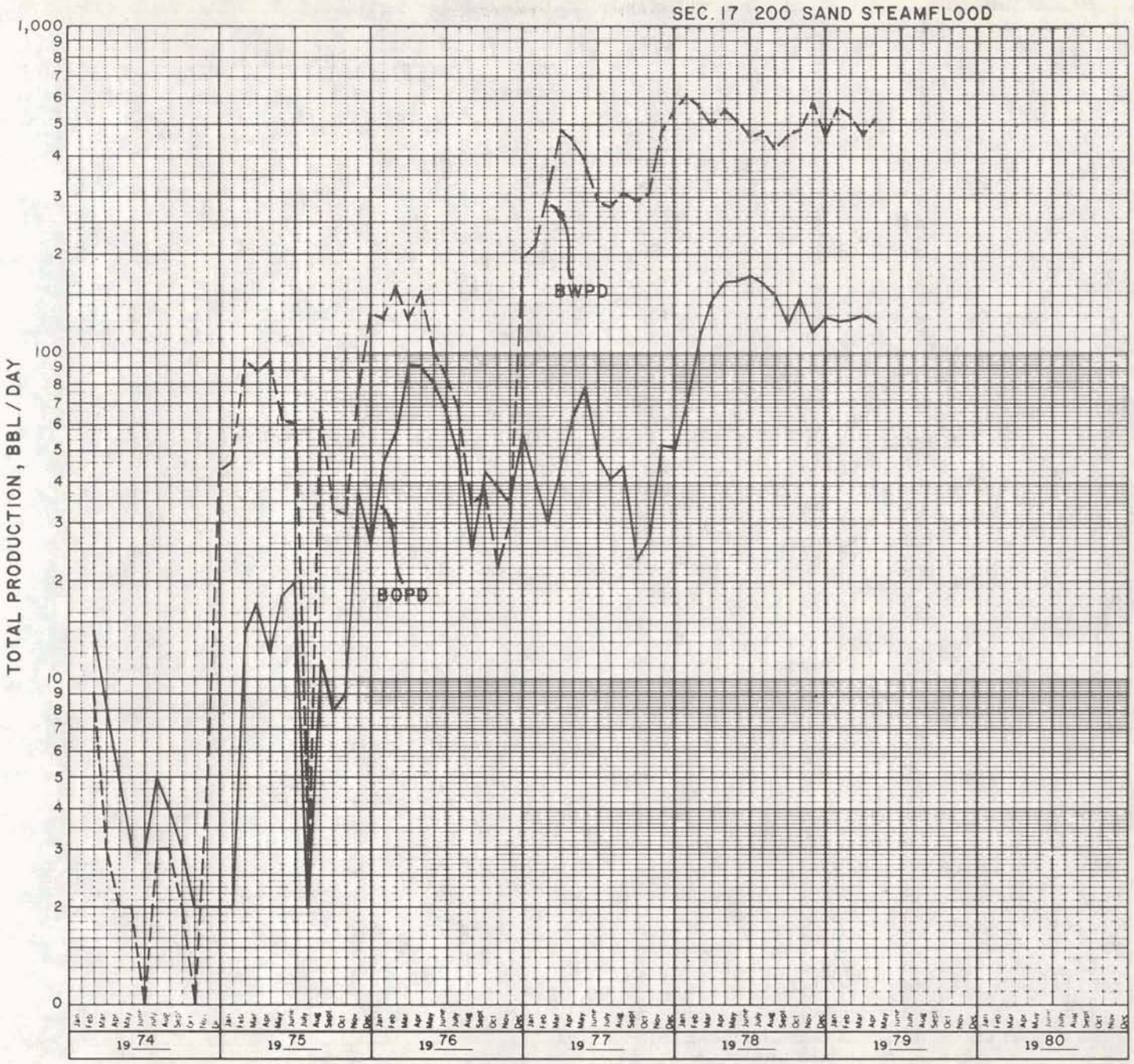

SEC. 17 200 SAND STEAMFLOOD
TOTAL PRODUCTION, BBL / DAY
1,000
100
10
BWPD
BOPD
Jan Feb Mar Apr May June July Aug Sept Oct Nov Dec
1974
1975
1976
1977
1978
1979
1980

FIG. 5

PRODUCER 254 - 17 X

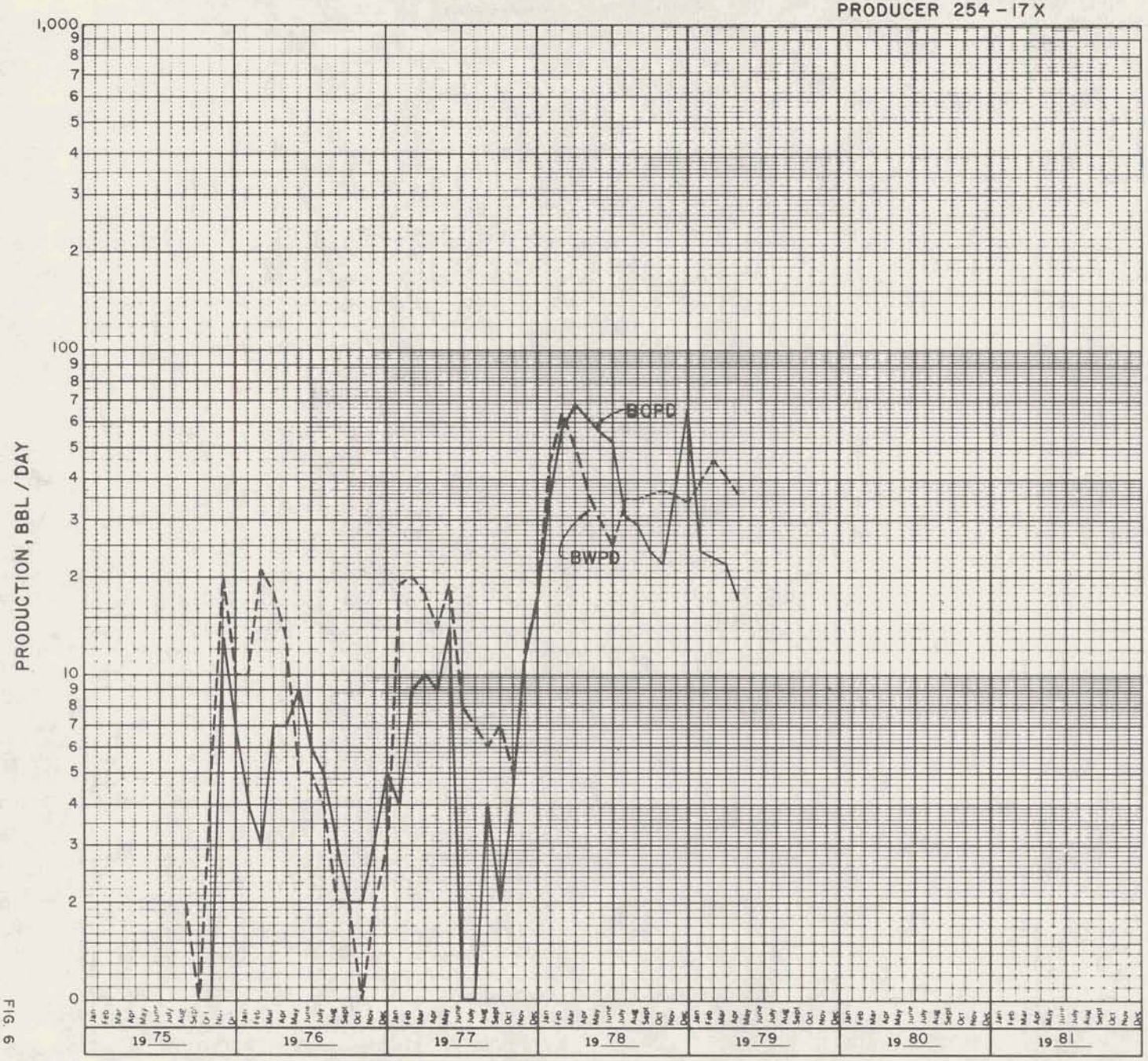


FIG 6

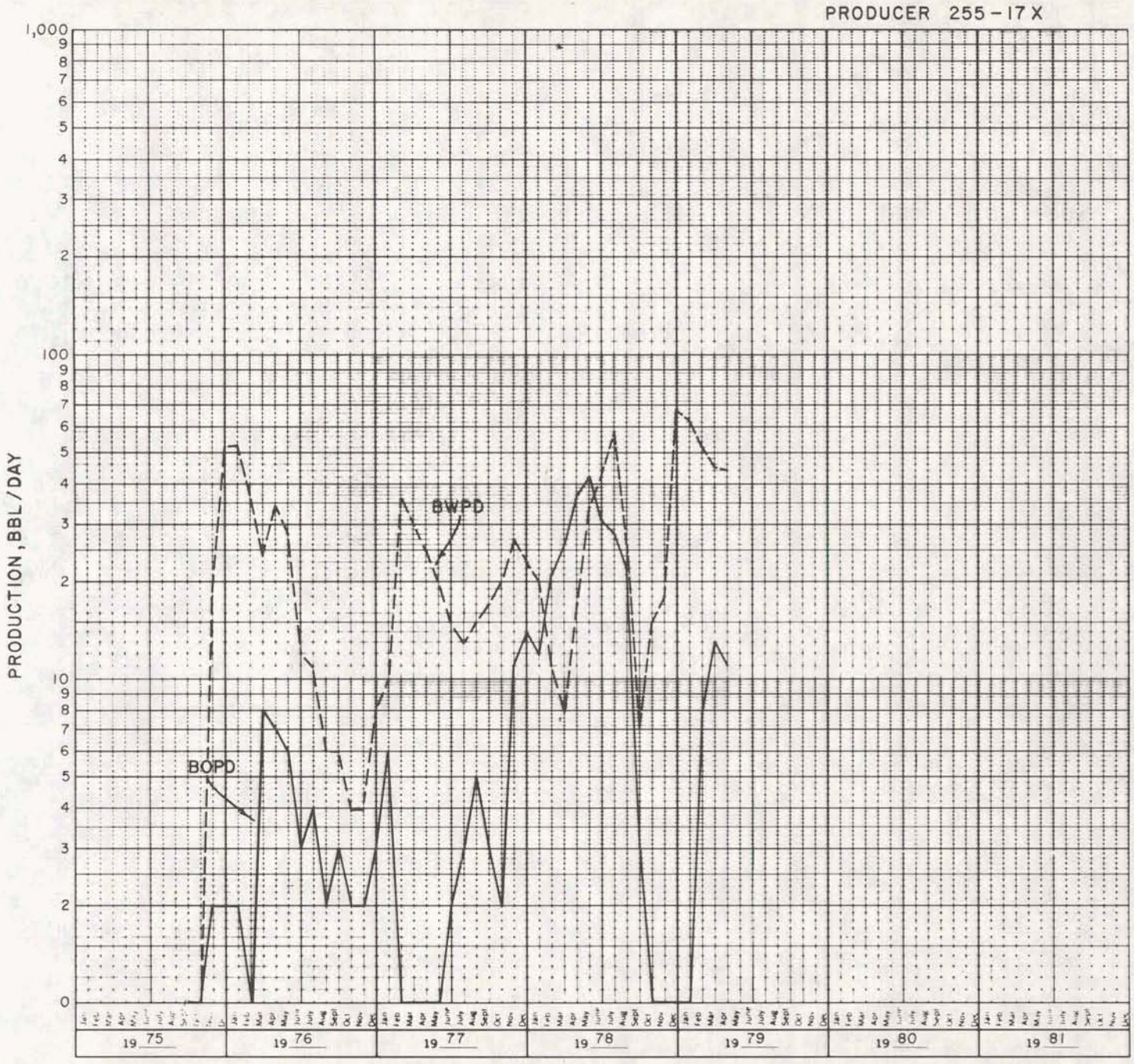

PRODUCER 255 - 17 X
PRODUCTION, BBL/DAY
1,000
100
10
BWPD
BOPD
19 75
19 76
19 77
19 78
19 79
19 80
19 81

FIG. 7

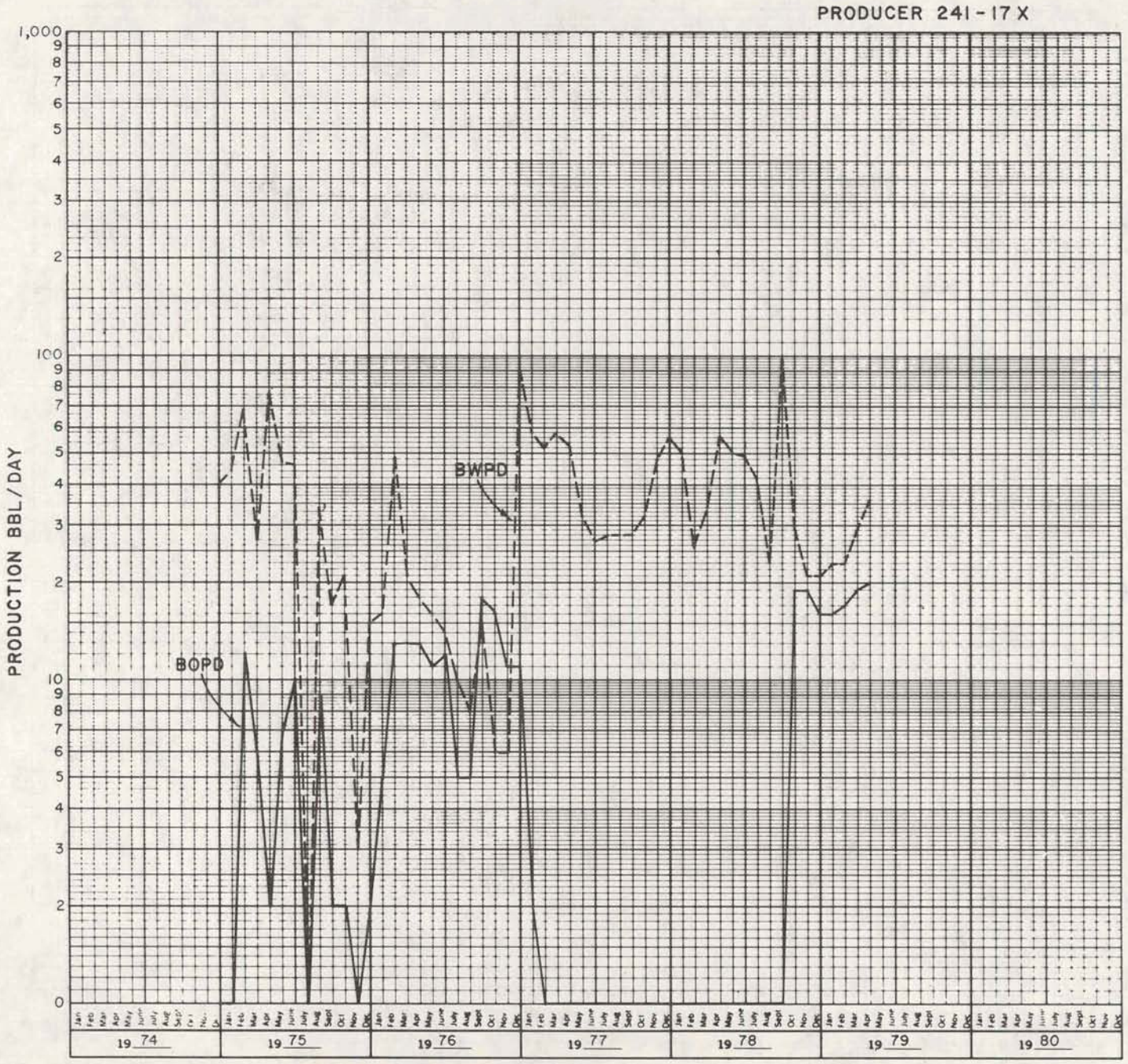

PRODUCER 241-17X
PRODUCTION BBL/DAY
1,000
100
10
BWPD
BOPD
19 74
19 75
19 76
19 77
19 78
19 79
19 80

FIG 8

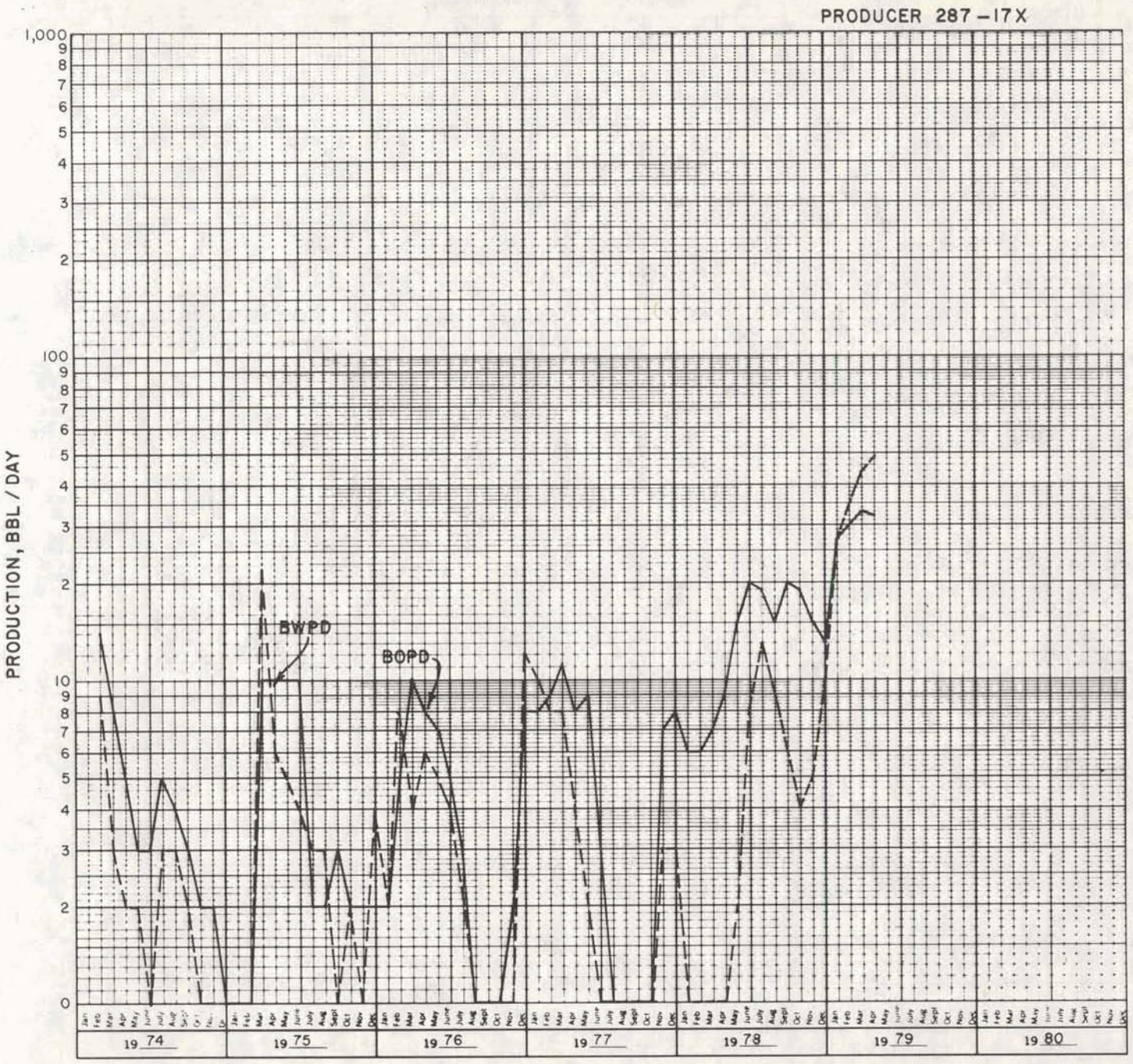

PRODUCER 287 – 17X
PRODUCTION, BBL / DAY
1,000
100
10
0
BWPD
BOPD
19 74
19 75
19 76
19 77
19 78
19 79
19 80

FIG. 9

POTENTIAL USE OF PETROLEUM COKE AND CALIFORNIA LIGNITE AS FUELS FOR ENHANCED OIL RECOVERY

BY

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ABSTRACT

This paper summarizes a recent Acurex program sponsored by the Department of Energy and evaluates the potential for using petroleum coke and lignite as fuels for thermal Enhanced Oil Recovery (EOR) in California.

Petroleum coke is attractive because of the relative proximity of coke-producing refineries to all of the California oil producing fields. California lignite, a small, surface reserve located in central California is relatively close to south-central California oil fields. In the past neither of these resources has been used as fuels for E.O.R.

This paper summarizes the two phases of the program. The first phase is an economic analysis which considers each of the cost elements involved with large scale use of these fuels and finally compares the resulting economics with those associated with the use of Western Coal. The economic analysis includes fuels characterizations (qualitative, quanitative and logistic), a survey of applicable combustion systems, process designs for the candidate systems, and all evaluation of the related technical and economic uncertainties.

The second phase yielded data from an actual combustion test of petroleum coke in a fluidized bed combustor. The test data are used to address the uncertainties of the earlier analyses and to evaluate the oil patch operation of a thermal EOR steam generator.

INTRODUCTION

The project described herein evaluates the fuel potentials of petroleum coke and lignite available in California where the vast majority of thermal EOR takes place. Petroleum coke has been considered because of the relative proximity of coke-producing refineries to the producing oil fields. California lignite, a small, surface reserve located in central California has been considered since it offered a source of solid fuel relatively close to south-central California oil fields.

This program has two phases. The first phase, entitled Economic Analysis, considers each of the cost elements involved with large scale

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Prepared for DOE under Contract No. ET-78-C-03-2157

use of these fuels and finally compares the resulting economics with those associated with the use of Western coal. Phase II includes actual combustion testing of petroleum coke fuel.

The economic analysis of California lignite indicated that its delivered cost to many EOR sites was higher than that of petroleum coke or western coal. Because of this, it was not recommended for further evaluation. In addition, lignite will not be discussed in this report so that petroleum coke can be dealt with in more depth.

PETROLUEM COKE CHARACTERIZATION AND COST ANALYSIS

Petroleum coke is a product of crude oil refining. The amount of coke produced from a barrel of crude oil depends on composition of the crude oil and demand for the coking products. Petroleum coking involves the pyrolytic polymerization and thermal decomposition of high molecular weight hydrocarbons. These hydrocarbons are contained in the distillate residual (bottoms) from the crude oil distillation process. Distillate liquids and gases are the preferential products of coking, while petroleum coke is a by-product. Coking is performed because the yields of distillates having a high market value are increased by coking of the petroleum residual.

Coking economics are essentially governed by petroleum distillate product economics. The need for petroleum distillates has led to development of several commercial petroleum coking processes. Among them, the delayed coking and fluid coking process have the most widespread continual application. Table 1 shows the process characteristics of various commercial coking process.

Chemical composition of petroleum coke is highly variable. Table 2 shows the range of properties for both fluid and delayed coke. Since petroleum coke is a "bottom-of-the barrel" by-product, its composition is highly dependent on the nonvolatile fraction of the crude feedstock. It is this nonvolatile fraction composed primarily of sulfur and ash that determines the value of the coke as an industrial product.

Three interrelated factors affect the final quality of petroleum coke. They are the feedstock characteristics, coke processing characteristics, and engineering variables associated with solids handling and operating characteristics. These three factors are shown in Figure 1.

For the following sections, it is necessary to base all cost estimates and determinations on a baseline petroleum coke. For the cost analysis discussión that follows, the baseline petroleum coke shown in Table 3 will be used.

Petroleum coke is produced in 11 refineries in California, as indicated in Table 4: three in the San Francisco bay area and the rest in the Santa Barbara-Los Angeles-Kern County triangle.

Taking the baseline petroleum coke previsouly defined and combining raw material costs and transportation costs, Figure 2 shows the costs of

delivered petroleum coke to most locations in California. Transportation costs for petroleum coke were based on existing rail transport costs for shipments varying from 50 to 500 tons, corresponding to one to ten typical railroad hopper cars.

This map shows that nearly all locations in California can be served by petroleum coke at a lower cost per million Btu than delivered western coal. This assumes that solids handling equipment is available at both ends of the transport -- the refinery and the destination. All major thermal EOR regions are included in this region.

The western coal used for comparison in this study is a 11,510 Btu per pound Utah coal, with 8.5 percent moisture, 8.5 percent ash and a sulfur content of 0.5 percent. The rail delivered cost of this coal is $42 per ton at $1.83 per million Btu.

Although present petroleum coke production and costs are relatively easy to assess, the trends in production capacity are governed by several factors which are difficult to quantify exactly. These are:

- Feedstock trends -- California refineries continue to increase their use of Alaskan north slope crudes. Use of these high sulfur, asphaltic crudes quickly results in increased high sulfur petroleum coke production.

- Distillate product demand -- The market for distillate products, especially gasoline blending components, is increasing yearly. This demand is being met in part by increased coking of residual stocks which results in larger quantities of petroleum coke.

- Desulfurization of residual -- The need for low sulfur fuel oils in California has led to the use of desulfurization processes in several refineries. Increased desulfurization of distillate products will result in increased sulfur content in the coke.

- International trends -- There continues to be increasing pressure on us from foreign oil suppliers having both light and heavy crude reserves to take greater quantities of the heavy, lower quality crudes. If this trend continues an increase in coke production will follow accordingly.

In general, petroleum coke production levels should increase in the years ahead. However, a firm market projection is not possible without much more detailed information from individual refiners.

COMBUSTION SYSTEM SURVEY

There are a large number of combustion technologies capable of using petroleum coke as a fuel for EOR applications. Three candidate combustion systems were chosen for this study. The coke combustion technologies were:

- Stoker-grate
- Fluidized bed
- Gasification

One of the major points to arise from the choice of the candidate combustors is that the physical-chemical composition of petroleum coke, particularly delayed coke, is analagous to coal and these three combustion technologies are all viable with coke as fuel. In addition, these technologies are generally economically competitive at the present scale of EOR combustion systems.

To develop accurate economic cost projections, a conceptual design was developed for each of the candidate combustor systems. The designs are all based on a typical EOR steam generation system and include the following subsystems:

- Solids storage and handling
- Fuel combustion
- Steam generation
- Air pollution control
- Solid waste handling
- Instruments and controls

The design basis for the combustion systems is given in Table 5.

Stoker Combustion System

The stoker combustor is one of the most widely utilized direct combustion techniques in the process industries. The stoker-fired system is a straightforward combustor for solid fuels. The solids are dispersed into the combustion zone where they form a bed on top of the stoker grates. The grates support the bed of coke and ash and permit the introduction of combustion air from underneath the fuel bed. The "underfire" air rises through the burning fuel bed and provides combustion air to each fuel particle. Combustion air is also introduced at the top of the bed in order to provide complete combustion of the solids and the volatilized components.

The combustion characteristics of the stoker-fired combustor require individual control for particulate matter, nitrogen oxides, and sulfur oxides. Nitrogen oxide formation can be controlled to some extent by combustion modifications, such as reducing the oxygen availability or the flame temperature. It is estimated that combustion modifications alone could not reduce the NO_x emissions to the design level of 225 ppm. In order to reduce NO_x emissions to 225 ppm or lower, it would be necessary to inject the flue gases with ammonia. Ammonia injection has

been demonstrated on a 50 million Btu per hour steam generator and NO_x emissions were reduced by as much as 70 percent. The use of combustion modifications and ammonia injection offers the potential for NO_x emission reductions of up to 75 percent.

Sulfur oxides generated in the combustor must also be controlled. The required emission reduction can be achieved with the use of a flue gas scrubber, such as a single alkali scrubber. These types of scrubbers are presently being tested on oil-fired steam generators in California. Therefore, the single alkali scrubber system was utilized in the conceptual design of the stoker combustion system.

Particulate control would also be required in order to meet the design criteria. For the purpose of this design, a mechanical cyclone and a baghouse filter are utilized. The removal efficiency of this system is estimated to reduce the particulate loading to nearly 0.1 grams/SDCF.

Fluidized Bed Combustion

Fluidized bed combustion (FBC) technology is another type of direct combustion technology. This direct-fired combustion system produces several operational advantages over the stoker combustion technique. The primary advantage is the capability to control the formation of sulfur and nitrogen pollutants in the combustion bed rather than removing the pollutants from the voluminous flue gases. This control capability not only reduces the complexity of the overall combustion system, but also eliminates the inherently expensive downstream removal technologies.

Combustion in the FBC occurs in a turbulent, well mixed bed of granular, noncombustible solids. The bed is comprised of limestone solids and the fuel coke. This bed can be "fluidized" into a turbulent mixture of solids and air by evently distributing air through it at velocities of 4 to 12 feet per second. The turbulent, well mixed characteristics of the solids and gases in the bed promotes efficient combustion of the fuel. Bed turbulence also promotes high heat transfer rates through steam generation tubes which are spaced throughout the bed.

In coke combustion, the sulfur in the coke is oxidized to gaseous sulfur dioxide. With the FBC, the sulfur dioxide reacts with the limestone sorbent which is added to the combustion bed and the sulfur constituents are retained by the limestone. This control method alone is sufficient to meet the design basis. Therefore, downstream flue gas scrubbing is not required.

The bed temperature of this combustor is approximately 1500-1600^{o}F during normal operation. This temperature is very uniform throughout the bed and can be closely controlled by adjusting the heat removal rates in the bed tubes and the amount of fluidized air used. This results in optimization of combustion efficiency as well as the control of nitrogen dioxide formation to below the regulated level.

The effluent gas from the combustor has a high particle loading due to entrainment of some of the ash and limestone. Eighty-five to 90

percent of the particulates can be removed by a mechanical cyclone collector; however, it does not remove enough of the small particulates (<5) to meet the design basis. These small particulates must be removed from the gas downstream in a baghouse filter before venting the flue gas. The solids removed from the cyclone are usually returned to the bed, while those collected in the baghouse are disposed of.

Gasification-Combustion

Petroleum coke can also be utilized in EOR steam generation via gasification. Gasification of petroleum coke produces a combustible gas which can then be combusted in a boiler to produce steam. The gasification process generates the combustible gas by combusting the coke with a substoichiometric amount of oxygen. The combustion which occurs results in the partial combustion of some of the coke and the devolatization and thermal decomposition of the remainder. The gasification technology chosen for assessment and costing purposes of this study was an atmospheric, air-fed system (such as the Wellman-Galusha gasifier).

This two-staged gasification/combustion process offers advantages in the area of sulfur emissions control. The reaction environment of the gasifier is reductive, and sulfur in the fuel is generally produced as hydrogen sulfide. Control of hydrogen sulfide is generally more efficacious than sulfur dioxide for two reasons. First, hydrogen sulfide reacts easily with various sorbents which can be regenerated and continuously used. This process can also result in the production of elemental sulfur. Second, the volume of gas from the gasifier is significantly less than the flue gas volume from combustion. Therefore, a smaller gas contactor can be utilized.

The gases from the gasifier combust in the boiler at approximately 3000°F. At this combustion temperature, estimates of NO_x emissions show a NO_x emission concentration of under 100 ppm. This eliminates the need for any NO_x emission control technology.

A final gas clean up is performed in a baghouse filter downstream of the combustor.

ECONOMIC ANALYSIS

The costs of the three candidate combustion systems were developed utilizing:

- Location
- Design basis
- Thermal EOR process characteristics
- Economic analysis criteria

The location chosen for the evaluation was the Cat Canyon, California lease site. The Cat Canyon site is a well established, operational California thermal EOR site.

The EOR operations at Cat Canyon reflect two major features:

1. The production well sites are relatively dispersed throughout the lease. A steam generator may service several wells, but it is cost-effective to have the steam generators spread throughout the lease.

2. The steam producers are generally skid mounted. Production practices sometimes require several relocations of a steam generator throughout its system life.

For this project, the candidate processes were compared on a dispersed 50,000 pound/hour system basis. Due to the need to relocate the steam generation system periodically, the candidate combustor economics were developed with little site preparation costs. This reflects the incorporation of a skid-mounted, transportable system, equivalent to the existing technologies.

The evaluation of the three candidate combustion systems are based on certain common economic criteria. They are:

- The major equipment items are depreciated via straight line depreciation for a 15-year period, with 10 percent interest rate
- All costs are constant 1978 dollars.
- Labor was assessed at $10 per hour.
- Energy costs were calculated at a rate of $0.04 per kWh.
- Annual maintenance costs were assessed at the following rates:

	% of Capital
Solid	20
All other equipment	7

- Disposal costs for the various waste streams were based on the following criteria:

	$ per Ton
Solid	7.00
Slurry	8.50

- Insurance changes are assessed at the rate of 2.5 percent of capital per year.

- Yearly operation is 7446 hours (85 percent on stream).
- Pipeline distribution costs for produced steam are not included.
- No credit was taken for the potentially marketable solids generated by the systems (i.e., spent sorbent and elemental sulfur or sludge).
- The coke consumption rate was 19,000 ton per year.
- Limestone costs are:

$13.00/ton	raw material
17.76/ton	transportation
$30.76	total

The estimated capital costs of each of the EOR steam generation processes is shown in Table 6. Capital costs of the three combustion systems were based on telephone surveys of several representative manufactures.

The direct combustion processes, FBC and stoker, have the lowest capital costs, followed by the gasifier. These costs generally reflect the degree of complexity of each of the steam generation processers. The FBC accomplishes SO_x control, fuel combustion and steam generation inside the combustion reactor. The stoker has to rely totally on downstream fuel gas cleanup for emission control even though its fuel combustor and boiler are housed together. The gasifier, on the other hand, has separate gasifier and steam generation sections and an external sulfur control process.

Based on the costing criteria, the annual operating and maintenance (O&M) costs for the three EOR steam generation processes were calculated. Table 7 includes a cost breakdown and comparison of the individual cost items as well as the total O&M costs.

The gasifier has the lowest O&M costs. In general, this reflects the lower costs associated with the emission control technologies utilized with gasification and the nearly negligible solid waste disposal costs. However, the gasification process has the highest maintenance costs. The high maintenance charges reflect the labor required to maintain the more costly gasification process equipment.

The FBC has the second lowest total O&M costs. The largest nonfuel cost component is the sorbent cost which is coupled with a relatively high waste disposal cost. These costs are generally offset though by the low maintenance costs fo the system. This reflects the relatively simple sulfur dioxide emissions removal ability of the FBC sorbent combustion bed.

The stoker has the highest O&M costs. Sorbent and waste disposal costs, are high as well as maintenance costs are high. These cost components reflect the overall costs of downstream flue gas cleanup technologies.

The total annualized costs of each of the EOR steam generating systems is compared in Table 8. The FBC process has the lowest total cost, equivalent to $3.75 per 1000 pounds of generated steam. The gasification and stoker technologies have steam generation costs of $3.83 and $4.13 per 1000 pounds of steam respectively.

Cost Sensitivities

The FBC operating and maintenance cost breakdwon shows that limestone sorbent is the largest single nonfuel expense. This cost component is subject to wide fluctuations based on variations of two factors. These are:

- The amount of limestone required for adequate sulfur absorption rates
- The transportation costs

The first factor is very significant. A sulfur reduction of approximately 90 percent is required to meet the emission rate established in the design basis. Tests with limestone sulfur absorption ratios show that this level of sulfur reduction is quite possible but the amount of limestone required is an extremely strong function of its composition. For a 90 percent sulfur retention by the limestone, the lime/coke weight ratio can vary from approximately 0.3 to 1.1. The reasons for this variation is not known, but appears to be related to the surface area of the limestone rather than chemical composition. This is a very large potential fluctuation and would influence the sorbent costs in particular and the FBC costs in general. (A median weight ratio of 0.7 was used in the design.)

In addition to the sorbent cost being affected by the uncertainty of the required amounts, the total cost is also strongly affected by the transportation costs associated with the location of the EOR lease site. Some EOR sites are close enough to limestone sources that the transportation cost of $17.76 per ton could be reduced by a factor of three or more. Although the base price of the limestone can vary, estimates indicate that only $\pm$ 20 percent variation can be expected in most regions. Although this is important, it is not nearly as significant as the potential 300 percent variation in transportation costs.

Another factor which is very important to the cost comparision is the use of a dispersed well scenario. In this study, single 50,000 pound per hour steam production systems were compared to each other. The gasification technology has the potential though to serve many 50,000 pound per hour boilers with one central gasifier. This process layout is possible if the wells are concentrated in one area. This will allow the cost effective pipeline transport of the combustible gas from a central gasifier to many individual steam boiler systems.

FBC COMBUSTION TESTS

In order to further characterize the characteristics of petroleum coke for thermal EOR applications, combustion tests were completed in a

pilot scale FBC. The FBC system was chosen based on the economic assessment developed in the study which depicted the system as the most cost-effective of the three candidate combustion systems.

Delayed petroleum coke from the Union Oil Refinery at Santa Maria was used in the tests. Limestone from the Pfizer quaries in Lucerne Valley was used as the sorbent. The tests were conducted in a 20-inch internal diameter FBC which was equipped with on-line flue gas analytical instruments. A parametric evaluation of the combustion variables was conducted. The variables included:

- Combustion temperature
- Limestone-to-coke ratio
- Coke feed rate
- Fluidization velocity
- Combustion oxygen
- Overfire air ratio
- Feed point ratio (in-bed: top-of-bed)

These combustion tests have just recently been completed and a full analysis of the data is not available at the writing of this report. However, several preliminary assessments of the results can be made at this time. These are:

- Optimum combustion temperature is 1550°F.
- Steam generation tubes in the combustion bed captured between 40 to 56 percent of the available thermal energy.
- SO_x was effectively controlled at limestone addition rates of 5:1 mole ratio of Ca:S. Lower ratio's could be used with a more active limestone.
- NO_x emissions were controlled to 225 ppm.
- NO_x levels of approximately 100 ppm appear attainable with combinations of:
  - -- Overfiring of excess air
  - -- Split feeding of the coke (in-bed and top-of-bed)

CONCLUSIONS AND RECOMMENDATIONS

Petroleum coke is an important potential fuel for thermal EOR process applications in California. The delivered costs of petroleum coke are lower than costs of Western coal throughout the EOR regions of

California. In addition, there are growing supplies of petroleum coke which could be used for this application.

The increasing quantities of petroleum coke available for thermal EOR use match the growth trends of thermal EOR applications in California since thermal EOR in California has grown steadily since 1968. This trend should continue especially with the wide range of incentives recently offered by the Economic Regulatory Agency of the U.S. Department of Energy. Two advantages of using coke are:

- Oil is not consumed for combustion. This increases the net yield of petroleum production.
- The petroleum companies can supply fuel for thermal EOR generated in their refineries.

Petroleum coke can be utilized as a fuel by several technologies. These technologies include the fluidized bed combustor (FBC), stoker combustor, and gasifier combustion system. These combustion processes are all applicable to thermal EOR production. The costs of each technology are strongly affected by site specific factors of the EOR site such as available supplies and the requisite transportation distances.

The FBC appears to be the most cost effective technology of the three. Preliminary results from combustion tests indicate that efficient and environmentally acceptable use of petroleum coke in a FBC is possible for EOR. Therefore, it is recommended that the development of petroleum coke as a thermal EOR fuel be pursued since the commercialization of this fuel has many advantages and appears technically cost-effective as this time.

TABLE 1. COMPARATIVE DATA ON COMMERCIAL COKING PROCESSES

Method	Type	Coking temperatures	
		Type	Range, °F
Atmospheric still coker	Batch	Low	900-1000
Delayed coker	Semicontinuous	Low	900-935
Broad-oven coker	Batch	High	Greater than 1600
Contact coker	Continuous	Low	900-960
Fluid coker	Continuous	Low	900-950

TABLE 2. CHEMICAL COMPOSITION OF PETROLEUM COKE

Coking Process	Moisture Wt%	Volatile Wt%	Fixed Carbon Wt%	Sulfur Wt%	Ash Wt%	Vanadium Wt%	Nickel Wt%	Iron Wt%	Size (Mesh)	Heating Value Btu/#
Delayed	1-10	5-12	80-89	0.1-5.0	0.1-0.6	0.04-0.29	0.01-0.03	0.01-0.03	VARIES	14000
Fluid	0-20	4-7.5	85-94	1-7.0	0.2-3.0	0.02-0.06	0.01-0.02	0.01-0.05	35	14500

TABLE 3. BASELINE DELAYED PETROLEUM COKE

- $25/ton
- 4 percent sulfur
- 80 percent fixed carbon
- 10 percent volatiles
- 0.4 percent ash
- 3 percent moisture
- 14,000 Btu per pound

TABLE 4. CALIFORNIA PETROLEUM COKE: PRODUCTION AND DISPOSITION

Company	Location City, County[1]	Production[1]	Price[1]	Percent Sulfur	Type[3] Calcined	Delayed	Fluid	Present Disposition[3] Contracted	Available
Shell	Wilmington, Los Angeles	1800 t/d	**	**	**	**	**	All to IMC	
Mobil*	Torrance, Los Angeles	2900 t/d	$35-50/t	3%	X			All to IMC or Great Lakes Carbon	
Mobil	Torrance Los Angeles		$8-15/t	4-6%			X	All to IMC or Great Lakes Carbon	
Chevron	El Segundo Los Angeles	2200 t/d	$10-23/t	1.9-5%		X		All to IMC	
Exxon	Benecia Solano	1000 t/d	$.85-1.00/ Btu				X	All contracted	
Tosco	Avon Contra Costa	1200 t/d	$1.50/Btu	2.21			X		Must take all daily
Tosco	Bakersfield Kern	250 t/d	**	**	**	**	**	**	**
Union	Rodeo Contra Costa	1850 t/d	**	2%	X			All contracted	
Union[2]	Santa Maria	1055 t/d	$23/t	4%			X		Must take all daily
Champlin	Wilmington Los Angeles	650 t/d	**	2	X			All contracted	
Texaco	Wilmington Los Angeles	1650 t/d	$11-35/t	2		X		All contracted	
Atlantic-Richfield	Carson Los Angeles	1800 t/d		2	X			All contracted	

*The type of coke produced, its price and sulfur content depends on the crude oil used.
**Information not available.

[1]The Oil and Gas Journal, March 20, 1978, pp. 116-117.
[2]Personal communication, D.E. Barth, Union Oil Co., based on his figure of 380,000 tons per year.
[3]Personal communication with representatives of the oil companies.

TABLE 5. DESIGN BASIS FOR EOR STEAM GENERATION SYSTEM

• Steam Production	50,000 pounds per hour 2,500 psig 80 percent quality
• Emissions	
- Particulates	0.2 grains/Standard Dry Cubic Foot
- NO_x	225 ppm
- SO_x	Equivalent to 0.5 wt% sulfur in fuel
• Operating characteristics	High reliability Minimum operator attendance

Table 6. CAPITAL COST COMPARISON OF CANDIDATE COMBUSTOR SYSTEMS

Candidate System	Capital Cost ($1000)
Stoker	2800
FBC	1700
Gasifier	3720

TABLE 7. ANNUAL OPERATING & MAINTENANCE COST COMPARISON
$(1000)

Item	Stoker	FBC	Gasifier
Fuel	475	475	475
Sorbent	323	404	90
Labor	20	22	25
Utilities	30	35	35
Maintenance	196	119	257
Disposal costs	90	99	10
Insurance	70	43	93
Total	1204	1197	985

TABLE 8. TOTAL ANNUALIZED COST COMPARISON

Candidate System	Total Annualized Cost ($1000)	Cost For 1000#/Steam
Stoker	1537	4.13
FBC	1399	3.75
Gasifier	1425	3.83

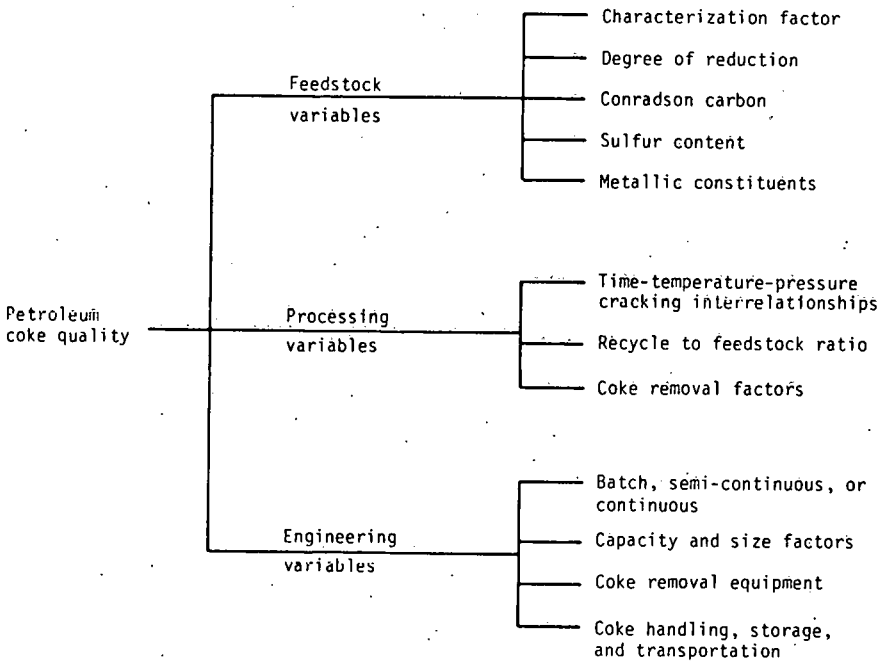


Figure 1. Interrelated petroleum-coke quality variables.

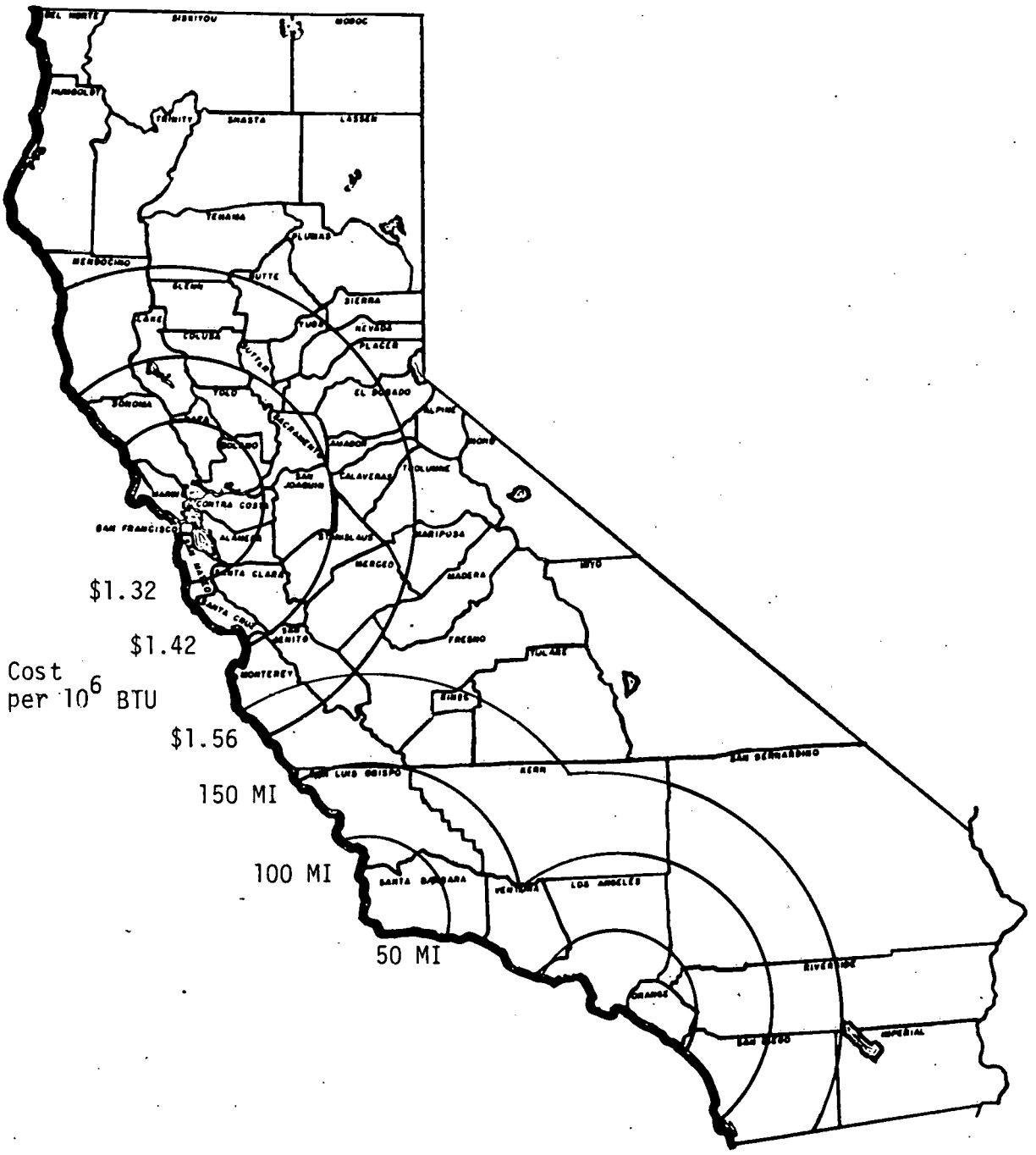


Figure 2. Delivered petroleum coke costs.

FIELD TESTING OF THE VAPOR THERM™ PROCESS IN THE EASTBURN (CHEROKEE) FIELD VERNON CO., MISSOURI

By
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ABSTRACT

Since April, 1978, Carmel Energy has been conducting a field research pilot test in Vernon County, Missouri, under a contract with the Department of Energy using the Vapor Therm™ process of enhanced oil recovery. The purpose of this field test was to determine if injecting a mixture of nitrogen, carbon dioxide, and super-heated steam would stimulate recovery of the shallow highly viscious crude oil which is found in abundance in parts of Western Missouri, Kansas, and Oklahoma. At least three major oil companies and several independents have tried to produce this oil using conventional steam injection and insitu combustion. All prior attempts at economical recovery have been unsuccessful.

This paper presents the results of the oil production response of this reservoir to stimulation by Vapor Therm™ gases. Oil production responses after Vapor Therm™ injection have been encouraging. The first stimulation of C.E.I. #6 yielded initial rates as high as 53 BOPD and a sustained average of 12.3 BOPD. The second stimulation of this well was even better, with a peak rate of 58 BOPD and an average of 18.2 BOPD. The third stimulation yielded peak production rates of 97.5 BOPD.

Results of oil production after stimulation of the other two wells in the three-well field research pilot test in this reservoir were not as encouraging. C.E.I. #5, with a k-h product of 3.4 apparently did not have the capacity to accept Vapor Therm™ gases and after three attempts at injecting Vapor Therm™ at temperatures in excess of 500°F. this well was abandoned as an injector-producer well. C.E.I. #8 encountered serious difficulties with initial injection. Analysis of the very rapid oil production declines after the first stimulation suggested the presence of water sensitive clays. Thin section and x-ray diffraction analyses confirmed the presence of these clays. A system was developed to enable the Vapor Therm™ gases to be injected into the well and produced after stimulation without excessive permeability damage.

All wells were completed open hole and considerable difficulty was encountered after stimulation with wells being sanded up and in one case completely plugged. A cased hole completion is indicated.

Prepared for DOE under Contract No. ET-C-03-2046

ABSTRACT (cont)

It was observed that oil production could be improved in each of the three wells by injecting into one of the off-setting wells. After three written requests for extension of the contract to study further the problems of well completion, water sensitive clays and the drive mechanism, absence of funding did not permit further investigation.

I. INTRODUCTION

Carmel Energy completed a 12 month cost sharing contract with the U.S. Department of Energy in April 1979. The Vapor Therm^{TM} Process had previously been demonstrated to be commercial in a 870 ft. Bartlesville sandstone on the Clinkenbeard Lease in Allen County, Kansas near the town of Iola, Kansas.

Carmel's Vapor Therm^{TM} Process is designed to produce a mixture of super-heated steam, CO_2, and nitrogen which when injected into a sandstone reservoir containing heavy oil will stimulate oil production by: (1) reducing oil viscosity by application of heat; (2) energizing the reservoir by repressuring CO_2, N_2 gas; (3) absorption of CO_2 into the cold oil with oil phase swelling and resulting viscosity reduction. It is the intent of the Vapor Therm ^{TM} Process that the stimulation mechanism take place in a way so that it is not damaging to the permeability of oil flow in the formation.

This paper will present results of all injection-production cycles through April 1979 and will discuss problems encountered with application of Vapor Therm^{TM} technology and solutions which were developed to solve these problems.

II. HISTORY OF RECOVERY ATTEMPTS IN WESTERN MISSOURI

Oil production occured in western Vernon County, Missouri before the year 1870. Oil was discovered in the shallow Bluejacket and Warner Sands when area farmers drilled water wells. The first serious attempt at primary production occured between 1915 to 1920 when, during W.W. I a small refinery was built near Richards, Missouri. Initial primary production rates were typically 2 or 3 B@PD but quickly fell off to less than 1/4 BOPD per well. It became obvious when the refinery was forced to close due to the absence of sufficient crude that economic recovery of this oil was going to require stimulation.

The first serious attempts at enhanced oil recovery from these sands occured in the mid 1950's when Carter Oil attempted a steam drive north of Deerfield, Missouri. Phillips, Sohio and Shell followed with similar thermal projects in the 60's. These attempts involved some form of thermal recovery either by steam injection or insitu combustion. None of these attempts

II. HISTORY OF RECOVERY (cont)

were considered successful due to the fact that response was erratic and production rates were not sufficient to sustain commercial production.

Carmel Energy entered into an agreement in late 1977 to acquire rights to oil and gas leases covering approximately 37,000 acres in Vernon Co., Missouri. In April 1978, Carmel undertook a 10 well coring program. From results of this coring program, Carmel selected the west half of Section 33, T35N, R33W for the Vapor Therm™ test. Carmel learned from Missouri records that this deposit had been discovered in 1915 and was identified as the Eastburn (Cherokee) Field.

III. EASTBURN (CHEROKEE) FIELD

The Eastburn (Cherokee) Field test of the Vapor Therm™ Process was located approximately 6 miles south-southwest of Deerfield, Missouri as illustrated in Figure 1. The Ida-Fauvergue Lease was selected as the site for the test because: (1) abandoned oil field equipment and several unplugged oil wells indicated that there had been some primary production; (2) core analyses from 8 wells in the field indicated that reservoir quality was apparently better than other locations in western Missouri; (3) Carmel was able to secure old production records which enabled us to certify the Ida-Fauvergue Lease for stripper oil prices.

Carmel cored 8 wells on the Ida-Fauvergue Lease and selected C.E.I. #5, #6, and #8 to be completed as test wells. Carmel's core analysis data and that obtained from previous operators in the field illustrated that permeability in the upper Bartlesville (Bluejacket)sandstone increased with depth. From this information and detailed analysis of sand particles, which showed the sand to be a medium to fine grain, well sorted, sub-angular; Carmel concluded that the environment of deposition was a non-marine fluvial, river channel deposit which occured during Pennsylvanian Age. Mapping the sand turned out to be difficult due to the rather limited aerial extent of the field; however, it was determined that the axis of the river channel trended north/south with extensive levy deposits on both the east and west bank of the channel. It was postulated and later confirmed that the best sand quality would be found along the axis of the river channel.

Carmel originally estimated oil in place on the Ida-Fauvergue Lease to be in excess of 2.5 million barrels. This figure was later reduced as more knowledge of the reservoir was obtained. To this date neither the northern or southern extent of the channel deposit has been determined.

In order to certify Ida-Fauvergue Lease Production for

stripper pricing, it was necessary to obtain one year's production data. This was done and the average primary production rate from 8 wells was .07 BOPD per well.

IV. APPLICATION OF VAPOR THERM™ TO RECOVERY OF EASTBURN (CHEROKEE) OIL

In the Vapor Therm™ Process, super-heated steam, CO_2, N_2, and other gases are generated for injection into heavy oil bearing sandstone reservoirs. The approximate chemical analysis of the Vapor Therm™ stream is as follows:

Component	MOL %
Super heated steam	68.0-70.0
Nitrogen	25-26
Carbon Dioxide	3.5-4.0
Oxygen	0-.5
Hydrogen	Trace
Carbon Monoxide	Trace

The reader is invited to refer to references cited in Chapter IX for detailed descriptions of the Vapor Therm™ generating equipment, surface distribution piping, well head, and production facilities. Facilities used in Missouri for testing the Vapor Therm™ Process were very similar to the facilities used near Iola, Kansas. Therefore, detailed descriptions of the equipment will not be included in this report. It should be emphasized, however, that Carmel has learned how to generate Vapor Therm™ gases essentially without difficulty and to inject these gases into the sandstone formations without noticable corrosion or other adverse side effects. Carmel has, through experience, found that by operating at slightly excessive oxygen concentration, formation of coke is prevented and elemental hydrogen and carbon monoxide are generated. Hydrogen and carbon monoxide are excellent reducing agents to scavenge out oxygen down stream and to assist in corrosion control.

Carmel modified the Vapor Therm™ generation unit in Missouri for addition of anhydrous ammonia to the top of the steam drum for pH control which again helped in eliminating corrosion, and for assistance in preventing hydration of clays when steam condensed in the formation.

The Vapor Therm™ generation unit requires approximately 15 gallons per minute of net process water which will, of course, vary with the quantity of fuel being burned in the unit; 440 volt, 3 phase power which Carmel generated on site with a portable diesel powered generator and propane to fire the air compressor engine and for miscellaneous heat. Process water, diesel fuel for firing the Vapor Therm™ unit and running the electric generator, and propane were purchased from local suppliers.

IV. APPLICATION OF VAPOR THERM™ (cont)

C.E.I. #6 and #8 were drilled as 2 outside wells of a hexagonal, 7 spot pattern with one well per acre spacing. This well spacing was selected after calculations illustrated that one well per acre spacing might be near optimum in Missouri where total depts of about 130 ft. and individual well costs are low relative to capital investment in surface facilities. With one well per acre in a hexagonal, 7-spot pattern a distance of 223.4 ft. between wells resulted. C.E.I. #5 was drilled outside of the hexagonal, 7-spot pattern and was completed primarily for the purpose of determining lower limits of reservoir quality for application of Vapor Therm™ technology.

As shown in Figure 2, the Vapor Therm™ unit, air compressor, electric generator, ammonia and propane storage, office and shops were located near the center of the potential hexagonal, 7-spot. Vapor Therm™ gas after generation is distributed via insulated 2" pipelincs as illustrated in Figure 2 to each of the 3 injection-production wells. Project design criteria dictated that 150 MMBTU was to be injected in 24 hours into each well or in the event an individual injection well would not accept Vapor Therm™ at such high rates, then at least 4,000 pounds per hour of Vapor Therm™ was to arrive at the well at or above 500°F.

For the duration of the field test, Carmel used fuel nozzels in the furnace that permitted the unit to burn 45 gallons of #2 diesel fuel per hour. This meant that it took 2 days to inject a well with 150 MMBTU's of Vapor Therm™. However, even at this rate, with the final exit gas temperature off the Vapor Therm™ unit between 650-700°F, and only 50°F. of heat loss in the transmission lines, and 50°F. down hole loss, a sand face temperature of 550-600°F. resulted. Injection pressure was limited to 180 psi at the sand face.

Very little operating difficulty of the Vapor Therm™ generating unit itself occured other than the problems discussed later in the first attempt at injection and in very cold weather operation. These problems were solved as discussed in the next section.

Top of the upper Bartlesville (Bluejacket) sand on the Ida-Fauvergue Lease occured at a nominal 100 ft. of depth. Each well was drilled to the top of the Bluejacket and the entire Bluejacket interval cored. Results of the core analyses for C.E.I. #5, #6, and #8 are shown in Figures 3 through 5, respectively. Also shown in Figures 3-5 are gamma ray neutron logs from each well. Reservoir parameters are shown in Figure 1.

Analysis of Vapor Therm™ production response from the Caryle Pool test in Iola, Kansas indicated that much of the reservoir energy in the form of CO_2 and N_2 gas repressurization was being lost due to the fact that the wells were completed open hole by setting casing on the top of the pay. In the Eastburn (Cherokee) field test, it was decided early that either the casing would be submerged in an open hole completion

IV. APPLICATION OF VAPOR THERM^{TM} (cont)

or a-cased hole completion with 10-15 feet of rat hole and perforations in the bottom 1/4 or 1/3 of the pay would be used. An open hole submerged casing completion was selected. Individual well casing points are illustrated in Figures 3-5 for each of the wells. By submerging the casing at least 1/2 way into the pay and completing open hole it was felt that gases would be retained in the formation and reservoir energy would, therefore, be maintained much better. It was further postulated that since there was no active bottom water in the Bluejacket Sandstone that the wells would flow continuously after stimulation therefore eliminating the need for pumps and pump jacks.

V. PROBLEMS ENCOUNTERED AND SOLUTIONS

During the first attempt at injection, in April 1978, Carmel used a diesel fired, 750 CFM at 125 psi screw-type air compressor. This machine was designed to bring air pressure up to 125 psi and hold this pressure through action of a governor on the diesel engine. This type of compressor proved to be impossible to operate in the field as part of the Vapor Therm^{TM} system.

At the first attempt to inject simultaneously into C.E.I. #6 and #8, the wells began to take Vapor Therm^{TM}; however, they quickly pressured up and air flow through the Vapor Therm^{TM} generating unit was reduced. The rate of fuel injection into the unit which is regulated by the difference in system pressure and fuel injection pressure remained constant. The result was serious coking, coke plugging off the sand face with further reduction in air flow through the unit causing an even more serious coking problem.

Operators in the field were not able to regulate the ratio of fuel to air properly with this type of compressor. Finally, the sand face at each well was totally sealed with coke and careful testing confirmed that the wells were not taking Vapor Therm^{TM}.

Upon pulling the 2-3/8" EUE tubing in each well, the well bore was found to be completely full of coke. Each well had to be washed out and the sand face was shot with 22 pounds of HDP Dupont Explosives to loosen the coke and then jetted and washed with 1% KCL water to clean up the sand face.

The problem of air compressor selection was solved by moving in an Ingersoll Rand three stage compressor capable of delivering 2.2 MMSCF/D of air at 300 psi. This compressor maintains essentilly constant air through put to the unit and even though a well may pressure up during an injection cycle the ratio of fuel to air is held essentially constant.

V. PROBLEMS ENCOUNTERED AND SOLUTIONS (cont)

The first attempt at a sequential hydrochloric--hydrofloric acid treatment completely destroyed the tubing and part of the wellhead on C.E.I. #8. Furthermore, packing glands on each valve had to be changed to Teflon from the graphite glands originally furnished. However, much less corrosion was observed with concentrated acids, and almost no corrosion was observed in the 70% hydrochloric acid treatment. It would appear that many treatments with 70% hydrofloric acid will be possible before appreciable corrosion.

Open hole completions apparently were the reason for the serious sand problems encountered throughout the duration of the field test. As discussed earlier, each well was completed open hole and frequently became plugged with sand. Sand plugging could be observed by attention to daily production rates. Frequently, the problem of sand plugging was solved by air lifting sand out of each well by intermittently injecting air down the tubing and then down the annulus and flowing loose sand up the tubing to the surface tanks. In most cases this procedure lifted out the sand and the well was quickly placed back on production. However, on more than one occassion it was necessary to pull the tubing when the entire well bore became sanded up. This resulted in a very messy pulling job since the reservoir was under sufficient pressure to unload hot oil, water and sand on the pulling unit crew.

Another problem that Carmel encountered during the test was caused by extreme cold weather during the winter of 1978-79. Low temperatures for the area was a one day record all time low of $-24^{\circ}F$. and two days at $-20^{\circ}F$. A record 42 inches of snow fell during the winter. As can be seen in the production decline curves, cold weather definitely affects production. Even though the production lines were buried below expected frost depth they frequently became frozen, especially at low points in the production lines. The stock tanks were not properly insulated and had to be thawed almost every day during the winter with hand-held torches. It is recommended that any field test that is to be conducted during the winter in Kansas or Missouri should be properly designed for winter operation.

VI. RECOVERY

Air injectivity tests were conducted on each well before firing up the Vapor Therm™ unit. Initial air injectivity at each well was negligible at over 200 psi. However, after 24 hours, C.E.I. #6 and #8 began to take air at a rate of approximately 1.1 MMSCF per day each. No measurable air injectivity occurred at C.E.I. #5.

VI. RECOVERY (Cont)

C.E.I. #6 was injected first cycle with 152.2 MMBTU's of Vapor Therm^{TM} and after 25 hours of soak was placed on production. Production from the first and subsequent cycles for C.E.I. #6 is shown in Figure 7.

Carmel has heretofore used 150 MMBTU's as a "standard" injection quantity for Vapor Therm^{TM}. To get a comparison of Vapor Therm^{TM} quantities, C.E.I. #8 was injected first cycle with 311.8 MMBTU's of Vapor Therm^{TM}. Oil production from C.E.I. #8 for the first and subsequent cycles is illustrated in Figure 8.

Injection was attempted for 10 consecutive days into C.E.I. #5. At the end of 10 days, this well had taken less than 50 MMBTU's. This rate was considered unacceptable and it indicated either that the reservoir quality of this well was below the minimum required for injectivity, or that severe permeability damage due to the presence of water sensitive clays was reducing the permeability, or perhaps both of these situations existed simultaneously. This well was later shot with 20 pounds of HDP explosives, jetted and washed, and another injection attempt was made which was also a failure. However, later on during the test as the reservoir was pressured-up this well produced, at a consistent rate, an excess of 2 barrels of oil per day strictly from the drive mechanism resulting from injection into wells #6 and #8.

Production response from C.E.I. #6 during the first injection-production cycle, was considered satisfactory. This well produced 442.5 barrels of cumulative oil during the first month of production. However, analysis of production from C.E.I. #8 and confirmation of sand face temperatures through surface measurement of a termal couple cemented near the middle of the sand indicated that this well was producing at only 21.7% of the expected rates. Area injectivity tests on C.E.I. #8 after 15 days of production were conducted and compared to the same tests conducted at the beginning of the first injection 19 days earlier. The tests confirmed that air permeability had been reduced to 19.2% of the original value. This suggested severe permeability damage due to clay and perhaps other mineral constituents in the sandstone formation. It was on this well that Carmel developed its acid treatment which has been previously described. A similar treatment was given C.E.I. #6 at the next injection cycle.

As can be seen from the decline curves for both wells, there is no doubt that the acid treatments made a material difference in the production response to C.E.I. #8 and little doubt

"I. RECOVERY (cont)

that the acid treatment helped reduce permeability damage in C.E.I. #6. In fact, peak production for C.E.I. #6 increased to 97.5 BOPD in this well at the beginning of the third production cycle.

Cumulative monthly production for each well is shown in Table 2. Cumulative injections for each well and stimulation response ratios are also presented in Table 2.

VII. CONCLUSIONS

The Vapor Therm^{TM} process will stimulate oil production from the Upper Bartlesville (Bluejacket) sandstone in Western Missouri, provided the reservoir quality criteria are met on a well-by-well basis. Prospects for field wide application of this technology in the Eastburn (Cherokee) Field on a commercial basis are excellent. In fact, since concluding the field test a commercial 30 well development drilling program has been completed. Out of 30 new wells drilled, 11 were completed as injector-producers and 10 were completed as tubingless producers only with 2 3/8" casing cemented to surface. Nine wells were plugged and abandoned as not meeting a reservoir criteria of 3.5 d-ft. or better. At the time of writing this paper, less than half the wells were tied into production; only three new wells had been stimulated. Peak production has been approximately 290 BOPD with an average of more than 100 BOPD from 10 wells.

One may furter conclude that in closed, non-bottom water reservoirs the wells may be made to flow after stimulation, completely eliminating the needs for pumps and pump jacks. This is obviously due to the presence of CO_2 and N_2 gases and therefore indicates a definite technical, with resulting economic advantages over straight steam alone.

Finally, this field test demonstrates the importance of attention to geologic detail as probably the most important factor in applications of Vapor Therm^{TM} technology to recovery of heavy oils from "dirty" sandstone reservoirs. Successful application of Vapor Therm^{TM} in a "dirty" reservoir, requires a detailed knowledge of reservoir fluid composition, complete analysis of the pore space for clays and other minerals along with customary detailed core analysis. From this information, a Vapor Therm^{TM} recovery system may be designed which will economically recover a high percentage of the oil in place.

VIII. ACKNOWLEDGEMENTS

The authors wish to acknowledge the financial and technical contributions and encouragement of R. W. Krajicek, whose unwavering support of this test from beginning to end was most helpful and appreciated. Wendell Weatherbie, member of the Tertiary Oil Recovery Advisory Board for the State of Kansas assisted in our field operation and made many important suggestions and recommendations. Finally, Field Superintendant, Richard Zornes and his assistant, George Sailor, handled field injection and production problems even during the severe winter of 1978/79. Without the dedicated work of all these people this project would not have been completed and would not have been successful.

IX. REFERENCES

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2. Sperry, John S., Poston, Robert S., and Young, Jr., Farrile S.; "Development and Field Testing of the Vapor Therm™ Process in the Carlyle Pool - Allen County, Kansas", Proceedings, Fourth Annual DOE Symposium, Enhanced Oil & Gas Recovery & Improved Drilling Methods, Vol. 1B - Oil, The Petroleum Publishing Co., Tulsa, Oklahoma, pp. D-2/1 - D-2/30.

TABLE I - RESERVOIR PARAMETERS

Depth to Top of Bluejacket Sand -	100 - 120 ft.
Total Sand Thickness (5 to 33.5 ft)	22 ft Avg.
Oil Sand Greather than 200 md	18 ft.
Aquifer	None
Oil Gravity	21.6° API
Porosity (20.0 to 26.7%)	24.5%
Absolute Permeability (200 to 850 md)	650 Avg.
Oil Saturation (60 to 85%)	80%
Initial Reservoir Pressure	54 PSI
Initial Reservoir Temp	70°F
Viscosity at 70° F	710 cp

TABLE II

PRODUCTION RESPONSE TO STIMULATION

Month	CEI #5 BOPM	CEI #6 BOPM	CEI #1 BOPM
Oct. '78	-0-	448.1	60.2
Nov. '78	-0-	626.2	265.9
Dec. '78	6.6	613.6	195.8
Jan. '79	141.1	262.5	171.3
Feb. '79	33.9	576.7	362.1
Mar. '79	45.5	556.4	419.9
Apr. '79	40.5	848.0	233.1*
Cumulative, Bbls	267.6	3,931.6	1,708.3
less frac oil	(40.0)		
Net Total, Bbls	227.6	3,931.6	1,708.3
BOPD/Well	1.1	18.7	8.1
% Oil in Place Rec.	2.0%	13.1%	5.7%
MMBTU Injected	123	537	632
BO/MMBTU	1.8	7.3	2.7
BO/Bbls Steam	.8	3.1	1.2
Cumulative Field Production/Bbl. Steam Inj.			2.4

*Tied into central storage and treating on 4/27/79.

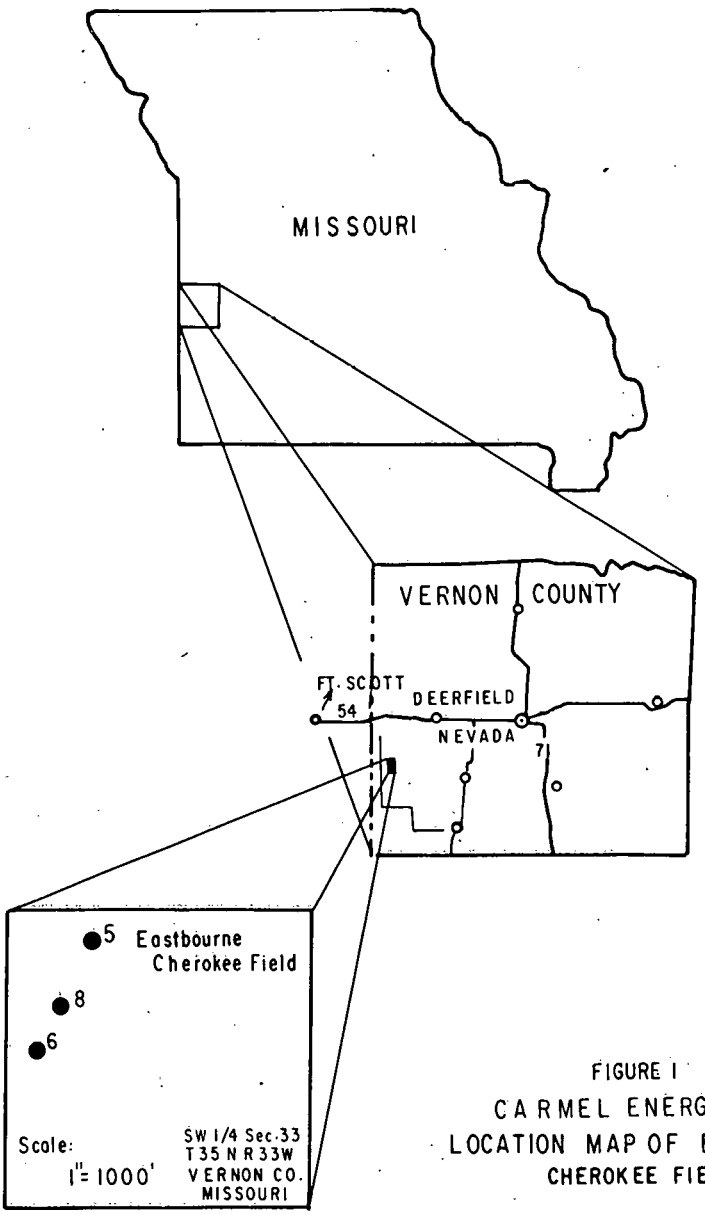


FIGURE I

CARMEL ENERGY, INC.

LOCATION MAP OF EASTBOURNE

CHEROKEE FIELD

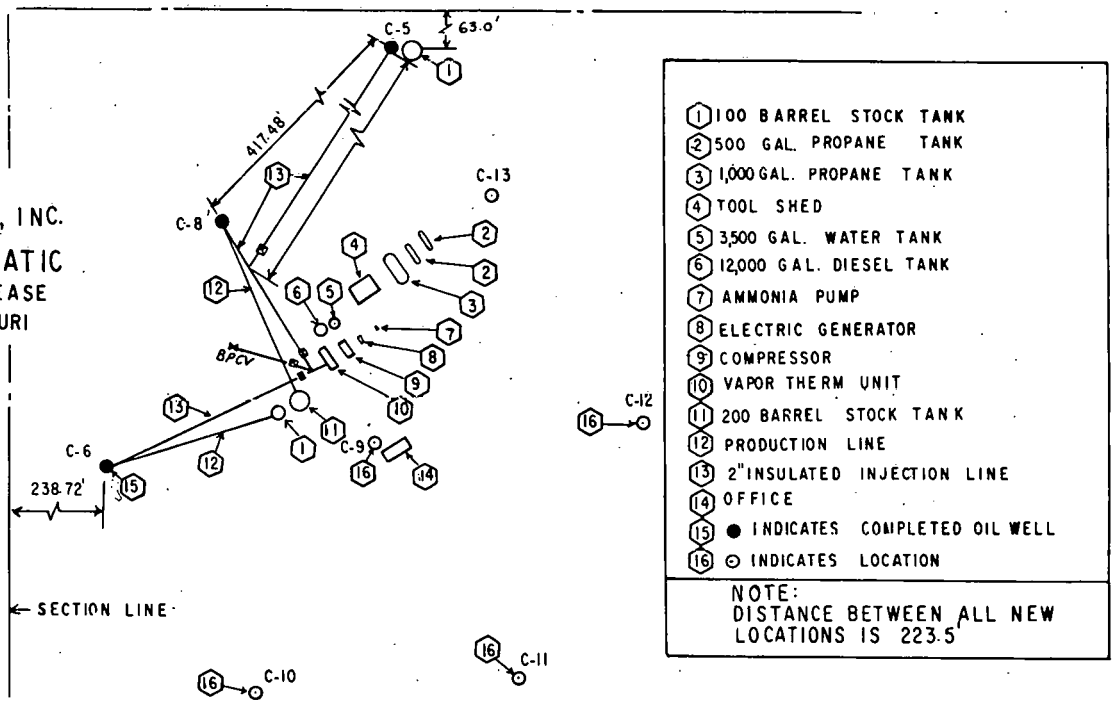
FIGURE 2

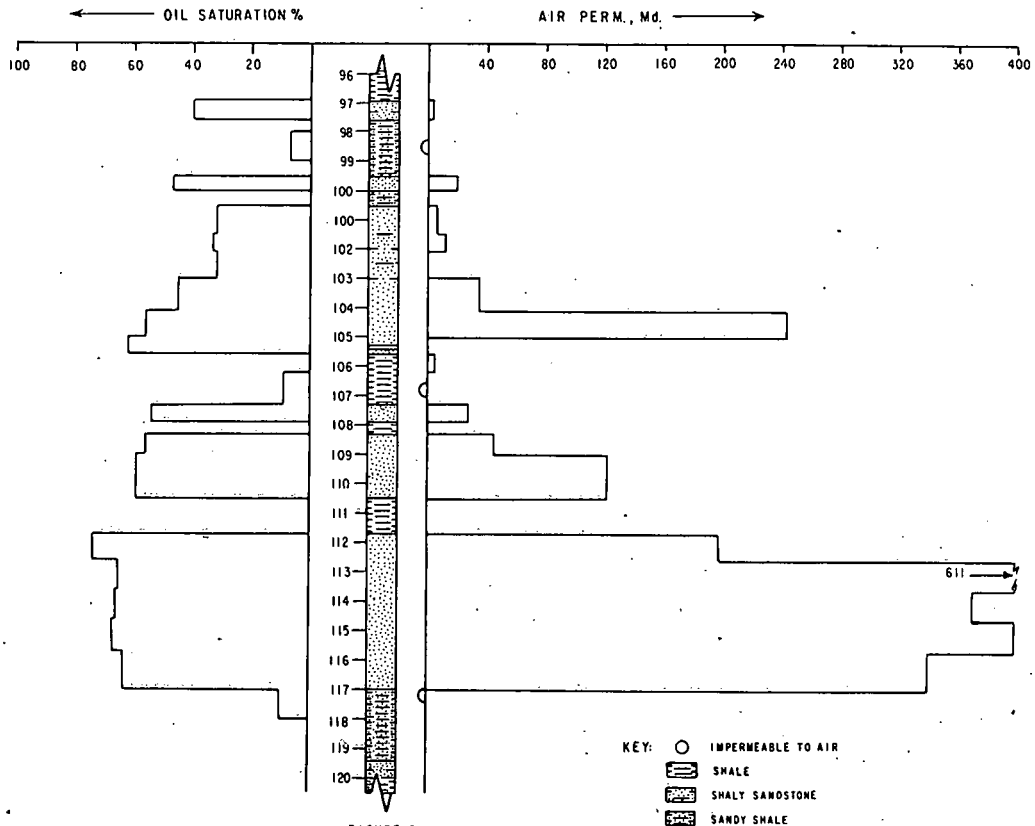
CARMEL ENERGY, INC.

PROJECT SCHEMATIC

IDA FAUVERGUE LEASE

VERNON CO. MISSOURI





FIGURE, 3

CARMEL ENERGY, INC.

PETROPHYSICAL DATA

CEI NO. 5

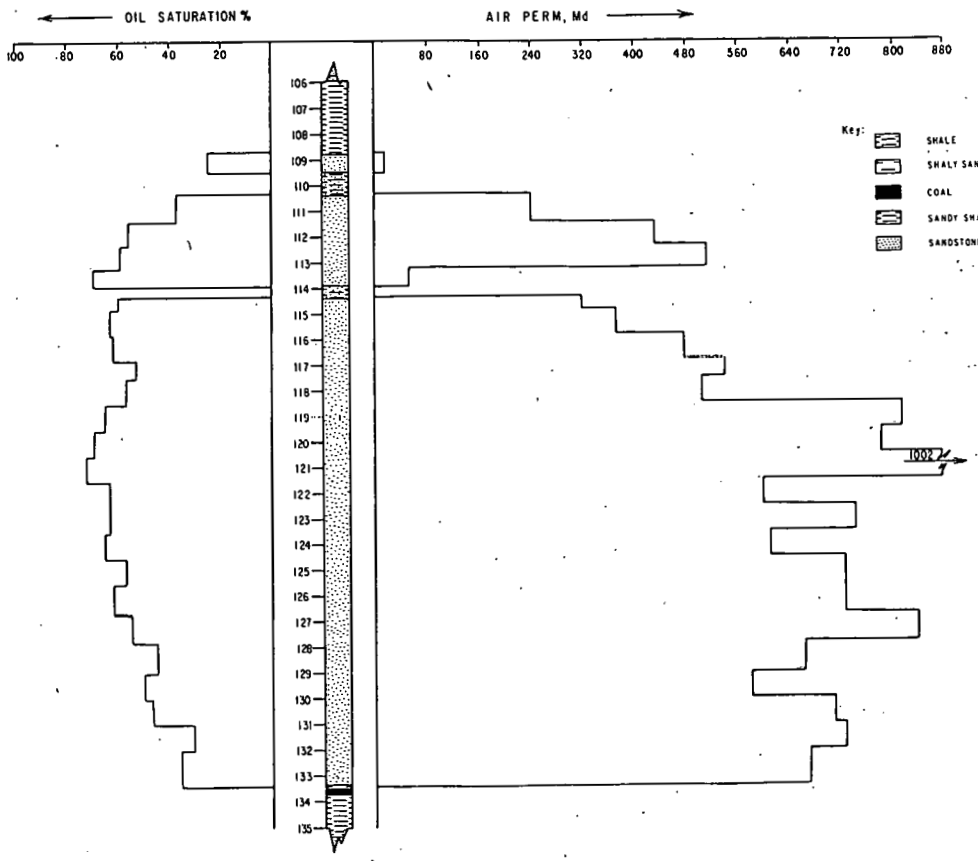


FIGURE 4
CARMEL ENERGY, INC.
PETROPHYSICAL DATA
CEI NO. 6

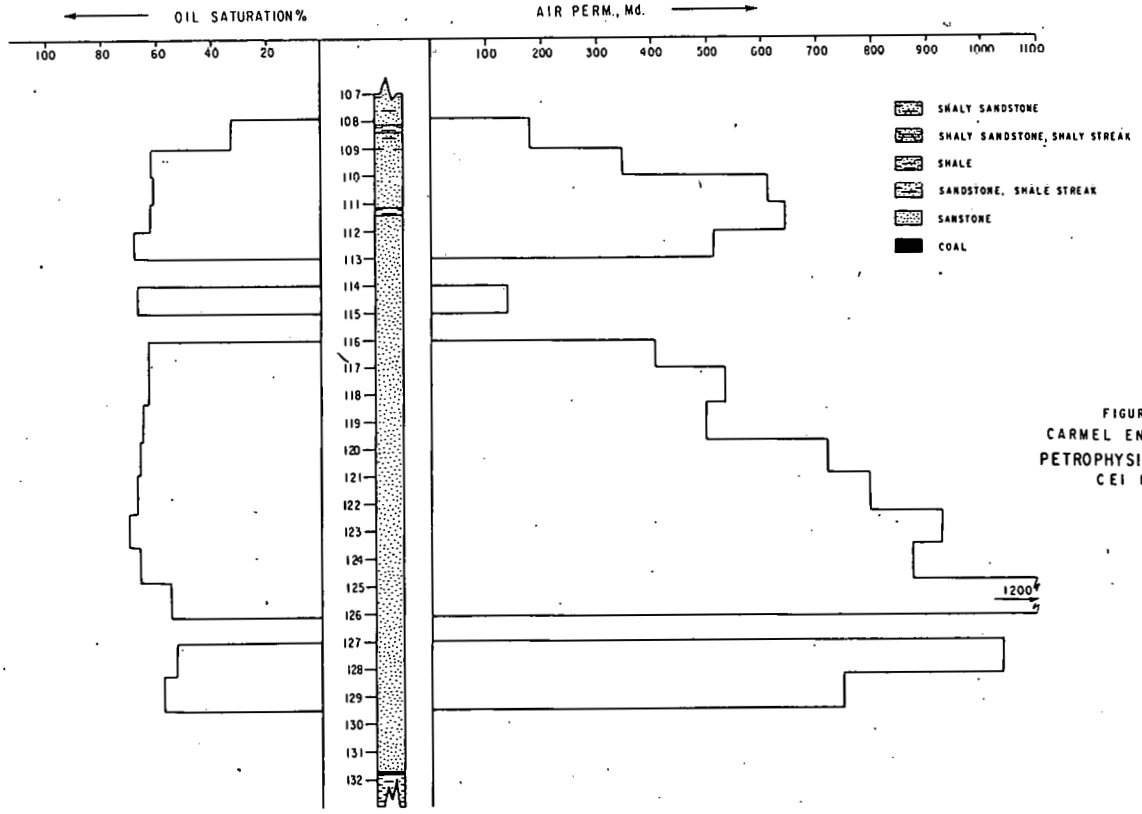


FIGURE 5
CARMEL ENERGY, INC.
PETROPHYSICAL DATA
CEI NO. 8

FIGURE 6

PRODUCTION RATE vs TIME
C.E.I. WELL NO.5
IDA FAUVERGUE LEASE
VERNON COUNTY MISSOURI

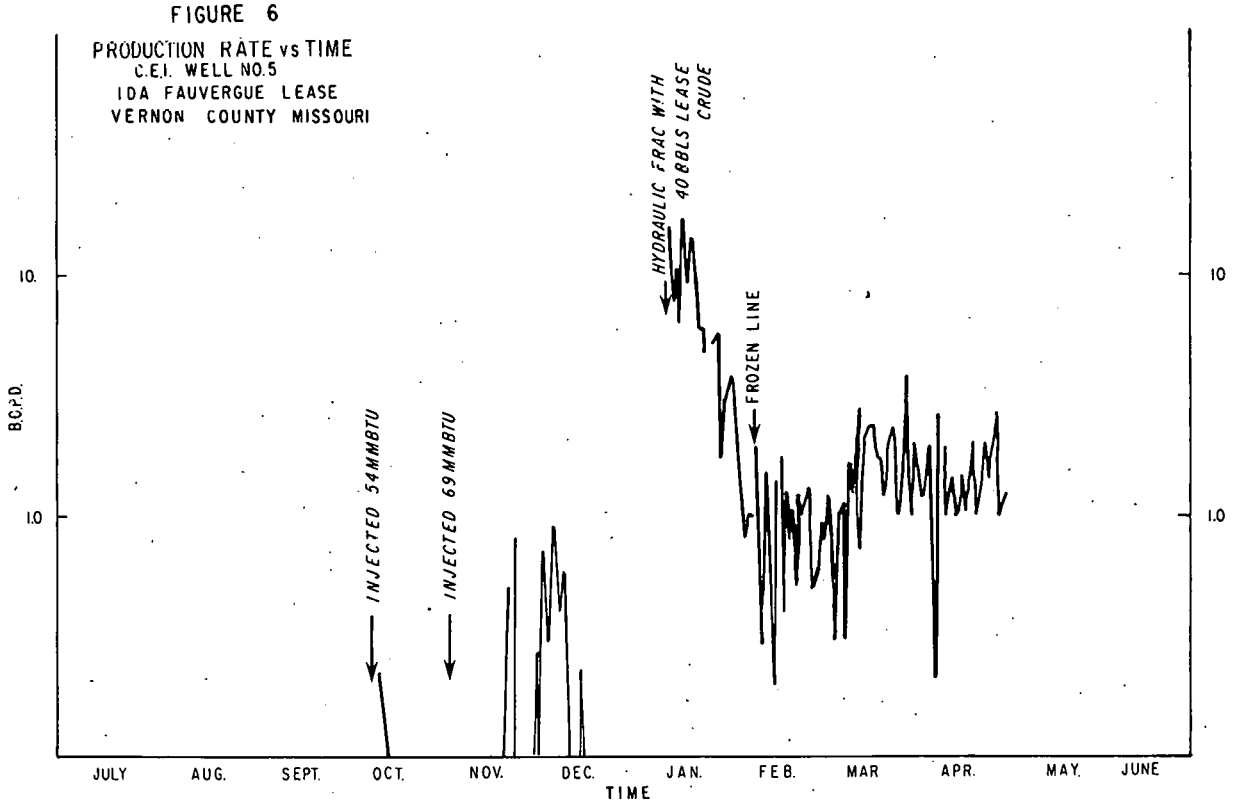
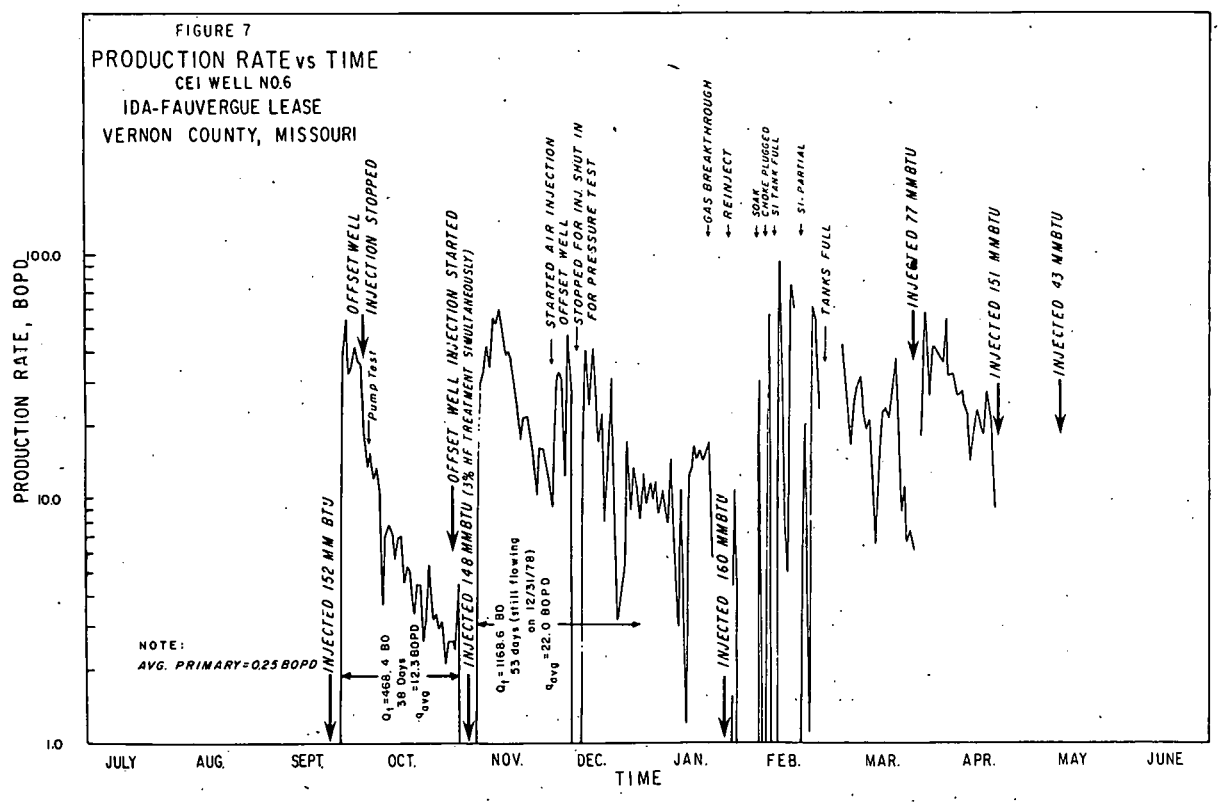
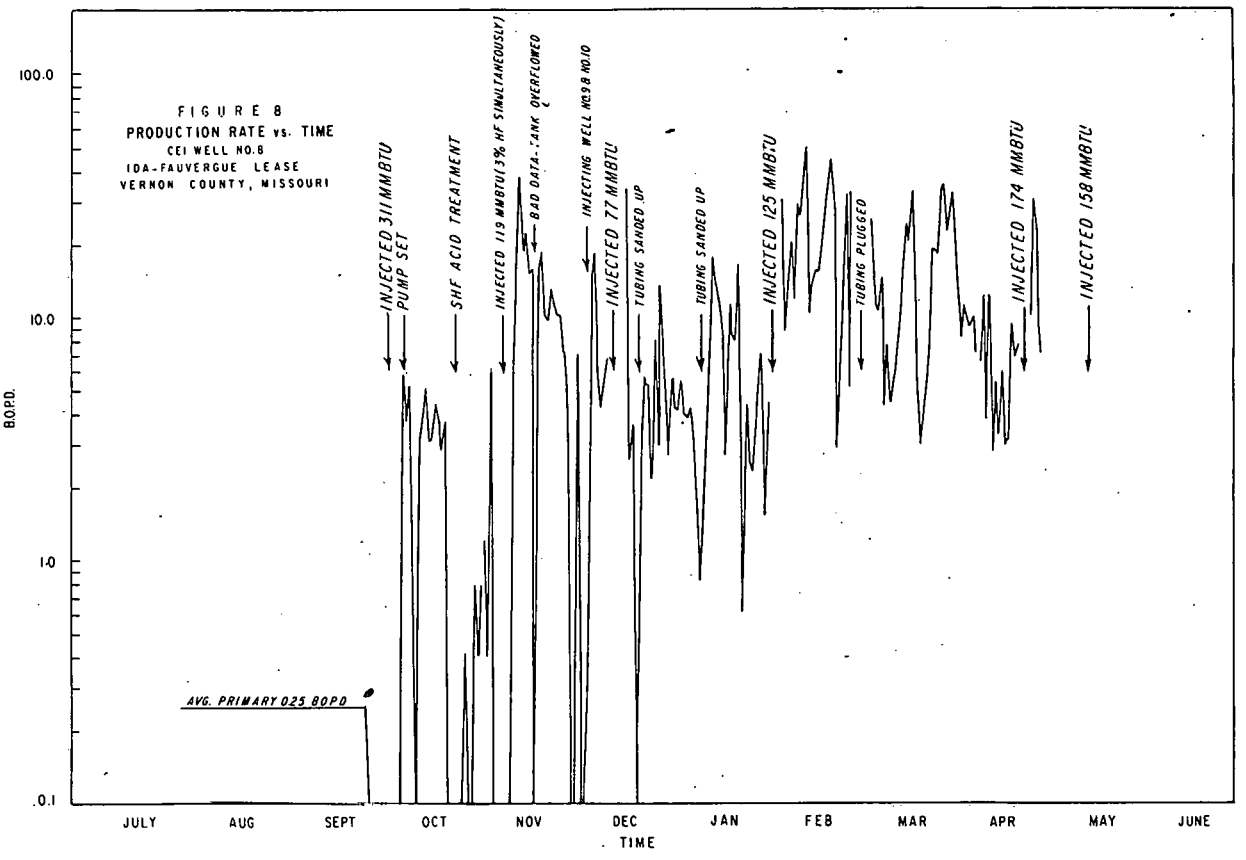


FIGURE 7

PRODUCTION RATE vs TIME
CEI WELL NO.6
IDA-FAUVERGUE LEASE
VERNON COUNTY, MISSOURI




FIGURE 8
PRODUCTION RATE vs. TIME
CEI WELL NO.8
IDA-FAUVERGUE LEASE
VERNON COUNTY, MISSOURI
100.0
10.0
1.0
.0.1
BOPD.
AVG. PRIMARY 025 BOPD
INJECTED 311 MMBTU
PUMP SET
SHF ACID TREATMENT
INJECTED 119 MMBTU (3% HF SIMULTANEOUSLY)
BAD DATA-TANK OVERFLOWED
INJECTING WELL NO.9 NO.10
INJECTED 77 MMBTU
TUBING SANDED UP
TUBING SANDED UP
INJECTED 125 MMBTU
TUBING PLUGGED
INJECTED 174 MMBTU
INJECTED 158 MMBTU
JULY
AUG
SEPT
OCT
NOV
DEC
JAN
FEB
MAR
APR
MAY
JUNE
TIME

WILLOW DRAW FIELD, ATTIC AIR INJECTION PROJECT, PARK COUNTY, WYOMING

By

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ABSTRACT

Santa Fe Energy Company, in conjunction with the DOE (which is no longer a financial participant) has been conducting a field trial of attic air injection in the Willow Draw Field, Park County, Wyoming, since May 1975.

The reader is referenced to the Proceedings, Third and Fourth Annual DOE Symposia, Volumes 1 and 1B, respectively, to review the inception and activities to date of this project.

In this paper, the results of the test to date are reviewed in detail and compared with expectations, and circumstances yield superior applications of the process will be reviewed.

In general, the project has behaved qualitatively as predicted by the reservoir theory described in previous papers, but quantatively has not achieved results as good as hoped. The results are sufficiently encouraging to warrant continued operations. Economically the project has been successful; technically it has been disappointing to date.

Prepared for DOE Under Contract No. ET-78-C-02-1810

Note: Copies of this paper are available from the author.

IN SITU THERMAL PROCESSING

by

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ABSTRACT

Tar sands in Eastern Utah contain more than 28 billion barrels of oil in place. The tar sand oil or bitumen is very viscous at reservoir temperatures and will not flow into a wellbore unless it is heated or decomposed. About 10 percent of Utah's tar sand can be surface mined; however, the remainder must be developed by in situ methods since overburden thickness is excessive.

Laramie Energy Technology Center (LETC) is conducting in situ recovery experiments at Asphalt Ridge in Northeastern Utah. A hydraulic fracture experiment is planned within the tar sand layer as a means of creating the necessary flow path between the formation and the wells for improved control of the burn and production of the mobilized bitumen. Terra Tek, Inc. is assisting LETC in the design and analysis of the fracture treatment. The analytical prediction of fracture geometry based on rock mechanics consideration will be compared to the field measurements. Such comparison provides a basis for the design of the well pattern for any future in situ combustion project.

Prepared for DOE under Contract No. ET-78-C-03-2041

Note: Copies of this report are available from the authors.

DEEP STEAM: Development of Downhole Steam Generation Systems and Injection String Modifications for DEEP STEAM Injection *

by

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ABSTRACT

The physical phenomena which limit the depth for economic enhanced recovery of heavy oil by steam injection are: (1) heat loss during delivery, (2) loss of steam quality at the sand face, (3) reduction in specific volume of the vapor phase, (4) change in the two phase enthalpy distribution, and (5) lower reservoir permeability. The application of improved thermal well completions can be successful in reducing heat loss and improving sand face steam quality. Computational analysis and experimental test programs for development of thermal well completion methods are presented.

Two designs for downhole steam generation are under development. These designs both use the combustion of hydrocarbon fuel to supply the energy for steam production, but differ in combustion pressure and method of heat transfer. The low pressure combustion generator gives higher energy efficiency. The high pressure generator introduces additional phenomena which can reduce recovery cost and offer improved air quality. Computer modeling of recovery operations have predicted the additional recovery mechanisms contained in the high pressure design more than offset the higher energy efficiency of the low pressure device in many applications. Field operations which test some of the promising aspects of high pressure generator technology as well as problem areas associated with this recovery approach are underway in the Kern River field of California. Progress of the design programs and the field test will be reviewed.

*This work was supported by the United States Department of Energy (DOE) under contract number DE-AC04-76DP00789.

Introduction

The work described in this paper is part of the Department of Energy's Project DEEP STEAM. The objective of the project is to reduce the cost of steam recovery from deep reservoirs through application of advanced technology. There are several tasks covered by the project, including modification of delivery processes for surface generated steam and development of methods for production of steam at the sand face. The increase in cost of drilling and completing deeper wells accounts for only a small fraction of total cost increase with depth. A variety of physical effects contribute to reduction in the efficiency of production, these include:

1) greater heat loss during delivery,

2) loss of steam quality at the sand face,

3) reduction in specific volume of the vapor phase,

4) change in the two phase enthalpy distribution, and

5) lower permeability of reservoirs.

Some of these effects can be addressed by modifications of existing steam injection technology. The first two of the above effects can be reduced by application of thermally efficient injection techniques. The first two effects are eliminated if steam production is carried out at the sand face. In addition, items 3 and 4 are addressed by certain designs of downhole generators.

Most approaches to improvements in thermal well completion techniques are readily integrated into existing steam injection procedures. Downhole steam production is a departure from current oil production methods and therefore requires more technology development and longer testing to determine economic viability.

Thermally Efficient Well Completions

The computational simulation of heat loss during transportation of steam through concentric tubulars has been the object of many investigations.[1-5] The production obtained from existing computational methods has been verified in laboratory simulations and field testing. The increase in heat loss due to eccentric installation of the injection string has been discussed,[6] however, computational techniques comparable to those used for the concentric installation have not been developed. The cross section of an eccentrically installed tubular is shown in Fig. 1.

Determination of the heat transfer requires calculation of the entire temperature field which exists in the annulus. For quasi steady heat transfer (as has been assumed in the concentric calculation) the Laplace equation gives a sufficient description of the temperature field. Boundary conditions for the Laplace equation, which include eccentricity, are obtained by assuming the metal casing to have a high thermal conductivity.

The Laplace equation for eccentric cylinders reduces to the similar case of electrostatic potentials which has been solved using the method of images.[7]

$$T = C_1 \ln \frac{r^2 + (d_1 + S)^2 - 2r(d_1 + S)\cos\theta}{r^2 + d_2^2 - 2r\, d_2 \cos\theta} \tag{1}$$

where T is the temperature at r, θ location, d_1, d_2 are given by

$$2d_1 d_2 = r_c^2 + r_t^2 + r_t^2 - S^2 - \sqrt{r_c^4 + (r_t^2 - S^2)^2 - 2r_c^2(r_t^2 - S^2)}$$

r_c is radius of casing, r_t is radius of tubular, S is separation distance between center of the casing and tubular. The heat flux, Q, can be obtained by combining with the heat flux equation

$$\frac{dQ}{dZ} = k_{CON} \nabla T \cdot d\vec{\ell} \tag{2}$$

where k_{CON} is the thermal conductivity. The total heat loss per unit time is

$$\begin{aligned} \frac{dQ}{dZ} &= -k_{CON} \oint d\vec{\ell} \cdot \nabla T \\ &= 2k_{CON}\, r_c \frac{T_t - T_c}{\ln\left(\frac{r_c r_t}{d_1 d_2}\right)} \end{aligned} \tag{3}$$

where T_c, T_t are temperatures of the casing and tubular. Equation (3) can be used to obtain an overall heat transfer coefficient for eccentric string

$$U = \left[\frac{r_t}{r_t h_r + k_{CON}\, r_c / \ln(r_t r_c / d_1 d_2)} + \frac{r_t \ln(r_h / r_c)}{k_{CEM}} \right]^{-1} \tag{4}$$

where r_h is wellbore radius, k_{CEM} is cement conductivity, and h_r is radiative heat loss coefficient.

The heat loss as a function of installation eccentricity of an uninsulated injection string is shown in Figs. 2 and 3 for 500 ft and 3000 ft reservoirs. The figures show that unless the string is in contact or very close to contact

with the casing, the loss from eccentric installation is negligibly different from a concentric installation. These figures demonstrate that the effect of contact between injection string and casing for uninsulated tubulars is a smaller percentage increase for deeper reservoirs. The reduction in the effect of contact with depth is due to the higher casing temperatures obtained at depth. The higher casing temperatures result from increased radiative heat transfer.

The application of insulation to concentrically installed injection strings has been presented in existing literature. Insulation has been used to reduce thermal stress on casing in injection wells as well as for reduction in heat loss.

The effect on heat loss of an eccentrically installed injection string which is equipped with 1 in (2.54 cm) of calcium silicate insulation is given in Fig. 4 for a 3000 (914 m) ft reservoir. The insulation reduces the effect of contact between the string and the casing sufficiently to eliminate the need for centralizing devices in most applications.

An experimental approach for obtaining quantitative performance characteristics of these devices is being carried out under the DEEP STEAM project. The facilities for testing the components required for thermally efficient delivery systems are diagramed in Fig. 5. A complete section of injection tubular with joints at both ends and a thermal packer can be installed within the 70 ft vertical tower. An above ground tower is used because of ease of installation of diagnostic instrumentation and ease of removal of downhole components for failure analysis. Failure analysis of individual components will aid in development of devices which overcome materials problems in deep steam operations. Packer sealing surfaces have encountered considerable materials problems in field applications.[8] The tower has the capability to simulate reservoir pressures to 3000 psi. The facility is located in Tacoma, Washington, and the program is being carried out under contract with General Electric.

The test program, which will extend through the fall of 1979, will compare most commercially available high temperature packer designs, calcium silicate tubular insulation, sodium silicate foaming in-place insulation, multi-layered radiation barriers with fiberglass insulation, mineral wool insulation, hermetically sealed and evacuated steel bellows joints, gas packs, and annular flow restrictors.

Downhole Steam Generation

Contracts for conception and feasibility testing of downhole steam generation systems were placed with Rocketdyne Division of Rockwell International Corp., Canoga Park, CA, and Foster-Miller Associates of Waltham, MA. Subcontractors include the Doschers Group for Rocketdyne; MIT, Gulf Oil Corp, and Cash and Jenkins for Foster-Miller. A systems and economic analysis of various methods for production of steam at the reservoir was carried out by Rocketdyne. The three systems estimated to produce steam downhole at the lowest cost were: low pressure combustion of hydrocarbons, liquid heat transfer, and high pressure combustion of hydrocarbons. The estimated cost per barrel of water converted to steam at 1500 psi for these systems are $1.66, $1.84, and $1.96, respectively. The low pressure combustion design produces steam with the least cost and Rocketdyne is testing this design under laboratory simulated high pressure conditions.

Figure 6 expresses the energy usage of the fuel supplied to the Rocketdyne low pressure design. The table shows that 92% of the energy in the fuel is delivered

o the 2500′ reservoir which represents a 25-50% increase in efficiency over a urface generated steam system. The low pressure combustion downhole generator uses a compact heat exchanger to transfer heat of combustion to water which is delivered from the surface producing high pressure steam at a high quality. There is no direct contact between the high pressure water and low pressure combustion gas. The exhaust gases must be transported to satisfy environmental regulations to the surface for treatment.

The liquid heat transfer generator uses liquid salts which have been heated at the surface to transfer energy to water at the reservoir location. The liquid heat transfer design has similar environmental problems to the low pressure generator and the injected fluid, i.e. high quality steam, will encompass the same recovery mechanisms. The cost of production of steam was therefore considered to be a valid criteria for comparison of these two systems.

The high pressure combustion design oxidizes hydrocarbon fuel at high enough pressure so that exhaust gases can be injected into the reservoir with the steam. The physics of recovery are therefore sufficiently different to require data in addition to cost of steam to determine comparative recovery efficiency.

Foster-Miller Associates are pursuing the development of high pressure combustion downhole steam generation. Figure 7 gives the energy usage of fuel supplied to a high pressure combustion generator. The table shows that 81% of the energy is delivered as steam to a 2500 ft reservoir which is 11% less than for the low pressure design. However, the injection of combustion gases into the reservoir could be a significant factor in addressing air quality problems.

The performance of high and low pressure combustion approaches has been examined by computer simulation. Figure 8 compares the recovery from these two designs predicted by the in situ combustion code of Intercomp Resources Development and Engineering Company, Houston, TX. The figure shows that the predicted effect of the combustion gases was favorable enough to overcome the lower energy injection rate of the high pressure generator. The high pressure generator recovered the in place oil in approximately 30% less time than required for the steam only injection of the low pressure concept. A variety of computer simulations have been carried out using both the Intercomp code and a similar code developed by Gulf Oil Corporation. Results of the computer simulations for both concepts show that best recovery is dependent on the nature of the reservoir and characteristics of the recovery operation (well spacing, injection rate, etc.); however, the high pressure design has been shown to be advantageous in a majority of computations.

Field examination of the performance of steam recovery and steam with combustion gases is under evaluation in the Kern River Field in California. The test is being conducted with Chevron, USA, using a 6.5" diameter by 35" long generator which produces 5×10^6 Btu/hr. The field test site layout is presented in Fig. 9. The geometry of the generator is compatible with downhole operation; however, the preliminary tests are being conducted with the device on the surface. The delivery of steam to the reservoir utilizes a well completion equivalent to that in operation with existing surface steam recovery. The test includes monitoring of produced gases for environmental acceptability as well as examination of the reservoir flow characteristics of the various injected fluids and particulate.

Summary

Thermally efficient well completions for steam drive recovery from deep reservoirs are under comparative examination in full scale simulation test. The test facility developed for this purpose utilizes an above ground 70 foot tower which contains a complete section of injection string, two joints, and thermal packer. The facility is capable of operation throughout the range of pressure and temperature required for the DEEP STEAM Project (to 700°F, 3000 psi).

Two downhole steam generator designs are under development. These designs are the result of systems and economic study of a variety of approaches. The designs are characterized by the high pressure combustion of hydrocarbon fuel and the low pressure combustion of hydrocarbon fuel.

Computer analysis has indicated that a high pressure combustion design which injects combustion gases with steam will give a more rapid recovery than injection of pure steam in many operations. Injection of steam and combustion gases is underway in the Kern River Field in California using a high pressure combustion generator design compatible with downhole operation.

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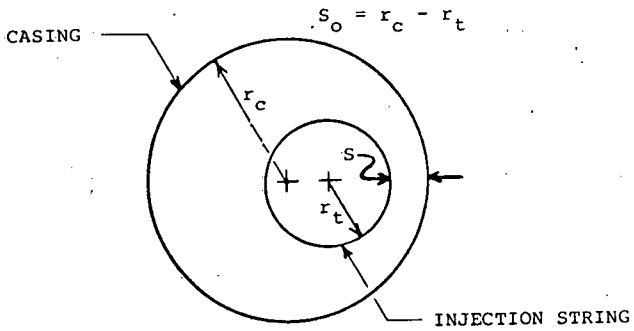


FIGURE 1. Eccentric Installation of Injection String.

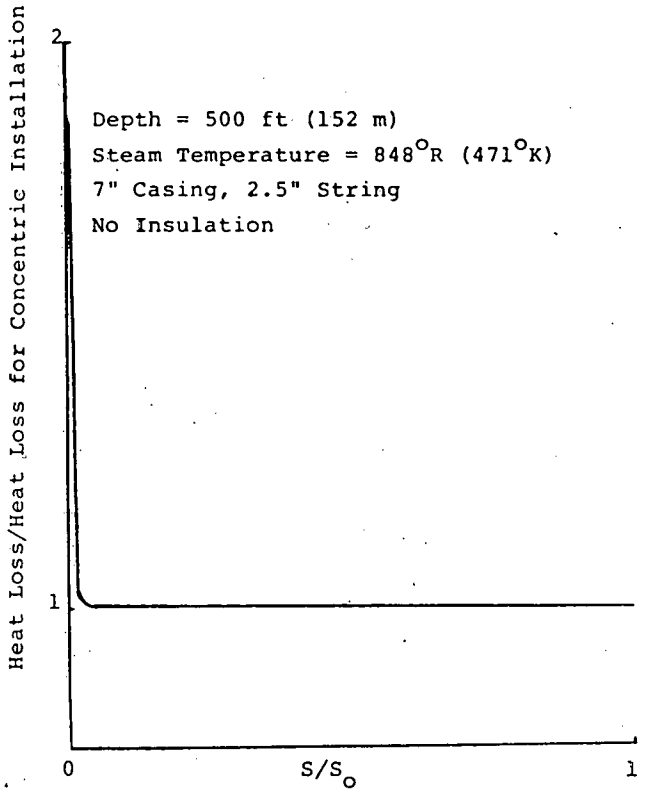


FIGURE 2. Heat Loss from Eccentric Injection String for Injection into 500 ft (152 m) Reservoir.

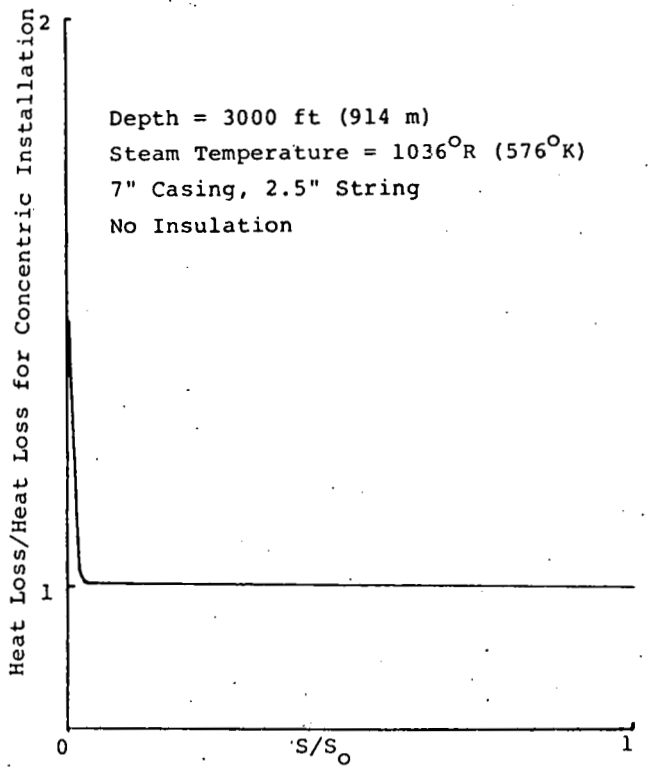


FIGURE 3. Heat Loss from Eccentric Injection String for Injection into 3000 ft (914 m) Reservoir. (See Figure 3).

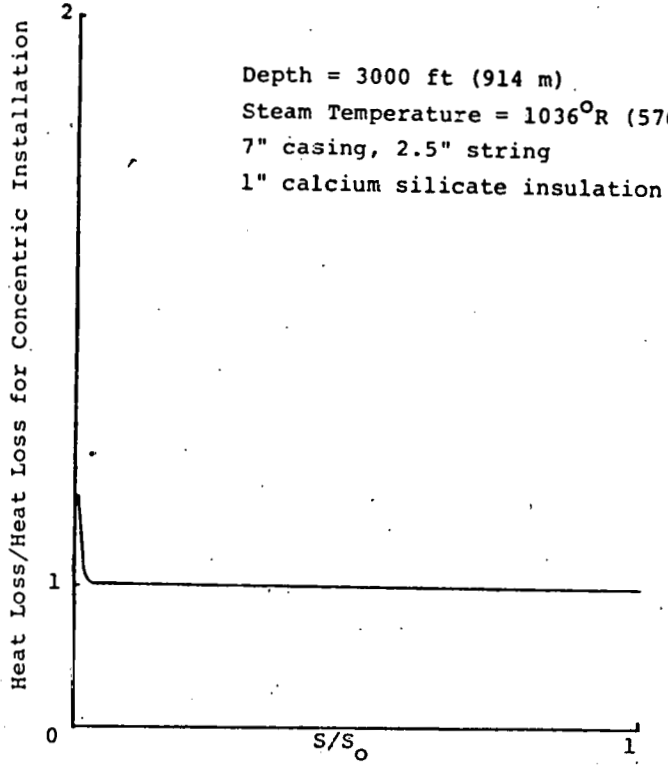


FIGURE 4. Heat Loss From Insulated Eccentric String for Injection into 3000 ft (914 m) Reservoir.

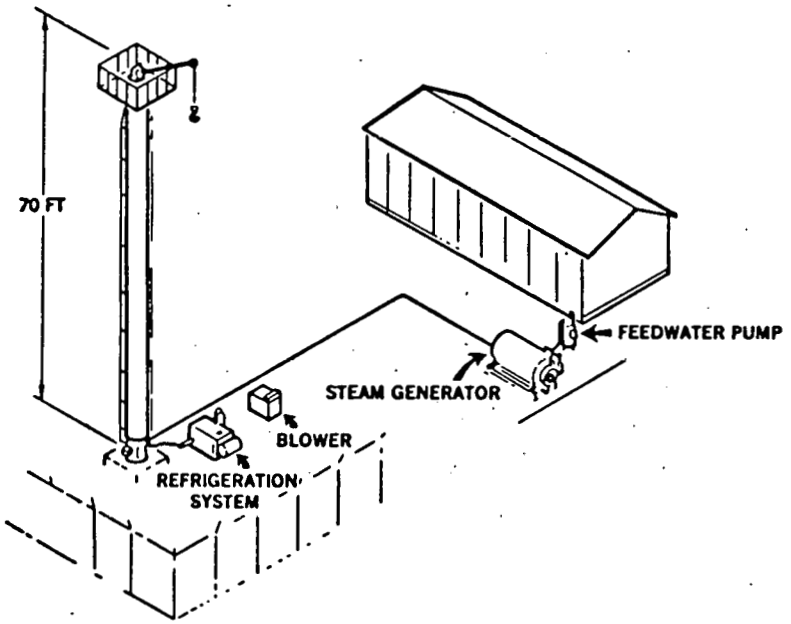


FIGURE 5.

INSULATION AND PACKER TEST FACILITY (GENERAL ELECTRIC)

FIGURE 6

GEOTECHNICALLY INSTRUMENTED SEAFLOOR PROBE
PORE PRESSURE MODULE

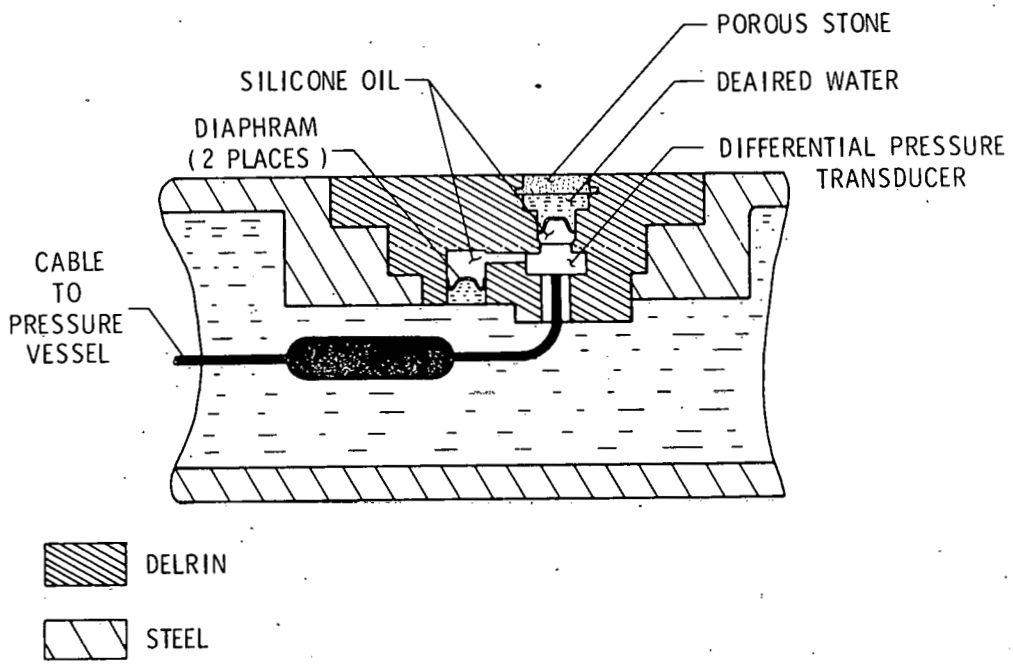


FIGURE 6. HEAT BALANCE FOR LOW PRESSURE DOWNHOLE STEAM GENERATOR

INJECTION PRESSURE 1500 PSIA, DEPTH 2500 FT

BASED ON HEATING VALUE = 18,293 BTU/LB

HEAT INPUT

SOURCE	%
COMBUSTION FUEL(750.02 LB/HR)	81.9
COMPRESSOR FUEL (165.71 LB/HR)	18.1
TOTAL (915.73 LB/HR)	100

HEAT OUTPUT

	%	
COMBUSTION EXHAUST LOSS	4.24	
DIESEL ENGINE EXHAUST LOSS	2.15	
DIESEL COOLANT LOSS	0	
OTHER: DIESEL STRAY & PUMP WORK	0.95	
ABOVE GROUND TOTAL		7.34
WELL BORE LOSS	0.50	
INJECTED GAS (EXCLUSIVE OF STEAM)	0	
USEFUL HEAT (85% QUALITY STEAM)	92.17	
BELOW GROUND TOTAL		92.67
TOTAL		100.0

FIGURE 7. HEAT BALANCE FOR HIGH PRESSURE DOWNHOLE STEAM GENERATOR

INJECTION PRESSURE 1500 PSIA, DEPTH 2500 FT

BASED ON HEATING VALUE = 18,293 BTU/LB

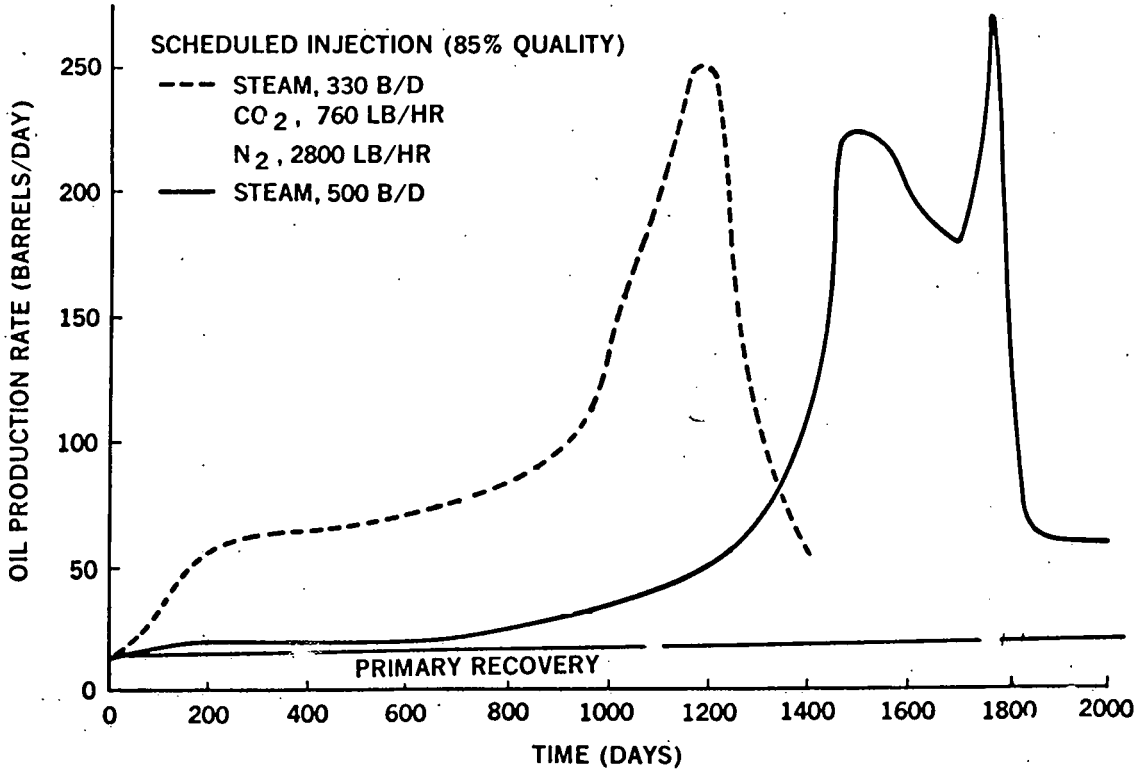
HEAT INPUT

SOURCE	%
COMBUSTION FUEL (676.8 LB/HR)	65.3
COMPRESSOR FUEL (360 LB/HR)	34.7
TOTAL (1036.85 LB/HR)	100

HEAT OUTPUT

	%	
COMBUSTION EXHAUST LOSS	0	
DIESEL ENGINE EXHAUST LOSS	4.9	
DIESEL COOLANT LOSS	7.1	
OTHER: DIESEL STRAY & PUMP WORK	0.8	
ABOVE GROUND TOTAL		12.8
WELL BORE LOSS	0.2	
INJECTED GAS (EXCLUSIVE OF STEAM)	5.6	
USEFUL HEAT (85% QUALITY STEAM)	81.4	
BELOW GROUND TOTAL		87.2
TOTAL		100

FIGURE 8. OIL PRODUCTION RATE VS TIME FOR STEAM DRIVE ALONE COMPARED TO STEAM WITH COMBUSTION GASES



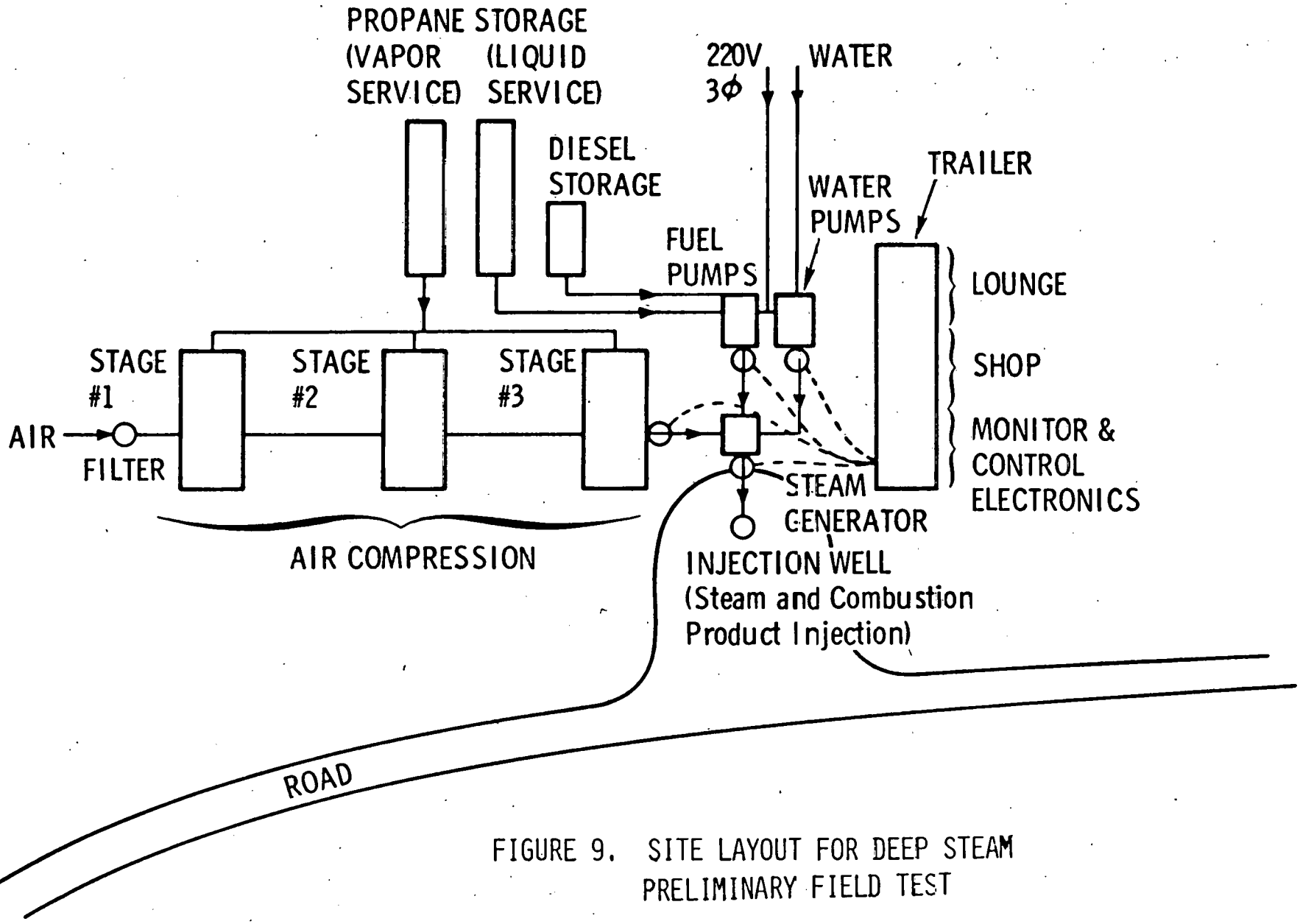


FIGURE 9. SITE LAYOUT FOR DEEP STEAM PRELIMINARY FIELD TEST

SCALE 1" = 20'

IN-SITU COMBUSTION STUDIES AT SUPRI

by

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OVERALL PROGRAM

The Stanford University Petroleum Research Institute (SUPRI) was established under the U.S. ERDA (now DOE) Grant No. E(04-3)1265 at Stanford, California in May, 1976. The main objective of SUPRI is to conduct research and development that will be useful for predicting and improving enhanced recovery of heavy oils. At present the research is in four major areas:

(I) Flow Property Research at High Temperatures
This project is designed to measure absolute and relative permeabilities to oil and water, capillary pressure and electrical resistivity as functions of pressure, temperature and fluid saturation.

(II) In-Situ Combustion Studies
This project is aimed at evaluating the parameters which affect the relative success of in-situ combustion field projects, and to design and operate a laboratory in-situ combustion tube apparatus for pertinent process parameters.

(III) Additives to Improve Steam Injection Efficiency
This project is aimed toward the design of equipment and testing of additives which will reduce the tendency for steam to channel in steam floods.

(IV) Well-to-Well Formation Evaluation
This project is aimed at methods to better define the reservoirs in which enhanced recovery methods are used through use of tracers, well logging and pressure interference tests.

(V) Field Support Services
In this project, the general information generated in the other four projects is applied to specific fields to aid in optimizing the total recovery and the total information generated in these fields.

It is not possible in a single paper to cover completely the effort in this entire program. For this reason we decided to concentrate on only one of the above projects; (II), In-Situ Combustion Studies. Those who are

interested in other facets of the program can find brief summaries of the work in the other projects in the quarterly DOE reports. Details are available from the SUPRI reports listed in those quarterly summaries. Some of these reports are available through the National Technical Information Service, U.S. Department of Commerce, Virginia 22161.

INTRODUCTION

In many heavy oil reservoirs, particularly in California, the most effective way to stimulate production is by the application of heat. Among the most important thermal recovery processes is either dry or wet forward combustion.

Describing the movement of heat and fluids analytically or numerically during the in-situ combustion process has been a subject of interest to numerous investigators.[1-5] Many results of both field tests and laboratory combustion tube studies have been reported.[6-13] However, there is no complete model which describes the movement of heat and fluids analytically. The steam plateau, heat and fluid movement ahead of the steam plateau, and the burning front itself have not been modelled in general.

The research conducted at the Petroleum Engineering Department of Stanford University, particularly at SUPRI (Stanford University Petroleum Research Institute) is directed toward study of these remaining parts of the in-situ combustion process.

In this study, the temperature distribution in the steam plateau portion of combustion tube experiments has been investigated and a mathematical model developed to describe nonisothermal fluid flow behavior in this region.[14] Also, the reaction kinetics occurring in the burning front zone have been under study. Besides these analytical studies, a numerical model has been developed that includes the thermal, thermodynamic, and hydrodynamic aspects of the process.[15] The model is capable of simulating the in-situ combustion process in a linear system. The computed temperature profiles match those obtained from laboratory studies.

Another research interest in the SUPRI laboratory is the investigation of the wet combustion process. To this end, we have already developed a numerical model that can handle a linear system. All experimental and mathematical results including the wet combustion model will be summarized below.

The continuing research on developing useful recovery correlations for dry in-situ combustion processes has resulted in a second improved correlation. The results of the first correlation have already been published in the literature. The second correlation and its application will also be discussed in the following summary.

EXPERIMENTAL STUDIES

There were two main purposes of the experimental phase of this study: (1) to develop a physical model permitting laboratory study of phenomena affecting field operations, and (2) to provide data to test analytical formulations for the steam plateau and the burning front, and also the numerical modelling of the in-situ combustion process. Furthermore, and more important, these models could be used to plan field applications and to interpret field data.

A total of six tube runs were performed in the SUPRI laboratory in 1978. A detailed discussion of the experimental equipment and the initial pack conditions can be found in reference 16. However, a summary of combustion tube results for each tube run is shown in Table 1.

STEAM PLATEAU STUDIES

During dry forward in-situ combustion, air is injected to burn a part of the in-place hydrocarbons. Combustion gas and a steam plateau ahead of the combustion front displace oil toward production wells. The heat is transferred ahead of the combustion front by the convection of combustion gases, by vaporization and recondensation of connate water, and by conduction.

In the combustion process, the steam plateau starts growing immediately after ignition takes place. Because the steam plateau plays an important role in the transportation of heat ahead of the burning front, it is important to obtain a reasonable estimate of the size and temperature of this plateau as a function of time. Gates and Ramey[17] have shown that oil recovery from forward combustion is much higher than would be expected based on burning front displacement alone. Study of the steam plateau may help explain this observation. Another significant value to having a mathematical model for the steam plateau is that it will help advance the analytical description of combustion tube studies when combined with Penberthy's model.[12]

A steam plateau is often observed in laboratory experiments as a flat temperature region ahead of the burning front. Laboratory combustion tube runs and numerical models indicate that steam, noncondensable gases, water, and oil exist in the steam plateau. The model described herein assumes steam and noncondensable gases flow, and mass transfer due to condensation of steam occurs to generate a water saturation. However, it is also assumed that water and oil are not mobile, although water and oil are considered for heat storage. Assuming a constant oil saturation in the steam plateau is in agreement with the experimental saturation-distance profile that was presented by Martin et al.[9] Actually, oil and water in the steam plateau move due to hot gas drive, steam drive, miscible phase displacement, gravity drainage, and pressure gradient; but for practical purposes, dynamic effects on the heat balance in the steam plateau can be neglected because latent heat is the dominant factor.

The entrance steam plateau temperature is nearly constant and can be related to the vapor fraction of the steam in the gas phase. That is, the steam plateau temperature is assumed to be under phase equilibrium control. Experimental results indicate that the steam concentration in the gas phase in the steam plateau is considerably higher than the amount of steam formed due to burning the hydrocarbon fuel. This is caused by the vaporization of connate water ahead of the burning front in the region between the burning front and the steam plateau.

The temperature in the steam plateau decreases due to pressure drop in the direction of flow. There are also heat losses from the steam plateau to the surroundings. Latent heat of condensation of steam compensates for the heat loss.

Important conclusions concerning steam plateau phenomena may be gained by the use of a simple heat-transfer model for the movement of hot fluids in a linear system. The problem to be considered involves heat transfer by convection, condensation, and heat loss. Heat transfer by conduction is neglected.

An energy balance equation written for a differential element in the steam plateau yields the following first-order nonlinear hyperbolic partial differential equation:

$$(\beta+\gamma T_D+\varepsilon T_D^2)\frac{\partial T_D}{\partial x'}+\frac{\partial T_D}{\partial t}=-\theta T_D \tag{1}$$

where:

$$\beta=\frac{u_g\rho_g}{\rho_l C_l}\left[C_g+c'(T_a')^2\right]-v_{sp} \tag{2}$$

$$\gamma=\frac{u_g\rho_g}{\rho_l C_l}\left[4c'T_a'(T_i-T_e)\right] \tag{3}$$

$$\varepsilon=\frac{u_g\rho_g}{\rho_l C_l}\left[3c'(T_i-T_e)^2\right] \tag{4}$$

$$\theta=\frac{2U}{r\rho_l C_l} \tag{5}$$

$$c'=\alpha\left((C_w-C_g)+\frac{L_v}{(T_i-T_e)}\right) \tag{6}$$

$$T'_a = T_a + T_e \tag{7}$$

$$T_D = \frac{T-T_e}{T_i-T_e} \tag{8}$$

$$\alpha = \frac{R}{pM_g L'_v} \frac{dp_v}{dT'} \text{ , a constant for the conditions assumed} \tag{9}$$

$$T' = T + T_a \tag{10}$$

$$x' = x - v_{sp}\, t \tag{11}$$

Applying the method of characteristics solution yields the pair of ordinary differential equations:

$$T_D = \exp(-\theta t) \tag{12}$$

$$x' = \beta t + \frac{\gamma}{\theta} [1-\exp(-\theta t)] + \frac{\varepsilon}{2\theta} [1-\exp(-2\theta t)] \tag{13}$$

Equations 12 and 13 yield temperature as a function of time and location for a fictitious particle moving into the steam plateau starting with a temperature $T_i = x' = 0$.

Figure 1 shows an example of calculated temperatures in the steam plateau at various times for Run 78-2. The agreement is reasonably close to the experimental results. The analytical solution indicates a larger size for the steam plateau. This is essentially because the analytical steam plateau with a sharp front moves as an idealized step function temperature profile. The movement of a steam plateau with a sharp front is mainly a result of neglecting heat transport by conduction. At the present time, the effects of conduction and the unsteady state heat loss to the surrounding on the steam plateau have also been studied. A modified energy balance equation including heat transfer by conduction in the linear direction and heat loss expressed by an unsteady state overall heat transfer coefficient[18] has been written and solved numerically.

NUMERICAL MODELLING OF THE IN-SITU COMBUSTION PROCESS

A companion effort to this work was devoted to development of a numerical model to simulate the combustion tube behavior. Details of the model are presented in reference 15, and will not be given here. Instead, we briefly mention the essentials and present some qualitative comparisons with laboratory results.

We consider a one-dimensional, homogeneous, porous system analogous to a laboratory combustion tube in which oil, water and its vapor, and air exist in thermodynamic and hydrodynamic equilibrium under given initial conditions of temperature and pressure. Air is injected into the system at one end at a given rate, while maintaining a fixed back-pressure at the other end. Fuel is ignited using a heater at the inlet end for a specified time. Heat is also generated within the system by direct burning of oil. An Arrhenius-type equation is used to represent the kinetic reaction. Heat is transported by conduction, convection, and vaporization and condensation. Heat is lost to the surroundings by convection.

The model deals basically with a three-phase flow system: oil, water, and gas. The gas phase consists of three components: inert gas, oxygen, and water vapor.

Heat and fluid flow are controlled by the rock and fluid physical and thermal properties. These properties are functions of pressure, temperature, and fluid relative saturation.

Mass balance equations are required for each flowing phase. Gas is considered to be a mixture of inert gas, oxygen, and water vapor. The term "inert gas" is used to include nitrogen, carbon dioxide, and carbon monoxide. A separate mass balance equation is developed for the water phase (both liquid water and steam). This approach eliminated the need to calculate the amount and direction of water phase change at every cell. If separate material balance equations are written for water and steam, more numerical iterations and possibly a smaller time step would be needed.

The formulation in this study has tied the water phase change directly to the dependent variables. Hence equilibrium must exist at each iteration. In this aspect, the subject model has an advantage over the Gottfried[3] model. Also, this could be a reason why his model needed a very small time step (0.01 hr) and required a large number of iterations.

The material balance equation for oxygen was determined by oxygen concentration, injection/production, and chemical reaction.

$$\frac{\partial}{\partial t}(\phi S_g \rho_g y_1) = \frac{\partial}{\partial x}\left(\frac{k k_{rg}}{\mu_g} \rho_g y_1 \frac{\partial p}{\partial x}\right) + q_1 - S_1 \gamma \qquad (14)$$

In similar fashion, the material balance equation for the inert gas is:

$$\frac{\partial}{\partial t}\left(\phi S_g \rho_g y_2\right) = \frac{\partial}{\partial x}\left(\frac{kk_{rg}}{\mu_g}\rho_g y_2 \frac{\partial p}{\partial x}\right) + q_2 + S_2\gamma \qquad (15)$$

The water conservation equation is developed, as mentioned previously, for the chemical constituent water, and its presence is considered in both the gas and liquid water phases.

$$\frac{\partial}{\partial t}\left[\phi(S_g\rho_g y_3 + S_w\rho_w)\right] = \frac{\partial}{\partial x}\left(\left(\frac{kk_{rg}}{\mu_g}\rho_g y_3 + \frac{kk_{rw}}{\mu_w}\rho_w\right)\frac{\partial p}{\partial x}\right) + S_3\gamma \qquad (16)$$

The material balance for oil is:

$$\frac{\partial}{\partial t}\left(\phi S_o \rho_o\right) = \frac{\partial}{\partial x}\left(\frac{kk_{ro}}{\mu_o}\rho_o \frac{\partial p}{\partial x}\right) - \gamma_A \qquad (17)$$

The energy balance equation has been developed in terms of enthalpy for different components, rather than temperature, making the formulation more capable of handling the sharp temperature gradient usually found in in-situ combustion processes.

The kinetic and potential energy effects have been neglected, as has viscous energy dissipation. Also, the pressure-volume terms needed in the accumulation terms (the left hand side) have been neglected.

$$\frac{\partial}{\partial t}\left\{\phi\left[S_w\rho_w h_w + S_o\rho_o h_o + S_g\rho_g(y_1h_1+y_2h_2+y_3h_3)\right] + (1-\phi)\,(\rho C_P)_R\, T\right\}$$

$$= \frac{\partial}{\partial x}\left\{\left[\frac{kk_{rw}}{\mu_w}\rho_w h_w + \frac{kk_{ro}}{\mu_o}\rho_o h_o + \frac{kk_{rg}}{\mu_g}\rho_g(y_1h_1+y_2h_2+y_3h_3)\right]\frac{\partial p}{\partial x}\right\}$$

$$+ \frac{\partial}{\partial x}\left(K\frac{\partial T}{\partial x}\right) + H_A\gamma_A \qquad (18)$$

Saturation and composition constraints are the following:

$$S_g + S_w + S_o = 1 \tag{19}$$

$$y_1 + y_2 + y_3 = 1 \tag{20}$$

As a result of the complexity of the problem and the nonlinear dependence of the equation coefficients on pressure and temperature, we have solved the problem using an iterative, fully implicit, simultaneous solution technique. Furthermore, the finite difference is set up so that the dependent variables used are the changes or increments over the time step rather than the total values. We believe this method reduces numerical oscillation. Consequently, it permits use of a larger time step without loss of accuracy.

In Figure 2, some typical temperature distributions as computed by the model at various times are shown. The qualitative similarity between actual experimental data, Figure 1, and temperature distributions computed by the model, Figure 2, is apparent.

Figure 3 shows the computed water saturation as a function of distance and time. Here, water saturation includes initial water plus condensed steam. As shown in this figure, water saturation rises above its initial value and forms a bank between the primary and secondary oil banks.

Oil saturation distributions at various times are shown in Figure 4. The most important characteristic is a double peak in oil saturation. It is not clear that this double saturation peak will really occur in an actual laboratory run. This apparent behavior depends strongly on the nature of the relative permeability curves, and data is sparse for relative permeabilities under these conditions. The double peaks in oil saturation are consistent with the relative permeabilities used, and are not caused by numerical error.

The model has been compared with known numerical and experimental data. It compares favorably in both cases.

MATHEMATICAL MODEL FOR WET IN-SITU COMBUSTION PROCESS

The model describes one-dimensional linear flow with conductive heat loss to the surrounding media for computing the temperature distribution for two-phase flow in a porous medium during a dry or wet in-situ combustion process. The proposed model allows computing the temperature profile within the reservoir at any time, vertical heat loss, and the expansion of the steam plateau. This model describes such thermal methods as hot or cold water

injection, steam injection, and dry or partially quenched combustion.

The following assumptions were made to develop the model:

1) reservoir pressure is constant and equal to the injection pressure,
2) the total injection rate of gas and water (steam) into the reservoir is known,
3) oxygen reactions take place only at the linear combustion front, $x - x_f$, and
4) water vapor partial pressure in the gas phase is equal to the equilibrium vapor pressure.

According to these assumptions, the energy balance equation can be written as follows:

$$K_{res}\frac{\partial^2 T}{\partial x^2} - \frac{\partial H}{\partial x} - Q_{LOSS} + g_{gas}N_o G\cdot\delta(x-x_f) = (C\rho)_{res}\frac{\partial T}{\partial t} \qquad (21)$$

The function H is defined as:

$$H = \begin{cases} g_{gas}C_{gas}T + g_w^* C_w T + g_s E_s, & T \leq T_{SAT} \\ g_{gas}C_{gas}T + g_w E_s + g_w C_S(T-T_{SAT}), & T > T_{SAT} \end{cases} \qquad (22)$$

where: T_{SAT} = temperature of evaporation of all injected water

g_w = water mass influx

g_{gas} = gas mass influx

g_s = steam mass flow rate at x-coordinate

$g_w^* = g_w - g_s$ = water mass flow rate at x-coordinate

Equation 21, with the H-function defined in Equation 22, is a highly nonlinear equation, and can only be solved numerically. To make the results more useful, we convert Equation 21 into dimensionless form by using new variables:

$$x_D = x/H_{res} \qquad (23)$$

$$t_D = K_{res}t/[(C\rho)_{res}H_{res}^2] \qquad (24)$$

$$T_D = (T-T_{in})/T_{SAT} \tag{25}$$

$$H_D = H[H_{res}/(K_{res}\cdot T_{SAT})] \tag{26}$$

$$\gamma = g_{gas}\, N_o\, G\, H_{res}/(K_{res}\cdot T_{SAT}) \tag{27}$$

In dimensionless form, the system of equations can be written as follows:

$$\frac{\partial^2 T_D}{\partial x_D^2} - \frac{\partial H_D}{\partial x_D} - Q_{D_{LOSS}} + \gamma\delta(x_D - x_{fD}) = \frac{\partial T_D}{\partial t_D} \tag{28}$$

$$\left.\begin{aligned} T_D(0,t_D) &= T_{D_{inj}} && (29)\\ T_D(x_D,0) &= 0 && (30)\\ \lim_{x_D\to\infty} T_D(x_D,t_D) &= 0 && (31)\end{aligned}\right\}$$

where

$$x_f = \frac{g_{gas} N_o w}{z_{fuel}} \cdot t \tag{32}$$

or in dimensionless form:

$$x_{fD} = \alpha \cdot t_D \tag{33}$$

where:

$$\alpha = \frac{g_{gas} N_o w (C\rho)_{res} \cdot H_{res}}{z_{fuel} \cdot K_{res}} \tag{34}$$

w = oxygen/fuel ratio

z_{fuel} = fuel content in a unit of pore volume

Equation 28 is solved numerically by using an explicit-implicit finite difference scheme: a two time-level explicit difference scheme for Equation 28 and a fully implicit scheme for describing heat loss $Q_{D_{LOSS}}$ in a vertical direction.

Several runs were made for different cases of an in-situ combustion process as an example of using the mathematical model described herein. On Fig. 5 there is a temperature distribution computed according to the subject model. On Fig. 6 an example of temperature profiles during the "wet" combustion process is shown. As can be seen in Fig. 5, results in the steam plateau region appear more realistic than those predicted in the analytic model. New work presently underway will emphasize improvement of both the steam plateau and combustion burning zone modelling.

REACTION KINETICS OF IN-SITU COMBUSTION

A knowledge of the kinetic data for various reactions involved is imperative for making meaningful predictions of the effectiveness of an in-situ combustion project. A limited number of studies has been carried out to investigate this area.[10,11,19] Thomas et al.[20] recently presented a rather detailed study of the kinetics of in-situ combustion. However, they could not elucidate the effects of several factors, such as low temperature oxidation reactions, surface area, or clay content on reaction rates. Also, their results were based on a limited number of experiments.

Thus, because of the present scarcity of applicable data in the current literature, and also to provide a better understanding of the reactions occurring at the combustion front, it is necessary to undertake new laboratory studies.

As a high temperature combustion front approaches a volume element in a porous media, water and some light hydrocarbons are stripped off by gas flow and distillation. Then the temperature increases more rapidly, causing more evaporation of oil, until the temperature exceeds about 600°F. At high temperatures the residual oil cracks into a volatile fraction (which flows downstream) and a nonvolatile residue consisting of coke, tar, and pitch. The oxidation of the deposited residue generates the heat energy for the process. Part of the flowing oxygen escapes the combustion front and oxidizes the downstream oil (low temperature oxidation). It has been found that these phenomena interact to affect the amount of fuel deposition.

Experiments are underway at SUPRI to determine:

1) which reactions are dominant in this process,

2) whether the steps in these reactions are chemically controlled or whether the diffusional steps are rate controlling, and

3) what the appropriate reaction rate constants are (energy of activation, reaction order, pre-exponential factor).

The ultimate goal will be to correlate these data with the crude oil properties to find a generalized method of forecasting the success or failure of any in-situ combustion process.

RECOVERY CORRELATIONS FOR IN-SITU COMBUSTION FIELD PROJECTS

Oil recovery predictions for in-situ combustion projects are needed for simple engineering calculations. The first recovery correlation developed for dry in-situ combustion field projects was already discussed in detail in refs. 8, 16, and 21. For the convenience of the reader, the first correlation is shown in Fig. 6.

This section presents the results of extensions and improvements made on that correlation work and it describes a second correlation developed to predict the fieldwide oil recovery of dry in-situ combustion processes. The new correlation is based on the same combination of an engineering and a statistical approach used for the first one, but it more accurately predicts oil recovery for fields. The parameters that appeared promising from heat and material balance analysis were included to reach the first step for correlation. Then multiple linear regression analysis was used to include those variables judged to be important for the second and final step.

The first correlation has a linear relationship between recovery and oil viscosity, with a negative coefficient. Thus we predict a lower recovery for a high viscosity reservoir. Although this is qualitatively correct, if one used the correlation to predict recovery from a reservoir with an oil viscosity of several thousand centipoises, the prediction would be unrealistically low. It might even be negative!

Because of this unrealistic prediction at a high oil viscosity, it appeared that the viscosity ought to be handled in some other fashion than it is in Fig. 7. Oil viscosity was thoroughly investigated as an independent variable by multiple regression analysis. The reciprocal of viscosity was tried and also the logarithm of viscosity, but these ideas did not improve the correlation. Then we considered that the effect of viscosity should be according to some power less than one. The reason for this is that combustion is primarily a method of getting heat to the reservoir, and the viscosity of a crude is not linear with temperature.

These concepts led to study of the reciprocal of viscosity to a power less than one as a correlating factor. The results showed that a power of 0.25 fit the data best. Also, in the development of the second correlation, the oil in place at the start of the combustion process rather than original oil in place was used to normalize the ordinate in the correlation. This seemed logical, since a few fields exhibited considerable recovery prior to the onset of combustion, and we would expect the recovery to depend on the amount of oil in place at the time combustion was initiated.

The resulting correlation equation with $(1/\mu_o)^{0.25}$ as an independent variable was:

$$\frac{y}{47.00} = \left[0.427S_o - 0.00135h + 2.196 \left(\frac{1}{\mu_o}\right)^{0.25} \right] X \qquad (35)$$

where

$$y(\%) = \frac{CIOP+FB}{OIP} \times 100 \tag{36}$$

and

$$X\left[\frac{MSCF}{bbl}\right] = \frac{CAI \times (O_2\ Ut.)}{(OIP/\phi S_o)(1-\phi)} \tag{37}$$

Figure 8 shows the actual values of the recovery function (y) versus the values on the right-hand side of Eq. 35 for each of the 12 fields for which complete data were available. The scatter is ±14% in the latter portion of the field results where the abscissa is 0.20. As was done for the first correlation, a smooth curve was drawn through the data of Fig. 8. This curve can be used as a general recovery correlation curve, and is shown in Fig. 9. The results at the same air injection values indicate that the new correlation has a standard deviation of 9% with a maximum error of 14%, compared to a standard deviation of 17% with a maximum error of 21% for the first correlation. Thus it is clear that this correlation fits the field results considerably better than does the first correlation.

The use of the second correlation is also restricted. If any parameters are outside of the range of data used to develop this correlation, the results could be in error. The ranges of S_o, μ_o, and h used were the same as given earlier. However, the effect of the viscosity is different for this correlation. If one used the correlation to predict recovery for an oil with a viscosity smaller than ten centipoises, the prediction could well be unrealistically high.

There are two basic differences between the two correlations in Figs. 7 and 9: (1) for the correlation in Fig. 7, the dependent variable y represents the incremental oil recovery per original oil in place, and for Eq. 35, the variable y represents the incremental oil recovery per oil in place at the start of the combustion process; and (2) the first equation uses oil viscosity, μ_o, to the first power as one of the three independent variables, while Eq. 35 uses $(1/\mu_o)^{0.25}$. Because of these two differences in the correlations, the user should prefer to use one or the other of them depending on the values of the correlating parameters used in the recovery prediction, and depending on the recovery history of the field: (1) whenever the oil viscosity is 10 cp or smaller, the first correlation, Fig. 7, should be used; (2) whenever the oil viscosity is 700 cp or higher, the second correlation, Fig. 9, should be applied; (3) whenever there has been considerable recovery prior to the onset of in-situ combustion, the second correlation should be preferable to the first one. In general, it appears that for most applications, the second correlation will be the better one to use.

As a part of the study, the second correlation was applied to pilot dry in-situ combustion projects. There were five pilot projects available for the application. Fig. 10 shows the oil recovery - air injection histories of the pilot projects as compared to the second correlation. This figure leads to the conclusion that the correlation parameters used

for fieldwide projects appear to be reasonable as correlating parameters for dry pilot projects. As expected, the study of the pilot tests indicated that air injection and/or oil migration losses are important factors affecting the recovery mechanisms of a pilot project. Thus in pilot projects, for the same air injection, the recovery is somewhat less than found in fieldwide cases.

CONCLUDING REMARKS

It is clear that this is a continuing research effort and further results will be forthcoming. Also the reader should bear in mind that the work reported herein is only one phase of the total work program at SUPRI. However, the work reported here has resulted in a number of useful results, as follows:

(1) The combustion tube laboratory apparatus is performing well. It is generating data which is of great value as input for the modelling effort reported here. In addition, combustion tube runs can be made on request for any specific reservoir systems of interest to DOE and the industry.

(2) An analytic model of the steam plateau has been formulated and solved using the method of characteristics. The model produces a satisfactory fit of combustion tube data.

(3) A one-dimensional numerical model of the dry combustion process has been developed which compares favorably with known numerical and experimental data and which runs faster than previous numerical models.

(4) Another one-dimensional numerical model has been formulated which can include the injection of water along with air and which includes conductive heat loss to the surrounding media. Preliminary runs indicate the model produces more realistic results than do the analytic formulations.

(5) At present, studies of the reaction kinetics of the combustion process are underway. At this time, it is too early to have definitive results from this work, but we expect to be able to report specific results at this meeting next year.

(6) A recovery correlation for dry in-situ combustion field projects was discussed last year. Since then we have improved the correlation markedly. Further, we have tested these same correlating parameters against pilot test results, and they also appear to correlate the pilot data satisfactorily.

MENCLATURE

C_p = specific heat on a mass basis, Btu/(lb-°F)

h_g = enthalpy of gas phase, Btu/(lb mole)

h_o = enthalpy of the oil phase, Btu/(lb mole)

h_w = enthalpy of the water phase, Btu/(lb mole)

H_A = heat of reaction for the oil oxidation, Btu/(lb mole)

k = absolute permeability, md

k_{r_g} = relative permeability to gas

K_T = thermal conductivity of the formation, Btu/(hr-ft-°F)

L_v = latent heat of vaporization, Btu/lb

L'_v = latent heat of vaporization, (psi-cu ft)/lb

M_g = molecular weight of the steam-noncondensable gas mixture, lb/lb mole

p = injection pressure, psi

p_v = vapor pressure for steam, psi

q_i = injection rate of component i, lb mole/(day-cu ft)

r = radius of the combustion tube, ft

R = gas constant, (psi-cu ft)/(lb mole-°F)

S = saturation, fraction

S_i = stoichiometric ratio

t = time, hr

t_{ign} = time spent for ignition, hr

T = temperature, °F

T_a = absolute temperature, °F

T_D = dimensionless temperature, °F

T_e = elevated pack temperature, °F

T_i = temperature at the beginning of the steam plateau, °F

T'_a = sum of absolute temperature and elevated pack temperature, °F

u_g = air flux at steam plateau, scf/(hr-sq ft)

U = overall heat transfer coefficient, through annular insulation based on radius of combustion tube, Btu/(hr-sq ft-°F)

v_{sp} = velocity of the beginning of the steam plateau, ft/hr

x = distance, ft

Nomenclature, continued

x' = distance from the beginning of the steam plateau, ft

y_i = mole fraction of component i in the gas phase, i - 1, ..., t

Greek

ϕ = porosity, fraction

ρ_g = density of the steam-noncondensable gas mixture, lb/cu ft

μ_o = oil viscosity, cp

$c', \alpha, \beta, \gamma, \varepsilon, \theta$ = constant parameters defined in Eqs. 6, 9, 2-5

Subscripts

a = absolute

e = elevated

f = formation

g = gas

i = initial

o = oil

s = steam

x = x-direction

w = water

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TABLE 1

SUMMARY OF COMBUSTION TUBE RESULTS

	TUBE RUN NUMBER					
	78-1	78-2	78-3	78-4	78-5	78-6
Injected Air Flux, lit/hr	115	123	156	120	167	165
Injection Pressure, psig	100	100	100	100	100	200
Burning Front Velocity, cm/hr	11.8	10.2	10.8	7.2-12.3	13.0	15.4
Steam Plateau Velocity, cm/hr	16.9	16.5	11.3	---	13.5	15.7
Produced Gas Analysis, Vol. %						
Carbon Dioxide	10.8	10.6	12.5	14.7	14.5	12.9
Carbon Monoxide	1.5	6.1	4.7	3.5	5.2	5.2
Oxygen	4.4	3.7	1.1	1.9	1.4	2.3
Nitrogen	82.3	78.7	80.7	78.8	78.9	78.4
Atomic H/C Ratio of Fuel	1.9	0.86	1.29	0.66	0.67	0.68
Fuel Concentration, lb/ft^3 Bulk Vol.	1.07	1.53	1.44	2.22	1.87	1.39
Air-fuel Ratio, scf/lb	232	117.5	199.3	168.5	162.5	164.0
Air-sand Ratio, mmscf/ac-ft	10.7	11.7	10.7	16.3	12.8	9.9

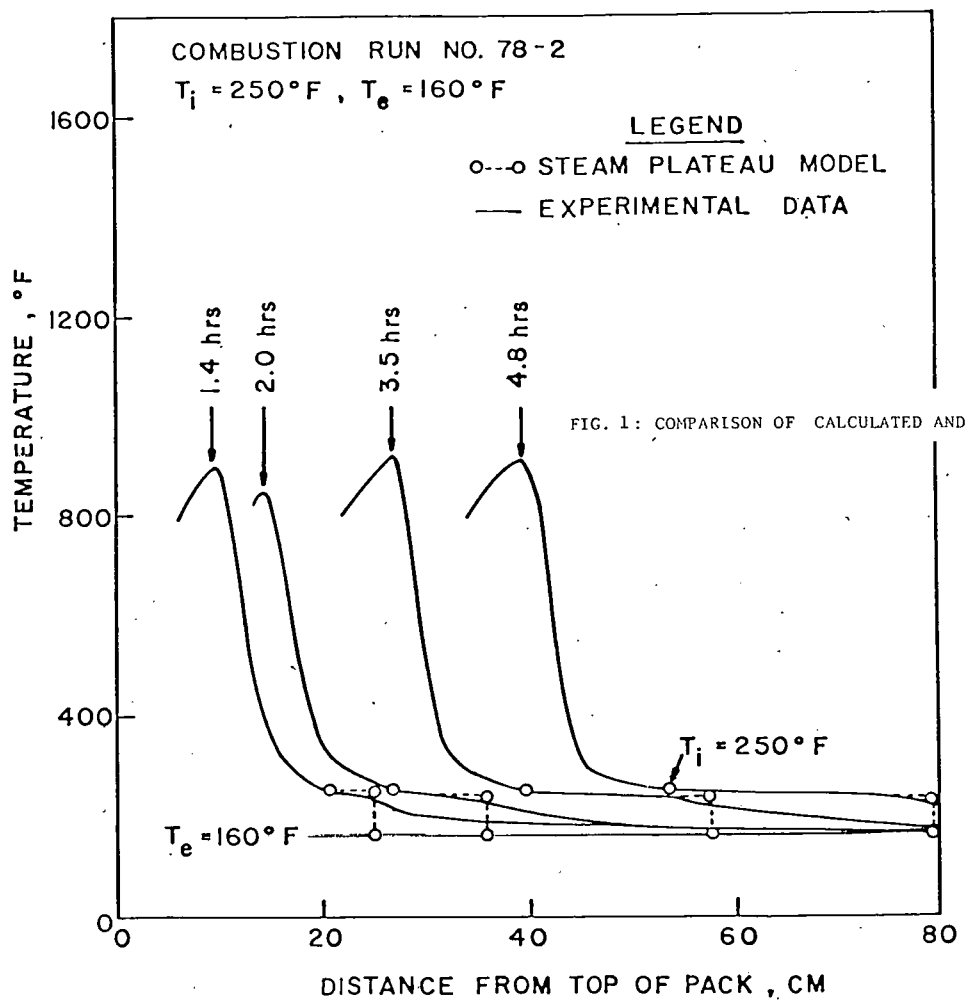


FIG. 1: COMPARISON OF CALCULATED AND EXPERIMENTAL RESULTS FOR RUN 78-2

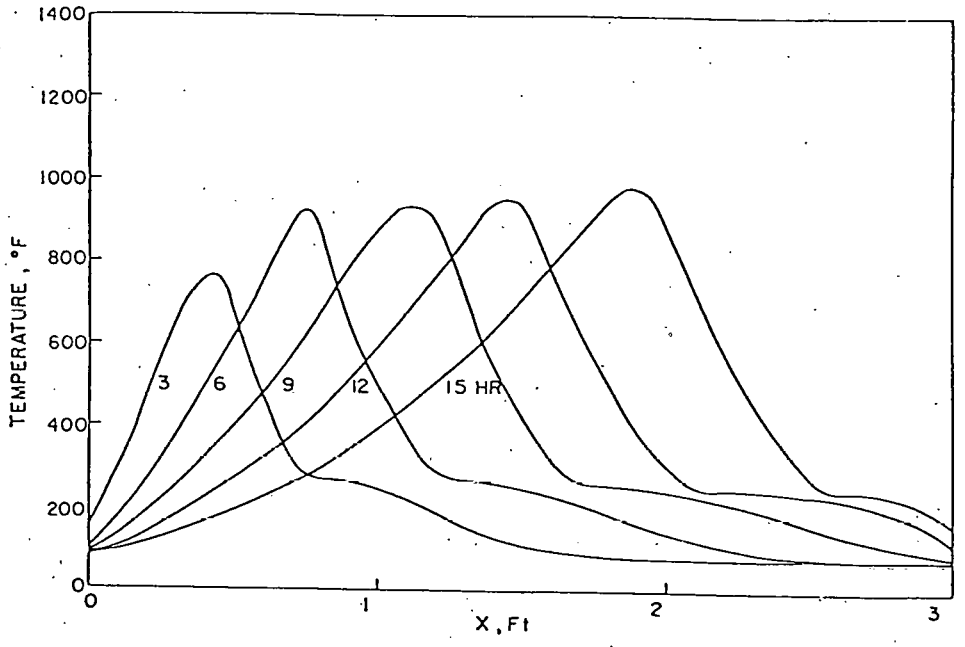


FIGURE 2 - COMPUTED DRY FORWARD COMBUSTION TEMPERATURE PROFILES

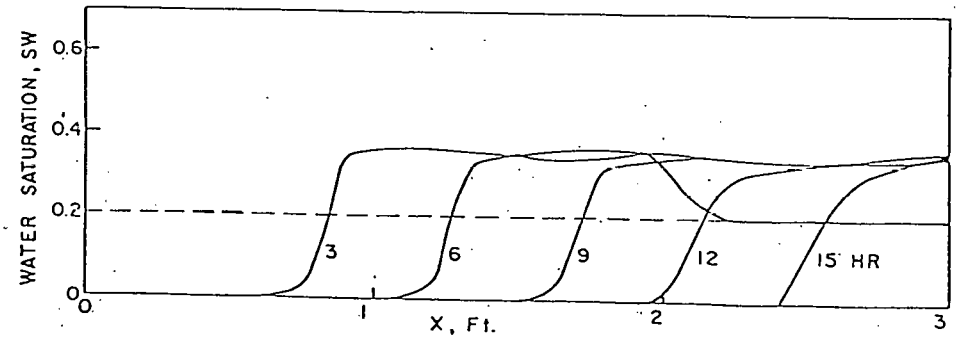


FIGURE 3 - COMPUTED DRY FORWARD COMBUSTION WATER SATURATION PROFILES

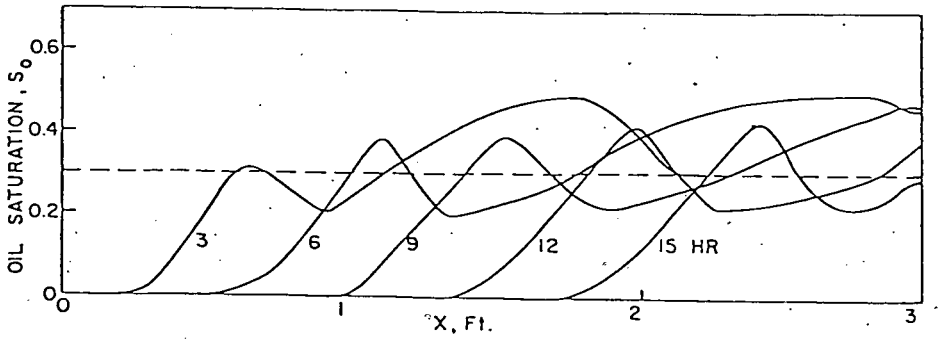


FIGURE 4 - COMPUTED DRY FORWARD COMBUSTION OIL SATURATION PROFILES

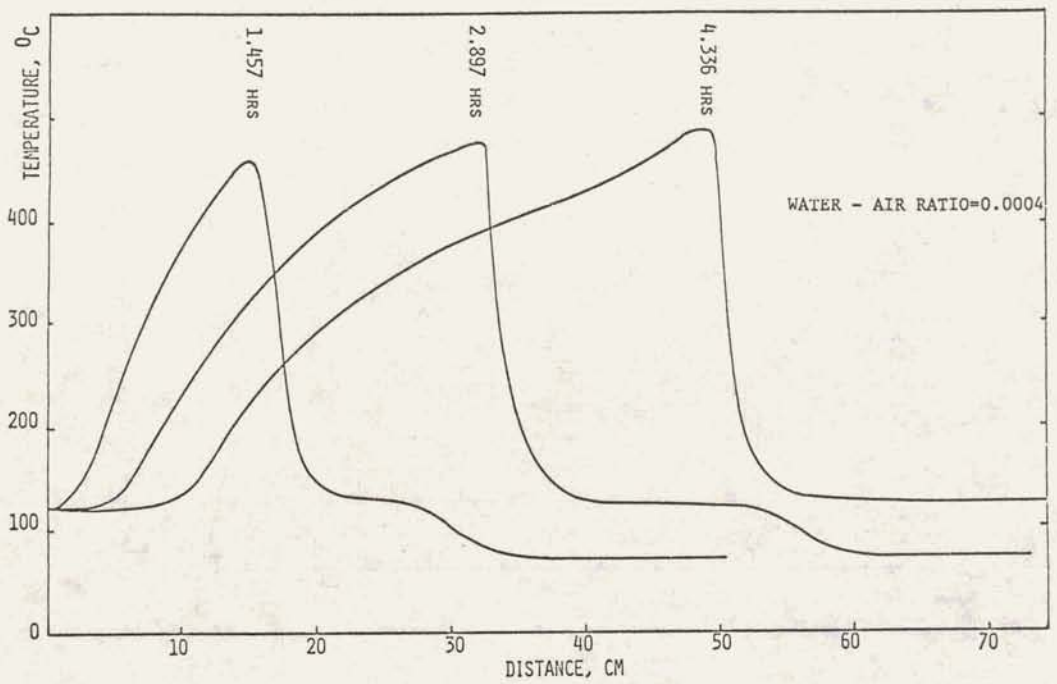


FIG. 5 - COMPUTED DRY FORWARD COMBUSTION TEMPERATURE PROFILE

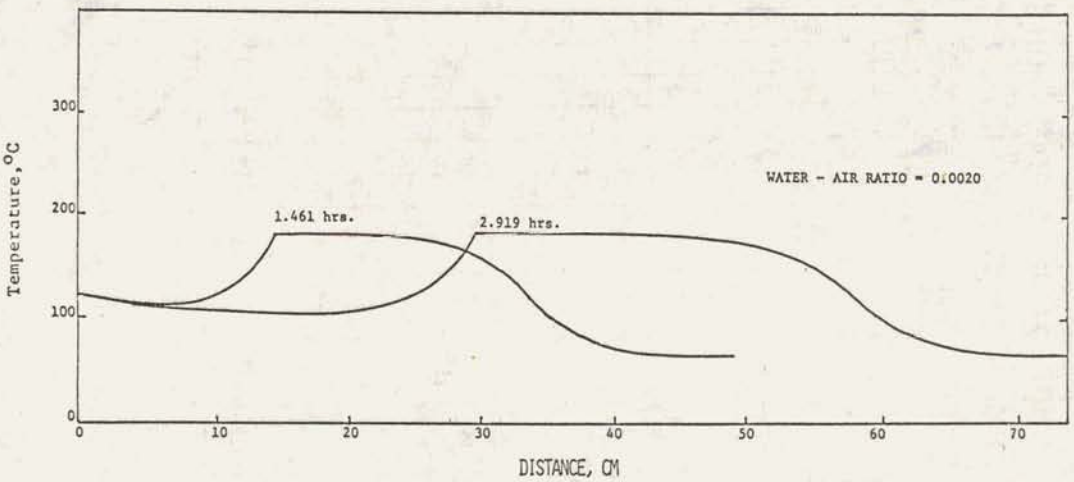


FIG. 6 - COMPUTED WET FORWARD COMBUSTION TEMPERATURE PROFILE

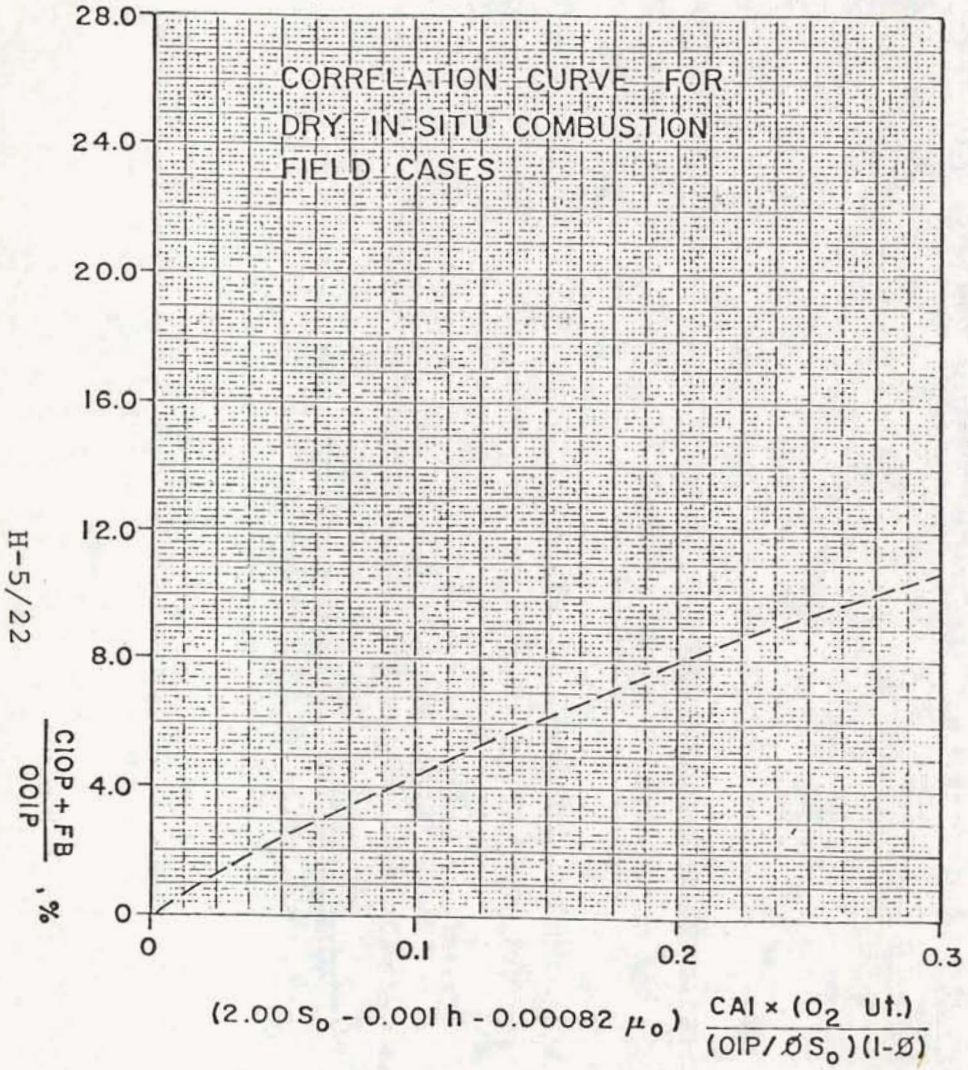


FIG. 7 : FIRST CORRELATION CURVE

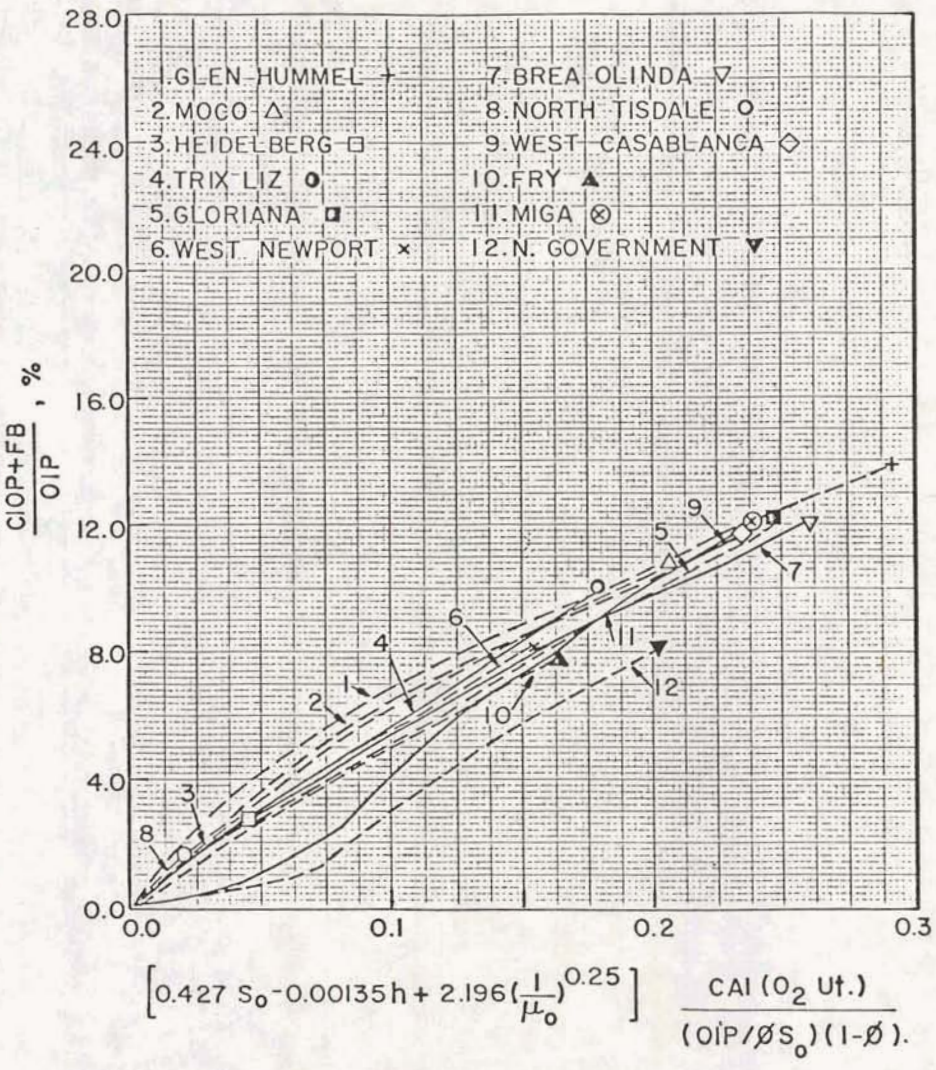


FIG. 8 : DATA FOR THE SECOND CORRELATION

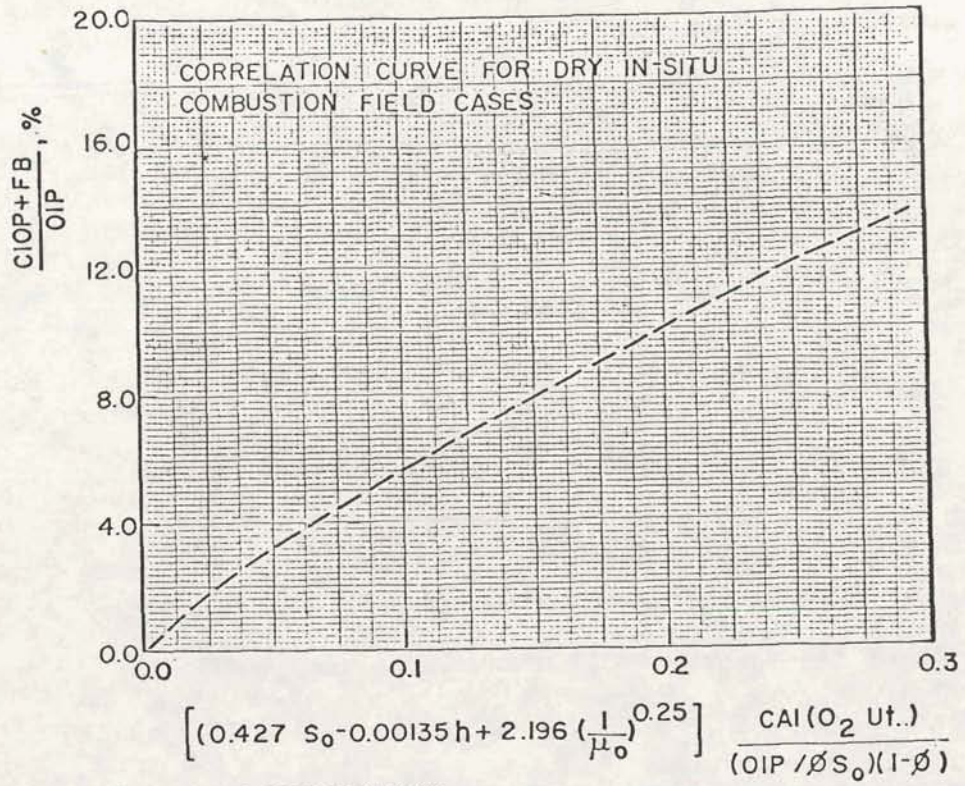


FIG. 9 : SECOND CORRELATION CURVE

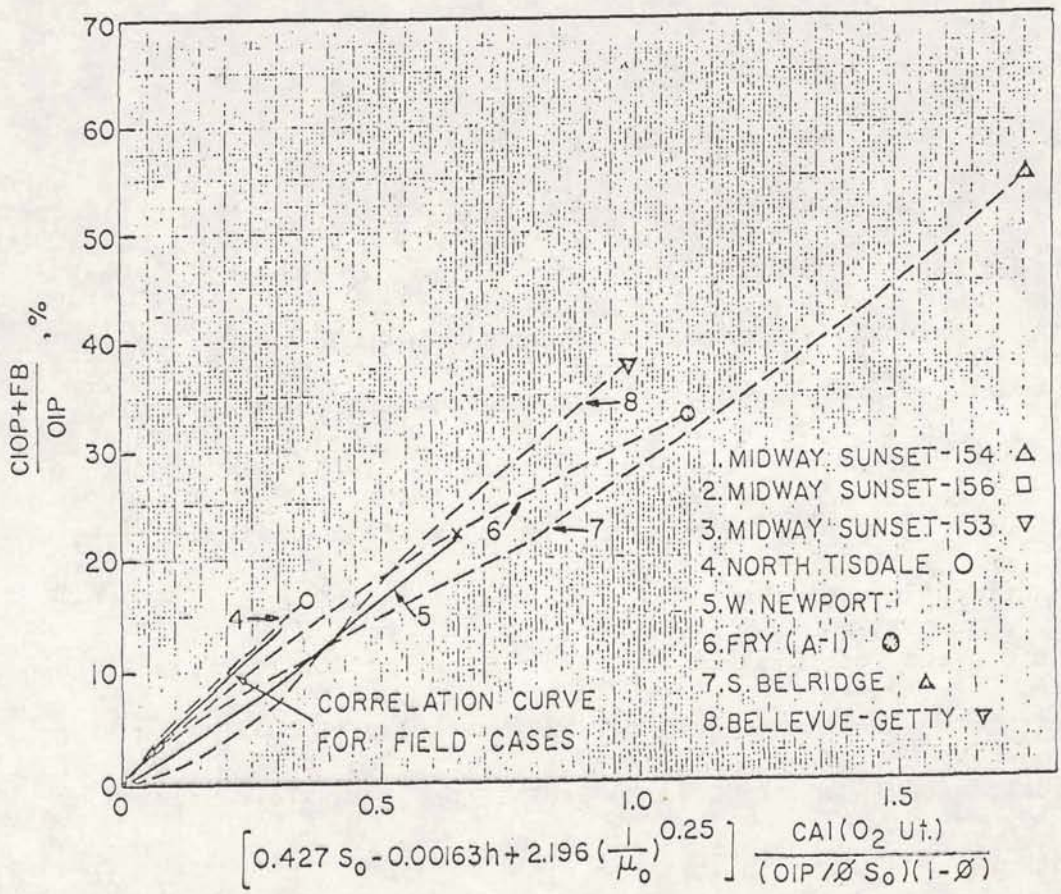


FIG. 10: APPLICATION OF THE SECOND CORRELATION TO PILOT DRY COMBUSTION TESTS

PHYSICALLY SCALED MODEL OF STEAM DRIVE OPERATIONS

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I. INTRODUCTION

The Department of Energy's San Francisco Operations Office has supported a project since September 1977 on the design and operation of scaled physical models of steam injection operations.

The design and construction of the models has borrowed heavily from prior studies of the theory of dimensionally scaled models for petroleum reservoir presented in 1955 by Geerstma, et al. (1), and of models that were designed specifically for steam displacement operations by workers at Shell Development Co. (2), and at the Rijswick Laboratories of KSEPL.

The goals of the work were several: One was to assist in the training and education of graduate students majoring in petroleum engineering in the reservoir behavior of steam drive operations. A second goal was to construct a physically scaled model system which could be used, as desired, by the regional industry for specific problems encountered in commercial application of the steam drive. Finally, to provide the department of petroleum engineering with a facility to conduct research into novel modifications of the steam drive operation which might further improve the efficiency of this already powerful and proven recovery technique.

The first two goals have been met by the spring of 1979. The first physically scaled models constructed under this program were completed by graduate students whose acquaintance with steam drive operations comprised a graduate course in thermal recovery techniques. Their knowledge of scaled

models was derived from seminars and the available literature, and telephone conversations and visits with Dr. Stegamier and Mr. Volek of Shell Development Co. and Shell Oil Co., respectively.

The first working model was fairly unreliable, and few runs could be completed without the need for emergency repairs which frequently invalidated the results. After some 12 months, a run could be reliably completed and it is the resulting model, Fig. 1, and model runs made with it that proved to the students that indeed field performance as represented in the literature could be fairly well approximated in the laboratory.

Continued study of the operation of the model led to the design and construction of a neater, streamlined, highly reliable system which has just been completed and will be described in the annual report for the year ending September 15.

Meanwhile many regional operators have visited to examine the model and its operation, and the Husky Oil Company and the Instituto Technologico Venezolana del Petroleo, INTEVEP, have joined the DOE in supporting studies on such work at the University.

The current research effort is a study of the effect of steam velocity on recovery and oil steam ratio, and project plans call for the study of additions of non-condensible gases to the steam, the use of condensing solvents in lieu of steam, and the conceptual effect of foams on recovery efficiency.

It is the purpose of this paper to present some of basic premises of physically scaled models for steam injection operations, to describe some of the fundamental calculations used in establishing the proper scaling, and to present some of the early results obtained in the program.

II. A Precis of the Basis of Physical Scaling

A laboratory study of fluid flow in porous media can be made to be truly representative of the prototype behavior if the laboratory experiment is physically scaled. If the laboratory experiment is not properly scaled, then at the best the laboratory model may be representative of only a small segment of the prototype.

Proper scaling starts with choosing the desired ratio of model dimensions to prototype dimensions. Then, the parameters that are known or believed to affect the process being studied are listed, and are grouped together as they occur in the equations which control the flow of fluids (and of heat for a process, such as steam drive, which involves such flow).

Such groups are then reduced to a dimensionless form by multiplying them or dividing them by a characteristic parameter of the system, viz., length, or time, or heat capacity, etc.

For example, the linear velocity of fluids through the reservoir are certainly expected to be of importance in any fluid displacement process; therefore a group of parameters characterizing linear velocity, as expected, is revealed to be an important non-dimensional coefficient of equations describing fluid flow:

$$\left[\frac{k_R P_R}{(\phi \Delta S)_R \mu_R L_R}\right]\left[\frac{t_R}{L_R}\right]$$

Linear fluid velocity, denoted by the term in the first parenthesis, has been non-dimensionalized by multiplication by (t_R/L_R), the ratio of some characteristic

time and length that pertains to the system being studied, e.g., the time during which steam is injected, and the thickness of the reservoir. The resulting dimensionless group is known as the Poiseuille Number.

Longitudinal flow, characterized by the Poiseuille Number, however, can be expected to interact with a dimensionless group that characterizes vertical flow, i.e., the Stokes Number:

$$\left[\frac{k_R \Delta \rho_R g_R}{(\phi \Delta S)_R \mu_R}\right]\left[\frac{t_R}{L_R}\right]$$

in which the gravity gradient has replaced the viscous gradient in the Poiseuille Number.

The ratio of the two, Poiseuille Number to Stokes Number, known to be a significant factor in affecting fluid flow and displacement, is again revealed to be a nondimensional coeffient in fluid flow equations. Therefore, in a properly scaled laboratory model the ratio of the Poiseuille Number to the Stokes Number should have the same value as the ratio of the two in the prototype.

The ratio of the two is:

$$\frac{p_R}{\Delta \rho_R g_R L_R}$$

Since g is identical in both model and prototype, and the difference in densities of the key fluids in the model is not very different than in the prototype, it follows that the pressure gradient in the model $(p/L)_M$ must be

equal to that, $(p/L)_p$, in the prototype.

It is virtually impossible to scale pore size distributions in a laboratory model. Since the pore size distribution (approximately represented by the J-function) cannot be scaled, then neither can the capillary pressure and the relative permeabilities. Hence where the interplay of such factors are anticipated to significantly affect a displacement process, the physical scaled model loses some of its attractiveness. However, in some cases the effects may be sensed by a series of experiments in which the capillary pressure plays an increasing role although never precisely scaled.

For steam injection operations, the inability to scale capillary pressure is not a serious shortcoming. Any estimation of the relative role of viscous and gravity forces and capillary forces in steam injection operations indicate that the latter is overwhelmed by the former two.

Relative permeability is a concept that can be validated when working with small cores in which diffuse flow can be maintained. When flow is not diffuse, but stratified it has become a matter of convenience and necessity to employ pseudo-relative permeabilities, or to derive an "effective relative permeability function" by history matching (3). Post-mortem cores taken between injection and production wells of steam drive operations indicate such a high degree of stratification (4) of steam and oil saturations that the use of the concept of relative permeability to account for such performance may be questioned.

In lieu of relative permeability scaling, the substitute dimensionless term that is scaled in steam injection operations is the following:

$$f\frac{(\mu/\rho)_S}{(\mu/\rho)_O}$$

where f is the quality of the injected steam. This dimensionless term is basically the ratio of the mass velocity of the oil per unit pressure gradient to the mass velocity of steam per unit pressure gradient. The implicit assumption is made that for such stratified, parallel flow the ratio of the resistances to mass flow of steam and oil is the same regardless of the nature of the porous medium.

As examples of the scaling parameters that enter because of heat flow in the system two dimensionless ratios involving heat flow can be examined:

$$\frac{f_{SR}L_{VR}}{C_R T_R} + 1$$

which is the ratio of the total heat in the steam to the sensible heat, and

$$\left[\frac{k_{hr}}{\rho_{cr}C_{cr}}\right]\left[\frac{t_r}{L_r{}^2}\right]$$

which is the ratio of the heat conductivity to the heat capacity of the cap rock multiplied by a characteristic value of (t/L^2) to render the ratio dimensionless.

The scaling parameters that are used for the steam injection operation are listed in Table I, somewhat modified from Stegamier, Laumback and Volek (2), and for which we have cited the physical phenomena which they characterize.*

* A fully rigorous derivation of these scaling parameters can be found in the cited publication (2).

The problem of finding a model oil that will show a change in viscosity between highest and lowest model steam temperature, scaled to the change in viscosity experienced by the prototype crude, is lessened the higher the temperature gradient in the model.

Perhaps the most important reason for using sub-atmospheric pressures in the model work is that the loose sands of the model are sealed well by the boundary plastic films that are sucked in by the application of a vacuum to the model. Also, the relatively low temperatures permit the use of materials of construction that do not have to possess a high degree of thermal stability.

Therefore, the pressure range chosen for model operation is 8.5 to 6.0 psi. This choice of pressures also defines the injection and producing well temperatures.

C. Model reservoir temperature and steam quality. There is no apriori limitation on the choice of the initial reservoir temperature except that it be less than steam temperature, and that the model oil show a change in viscosity between the initial reservoir temperature and steam temperature which is properly scaled to that of the prototype crude under prototype conditions. Again, the larger the temperature difference between steam temperature and initial reservoir temperature, the easier it becomes to find an appropriate model oil.

However, another significant reason for setting the initial reservoir temperature as low as possible is that fact that the steam quality in the model is a function of the temperature difference between the steam and the initial reservoir temperature.

Having specified the appropriate number of non-redundant scaling parameters, it is necessary to set the value of these dimensionless ratios in the model exactly equal to the corresponding ratios of the prototype to construct the scaled physical model.

III. Examples of Scaling Calculations

Given that the length of the model compared to the prototype is set for convenience, and certain other parameters of the model are dictated by available materials (glass beads for the reservoir sandstone, the fixed relationship between pressure and temperature of steam, the conductivity of insulation materials, etc.) substitution of these given values in the scaling relationships immediately defined the values of the parameters that must be controlled.

To illustrate the procedures used, a few typical calculations are presented.

A. The distance between injection and producing wells in the prototype field is 345 feet. Using a scaling factor of 183, the distance between wells in the model is 22.6 inches.

B. The injection well pressure in the prototype is known to be 500 psi and the producing well pressure is 50 psi. The pressure gradient is therefore 1.3 pounds per foot. The pressure drop across the 22.6 inch model must therefore be 2.5 psi. If supra-atmospheric pressure were to be chosen for the model, the temperature gradient across the model would be relatively small. However, if sub-atmospheric pressures are used the resulting temperature gradient for 2.5 psi is considerably greater.

Scaling parameter No. 2, Table I, is used to determine the steam quality.

$$f_{SM} = \left[\frac{C_W\,(T_S - T_i)}{L_V}\right]_M \left[\frac{f_s L_V}{C_W\,(T_S - T_i)}\right]_P \quad (C.F.)$$

$$C.F.^{*} = \left[\frac{(\phi\,\Delta S)_P}{(\phi\,\Delta S)_M}\right]\left[\left(\frac{\rho C}{\rho_c C_c}\right)_P \Big/ \left(\frac{\rho C}{\rho_c C_c}\right)_M\right]$$

It is apparent that the steam quality in the model can be increased the higher the value of $(T_s - T_i)_M$. For practical reasons the initial reservoir temperature must obviously be above 32°. A value between 32° and 40°F is used in this work.

Steam qualities in the model of 15% and 25% are generally encountered in scaling steam drive operations.

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*The correction factor compensates for the differences in thermal storage of the cap and base rocks compared to the reservoir (second bracket), and of the specific heat of the reservoir rock (first bracket), when these parameters are not the same for the model and prototype.

IV. Model Design and Construction

The experimental apparatus used for scaled models of steam floods consists primarily of a glass bead pack, which is operated under vacuum and refrigeration conditions, and associated injection and production facilities (Figure 2). The first design is described below. As already noted, a superior design has only recently been completed and will be described in greater detail in the Annual Report of this project in the Fall of 79.

A. Bead Pack. A simple geometry of a quarter of five spot was arbitrarily chosen in the first phase of the laboratory investigation of scaled model steam flooding. The design and construction of the scaled model will be described in terms of this quarter five-spot pattern. For a perfect five spot, the boundaries of a quarter are no-flow boundaries, and therefore it is appropriate to use such a model as representative of total pattern performance. Multiwell models of more complex geometries can be designed in a similar manner. Data from a California reservoir in the Kern River Field was used in this study.

The right angle triangular pack of 6-8 mesh glass beads are surrounded by a rigid fiberglass frame. The 3/8" (thickness) x 4.594" (width) boards are cemented by epoxy to three wells which are machined from fiberglass blocks (lower left photo of Figure 1). The fiberglass frame corresponds to the no-flow boundaries.

A few injection patterns are possible with this three-well system. Two injector-one producer, two producer-one injector, or one injector-one producer with one shut in well can be adopted. The length scale is changed if one well is shut in.

A cylindrical chamber of 1/4 inch diameter was bored vertically through each well block. A small slit was cut along the axis of the cylindrical chamber at the face contacting the bead pack. The slit widths, w, were scaled down from the effective well radius r_w by the relation $w/r_w = 2.59$, which is a log-linear approximation of bead size effect on slit width (2). The value 2.59 was interpolated from the assumed linear relation of w/r_w with respect to log (r_{bead}) corresponding to $w \simeq 2r_{bead}$ (slit widths are 0.130" and 0.108" for the producer and injector respectively while the average bead size is 0.111 inch).

A 1/4 inch hole was drilled near the bottom of the cylindrical chamber. Severe gravity segregation of steam and water may occur during steam injection if an excessively large chamber is bored. Connections for a thermocouple and a pressure gauge were also made at each model well. A diaphragm seal was connected between the well and the pressure gauge to prevent oil plugging.

A thin fiberglass board was cemented to the bottom of the model frame to reduce leakage problems that are more likely to occur if a teflon film were used. There was no evidence that this discontinuity engendered significant by-passing of fluids and calculations indicated a trivial effect on scaling of heat losses to the base rock. Twenty 1/8 inch diameter copper-constantan thermocouples were installed throughout the model. Glass

beads were then packed by uniformly sprinkling beads on the vibrating model frame into which water was being added. After filling up the model, beads near the top flange of the frame were trimmed so that two sheets of 0.005" bondable TFE teflon films could be properly cemented to the top flange. Care was taken to avoid any possibility of channeling through the less resistant route along the joint between the teflon film and the fiberglass board. After the beads were packed, the model was positioned on a Berea Sandstone block on whose top surface was placed a thin rubber sheet to improve heat transfer contact between the model and the simulated base rock. The heat losses to the base rock are not significantly distorted by introducing the thin rubber sheet. Thermal conductivity of fiberglass is relatively close to that of the Berea rock.

After production and injection lines were connected to the model wells, potting compound was applied to the top of the teflon film simultaneously with application of vacuum in the model. A thin neoprene sheet was placed between the teflon film and the overlying cap rock of Berea Sandstone block to act as a gasket for the vacuum system. The cap rock, like the base rock, has a thickness of 9 inches to allow simulation of heat losses to infinite adjacent formations up to approximately 15 hours.

Styrofoam was used to insulate the fiberglass sidewalls of the model. Optical observation of gravity segregation of the steam displacement process can be made through a Pyrex glass window on one side of the frame. The whole system described up to this point was enclosed in a plywood box insulated with 4 inch styrofoam. A refrigeration unit was installed which permitted cold air to be circulated within the box and recycled back over the evaporator coil.

B. Injection Equipment. Quality of the steam injected into the model reservoir can be controlled by maintaining constant mass flow rates of superheated steam at preset temperature and pressure and of water at room temperature. These two streams are mixed at a known pressure to obtain a scaled quality of saturated steam.

Superheated steam of about 230°F is generated through a boiler which is an 8 foot-1/4 inch stainless steel tubing; silver soldered to two pieces of heating elements side-by-side. Two heating elements require 225 V electric power and provide a total wattage of 6 Kw. The wattage of the upstream heating element is controlled by an autotransformer and the downstream one by a temperature controller. The nonuniform temperature distributions created in this type of boiler are smoothed by wrapping the tube-element assembly with copper wires or copper braids. Fiberglass pipe covering is used to insulate the boiler.

Water should be deaerated before entering the vacuum system. Deaeration is achieved by introducing water into a vacuum chamber via a needle valve. A high pressure drop across the boiler due to boiling of water requires a pump to inject steam into the vacuum model. A tubing pump with multiple pump heads is used to profide relatively constant flow rate. Rotameters with 10 in scales are used to measure flow rates with accuracies about ± 1%.

The steam of water which mixes with superheated steam, to provide the desired quality steam, contains polyetchylene glycol to control the scaled viscosity of the steam condensate. A check valve is used at the end of this line before joining the superheated steam to prevent any backflow.

All surfaces of the steam line are convered by insulation tape to reduce heat losses to ambient air.

C. Production Equipment. The produced fluid passes through a heat exchanger before entering a collector. The heat exchanger is of "double pipe" type, i.e., the produced fluid flows in the tube side while the heat transfer fluid, water in this case, flows in the annular side: 3.5 feet of 3/8" and 3/4" aluminum tubings are connected, and the annular space is sealed by using a tee and reducer fittings on each end. This heat exchanger serves as a heater for the cold effluent before steam breakthrough and as a condenser for the produced steam after its breakthrough.

The fluid collector consists of a pair of flasks positioned in vacuum chambers between which valves are connected to allow change of breaker and release of vacuum during operation. The polycarbonate vacuum chambers are connected to a vacuum pump through a vacuum trap. A "Drierite" column is added in between to prevent accidental overflow of steam into the vacuum pump. Because of the large volume involved and high tendency for leakage to develop in the vacuum system, a vacuum pump of higher displacement capacity rather than of higher vacuum is perferred.

High temperature epoxy and teflon were found to be satisfactory in the vacuum system containing steam and hydrocarbons.

D. Preparation for Experiment. Before conducting an experiment, it is necessary to deaerate the model, and saturate the model with water and oil to the desired saturation. The water contains polyethylene glycol in an appropriate amount to secure the desired scaled viscosity. The polyethylene glycol solution may be heated to raise the temperature of the model in order to facilitate subsequent injection of the heavy oil. The injection lines are either insulated or heated to promote oil flow. The injection of

oil continues until there is no water in the produced fluid.

E. Cooling of the Model. After the desired oil saturation is obtained, the model in the insulated box is cooled by a refrigeration unit for at least 24 hours. The bead pack, cap and base rocks are maintained at about 37°F as indicated by thermocouple readings. Before the experiment, it is also necessary to establish the proper pressure in the model, which results in some depletion.

F. Operation of Experiments. During the startup period, an attempt is made to establish constant flow rate, temperature, pressure and steam quality. Sufficient amounts of water are deaerated before proceeding to the next step. Through proper adjustment of the temperature controller, tubing pump and vacuum pump, steam of desired quality, pressure and temperature is generated and flows through a bypass line where steam is condensed. The bypassed flow is switched to the bead pack after stabilized conditions are achieved. A timer is set at zero at this moment. Part of the residual oil in the flow line is removed by this bypassed steam.

A 24-channel strip chart recorder is used to acquire the data on temperature profiles during the steamdrive. Prior to steam breakthrough hot water is introduced in the annulus of the "double pipe" heat exchanger to promote the cold oil flow in the tube side. After breakthrough, it may be necessary to run tap water at room temperature to the annulus to condense produced steam, especially when oil-steam ratio is low.

The produced fluids are collected at regular intervals. A small amount of demulsifier or solvent is added to each sample of collected fluid, and the sample is transferred to separatory funnels. After separation of

il and water is complete, the water is drained and the volumes of oil and water are measured.

The bead pack is dismantled, cleaned and reassembled for subsequent runs. To facilitate the completion a series of experiments using the same model configuration two or three fibre glass frames and associated facilities are employed.

V. Experimental Results

The results of a model run based on a Kern River prototype, Table II, are shown in Figures 3 to 8.

Breakthrough of steam is observed after about 0.9 of a year of steam injection and oil production shoots up upon breakthrough, Fig. 3. Cumulative production is shown in Figure 4, and the steam oil ratio in Figure 5.

An important observation is that oil production continues at a low rate even where the steam oil ratio, rising rapidly, has risen to the fairly high value of 5 after the recovery of about 45% of the oil in place.

The expansion of the steam zone, Figures 6, 7, and 8 clearly indicates the dominance of the gravity overlay in this homogeneous model. The steam zone, following breakthrough, expands vertically downwards. The mechanism of oil production is obviously some kind of attrition phenomenon by which the heated oil at the steam oil interface is dragged to the production well by the momentun of the flowing steam. (The justification for introducing Scaling Parameter No. 3, Table I, is apparent.)

Conclusions

The scaled physical model study of steam injection operations supported by The Department of Energy has met its goals in (1) providing a training program for graduate students, and, (2) in generating the support of oil producers to address some of their unique problems in applying the steam drive.

Continued support will permit meeting the final goal of using scaled physical models to seek ways for improving one of the most effective oil recovery schemes available to the industry, the steam drive.

The scaled physical model studies carried out to date indicate that steam displacement of crude oil is not due to a frontal advance of steam into the reservoir, but results from a viscous drag of oil by the parallel flow of steam.

NOMENCLATURE

C	---	Specific heat, BTU/1 bm °F
f_s	---	Steam quality, fraction
g	---	Gravity acceleration constant, ft/sec^2
h	---	Enthalpy per unit mass, BTU/ 1 bm
k	---	Permeability, darcy
k_n	---	Thermal conductivity, BTU/hr ft °F
L	---	Length, foot or inch
p	---	Pressure, psia
Q	---	Volumetric flow rate, cc/sec or bbl/day
r	---	Effective well radius, inch
S	---	Saturation, fraction
t	---	Time, min. or year
T	---	Temperature, °F
W	---	Mass flow rate, 1 bm/sec.
w	---	Width of linear model well, inch
μ	---	Absolute viscosity, cp
ν	---	Kinematic viscosity, centistokes
ϕ	---	Porosity, fraction
ρ	---	Density, gm/cc

Subscripts

a	---	Aqueous phase
c	---	Cap or base rock
i	---	Initial
M	---	Model
o	---	Oil
p	---	Prototype
r	---	Reference value
s	---	Steam
w	---	Water

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3. Dietrich, J. K., "Releative Permeability During Cyclic Steam Stimulation of Heavy Oil Reservoirs", SPE 7668, presented at the 49th Annual California Regional Meeting, Ventura, California, April 1978.

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4b. Blevins, T. R., and Billingsley, R. H., "The 10 Pattern Steam Flood", J. Pet. Tech., December 1975, 1505.

4c. Neuman, C. H., "A Mathematical Model of the Steam Drive Process - Applications", SPE 4757, Secondary Recovery Symposium, April 1974 in Tulsa.

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Table I

SCALING PARAMETERS

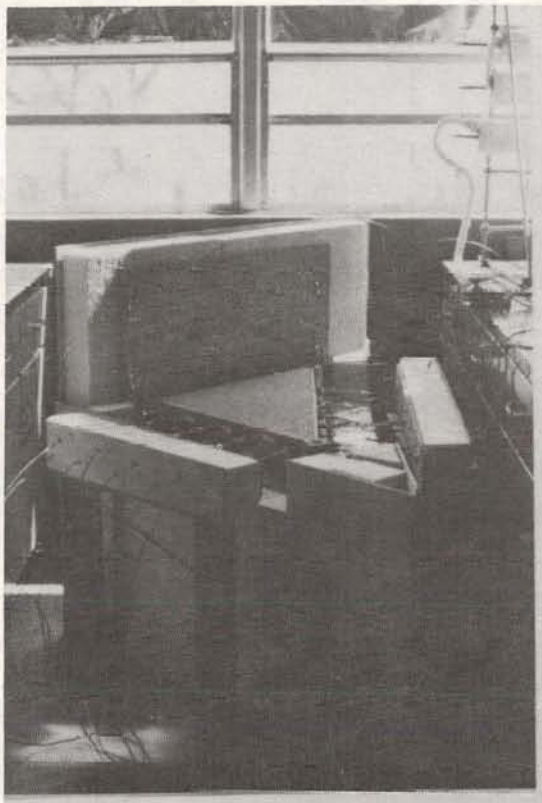
1.	$\frac{P_R/L_R}{\Delta\rho_R g_R}$	Ratio of viscous pressure gradient to gravitational gradient.
2.	$\left(\frac{f_{sR}L_{vR}}{C_{wR}T_{sR}} + 1\right)$	Ratio of total heat of injected heat to sensible heat in injected steam. A correction factor is applicable when $(\phi\Delta S)_m \neq (\phi\Delta S)_p$.
3.	$f_s \frac{(\mu_{sR}/\rho_{sR})}{(\mu_{oR}/\rho_{oR})}$	Ratio of mass velocity of oil per unit pressure gradient to mass velocity of steam per unit pressure gradient.
4.	$\frac{k_{hR}}{\rho_{cR}C_{cR}} \cdot \frac{t_R}{L_R^2}$	Thermal diffusivity of cap rock non-dimensionalized by multiplication by (t/L^2).
5.	$\frac{k_R(\Delta\rho)_R g_R}{(\phi\Delta S)_R \mu_R} \cdot \frac{t_R}{L_R}$	Vertical velocity of liquids in steam atmosphere nondimensionalized by multiplication by (t/L).
6.	$\frac{W_R}{\rho_R(\phi\Delta S)_R L^2} \cdot \frac{t_R}{L_R}$	Linear velocity of steam non-dimensionalized by multiplication by (t/L).

Table II

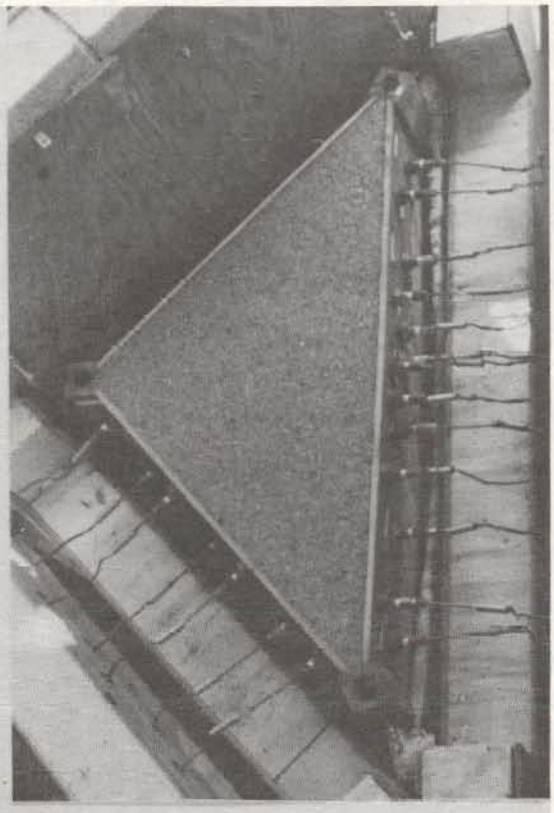
PROTOTYPE PROPERTIES OF STEAM FLOODING
and the CORRESPONDING MODEL VALUES

	Prototype *	Model
Pay thickness	73 ft	4.594 inch
Well spacing	361.5 ft	22.744 inch
Porosity	0.35	0.35
Residula oil saturation to steam	0.04	0.12
Irreducible water saturation	0.05	0.20
Initial movable saturation	0.91	0.68
Permeability (darcy)	7.6	3817
Reservoir temperature (°F)	80	38
Steam injection pressure (psia)	400	7.4
Initial reservoir pressure (psia)	240	6.6
API gravity	14	11.8
Oil viscosity (cp)	3651 @ 80°F 2.35 @ 100 psi	8325 @ 38°F 3.9 @ 76°F
Water viscosity (cp)	0.111 @ 100 psia	0.26 @ 5.8 psia
Thermal conductivity of reservoir (BTU/hr/ft °F)	1.2	0.5
Thermal conductivity of adjacent formations (BTU/hr/ft °F)	1.2	1.2
Heat capacity of reservoir $\left(\frac{\text{BTU}}{\text{ft}^3\,^\circ\text{F}}\right)$	35	29
Heat capacity of adjacent formations (BTU/ft^3 °F)	35	35

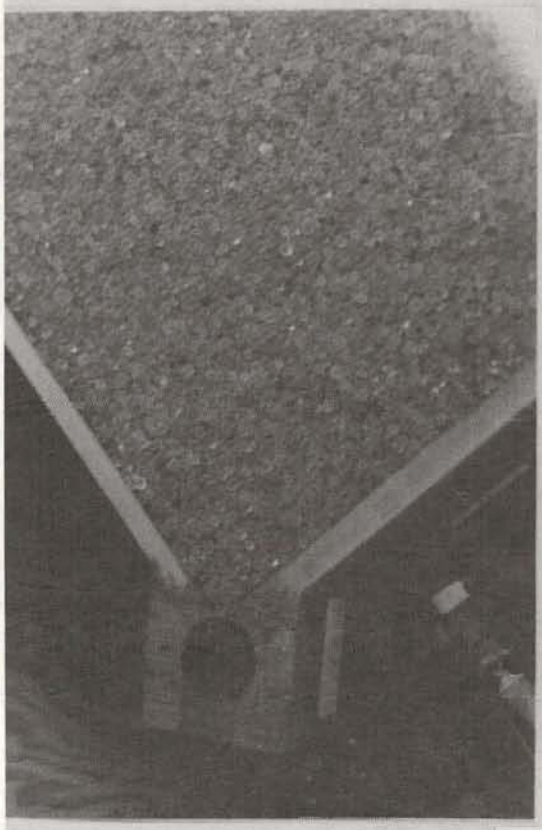
*Based on properties of reservoirs in the Kern River Field, California



CAP ROCK REMOVED

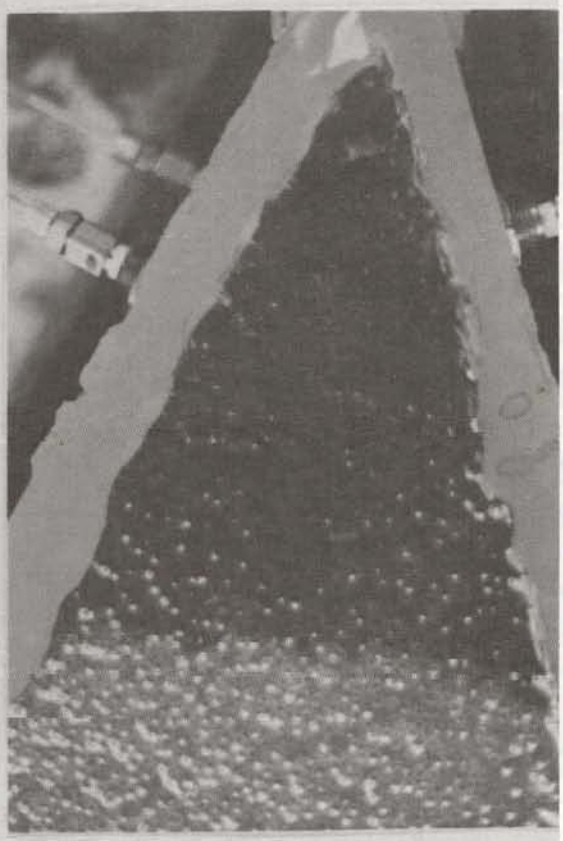


CONNECTION OF THERMOCOUPLES



WELL CONFIGURATION

Figure 1



OIL INVADING

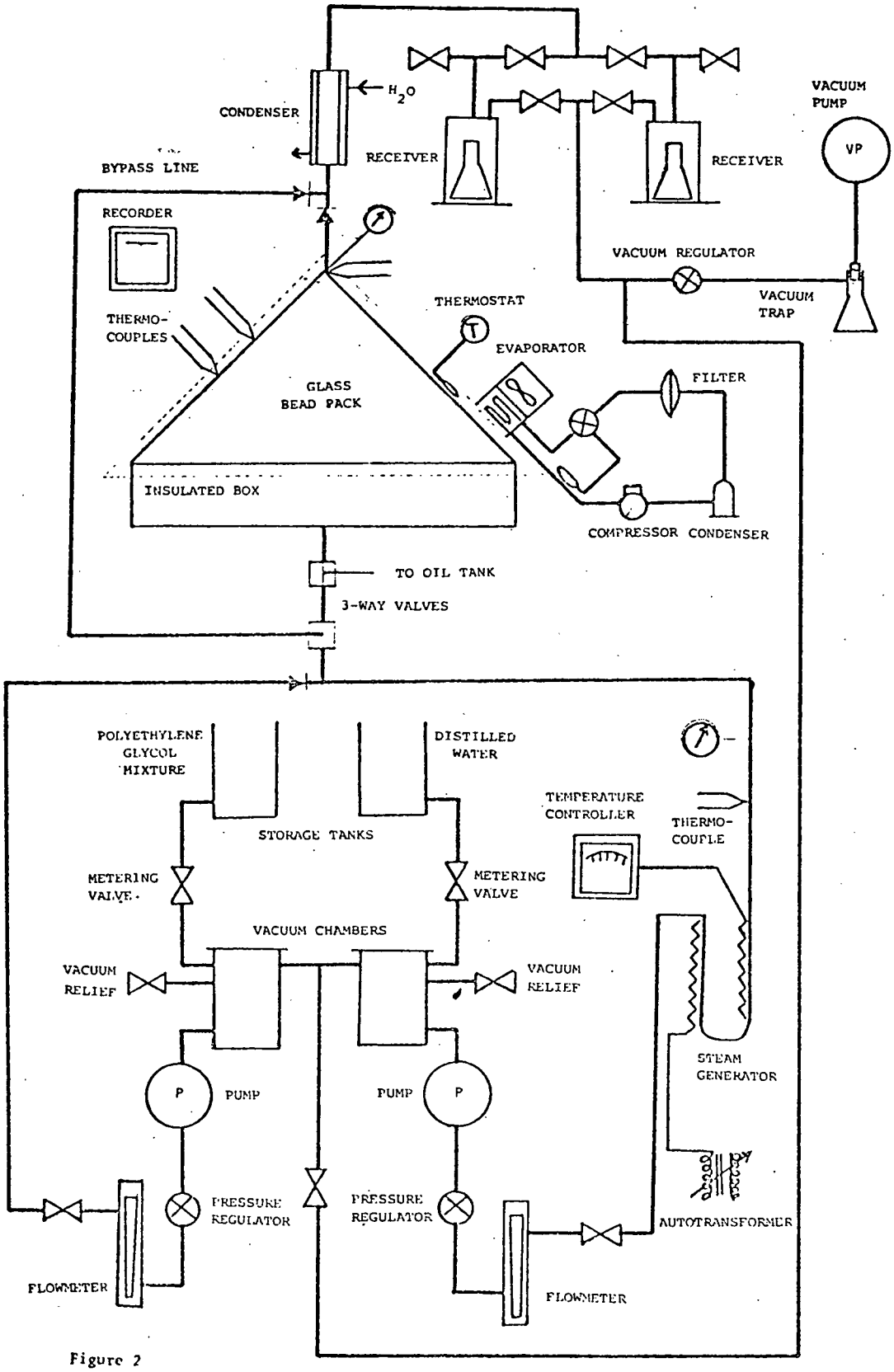

CONDENSER
H_2O
VACUUM PUMP
VP
BYPASS LINE
RECEIVER
RECEIVER
RECORDER
VACUUM REGULATOR
VACUUM TRAP
THERMO-COUPLES
THERMOSTAT
EVAPORATOR
FILTER
GLASS BEAD PACK
INSULATED BOX
COMPRESSOR CONDENSER
TO OIL TANK
3-WAY VALVES
POLYETHYLENE GLYCOL MIXTURE
DISTILLED WATER
TEMPERATURE CONTROLLER
THERMO-COUPLE
STORAGE TANKS
METERING VALVE
METERING VALVE
VACUUM CHAMBERS
VACUUM RELIEF
VACUUM RELIEF
STEAM GENERATOR
P
PUMP
PUMP
P
PRESSURE REGULATOR
PRESSURE REGULATOR
AUTOTRANSFORMER
FLOWMETER
FLOWMETER

Figure 2

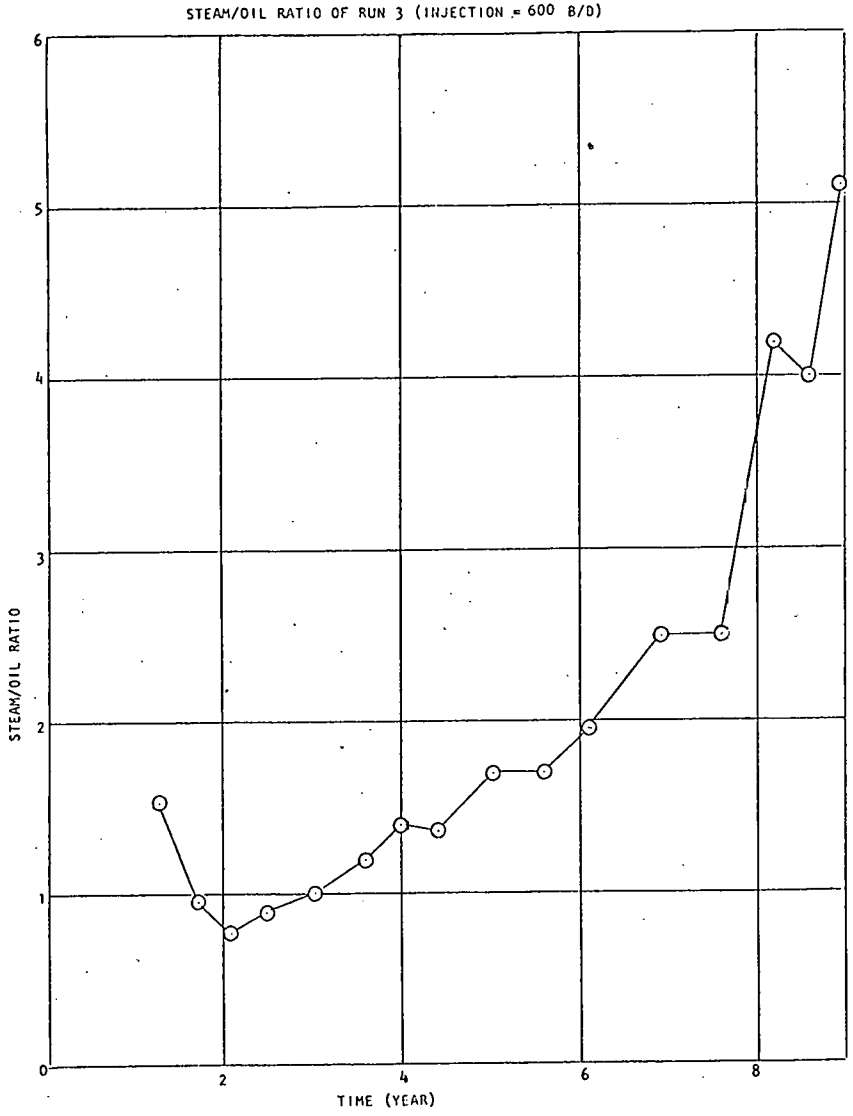


Figure 3

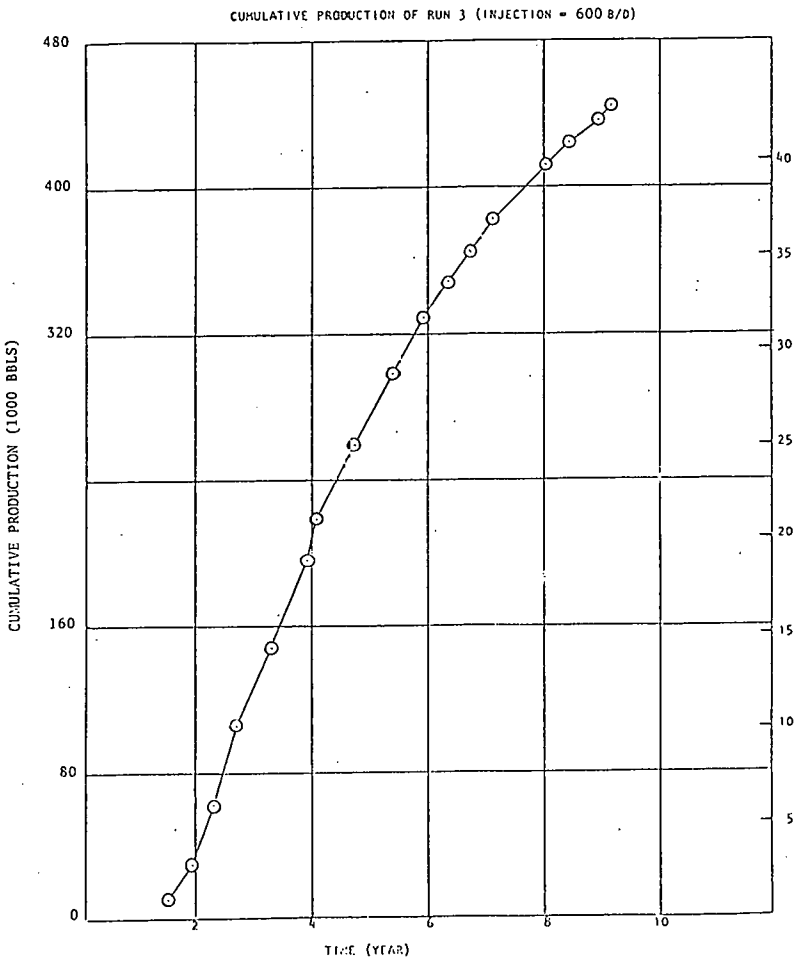


Figure 4

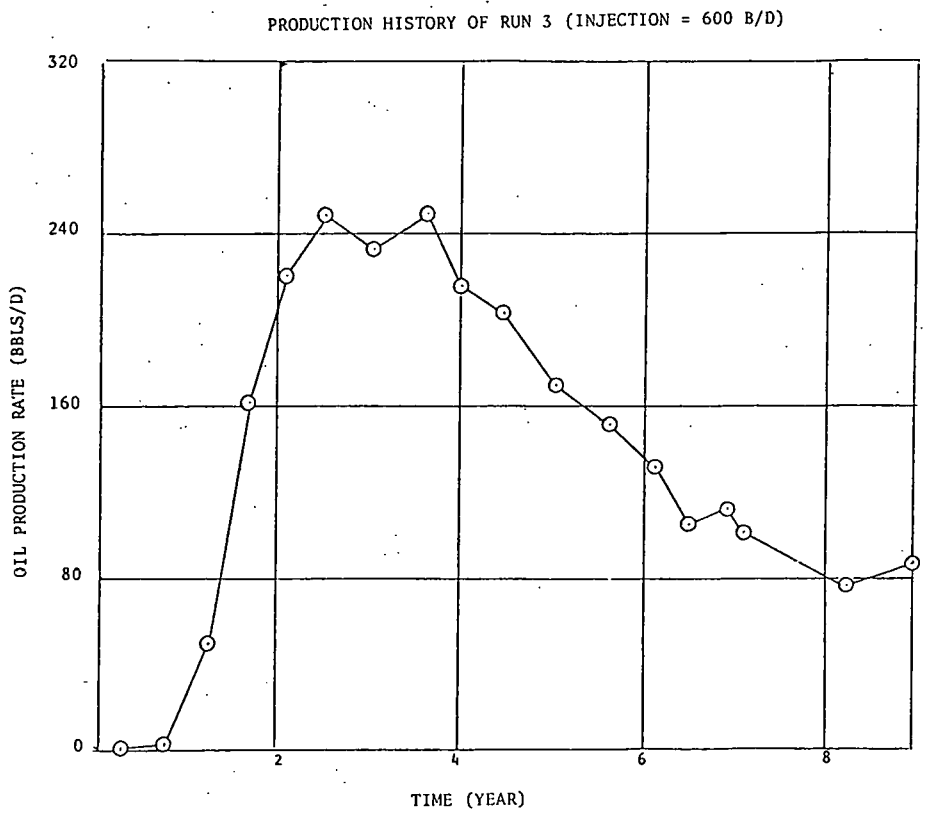


Figure 5

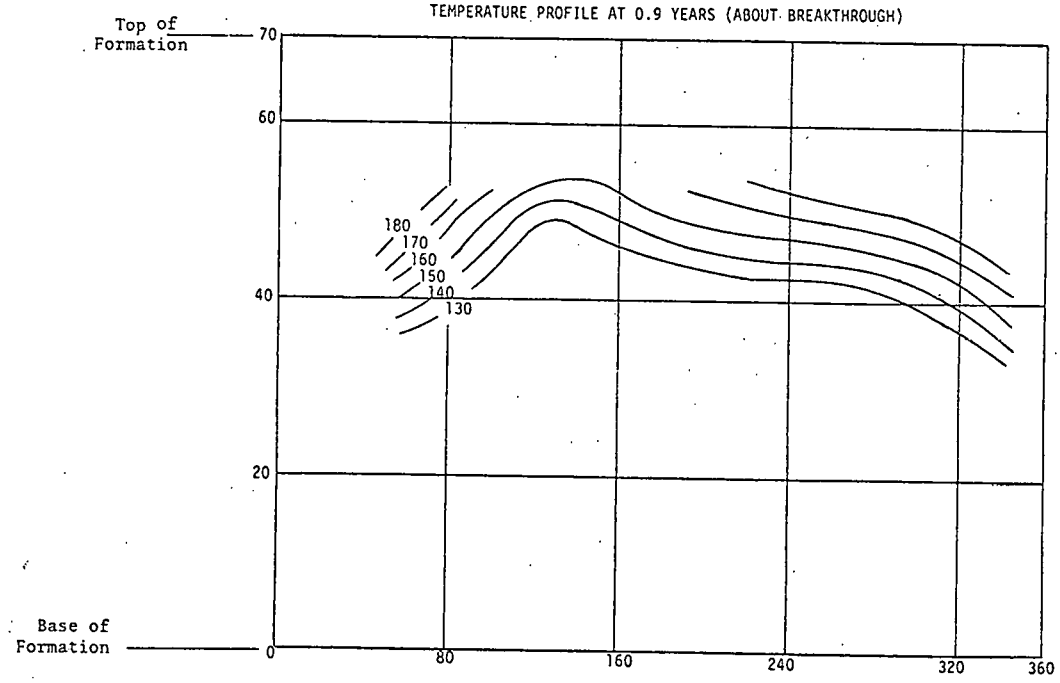


Figure 6

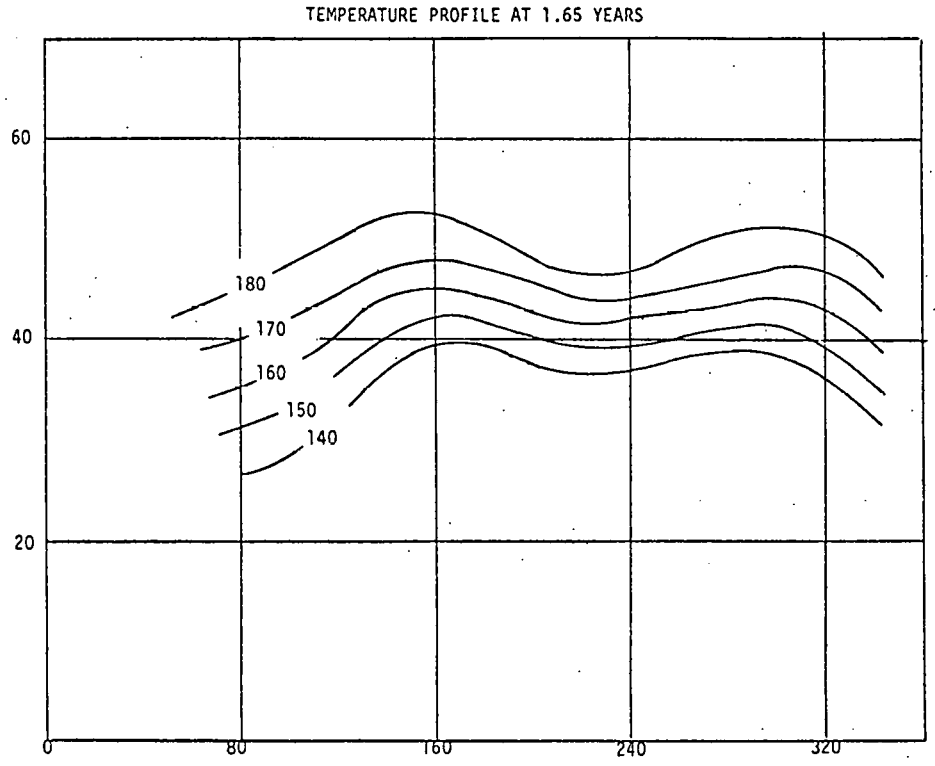


Figure 7

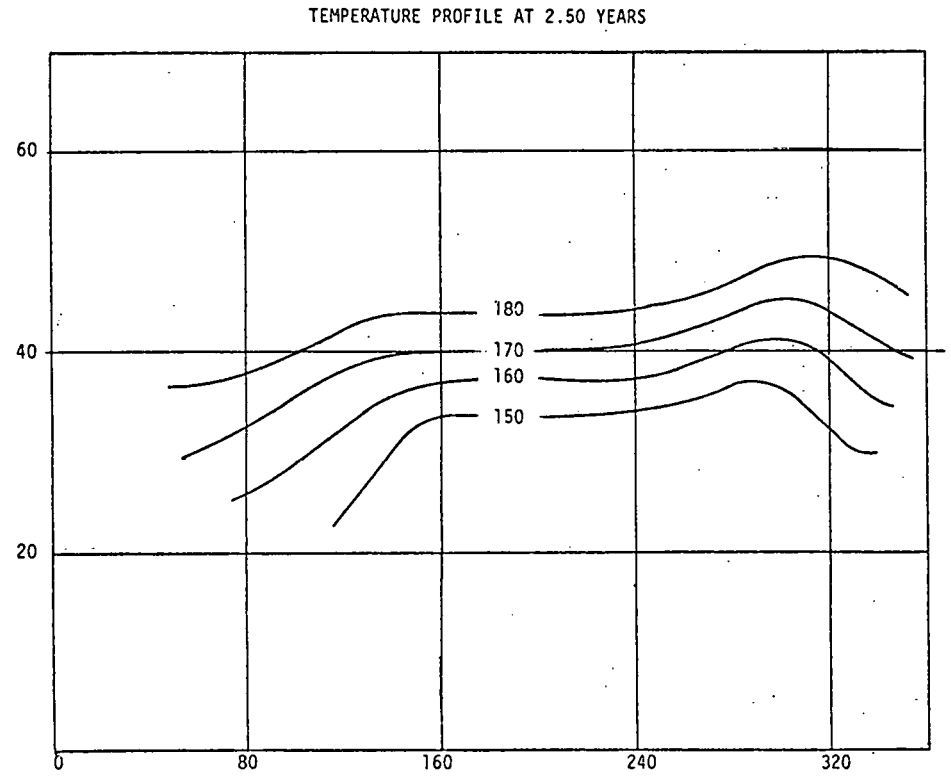


Figure 8

THE USE OF CHEMICAL ADDITIVES WITH STEAM INJECTION TO INCREASE OIL RECOVERY

by

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ABSTRACT

Various surfactants are being evaluated for their potential as additives for steamflooding to reduce oil-steam ratios. Of particular interest is the effect of temperature on adsorption of the surfactants on reservoir rocks. Experimental methods have been developed for measuring adsorption by both static and dynamic methods. Two classes of surfactants have been investigated. The anionic sodium dodecylbenzene sulfonate showed a decreasing adsorption with increasing temperature but at higher concentrations and in brine solutions the sulfonate precipitated. A definitive measurement of adsorption under these circumstances was not possible, but substantial loss of surfactant during floods was observed. The nonionic Igepal CO-850 was, on the other hand, well-behaved in the adsorption experiments. It does show, however, a cloud point. The adsorption as a function of temperature is the inverse at high temperatures over that at lower temperatures. Near the cloud point adsorption increases with increasing temperatures.

Several surfactant floods have been completed at 82°C and 177°C. Higher oil recoveries were observed at the higher temperature with Witco TRS 10-80 and Petrostep 465. In these first tests the additional oil was recovered at moderate to high water-oil ratios, but the results do indicate some benefits from surfactant flooding at elevated temperatures.

INTRODUCTION

Steam injection has been demonstrated to have considerable potential in improving oil recovery from fields containing high viscosity oils. The steam is known, however, to move through the upper portion of the reservoir while the lower portion of the reservoir is flooded only with hot or cold water. The residual oil saturation in the steam-swept portion of the reservoir has been observed to be near zero, but normal residual oil saturations are observed in the water-swept part of the reservoir. As has been suggested by others, oil-steam ratios could possibly be reduced if a suitable additive were found which would reduce the residual oil saturation in the waterflooded part of the reservoir (1,2). The objective of this research was to find chemical additives which may be suitable for this purpose.

Prepared for DOE under Contract No. EF-76-S-03-0113.

We are investigating both organic and inorganic chemicals, but the emphasis in this paper is on results obtained in evaluating some organic surfactants which have shown promise in reducing residual oil saturations in conventional waterfloods. One of our postulates has been that some synergistic effect might be observed between temperature and detergency such that the surfactants would be more effective recovery agents in the hot water portion of a reservoir undergoing steam injection than at reservoir temperatures in a conventional waterflood. If this is the case, the surfactant must move in the heated portion of the reservoir. Since the heat front will move more slowly than the hot water, the surfactant would have to be adsorbed to some degree if it is not to move out ahead of the temperature front. Ideally, then, a surfactant would be adsorbed adequately to remain always in the hot water zone. It must, also, be effective in reducing the residual oil saturation in this region and it must be stable at the high steam temperatures. Consequently, the project has several subsidiary aspects.

Our first efforts were to evaluate the stability of types of surfactants which have been shown to have possible application as oil recovery agents. These are principally the anionic petroleum sulfonates. We also evaluated some nonionics. The results of these studies have been reported previously (3). Secondly, we measured the effect of temperature on the interfacial tension between surfactant solutions and a San Joaquin Valley crude oil. These data were obtained by the pendent drop method and the results reported at the DOE Enhanced Oil Recovery Symposium in 1978 (4). These measurements are being continued using a spinning drop method. In the present report we are discussing the results of our studies of the effect of temperature on adsorption and on surfactant floods.

THE EFFECT OF TEMPERATURE ON SURFACTANT ADSORPTION

The position of the surfactant front in the reservoir relative to the temperature front is determined by the adsorption of the surfactant. If the surfactant is less strongly adsorbed in the heated portion of the reservoir, the surfactant will move more rapidly at the high temperatures than at low temperatures. In that case the surfactant may have a tendency to run ahead of the hot zone but be slowed when it reaches the cold zone where the surfactant is more strongly adsorbed. This effect would, then, tend to keep the surfactant in the hot region. Consequently, measurement of the effect of temperature on the adsorption of specific surfactants would be essential in selecting surfactants for use in steamfloods.

To establish trends in the dependence of adsorption on temperature, we selected the pure anionic sulfonate, sodium dodecylbenzene sulfonate (NaDDBS) and the nonionic surfactant, nonylphenoxypolyethanol with a molecular weight of 1100. The latter surfactant is manufactured by GAF under the trade name of Igepal CO-850. Although the NaDDBS is not used as a field surfactant, it is similar to the petroleum sulfonates. Nonionics similar to Igepal CO-850 are used as co-surfactants in some micellar solution formulations.

For a porous material we used fired and crushed Berea sandstone, sieved to various size fractions. Two types of experiments were performed to determine adsorption. These were static and dynamic tests. For both of

these the surface areas of the matrix material was determined by the B.E.T. method using a Nelsen-Eggertsen type apparatus (5). The surface area determined for the sand used in the static adsorption test was 1250 m^2/kg. The sands selected for the dynamic tests had specific surface areas of 340 and 460 m^2/kg.

For chemical analysis of the solutions use was made of the adsorption in ultraviolet spectrum which is characteristic of disubstituted benzene rings. Both surfactants contain a disubstituted benzene ring and exhibit strong adsorption within the ultraviolet spectrum. Wavelength scans of the absorbance and second derivative of absorbance from 300 nm to 200 nm were used to measure surfactant concentration. The standard base line method was used in measuring absorbance and second derivative values. Concentrations were determined by comparing measured values with calibration curves prepared from stock solutions.

Adsorption Tests

Static tests were conducted by equilibrating rock and surfactant solution in borosilicate glass ampules. The ampules had been sealed to prevent evaporation. Samples were equilibrated with agitation in a temperature-controlled bath. Samples were decanted at the test temperature and centrifuged prior to measuring the surfactant concentration.

In the dynamic method the core holder was packed with sand and mounted in the flow system as shown in Figure 1. The core was carefully saturated with deaerated, distilled water and then flushed with 50 pore volumes of .2 M NaCl brine to remove divalent cations from the system. The NaCl concentration of the resident core fluid was adjusted by further flushing to match that of the surfactant solution to be injected.

The samples were equilibrated at the test temperature and surfactant injected at the minimum selected concentration. Injection was continued until the effluent concentration reached a constant value. Surfactant concentration was measured as a function of the volume of fluid injected. The concentration of the injected surfactant was increased and again producing concentrations were measured as function of injected fluid until they remained constant. This process was continued, increasing surfactant concentrations stepwise until the maximum injection value was reached. Once adsorption saturation was attained, brine or distilled water were injected to desorb the surfactant. A material balance was run on the total surfactant injected and produced. A new sand pack was used for each series of runs.

RESULTS OF SURFACTANT ADSORPTION TESTS

Static adsorption tests were conducted on a variety of anionic surfactants to determine those which yield Langmuir isotherms. Solutions of NaDDBS in 0.2 M brine in crushed Berea sandstone do conform to the Langmuir model of adsorption as shown in Figure 2. To determine the temperature sensitivity of this surfactant-rock system, static adsorption tests were conducted over a temperature range of 25°C to 95°C. Low surfactant concentrations were used to improve the analytical accuracy of the adsorption

determination. As expected, the results do show in Figure 3 a decrease in adsorption with increasing temperature. Tests conducted with NaDDBS in distilled water show a less marked effect of temperature on adsorption. This is, presumably, a result of the general higher solubility of the surfactant in fresh water at all temperatures.

Reliable determination of the adsorption of NaDDBS by the dynamic method was hampered by the limited solubility of this surfactant in 0.2 M NaCl and dissolved minerals from the Berea sandstone. To minimize the solubility effect of extraneous salts the dynamic experiments were repeated with distilled water as the solvent. In this case the dynamic adsorption isotherm determined at 40°C agreed well with the static isotherm determined at about 25°C. On the other hand, NaDDBS floods even with distilled water showed precipitation problems at 110°C. Effluent concentration failed to reach the initial values even after prolonged injection. At high surfactant concentrations in the injection fluid, however, the turbidity observed in the produced fluids disappeared. This coincided with a significant overshoot in the effluent concentration above that of the injected fluid. Apparently, we were redissolving surfactant precipitated in the core during the preceding floods. This redissolution phenomena has been reported previously (6). Even after flushing with distilled water at ambient core temperatures, material balances on the surfactant indicated that up to 40% of the NaDDBS adsorbed at the beginning of the desorption floods remained in the core. However, flooding at 180°C with distilled water removed substantially all of the remaining adsorbed surfactant.

Nonionic surfactants are not as susceptible to salting out effects as are anionic surfactants. The primary determinant of solubility for surface active ethylene oxide adducts is temperature. The upper temperature limit for surfactant solubility is termed the cloud point. Cloud points are a function of both surfactant concentration and electrolyte concentration. Pertinent physical and sorption properties for Igepal CO-850 are given in Table I.

Static adsorption tests conducted over a temperature range from 45°C to 95°C indicate that the adsorption of Igepal CO-850 in distilled water on crushed Berea sandstone can be described by the Langmuir model as shown on Figure 4. In the low to mid-concentration range the adsorption decreases with increasing temperature, but at the higher concentrations this dependence is reversed with the higher temperatures showing higher adsorption. This type of behavior has been observed previously for a nonylphenoxypolyethanol surfactant (7). At higher temperatures, however, degradation of the Igepal surfactant is significant and a correction for this factor is necessary. An experimental modification is required to ascertain the effect of decomposition.

Dynamic adsorption tests were conducted with Igepal CO-850 over a temperature range of 45°C to 95°C. The breakthrough curves were S-shaped and no effluent turbidity was visible. Surfactant loss was apparently by adsorption only. Measurements of complete adsorption isotherms over the desired temperature range were made. This had not been possible with the anionic surfactant. Effluent concentration of the CO-850 always rose

smoothly to the injected level. This indicated negligible surfactant degradation at the selected temperatures and flow rates. The curves in Figures 5 to 7 represent the best fit of the surfactant transport model to the experimental data.

The adsorption isotherms determined by integrating the surfactant breakthrough curves are shown on Figure 8 for the three temperatures investigated. The relative trends of these isotherms reinforce the results determined in the static tests. At low concentrations the thermodynamics of the adsorption process are controlling, whereas at high concentrations, surfactant solubility is the dominant factor. Near the cloud point the hydration of the surfactant molecule may be less than at lower temperatures. In that case we would have a different molecular species in solution to be adsorbed.

Following the desorption floods at ambient core temperature, material balance calculations indicated that between 20% and 30% of the adsorbed surfactant remained within each core. For the 95°C flood an attempt was made to desorb additional surfactant by reducing the flood temperature to 45°C. This had no effect on surfactant recovery. When flooding was continued at 180°C additional surfactant was recovered along with dissolved rock. Effluent during these high temperature floods was usually clear and always transparent. Use of the second derivative of absorbance for concentration measurement greatly reduced any error introduced from ultraviolet interference. Finally, material balance calculations showed that less than 6% of the adsorbed surfactant remained in the core at completion of the thermal desorption flood. No effort was made to account for surfactant lost by thermal degradation.

Nonionic surfactants, similar to Igepal CO-850, are commonly used as co-surfactants in micellar solutions (8). Their presence in sulfonate formulations has been shown to provide a synergistic effect on interfacial tension reduction. At room temperature the nonionics by themselves do not give interfacial tensions low enough to mobilize residual oil. As temperatures are increased toward the cloud point, however, ultralow values of the interfacial tension are observed (less than 10^{-2} mN/m). When temperature becomes a process variable, surface active ethylene oxide adducts can become effective oil recovery agents in their own right. The high tolerance of nonionic surfactants to dissolved electrolytes makes their application to the steamflood process particularly attractive. The cloud point, however, places an upper limit on the surfactant concentration which can be injected.

THE EFFECT OF TEMPERATURE ON SURFACTANT FLOODING

An important aspect of adding a surfactant for steamflooding is the effect of temperature on surfactant flood performance. Preliminary studies have been completed evaluating the flood performance for two surfactants at elevated temperatures. These studies have been limited to a maximum temperature of 177°C. At temperatures greater than this the surfactants have been determined to be unstable. Even at 177°C, the experiments had to be designed to minimize the length of time the surfactants were exposed to the elevated temperature.

The porous material used for the floods was fired consolidated Berea sandstone. The cores were three inches in length and one inch in diameter. Some experimentation was required to find a satisfactory method for mounting these cores to withstand the high temperatures. The method eventually selected was to mount the cores in an Armstrong A-2 epoxy resin filled with aluminum powder. The resin was poured between the core sample and an outer aluminum jacket. The jacket was required to withstand core pressures in excess of the vapor pressure of water at 177°C.

The literature generally indicates that for a surfactant to be an effective oil recovery agent the interfacial tension between the surfactant solution and the oil must be less than .01 mN/m. On the basis of data reported in our previous paper we selected surfactant concentrations which would meet this interfacial tension requirement (4). For Witco TRS 10-80 the lowest interfacial tension at 177°C was observed at a surfactant concentration of 2.5 g/l and a NaCl concentration of 10 g/l. Floods were conducted in the absence of salt, however, for which the interfacial tensions as measured by the pendent drop method were in excess of .01 mN/m. All floods were conducted at constant temperatures of 82°C, a representative reservoir temperature, or 177°C, a minimum steamflood temperature. In one experiment the waterflood was conducted at 82°C and the surfactant flood at 177°C to simulate the temperature sequence for the surfactant-steamflood process. All floods were run at a constant pressure drop across the core sample. The actual flood rates varied only between one and four feet per day. Consequently, rate was not a significant variable in the experiments.

Experimental Results

The results of the floods are summarized in Figures 9-15. The first flood was at 82°C with a TRS 10-80 concentration of 2.5 g/l and a salt concentration of 10 g/l. The results of this flood are shown on Figure 9. A normal waterflood was conducted until two pore volumes of water had been injected. At that time 59% of the initial oil in-place had been recovered. The surfactant flood produced an additional 10% of the oil in-place after about three pore volumes of surfactant had been injected. These results are to be compared with a flood with the same surfactant and salt concentrations but at 177°C, as shown on Figure 10. The oil recovery after waterflooding at the higher temperature was 67% of the initial oil in-place (8% greater than at 82°C). This increase would have been expected as a result of the effect of temperature on the oil viscosity. However, an additional 20% of the initial oil in-place was recovered during the surfactant portion of the flood. This is significantly greater than that obtained at the lower temperature and the increase cannot be attributed to reduction in the oil viscosity.

The effect of a salt concentration on surfactant floods is illustrated in Figures 10-13. Although the oil recovery is somewhat larger with 10 g/l salt (93.7% of the oil in-place compared to 91.4%) the difference is less than might be expected, considering the pronounced effect of salt concentration on the interfacial tension. The water-oil ratio performance is also similar with or without salt as shown on Figures 11 and 13. These results are at variance with results others have reported for low temperature floods. If this result is confirmed in additional experiments, it will indicate that

:he oil recovery will not be adversely affected by the fact that, in a ;teamflood, the surfactant will be moving in a low salt concentration.

Figure 14 shows the results of a flood in which the waterflood was carried out at 82°C and the surfactant flood at 177°C. In this particular experiment no substantial difference was observed in the flood performance at two temperatures as compared to the flood at the single temperature of 82°C. The total recovery was 72.9% of the initial oil in-place when the surfactant flood was at the higher temperature as compared to 68.8% at the lower temperature. Additional floods are required to investigate the effect of variable temperature on the surfactant floods.

Petrostep 465 was the most stable at elevated temperature of all the surfactants we have studied (3). We have completed one flood with this surfactant. The surfactant concentration was 2.5 g/l and the salt concentration was zero. The results are shown in Figure 15. The surfactant is effective in recovering additional oil at 177°C.

CONCLUSIONS

1. The effects of temperature on the adsorption of a sulfonate surfactant and a nonionic surfactant have been investigated by both static and dynamic experiments. The methods showed good agreement for the nonionic surfactant and, under somewhat limited conditions, for the anionic surfactant.

2. Mineral dissolution at elevated temperatures caused sulfonate precipitation. Use of sulfonates as steamflood additives may require the addition of co-surfactants to improve surfactant solubility.

3. For the nonionic surfactant, Igepal CO-850, the adsorption decreased with increasing temperature at low concentrations. At higher concentrations, however, adsorption increased with increasing temperatures because of solubility effects near the cloud point.

4. Experimental methods were developed for mounting core samples suitable for flooding at 20 atmospheres and 200°C.

5. The two sulfonate surfactants tested showed increased oil recoveries when injected after the cores had been waterflooded to a residual oil saturation.

6. The TRS 10-80 showed better oil recovery performance at 177°C than at a normal reservoir temperature of 82°C.

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TABLE I

SUMMARY OF PHYSICAL AND SORPTION PROPERTIES FOR IGEPAL CO-850

Molecular Wt. = 1100 CMC = 100 μM[1]

Cloud Points[2]

C_o (M x 10^6)	Cloud Point °C
73	>140
366	113
640	106

Sorption Properties

Temp. °C	K_{eq} ℓ/(Mole x 10^6)	A (Mole x 10^6)/m^2	k_1 ℓ/Mole x 10^6-hr	k_2 hr^{-1}	ΔH°[3] Kcal
45	4.82×10^{-2}	5.70×10^{-1}	1.0×10^{-2}	2.1×10^{-1}	-8.1
70	2.35×10^{-2}	7.01×10^{-1}	7.0×10^{-3}	3.0×10^{-1}	
95	8.91×10^{-3}	7.29×10^{-1}	1.8×10^{-2}	2.0	

[1]Measured at 25°C in distilled water
[2]0.5 hr equilibration time
[3]Constant between 45°C and 95°C

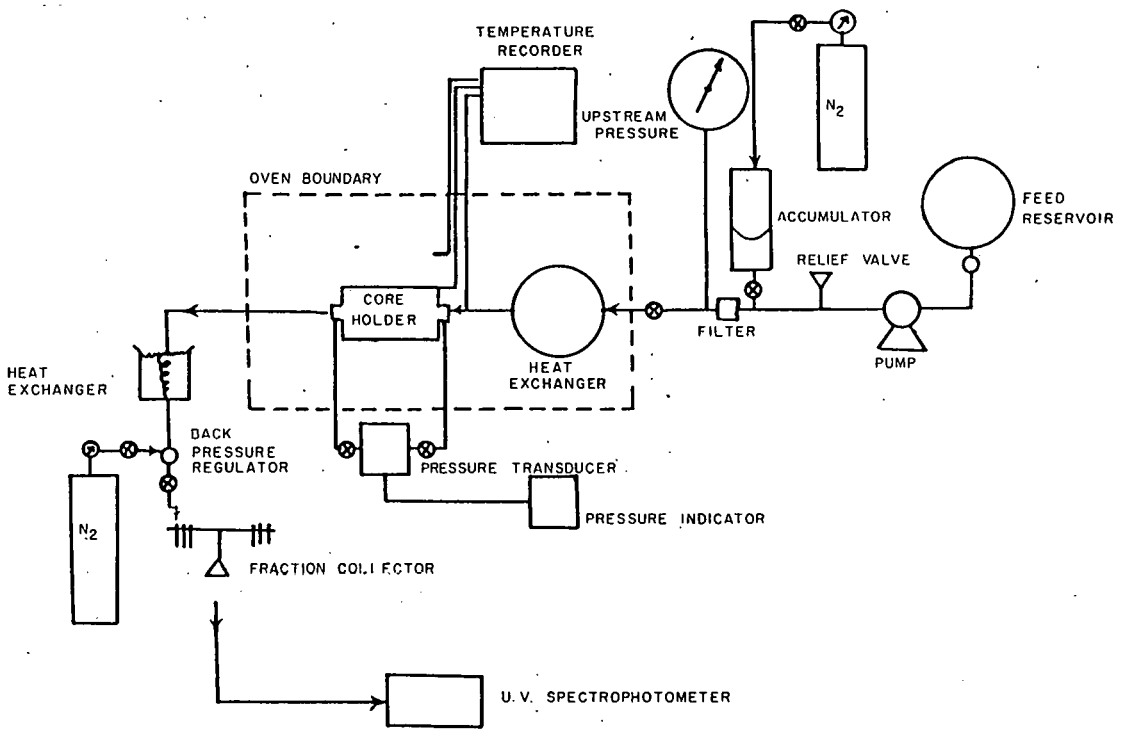


Figure 1. Schematic of Dynamic Adsorption Apparatus.

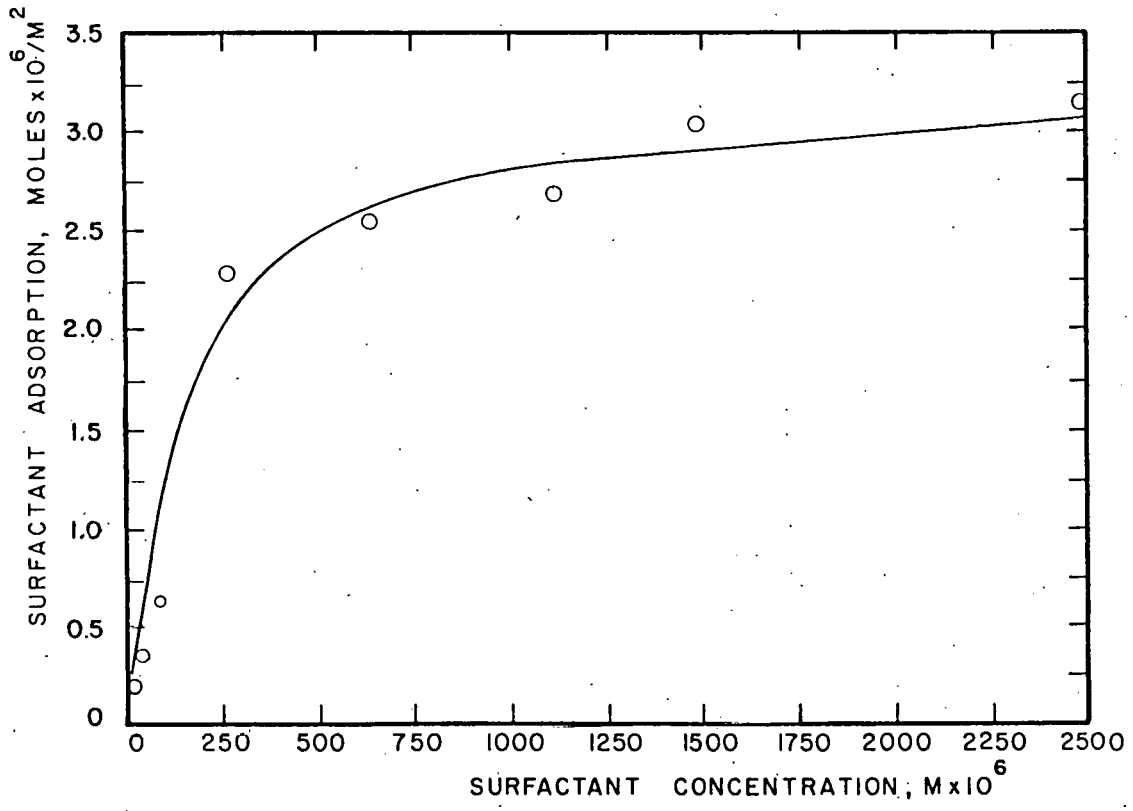


Figure 2. Static Adsorption Isotherm for NaDDBS at 25°C in 0.2 M NaCl. t_{eq} = 72 hrs.

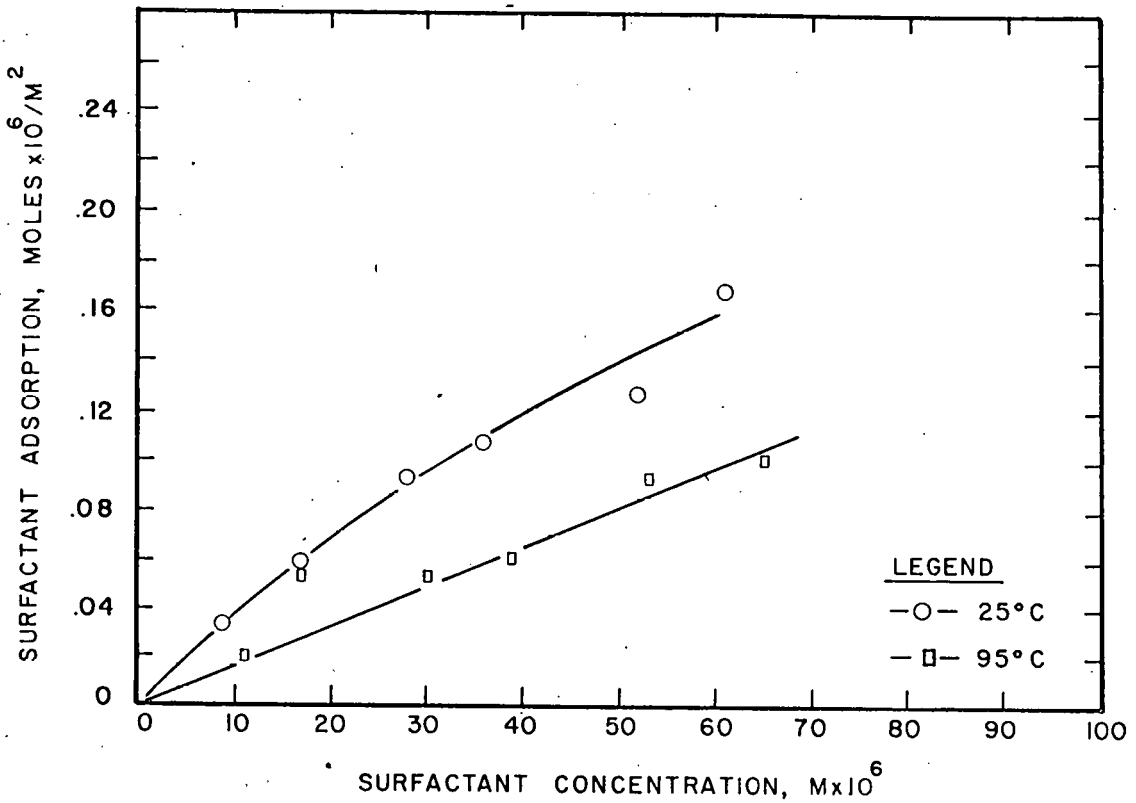


Figure 3. Static Adsorption Isotherms for NaDDBS. 0.2 M NaCl. t_{eq} = 3 hrs.

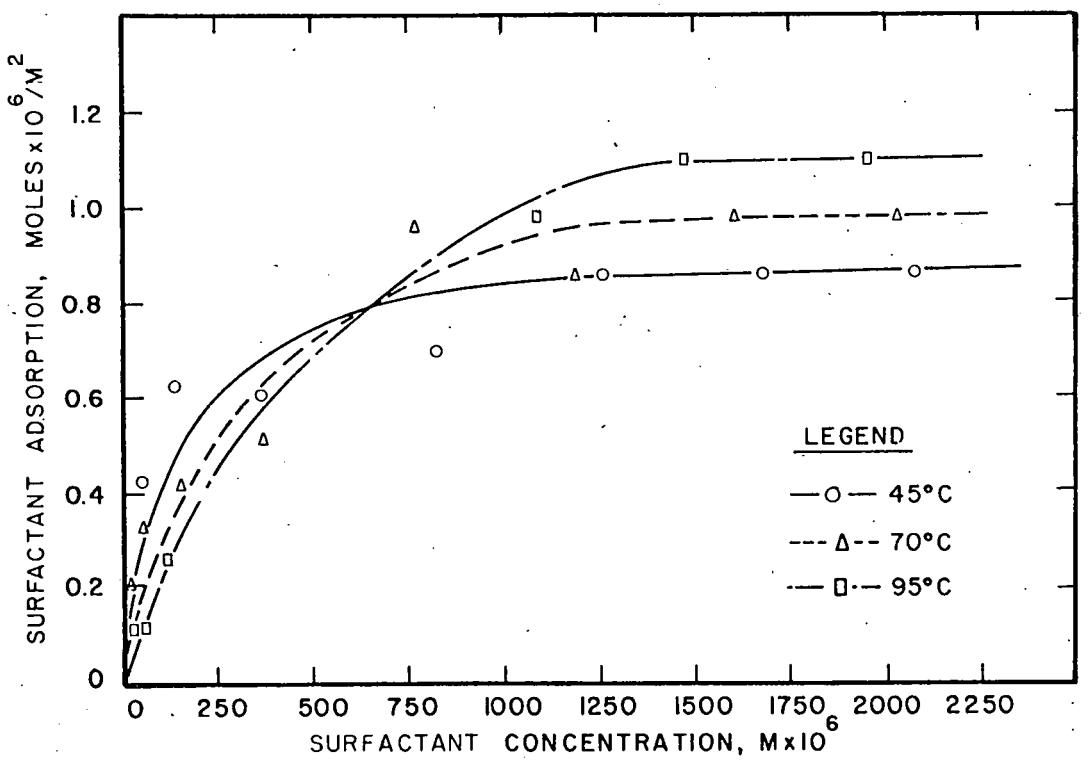


Figure 4. Static Adsorption Isotherms for Igepal CO-850. 0.0 M NaCl. t_{eq} = 23 hrs.

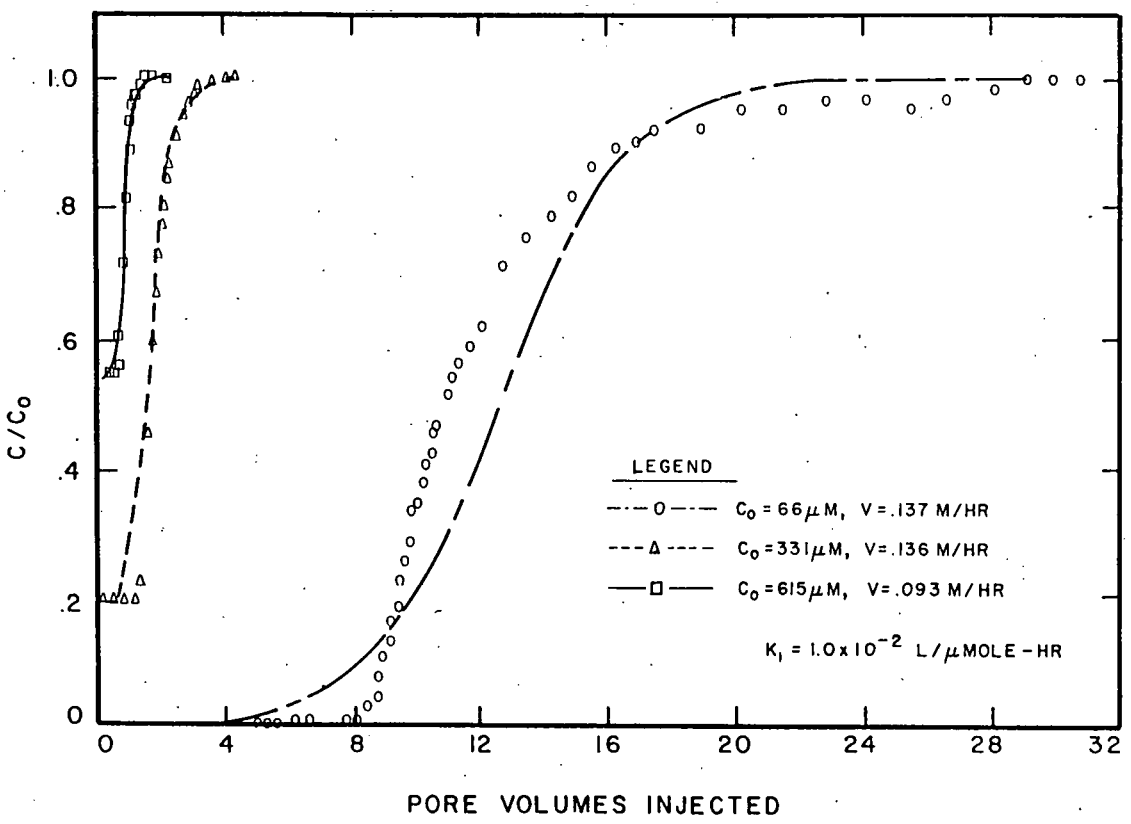


Figure 5. Effluent Concentration Curves for Igepal CO-850 at T = 45°C. 0.0 M NaCl.

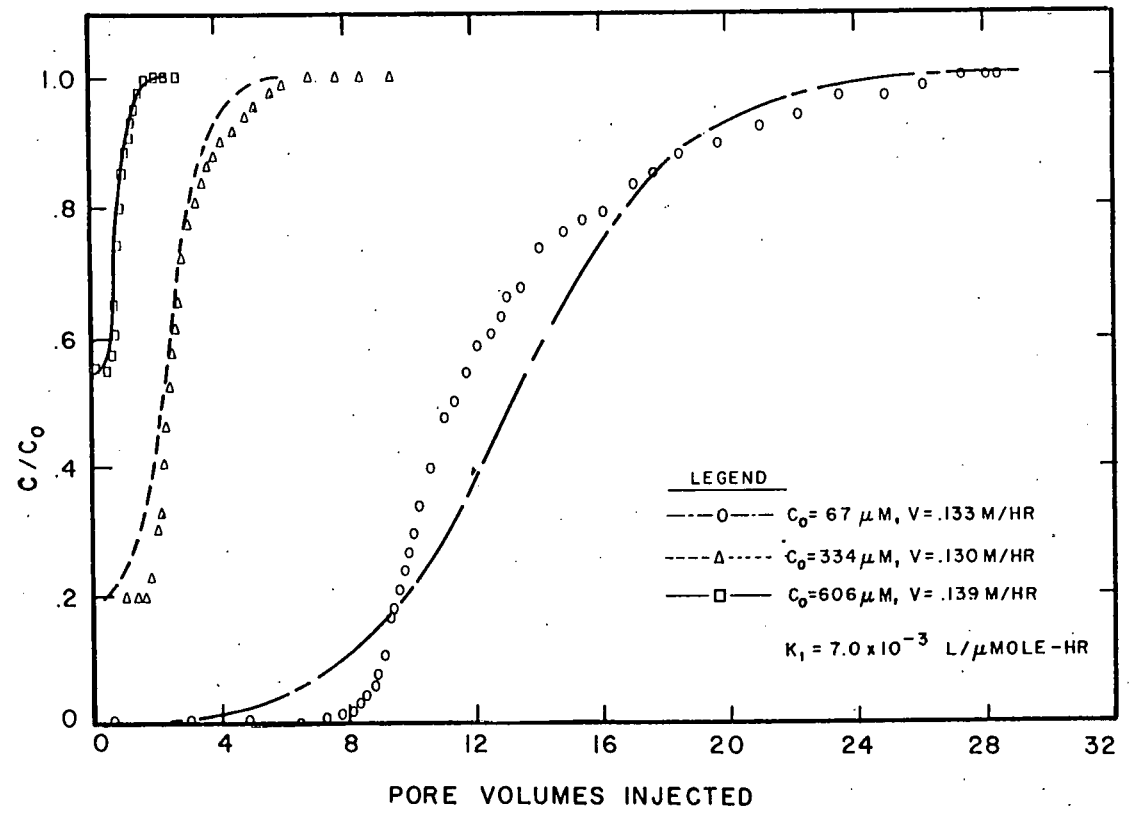


Figure 6. Effluent Concentration Curves for Igepal CO-850 at T = 70°C. 0.0 M NaCl.

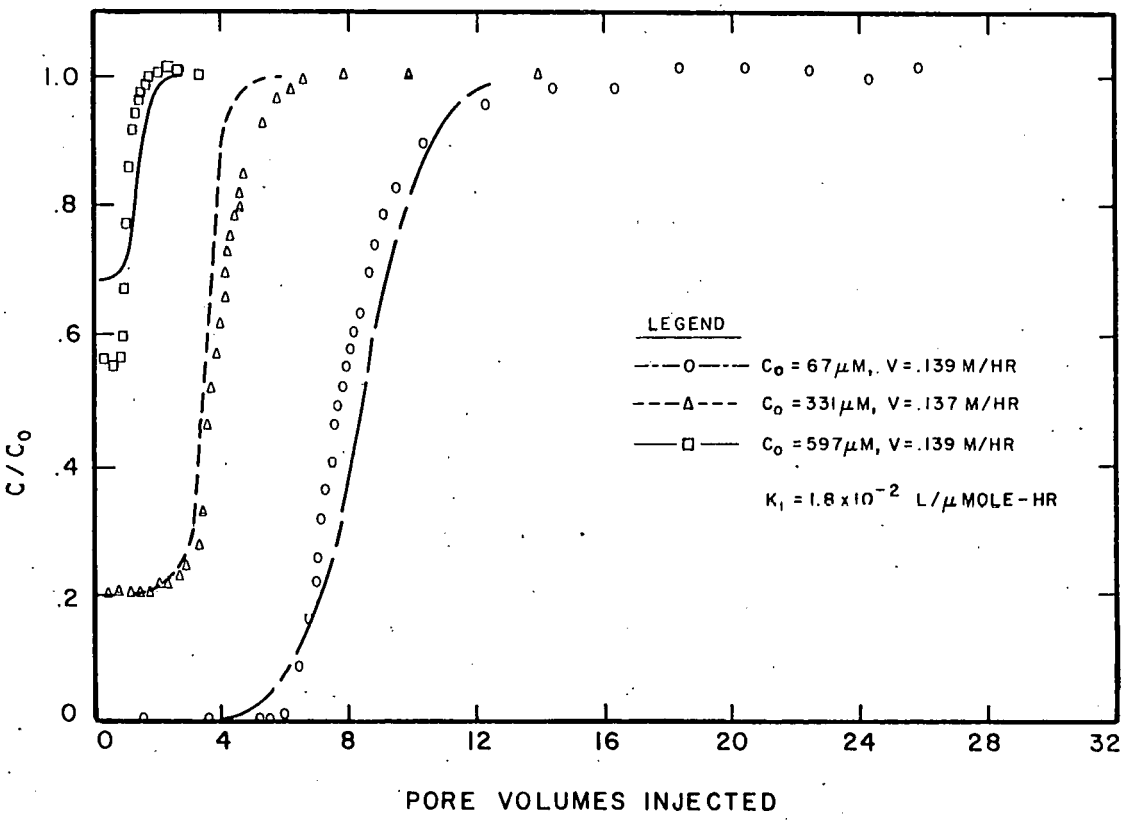


Figure 7. Effluent Concentration Curves for Igepal CO-850 at T = 95°C. 0.0 M NaCl.

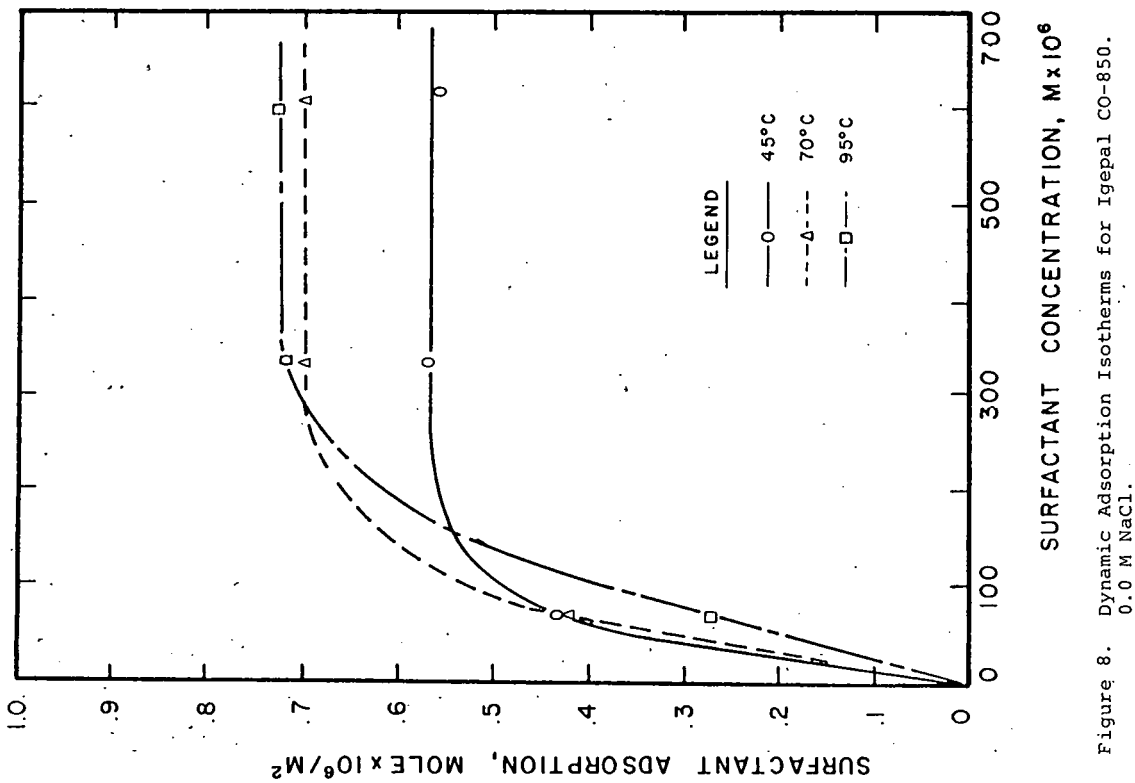


Figure 8. Dynamic Adsorption Isotherms for Igepal CO-850. 0.0 M NaCl.

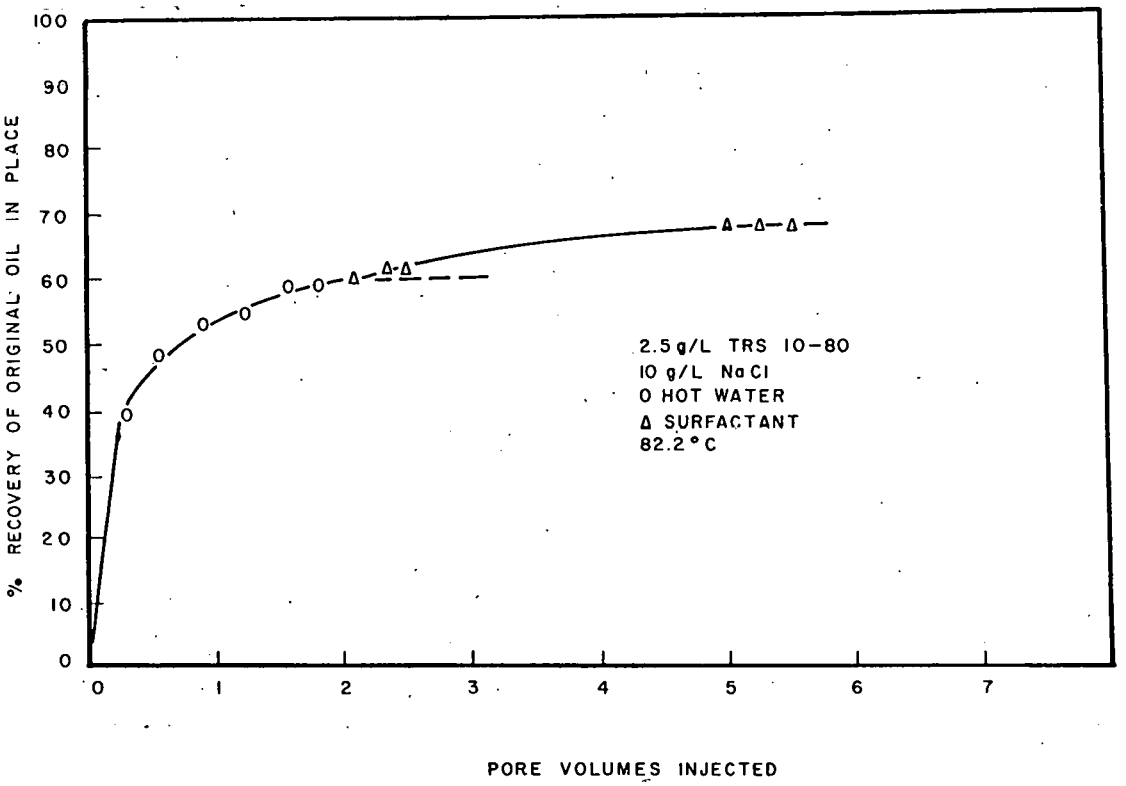


Figure 9. Oil Recovery for TRS 10-80 Surfactant Flood at 82.2°C.

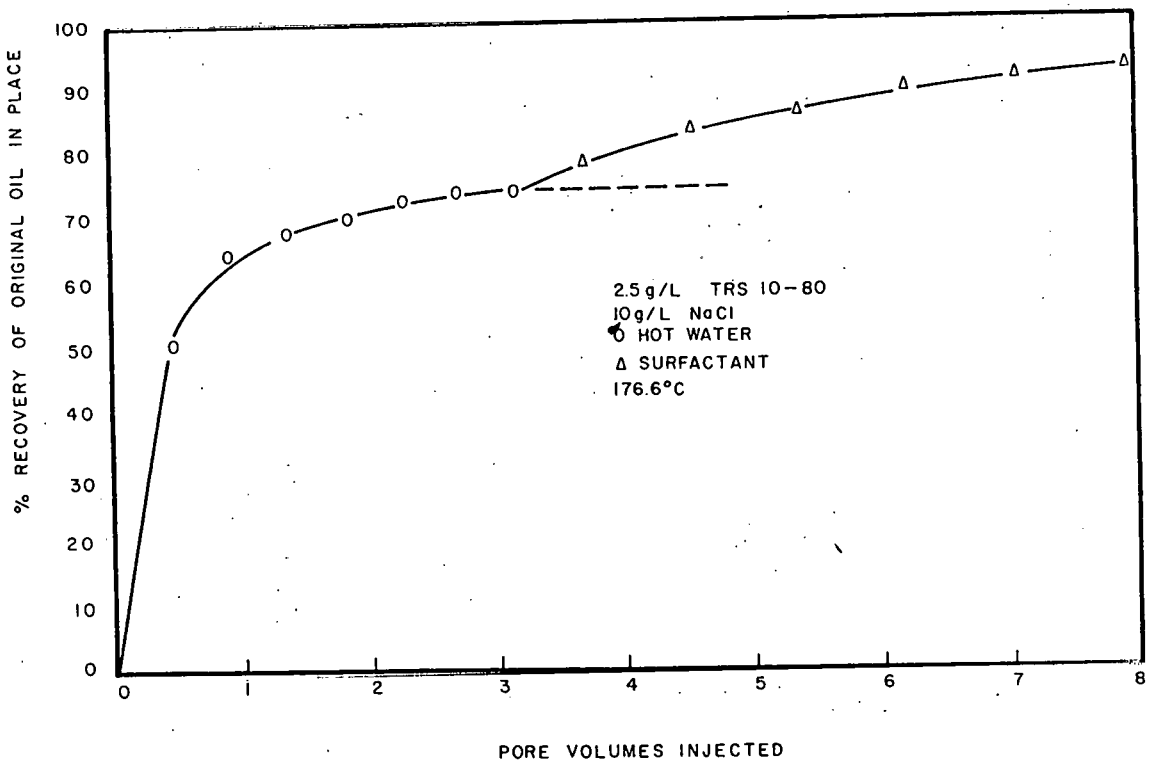


Figure 10. Oil Recovery for TRS 10-80 Surfactant Flood at 176.6°C.

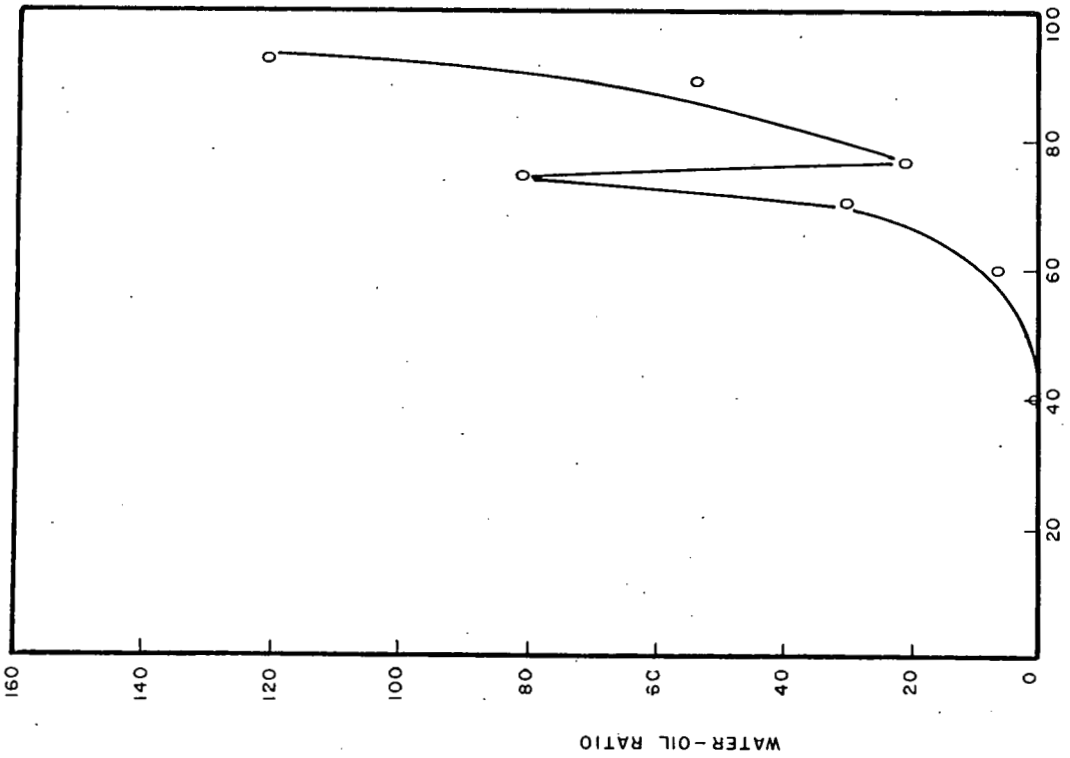


Figure 11. Water-Oil Ratio History for Surfactant Flood at 176.6°C. 25 g/l TRS 10-80 and 10 g/l NaCl.

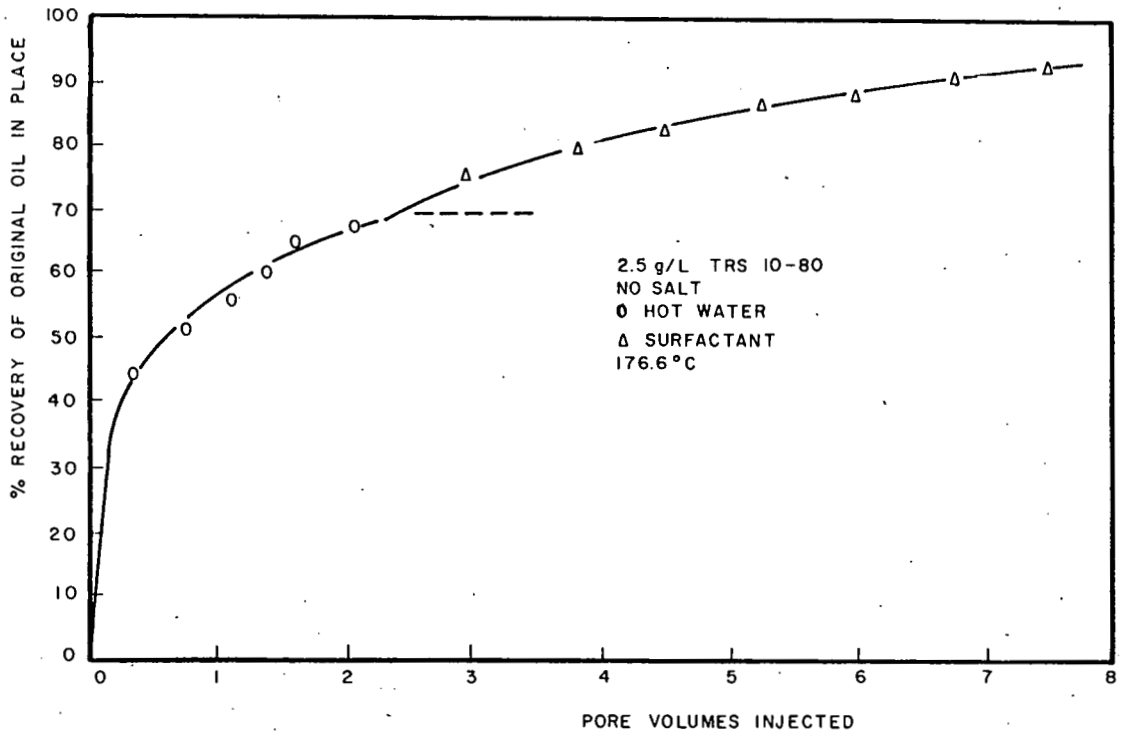


Figure 12. Oil Recovery for TRS 10-80 Surfactant Flood with No Salt at 176.6°C.

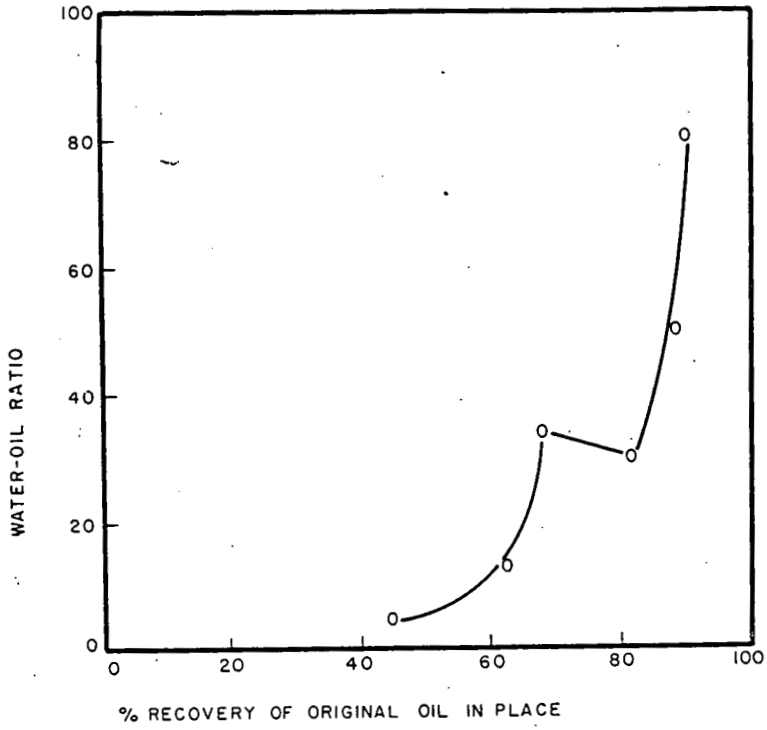


Figure 13. Water-Oil Ratio History for Surfactant Flood at 176.6°C. 2.5 g/l TRS 10-80 and 0.0 g/l NaCl.

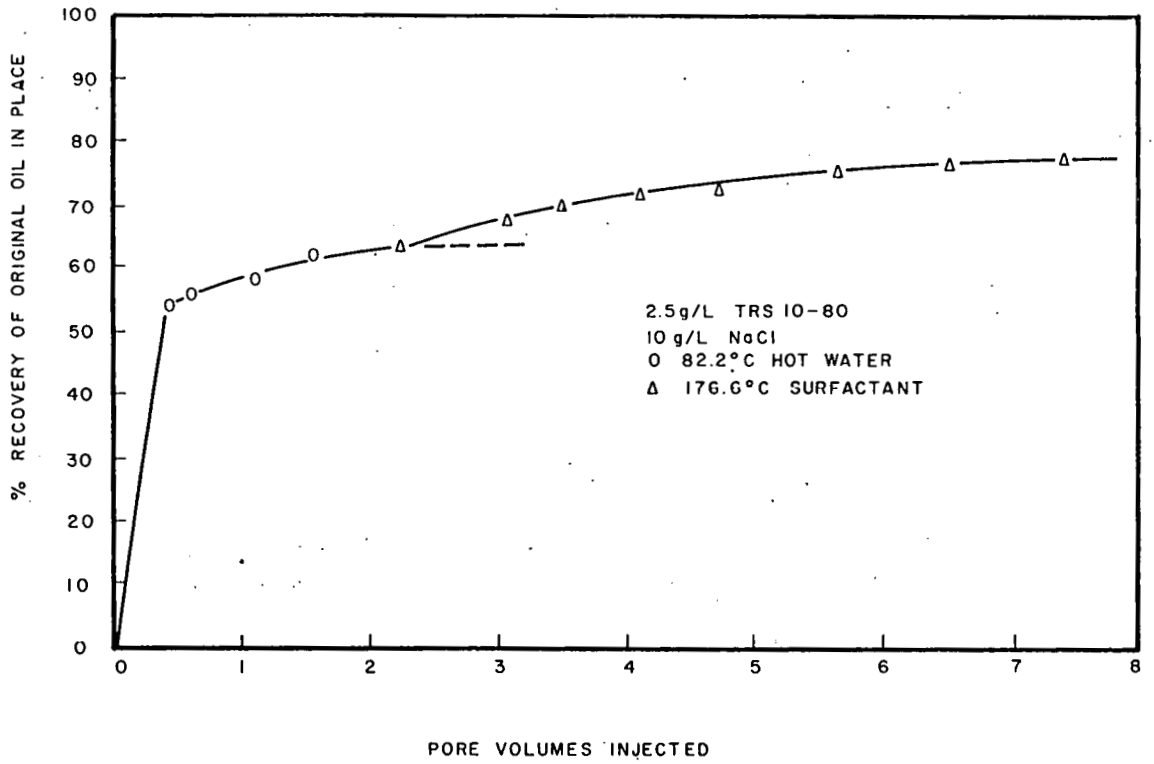


Figure 14. Effect on Oil Recovery for Waterflood at 82.2°C and Surfactant Flood at 176.6°C.

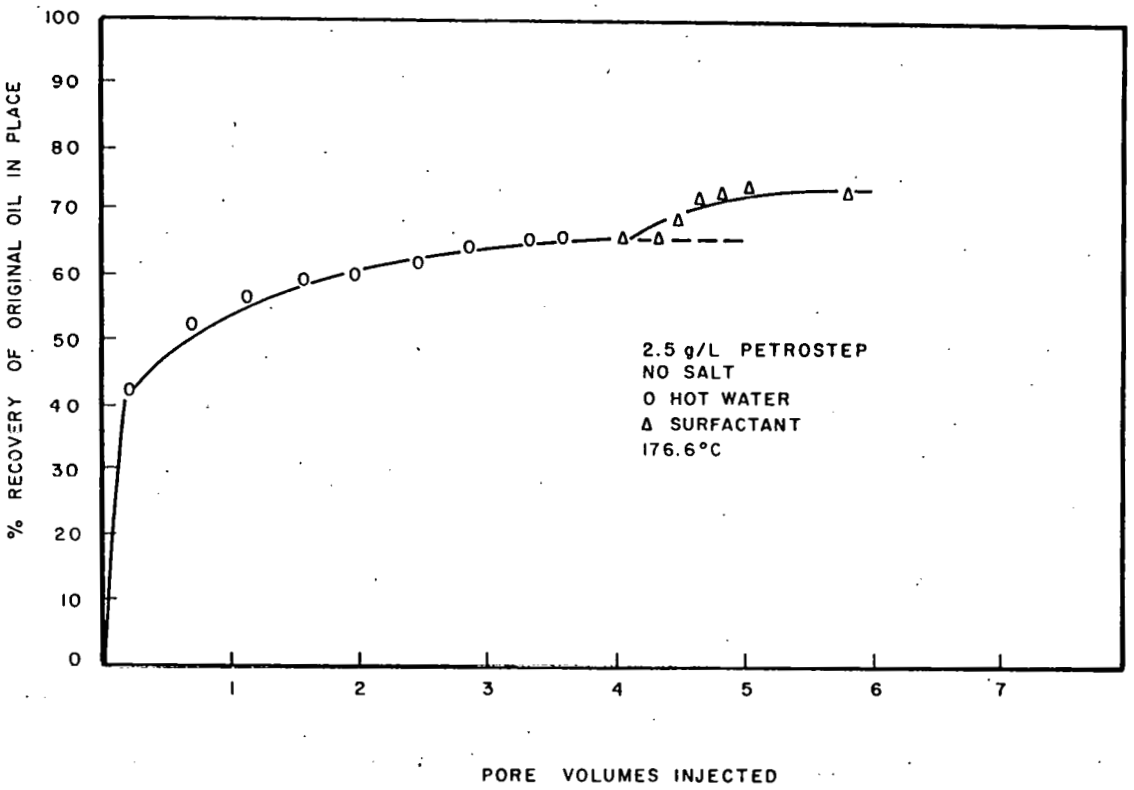


Figure 15. Oil Recovery for Petrostep 465 Surfactant Flood at 176.6°C.

COAL
AN ALTERNATE FUEL FOR
THERMAL ENHANCED OIL RECOVERY STEAM GENERATION

BY

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ABSTRACT

One of the near term options for substantial new domestic energy is Enhanced Oil Recovery (EOR). It is estimated that in existing developed oil fields, approximately 70 percent of the original out-in-place remains unrecovered after production by conventional methods has been exhausted. EOR will allow recovery of a portion of this reserve.

Presently, approximately 30 percent of the oil produced by the steam flood EOR technique is consumed as fuel in generating steam required for the process. Replacement of all or a portion of this crude oil by an alternate fuel would significantly increase the amount of oil available for sale without the need for increasing production from existing operations.

The Davy McKee Corporation has completed a project examining technical and economic aspects of using coal to replace lower tier crude oil as fuel for steam generation in this application. The location of the evaluation was Kern County, California. The primary consideration in the evaluation was compliance with emission limitations as proposed in the California Air Resources Board (CARB) Model Rule on April 26, 1978.

Three coal technologies were evaluated:

1. Coal-Oil Mixtures (COM)
2. Coal Gasification
3. Fluidized Bed Combustion (FBC)

This paper presents background for the project, basis of evaluation and technical and economic results of the project.

Prepared for DOE under Contract No. EX-77-C-01-2418.

INTRODUCTION

The decline of domestic petroleum production in the United States, along with the rising demand for petroleum products, is presenting significant strains on the national economy. Dependence on imported oil continues to increase as domestic reserves diminish at a rate greater than can be compensated for by new expansions and discoveries. One of the near term options for substantial new domestic energy is Enhanced Oil Recovery (EOR).

Presently, approximately 30 percent of the crude oil produced by the steam flood EOR technique is consumed in generating steam required for the process. Replacement of all or a portion of this crude oil by an alternate fuel would help to reduce our dependence on foreign oil sources. The project recently completed investigated the technical aspects of various coal technologies that could be used in this application, as well as the associated economics for implementation.

The intent of the project was not to select a particular technology to be used, or to provide an economic comparison of the technologies selected for evaluation, but rather to present technical and economic aspects associated with each technology.

Two philosophies for coal utilization in this application were investigated. The first philosophy was to examine technologies that could be retrofitted to existing steam generators. The second philosophy was to examine technologies that could be used for replacement or future expansion capacity.

Three coal technologies were selected for evaluation:

1. Coal-Oil Mixtures (COM)
2. Coal Gasification
3. Fluidized Bed Combustion (FBC)

Coal-Oil Mixtures and Coal Gasification were evaluated for retrofit application. Fluidized Bed Combustion was evaluated from the standpoint of providing a direct coal fired steam generator which could be used to provide replacement or future expansion capacity.

The primary consideration in the evaluation was compliance with emission limitations as proposed in the California Air Resources Board (CARB) Model Rule on April 26, 1978. This Model Rule proposes emission limitations for sulfur oxides and oxides of nitrogen from fossil fired steam generators having a heat input greater than five million Btu's per hour.

Adoption of the proposed rule would impose the following emission limitations on affected sources.

1. After September 1, 1980, owners and operators of steam generators which were constructed prior to September 1, 1978, would be required to limit sulfur oxide and nitrogen oxide emissions from such sources to 200 parts per million and 150 parts per million by volume, respectively. Sources subject to these provisions would be required to comply with specified increments of progress.

2. Sources which are constructed after August 31, 1978, would be required to limit sulfur oxide and nitrogen oxide emissions to 60 parts per million and 100 parts per million by volume, respectively, beginning on the date the steam generator(s) commence operation.

The technologies selected for evaluation must be capable of meeting these proposed emission limitations, either uncontrolled or through application of available control technologies.

In order to determine a fuel production or a steam generating requirement, a common basis for evaluation was established. This was done by creating a synthesized field. This field encompassed an area four miles in diameter and contained one hundred-50 million Btu per hour steam generators. When operated at 80 percent utilization, this would represent an annual production capability of approximately 3.5×10^{10} pounds of steam per year.

A Utah coal containing 0.5 percent sulfur, with a heating value of 11,570 Btu per pound was used for process evaluation. Coal costs were developed based on rail delivery to Kern County from central Utah. A delivered price of $40/ton was used in the economic evaluation. Cost of limestone, to be used in the Fluidized Bed Combustion section of the project, was developed based on rail delivery to Kern County from Las Vegas, Nevada. A delivered price of $15/ton was used in the economic evaluation.

The economic analysis of three technologies was based on implementing the coal based systems in the synthesized field. Capital and operating costs, including the cost for emission control equipment where required, were developed for each of the three technologies. In the evaluation of each option, the Internal Rate of Return, IRR, was assumed to be 15 percent after taxes. All figures are in 1978 dollars and are accurate to ±25 percent.

COAL-OIL MIXTURES

The Coal Oil Mixture, COM, concept is based on preparing a liquid fuel containing an appreciable fraction of pulverized coal, which can be burned in existing combustors with a minimum of modification. The resulting fuel would have characteristics which are weighted averages of the constituent fuels, for most properties. A COM containing a coal concentration of 50 percent by weight, would reduce oil consumption by approximately 40 percent.

Implementation of COM in the synthesized field requires construction of a preparation plant to supply the COM. Emission control equipment would have to be installed at the steam generators to reduce emissions of sulfur oxides and nitrogen oxides to acceptable levels. Particulate collection would also be required.

The plan for implementing COM in the synthesized field calls for one preparation plant to service the field. This plant would be located on the perimeter of the field. It is assumed that COM would be distributed to the steam generators using an exising oil distribution system.

The COM preparation plant for the project is a continuous process designed to produce approximately 27,900 barrels per day (405.6 million gallons per year) of stable COM with a 50 percent by weight coal concentration. This production requires approximately 3000 tons of coal per day, 15,800 barrels of crude oil per day and 155 barrels of stabilizer/additive per day. Coal would be pulverized to approximately 80 percent - 200 mesh, and subsequently mixed with crude oil and a stabilizer/additive to produce a stable COM.

Retrofitting steam generators to burn COM requires two considerations:

1. Installation of emission control equipment at the steam generators.

2. Modification of the steam generators to allow for removal of potential ash accumulation.

Estimates of emissions resulting from combustion of a COM containing 50 percent by weight Utah coal and 50 percent by weight lease crude oil indicate that sulfur oxide and nitrogen oxide emissions would have to be reduced by approximately 73 percent and 67 percent respectively to meet CARB limitations for existing steam generators. Particulate reduction required would be approximately 92 percent. Control of SO_2 and particulate emission would be achieved by using double alkali venturi scrubbers. The approach used to control NO_x emissions was non-catalytic ammonia injection.

Modification of a steam generator to allow ash removal presents somewhat of a problem. The present steam generator design does not readily lend itself to this modification. One approach that may be used would be the installation of a lance type soot blower in the bottom of the radiant section which would traverse the length of the steam generator. The objective would be re-entrain deposited ash or move the ash to one end of the steam generator for removal. A collection hopper would have to be installed at one end of the steam generator to receive the ash. The feasibility and success of this approach is speculative.

As can be seen from the previous discussion, burning COM in an environmentally acceptable manner would require scrubbers, non-catalytic ammonia injection and fly ash collection. Installation of this equipment would have considerable impact on the current method of operation. Slagging, ash removal and potential steam generator derating may present additional problems. In order to make an economic evaluation, we have assumed that emission limitations could be achieved by the methods discussed and capital and operating costs were developed accordingly. In addition, we have assumed that a steam generator could be modified to allow ash removal.

COAL GASIFICATION

Application of Coal Gasification was evaluated from the standpoint of producing a low-Btu, or medium-BTu gas which could be utilized in existing steam generators. A medium-Btu gas with a heating value of approximately 290 Btu/scf was selected based on economic considerations. At the scale required for our synthesized field, the economic associated with production of medium-Btu gas are more favorable than those associated with low-Btu gas. Production of equivalent Btu capacity of low-Btu gas would require more gasifiers and material handling equipment. The cost of this equipment would be greater than the cost of oxygen plants needed to produce medium-Btu gas while using fewer gasifiers. At this scale the equipment savings, along with improvement in thermal efficiency associated with the production of medium-Btu gas, justify the cost of oxygen production. It is estimated however that these economics would change in favor of low-Btu gas at a requirement of approximately 30 percent of that needed for our synthesized field.

The plan for implementing Coal Gasification in the synthesized field calls for one gasifier complex to service the field. This complex would be located on the perimeter of the field, with gas being distributed throughout the field by pipeline. The gasifier complex designed for this project calls for the production of 17.8 million SCFH of 296 Btu/scf, desulfurized gas. The production of this gas requires approximately 6800 tons of coal per day, 4500 tons of oxygen per day and 305,000 pounds of steam per hour. An additional 540 tons of coal per day is required to produce process steam for the plant. The use of coal

to generate additional steam to supply operating horsepower, allows the use of the recovered char as a supplemental fuel and improves the thermal efficiency of the project.

The major modification required to retrofit existing steam generators to gas firing would be the installation of a fuel supply train and proportioning system designed for gaseous fuels. The existing oil burner would be replaced by a dual fuel burner (oil or gas). Leaving the existing oil supply and proportioning system intact would give the capability of returning to oil firing if so desired. The design of this burner would differ from that used for natural gas, due to the increased gas volume required for the same Btu input, along with the specific combustion characteristics associated with lower Btu gases. Although considerable work has been done on combustion of lower Btu gaseous fuels, it is anticipated that work would be required to develop a burner which would provide a flame geometry compatible with the combustion chamber of a steam generator.

One factor associated with the use of either medium-Btu or low-Btu is steam generator derating. It is estimated that approximately a five percent derating would result when using medium-Btu gas, while derating would be in the neighborhood of ten percent if low-Btu gas were utilized.

Estimates of emissions of SO_2 resulting from the combustion of either medium-Btu or low-Btu gas indicate that both gases would be in compliance with the CARB standard for existing steam generators, as well as the standard for new steam generators. The use of the proposed medium-Btu gas, with a H_2S content of 100 ppm, would generate approximately 30 ppm of SO_2 in the flue gas of a 50 million Btu per hour steam generator when fired at rated capacity. This is well below the CARB limit of 60 ppm for new steam generators.

Estimates of NO_x emissions indicate that both low-Btu gas and medium-Btu gas would meet the CARB standard for existing steam generators. Low-Btu gas would also meet the standard for new steam generators, however, medium-Btu gas may not achieve this standard. The difference results from a higher flame temperature produced by medium-Btu gas. The adiabatic flame temperature of medium-Btu gas is approximately 3550°F, compared to approximately 2935°F for low-Btu gas. At this higher temperature, oxidation of a greater portion of the nitrogen, available in the combustion air, could result in higher NO_x. Laboratory test work would be necessary to resolve this issue.

Based on the above discussion it is believed that the need for flue gas cleaning devices to meet the CARB standards for sulfur oxide and nitrogen oxide, would not be required. Also, particulate control would not be required.

FLUIDIZED BED COMBUSTION

After examination of various direct coal fired technologies, the one which appeared most suited to EOR steam generation was Fluidized Bed Combustion. In FBC, coal is burned at relatively low temperature, 1400° to 1700°F, at approximately atmospheric pressure, in a bed of inert material. This bed material, which can be ash, sand dolomite or limestone, is subjected to an evenly distributed air flow which causes it to expand and become suspended in the gas flow. As the air velocity increases, the bed becomes highly turbulent and takes on the appearance of a boiling liquid. In this state, the bed is said to be "fluidized." Although there are no steam generators of this type in operation, there is considerable potential for FBC in this application.

The primary advantage of FBC over other combustion techniques is its ability to capture a high percentage of fuel sulfur when using a bed material such as limestone. This feature eliminates the need for expensive scrubbing equipment. Other benefits associated with FBC are lower emissions of oxides of nitrogen, high heat transfer coefficients, and volumetric heat releases, reduction or elimination of slagging and fouling, and dry waste material in an easily handled form.

The plan for implementing Fluidized Bed Combustion in the synthesized field calls for ten groups of FBC steam generators, with each group containing ten steam generators. Each unit would be rated at 50 million Btu per hour. Selection of this capacity was based on a unit size that could be shop assembled for shipment to the field as a package. This would minimize field erection and in turn lower overall cost.

The operation of each of the groups of ten FBC units requires approximately 730 tons of coal per day and 210 tons of limestone per day. Total coal and limestone requirements are approximately 7300 and 2100 tons per day respectively.

In order to meet emission limitations of the proposed CARB model rule, emission control equipment is required to reduce NO_x particulate emissions. Sulfur capture by limestone in the bed is sufficient to limit SO_2 emissions to an acceptable level.

Although test data from various sources indicate that uncontrolled emissions of NO_x from FBC units are below existing federal regulations, this level exceeds the limitations for new steam generators of 100 ppm as proposed in the CARB model rule. It was estimated that a reduction of approximately 80 percent would be required in order to be in compliance with the CARB limitation. A catalyic ammonia NO_x removal process was selected to be used in this application to achieve this reduction. Particulate emission control is accomplished by mechanical cyclone collectors followed by baghouse dust collectors.

ECONOMICS

The economic analyses for the project were based on implementing each of the three coal technologies in the synthesized field. Economics were developed on the basis of providing fuel or steam generating capacity to satisfy this criteria. It was recognized that the economics associated with each technology are not competitive with current operations using lower tier crude oil. World oil pricing would most likely be required to make these technologies economical.

It must also be noted that the results of the economic analyses do not lend themselves to direct comparison. Whereas the Coal-Oil Mixture and Coal Gasification programs would utilize existing steam generators, and hence are evaluated in terms of additional production costs, the Fluidized Bed Combustion program entails replacement or addition of steam generators. In this case, the calculated production cost more closely represents a total steam production cost. In addition, it must be emphasized that Coal Gasification exhibits greater economy of scale than either Coal-Oil Mixtures or Fluidized Bed Combustion. On a scale smaller than the synthesized field, it is expected that the incremental cost per thousand pounds of steam associated with these two technologies would be relatively close to that of the synthesized field, whereas this cost for Coal Gasification would increase. On a scale larger than the synthesized field, it is anticipated that costs associated with all three technologies would decrease.

Implementing the coal based systems in the synthesized field results in an additional cost for production of a thousand pounds of steam. For Coal-Oil Mixtures this figure is approximately $3.11. For the alternative of Coal Gasification the added cost is $6.00 per thousand pounds of steam. Implementation of Fluidized Bed Combustion in the synthesized field yields a steam production cost of approximately $6.36 per thousand pounds of steam. The operating costs and fixed charges contributing to these costs are shown in Table 1. In terms of dollars per barrel of oil available for sale, these costs would require an addition of $5.69, $9.00 and $9.54 respectively to the present per barrel selling price.

As can be seen from Table 1, the major portion of the cost associated with generating a thousand pounds of steam is attributed to the cost of raw material and in particular coal. Figures 1 thru 3 present sensitivity of steam cost as a function of the delivered price of coal. Varying this price by 25 percent above and below the value of $1.72 per million Btu used in the study yields costs per thousand pound of steam of $3.37 and $2.86 respecitvely for Coal-Oil Mixtures. The same variation for Coal Gasification yields a cost range of $6.70 to $5.22 per thousand pound of steam. For Fluidized Bed Combustion this cost range is $6.88 to $5.83 per thousand pound of steam.

ontinued operation of existing steam generators would require a capital xpenditure for pollution control equipment in order to meet the proposed CARB limitations. In order to estimate the cost that would have to be incurred to bring an equivalent existing operation into environmental compliance, a Base Case was established. It was estimated that this cost would add approximately $0.48 to the cost of producing a thousand pounds of steam. In terms of dollars per barrel of oil available for sale, this would represent an addition of $1.03 to the selling price per barrel. Applying these figures as credits to the coal based system costs results in a net additional cost of producing a thousand pounds of steam of $2.63 for Coal Oil Mixtures, $5.52 for Coal Gasification and $5.88 for Fluidized Bed Combustion. These costs are summarized in the following table:

Added Cost of Steam Production

Technology	Cost ($ per 1000 lbs Steam)		
	Coal Based System	Base Case Environmental Control	Net
Coal-Oil Mixtures	3.11	0.48	2.63
Coal Gasification	6.00	0.48	5.52
Fluidized Bed Combustion	6.36	0.48	5.88

In terms of dollars per barrel of oil available for sale, these costs would represent an addition of $4.66, $7.97, and $8.51 respectively to the per barrel selling price. In all cases the added cost includes the cost of new fuel rather than its incremental cost over existing fuel cost structure. In other words, no credit was taken for the cost of fuel currently being used.

CONCLUSION

The results of the project indicate that technically, coal could be used as an alternate fuel in the application. The results of economic analyses of the three coal based technologies however, clearly indicate that none of these technologies are economically competitive with the current regulated price in effect on oil produced from existing operations. The economics do indicate however, that the costs could be justified if world oil pricing were applied to oil produced by EOR techniques. President Carter's recent decision to decontrol the price of heavy oil may however provide the incentive required to make coal based systems viable in this application.

ADDED OPERATING COSTS AND FIXED CHARGES

TABLE 1

COST ($ PER 1000 LBS STEAM)

ITEM	COM	COAL GASIFICATION	FBC
Raw Materials (Not Incremental)	1.82	2.73	2.35
Other Operating Costs (Variable)	.46	.37	.50
Labor (Semi-Variable)	.08	.14	.22
Ad-Valorem Taxes and Insurance	.08	.30	.40
Total Incremental Operating Costs	2.44	3.54	3.47
Capital Charges	.67	2.46	2.89
Total Cost	3.11	6.00	6.36

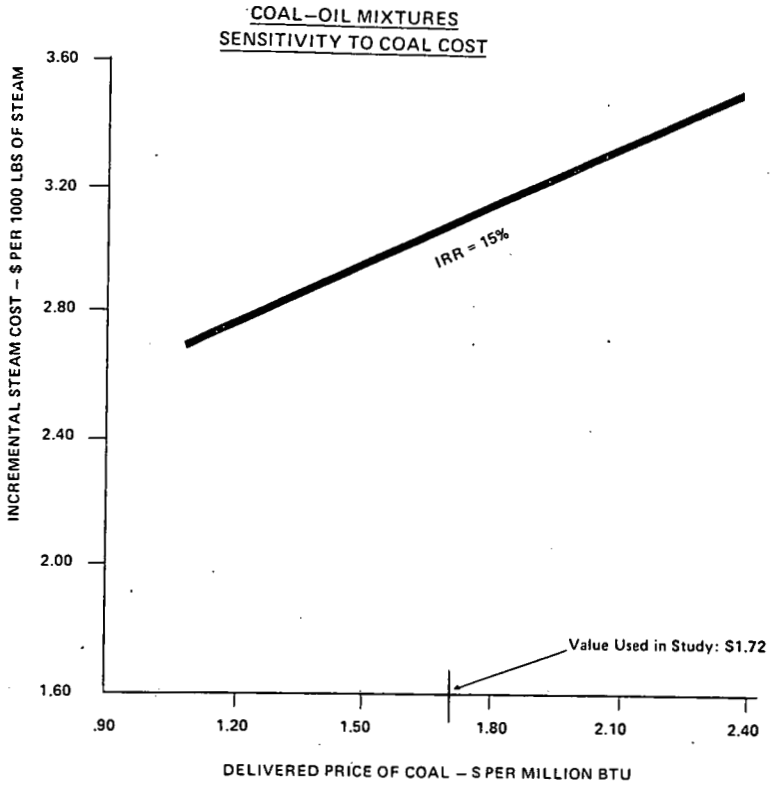


FIGURE 1

COAL GASIFICATION
SENSITIVITY TO COAL COST

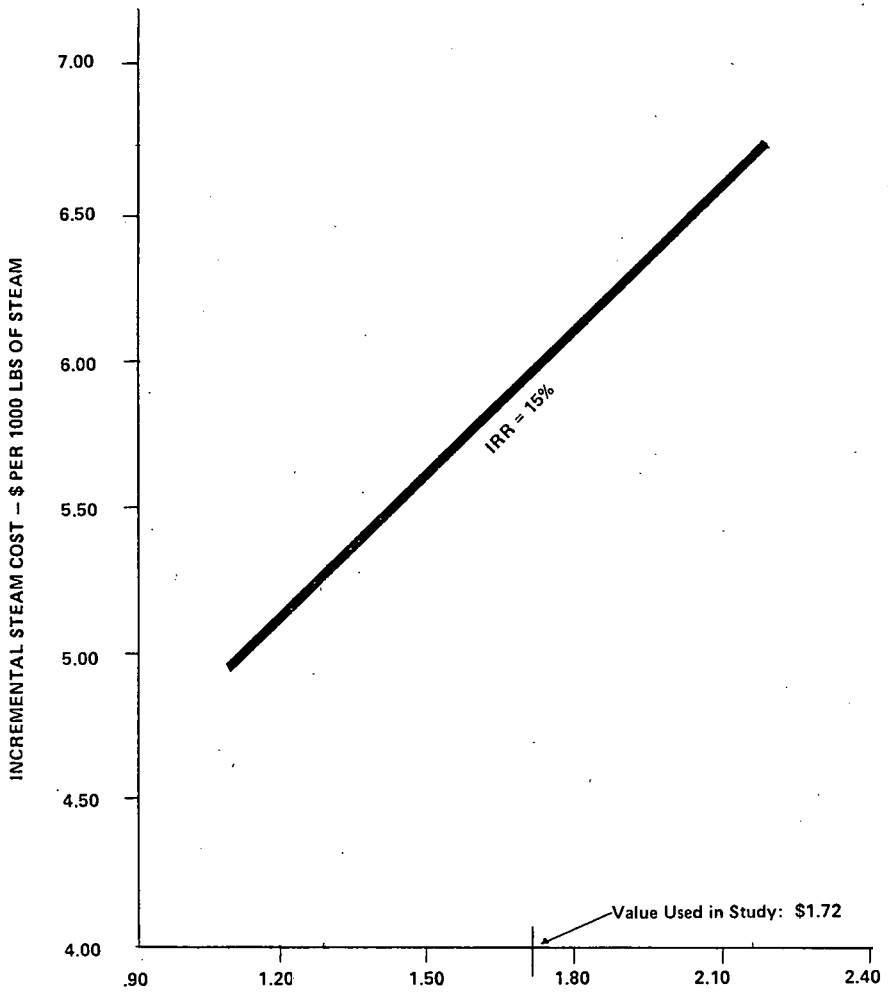


FIGURE 2

FLUIDIZED BED COMBUSTION
SENSITIVITY TO COAL COST

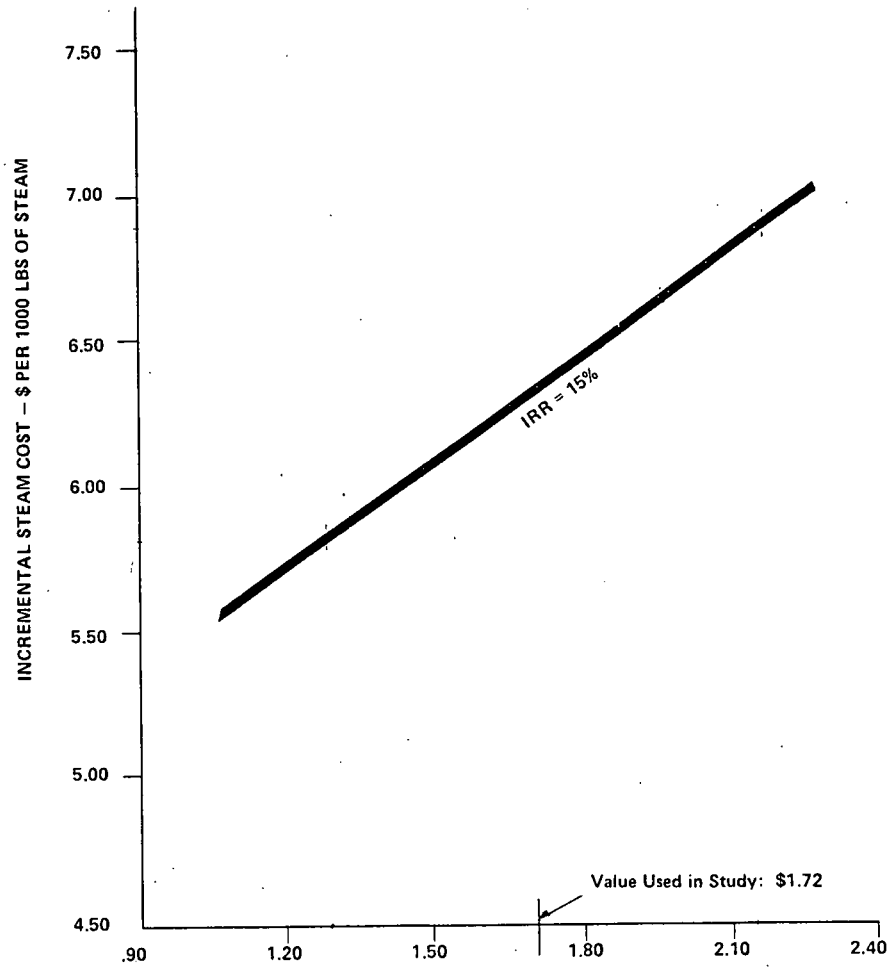


FIGURE 3

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DETERMINATION OF EOR TECHNOLOGY TRANSFER REQUIREMENTS

A Survey of the Data Needs of the Oil Industry and Other Users of EOR Technical Information

By
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ABSTRACT

Spears and Associates, Inc., is conducting a detailed field study to determine the technical information needs of current and potential users of enhanced oil recovery data. Under the direction of the Bartlesville Energy Technology Center (BETC), the study is designed to: (1) identify groups which have a need for EOR-related information, (2) determine the specific information needs of each user-group, and (3) outline methods for improved transfer of appropriate information to the end users. Closely allied to those tasks, this study is designed to uncover attitudes toward the EOR-related efforts of the U. S. Department of Energy (DOE) and the BETC and determine the role each should play in facilitating the commercialization of EOR processes. In addition, Spears and Associates will assemble a reference source containing all environmental regulations and guildelines relating to EOR. This reference source is to be in a language format which will make it a useful tool to personnel involved in on-site field operations.

The purpose of the project is to provide information to the BETC so that the commercialization of EOR processes will be accelerated by the improved transfer of state-of-the-art EOR technology. That task, together with the associated task of defining the role the DOE and BETC should play in the encouragement of EOR activities, is designed to increase the production of the domestic oil reserve and lessen the United States' dependence upon foreign oil imports. In addition, the compilation of an EOR environmental handbook will allow those personnel developing EOR programs and managing EOR field operations to minimize possible difficulties in operating within environmental regulations established by federal, state and local governments. Project work will be completed in December, 1979.

Prepared for DOE Under Contract No. DE-AC19-78BC00050.

INTRODUCTION

To determine the EOR information needs of various segments of the petroleum industry and other affected groups, Spears and Associates is conducting a survey of approximately 300 users and potential users of EOR information. Included in the survey sample will be representatives of major oil companies, independent oil companies, engineering consulting firms, university and private research organizations, financial institutions and federal, state and local policy-making bodies. In-depth questionnaires have been specifically designed for each group. Included in the questionnaires are items pertaining to (1) current level of EOR activity or interest, (2) current and projected EOR information needs, (3) assessments of the BETC's current information services and suggestions for improvement, (4) delineation of technical and economic constraints to increased EOR activity, and (5) steps the DOE might take to enhance the attractiveness of commercial EOR operations.

METHODOLOGY

To assure data quality and access to EOR decision-making respondents, the data gathering effort is being conducted by 14 Spears and Associates market research professionals. This interviewing team is made up of seven experienced field consultants (geographically located in key oil producing regions) and seven analysts and executive consultants from Spears and Associates' Tulsa staff. Personal interviews are being conducted with EOR information users in the following categories:

SURVEY INTERVIEW MIX

Data User-Group	Number of Interviews
Major Oil Producers	30
Independent Oil Producers	90
Oil Field Service Companies	20
Chemical Suppliers	15
Engineering and Research Consultants	15
Financial Institutions	30
Federal Administrative and Legislative Policy	20
State Administrative and Legislative Policy	40
Local Policy	15
Universities	15
Environmental/Consumer Groups	10
TOTAL	300

Interview candidates have been selected on the basis of their known interest in EOR or their resources with EOR potential. Independent oil producers are the most difficult group to pre-qualify and are being selected at random from areas expected to have high EOR potential. Whenever possible, interviewers are contacting those companies believed to have reserves or resources adequate enough to warrant an enhanced recovery project.

Throughout the study, Spears and Associates is using a liberal definition of "major" oil producers. Companies included in the Chase Group (a listing of oil companies maintained by Chase Manhattan Bank) and other large companies with integrated production, refining and marketing operations are considered major oil producers.

Survey work began in May and will be completed in August. Tabulation was initiated in June and will be completed by September. Analysis of the survey data will take place this fall. A final report on the results of the study and the publication draft of the environmental regulations handbook will be delivered to BETC in December.

PRETEST OF SURVEY QUESTIONNAIRE

A pretest consisting of interviews with 42 respondent companies was conducted in March and April to determine the effectiveness of the questionnaire design. Groups contacted during the pretest were: major oil producers, independent oil producers, financial institutions, academic institutions, engineering/technical consultants, and oil field service companies. Interviews were highly satisfactory. Spears and Associates' field interviewers were able to obtain personal interviews with executive-level respondents who are intimately familiar with EOR and are instrumental in developing or implementing their companies' EOR programs. Many interview sessions involved three to five participants. Interviews averaged 60 to 90 minutes in length.

ANALYSIS OF PRETEST RESULTS

In evaluating the results of pretest interviews, it is imperative to remember the purpose of the pretest phase. The pretest was intended to assess the validity of the survey instrument and determine if the intended information was being obtained through the questionnaire. In no way was the pretest designed to provide quantifiable results for analysis. If anything, it is erroneous to use pretest results as a basis for decision making. The pretest sample represents less than one-seventh of the total survey sample, and all interviews were conducted before President Carter announced decontrol of crude oil prices on April 5. In addition, the pretest interviews were not geographically representative of the entire nation. Thus, the results of the final survey may be considerably different from those which might be inferred from the pretest alone. The following pretest trends are presented in this paper for information only.

SUMMARY OF PRETEST TRENDS

It is premature to accept these pretest findings as anything but preliminary. However, the following distinct trends emerged during the pretest:

1. The level of EOR activity and interest is greatest in major oil companies, which have greater technical and financial resources than independents and can better afford to undertake EOR research programs.

2. Most independent oil companies do not have the technical or financial resources to undertake EOR research projects. Of those which have started such projects, the majority have been able to do so only because of DOE cost-sharing programs.

3. Some oil companies are reluctant to participate in DOE cost-sharing programs because of alleged delays, bureaucratic red tape and what the producers consider the federal government's "adversary" posture toward the oil industry.

4. Most major and independent producers believe the technical and economic restraints to EOR are interrelated and that the economic constraints are of greater significance than technical shortcomings.

5. Most oil service companies are aware of state-of-the-art EOR technology but have not undertaken their own research into technical application of EOR techniques. Service companies indicate that EOR does not involve processes or equipment which they do not currently utilize. The difference is that EOR operations require greater precision.

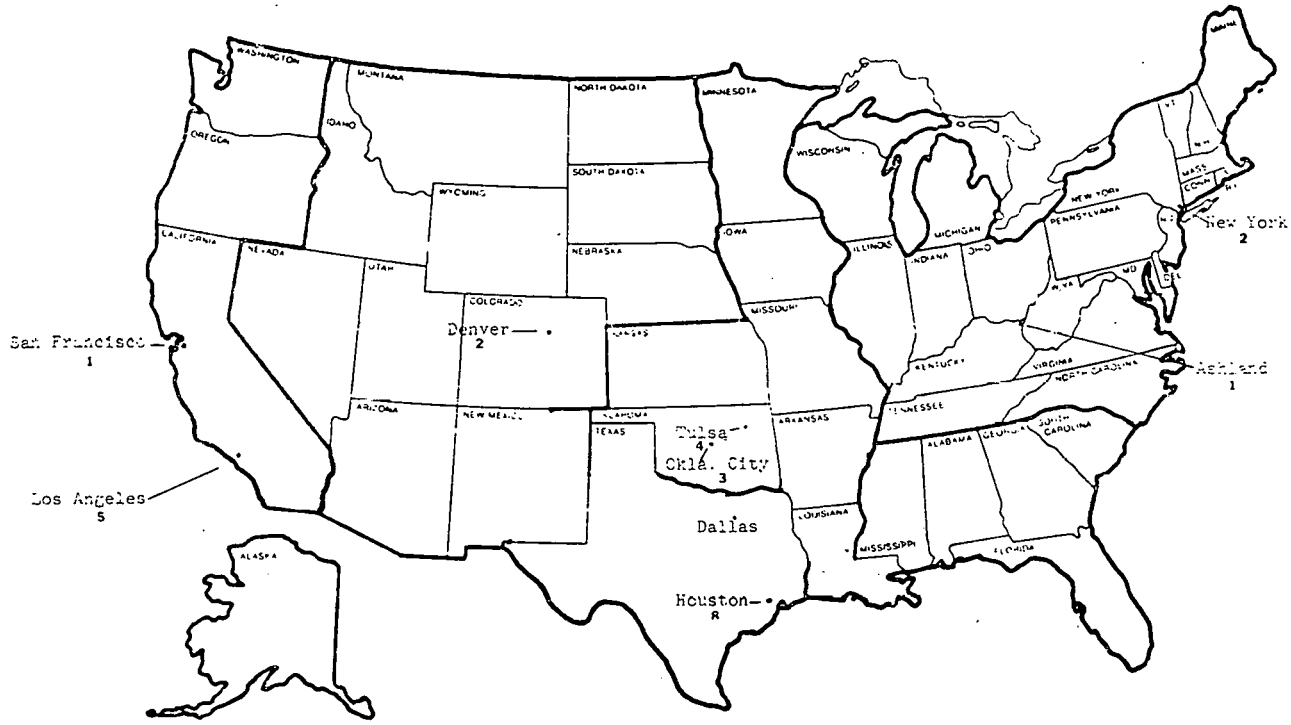
6. Under current loan procedures, all traditional "petroleum" banks interviewed during the pretest said they have not financed -- and will not finance -- EOR projects on a non-recourse basis. There seems to be no shortage of funds to be invested in oil activity, but such funds are generally loaned only to finance proven production. Banks currently consider EOR too risky to lend money on the basis of projected production. Banks indicate that they are willing to finance EOR projects through "balance sheet" loans (based on a company repayment guarantee or pledge of assets), but such terms are generally unacceptable to major oil companies and beyond the resource capabilities of most independent producers.

7. By and large, engineering consulting firms are aware of state-of-the-art EOR technology but have no interest in undertaking EOR research of their own. Their interests lie only in applying proven EOR techniques to commercially profitable projects operated by independent producers. Consulting firms, apparently under the mistaken impression that they will be "giving away" EOR expertise, are the only firms which have, upon occasion, been reluctant to participate in this survey.

8. Most major oil companies and many independent oil companies receive EOR information disseminated by the BETC. The majority of respondents indicate the material is useful and the most timely information available on a regular basis. Some respondents from major oil companies with a high level of EOR awareness say they would like technical and economic information on pilot projects to be given in greater detail. Respondents from independent oil companies, many of whom have nothing but an academic interest in EOR, say they would like information in a more capsulized form.

Figure 1

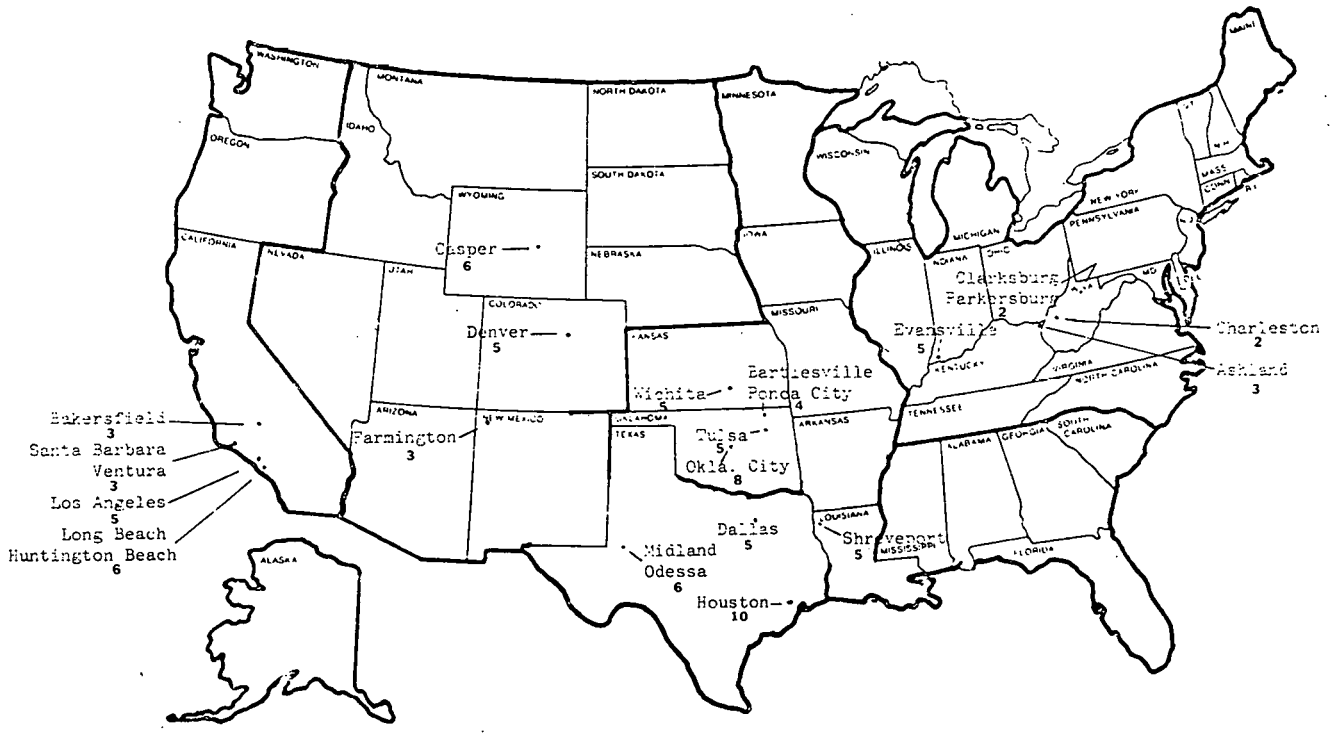
MAJOR OIL PRODUCERS



NOTE: Numbers indicate total interviews in each area

Figure 2

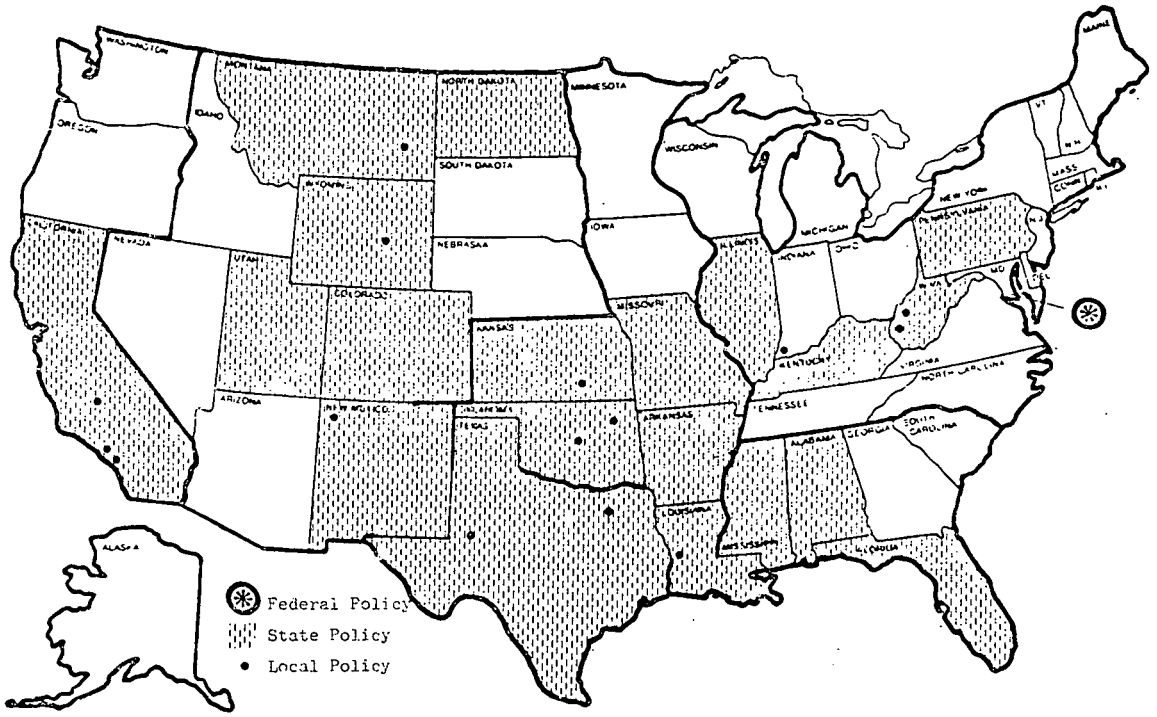
INDEPENDENT OIL PRODUCERS



NOTE: Numbers indicate total interviews in each area

Figure 3

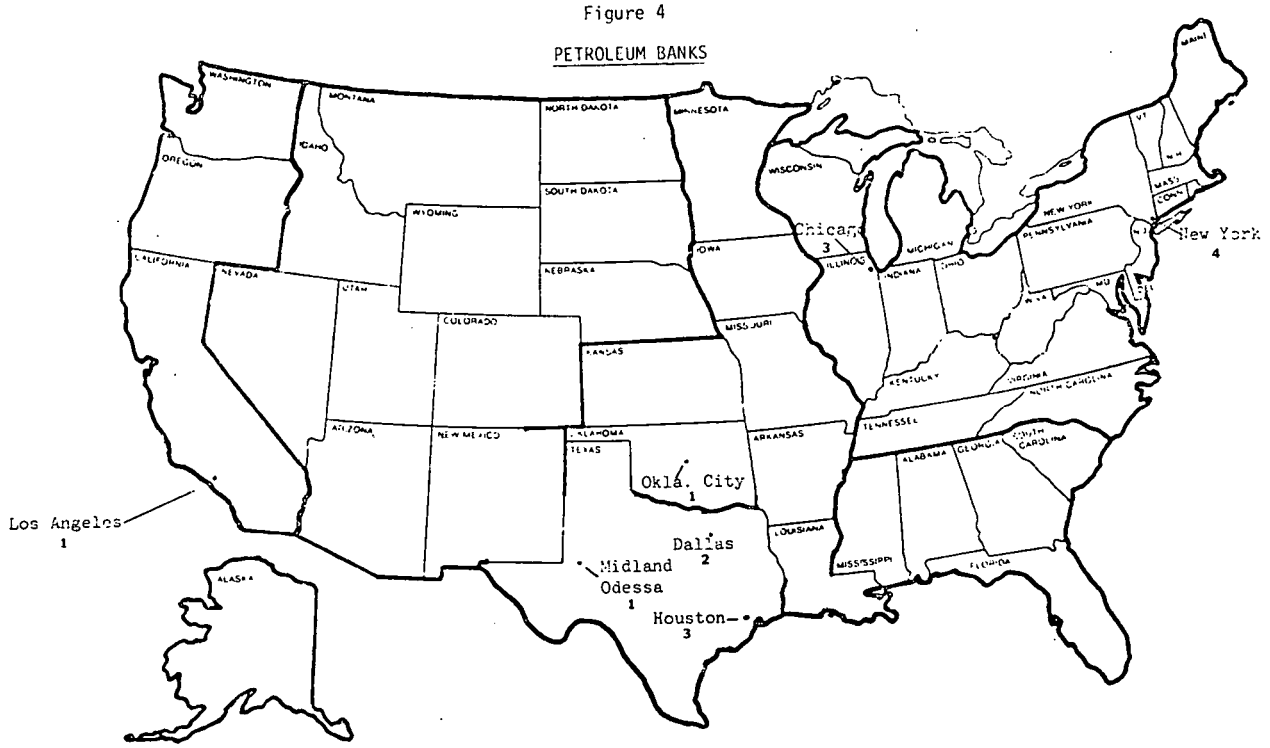
POLICY GROUPS



NOTE: Shaded areas and dots indicate states and cities included in survey

Figure 4

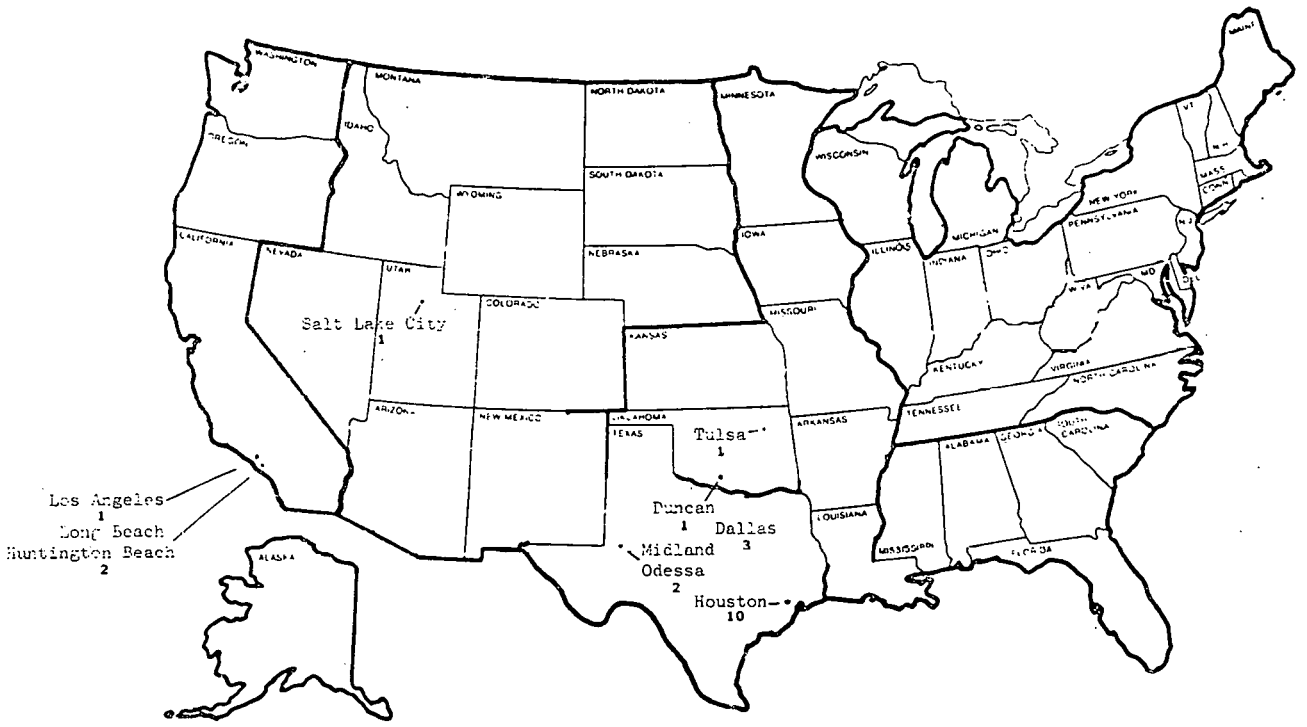
PETROLEUM BANKS



NOTE: Numbers indicate total interviews in each area

Figure 5

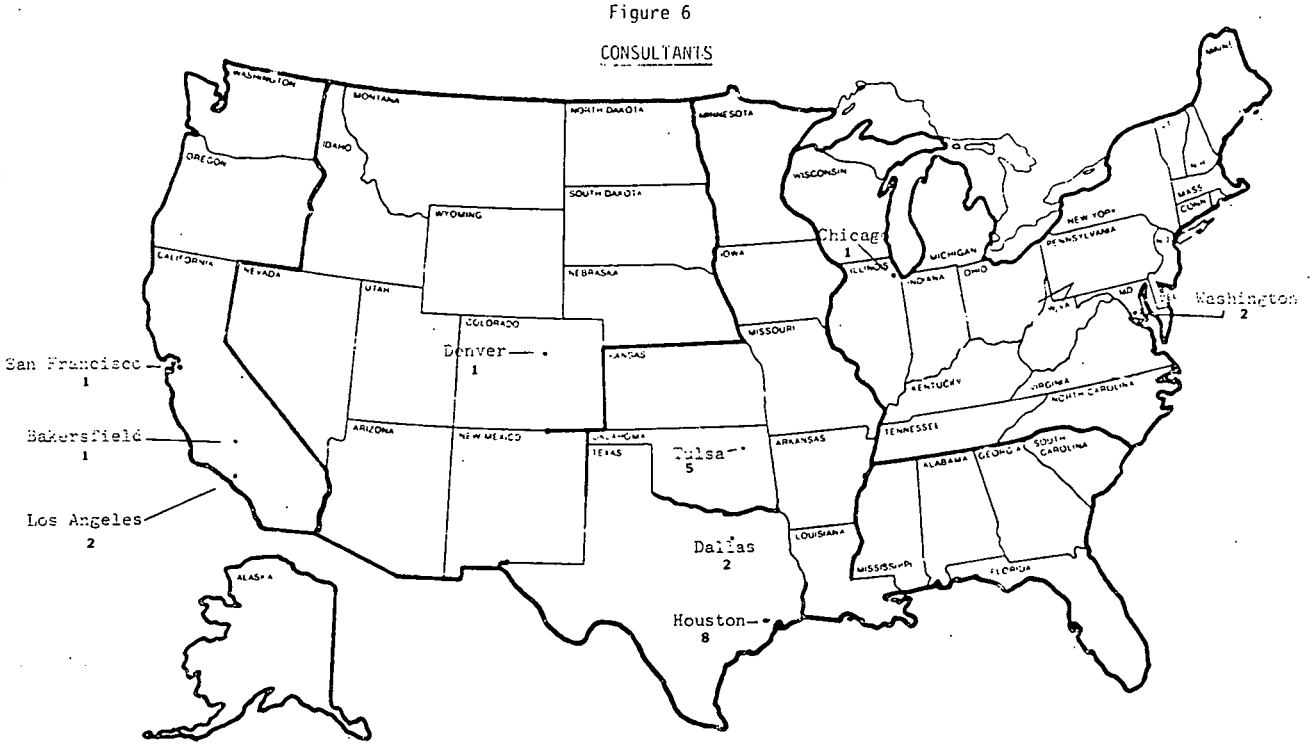
OIL FIELD SERVICES



NOTE: Numbers indicate total interviews in each area

Figure 6

CONSULTANTS



NOTE: Numbers indicate total interviews in each area

BIBLIOGRAPHIC DATA BASES: KEY TO EOR INFORMATION

by

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ABSTRACT

On-line systems for bibliographic and patent information retrieval are becoming widely used because of convenience and speed. A terminal, telephone, and password provide an individual or company with information formerly available only through tedious, time-consuming manual searches in a library. Commercially available data bases most useful for enhanced oil recovery (EOR) applications include Tulsa, APILIT, APIPAT, GeoRef, Compendex, NTIS, SSIE, Energyline, Enviroline, Pollution Abs, and CA Condensates. Files of interest are FEDREG and USCA, the on-line versions of the Federal Register and Commerce Business Daily, respectively.

INTRODUCTION

It is the responsibility of the individual to continue his professional growth by keeping up with the latest developments in his field; however, because of the quantity of information available on EOR, it is no longer feasible to do this solely by reading a few popular journals or by depending upon colleagues for supplementing awareness of pertinent information.

So, how does one know what has happened or is happening in the area of EOR? At the Department of Energy's Bartlesville Energy Technology Center (BETC), the technical staff is aided by an on-line bibliographic literature search service provided by the technical library. On-line searching seems at the present the only way to keep up with the large quantities of material published in the rapidly expanding field of EOR. For many researchers the unique opportunities and advantages offered by on-line searching are so new that they may not be utilizing this technical service. In the hands of a skilled operator, on-line bibliographic retrieval systems can quickly provide a busy researcher with a wide range of valuable bibliographic information. How on-line bibliographic retrieval systems work and a description of data bases of particular application to EOR follow.

The term "on-line" refers to the fact that a searcher is in direct communication with a data base and is conducting a search in a conversational manner with a computer. This interaction between the searcher and the computer requires a terminal connected to the computer through communications lines.

Reference to specific data base services does not imply endorsement by the Department of Energy.

There are two types of on-line interactive terminals: hard copy and display. At the BETC technical library we use a hard copy non-impact terminal in which a heated stylus moves across specially coated paper and the character image is essentially burned into the paper. Cathode ray tubes (CRT) are presently the most wide-spread type of display terminal. A beam of electrons controlled by electromagnetic fields set up across the path of the beam impacts on the back of the tube face and causes the phosphor-coated surface to emit light. Characters are generated from a pattern of dots. For information retrieval purposes, it is necessary to supplement a display terminal with a printing device capable of recording on paper anything displayed on the viewing screen.

Most organizations have a terminal which can be used for on-line bibliographic searching, but an acoustical coupler is required to permit data communications through an ordinary telephone. If access on existing equipment is not practical, then a small portable terminal may solve the problem. Portability is a desirable characteristic in a terminal used for on-line searching because the search then can take place in any office or lab--in some cases even at home. If purchasing a terminal, another aspect which should be considered is the baud rate. Whereas 300 baud rate terminals were the rule when on-line searching first became popular, 1200 baud rate terminals provide savings in computer connect time.

The terminal communicates with the computer by means of communications lines. A variety of data communications arrangements are available. An organization may use basic direct-dialing, arrange for private leased lines, or use the services of data communications networks such as TYMNET and TELENET.

Once the terminal and communication system are decided upon, commercially available search services make on-line searching so simple that anyone can confidently use one in a matter of hours. The services used at BETC are System Development Corporation's (SDC) ORBIT, Lockheed Information Systems' DIALOG, and the Department of Energy's RECON. At least two other services should be considered: Bibliographic Retrieval Services, Inc. (BRS) and the Information Bank of the New York Times.

Search services enter into licensing agreements with data base producers such as the University of Tulsa (Petroleum Abstracts) and the American Chemical Society (Chemical Abstracts). The data base producers allow the search services to load the data bases onto their computer system and to offer on-line access. If an individual requires a bibliography of information in some area of petroleum production, without on-line access he would go to the library and search the subject indexes of Petroleum Abstracts. With on-line access he dials SDC's computer in Santa Monica, California, through his password, identifies himself as a bona fide user of Petroleum Abstracts, and asks to be connected to "File Tulsa." He can then search Petroleum Abstracts from 1965 forward for the required information in a matter of minutes.

These on-line systems operate in such a way that each terminal user is given processing time when he needs it, thus creating the illusion that he is

e only user of the computer facilities. The computer receives data, processes it, and returns the results quickly enough to be used in an ongoing activity. Most of the time response is immediate.

The majority of on-line systems consist of three separate but related files: the index file, the inverted file of postings, and the unit record file. The index is an alphabetical list of searchable terms in the data base. This file contains the number of postings for each term and the address on the disk where the postings are stored. The inverted file stores a list of document numbers to which each index term applies. The unit record file stores bibliographic data for each document in the data base. For example, you want to know how many patents have been issued to Texaco on tertiary recovery. The index file can tell the searcher in seconds how many postings are listed for patents, how many for Texaco, and how many for tertiary recovery. When the searcher asks that the three sets be combined, the system goes to the appropriate addresses for the three terms in the inverted file, reads the document numbers associated with them into the core, compares the lists, and recognizes that there are common numbers in the three lists. If the searcher wants to see these, he enters the appropriate command causing the records for these items to be retrieved from the unit record file and displayed at the searcher's terminal.

This example of a possible search illustrates two main advantages of on-line searching: (1) the system reports how many postings it has in the index file for a term in a matter of seconds, which is not possible by searching hard copy indexes, and (2) terms can be combined using Boolean logic and the results shown in a matter of seconds, also not possible with the hard copy indexes. Another advantage is that through search services such as SDC and Lockheed, over a hundred different data bases are accessible right in your own office. The NTIS on-line data base on Lockheed's service contains the bibliographic records of government-sponsored scientific and technical research from 1964 to the present and is growing at a rate of 60,000 abstracts per year. Most technical libraries subscribe to the hard copy, Government Reports and Announcements (GRA), which is issued twice a month; but if you need occasional access to government reports without the bulk of the paper copy, on-line access is the logical route. The convenience of having a variety of information at hand amounts to a lot, but the savings in space and time equal dollars. Individuals and companies needing bibliographic information for any reason cannot afford to ignore this information source.

A description of what is needed for on-line bibliographic searching and an elementary description of how it works may be further expanded by a description of how we utilize it at BETC.

Although on-line retrieval systems have been widely used since the early seventies, they were not introduced at BETC until early 1977; the primary object being accessibility to RECON, DOE's information retrieval system at Oak Ridge, Tennessee. At that time the particular data base of interest to our staff was the Energy Data Base (EDB) which provides bibliographic data for government reports as well as books, conference proceedings, patents, and journal literature falling into the broad area of energy information. From a

practical point of view, it was felt that access to EDB would help utilize the huge quantity of reports received by BETC through standard distribution from DOE's Technical Information Center. Ideally, a subject search would provide a bibliography of pertinent reports or articles, and this could then be checked against our report and journal holdings lists.

Although the staff at BETC found RECON more than adequate for some needs, we recognized that it did not provide the comprehensive bibliographical information needed in specific areas of research. Therefore, contracts were signed with both Lockheed Information Systems and SDC so that access to the data bases on these services, along with RECON, now provides just about any bibliographic information the staff at BETC could possibly need.

Ordinarily this information is utilized by a researcher sitting down with the searcher and planning the literature searching strategy before the searcher goes on line. This is accomplished by utilizing a data base thesaurus, if it is available, and Boolean logic. The data base most frequently used at BETC is Tulsa, the on-line version of Petroleum Abstracts. By using the thesauri produced by the University of Tulsa, index terms are selected for the search. The use of Boolean operators AND, OR, and NOT tailor the search to specific needs. When two or more entries are linked by AND, only those unit records are retrieved which have been indexed by all the ANDed terms in the search statement. Linking two or more entries with the word OR results in the retrieval of all unit records that contain either one or more of the ORed terms in the search statement. When a term is preceded by NOT, the program rejects any unit record containing the term following NOT. After the search strategy is planned, the searcher then accesses the data base or bases which apply to the subject needed. Having the researcher at hand during the search is preferable so that he can make changes in the strategy, if necessary, or judge the relevance of results. There is no reason why the individual researcher cannot perform the actual search on line; however, on-line searching techniques and an awareness of the many different data bases and system improvements must be constantly updated. Few researchers have the time to do this and would rather depend upon a search specialist for the actual mechanics of the search.

After a search is completed, the researcher has a list of literature citations related to his particular interest. The next problem becomes how to acquire the actual documents. At BETC this problem is solved by the library staff. If the Center does not own the needed document, it is either borrowed from another library or purchased. If library services are not provided by your company, don't despair. Most public libraries provide interlibrary loan services as well as advice on where to get information. Many public libraries, including Tulsa City-County, provide on-line searching services for a small fee.

So far nothing has been mentioned about the actual cost of using on-line systems. Excluding the terminal and communications costs, Lockheed Information Systems and SDC charge for actual computer connect time. Data base connect time charges vary widely, and many data bases charge lower rates for their hard copy product subscribers. Off-line prints are usually less costly than printing citations on line. At BETC an average search runs around $20.

he cost depends a great deal on planning the search strategy before going on ine, how many prints are either printed out at the terminal or ordered off line, and the computer connect charges for the particular data base used. It is relatively easy to predict and to control the costs of on-line bibliographic searching on the Lockheed and SDC services which BETC uses. It has been estimated that on-line searching costs are less than 20 percent of the costs of manual searching.

There are at least 11 bibliographic data bases accessible through either or both Lockheed's DIALOG Retrieval Service or System Development Corporation's ORBIT Retrieval Service which contain information applicable to EOR.

The Tulsa data base, produced by the University of Tulsa and accessible through SDC's ORBIT, provides world-wide coverage of literature and patents relating to the exploration, development, and production of oil and natural gas. The file covers 1965 to date and is updated quarterly. Computer connect rates are $125/hour and $.50/citation printed off line for minor subscribers and $75/hour and $.15/citation printed off line for major subscribers. Indispensable tools for using the Tulsa data base are the Exploration and Production Thesaurus and the Geographic Thesaurus available from the Information Services Division at the University of Tulsa.

Our experiences in searching the Tulsa data base have been very favorable. In fact, because this data base has such a wide coverage for EOR, DOE has contracted the University of Tulsa to provide a separate data base of just EOR material which is accessible on the DOE RECON system.

The American Petroleum Institute produces two data bases that complement the information on Tulsa. APILIT covering literature and APIPAT covering patents contain citations relating to the petroleum refining and petrochemical industry. These files cover from 1964 to the present and are updated monthly. Both files are accessible through SDC's ORBIT. Rates are $65/hour and $.11/off-line print for subscribers to the hard copy and $85/hour and $.20/off-line print for nonsubscribers. The API Thesaurus, available from the American Petroleum Institute, is an important tool in searching the APILIT/APIPAT files.

GeoRef, accessible through SDC's ORBIT, is produced by the American Geological Institute. It provides world-wide coverage of the earth and planetary sciences. Coverage is from 1961 to the present, and it is updated monthly. Rates are $75/hour and $.25/off-line citation. GeoRef Thesaurus and Guide to Indexing is available from the American Geological Institute. The editorial staff of GeoRef is in the process of indexing all U.S. Geological Survey serial publications that appear in the monthly list "New Publications of the Geological Survey." Obviously, this is an important addition to an already valuable file for EOR.

Compendex is the on-line name for Engineering Index and covers significant engineering literature from 1970 to date. It is updated monthly. As of June, 1979, the file included over 1,300,000 records. Produced by Engineering Index, Inc., access to the data base is available through both Lockheed's DIALOG and SDC's ORBIT for $65/hour and $.10/citation printed off line.

For searching government reports the most comprehensive data base is NTIS, the on-line version of Government Reports and Announcements produced by the National Technical Information Service. The file contains citations and abstracts of government-sponsored research and development reports and other government analyses prepared by federal agencies or their contractors and grantees. The file is accessible through both Lockheed's DIALOG and SDC's ORBIT but with different coverage and charges. Lockheed's file dates from 1964 to present and costs $35/hour and $.10/full record printed off line. SDC's file dates from 1970 to present and costs $45/hour and $.08/citation printed off line. All EOR reports on government-sponsored contracts are supposed to be in this file. Reports in the file can be ordered on line if the searcher has a deposit account with NTIS.

The on-line data base that covers the prepublication gap is SSIE, produced by the Smithsonian Science Information Exchange. The file covers ongoing and recently completed research sponsored by government agencies, associations and foundations. SDC's file covers FY 1974 to date, is updated monthly, and costs $110/hour and $.25/citation printed off line. Lockheed's file contains the latest two years of notices of research projects. Rates on Lockheed are $90/hour and $.20/off-line print. The SSIE data base is non-bibliographic but, as a research-in-progress data base, is important to EOR. This particular data base can help the user: avoid research duplication, obtain information to support a proposal, locate sources of support, identify leads to the literature, identify gaps in areas of research, locate individuals with expertise, and complement bibliographic data.

Energyline is a comprehensive source of citations to energy-related literature. It corresponds to energy materials from Environment Abstracts from 1971 through 1975, and includes all materials from Energy Information Abstracts beginning in January 1971. The data base, produced by Environment Information Center, Inc. (EIC), is accessible through both Lockheed and SDC for $90/hour and $.20/off-line citation. As of February, 1979, the file contained 23,312 records and covers 1971 to present, with monthly updates of approximately 800 records.

Enviroline, also produced by EIC, covers the world's environmental literature. Included are such fields as management, technology, planning, law, geology, and chemistry as they relate to environmental issues. Rulings from the Federal Register and patents from the Official Gazette are included. Enviroline is accessible through Lockheed and SDC at $90/hour and $.20/off-line citation.

Pollution Abstracts on Lockheed and Pollution on SDC are the on-line version of Pollution Abstracts, produced by Data Courier, Inc. It is a leading resource for references to environmentally related technical literature on pollution, its sources, and its control. The file contained 57,600 records as of February, 1979, is updated bimonthly, and coverage is from 1970 to present. The data base costs $75/hour on Lockheed and $65/hour on SDC. Off-line prints are $.15/citation through both services.

Chemical Abstracts, produced by the American Chemical Society, is available on line through both Lockheed and SDC in multiple files and under

different names. Lockheed provides access to Chemical Abstracts as follows: A SEARCH 67-71, corresponding to the 8th Collective Index of the hard copy; CA SEARCH 1972-1976, corresponding to the 9th Collective Index; CA SEARCH 1977-, corresponding to the 10th Collective Index; and CHEMNAME (CA Chemical Name Dictionary), listing chemical substances cited two or more times in the 9th Collective Index period. The cost of the CA SEARCH files is $45/hour and $.08 or .16/off-line citation depending on the format. CHEMNAME is $60/hour and $.12/off-line print. SDC's chemical data bases are CAS7071, CAS7276, and CAS77. SDC's CHEMDEX contains records from the Chemical Abstracts registry nomenclature file. The rates for these files are $60/hour and $.12/off-line print.

Two new files accessible through SDC and of interest to EOR are FEDREG and USCA. FEDREG covers the contents of the Federal Register: new rules, proposed rules, notices, meetings, hearings, public law notices, etc. The file covers March 1977 to date and is updated weekly. Rates are $80/hour and $.25/citation.

USCA or U.S. Contract Awards contains all contract awards announced in Commerce Business Daily in sections A (Experimental, Developmental, Test and Research Work), H (Expert and Consultant Services), and U (Training Services). USCA now contains all FY 78 data and is updated monthly as new FY 79 awards are made. Each unit record contains the project title, awardee, sponsoring organization, funding, Commerce Business Daily announcement date, contract and RFP numbers, and category codes. The cost of searching USCA is $85/hour and $.15/printed citation.

CONCLUSION

Reasons for using on-line bibliographic searching systems for retrieval of EOR information are:

1. AVOID DUPLICATION. Each new research idea should be searched to avoid costly duplication of research effort.

2. COMPLETENESS. A computer can quickly and accurately process a large volume of information. It doesn't get tired.

3. RESOURCE EXPANSION. One can search data bases not subscribed to in hard copy. In this way, resources are greatly expanded.

4. COST. The experiences at BETC show that on-line searching is available at a relatively moderate cost.

5. SPEED. Results of a search are available immediately at the terminal if desired. Off-line prints usually arrive in two days.

6. BOOLEAN COMBINATIONS. There is no limitation on term combinations. Many searches easily done on line would be difficult, if not impossible, to do manually.

7. PRODUCTIVITY. An on-line system can accomplish in a few minutes what would take several hours or more to do by manual methods. Therefore, it greatly increases searcher productivity.

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DATA BASES FOR EOR INFORMATION

Name	Hard Copy Equivalent	Broker	Year Range Covered/ Update Frequency	Computer Connect Hourly Cost	Off-line Print Cost
Tulsa	Petroleum Abstracts	SDC	1965 to date/ quarterly	$125 nonsubscribers $ 75 subscribers	$.50 nonsubscribers $.15 subscribers
APILIT APIPAT	Abstracts of Refining Lit.	SDC	1964 to date/ monthly	$ 85 nonsubscribers $ 65 subscribers	$.20 nonsubscribers $.11 subscribers
Geo Ref	Bibliography and Index of Geology plus other lit.	SDC	1961 to date/ monthly	$ 75	$.25
Compendex	Engineering Index	Lockheed SDC	1970 to date/ monthly	$ 65	$.10
	Government Reports and Announcements	Lockheed	1964 to date/ biweekly	$ 35	$.10
NTIS	(GRA)	SDC	1970 to date/ biweekly	$ 45	$.08
		Lockheed	Latest two years/ monthly	$ 90	$.20
SSIE	None	SDC	1974 to date/ monthly	$110	$.25
Energyline	Environment Abstracts Energy Information Abstracts	Lockheed SDC	1971 to date/ monthly	$ 90	$.20
Enviroline	None	Lockheed SDC	1971 to date/ monthly	$ 90	$.20
Pollution Abstracts	Pollution Abstracts	Lockheed SDC	1970 to date/ bimonthly	$ 75 $ 65	$.15 $.15

DATA BASES FOR EOR INFORMATION

Name	Hard Copy	Broker	Year Range/Update	Computer Connect Hourly Cost	Off-line Print
CA SEARCH 1967-1971 1972-1976 1977-	Chemical Abstracts 8th Collective 9th Collective 10th Collective	Lockheed	 1967-1971 1972-1976 1977-/biweekly	$45	$.08/.16 depending on format
CHEMNAME		Lockheed		$60	$.12
CAS7071 CAS7276 CAS77	Chemical Abstracts 8th Collective 9th Collective 10th Collective	SDC	1970-1971 1972-1976 1977-/biweekly	$60	$.12
CHEMDEX		SDC		$60	$.12
FEDREG	Federal Register	SDC	March 1977 to date/ weekly	$80	$.12
USCA	Commerce Business Daily--Sections A, H, U	SDC	FY 1978 to date/ monthly	$85	$.15

INFORMATION RETRIEVAL FOR THE PETROLEUM PRODUCTION INDUSTRY

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ABSTRACT: The information needs of the exploration, development and production segments of the petroleum industry are being satisfied by the Information Services Division of The University of Tulsa. The Petroleum Abstracts Bulletin, published weekly, provides current awareness of technical articles and patents published in this area of technology, with more than 600 publications being continuously reviewed and pertinent documents selected for abstracting and indexing. Retrospective information retrieval of past publications can be accomplished by printed Alphabetic Subject Indexes and microfilmed Dual Dictionary Coordinate Indexes, or by computer searching of a periodically updated Master Record Tape. Approximately 15,000 new citations are generated each year, and the entire computerized data file, from 1965 to the present, contains more than 210,000 citations. This data bank is currently maintained by the System Development Corporation in Santa Monica, Calif. and is searchable over the Tymshare network by means of the ORBIT IV information retrieval program. The segment of the file pertaining to enhanced petroleum recovery is being prepared for inclusion in the DOE Recon system, and will include machine-readable abstracts for on-line retrieval.

The petroleum industry today is characterized by a rapidly changing technology as new and improved methods are devised for extracting petroleum and natural gas from semi-depleted reservoirs, or under hostile environmental conditions. A flood of technical publications and patents is being issued to document these new techniques, but their number is such as to overwhelm the individual engineer and make it impossible for him to keep abreast of current developments. In a few years, he is in danger of becoming obsolescent unless he takes positive steps to continuously educate himself regarding new industry developments and procedures.

There are a number of ways he can accomplish this. One is to participate in technical society functions, attend technical conferences, and read society publications, for it is here that the latest technological theories and procedures are first publicly released. Another approach is to attend continuing education short courses, offered periodically by these technical societies and by many universities, in which old techniques are reviewed and new developments explained.

Finally, the engineer can comprehensively monitor the current technical publications of the day: technical journals, trade journals, government reports, patents, etc. This seemingly impossible task is made

Prepared for the Department of Energy Under Contract No. DE-AC05-79IR10006.

feasible by "scanning" such new publications by means of an "abstract" journal, which appears at regular intervals and prints short, informative summaries of such publications. Thus, in a few hours, the engineer can scan the contents of hundreds of technical journals, and become aware of the nature of new industrial developments that might affect him and his work. When he does see an item of special interest, he can obtain the original document and read it in detail, without trying to actually read everything that is published, for fear of missing a vital article or patent.

Many abstracting services have been established, devoted to specific industries or areas of knowledge. In the petroleum industry, The University of Tulsa, Information Services Division, publishes a weekly Petroleum Abstracts Bulletin that comprehensively covers the areas of petroleum exploration, development, and production. This coverage includes over 600 different technical journals and government publications, as well as reviewing new patents from many different countries.

Each issue of the bulletin contains from 200 to 300 concise abstracts of published items, published in double-column "newspaper" style, and grouped by subject classifications, for easy reading. Each abstract is preceded by a complete bibliographic citation which includes the title, author, and publication reference of the item, to facilitate finding the original document in the library, if so desired. Approximately 15,000 such abstracts are prepared and published each year.

The Petroleum Abstracts Bulletin is in its nineteenth year and to date, over 265,000 abstracts of technical publications, pertinent to the petroleum industry, have been printed. It is distributed to petroleum companies, worldwide, and they in turn share the cost of maintaining this nonprofit information service.

The advantages of an abstracting service such as this lie not only in its "current awareness" aspects but also in its "information storage and retrieval" capabilities. Published technical data (often referred to as the "known" technical literature) quickly becomes the "forgotten" technical literature, unless some effort is made to organize it so that it can be found later, when needed. Without such a system, it is often easier to duplicate experimental work (a costly and wasteful process) than it is to retrieve the desired data from voluminous library archives.

Most people are familiar with indexes, in which subject headings direct one to items of special interest. Such indexes are greatly enhanced by cross-referencing an item under a number of different appropriate subject headings. This principle is used by The University of Tulsa in its Indexing and Retrieval Services, supplementing the abstracting service. Each item that is abstracted is analyzed with regard to subject content, and a listing is made of all topics discussed in the original document.

In any retrieval system, it is important that a "controlled vocabulary" be used to identify and describe the subject matter of each item. The

existence of synonyms in the system may mean that a person looking for information under a given subject may not find it because it has been "indexed" under another term with identical meaning. To prevent this, The University of Tulsa has prepared an "Exploration and Production Thesaurus," which lists appropriate terms for all indexable subjects, rejecting all synonyms by indicating the preferred term, for retrieval purposes.

Every two months, an Alphabetic Subject Index is published, based on the various topics assigned to each abstract published over the two-month period, and arranged alphabetically by subject. The final index for the year is cumulative, providing a convenient subject index to all abstracts published during the year, in a single comprehensive volume. In addition to the subject index, supplemental listings of bibliographic data, of names of authors and inventors, and of patent numbers are included in each issue of the Alphabetic Subject Index.

Another searching tool, produced semi-annually on microfilm, is the Dual Dictionary Coordinate Index. This index, known as an "inverted index," is arranged, not by abstracts or titles, but by individual topics, arranged alphabetically. Following each topic is a complete list of the abstract numbers of publications pertinent to this subject. In use, the searcher looks up the subject in which he is interested and obtains a list of abstract numbers, to which he can refer in the abstract bulletins. If the subject for which he is searching is very specific, it is possible to combine several general topics and thus eliminate items which only partially meet his requirements.

In addition to inclusion in these manual searching tools, the retrieval data (title, abstract number, authors, bibliographic data, patent numbers, subject designations, etc.) are stored on magnetic tape for computer retrieval. Individual Master Record Tapes are distributed to participating companies for "in-house" computer searching, greatly speeding up the time required to find references on a desired subject, from the entire Petroleum Abstracts file.

Recently, this data file was deposited with the System Development Corporation in Santa Monica, California. This company maintains more than fifty different data banks in computer memory for on-line searching over a Tymshare telephone network, available in most areas of the U.S., and at selected locations in Europe by satellite linkage. Searches can be made in most of these data files (including the Petroleum Abstracts file), with charges based on computer-connect time.

A contract has been completed with the U.S. Department of Energy to provide complete retrieval information (including titles, bibliographies, abstracts, and subject descriptors) on more than 20,000 references (covering the period 1965 to the present) pertaining to the topic of "Enhanced Oil and Gas Recovery Operations." This will include primary, secondary, and tertiary recovery processes, as well as well stimulation methods. When the project is completed, this information will be accessible through the DOE/Recon data base.

Thus, the scientist or engineer of today, if he wishes to obtain comprehensive, up-to-date information on any phase of the petroleum industry, can quickly and easily do so by making a retrospective search of the Petroleum Abstracts files, either by use of printed indexes, or by computer searching.

Any research or development project should begin with a comprehensive look at what is already known on the subject, in published articles and patents, and thus avoid wasteful duplication of effort. As for the individual engineer or scientist, there is no reason why he should not be able to stay up-to-date on all of the latest developments in petroleum technology, with a minimum of effort.

INFORMATION CAN MAKE A DIFFERENCE

by

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Abstract

INFORMATION CAN MAKE A DIFFERENCE

DOE's multifacted technical information system is committed to playing an active and supporting role in solving our nation's energy problems. This can be accomplished by:

1. Assuring information systems, goals, and priorities are fully coordinated and complimentary to DOE goals, objectives and priorities;

2. Improving the coverage, timeliness, and thruput of collecting, organizing, processing, and distributing energy information;

3. Making DOE's Energy Data Base available commercially;

4. Entering into new bilateral agreements with foreign countries substantially expanding information in the DOE Data Base on foreign technology;

5. Capturing and reporting on all DOE research in progress;

6. Designing and implementing new information tools to help managers manage (i.e., TIMS); and

7. Improving information outreach and technology transfer.

INFORMATION CAN MAKE A DIFFERENCE

The work you are doing can have a significant impact in developing solutions to difficult energy problems, but could you carry out your work without relevant and timely information? If you were asked to list the key resources which you utilize to carry out your responsibilities, you would probably list the resources traditionally mentioned - dollars, personnel, equipment and materials and maybe time. We in the information business support the premise that information matters as much as matter matters and that until top management comes to view information as a resource that the relative contributions of information in making things happen will be substantially less than it could or should be.

With that introduction, I would like to tell you about the Department of Energy's Technical Information Center located at Oak Ridge, Tennessee, and show you how our products and services can help you do your job better. It is our philosophy that if our products and services are not helping you, we need to know why and make the necessary changes to assure that they do. The Technical Information Center's mission is to provide information support for the Department of Energy's programs of research, development, demonstration, education, and public awareness. Our products and services are all designed to further this mission and the Department's aims and goals. Within this broad mission, our specific tasks are:

- Collection, Organization, Processing and Distribution of Energy Information
- Data Base Production
- Information Retrieval (DOE/RECON)
- Information Outreach (internal and public)
- Technology Transfer

TIC identifies, locates, and acquires the world's energy related scientific and technical literature regardless of language or form and determines its validity and worth to the DOE Energy Information Data Base.

Literature is acquired by the following methods:

Routine distribution to TIC by DOE contractors and some U. S. Government agencies.

Bilateral agreements with foreign establishments.

Publication exchanges initiated either by TIC or by the exchange partner.

Gifts (books, conference proceedings, journals, and other published literature).

Direct purchases.

Directly from the publishing outlets of technical societies, such as the American Institute of Physics, and from Engineering Index.

From other government agencies, such as National Technical Information Service (NTIS) and National Aeronautics and Space Administration (NASA).

This information is then evaluated, recorded, abstracted, indexed, categorized, and cataloged. The computer-based records that are created as a result of these activities create various data bases which are used to provide a wide variety of products and services for users of information. These data bases include:

Energy Data Base (EDB)

Our principal product is the Energy Data Base (EDB). This is the corpus of bibliographic citations, appropriately categorized, abstracted, and indexed that, as nearly as we can make it, covers the world's literature of energy, conventional, alternative, and future. At present, this collection numbers around 1,000,000 items. It contains records of DOE reports, other reports, monographs, theses, patents, journal articles, and conference literature, on the subjects of solar energy; geothermal energy; fossil and synthetic fuels; fusion energy; nuclear energy; energy conservation; energy policy and management; energy storage; energy conversion; advanced automotive systems; electric power engineering; socioeconomic and environmental aspects of energy source development and utilization. It is searchable as a whole through the on-line retrieval system, DOE/RECON, and it is used as a reservoir of data from which other products are obtained.

Research in Progress (RIP)

The RIP file contains records that characterize energy and energy-related research projects. Designed especially to provide a record of DOE research, the file also includes records of projects funded by other government agencies (federal and state) and private industrial and research organizations.

Each project record contains the title of the project, the names of persons and organizations conducting the research, sponsoring organizations, a summary description of the project, subject indexing terms, and subject categorization. All information is machine searchable.

General and Practical File (GAP)

The GAP file records popular scientific and technical and "how-to-do-it" information.

Specifically, the file includes energy information available as mass-media products, such as pamphlets, flyers, films, and posters, and technical information for the layman. Information in the areas of energy conservation and solar energy primarily answers the question, "How can I?" Management information, such as energy audit procedures, information on socioeconomic impacts of energy policies or actions, and information on pertinent government policies, regulations, building codes, etc., is

included as well as information on the economics of energy conservation and any other information designed to help bring about adoption of energy-saving and energy-alternative techniques and technologies that reduce consumption of depletable fuels.

Information is excluded if it is in a foreign language, is a progress report (except final reports), is a patent (except for handyman types), and was published before 1975 (except very special information).

Technical Information Management System (TIMS)

TIMS is a file created from records that reflect the Department of Energy's research contracts and the publications that either should be written or have been written reporting the results of the research. It is primarily a management system, designed to track the submission and receipt of DOE-sponsored reports; however, it serves as a technical information resource for those who need to locate the research results of a specific contract. At present access to this information is available only on request to the TIC.

From these comprehensive integrated data bases a wide variety of information products flow including bibliographies, journals and updates, books, monographs, and conference proceedings.

Indexed bibliographies can be produced on demand from the EDB. Some comprehensive bibliographies that have been produced in recent years are: Magnetohydrodynamics, Batteries, and Nuclear Medicine.

The journal and updates produced from the data bases include:

Energy Research Abstracts (ERA), a bimonthly journal which is the primary announcement medium for DOE-sponsored technical literature, reports, journal articles, conference papers and proceedings, patents, and theses. It also covers other U. S. Government-sponsored energy research literature, international nuclear literature, and foreign energy literature received by TIC under bilateral agreements. Each issue contains personal author, corporate author, contract number, report number, and subject indexes. All indexes are cumulated annually.

Energy Abstracts for Policy Analysis (EAPA) is a monthly journal devoted to the nontechnical or quasitechnicological literature of energy, and includes such areas as economics, sociology, politics, supply and demand, policy, and regulation as they relate to the energy situation. EAPA coverage is not restricted to DOE-sponsored sources.

In addition, we have updates in five subject-oriented monthly abstract journals which announce all (not just DOE-sponsored) items in the particular subject area added to the data base the preceding month. The journals are Fossil Energy Update, Solar Energy Update, Fusion Update, Geothermal Energy Update, and Energy Conservation Update. These serve for retrospective searching as well as being current awareness media, since each contains the same kinds of indexes found in ERA. These indexes, too, are cumulated annually.

In addition, TIC provides editorial and publishing services to DOE program divisions for the production of technical publications including books, monographs, and conference proceedings originated under their sponsorship. These publications include manuals, a DOE Symposium Series, and critical reviews. Most are available for sale from NTIS.

We also provide access to these data bases by an on-line retrieval system (DOE/RECON), available to organizations whose mission and responsibilities require access to the DOE data bases. It is accessed by 40 dedicated lines and by around 400 dial-up facilities. There are, at present, 21 data bases accessible on DOE/RECON, including the Energy Data Base, the Research in Progress file, the GAP file, and FEDEX, an index to data in certain energy information agency publications.

The TIC serves as the central DOE film library, offering a free loan service of energy-related films that results in a yearly activity of around 65,000 loans to schools, universities, service clubs, and industrial groups.

TIC has a citizens assistance response service to handle the thousands of inquiries and requests for information that come from the general public. These inquirers and requesters are teachers, students, businessmen, householders, farmers, or anyone who wants information on energy that he believes can be obtained from DOE. We respond to these by several means: referrals, publications, or a list of references. We maintain the stocks of public information types of brochures, guides, and so forth that are used to respond to these requests from the public and supply them in quantity to other offices in DOE that provide similar services.

We know our products and services can make a difference in helping solve the energy problems of this nation and we are committed to the following goals:

1. Assuring information systems, goals, and priorities are fully coordinated and complimentary to DOE goals, objectives, and priorities. Determining information needs and designing information products and services are a joint responsibility of the information user and the information processor and distributor. Products and services should be evaluated, weighing their usefulness and impact against cost and alternatives.

2. Improving the coverage, timeliness, and thruput of collecting, organizing, processing, and distributing energy information. Information that is not available when needed is no different than no information. Timely announcement of new research and development information can have a major impact on solving problems and assuring state of the art technology is transferred when it will be utilized.

3. Making DOE's Energy Data Base available commercially. DOE's RECON on-line retrieval system is currently limited to DOE organizations and their contractors. We plan on making the data base available commercially in early 1980.

4. Entering into new bilateral agreements with foreign countries substantially expanding information in the DOE Data Base on foreign technology.

Experts claim that one half to two thirds of all research and development in energy is being conducted outside of the United States. The United States has been considerably more liberal in seeing that others received the results of our research than assuring that our scientists and engineers had access to foreign research and development.

5. Capturing and reporting on all DOE research in progress. This information is vital for researchers and the program managers to reduce overlap and duplication and speed up the practical application and implementation of research results.

6. Designing and implementing new information tools to help managers manage (i.e., TIMS). The TIMS system requires research and development report deliverables as a part of the procurement process to assure that R&D results are captured, processed, announced and distributed. In addition, TIC has been made a part of the contract closeout procedure to certify that report deliverables have been received. This sytem will assure that R&D results are received, announced and disseminated when appropriate.

7. Improving information outreach and technology transfer. When a technology is developed that will result in substantial energy savings or new or improved energy technology, the announcement and dissemination of this information is vital if the new technology is to be adopted and installed. This requires us to seek out the individual user communities and develop products designed to encourage acceptance and utilization.

I believe information management has an exciting future. The work is stimulating and challenging. It also helps if the information is accurate. I recall a syndicated comic strip in which a character set up a "Questions Answered, 5¢" desk. To the question, "What's the capital of Belgium?" the character replied, "Tulsa!" When she was taken to task, she said, "Oh...correct answers! You want my partner!"...who was sitting at a desk marked, "Questions Answered Correctly, 10¢."

We'll work with you to assure that our information is useful, timely and accurate.

INFORMATION MANAGEMENT TECHNOLOGY: AN INTEGRATION OF THE BEHAVIORAL, INFORMATION AND COMPUTER SCIENCES

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ABSTRACT

Manual and computerized information systems have been instrumental in achieving technology transfer. Continuing exponential growth in the generation and consumption of technical data has dictated widespread use of these systems. Yet, many information systems have a limited utility because their design has been based upon a very specific set of user characteristics and an inflexibility in accommodating the diversified and dynamic nature of information. This paper describes a multi-disciplinary approach to information system design which draws upon the behavioral, information and computer sciences. It suggests specific methods which can be borrowed from those disciplines to improve information system utility. The application of this approach to the design of an Enhanced Oil Recovery information system at the Bartlesville Energy Technology Center (BETC) is discussed.

INTRODUCTION

Research necessary to achieve breakthroughs such as the economic recovery of residual oil demands the proper synthesis of outstanding facilities, the application of experience, and the ability to collect and evaluate information. The advancement of our society has been traced directly to the abilities of scientists to remain on the "frontiers" of technology through their use of information to support research and move to new levels of productivity. The current shortage of energy sources increases the need to use information effectively in programs such as enhanced oil recovery.

Scientists have always been perceived as consumers of information. But the reverse is also true. Scientists have been and continue to be some of the greatest producers of information. The result of activity in the scientific sector has been an exponential generation of information. The volume of technical journal literature has grown in direct proportion to the size of the scientific community. Figure 1 shows a projection for nearly one million technical journals by the end of the 1990's. (Price, 1975)

Specifically, the number of periodical titles increased from 28,000 in 1966 to 55,000 in 1974, and the number of journal articles increased during the same time from 207,000 to 423,500. This growth has created a need for rapid conversion of information from its hard form into machine storable and retrievable form. The number of machine readable data bases

is now judged to be nearly 500. The availability of these data bases has in turn lead to a phenomenal increase in the number of computer terminals used to access information. It has been estimated that as many as 3 million computer terminals will be in use in this country by 1981. (Wolpert, 1977)

Planners have been predicting the "Information Age" or "Information Revolution" (NICE III, 1979) as if it were some time in the future. However, if these statistics are any indication, the future has become the present. The challenge to the scientific community is to measure and manage both the information needed and the information generated in order to continue a high rate of technical achievement.

It is important to recognize specifically how information management will be involved in technology development. Stanfield (1977) has predicted that major technology improvements will be characterized by improved abilities to forecast or estimate resources, and by the transfer of techniques from one discipline to another. Both of these types of technology improvements rely on information management. Clearly enhanced oil recovery (EOR) and the estimation of residual oil saturation (ROS) will benefit directly from both improved forecasting and technology transfer. Therefore, EOR/ROS research and information management appear to be strongly linked.

SINGLE-DISCIPLINARY APPROACHES

The growing need for improved information management has not been ignored by technology developers. Among the technical disciplines that have addressed the problem are behavioral science, library science, and computer science. Companies that produce telecommunications devices, office equipment, and computers have responded to the problem with an impressive assortment of products. Giant corporations such as IBM and Xerox have developed familiar advertising and marketing campaigns which aim specifically at information management technology.

The behavioral sciences have been active in both research and applied aspects of the problem. Experts in artificial intelligence have been working on the "automated office" concept in which simple office functions now performed by people (e.g., scheduling, appointment management, etc.) can be replaced or at least accelerated by computers. There is evidence that significant numbers of established behavioral scientists are being employed by major product-oriented companies aiming at the information management markets.

The emphasis on information management is also evident within the library science community. The growing use of on-line bibliographic systems leads to the demand for new skills and stimulates continuing debates about the information specialist's role in relation to the user and the information system. The need for the integration of bibliographic data bases with numerical data bases was a major new issue for discussion at the recent National Information Conference and Exposition III (NICE III, 1979). That conference itself is an indicator of new dimensions in library science that are being developed in response to information accumulation, storage, retrieval, and consumption problems.

The computer sciences have, of course, been extremely active in area of information management. Some representatives of this industry claim that information management is their business. It is evident, however, that information management has not been exclusively their area of concern, nor has their contribution spanned all aspects of the information management problem. Even so, the impact of computers on information management has been dramatic.

Since relevant, complete, and accurate information is becoming more difficult to obtain and increasingly critical for technical and managerial problem-solving, information is now a valued commodity. Therefore, it is marketable. The buying and selling of information and/or information services is a development that is not received without some concern in circles where information has been regarded as a free and public resource. A recent registry of the Information Industry Association listed over 100 companies having information or information services as their primary product area. It would be difficult to estimate the number of companies in research, consulting, and the administrative/technical support business that now offer information management services to their clients.

SHORTFALLS OF SINGLE-DISCIPLINARY APPROACHES

Although the responses by various technical disciplines to the information management problem have been significant, a gap remains between what is needed and what is available. For example in the area of computer science, data base management elements, but no practical implementations of such relational systems are in general use. Storage has become relatively cheap and retrieval is aided by higher-level query languages, but many on-line information retrieval systems will require specialists to be used effectively.

Like the computer sciences, the library sciences are not yet adequate to meet the challenges of improved information management. Information retrieval has centered around the organization of information by subject, and the interrelationship of concepts through the coordination of subject classifications. New areas such as enhanced oil recovery suggest changing subject terminology which is not inserted into traditional classification mechanisms.

Information science has utilized computer technology in an effort to counteract the explosive growth of the information itself and to meet the requirements of users to have access more rapidly. With the advent of machine-readable information storage, information can be retrieved using a keyword-in-context technique. Although this was an improvement over catalogue and index searching, it has not proven sufficient to produce user satisfaction. In the library sciences, there has not been enough emphasis on end user search patterns and whether or not computerized information retrieval was designed to satisfy users. The traditional mechanisms for determining user needs such as surveys, questionnaires, and interviews were adequate when retrieval was manual. But as computerized information systems have become more available, the traditional mechanisms for assessing user needs and insuring a high level of user relevancy have become less adequate.

Finally, behavioral and management scientists are understanding more about perception, memory, and problem solving behavior, but have made only a start in addressing human behavior in information seeking tasks. These sciences are attempting to develop improved management information systems (MIS's), but the mood among users seems to be a lack of satisfaction with the value of many MIS's.

The magnitude and criticality of the information management problem seems to outpace the remedies available from individual technologies. More computer memory for the dollar does not solve the useability problem. Librarians who have studied the behavior of information users as a community now need to understand the behavior of users as individuals interacting with a computer-based collection. Practical applications of artificial intelligence models require the description of relationships by persons outside the behavioral science community. Numerous other examples could be cited to suggest that single-discipline approaches to meeting the information management challenge are unlikely to offer real promise.

CONTRIBUTIONS TO A MULTI-DISCIPLINARY APPROACH

The premises of this paper are that the separate disciplines:

- should be integrated, and
- can be integrated

to focus on the information management problem. The case that they should be integrated rests on the view that information management involves complex interactions between users, devices and the nature of the information itself. Thus, the behavioral library and computer sciences are linked by these interactions. Furthermore, there is evidence that the separate technologies, although evolving rapidly, are not addressing all the interactions. In the conclusions of a paper on educational trends, Stanfield (1977) summarizes effectively be stating "information management requires visibility as an integrated academic programme, rather than being treated partially by librarianship, computer sciences, business school, etc."

The case that the separate disciplines can be integrated is the hypothesis that is supported in the remainder of the paper. As a starting point, we describe briefly some contributions from the separate disciplines which have direct relevance to the design of information management systems. They may be regarded as raw materials for synthesizing a multi-disciplinary approach called information management technology.

BEHAVIORAL SCIENCE

The behavioral sciences have developed much technology applicable to information management. For example, behavioral scientists have developed techniques for determining information requirements, for testing and observing the utility of devices and methods, and for describing and emulating decision-making behavior. Each of these areas offers potential benefits for information system designers.

Ramsey (March, 1978) has described methods taken from the field experimental psychology that have proven useful in establishing user information requirements. Task analytic methods have been used successfully to elicit information requirements that are difficult to obtain from users. These methods operate on the premise that users may employ information to do their jobs in ways that are observable but that the users may be unable to articulate accurately. Therefore, to remove the distortions and omissions that may arise from interviews or surveys, task analyses have a role. If an information user's real environment is difficult to observe, paper simulations (Ramsey et al, 1979) may be useful in determining user information needs. In a paper simulation, a hypothetical information system is assumed to be operational. In carefully constructed scenarios, the user is allowed to use the "system" whose function is emulated by the system designer's use of artificial outputs such as displays, reports, etc. Other techniques for defining information requirements that have been borrowed from the behavioral sciences include critical incident analyses and decision modeling. All of these methods have been devised to obtain data from people concerning behavioral phenomena that are difficult for subjects to articulate. The behavior that is of interest here is, of course, the search for and utilization of information.

Although the effectiveness of an information management system is often measured in terms of performance parameters such as response speed, information volume stored and retrieved, or accuracy of information output, the fact remains that ultimate value must be measured in user terms. Since user satisfaction is the objective of the system, the behavioral sciences should be examined for techniques relevant to collecting feedback after users have tried the system. The emphasis in the behavioral sciences on experimental design, on observational techniques, and on isolation of the cause and effect variables involved in human behavior has produced methodology that is potentially integrable with the information system design process.

Finally, the behavioral sciences have studied the cognitive processes. Recent advances in the area of artificial intelligence have produced systems that can diagnose diseases reliably or prepare data for a structural analysis computer program (Shortliffe, 1976). Another system deducts from user responses the type of information that might be relevant to a user and retrieves it without explicit direction. These systems work on constructs called "production rules" which describe the basic behavior relationships involved in a problem-solving situation (or paradigm). Atwood has proposed to develop the production rules underlying the strategy of an information specialist's utilization of an on-line bibliographic system. Success in that effort could lead to improved effectiveness and user satisfaction. A summary of the literature and an assessment of the state-of-the-art in computer-aided problem solving can be found in Ramsey et al (1975). The few examples cited here serve only to illustrate that many contributions to the design of information management systems can be taken from the behavioral sciences.

LIBRARY SCIENCE

Library science also has techniques that can be integrated into a multi-disciplinary approach to information management. This discipline has always concerned itself with the hierarchical subject relationships of information. That is, broad fields of knowledge subdivided into specialized categories. The classification schemes that have evolved are extremely general and are widely accepted as standard ways of organizing information. The criteria for judging the utility of such classification schemes can be applied to the design of any information system.

The goal of most libraries and information centers has been to bring needed information to the user who requests it. Historically, user characteristics and user needs assessment have been systematically investigated in order to facilitate this process. Survey, interview, and simulation techniques were the tools used to make manual information retrieval systems work better. These are tools similar to those used in human factors studies to enhance machine retrieval. However, the characterization of classes of users (as distinguished from individual users) is highly developed in the library sciences.

Limited funding and the concept of "free" information have forced the information specialists to think in terms of cooperative systems and interlibrary networks. They are now in a position to contribute that experience to the design of either centralized or decentralized computer-linked systems. Many of the procedural details for networking and servicing multiple-location users can be taken from library experience. It is not a big step from manual procedures to computer system functional design.

COMPUTER SCIENCE

Finally, the computer sciences may be relied on for technology to incorporate into a multi-disciplinary approach to information management. Implementation mechanisms for many information management concepts are provided by the state-of-the-art in computer-related disciplines. Advances in communications can provide once-isolated users with the capability to query remote sources of information. Miniaturization of circuitry now makes it possible for outlying points of inquiry to possess more processing power under close control of the user. In addition, extremely remote and isolated sources of information can become viable data collection points. Evolution within the technology of large-scale data storage devices is allowing both the concentration of more information in fewer sites, and the capture and storage of data that previously had to be forgone because it was too "bulky". Electronics is providing the capability to gain rapid access to larger quantities of data from dispersed points of inquiry.

Computer science has also been addressing the interfaces between human users and data processing machinery. From the discipline has come an organized framework for system design, protocols for human-

-machine and machine-to-machine communication and algorithms for data nipulation. Specifically, "top-down" and structured (modular) approaches to system design have found widespread propagation through the computer users community. Evolution in computer programming languages, human-computer dialogue designs and standards for inter-machine communications have arisen from computing science. The development of efficient, minimal-time data access and retrieval procedures, analytical methods, and data display techniques have potential application to information management.

Data management has turned in the direction of distributed data bases and distributed data processing. Data, that are resident at numerous locations, can now be made available to user's at outlying work stations. Conversely, summary data from dispersed locations can be concentrated at a centralized location for processing and subsequent feedback to remote sites for further processing. The equipment furnished by the electronics industry and the logical, organizational, and functional elements supplied by computer science have enabled these forms of information management to exist.

A MULTI-DISCIPLINARY APPROACH

Single-discipline approaches to information management have produced some workable, partial solutions, but not without attendant shortcomings. There are many usable tools, techniques, and insights available from each of these disciplines. Therefore, it seems reasonable that a more user-oriented and efficient information management system can be devised by uniting the various disciplines in an organized approach to the system's development.

Assume that the approach can be expressed simply as the following steps: 1) design; 2) implementation; and 3) refinement and expansion. The participation of the various disciplines at each step is elaborated in the following sections.

DESIGN

Classically, the design step for a computer system has consisted of specialists specifying computer file formats and input/output conventions adequate to access the files, based upon a user-provided design specification. In environments that are rigidly structured, slowly changing, and well understood, the classic approach is able to provide adequate designs. However, in typical information management application, the information is not well behaved and predictable. The context is constantly changing. The relationships among pieces of information are very dynamic. Older information is constantly being enhanced, revised, or replaced by the latest discoveries. The classic approach is not suited to so demanding an environment. An explicit design specification is difficult to produce, and in many cases a design predicated upon such a specification is proven to be faulty.

The multi-disciplinary approach to computer-assisted information management recognizes this, and, therefore, includes a design specification development activity conducted not only during the design step, but throughout the process of information system development. Both the behavioral and library sciences provide techniques for defining user characteristics. Once the user community is defined, library science provides tools to define and forecast the information content required to satisfy the needs of that group, and provides a relational structure to organize that information into a systematic framework which is logical and accessible. The library and computer sciences jointly react to the anticipated information content while devising the formats of computer files and the configuration of file access, updating and deletion mechanisms. The computer and behavioral sciences both participate in the design of dialogues that are as "natural" and unambiguous as possible and that can accommodate users of various skill levels, if such a mix of users is anticipated. Briefly, the participation of all disciplines during this step causes a more flexible, responsive design to emerge, based on a soundly defined (but still evolving) design specification.

IMPLEMENTATION

Conventionally, the implementation step consists of the development of all mechanisms and procedures called for in the design, whether manual or computerized. Changes to the design which must be made during implementation usually cause a great struggle. In contrast, the multi-disciplinary approach suggests the initial implementation of only a few of the more salient system features; full implementation is delayed. This implementation of only part of the system is a technique derived from the behavioral sciences. The early, partial implementation provides a prototype for soliciting user reaction to portions of the eventual system. The expertise of the computer scientist is used to produce "quick and dirty", functioning subsystems on the computer. Library and behavioral scientists apply the techniques of their disciplines to monitor and interpret user reactions. These trial subsystems will actually be changed throughout the implementation step; an iterative process between the user and the builder is employed to allow hands-on experience and design modification. A solid basis for understanding the information, the environment and the users associated with the information system is caused to exist.

REFINEMENT AND EXPANSION

In the classical approach to system design, this step in the development process does not exist. In this multi-disciplinary approach the refinement and expansion step is mandatory; it is where actual, full system implementation takes place. The "quick and dirty" partial implementation is refined for efficiency; the unimplemented segments can be built with relative confidence of their immediate utility. Now, the design specification is recorded in its final form, in contract to the classical approach, where in it preceded the implementation step. The participation of all of the discipline specialists is maintained through the completion of this step to assure the correct interpretation and implementation of each system design feature.

THE RESULTING SYSTEM

The multi-disciplinary approach to the development of an information management system produces a product that is tailored to the environment in which it must perform. The initial design integrates the content and the structure of pertinent information with the user characteristics and computer system capabilities to produce a customized, initial system specification. When a subset of this specification is implemented, desirable changes are solicited, analyzed, and incorporated to the highest degree possible in order to further assure that the ultimate system satisfies the needs of the various users. The specification is finalized only after the previous activities are complete; then, the prototype is modified for efficiency and the remaining features implemented with confidence that the system and its users form a single information management entity.

AN EXAMPLE AT BARTLESVILLE

A "real-world" application is developing at the U. S. Department of Energy's Bartlesville Energy Technology Center. The Residual Oil Saturation (ROS) Project is using the multi-disciplinary approach to design a system to support its unique information requirements and to anticipate future needs. The ultimate goal of this effort will be an ROS information management system. A shorter term objective is the development of a demonstrable subsystem during this year.

Progress to date has included the definition of relevant information resources both internal and external to the ROS Project. A system for characterizing potential system users has been devised and applied. The relational structure linking the various information resources has been defined and translated into a preliminary referencing scheme. Preliminary implementation of the subsystem is about to begin.

ACKNOWLEDGEMENT

The authors wish to thank their colleagues for contributing both concepts and specifics to this paper. Many of our views have resulted from rewarding associations wich persons such as Dr. Rudy Ramsey, Dr. Michael E. Atwood, Dr. James R. Van Doren and Ms. Sallye Smith, all of whom are scientists making substantive contributions to information management and having in-depth understanding of their respective specialities.

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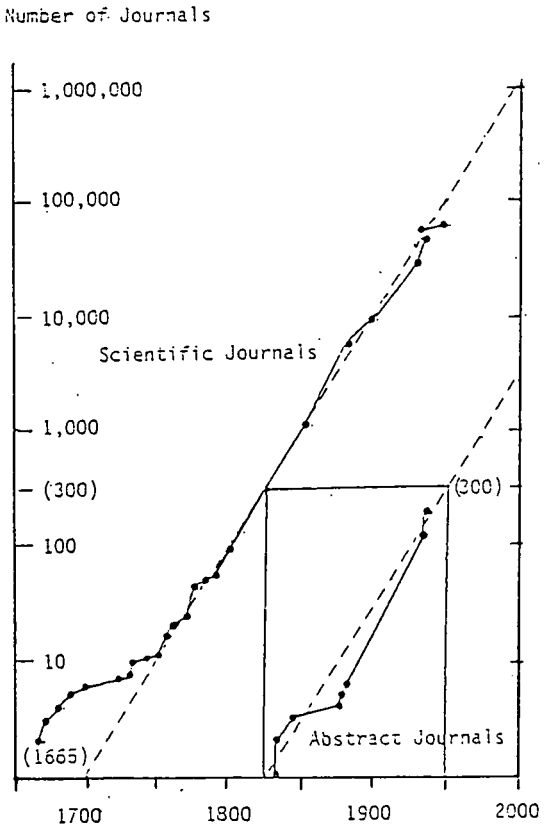


Figure 1
NUMBER OF JOURNALS FOUNDED*

*From Science Since Babylon, 1975, Derek de Solla Price, Yale Univ. Press

PETROLEUM DATA SYSTEM: SCOPE AND APPLICATIONS

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ABSTRACT

The Petroleum Data System (PDS) is a comprehensive computer base of petroleum information. The data is maintained by the University of Oklahoma, under contract to the United States Geological Survey. The data is made available to the public through the Freedom of Information Act. The data bases contain information on over 80,000 oil and gas fields in the United States and Canada. Information on PDS includes the name of the field and pool, location, annual and cumulative production, lithology, and various geological and engineering data, such as lithology, trap types, reservoir temperature, porosity, permeability and pressure.

PDS is the only large computerized data base containing reservoir parameters. As such, the data is being used extensively on various types of enhanced recovery projects. Furthermore, additional data derived from many of these projects is being released to PDS.

TEXT

The Petroleum Data System consists of information on over 80,000 fields and reservoirs (pools) in the United States and Canada. PDS is the only large computerized data base of reservoir characteristics covering every reported field and reservoir in the United States. As such, the data has been found to be very useful in many different kinds of enhanced recovery studies. The initial contract to develop this data base was awarded to the University of Oklahoma Office of Information Systems Programs in 1979 by the Department of Interior. The contract has been supported by the U. S. Geological Survey since that time.

The data included in PDS are available to the public through the Freedom of Information Act.

Over 140 petroleum companies are accessing PDS, and in addition, Federal and State Government agencies and others such as consulting firms, banks, mining companies, and petroleum associated companies.

There are over 300 validated user numbers on the system representing approximately 1000 individual users. The user community consists of geologists, engineers, geophysicists, and personnel associated with these functions. As far as actual users, there is a broad range--from chief geologists and engineers, to office and administrative clerks, secretarial personnel and librarians.

There are broad classifications of information in the file including names of fields and pools, their locations, and production, geological and engineering data.

The primary sources of information for PDS are the annual state reports for the oil and gas producing states. For example, in the state of Texas the Texas Railroad Commission annual report is the primary source of input. ...e state reports are supplemented by many additional sources of information ...cluding the International Oil Scouts Association, the American Association of Petroleum Geologists, and for Canada, the Canadian Provinces Conservation Boards. However, hundreds of publications have been screened and information extracted for inclusion in PDS.

Federal agencies make major contributions to the data base, the primary source being USGS. As the sponsoring agency, USGS has an active interest in the success of the project and plays a vital role in advising on the expansion of the data base and in supplying additional information to be included in the file.

Other federal agencies that have played a key role are the Federal Power Commission, Federal Energy Administration, Energy Research and Development Administration, and the Bureau of Mines (now the Department of Energy). Their contributions are greatly appreciated and will be discussed later in this paper.

Some of the key data elements include identification of the fields and pools, locations, such as county, section, township and range, present producing status, and the geological age of the producing formation. The trap type, depth information, discovery well information, average thickness, the proved acreage and spacing are included. Also included where available are reservoir lithology, number and types of wells, porosity, permeability, reservoir pressure and temperature.

The file includes much information on production--both annual and cumulative. The crude oil and natural gas analysis file from the Bureau of Mines, and now maintained by ERDA, are part of PDS.

PDS is not a static data bank. The file content is continually being enhanced and expanded. Prior to January, 1977 only three data bases, TEXS, OILY and CNDN were available for public access. PDS presently consists of 14 data bases.

1) TEXS, OILY - These data bases contain all of the information that is being collected on the oil and gas fields and reservoirs in the United States, including all of the data elements described above.

2) CNDN - This data base contains similar information on fields and reservoirs in four Canadian provinces, including Alberta, Ontario, British Columbia, and Saskatchewan. Alberta data, in particular, includes much more information on reserves and enhanced recovery activities than is usually available in the United States.

3) SECR - This data base contains information being collected on secondary and enhanced recovery projects in the United States. Data collected is being obtained from state publications describing activities on secondary and enhanced recovery operations in the state. At the present time, information on projects in Texas and Kansas are included in the data base. Information on other states will also be included as the data is computerized.

4) FM15 - This data has been furnished by the Federal Power Commission and contains information on natural gas reserves reported by companies on FORM 15, Schedule 2 for the years 1973 and 1976. The form was used to account for gas reserves dedicated by producers to the interstate pipeline network.

5) FEAR - This data was furnished to PDS by the Federal Energy Administration. It contains field reserve information for 65 major fields in the United States. The data was aggregated to a field level from company reports required by the government and was then edited and updated by the Bureau of Mines in Dallas, Texas.

6) PBRF - This data base is another special reserve file. It contains oil and gas reserve estimates, as well as estimated ultimate recovery and original in-place values for reservoirs in the Permian Basin, as of December 31, 1975. The estimates were supplied by the Bureau of Mines, Dallas, Texas.

7) OHST - This data base contains historical production information by field since 1942. The data was made available to PDS by the International Oil Scouts under contract to the United States Geological Survey. This data is available for all states except Texas, for the years 1942 through 1972. It has been utilized in a decline curve study by the Federal Energy Administration.

8) CHST - The data base contains the historical reservoir production and injection data for the province of Alberta for the years 1962 through 1977.

9) COIL - This data base contains over 8,000 crude oil analyses originally collected by the Bureau of Mines and now maintained by the Energy Research and Development Administration.

10) GANL - This data base contains approximately 13,000 natural gas analyses originally collected by the Bureau of Mines and now collected and maintained by the Energy Research and Development Administration.

11) GCO2 - This is a special gas analyses file donated by Gulf Universities Research Consortium (GURC). The data was collected by GURC under a contract to the Department of Energy. The purpose of the contract was to locate natural occurrences of carbon dioxide which might be used as sources for CO2 injection. This data base includes only those gas analyses which have a CO2 content greater than 5 percent. One source of this information was the original gas analysis file from the Bureau of Mines (GANL).

12) LPR5 - The Lease Production Revenue - System 5 data base contains lease bidding information, including names of bidders and amounts of all bids received on Federal Outer Continental Shelf (OCS) leases. The data is compiled and maintained by the Conservation Division of the United States Geological Survey.

13) LPRX - The Lease Production Revenue - System 10 data base contains annual production royalty and rental amounts for each Federal Outer Continental Shelf lease. The data is also maintained by the Conservation Division of the United States Geological Survey.

PDS is constantly being upgraded to include new information sources as well as to improve software capabilities.

The Department of Energy office in Dallas, Texas, is supervising the efforts of graduate engineering students in an effort to upgrade PDS with a substantial amount of reservoir engineering data not readily available in state reports. The data is being extracted from many sources, including: 1) AAPG Bulletins back to 1930; 2) American Institute of Mining and Metallurgical Engineers (AIME) bound volumes; 3) individual SPE papers;

4) Journals on Petroleum Technology; 5) Bureau of Mines special reports; 6) API bound volumes from 1930-1974; 7) Maximum Efficient Rate hearings; IOCC annual and special reports.

Petroleum engineers are now working to screen and evaluate data collected in the field file folders.

The addition of this data should greatly enhance PDS with data that will allow geologists and engineers to better evaluate each reservoir as well as to compute potential reserves based on the known characteristics of the reservoir. Work has been completed on three states: Colorado, Mississippi, and New Mexico. The data is now available for retrieval in PDS.

The U. S. Geological Survey is digitizing field outlines, providing outline coordinates, and also assigning a center point latitude, longitude to each field in the file.

The latest information on secondary and enhanced recovery projects in the states of Louisiana and Illinois are now bieng converted for inclusion in PDS.

In order to make PDS more user-oriented, a menu of pre-established reports, called Standard Retrieval Control Files, has been established. The user may specify the report, enter the criteria required and submit the job.

Since the data was made available to the public four years ago, PDS has been used for many different types of applications.

Some of these applications include:

1) Exploration project evaluations to compare data on similar fields in order to determine the economics of drilling other wildcat wells.

2) Evaluation of lease properties prior to sale.

3) Estimating future crude oil supplies and reserves.

4) Evaluation of production potential to determine the feasibility of future pipeline or refinery construction.

5) Basin potential studies to compare data from similar basins in order to determine the best areas of future drilling.

6) Large scale statistical analyses, computing field size distributions, and chance of success and sample sizes.

7) Enhanced recovery studies.

PDS is receiving a great deal of use at the present time for many different types of enhanced recovery studies. Some of these studies include using PDS to help screen potential reservoir candidates for various types of enhanced recovery. PDS may be used to supplement information the company already has on a reservoir. It may also be used to help find potential reservoir candidates. PDS can be searched to find reservoirs which meet the requirements of the candidate reservoirs. Since the data in PDS is not always complete, the approach is usually to look for reservoirs that do not fail any of the requirements. If certain information is not available, but the reservoir meets the other criteria for which information is available, the reservoir may be selected for further investigation.

Since PDS has information on secondary and enhanced recovery projects, it can also be used to determine the current activity on a reservoir, and also to look at what has happened on other reservoirs undergoing a similar type of enhanced recovery operation.

Another application for which PDS was used was to find potential sources of CO2 for use in CO2 recovery projects.

Most of the enhanced recovery studies which are being done involve setting up a data file which is then supplemented with data from PDS and many other sources. Many of these companies are under contract to the Department of Energy and are required to release the results of their study back to PDS. One example is the CO2 file which was mentioned earlier. GURC also has another data base on 165 enhanced recovery projects which will be released to PDS after it is completed. Data being aggregated by Intercomp in Denver will be used to identify reservoir candidates for miscellar polymer flooding. This data will also be released to PDS.

All of the PDS data bases are accessed in the same manner via the same software, making it much easier for the person accessing the data.

The PDS software has its own retrieval language consisting of approximately 12 commands. The Select and Iterate commands provide you with the ability to retrieve any subset of data which meet your search criteria. You may specify as many conditions as necessary to define your search parameters. One of the most common types of retrievals is to obtain all information on a given field, or a county in a state.

Once the subset of records is selected, you have several options available for output. The PRINT command allows you to output all information in a given subset of records. Using the LIST command selected items can be listed from the records. The COPY command allows you to output data from the data base to tape or disk and interface with other programs, statistical packages or plot routines.

PDS is used extensively by companies searching for candidate reservoirs for various types of enhanced oil recovery. Figure A illustrates the retrieval language of the PDS software. It shows a typical retrieval that was set up to find such a group of reservoirs from the TEXS data base. The primary conditions were that the reservoirs selected must be oil reservoirs, not offshore, and must have produced greater than 20,000,000 barrels of oil. Secondary conditions specified were sandstone lithology, depth less than 12,000 feet and API gravity greater than 20. Since all data is not always available in PDS it was decided to accept records which did not have lithology, depth or gravity as long as they met the primary conditions or they did not fail any of the secondary criteria. This retrieval provided a sizable subset of reservoirs for consideration. You can then compare and evaluate the information on this subset of reservoirs from PDS with other sources to determine their true EOR potential.

Of course, the conditions used to select the candidate reservoirs for enhanced recovery will vary depending on the type of recovery technique that is planned. Many times a company will vary the ranges on a retrieval to see what effect it has on the subset of records.

PDS is receiving the support of the oil industry. One example of this is the linking of a package developed by AMOCO Production Company to the PDS

software. The Applications Management System (AMS) provides PDS with additional data processing, file interface, and display capabilities.

AMS modules which are currently available through PDS include scatterplot, histogram, and triangle plot. Other modules which are being developed include trend analysis, report writer, a statistical package, multiple linear regression analyses and candidate score.

In order to make all the data systems available to the industry, the University of Oklahoma signed a contract with General Electric Company early in 1976 to make the data bases available on GE's Worldwide Mark III system.

The General Electric Mark III Computer Network consisting of over 100 computers, is accessible through a local phone call, around the world, seven days a week. Local service is available in over 500 cities in the United States, Canada, Europe, Mexico, Singapore, Japan, and Australia. GE gives local support to users of the Mark III System and assists the University of Oklahoma in training workshops in the use of GIPSY and PDS.

In order to access the data, a company or agency must have a contract to use the GE Mark III Service. Assuming you have such a contract, and many companies already do, you merely need a user number in the University of Oklahoma catalogue with a discreet password to allow you to access the data bases. Any one of a number of low speed terminals may be used to access the Mark III System through a local phone call. You then submit your request to search the file and retrieve the data.

Access to GE is by way of a low speed terminal, through what we call a foreground or interactive computer. By placing a local call from any of the 500 remote locations the foreground computer then submits the request to the background or batch type system, an IBM 370/158, where the GIPSY retrieval system searches the data and formats your request. The retrieved data then is transferred back to the foreground system where you can print it on your terminal. If the retrieval is too voluminous to print on your low speed terminal, you may divert it to a high speed printer in your operation or arrange to have it printed at GE. You could even retrieve it on microfiche.

So what does it cost to get into this computer network and access the Petroleum Data System?

Assuming you are already a Mark III service user, your obligation is no more than a $20 per month minimum charge, assuming no usage. There is no front-end charge or subscription fee for using PDS. You pay only for what you use.

In summary, PDS is already getting wide usage because it is truly a comprehensive computer base of petroleum information. Although the data, which is all public information, is obtainable from other sources, PDS on the Mark III system is the only place it is offered worldwide with fast response. The cost is low and the data can be in your hands in a matter of minutes, eliminating many man hours of search time.

As stated before, the University of Oklahoma is committed to the continual updating of data and is also committed to expanding PDS by incorporating additional information which will be of value to the petroleum industry.

A TYPICAL RETRIEVAL
TO FIND CANDIDATE RESERVOIRS
FOR ENHANCED RECOVERY

SELECT

A. OIL
   OIL (STATE DESIGNATION OF FIELD OR POOL)

B. CRUCM GT 20,000,000
   CUMULATIVE CRUDE OIL (BBLS)

C. OFFSHR
   OFFSHORE LOCATION

LOGIC A AND B AND NOT C

SEARCHED 40920

SELECTED 279 SUBSET 1

ITERATE

A. APIGRAV GT 20
   AVERAGE API GRAVITY

B. APIGRAV
   AVERAGE API GRAVITY

C. SAND
   SANDSTONE (RESERVOIR LITHOLOGY)

D. LITHOL
   LITHOLOGY

E. DPTHTOP LT 12000
   DEPTH TO TOP (PROD INTERVAL) FT.

F. DPTHTOP
   DEPTH TO TOP (PROD INTERVAL) FT.

LOGIC (A OR NOT B) AND (C OR NOT D) AND (E OR NOT F)

SEARCHED 279

SELECTED 174 SUBSET 2

FIGURE A

EVALUATION OF TARGET OIL IN 50 MAJOR RESERVOIRS IN THE TEXAS GULF COAST FOR ENHANCED OIL RECOVERY

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ABSTRACT

This investigation determines the target oil available for enhanced oil recovery (EOR) from 50 major oil reservoirs in the Texas Gulf Coast. A preliminary screening process was used to determine which of five EOR methods, if any, were suitable for each of these reservoirs. Target oil in the 50 reservoirs is estimated to be 4.4 billion barrels of oil unrecoverable under present operating conditions with about 1.5 billion barrels susceptible to EOR processes. None of the reservoirs have an outstanding potential for thermal recovery; however, 7 reservoirs have carbon dioxide miscible flood potential, 7 have surfactant flood potential, and 9 have polymer flood potential. None of the five methods was considered suitable for the remaining 27 reservoirs.

INTRODUCTION

Domestic oil reserves in the United States have declined for the past several years because not enough new reserves have been found to offset annual withdrawals. Because of the lack of new discoveries and the resultant decrease in reserves, investigations are being made to determine how much target oil is available in known domestic oilfields and which EOR process would be most suitable for additional recovery.

For this study, 50 of the largest fields in Texas Railroad Commission districts 2, 3, and 4 were selected based on estimated ultimate recoverable oil. The majority of the fields contained more than one reservoir or zone.

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[2/] Engineering Technician

When there was more than one reservoir in a field, the largest or predominant reservoir was selected. Fields with numerous small reservoirs, which are commonly found as a result of piercement-type salt domes, were not included in the study. There were about 40 of these types of fields found in the three Railroad Commission districts but not included in this study. Figure 1 shows the location of the selected reservoirs in Texas Railroad Commission districts 2,3, and 4. There were 17 in district 2, 20 in district 3, and 13 in district 4.

To increase the ultimate recoverable oil, certain enhanced oil recovery processes have been developed in the laboratory and field-tested with varying degrees of success. EOR methods considered in this investigation are: (1) steam injection; (2) in-situ combustion; (3) carbon dioxide miscible flooding; (4) surfactant flooding; and (5) polymer flooding. In steam injection, heat is applied to the reservoir by injecting steam into the producing well. In-situ combustion consists of generating heat in the reservoir by injecting air and burning part of the crude oil. Carbon dioxide miscible flooding consists of displacing the oil in the reservoir by injecting a slug of carbon dioxide which will dissolve in the oil. Surfactant flooding is a multiple, slug-type process involving the addition of chemicals to water. Polymer flooding is an augmented water flood.

This study reviewed the geological, reservoir, and fluid characteristics of 50 major reservoirs in the Texas Gulf Coast. Using selected screening criteria,[2,3] the most suitable EOR method for each reservoir was determined. It was found that the thermal methods, steam drive and in-situ combustion, were not likely to be suitable processes for these reservoirs.

Similar work evaluating selected reservoirs in the United States for enhanced oil recovery has been done.[2,3,5] This report differs in that it is confined to the coast of Texas and contains detailed information on reservoirs in the area. No attempt has been made to predict increased oil recovery by EOR methods or the economics involved.

This report contains estimates of initial oil in place, ultimate recoverable oil using present technology, and target oil or the amount of oil in place that will be left unrecovered.

RESERVOIR SELECTION

The largest producing oilfields in Railroad Commission districts 2, 3, and 4 were identified on the basis of estimated ultimate recoverable oil and listed in descending order. For a multi-reservoir field, the largest reservoir was used. If a field consisted of numerous small reservoirs, which are commonly found as a result of piercement-type salt domes, none of the reservoirs in the field were used. The geographical locations of the 50 reservoirs selected are shown in figure 1.

Estimates of the initial oil in place, ultimate recoverable oil, and rget oil are tabulated in table 1. The reservoirs are ranked in order of estimated ultimate recoverable oil.

These estimates were made by using the volumetric method and rate versus cumulative oil production plots. The first method was used on 20 reservoirs, while the latter was used on the remaining 30 reservoirs.

EOR METHOD SELECTION

The procedure for selecting the best EOR process consisted of collecting all available reservoir and fluid characteristics and comparing these characteristics to the criteria set forth in table 2. The reservoir data was collected from several sources.[4,6-10] The screening criteria in table 2 is based mainly on that published by the National Petroleum Council.[2,3] The characteristics of the 50 reservoirs were checked against the 16 items on table 2. The method with the most favorable items was generally recommended for a particular reservoir. Reservoirs with a strong water drive or a large gas cap were generally disqualified as an EOR candidate. Other considerations, such as secondary recovery projects and EOR proposals, were taken into account.

It should be kept in mind that a much more sophisticated screening process and detailed reservoir studies are needed before assuming that any of the suggested processes are the way to proceed. This is especially true when one considers the wide range of values found in the literature for the reservoir and fluid characteristics of any one reservoir.

DISCUSSION

After the reservoirs were selected, the initial oil in place and the ultimate oil recovery had been estimated, the reservoirs were screened to see which of the EOR methods, if any, could be applied. A comparison of the reservoir and fluid characteristic data with the tolerances shown by table 2 quickly indicated the most desirable EOR method. Strong water drives and large gas caps generally disqualified the reservoir as far as being an EOR candidate was concerned.

As illustrated by table 3, the screening criteria indicated that none of the reservoirs qualified for a steam drive or in-situ combustion process. These two processes normally lend themselves to shallow reservoirs with low gravity viscous crudes, high permeability, and large quantities of oil in place per acre foot. To summarize the results of table 3, there are 7 reservoirs with carbon dioxide potential, 7 reservoirs with surfactant potential, 9 reservoirs with polymer potential, and the remaining 27 reservoirs do not meet the selection criteria for any of the five EOR methods considered.

Of the 4.4 billion barrels of target oil, 0.4 billion are susceptible to the carbon dioxide flooding process, 0.6 billion are susceptible to the surfactant process, 0.5 billion are susceptible to the polymer process, and 2.9 billion are not listed under any of the five EOR methods. This is shown by table 4. As stated previously, this is a preliminary selection process based

on available published and unpublished data[4,6-10] for each reservoir. Therefore, the selected EOR process shown for each reservoir should not be considered the only method of increasing recovery nor does it suggest that the EOR process will be successful.

Table 5 illustrates the portion of the total Texas Gulf Coast oil that is contained by the 50 major reservoirs. Initial oil in place is about 32.1 percent, ultimate recoverable oil is about 40.2 percent, and the target oil is about 25.9 percent. This can be expanded one step further by assuming that the target oil susceptible to EOR methods for the 50 reservoirs is also 25.9 percent of the Texas Gulf Coast target oil. This would mean that the total target oil susceptible to EOR methods in the Texas Gulf Coast would be 5.8 billion stock tank barrels (1.5×10^9 bbl ÷ 0.259).

CONCLUSIONS

According to the preliminary screening criteria used in this study, the following conclusions were reached:

1. None of the 50 reservoirs studied qualified for a thermal EOR process.

2. There are 23 of the 50 reservoirs studied with potential for a carbon dioxide miscible flood, a surfactant flood, or a polymer flood.

3. Of the 4.4 billion barrels of target oil in the reservoirs studied, 1.5 billion barrels are susceptible to an EOR process.

4. Of the 17.0 billion barrels of target oil in the Texas Gulf Coast, 5.8 billion barrels may have a potential for some type of EOR process.

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TABLE 1.—Summary of estimated initial oil in place, ultimate recoverable oil, and target oil for 50 major oil reservoirs in the Texas Gulf Coast in MSTB

Map no.	Field	Reservoir	Railroad Commission district	Initial oil in place	Ultimate recoverable oil	Target oil
1.	Conroe	Main Conroe (Cockfield)	3	1,316,899	750,633	566,266
2.	Hastings, West	Upper Frio	3	960,366	662,653	297,713
3.	Webster	Frio	3	890,120	578,578	311,542
4.	Thompson	Frio	3	848,334	351,804	496,530
5.	Tom O'Connor	5900	2	549,311	337,067	212,244
6.	Anahuac	Anahuac Main Frio	3	484,002	272,687	211,315
7.	Tom O'Connor	5800	2	421,282	251,893	169,389
8.	Oyster Bayou	Seabreeze	3	227,955	145,549	82,406
9.	Greta	4400	2	312,939	141,830	171,109
10.	Tom O'Connor	5500	2	261,120	139,621	121,499
11.	Hastings, East	Upper Frio	3	212,129	111,495	100,634
12.	West Ranch	Greta	2	229,855	111,094	118,761
13.	West Ranch	41A	2	203,400	108,087	95,313
14.	Magnet Withers	Magnet Withers	3	162,928	91,093	71,835
15.	Lake Pasture	H-440	2	132,793	73,408	59,385
16.	Sugarland	Frio	3	142,870	70,678	72,192
17.	Willamar, West	West Willamar	4	160,000	64,985	95,015
18.	West Ranch	Glasscock	2	127,653	61,886	65,767
19.	Loma Novia	Loma Novia	4	123,257	60,026	63,231
20.	Seven Sisters	Government Wells	4	142,231	55,655	86,576
21.	Portilla	7400	4	75,380	51,198	24,182
22.	Gillock, South	Big Gas Sand	3	77,945	45,590	32,355
23.	West Ranch	98A	2	81,543	42,427	39,116
24.	Withers, North	"A-B-C"	3	58,694	39,844	18,850
25.	Thompson, South	Frio	3	80,402	37,580	42,822
26.	West Ranch	Ward	2	61,320	36,512	24,808
27.	Tomball	Kobs	3	59,393	35,626	24,267
28.	Thompson, South	4400 Sand	3	56,982	34,189	22,793
29.	Fig Ridge	Seabreeze	3	57,050	33,557	23,493
30.	Lopez	Mirando	4	118,709	33,001	85,708
31.	Tom O'Connor	4500 Greta Massive	2	58,934	32,958	26,026
32.	Ganado, West	4700 Zone	2	68,804	32,671	36,133
33.	Bloomington	4600	2	68,955	31,416	37,539
34.	Gillock	East Segment (Big Gas Sand)	3	43,738	31,326	12,462
35.	O'Hern	O'Hern	4	83,257	29,972	53,285
36.	Thompson, North	Vicksburg	3	52,263	28,922	23,341
37.	Maurbro	Marginulina	2	51,100	25,320	25,780
38.	Hoffman	Lower Cole	4	66,767	24,510	42,257
39.	Helen Gohlke	Wilcox	2	48,102	24,431	23,671
40.	Prado	Middle Loma Novia 1-2-3	4	37,796	23,717	14,079
41.	Clear Lake	Frio	3	51,721	23,497	28,224
42.	Trinity Bay	Frio 12	3	35,759	23,472	12,287
43.	Bonnie View	Bonnie View	2	49,586	23,286	26,300
44.	Colorado	Cockfield	4	41,427	21,799	19,628
45.	Piedre Lumbre	Government Wells	4	94,956	21,593	73,363
46.	Livingston	Cockfield	3	55,845	20,512	35,333
47.	Aransas Pass	Aransas Pass	4	44,500	20,043	24,457
48.	Alazan, North	H-21	4	79,652	19,674	59,978
49.	Slick	Wilcox	2	32,123	19,643	12,480
50.	Willamar	Frio 1 East	4	44,734	18,955	25,829
	TOTAL			9,747,531	5,327,963	4,419,568

TABLE 2. - Screening criteria standards for enhanced oil recovery methods[2,3]

Screening parameters	Enhanced oil recovery (EOR) method				
	Steam injection	In-situ combustion	CO_2 miscible flood	Surfactant flood	Polymer flood
1. Oil gravity, °API.....	≤ 25	≤ 25	≥ 27	≥ 25	--
2. Permeability, md.....	--	--	--	≥ 20	≥ 20
3. Oil net pay thickness, ft.....	≥ 20	≥ 10	--	--	--
4. Oil viscosity, cp.....	≥ 20	≥ 20	≤ 10	≤ 30	≤200
5. Transmissibility, $\frac{md\text{-}ft}{cp}$	≥100	≥ 20	--	--	--
6. Initial reservoir pressure, psig.....	--	--	>1,200	--	--
7. Reservoir temperature, °F....	--	--	< 250	≤250	≤200
8. Depth, ft.....	>200 ≤5,000	≥5,000	>2,300	--	--
9. Target oil, STB/ac-ft.	>500	>500	--	--	--
10. Percent of initial oil in place before EOR begins.....	≥ 50	≥ 50	≥ 25	≥ 25	≥ 50
11. Lithology.....	Sandstone or Carbonate	Sandstone	Sandstone or Carbonate	Sandstone	--
12. Fractured.....	0 to minor	0 to minor	no natural fractures	0 to minor	0 to minor
13. Water drive.....	0 to weak	0 to weak	0 to weak	0 to weak	0 to weak
14. Gas cap.....	0 to minor	0 to minor	0 to minor	0 to minor	0 to minor
15. Salinity (TDS),ppm....	--	--	--	≤200,000	--
16. Hardness, (calcium and magnesium) ppm.....	--	--	--	<1,000	--

TABLE 3. — 50 major Texas Gulf Coast reservoirs categorized by EOR method

EOR method	Number of reservoirs
Steam injection.....	0
In-situ combustion.....	0
CO_2 miscible flood.....	7
Surfactant flood.....	7
Polymer flood.....	9
None.....	27

TABLE 4.—Summary of 50 major reservoirs in the Texas Gulf Coast indicating target oil available for possible recovery by enhanced oil recovery methods in MSTB

Map no.	Field	Reservoir	Railroad Commission district	None	CO_2 miscible	Surfactant flood	Polymer flood
1.	Conroe	Main Conroe (Cockfield)	3	566,266			
2.	Hastings, West	Upper Frio	3	297,713			
3.	Webster	Frio	3			311,542	
4.	Thompson	Frio	3	496,530			
5.	Tom O'Connor	5900	2	212,244			
6.	Anahuac	Anahuac Main Frio	3	211,315			
7.	Tom O'Connor	5600	2	169,389			
8.	Oyster Bayou	Seabreeze	3	82,406			
9.	Greta	4400	2	171,109			
10.	Tom O'Connor	5500	2		121,499		
11.	Hastings, East	Upper Frio	3	100,634			
12.	West Ranch	Greta	2		118,761		
13.	West Ranch	41A	2			95,313	
14.	Magnet Withers	Magnet Withers	3	71,835			
15.	Lake Pasture	H-440	2	59,385			
16.	Sugarland	Frio	3			72,192	
17.	Willamar, West	West Willamar	4		95,015		
18.	West Ranch	Glasscock	2				65,767
19.	Loma Novia	Loma Novia	4			63,231	
20.	Seven Sisters	Government Wells	4				86,576
21.	Portilla	7400	4	24,182			
22.	Gillock, South	Big Gas Sand	3		32,355		
23.	West Ranch	98A	2			39,116	
24.	Withers, North	"A-B-C"	3	18,850			
25.	Thompson, South	Frio	3	42,822			
26.	West Ranch	Ward	2		24,808		
27.	Tomball	Kobs	3	24,267			
28.	Thompson, South	4400 Sand	3	22,793			
29.	Fig Ridge	Seabreeze	3		23,493		
30.	Lopez	Mirando	4				85,708
31.	Tom O'Connor	4500 Greta Massive	2	26,026			
32.	Ganado, West	4700 Zone	2	36,133			
33.	Bloomington	4600	2	37,539			
34.	Gillock	East Segment (Big Gas Sd)	3	12,462			
35.	O'Hern	O'Hern	4				53,285
36.	Thompson, North	Vicksburg	3		23,341		
37.	Maurbro	Marginulina	2				25,780
38.	Hoffman	Lower Cole	4				42,257
39.	Helen Gohlke	Wilcox	2	23,671			
40.	Prado	Middle Loma Novia 1-2-3	4			14,079	
41.	Clear Lake	Frio	3	28,224			
42.	Trinity Bay	Frio 12	3	12,287			
43.	Bonnie View	Bonnie View	2	26,300			
44.	Colorado	Cockfield	4			19,628	
45.	Piedre Lumbre	Government Wells	4				73,363
46.	Livingston	Cockfield	3	35,333			
47.	Aransas Pass	Aransas Pass	4				24,457
48.	Alazan, North	H-21	4	59,978			
49.	Slick	Wilcox	2	12,480			
50.	Willamar	Frio 1 East	4				25,329
	TOTAL			2,882,173	439,272	615,101	483,022

TABLE 5. — Initial oil in place, ultimate recoverable oil, and target oil in the 50 major reservoirs and in the total Texas Gulf Coast

Oil	50 major reservoirs, billion STB	Total Texas Gulf Coast, billion STB	50 major reservoirs, percent of total Texas Gulf Coast
Initial oil in place.....	9.7	30.2*	32.1
Ultimate recoverable oil.....	5.3	13.2*	40.2
Target oil.....	4.4	17.0*	25.9
Target oil susceptible to EOR...	1.5	5.8	25.9

*API

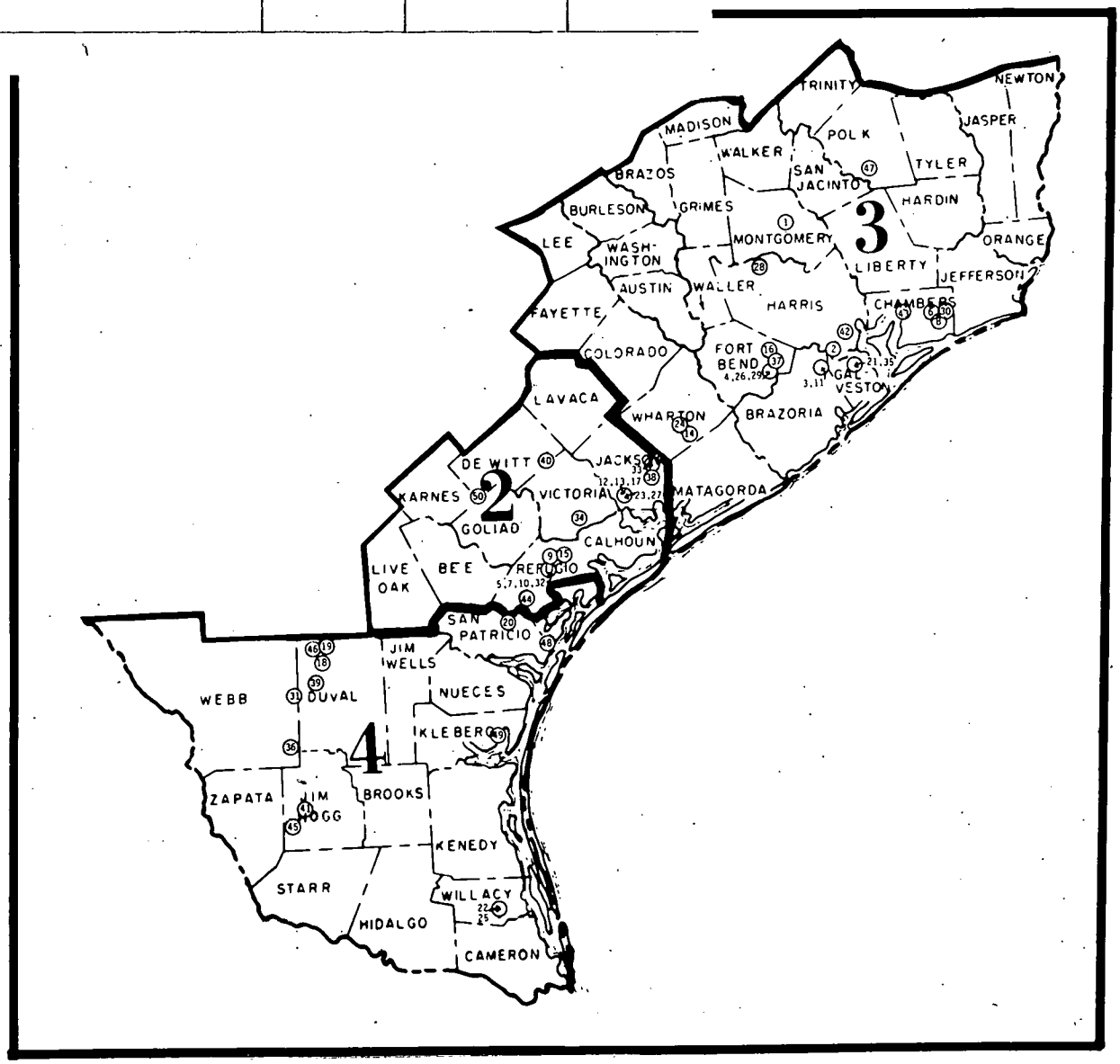


FIGURE 1.—Approximate geographical location of 50 major reservoirs in the Texas Gulf Coast.

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WEEKS ISLAND "S" SAND RESERVOIR B
GRAVITY STABLE MISCIBLE CO_2 DISPLACEMENT
IBERIA PARISH, LOUISIANA

By

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ABSTRACT

Shell Oil Company in conjunction with the Department of Energy is conducting a gravity stable displacement field test of the miscible CO_2 process. The test is being conducted in a 12,800-foot deep Gulf Coast reservoir. Injection of the CO_2 slug at the producing gas-oil contact commenced in October 1978. The slug of CO_2 is being moved downward by production of downdip water. Injection of the 50,000-ton slug should be completed in late 1979.

Neutron logging devices are being used to monitor the CO_2 movement in the vicinity of the observation well. The logs have been successful in detecting CO_2 and its subsequent movement at the observation well. Qualitative estimates of CO_2 saturations have been made using these neutron logs.

INTRODUCTION

The "S" Sand Reservoir B CO_2 pilot is designed to field test a downward CO_2 displacement in a steeply dipping, high temperature, high pressure Gulf Coast reservoir. Reservoirs of this type typically are produced by natural water drives which leave a significant residual oil volume. Other major watered-out reservoirs in the Weeks Island Field have an estimated tertiary potential of 26 million barrels of oil which could be recovered by CO_2 displacement.

Reservoirs of this type are not suitable for surfactant flooding as the temperature and water salinities are too high for currently available chemical systems, while the depth and usually good oil mobilities preclude any additional recovery by thermal stimulation.

The downward CO_2 displacement is designed to utilize gravity forces to stabilize the displacement and increase the sweep of the injected CO_2.

Prepared for the Department of Energy, under Contract EF (77-C-05-5232).

Laboratory work indicates the process will not achieve first contact miscibility ; miscibility was not developed in our 5-foot sand pack displacements. ..owever, the laboratory displacements indicated substantial recovery can be obtained.

Following an evaluation of the residual oil saturation, injection of the CO_2 slug commenced on October 4, 1978. Injection has averaged 107 tons of CO_2 per day and injection of the 50,000-ton slug should be completed in late 1979.

Neutron devices have been used to monitor the CO_2 in the vicinity of the new downdip observation and future production well. The CO_2 has been detected in the top of the sand, while appearance of oil at the observation perforations in the new well indicates the remaining oil column (oil rim remaining from waterflood) is being displaced into the watered-out sand.

PROJECT SETTING

The Weeks Island Field is located on a Gulf Coast piercement type salt dome. Hydrocarbon shows have been found in sands of the Pleistocene to Lower Miocene age at depths from 1,000 to 17,000 feet. Commercial production has been established in 37 Lower Miocene sands, predominately below a depth at 9,500 feet. The bulk of the original in-place oil (87%) was trapped in the downthrown fault block on the north flank of the field, where hydrocarbon column heights of up to 2,600 feet have been proven in sands that are inclined against the intruding salt and sheath. The majority of these reservoirs are driven by a strong water influx.

The "S" Sand Reservoir B occurs in a fault block on the north flank of the dome with the reservoir sealed against the dome by radial and peripheral faults. The "S" Sand Reservoir B contained two oil columns with over 3 million barrels of original in-place oil overlain by a 1,300-foot gas column which contained 24 BCF of wet gas. The CO_2 displacement is being undertaken in the west flank oil column which contained all but 200,000 barrels of the original in-place oil. A structure map and dip cross section of the west flank oil column is shown on Figure 1. Prior to CO_2 displacement, the west flank oil column was flooded with freshwater. The water was injected into Smith-State Unit G-2 which penetrated the reservoir below the oil-water contact.

Prior to CO_2 injection, the remaining oil column had been produced to an estimated thickness of 23 feet. The oil column height was estimated from the water level logged at -12,786 in the new well, Weeks Island State Unit A-17, on January 1, 1978, while the gas-oil contact on January 1, 1978 was estimated at -12,760 from the production characteristics of Weeks Island State Unit A-16-A.

The producing gas-oil contact was confirmed when the new injection perforations in Weeks Island State Unit A-16-A, located at a subsea depth from -12,750 to -12,760, backflowed gas and condensate in August of 1978. Both excess gas and water were being produced from the final preflood completion in Weeks Island A-16-A, which was located at a subsea depth of -12,777 to

-12,787 feet. The production of Weeks Island State Unit A-16 and the water injection into Smith-State Unit G-2, prior to CO_2 injection, are illustrated on Figure 2, the "S" Sand Reservoir B oil column production and injection history.

PREFLOOD RESERVOIR EVALUATION

Prior to initiating the CO_2 injection, a new well, Weeks Island State Unit A-17, was drilled at the location illustrated in Figure 1. This well, which was drilled to evaluate the reservoir parameters, is being used to monitor the displacement and will ultimately serve as a downdip producer. The evaluation of the new well was not completed when last year's symposium paper was written; however, the results of the reservoir evaluation were orally reported at the symposium and were published in the project's first annual report dated June 1978.

The reservoir was found to have an average stressed porosity of 26 percent which contained a waterflood residual oil saturation of 22 percent or 288 barrels per acre foot. The residual oil saturation was calculated by the following three methods:

Log-Inject-Log (LIL)
Core Analysis
Open-Hole Log Analysis

The residual oil measurements obtained by the different methods appear consistent and are illustrated on Figure 4. The comparative calculations were done in the interval of the LIL perforations which are illustrated on the Figure 1 cross section. On the Figure 4 comparison, the points represent our best estimate of each method, while the arrow bars represent our confidence limits on the individual residual oil determinations.

The residual oil saturation determined from LIL (.221$\pm$ .025) is in good agreement with oil saturations measured in the core and calculated from open-hole logs (.23$\pm$ .042 and .243$\pm$ .054, respectively). The residual hydrocarbon saturation measured on the open logs in this interval was .33. However, the FDC-CNL indicates a free gas saturation of 8.7% and, hence, must be subtracted from the total hydrocarbon saturation to arrive at the residual oil saturation. The residual gas saturation was present because a 900 psi decline in the reservoir pressure had released solution gas from the initially gas saturated crude.

The average residual oil saturation as determined from CCI data in the LIL interval is .293. Values determined from this method are believed to be a good estimate of the expected residual hydrocarbon saturation assuming the rock is 100 percent water wet. In the case of Weeks Island Reservoir B, this number should be equal to or less than the total hydrocarbon saturation calculated from the open-hole logs, but higher than the residual oil saturation due to the existence of a gas saturation.

CO2 INJECTION

The project will displace approximately 900 acre feet of the reservoir which is illustrated as 120-foot vertical displacement interval on the Figure 1 cross section. A 50,000-ton slug of CO_2 is being injected into Weeks Island State Unit A-16-A at a position just above the producing gas-oil contact. The density of the injected CO_2 is being reduced by the addition of 5 percent natural gas. Although our equilibrium experiments indicate the slug density will be reduced by methane absorbed from the oil and gas contacted in the reservoir, the 5 percent dilution reduces the initial slug density to approximately 95 percent of the in-place density of the S Reservoir B oil.

Because of its density, the CO_2 slug should spread between the less dense gas cap and the more dense oil column. Gravity forces should displace the remaining oil column and CO_2 slug into the watered-out sand as the water column is produced. Water column voidage in the sealed reservoir is being created by the production of the downdip well, Smith-State Unit G No. 2.

Continuous CO_2 injection was commenced on October 4, 1978. Injection was delayed two months by plugging of the injection well and a maintenance shutdown of the ammonia plant which supplies the CO_2. The well plugging was attributed to lubricating oil deposits in the injection line. The deposits had accumulated in approximately one mile of former gas injection line which was reused by the project. It appears that the deposits were mobilized by the CO_2 since no plugging occurred during the short gas injection period which preceded the CO_2 injection. Daily injection volumes and pressures are illustrated on Figure 3.

No plugging problems occurred after the line was thoroughly cleaned and a wellhead filter was installed. The line was heated with steam and treated with the hydrocarbon solvent and acid, which were displaced by line pigs. The wellhead filter was field fabricated to accept a 10-micron filter element.

LOGGING PROCEDURES USED TO MONITOR FLOOD FRONT

In monitoring the Weeks Island SRB, we are attempting to observe two things:

(1) The movement of the CO_2 front down through the reservoir.
(2) The movement of the oil bank ahead of the CO_2.

We felt that the neutron porosity device would be an excellent monitoring tool to detect the movement of the CO_2, since CO_2 should significantly reduce the apparent porosity reading. The neutron log responds directly as a function of the Hydrogen Index of the formation. The neutron response porosity equation may be expressed as follows:

$$\phi_N = \phi(H_\omega S_{\chi o} + H_h S_h + H_{CO_2} S_{CO_2}) \qquad (1)$$

where ϕ_N = Neutron apparent porosity

H_ω = Hydrogen index of the water in zone of investigation of the neutron tool

H_{CO_2} = Hydrogen index of the CO_2

H_h = Hydrogen index of the hydrocarbon

S_h = Hydrocarbon Saturation

$S_{\chi o}$ = Water Saturation in zone of investigation of the neutron tool

S_{CO_2} = CO_2 Saturation

Via personal communication between Shell's Bellaire Research Center and Dr. L. L. Raymer of the Schlumberger-Doll Research Center, it was suggested that a value of 0.0 be used as the Hydrogen Index of CO_2. Therefore, as can be shown from equation (1), a CO_2 saturation causes a much lower apparent neutron porosity. (Modeling studies done by Dr. Raymer show that 100% CO_2 saturation at a density of 1 g/cc would result in a compensated neutron porosity of a negative 2-3 porosity percent.)

Pulsed neutron logs are being used to monitor the flood front. Originally, it had been planned to use both the pulsed neutron and thru-tubing compensated neutron logging device; however, the latter tool has been removed from the market due to safety requirements. A normal thru-tubing chemical source neutron device was run in conjunction with the pulsed neutron log on the first two monitor runs; however, the quality of this data was insufficient to add to the interpretation derived from the pulsed neutron log. Thus far, three monitor runs have been made since December 1978. Plans are to continue frequent monitoring through the remainder of 1979.

The pulsed neutron log records a time value indicating the rate of decay of thermal neutrons in the formation. This decay is a function of the capture cross section (Σ) of the formation. The capture cross section recorded by the tool may be expressed by the following simplified equation in terms of formation properties:

$$\Sigma_{Log} = \Sigma_{ma}(1-\phi) + S_\omega\Sigma_\omega\phi + (1-S_\omega)\Sigma_h\phi + K \qquad (2)$$

where Σ_{LOG} = Capture Cross Section Recorded by Logging Device

Σ_{ma} = Capture Cross Section of the Matrix

Σ_ω = Capture Cross Section of the water

ϕ = Porosity

S_ω = Water Saturation

Σ_h = Capture Cross Section of the hydrocarbon

K = Diffusion Correction

The capture cross section for oil typically runs between 20-22 units, about the same as freshwater. Hydrocarbon gas typically runs between 8-12 units but may vary considerably due to temperature, pressure, and composition. The capture cross section for water varies greatly with salinity and runs between 20 units for freshwater to approximately 130 units for salt saturated brines.

Present day pulsed neutron logs are equipped with a long spaced detector. The count rates at the two detectors are used to produce a ratio curve which is essentially a dual-spaced neutron.[1] Unlike a normal compensated neutron, since it is responding to gamma-rays of capture, the ratio is a function of salinity. By using the Σ curve which is also a function of salinity, a pseudo neutron porosity curve can be produced. Figure 5 is a comparison between the computed open hole porosity, the open hole compensated neutron porosity, and the computed neutron porosity from the pulsed neutron log. The apparent pulsed neutron porosity was computed using a regression analysis equation based on Schlumberger's Σ-ratio crossplot chart for the appropriate size casing and salinity.

An estimate of the CO_2 saturation can be derived from the neutron response equations. An equivalent saturation based on hydrogen indices can be calculated from the following:

$$S_{\omega H} = (S_{\chi o} H_{\omega}) + (H_h S_h) + H_{CO_2} S_{CO_2} \qquad (3)$$

Using this equation in conjunction with equation (1) and solving these equations simultaneously with the equation for the "excavation effect" provided by Segesman and Liu[2], an estimate of CO_2 saturation can be calculated.

Since the hydrogen index of water and oil are nearly equal, the technique used to monitor the CO_2 movement is not applicable for monitoring the oil bank movement. Normally in the Gulf Coast with rocks of this porosity and depth, the pulsed neutron log can discern the difference between oil and water due to the difference in capture cross section between oil and salt water. However, as discussed in last year's report, freshwater was used in the SRB waterflood unit. As a result, we see a wide variation in salinity in the observation well with the water near the present day oil-water contact expected to be virtually fresh. Early movement of the oil bank is not easily discernable since the oil and water have similar capture cross sections. As the oil bank moves lower in the interval where the water becomes salty, we may be able to monitor the oil movement with the capture cross section curve. Present devices capable of discerning the differences between oil and freshwater such as the Carbon/Oxygen Log[3] can not be run through tubing.

DISPLACEMENT OBSERVATIONS

Observations made in Weeks Island State Unit A-17 suggest a gravity segregated displacement is occurring in the vicinity of this well. Log analysis from the first monitor run in December 1978 indicates the initial CO_2 invasion was in the gas cap. Subsequent logs indicated the CO_2 had displaced the oil column at this location. An April 1979 production test of the observation perforations, 28 feet below the CO_2 level indicated by the log analysis, shows that oil is resaturating the previously watered-out sand.

As illustrated by the porosity curves computed from the pulsed neutron logs in Figure 6, the December 20, 1979 logs show a significant reduction in porosity in the top of the SRB indicating a high CO_2 saturation to a well depth of 12,866 feet. This initial CO_2 invasion was principally above the producing gas oil contact which was predicted to be at a well depth of 12,862 feet in January 1978. The subsequent logs on February 21 and April 12, 1979 indicate CO_2 has invaded the oil column down to the lower quality sand interval from 12,882 to 12,888. No downward movement of CO_2 was detected between February and April.

The column of CO_2 logged in Weeks Island State Unit A-17 indicates the injected CO_2 was concentrated at this location and had not spread uniformly over the gas-oil contact. The February 21, 1979 logs indicated CO_2 was present in the 38-foot interval from the top of the sand to the poorly developed porosity at 12,882 feet. A uniform distribution of the CO_2 injected through February 22 in a 38-foot column over the entire 6.9 acre area of the gas-oil contact would have resulted in an average CO_2 concentration of 25 percent. Over much of this interval, the neutron porosity is 0.0% (actual porosity is 25%). The minimum CO_2 saturation necessary to produce this apparent porosity is greater than 65%. The bell shape of the neutron porosity (the apparent decrease of neutron porosity with depth) computed from the April 1979 log is an indication that the CO_2 saturation is decreasing in the upper portion of the sand at the Weeks Island State Unit A-17 location. Possible reasons for the decrease in CO_2 concentration could be spreading of the CO_2 or additional downdip displacement of the CO_2 above the poor porosity interval. Unfortunately, this poorly developed sand in the 12,882- to 12,888-foot interval of the observation well has obscured the movement of CO_2 in the vicinity of the observation well. We therefore cannot see the leading edge CO_2 column. We expect to see the base of the CO_2 column below the poor porosity interval as the displacement, evidenced by the oil production from the deeper observation perforations, proceeds further.

The observation perforations which are located at a well depth interval from 12,910 feet to 12,920 feet are 21 feet lower than the water level logged when the well was drilled in December 1977. During a 6-hour test of the perforated interval on May 2, 1979, the well flowed 17 barrels of oil and 32 barrels of load water. A pressure gradient survey after the production test indicated that the tubing was essentially filled with oil and the interval had produced little or no water. A chromatographic analysis measured normal preinjection CO_2 content of one percent in the gas produced with the oil. The oil was detected as preparations were being made to swab the well for an indication of hydrocarbons. The 250,000 barrels of water produced through mid-April should have resulted in the resaturation of the watered-out sand in the interval of the observation perforations.

As expected, initial detection of the oil movement in the previously watered-out sand with pulsed neutron logs has been extremely subtle at best; this is due to the low salinity water at the oil-water contact. Figure 7, which compares the capture cross section between the base log and the last monitor run, gives some indication that oil or freshwater is being pushed down into the saltier interval below 12,920.

CONCLUSIONS

CO_2 is being injected at an average rate of 107 tons per day. No injectivity problems have been encountered other than initial injection well plugging. The initial plugging has been attributed to CO_2 mobilization of a heavy residue in the injection line.

Pulsed neutron logs have been used to qualitatively define the CO_2 column in the vicinity of the observation well. However, because of low water salinity, the logs have not defined the displaced oil column.

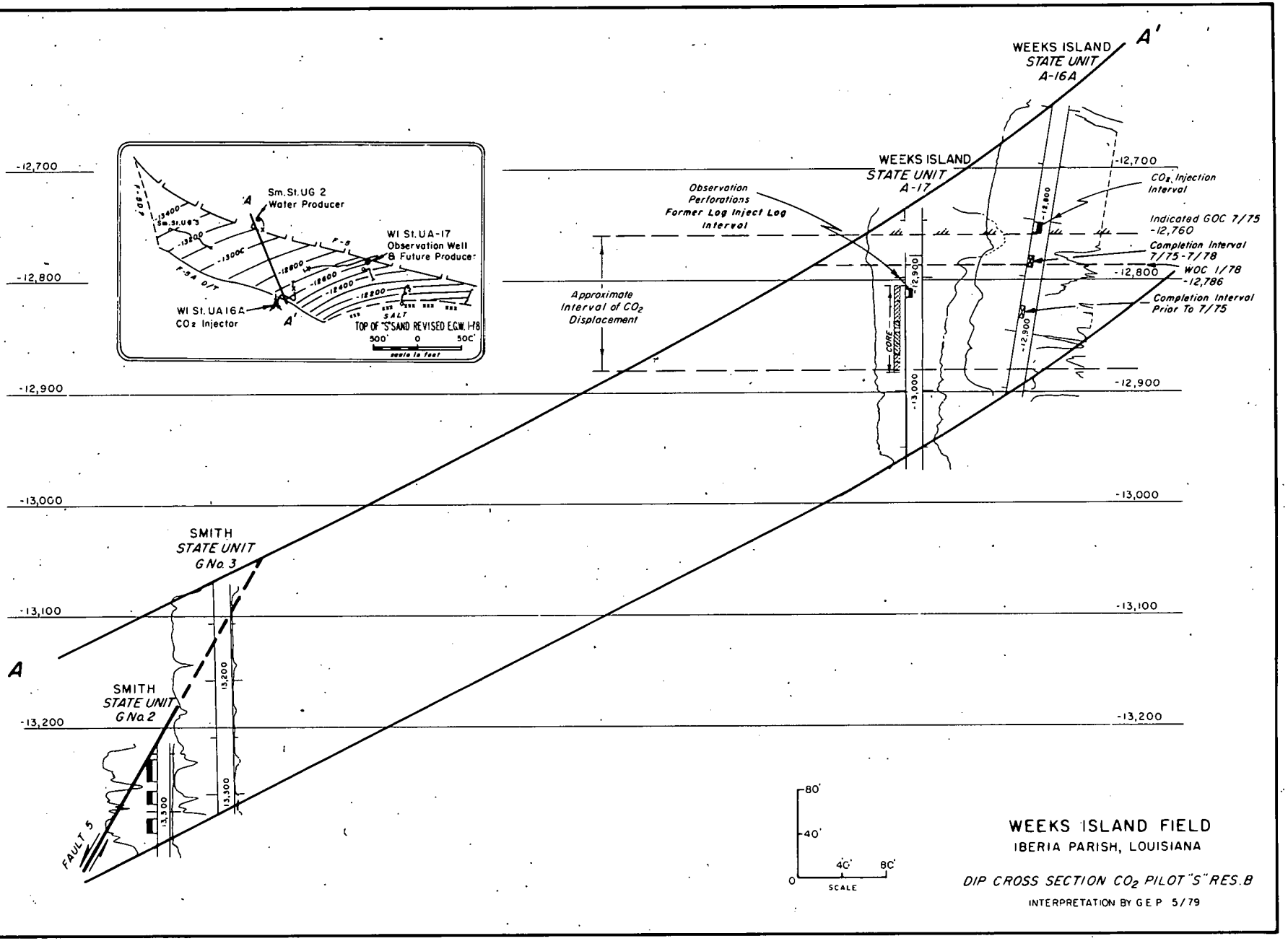
At the one observation point the displacement has been gravity segregated. The thickness of the CO_2 column, however, indicates the CO_2 was not uniformly spread over the entire area of the gas-oil contact.

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(2) Segesman, F. and Liu, O.: "The Excavation Effect," SPWLA Symposium, Dallas, May 2-5, 1971.

(3) Lock, G. A. and Hoyer, W. A., "Carbon-Oxygen (C/O) Log: Use and Interpretation," Journal of Petroleum Technology, September 1974.


WEEKS ISLAND
STATE UNIT
A-16A
A'
WEEKS ISLAND
STATE UNIT
A-17
Observation
Perforations
Former Log Inject Log
Interval
CO₂ Injection
Interval
Indicated GOC 7/75
-12,760
Completion Interval
7/75 - 7/78
WOC 1/78
-12,786
Completion Interval
Prior To 7/75
Approximate
Interval of CO₂
Displacement
-12,700
-12,800
-12,900
-13,000
-13,100
-13,200
CORE
-12,900
-13,000
Sm.St.UG 2
Water Producer
WI St.UA-17
Observation Well
& Future Producer
WI St.UA16A
CO₂ Injector
A
A'
SALT
TOP OF "S" SAND REVISED E.G.W. 1-78
500' 0 500'
scale in feet
SMITH
STATE UNIT
G No. 3
SMITH
STATE UNIT
G No. 2
FAULT 5
13,200
13,300
13,300
80'
40'
0
40'
80'
SCALE
WEEKS ISLAND FIELD
IBERIA PARISH, LOUISIANA
DIP CROSS SECTION CO₂ PILOT "S" RES. B
INTERPRETATION BY G.E.P. 5/79

N-1/9

FIGURE 1

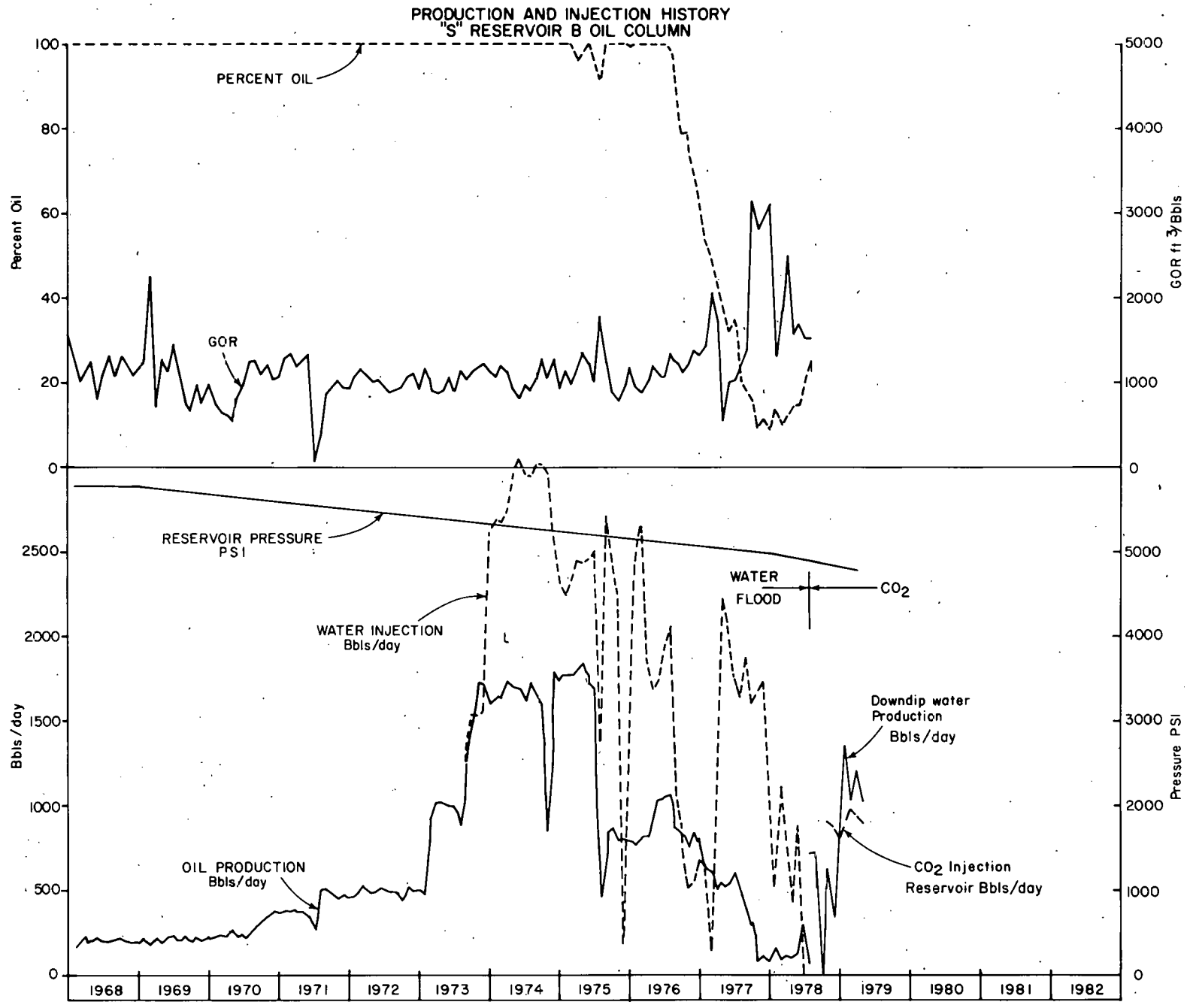

PRODUCTION AND INJECTION HISTORY
"S" RESERVOIR B OIL COLUMN
PERCENT OIL
GOR
Percent Oil
GOR ft³/Bbls
RESERVOIR PRESSURE
PSI
WATER INJECTION
Bbls/day
WATER
FLOOD
CO2
Downdip water
Production
Bbls/day
OIL PRODUCTION
Bbls/day
CO2 Injection
Reservoir Bbls/day
Bbls/day
Pressure PSI
1968
1969
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982

FIGURE 2

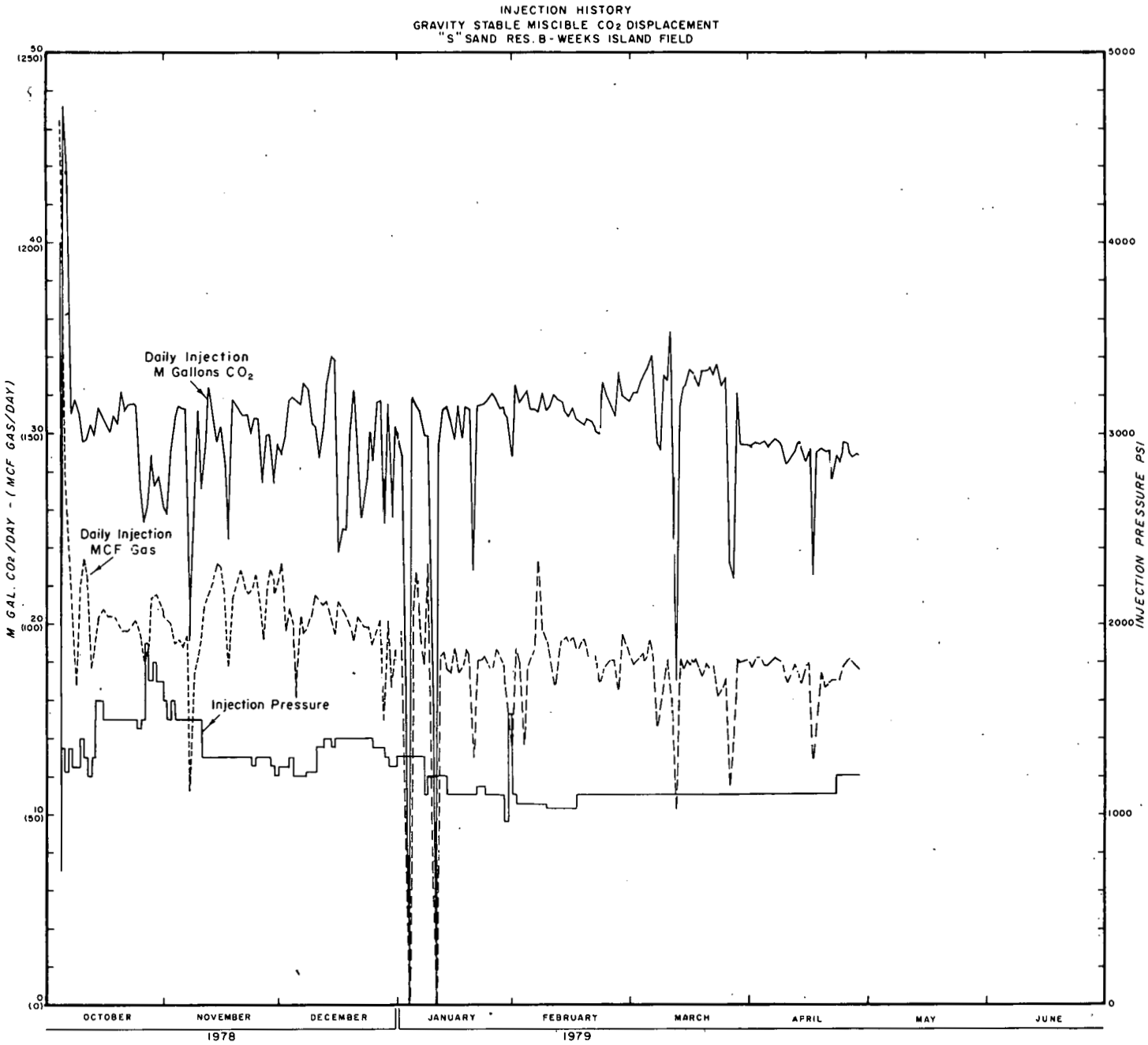

INJECTION HISTORY
GRAVITY STABLE MISCIBLE CO_2 DISPLACEMENT
"S" SAND RES. B - WEEKS ISLAND FIELD
M GAL. CO_2/DAY - (MCF GAS/DAY)
INJECTION PRESSURE PSI
Daily Injection M Gallons CO_2
Daily Injection MCF Gas
Injection Pressure
50 (250)
40 (200)
30 (150)
20 (100)
10 (50)
0 (0)
5000
4000
3000
2000
1000
0
OCTOBER
NOVEMBER
DECEMBER
JANUARY
FEBRUARY
MARCH
APRIL
MAY
JUNE
1978
1979

FIGURE 3

COMPARISON

RESIDUAL OIL MEASUREMENTS
WEEKS ISLAND ST U A-17
"S" SAND RESERVOIR B

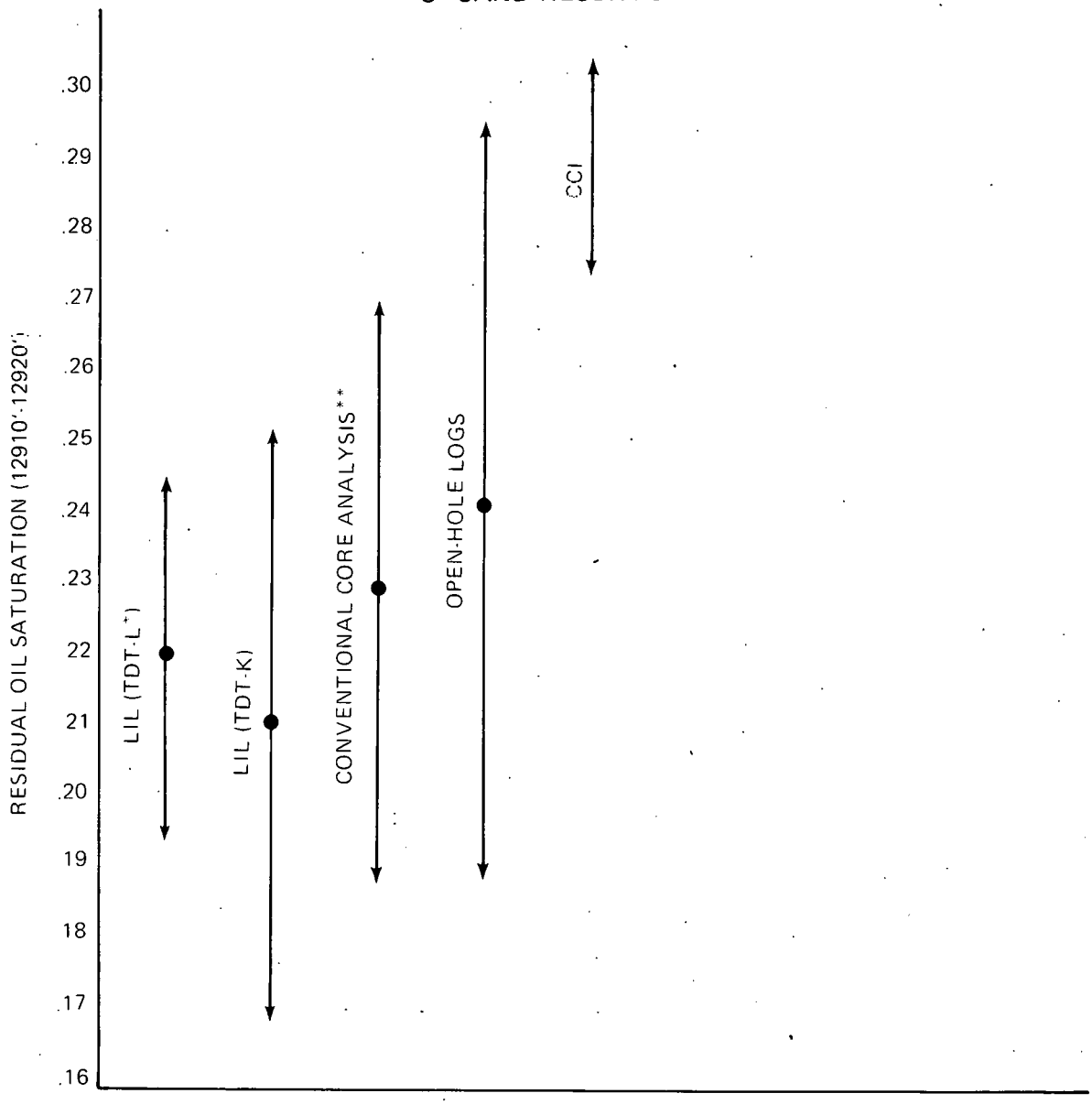


FIGURE 4

METHOD OF DETERMINATION

* This is a modified TDT-K with TDT-G electronics source-detector spacing 60 cm. Readings are taken while stationary.

** Saturation of core plug at 12918 is omitted. The saturation of this plug was over 2.5 standard deviations from the average.

COMPARISON OF TOTAL POROSITY COMPENSATED NEUTRON POROSITY AND COMPUTED PULSED NEUTRON BASE LOG POROSITY

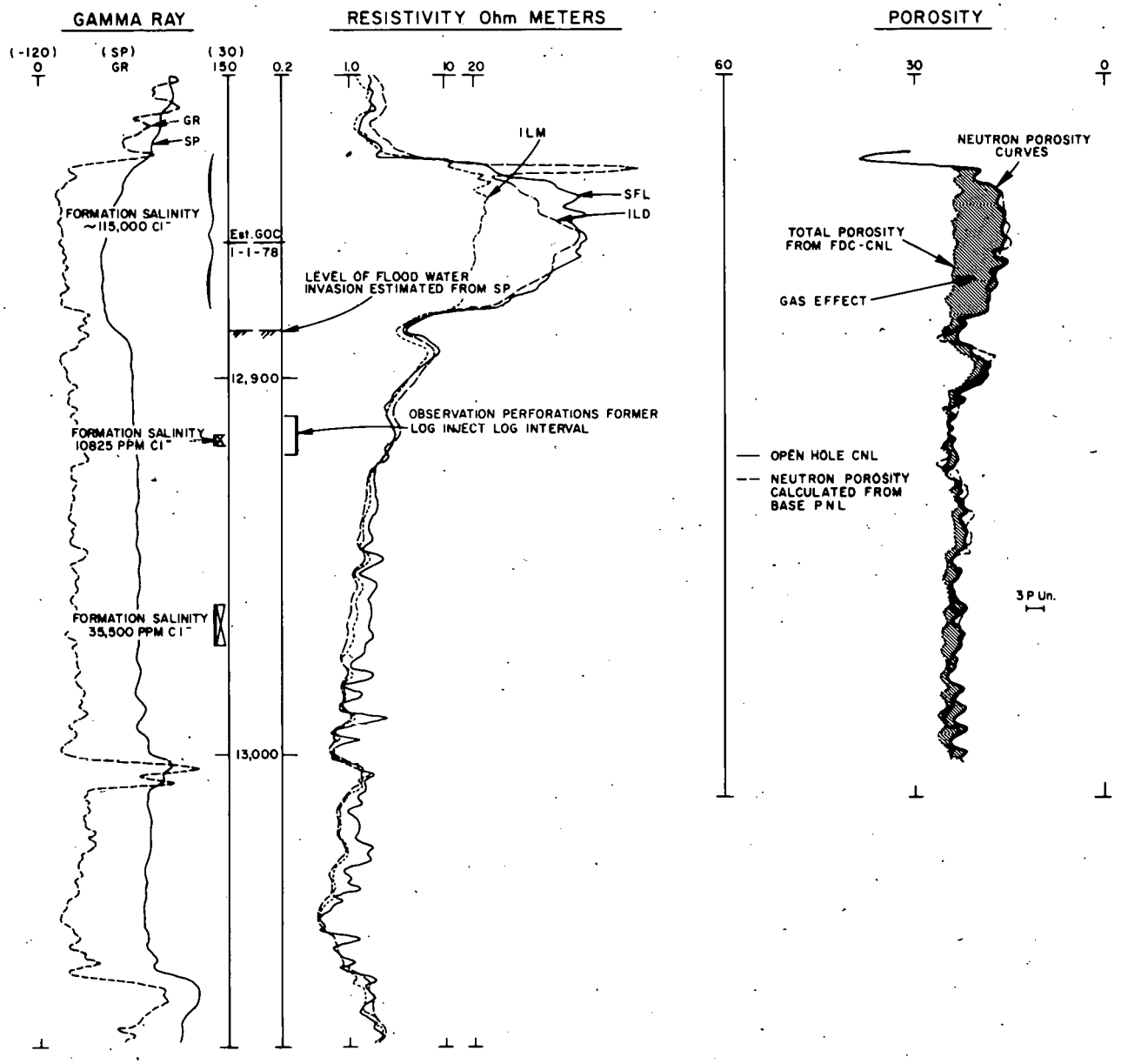


FIGURE 5

NEUTRON POROSITY MONITORING OF CO_2 FLOOD FRONT MOVEMENT

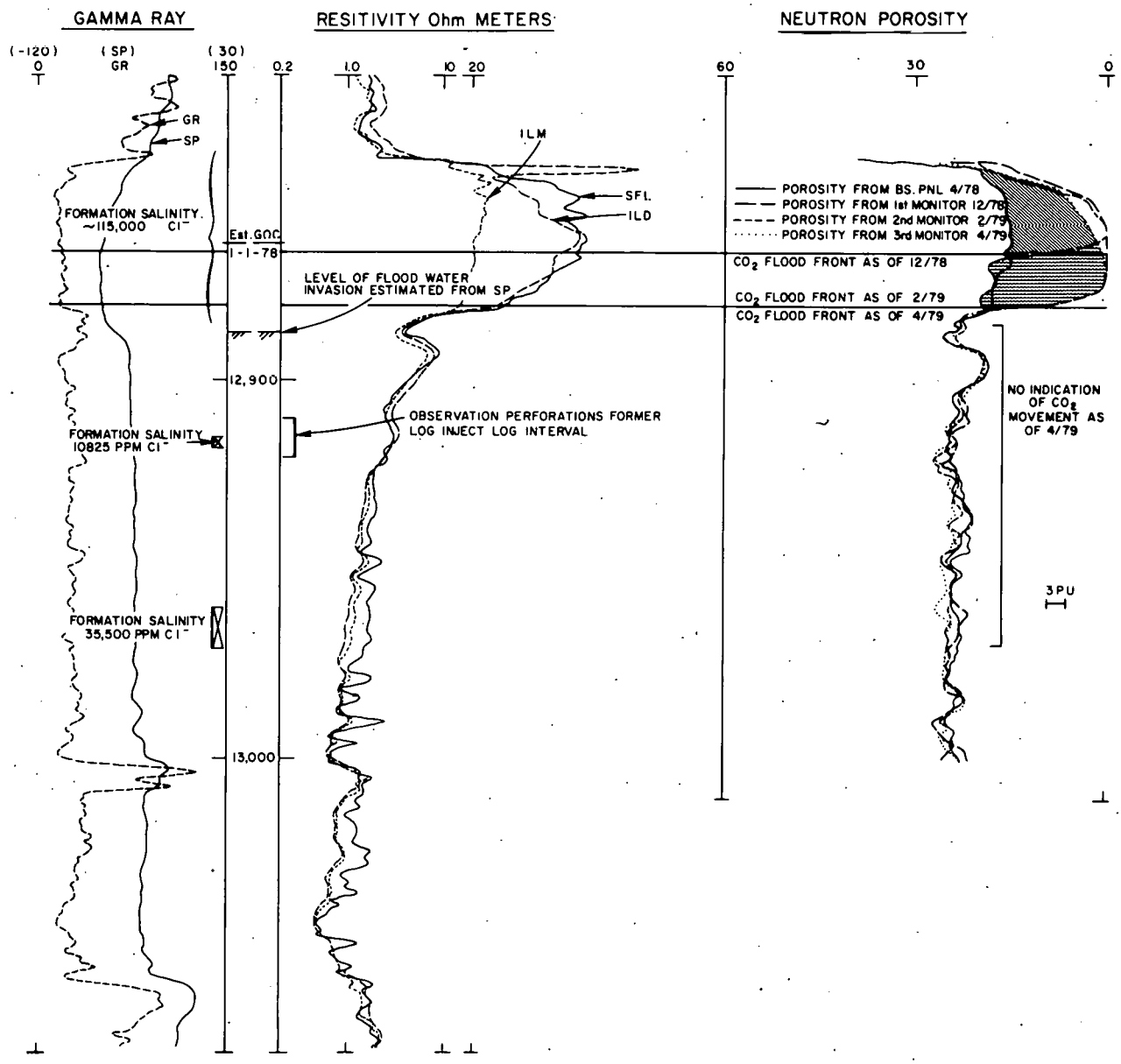


FIGURE 6

CAPTURE CROSS SECTION
CHANGE DUE TO CO_2 INJECTION

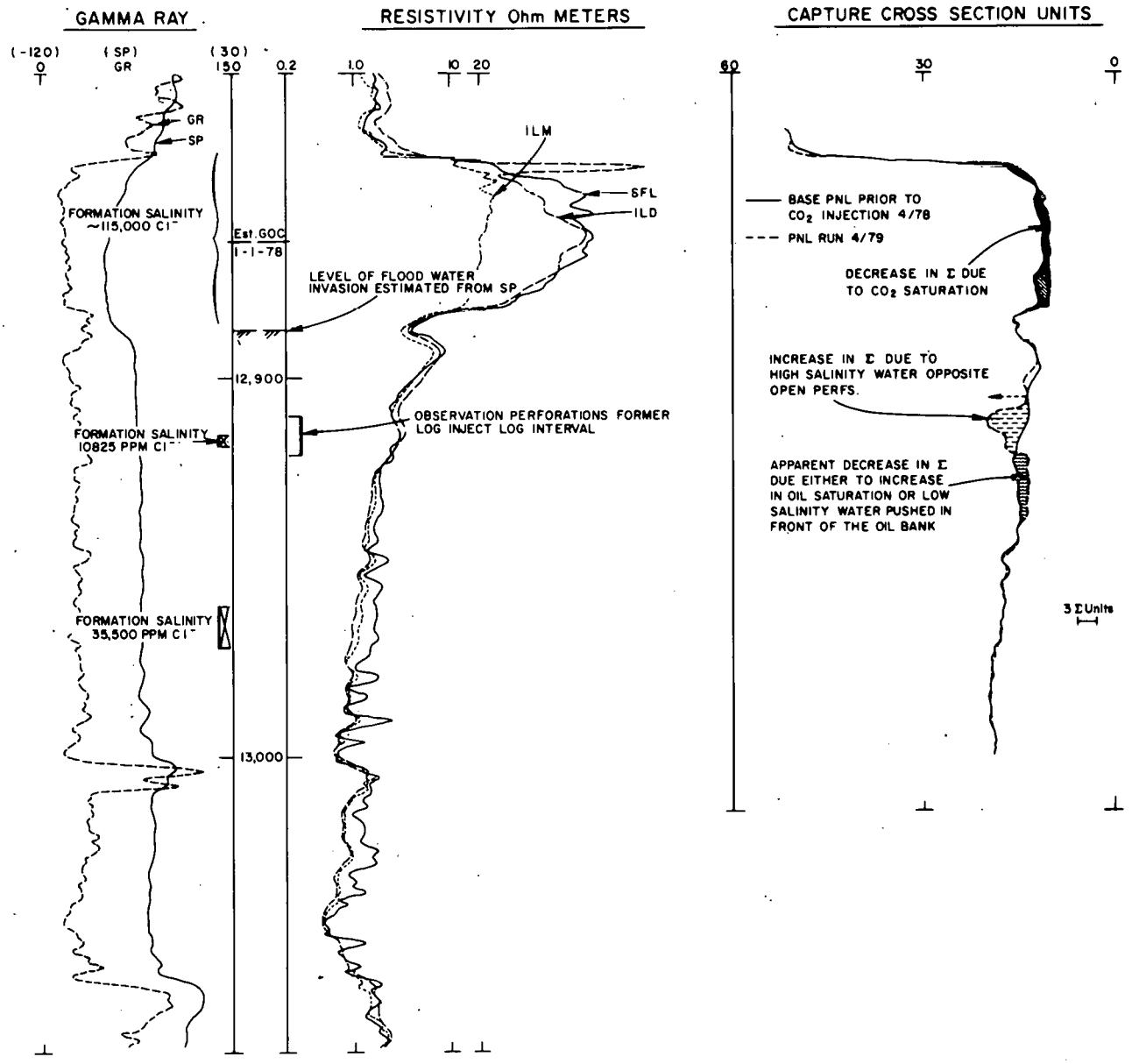


FIGURE 7

SURVEY AND ANALYSIS OF CORROSION PROBLEMS CAUSED BY CO_2 INJECTION FOR ENHANCED OIL RECOVERY

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ABSTRACT

The objective of this study was to identify and document the surface and downhole corrosion problems and potential corrosion control measures associated with CO_2 miscible flooding. A literature survey supplemented by industry contacts was used to analyze the direct corrosive effects of elevated CO_2 pressure in oil production systems as well as effects on corrosion due to other environmental factors.

A general conclusion is that corrosion can become severe if adequate prevention measures are not planned in advance and implemented. Corrosion can be reduced to acceptable levels by a combination of control procedures including proper choice of materials and coatings, use of corrosion inhibitors and oxygen scavengers, and equipment design and operation. These measures and their interactions are presented to aid design and corrosion engineers in choosing the proper mix for each situation. A general review of corrosive effects of CO_2 is also given.

INTRODUCTION

Injection of carbon dioxide is a promising method for recovering large amounts of oil that cannot be recovered by conventional (primary and secondary) technology. As with any relatively new technology, there are aspects of CO_2 injection that, without adequate assessment, could discourage its use. One of these aspects is the potential for increased corrosion of oil field equipment that could result from CO_2 injection. The purpose of this study was to document the specific effects of CO_2 on corrosion and to identify promising methods for controlling corrosion in fields using CO_2 injection. This paper emphasizes the control methods. Results of the analysis of specific corrosive effects of CO_2 are detailed in the final report resulting from this contract.

Prepared for the Department of Energy, under Contract DE(AC21-78MC08442).

Engineering metals are not attacked by CO_2 under oil field environments unless liquid water is also present. Plain and low alloy steels are attacked by mixtures of CO_2 and liquid water. Attack on these bare metals may become serious at a CO_2 partial pressure as low as 4 psi and it increases with CO_2 partial pressure although not in direct proportion. Fluid flow rate is an important factor in CO_2/water corrosion. Practically all stainless steels and similar resistant alloys are not particularly subject to corrosion by CO_2/water mixtures alone, even at high CO_2 pressures. Elevated levels of CO_2 can aggravate the corrosive effects of other species such as hydrogen sulfide, oxygen, and chloride. Mixtures of CO_2, carbon monoxide (CO), and water can cause stress corrosion cracking of plain steels.

Corrosion problems in CO_2 systems should be circumvented when possible by avoiding combination of the corrosive components. Although water cannot be excluded throughout the CO_2 injection-oil production-CO_2 and water reinjection chain, air in-leakage can be minimized and oxygen scavengers used to remove any residual. Exclusion of oxygen is important to the successful use of other corrosion control measures.

CORROSION CONTROL METHODS

This section describes in general terms the main methods used for corrosion control in the CO_2 injection-enhanced oil recovery process. Choice of materials is included as a control measure. Most of the discussion in this section assumes that corrosion cannot be prevented by removal of one or more corrosive agents from the process stream. Selection of a good corrosion control method does not guarantee good results. Proper detailed specifications, construction and operation is also necessary. Without this attention the most expensive alloy component can be ruined or the "low bid" coating may ultimately cost much more than a quality job.

Metals

Constructing all equipment from resistant metals could "solve" practically all corrosion problems caused by CO_2. This would be far too expensive, however, due to the scale of equipment involved. The more resistant metals are very useful for limited areas where temperatures or flow rates are too high for coatings to be reliable or where the CO_2 partial pressure is high and the presence of liquid water may be unavoidable. Some such areas might be treatable with inhibitors. If inhibitor effectiveness is marginal, equipment reliability is critical or it is mechanically difficult to ensure inhibitor access to the area, the use of resistant metals is probably indicated. Due to the extra initial expense involved in using a resistant metal, the specification should be done carefully and the need for any precautions in applying the material should be recognized. These factors are discussed below for the more likely choices of constructional or special purpose metals.

Stainless Steels

Stainless steels appear to be resistant to corrosion by wet CO_2 alone even at high CO_2 partial pressures under laboratory conditions. Dependence of general corrosion resistance on stainless steel compositions follows the usual pattern, with resistance increasing with increasing chromium content and with the addition of nickel. Overall, the selection of a stainless steel for use in aqueous CO_2 depends largely on other environmental factors such as other chemical species present, presence of solids or crevices in the system, and mechanical or strength requirements.

As a class, the stainless steels are very resistant to uniform corrosion in environments such as those considered here. Large quantities of wet, hot CO_2 under pressure are handled in the ammonia industry, for example, and extensive use of stainless steel is made in this case. Type 304 is normally the lowest grade used in this industry. In solutions containing chloride, however, they can become susceptible to pitting and crevice corrosion. Crevice corrosion does not necessarily require a mechanical crevice, it can occur under solid, scale, or sludge deposits on the metal. Fluid-wet gaskets are often a starting point for crevice corrosion. The likelihood of pitting or crevice corrosion increases drastically when small quantities of oxygen ($\sim$50 ppb) are present in solution. Susceptibility also increases with increasing temperature and chloride ion concentration. Resistance to localized corrosion increases with increasing amounts of alloying agent, especially chromium and molybdenum, in the steel. Thus Type 304, which contains no molybdenum, has considerably less resistance to chloride induced attack than Type 316. Type 317 with 3-4% Mo generally has the best corrosion resistance in this series.

Certain stainless steels, including the common austenitics Type 304 and Type 316, can undergo stress corrosion cracking (SCC) under certain combinations of chloride ion concentration, oxygen, temperature and stress. The likelihood of SCC increases as each of the above four parameters increases. The amount of stress needed to cause cracking is difficult to quantify in practical situations and it is usually best to assume that SCC is possible if the other three parameters are satisfied, no matter what the applied stress. SCC can occur under zero applied stress. Even so, austenitic stainless steel components should be specified in the fully annealed condition when possible.

It is noteworthy that small amounts of oxygen are often responsible in large part for corrosion of stainless steels. The removal of oxygen by stripping and addition of oxygen scavengers can eliminate many of these problems. Inhibitors may improve the performance of marginal grades but in view of the expense and complexity of most components relying on the corrosion resistance of stainless steel, it would seem best to either specify a better grade or thoroughly test the steel/inhibitor combination. As in other inhibitor applications, insufficient inhibitor concentration may induce or accelerate localized corrosion.

Carbon and Low Alloy Steels

These materials are not considered "resistant" except at low CO_2 pressures or when effectively coated or inhibited. As noted at several places in this report, corrosion of ordinary bare steels can become significant when exposed to uninhibited solutions of CO_2 at a partial pressure above about 4 psia. At CO_2 pressures higher than about 20 psia, serious attack is likely under such conditions.

When operating in a corrosive atmosphere, the grade of steel can be a factor. Normally, J-55 tubular goods are slightly more resistant than N-80 (1). All tubing and couplings in the SACROC unit field are normally J-55 grade; a one-time substitution of N-80 couplings resulted in severe attack on the couplings (2). Low alloy steels such as 4340 and 4145 do not appear to have any advantage over the normal types from a corrosion standpoint and may suffer more attack than the normal grades. An exception to this last statement is when higher strength levels are needed in sulfide stress cracking environments than can be safely obtained using the normal grades. In such cases, a high hardenability, modified version of AISI 4130 is said to be the best commercially available constructional steel for downhole service (3). An example is AISI 4135 Modified containing 0.8% molybdenum and 0.05% niobium. Severe localized corrosion near the upsets of tubing is often noted when a well is made sufficiently corrosive by CO_2. This "ringworm" corrosion can be eliminated by specifying tubing that is fully normalized over the entire length after the upsetting procedure.

Nonferrous Metals and Medium Alloy Steels

A number of nonferrous metals may be used for their mechanical properties or specific corrosion resistance. Often these requirements are linked as when higher hardness or yield strength than safely obtainable with most ferritic materials is needed in a sulfide stress cracking environment. The following alloys should be resistant to wet CO_2 and are usable in sour environments up to HRC 35 when properly heat treated (4).

- Nickel-copper alloys (Monel 400, Monel K-500)
- Nickel-iron-chromium alloys (Incoloys)
- Nickel-chromium alloys (Inconels)
- Nickel-chromium-molybdenum alloys (Hastelloys, Inconel 625)
- Cobalt-nickel-chromium-molybdenum alloys (MP35N, Elgiloy, Havar, Nimonic 105).

Even materials which are highly resistant to sulfide stress cracking can become susceptible under certain conditions. Monel K-500 can become susceptible if it is plastically deformed in service (5). MP35N has cracked when galvanically coupled to iron (3).

Medium alloy steels are classified here as those having more than 3% but less than 11% alloying agents such as chromium or nickel. Early corrosion problems in gas condensate and certain oil wells spurred interest

in these materials for downhole tubing. In laboratory tests, the 9% Cr and Ni materials showed significantly lower corrosion rates than the ordinary steels in corrosive, high CO_2 partial pressure environments (6). In field use, the general corrosion resistance was good but a number of corrosion cracking failures and pitting of the 9% Ni equipment were reported in (1). Most of the failures appeared to occur for tubing that was harder than RC-22; a maximum yield strength of 105,000 psi was suggested for use of this material. The 9% Cr or 8-9% Cr, 1% Mo alloy has been used more extensively in sweet gas condensate wells with generally good results. Some cracking has occurred, however, and this may be due to the high strength of the material combined with traces of H_2S in the fluid. NACE Standard MR-01-75 (1978) lists this material with maximum hardness of HRC22 as acceptable for sour downhole service. Pitting resistance of this material is often poor compared to ordinary steels such as J-55.

Protective Coatings and Nonmetallic Materials

A large number of coatings are available for corrosion protection purposes. Their basic purpose is to isolate the structural metal from the corrosive environment. In many cases the coating itself is not subject to attack, but its effectiveness depends on freedom from holidays, pinholes, and disbonding which exposes the bare metal. Coatings are often not applicable in situations where severe erosion, mechanical rubbing, high temperature or large cyclical temperature changes can occur. The use of coatings in very corrosive environments should be evaluated carefully, especially if the protected equipment is critical. The use of chemical inhibitors as back-up protection for large-scale coated equipment is worthy of consideration.

Plastic coated steel can display a much longer life than bare steel in moderately corrosive environments. Proper selection, application and use of these coatings must be done to utilize their protectiveness. The first stage of selection depends on whether the equipment will be under gas pressure, such as injection or production well tubing or will be used in fluids near atmospheric pressure. Thin coatings must be used in high pressure regions since gases such as CO_2 can permeate the coating. When the pressure is released, the gases cannot escape fast enough from thick film coatings and this results in blistering and disbonding. However, thin film coatings allow rapid gas relief and have been successfully used in such high pressure areas as SACROC CO_2 injection well tubing (2). Thick coatings may be desirable where this is not a problem since they may have fewer holidays and more resistance to erosion and abrasion. A number of thin film coatings are available from manufacturers and appliators and the quality of application may be as important as the coating composition. The more successful general types are phenolic and epoxy-phenolic in the thickness range of approximately 5-8 mils. Good surface preparation is extremely important in obtaining a satisfactory coating for corrosive environments.

Coated surface equipment may not be subject to pressure release disbonding but they are often exposed to fluids that contain oxygen through

air in-leakage and to high liquid flow rates. If properly applied, dense, thick films should have greater resistance to oxygen permeation and erosion. As with thin coatings, good surface preparation and application may be as important as actual coating composition. However, experience in handling produced fluids from CO_2 injection has indicated that thick film epoxy coatings have wider application than coal tar epoxy.

Equipment based mainly on nonmetallic materials can be considered when the fabricated material can withstand the pressure and temperature requirements of both its normal duty and any transient or upset conditions that may occur. Materials such as fiber reinforced plastic (FRP) can give good, economical corrosion service if carefully specified and designed to operate well below the recommended maximum pressure for any given temperature of use. When properly used, FRP materials can withstand corrosive environments that would rapidly attack steel vessels and piping.

Inhibitors

Inhibitors are chemical substances which can retard the corrosion of metals when added in small concentrations to the fluids contacting the metal. Most of the inhibitors used in the oil industry are organic chemicals which adsorb strongly on the surface of the metal and promote the formation of a mechanically protective oil film on the metal. The organic inhibitor normally has at least one highly polar chemical group which attaches to the metal and a nonpolar, oil soluble "tail" which encourages formation of an oil film over the inhibitor layer.

There is considerable evidence that conventional organic film-forming inhibitors can be effective against corrosion caused by CO_2 in a number of environments. Substances such as the filming amines have been used for a number of years for treatment of those oil wells which produce acid gases as well as for several years at the SACROC unit during production of injected CO_2 and relatively corrosive water. Such inhibitors are also used in condensate lines that carry wet CO_2. Although the high molecular weight amines usually have a low solubility in near neutal pH water, if dispersed they can dissolve in acidic solution areas and thus protect those parts of a system that are likely to corrode.

The effectiveness of an inhibitor depends on many factors, but in order for it to have a chance to be effective, it must reach the metal surface which is to be protected. Generally, this might be hampered for either chemical or mechanical reasons. The chemical reasons include whether the equipment is oil- or water-wet which in turn depends on the water cut and other properties of the fluids. Inhibitors for production wells are usually available as either oil-soluble, water-dispersible, or water soluble and their relative effectiveness will depend to a large extent on which type can best dissolve in the metal-wetting phase and be adsorbed on the metal to promote formation of a protective film. Inhibition may also be difficult for areas where fluid circulation is low or stagnant. Plans should be made in the design stage to provide optimum inhibitor injection points. It is also desirable to plan an inhibition program for start-up so that the inhibitor can be applied before a corrosion product layer is formed.

Selecting the treatment method that assures filming of the equipit is often as important as the inhibitor used for controlling corrosion in production wells. Types of treatment that may be suitable for conventional flowing or sucker rod type wells are given in reference 7 with the tubing set at or above the producing interval and some open hole below the bottom of the producing zone. Special considerations may be required for dual and gravel-packed completions, fluid and centrifugally pumped, and gas lift wells. Details on the application of the types of treatment shown are given by Endean (7) and in reference (8). Effectiveness of inhibition should be regularly monitored using coupons, iron concentration analyses and corrosion probes along with any variations in pH and CO_2 partial pressure.

Although not a direct inhibitor, chemicals which react with and remove oxygen from a liquid stream are useful for some streams. Low concentrations of oxygen can be very corrosive to both carbon and stainless steels, especially in the presence of chloride, H_2S and CO_2. Streams that may need to be treated include water injected during the water cycle of the WAG process and produced water that may become aerated. Oxygen concentrations as low as 10 ppb can influence corrosion and these can easily arise from inadvertent air in-leakage into low pressure lines. Sulfite in the form of sodium sulfite or SO_2 is a commonly used oxygen scavenger. In most cases a catalyst, such as low concentrations of divalent cobalt ion, is needed to increase the reaction rate between sulfite and oxygen. Commercial formulations of oxygen scavengers are available. Highly oxygenated streams may require stripping with inert gas prior to treatment.

CORROSION OF CO_2-ENHANCED OIL RECOVERY EQUIPMENT

The two areas with the highest potential for rapid corrosion are also the ones which are least well known to the industry: the high pressure CO_2 pipeline and the CO_2 injection wells. Although potential hazards exist, corrosion can be minimized in these areas with proper design and operation. Production of CO_2 will increase corrosion of any production well and surface equipment that has been designed to handle only moderately or noncorrosive fluids. The incremental increase in corrosivity is not overwhelming, however, and combinations of standard techniques used to control normally corrosive oil well fluids should be effective.

Overall, it is important for the producer to be aware of and prepare for an increase in corrosion problems ahead of time. Economic considerations will vary from field to field and even from well to well. But since CO_2 injection can produce corrosive conditions for a number of years of operation, the higher initial costs for good corrosion prevention measures will most likely be justified by increased production time and reduced maintenance.

Corrosion experience at the SACROC CO_2 injection unit is emphasized since it has been operating longer and on a larger scale than other facilities. Length of exposure is, of course, very important in establishing the validity of corrosion expereince. SACROC engineers feel that their experience may be somewhat atypical in some cases since the field is known to have

"corrosive waters" and effects due to increased water production and start of CO_2 injection are difficult to separate. Still, this field represents a very useful, if possibly conservative, model.

Pipelines For CO_2 Transport

Pipelines transporting CO_2 will operate under very high CO_2 partial pressures. The pipeline must be constructed from low alloy steel for economic reasons. Coatings or inhibitors should be considered unreliable under such high CO_2 pressures if any liquid water is present. On the other hand, if the CO_2 is effectively dehydrated, it is not corrosive to pipeline steels. Therefore the main means for prevention of interior pipeline corrosion is prior dehydration of the CO_2 at the source. This also eases the corrosion burden on any intermediate booster station equipment, the injection compressors, and to a certain extent on injection well equipment. The injection well presents more of a problem since water is often introduced during part of its operation.

The gas should be dehydrated well below the saturation point to ensure that no condensation will occur in the pipeline under unusual or upset conditions. Water content of SACROC supercritical CO_2 is specified as 50 ppm (by weight) maximum even though saturation is 2500 ppm and lab tests showed no attack on pipeline steel at 1000 ppm water and 800 ppm H_2S levels. Such conservation is probably called for in view of the very rapid corrosion that could occur if any liquid water collects and many historical cases of corrosion in pipelines carrying lower CO_2 pressures but water levels close to saturation. Continuous monitoring of the water content of gas input to the pipeline is highly recommended.

The pipeline should be thoroughly cleaned and dried prior to charging with CO_2. The following procedure has been used (9).

1) hydrotesting
2) cleaning with multiple mechanical scrapers
3) drying with methanol
4) displacement with dry air
5) packing with CO_2

The SACROC unit experienced difficulties with plugging by solid corrosion products from the pipeline soon after start-up using the above procedure. This was blamed on inadequate drying by methanol and presence of displacement air which caused the large internal area of the system to act as an "iron sponge or dry box treater" during the prolonged packing period. The plugging material disappeared rapidly with continued operation. One leak developed in a distribution system lateral line due to failure to completely displace hydrotest water.

After the initial start-up difficulties, corrosion in the dry CO_2 system at SACROC has been minimal. The highest measured corrosion rate was 1.2 mpy and the average over five years has been 0.13 mpy. No buildup in hydrogen pressure as measured by H_2 probes has been noted. Certain elastomers

undergo degradation in high pressure CO_2 service. Seals for valves and other applications should be chosen based on results given in reference 10.

Injection Well Equipment

Equipment associated with the injection well is subject to severe corrosion especially during the period when CO_2 injection follows water injection. Considerable time is needed to evaporate the water. During this time, any chloride or other impurities may be concentrated on the equipment and droplets will exist in the presence of high pressure CO_2. These conditions are often favorable for rapid localized corrosion. Pockets of CO_2 temporarily trapped when switching from gas to water injection might also cause problems.

One of the main ways to minimize this attack is to use separate gas and water flow lines to each injection well. This minimizes the amount of material that will be subjected to the alternating CO_2/water environment and which must be made resistant to these conditions. Due to the corrosive conditions and high pressures involved, the use of corrosion resistant metals should be the primary means for protecting surface injection well equipment.

Corrosion experience at SACROC has led to the use of 316 stainless steel for injection well meter runs, valves, and wellheads. Plastic coated steel was originally used for meter runs and valve bodies but severe corrosion occurred at any point of coating damage, especially at flange faces. Both gate and check valves using electroless nickel coatings were subject to catastrophic corrosion where the nickel coating was damaged. Coating damage by check valve disc action against the bodies caused failure of almost all such valves. Experience with meter runs using Type 316 pipe and fittings, Type 316 gate valves with Type 316 or ceramic gates and Type 316 check valves has been good. Several aluminum bronze gate valves with ceramic gates have also been used successfully.

Conversion to all 316 stainless steel wellhead assemblies is being done at SACROC and performance has been good. Original injection wellheads were made from 410 stainless steel with 410 stainless steel valves. This material gave generally good performance but was subject to intense pitting under scale or other debris from the injection water. This is a type of crevice corrosion and stainlesses containing molybdenum and additional chromium such as 316 are must less susceptible to it than the relatively low chromium 400 series materials.

Even the higher grades of stainless steels are subject to localized corrosion in the presence of oxygen and chloride. Stress corrosion cracking of austenitic stainlesses is also of concern if such conditions are encountered along with somewhat elevated temperatures ($\sim$120°F). An effective way of protecting stainless steel equipment is by ensuring that aqueous oxygen concentrations are kept very low. Oxygen scavengers are added to the brackish and fresh water make-up streams to the injection wells at SACROC. A water soluble inhibitor is also used in the injection water. These measures

may be partially responsible for the success of the Type 316 equipment. Crevice corrosion is sometimes a problem at stainless steel flanges using water absorbing asbestos gaskets. This can be minimized by using a non-water absorbing gasket, preferably without graphite. Other recommendations for specifying and using stainless steels are given in our final report.

Difficulty in obtaining an entirely leak-free valve seal between the CO_2 and water injection systems can cause rapid corrosion near block-off valves. Present practice at SACROC is to install a blind flange on either the CO_2 or water side during WAG operation. Water injection pumps at SACROC are made primarily from 316 stainless steel. Associated valves are aluminum bronze. Water piping to the injection wells is by cement-lined pipe. The main cause of leaks in this system is eccentric lining and failure to install asbestos gaskets at joints.

Tubing coated with thin film epoxy-modified phenolic plastic seems to give acceptable downhole performance in injection wells. Thick film coatings tend to be disbonded by escaping CO_2 when pressure is released. The basic tube material at SACROC is J-55. The main problem with downhole injection equipment has been the tube couplings. Teflon seal rings were originally used to prevent access of fluid to the engaged threads, but many failures still occurred, primarily due to mechanical damage and incorrect assembly or handling. Seal rings have been replaced by the use of a baked on polyphenylene sulfide (Ryton) coating material for the couplings. This is a tough, resiliant coating which has performed well. Packers coated with either the thin film material or fiber reinforced polyester have performed well. Emphasis is placed on proper handling of all the plastic coated materials.

Part of the success of the coated equipment may be due to use of inhibitors and oxygen scavengers in the injection water. These additives should at least slow corrosive attack at holidays or damaged portions of the coating and prolong equipment life.

Production Well Equipment

Production of injected CO_2 will increase the corrosivity of most produced fluids. Severity of corrosion will also depend on the fraction and composition of water produced, H_2S concentration and type of pumping system employed. The partial pressure of produced CO_2 is much lower than in injection wells so any corrosion due to CO_2 itself that occurs is not generally as rapid or catastrophic. Moderate additions of CO_2 may accentuate the corrosion modes of H_2S, however, and mildly corrosive sour wells could become more corrosive for this reason. Industry practice has dealt with corrosion caused by H_2S, CO_2 and water for some time. The user should be prepared to utilize such measures as inhibitor addition, protective coatings and alternate material selection in fields and wells that are not corrosive or only mildly corrosive in the absence of CO_2 injection.

Corrosion in the producing wells at SACROC due to CO_2 injection has ranged from minimal to severe. Downhole corrosion problems caused by

CO_2 are not general throughout the field, but they do occur. Assessment of effects is not clear-cut since production of larger quantities of corrosive water started at about the same time as CO_2. This experience does indicate that corrosion under these relatively severe conditions can be controlled using known inhibitors, coatings, and some resistant metals.

Before CO_2 and water production started, a typical SACROC installation was a flowing well with uncoated packer, tubing, and surface flow lines. Little water was produced and corrosion was limited. Now most wells use either rod pumps or submersible pumps. Now the usual water cut is fairly high and gas produced up the annulus of a typical well is about 30% (Vol.) CO_2 at about 150 to 200 psi. Typical produced water contains about 70,000 ppm chloride and 120 ppm or less CO_2 with a pH of about 6.3 to 6.4 (2).

Filming amine inhibitors are used to reduce corrosion in rod pump wells. Usual treatment is a weekly batch pumped down the annulus. Originally, treatment with oil soluble formulations had limited success since high wellbore fluid levels would not allow complete circulation of the inhibitor. Water soluble compounds were more successful under these conditions. Reduced fluid levels has now allowed many wells to be effectively treated with oil soluble inhibitors and has reduced corrosion due to CO_2. Rod pump barrels are Monel 400 with sprayed metal (316 SS) plungers. Rods are sprayed metal (316 SS) coated.

Equipment in SACROC wells using submersible pumps was found to be subject to corrosion by CO_2 on external pump and motor parts and on the internal areas of the J-55 production tubing. The tubing was coated with the same thin film epoxy-modified phenolic resin used on the injection tubing. Attack is similar to, but considerably less than, that occurring on injection well tubing. Pump and motor parts were coated with thick, glass-filled epoxy which offered protection but tended to cause the motors to run hot. Electroless nickel coatings were not acceptable due to extreme corrosion at holidays. A sprayed metal (316 SS or Monel) coating with baked epoxy overlay is used at present. Pump internals (NiResist nickel cast iron) have not been subject to appreciable corrosion. Corrosion of submersible pump electric cable, casing, and exterior of tubing due to a continuously injected scale inhibitor was controlled by adding a corrosion inhibitor to the process water used to flush the scale inhibitor.

Inhibitors are also used to control corrosion in the rod-pumped production wells at the Houston Natural Gas Twofreds Field near Pecos, Texas (11). The CO_2 injection program was started five years ago. The typical water cut is 50%. Some wells now produce gas containing 40-60% CO_2. Produced water pH was originally 6.5 to 7.5 and is now 5.5 to 6.0. Corrosion problems, primarily involving tubes and sucker rods, have increased with the quantity of CO_2 injected. Corrosion rates are higher in wells with higher gas volumes. Most of the tubing is uncoated. Inhibitor treatment was started at an early stage and is now done by weekly batch additions. The main problem has been in getting complete inhibitor circulation through the wells, and the water flush has been increased to deal with this. Another

problem is downhole frothing of the inhibitor and different formulations and techniques are being tried. Overall, corrosion has not been severe. Precipitation of calcium carbonate has been a problem since start of CO_2 injection.

Production Fluid Handling

Surface equipment servicing wells producing CO_2 will also be subject to corrosion. The course of action to be taken will depend on the materials used prior to start of CO_2 injection. Good quality nonmetallic piping (epoxy-fiberglass or equivalent) should be usable for wet CO_2 using conservative pressure ratings. Bare steel separators and similar equipment should be coated with a high quality, abrasion resistant plastic coating (thick film epoxy or equivalent). Water saturated CO_2 gas following separation can be very damaging to bare steel. Protection of existing steel gas lines is possible by treatment with volatile/non-volatile amine inhibitors. Points where water can condense and collect should be eliminated and ample drain points installed in suspect areas. Air in-leakage should be avoided wherever possible. Use of oxygen scavengers and corrosion inhibitors should prolong the life of coated fluid handling equipment.

The main corrosion problem at SACROC involving surface production equipment has been the sand filter shells. Erosion/corrosion occurring during backwash of the sand filters resulted in holes in the coal tar epoxy coated shells. No leaks have occurred in filters with a thick film epoxy coating.

CO_2 Removal and Dehydration Equipment

Removal of CO_2 from produced gases for reinjection will be desirable in most cases. Corrosive conditions can exist in both of the general processes in use, the hot potassium carbonate process and the monoethanolamine (MEA) process. These are primarily due to the presence of wet CO_2 at temperatures ranging from 105° to 300°F, high solution flow rates and hot spots in certain areas, and presence of sorbent degradation products. Corrosion inhibitors are used to protect carbon steel components. Inhibitors based on vanadium pentoxide are used in the hot potassium carbonate processes while amines, including several proprietary compounds, are used in MEA processes (12, 13).

Stainless steels are often used in high flow rate areas (pumps, pressure letdown valves, piping tees and ells), hot areas, traps and ring packing, and critical equipment such as sensors and instrumentation. Type 304 is frequently used in these areas and is usually the lowest grade specified. Type 316 may give somewhat better service in extremely corrosive areas. Equipment handling the hot, wet CO_2 stripped from solutions such as stripper overhead piping, condenser, and accumulator are frequently made from Type 304. Type 304 clad on carbon steel may be used for components such as the upper shell of strippers (12).

Intergranular corrosion and stress corrosion cracking of the austenitic stainless steels do not appear to be a problem in this equipment

probably due to the absence of or low levels of chloride. Inadvertent addition of chloride impurities should be avoided. Inhibitors used in the MEA processes also serve to protect Type 304 stainless steel. Air in-leakage which could occur during start-up or shutdown should be guarded against. Products of MEA decomposition can be quite corrosive to carbon steel, and a reclaimer unit for regenerating a side stream of the sorbent is often used.

Corrosion considerations for the lines leading to CO_2 compression and dehydration equipment and components of the units where liquid water can exist are similar to those for the removal equipment. Stainless steels are preferable for critical pressurized areas. A dual phase amine-type inhibitor has been used to protect carbon steel piping ahead of dehydrators and in interstage piping when stainless steel trimmed equipment was not available (9).

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EFFECTS OF SULFUR DIOXIDE ON RECOVERY SYSTEM FOR CO_2 FROM FLUE GAS

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ABSTRACT

Recovery of carbon dioxide from secondary oil recovery from flue gas is a potential process which would be made more difficult by the presence of sulfur dioxide in an oxidizing atmosphere. This study is an experimental examination of the contamination of absorbing solutions for CO_2 and effects. A significant problem could occur. This problem is minimized with MEA solution by absorption from a boiler operated as close to stoichiometric as possible, but continuous sulfate removal will probably be required.

INTRODUCTION

If natural gas sources of CO_2 are unavailable for enhanced oil recovery, the only large sources available to meet the needs for oil recovery are flue gases from power plants or industrial boilers or ammonia plants.[1,2,3] Carbon dioxide removal from gasification streams in ammonia plants is a known art, and the carbon dioxide is generally already earmarked for use.

The recovery of CO_2 from flue gas has been accomplished commercially for use in dry ice manufacture,[4] but the flue gas was basically sulfur-free. Most large sources of flue gas will contain sulfur oxides. This could cause operating problems in addition to the normal heavy expenditure of energy to regenerate carbon dioxide from the absorbing solution.[3] Thus it was decided to investigate the operating problems which might result in attempting to absorb carbon dioxide from flue gas with the most likely absorbing media [monoethanolmine - MEA, ammonia,

Prepared for the Department of Energy under Contract No. EF-77-S-05-5532

activated potassium carbonate solutions[1]]. It was anticipated that sulfates, thiosulfates, and other non-regenerable compounds might be formed, in analogy with results for high temperature, high concentration ethanolamine solutions absorption of SO_2 from smelters.[5]

EXPERIMENTAL

Two laboratory-size absorbers have been set up - a packed-bed and a weeping sieve-tray column. Gases fed to the columns were (1) flue gases from combustion of doped gasoline or fuel oil, or (2) simulated flue gas. The columns were run in a regenerating mode, and impurity compounds determined. Analyses included sulfite and sulfate by wet chemistry, and total sulfur of residue by a Leco sulfur analysis instrument. A mass spectrometer analysis of higher molecular weights compounds in the residue was accomplished. Atomic absorption was done to determine metallic impurities. A brief examination of corrosion on common metals was also accomplished.

RESULTS AND DISCUSSION

Sulfur dioxide is absorbed preferentially over carbon dioxide by both ammonical and MEA solutions. Our system operated at 99% absorption of sulfur dioxide in the column flue gas, and about 95% absorption of carbon dioxide as measured by gas chromatography. Nickel corrodes very slightly and goes into solution in ammonical solution to form a green-blue colored solution. If copper is present in any metal or alloy in contact with MEA, it corrodes badly and colors the solution green. It acts as a catalyst for oxidation of sulfites to sulfates. Other metals appear non-corrosive and non-interacting in the solutions.

The sulfur dioxide absorbed in 20% ammonical solution primarily appears as sulfate. Sulfite levels are smaller and a steady state is soon reached (in our experiments, near 800 ppmS). The sulfate levels grow linearly with exposure to the flue gas. This occurred even with no oxygen present in a simulated flue gas. Because of the blue-plume problem[6] and the ready oxidation problem in ammonical solution, no further work was done on this absorbing media.

Primary emphasis was therefore placed on investigating MEA solutions, as activated potassium carbonate solution will have similar impurity problems. In 20% MEA, both sulfite and sulfate are formed. The ratio of sulfite and sulfate obtained depends on oxygen levels in the flue gas, temperature of the system, and ratio of sulfur dioxide uptake and regeneration. Even in a simulated flue gas of CO_2, SO_2 and N_2 (no oxygen) some sulfate is formed. This is consistent with literature expectations.[7] It appears, however, that most of the SO_2 is absorbed

initially as the sulfite, then is either oxidized to the sulfate or driven off in the regenerator. Thus the temperature of the system and regeneration reboiler is important. Experimentally, higher temperatures favored oxidation to the sulfate.

Typical sulfite levels that might be expected at psuedo-steady-state would be 2000-4000 ppmS. Sulfur dioxide is being driven off with the carbon dioxide in the regenerator. Sulfate levels in a no-oxygen flue gas seemed to level at 300-1000 ppmS. In a flue gas containing sufficient oxygen, the sulfate level keeps rising to above 12000 ppmS. Thus in our experiments, 20% of the MEA had been tied up in a non-absorbing form that is not easily regenerable; higher levels are anticipated until the solution is rendered non-absorbing. The pH of the pure, original 20% MEA solution was 11.5; the above-contaminated solution had a pH of 9.8. At low pHs, CO_2 will no longer be absorbed; the solution will be saturated with sulfates/sulfites at a pH of 7.0. The partially contaminated solutions should have lowered absorption coefficients.

The contaminated MEA solutions were analyzed for higher oxidation states of sulfur compounds. No other sulfate forms were found in the mass spectrometer analysis of residue from the solution obtained by evaporation. This result was confirmed by a total sulfur analysis of the residue, which showed about 5% S in the residue. This corresponds to a maximum of less than 1% of the sulfur going to higher sulfate or more complex sulfated molecules.

Preliminary analysis of the contaminated solutions showed no detectable nitrates, but this must be further verified. Mass spectrometry did indicate carbonate degradation products - imidazoldone, oxazolidone, ethylene diamine - as well as MEA.

FUTURE WORK

Future work will include efforts to delineate the upper limits of sulfate contamination. The measurement of absorption coefficients in contaminated solution to gauge the effect of sulfur dioxide will be made more quantitative. The levels of sulfur dioxide in the carbon dioxide from the regenerator will be determined.

CONCLUSIONS AND RECOMMENDATIONS

The absorption of carbon dioxide from flue gases which contain sulfur dioxide is better accomplished with a MEA solution than with an ammonia solution. Corrosion problems probably will be minimal, unless copper is present in any metal in contact with MEA. As low a temperature

absorption as possible is recommended, both to reduce MEA loss through sulfate formation and to reduce evaporative MEA loss through the stack. It would be strongly recommended that the system be used with a boiler operating at near stoichiometric oxygen to reduce sulfate formation. Sulfur dioxide will be present in the recovered carbon dioxide, as it is also driven off in the regenerator. A continuous clean-up system for sulfate removal is required to minimize losses in absorption coefficients. Utilization of the carbon-dioxide recovery system in double duty as the stack-gas sulfur dioxide removal system to meet environmental regulations should be examined as a means of reducing the high capital and energy costs of a flue-gas CO_2 recovery system.

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THE ROLE OF RESERVOIR TEMPERATURE IN CO_2 FLOODING

By

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ABSTRACT

Laboratory research on enhanced oil recovery by the CO_2 process has generally focused attention on oil reservoirs at temperatures well above 88°F, the critical temperature of CO_2, where the oil displacement is by the supercritical gas drive. However, many oil reservoirs in the U.S., including some which are currently under CO_2 flooding through joint DOE-industry participation, are at temperatures well below 88°F and pressures sufficiently high so that the displacement is by liquid CO_2. Physico-chemical considerations imply that highest oil recoveries by either process are to be expected when the reservoir temperature is as close to the critical temperature as possible. These conclusions are supported by data obtained from secondary floods made on linear Berea cores saturated with a light crude oil and water and swept by water-driven slugs of CO_2 at temperatures below and above 88°F under similar flooding conditions. These results appear to have special implications for the CO_2-flooding process for the Appalachian region.

INTRODUCTION

Though CO_2 flooding for enhanced oil recovery is currently receiving nationwide attention, and numerous laboratory studies and field tests have been reported in the literature[1], it is generally assumed that the displacement is a "miscible" supercritical gas drive. In conformity with this assumption, the screening of CO_2-flood prospects is based on the ability of their formations to withstand a "miscibility pressure," the minimum CO_2 injection pressure required to ensure a satisfactory level of oil recovery. The concept of "miscibility pressure" and of the "miscible" gas drive as applied to CO_2 flooding appear to be somewhat arbitrary. This paper examines these precepts on the basis of the physical properties (solubility, phase behavior, critical properties, etc.) of hydrocarbons, carbon dioxide, and hydrocarbon-carbon dioxide systems under reservoir conditions that determine the physical state, liquid or gas, of carbon dioxide during a flood. The implications of the physical state of the carbon dioxide for oil recovery, in general, and particularly for the relatively "cold" Appalachian oil reservoirs that favor a liquid drive are examined in relation to laboratory core flood data.

ase Behavior of Hydrocarbon-CO_2 Systems

All pure substances are known to exist in at least three physical states: solid, liquid, and gas. Only the latter two, liquid and gas, are pertinent to this discussion. The equilibrium between the liquid and gaseous states of a pure substance such as carbon dioxide in a closed system is controlled by the temperature and pressure of the system. Figure 1 shows the saturated vapor pressure of (pressure — temperature) curves for various pure substances including carbon dioxide. Points above and below the CO_2 curve denote liquid and vapor conditions, respectively. Points on the curve represent conditions at which liquid and vapor coexist in stable equilibrium. The lower terminus of the curve is the freezing point and the upper terminal point its critical point (88°F and 1070 psia). At the critical temperature of 88°F, the cohesive or surface tension forces that hold the CO_2 molecules together in the form of liquid are overcome by their kinetic forces. Above the critical temperature, the CO_2 molecules show ideal gas behavior.

The above discussion applies equally well to all pure substances including hydrocarbons. It also applies, with proper modifications, to mixtures of pure substances. In general, the critical properties of pure compounds control the critical properties and phase behavior of their mixtures. Thus, the critical temperature of a binary mixture has a value generally (but not always) intermediate to that of the components. The phase behavior of multicomponent systems of hydrocarbons and CO_2 are of fundamental importance to CO_2 flooding and deserve consideration. However, an understanding of multicomponent systems can best be gained by an examination of the properties of simple binary systems as starting points. Three such systems that cover a wide range of natural reservoir conditions are represented by mixtures of carbon dioxide with methane, ethane, and n-butane with the latter three having critical temperatures of -117, 90, and 306°F, respectively[2].

A mixture of CO_2 and methane has a critical temperature between -117°F and 88°F depending on composition. Under laboratory conditions, both are gases and, therefore, their mixture is a homogeneous phase. On progressive isothermal compression of a methane-CO_2 mixture, a liquid condensate is formed at first. Further compression results in additional condensation and the attainment of a maximum condensate-to-gas volume ratio. Increase of pressure at this stage initiates the revaporization of the liquid phase (retrograde vaporization) and the pressure at which revaporization is complete may be considered to be the "critical pressure" of the mixture. The locus of this critical pressure on the PT diagram (Figure 2) is the "critical locus" of the methane-CO_2 system. It is characterized by a pressure maximum above which the mixture will always be a gas. The critical locii of the CO_2-CH_4, CO_2-C_2H_6, and CO_2-C_4H_{10} systems are shown in Figure 2. Unlike the CO_2-CH_4 system, the CO_2-C_2H_6 system has no pressure maximum ("miscibility pressure" maximum), but shows

a temperature minimum indicative of azeotrope formation[3]. The CO_2-C_4H_{10} system is similar to the CO_2-CH_4 system except that the critical temperature has shifted nearly 200°F to the right to the predominantly liquid-phase region. Over the temperature range of 88°F to 306°F which encompasses nearly all reservoir temperatures, the CO_2-C_4H_{10} system is far closer to the liquid state than the CO_2-CH_4 system. The CO_2-C_4H_{10} system is also more representative of natural systems in the sense that "dead" oil, the target of enhanced oil recovery, is essentially all liquid hydrocarbons and contains little or no methane gas.

In CO_2 flooding, each of the crude oil hydrocarbons form numerous binary systems (in reality, multicomponent systems) on contact with CO_2. It is believed that the lighter components of these systems have superior solvent properties with respect to the whole crude and are involved in an extraction process that ultimately results in an efficient miscible displacement. This concept implies that the CO_2 process would be more efficient for recovering heavier crudes than lighter ones. It is likely that in deep, warm reservoirs the injected super critical CO_2 gas is in equilibrium with liquid oil so that the flow is essentially two phase (discounting the aqueous phase) and overall miscibility of the CO_2-hydrocarbon system is never attained.

It follows from Figure 2 that at temperatures below 88°F, such as in Appalachian reservoirs, both the "dead" oil and CO_2 are, as a general rule, in the liquid state.

Reservoir depths and the "flooded out" conditions prior to CO_2 injection both ensure that the fluid systems in these reservoirs are all liquid, in other words, essentially noncompressible. The effect of an increase of pressure on such systems is not likely to bring about any substantial improvement in the solubility or miscibility of the liquid CO_2 with the oil, and consequently, no increase in oil recovery. Hence, the use of an arbitrarily determined "miscibility pressure" as a screening factor for candidate reservoirs in the Appalachian region apppears to be questionable. It is also significant that the usual definition of "miscibility pressure" as the minimum injection pressure at which CO_2 displacement of oil from a linear sand park such as a ¼ I.D., 80' long, 10 Darcy "slim" tube, would give a CO_2-breakthrough recovery of 80 percent of the original oil in place and an ultimate recovery of 94 percent is at best arbitrary.

Displacement Mechanisms

It was already stated earlier that CO_2 floods involve a supercritical or liquid CO_2 drive depending on reservoir temperature. In the more general case represented by the supercritical gas drive, the displacement mechanism is essentially a Buckley-Leverett type with mass transfer[4]. In this respect, CO_2 gas is no different from methane or nitrogen except that high pressures are required by the latter gases to bring about the same degree of gas-oil interaction as CO_2 to achieve comparable oil recoveries. Another crucial element of the recovery mechanism of particular significance to heavier

~~~ides is believed to be the ability of CO_2 to vaporize the lighter hydro-
~~~ons of the crude under supercritical conditions (retrograde vaporization) at "first contact" and the miscible displacement of the less volatile ends by some type of "condensing" drive. In general, a CO_2 flood should not be substantially different in operation and performance from the so-called pressure maintenance or recycling operations of earlier days with ethane-rich natural gas.

The recovery mechanism with liquid CO_2, appears to be considerably more complex. CO_2 oil mixing, upon which oil recovery depends, is controlled by concentration gradients that are possibly higher than in the gas-liquid systems, but at lower diffusion rates. The unfavorable mobility ratio of the CO_2 process may serve to angment mixing by lateral diffusion resulting in a somewhat better sweep. Another possible complication that can complicate the CO_2-liquid flood is the formation of additional liquid phases and their influence on oil displacement. It has been observed during PVT tests, that under certain conditions liquid CO_2 and oils can form a pair of partially miscible phases[5]. The formation of two or more such phases at the CO_2-oil front in a CO_2 flood is not unlikely. The flow, under such circumstances, would involve three phases, including the drive water, and may result in trapping some of the CO_2-rich oil phase or the oil-rich CO_2 phase behind the flood front. This could result in substantial losses of CO_2 to the formation, that may explain material balance losses observed in CO_2 floods.

Solubility of CO_2 in Hydrocarbons

The effectiveness of the CO_2 process may be attributed to its unique chemical and physical properties. As a very mildly polar substance, CO_2 gas is several times more soluble in crude oil and hydrocarbons than it is in water[5]. When dissolved in oil, it enhances oil mobility (increase of oil saturation by "swelling" and reduction of viscosity) in proportion to the amount dissolved. The solubility of a gas in a liquid, ideally, increases with pressure (Henry's Law) and decreases with increasing temperature. CO_2-hydrocarbon systems follow these general solution laws. On the other hand, the mutual solubility of a pair of immiscible or partially miscible liquids generally increases with temperature and is unaffected by pressure unless the solution process is accompanied by a net change in volume. Mixing of non-polar liquids such as hydrocarbons and CO_2, however, is usually volume-additive. Other conditions remaining the same; then, the solubility of CO_2 gas in crude oil will increase directly as the pressure and inversely as the temperature while the solubility of liquid CO_2 in crude oil will be unaffected by pressure but will increase with increasing temperature. It follows that maximum CO_2 solubility in oil would occur at the highest temperature at which it is still in the liquid state, i.e., at the critical temperature as the limit. Hence, oil recovery by CO_2 (liquid) flooding will tend to increase with reservoir temperatures up to 88°F.

Reservoir Environment and CO_2 Flooding

Any oil recovery process that involves fluid injectin is subject to certain constraints inherent in the reservoir. Among the most significant of these are reservoir depth and temperature. Reservoir depth is generally a rough measure of the maximum pressure the formation can withstand during fluid injection. This pressure, the "overburden" or "parting" pressure, on the average, is numerically equal in psi to the reservoir depth in feet. On the other hand, the natural hydraulic pressure within the reservoir pores (pore pressure) has an average value of 0.5 psi per foot of depth. In fluid injection operation, therefore, the production engineer has a choice of injection pressures between the overburden pressure and the pore pressure of approximately .5 psi per foot of depth. Thus, for a formation depth of 2,000 feet, the injection pressures can be between 1,000 and 2,000 psi.

While the production engineer has a choice in injection pressure control, no choice in regard to temperature is obviously possible. It was pointed out earlier that under most existing reservoir pressures, CO_2 will be liquid at temperatures below 88°F and gaseous at higher temperatures regardless of pressure. The physical state of carbon dioxide and the displacement mechanism would consequently be dependent on these reservoir conditions. Table 1 lists reservoir conditions that correspond to the different types of CO_2 drives, supercritical gas, liquid or vapor: (a) at temperatures above 88°F, the displacement would be simple (below 1,070 psia) or supercritical (above 1,070 psia) gas drives, (b) under reservoir conditions represented by points above the P.T. curve, the displacement will be by liquid CO_2, (c) a vapor drive would result if the injection pressure is below the saturated vapor pressure CO_2 (below the P.T. curve) at reservoir temperature e.g., the expansion of CO_2 from a tank of liquid CO_2 connected to the injection well head. The distinction between a vapor drive and a gas drive is that the gaseous state is associated with temperatures above the critical. A vapor can exist only below the critical temperature. While a gas is subject to the normal gas laws a vapor on compression condenses to a liquid with evolution of (latent) heat.

The conditions described in Table 3 exist in many actual reservoirs and their recognition may help design the type of drive that would be more effective in oil recovery. This would, however, require a clearer understanding of the oil recovery mechanism, under each set of conditions.

OBJECTIVE

The objective of this work is to determine the rôle of reservoir temperature on oil recovery by CO_2 flooding. The experimental work with Berea cores and a light Appalachian crude oil was specially oriented towards determining the disparate influence of temperature on liquid CO_2 and supercritical CO_2 gas flooding in oil recovery.

EXPERIMENTAL

T setup used for this study is shown in Figure 3. The pump used for brine, oil, and isopropyl alcohol is a piston type, positive displacement unit that provides a constant flow. Flow rates may be varied from 0.8 to 200 ml/hr with increments of 0.008 ml/hr in the low region and 2.0 ml/hr in the high region. All tubing, needle valves, and fittings are 1/8-inch stainless steel, Type 316. The core is a Berea sandstone obtained from quarries in Ohio. The specifications are listed in Table 4. The core is covered with heat-sensitive shrinkable plastic tubing and placed in a stainless steel bomb-type cylinder. Hydraulic pressure of 1700 psi is applied inside of the bomb against the outside of the core. The coil containing the liquid CO_2 is made of 1/8-inch stainless steel tubing, which has been calibrated, and has a needle valve at each end. Two 6-inch dial type pressure gauges (at inlet and outlet) indicate the pressure of the system. A pressure of 1155 psi is used for all tests and is controlled by back pressure (pressure relief valve) at the outlet of the system.

Materials used for the tests are listed in Table 4. For each test, the core was cleaned by flooding with four pore volumes of isopropanol. This was followed with four pore volumes of 2 percent brine to insure 100 percent water saturation of the core. Four pore volumes of Hilly Upland oil was then passed through the core to insure maximum oil saturation and to reach irreducible water saturation. Flow rates for all of the above liquids was 40 ml/hr with no back pressure applied.

A sleeve-type heating jacket was placed around the core holder to heat the core to the desired temperature. A thermocouple-type probe was inserted between the heating jacket and the core holder to measure the temperature. The heating jacket and the probe were connected to an on-off type indicating temperature controller. The time necessary for the heat to pass through the core was determined by drilling a hole halfway through the center of the core and inserting a thermocouple. The core was then placed in a water bath at the desired temperature, and the time for the thermocouple to reach that temperature was measured. The temperatures and corresponding times are listed below.

Temperature (°F)	Time (minutes)
86	6
100	10
130	10
160	12
190	16

A calibrated sample CO_2 coil (1/8" O.D. SS) was weighed and filled with liquid CO_2 and reweighed. The difference in weights gave the weight of the CO_2 slug. For tests below the critical temperature of CO_2, density correction for temperature at the cylinder provided the volume of CO_2,

which was then calculated for the pore volume of the slug. For tests above the critical temperature of CO_2, back calculations were made to determine the amount of liquid CO_2 that would provide the desired volume of gaseous CO_2. The displacement system was heated to the desired temperature and pressurized to 1150 psig. The CO_2 was then permitted to flow into the core and was then followed by one pore volume of 2 percent brine at the desired flow rate (10 or 20 ml/hr). This was followed by "blow down," at which time the pressure was lowered in steps until atmospheric pressure was reached and the test terminated.

A description of core and fluids used is given in Table 4.

DISCUSSION

Oil Recovery and Reservoir Temperature

It is obvious that the displacement of a liquid from a porous medium by another fluid would be greatly influenced by the physical state (liquid or gas) of the fluid. In displacements with CO_2, a methane-free crude would be entirely in the liquid state at temperatures below about 88°F, the critical temperature of carbon dioxide, and at pressures above its saturated vapor pressure.

At reservoir temperatures and pressures corresponding with points above the saturated vapor pressure curve of CO_2 (Figure 1), the displacement would be by liquid CO_2. In such a displacement, the transfer of CO_2 into the oil phase would be through a mixing or diffusional process. This process would naturally be promoted by higher temperatures at which the CO_2 and oil also have higher mutual solubilities. Oil recovery by displacement by liquid CO_2 must, therefore, increase with temperature until the CO_2 is no longer a liquid i.e., at 88°F.

Above 88°F, the displacing fluid (CO_2) is in the supercritical gaseous state. The solubility of the gas in oil under this condition decreases with increasing temperature but would increase with increasing pressure. However, the CO_2 concentration gradient between the gaseous and liquid phases cannot be as high as between liquid CO_2 and oil regardless of pressure, as the maximum concentration of the CO_2 phase is attained in the pure liquid state.

Table 2, Figure 4, give oil recovery data on Berea cores containing Hilly Upland (a light WV crude) oil and a 2 percent NaCl brine. These floods were made in the secondary (not tertiary) mode to most effectively illustrate temperature effects. The data show the definite trend of increasing recovery with increasing temperature up to the vicinity of 88°F, and decreasing recovery, thereafter, even though in the runs at higher temperatures, the throughput of gaseous CO_2 on a pore volume basis was from 2.15 to 3.9 times that of the liquid slugs used in the lower temperature floods on the same core.

These results imply that liquid CO_2 floods are superior to supercritical gas drives and that higher reservoir temperatures up to 88°F show greater oil recovery potential for liquid CO_2 floods.

Oil Recovery and Back Pressure

In the supercritical gas drive, the pressure of the carbon dioxide in the gas phase controls the transfer rate and amount of gas transferred into the oil phase. This has a maximum value at the injection well where gas pressure is highest. In a liquid CO_2 flood, however, the corresponding pressure (concentration potential) is at a maximum value as long as the CO_2 slug is not completely dissolved in the oil. On the other hand, if the natural sand face pressure in a production well is below the saturated vapor pressure of CO_2 at reservoir temperature, the liquid CO_2 slug would tend to vaporize at points in the reservoir at which the ambient pressure is just below the saturated vapor of CO_2, and a gas drive from this point on will be superimposed on the liquid CO_2 drive. Because such conditions may exist in field tests, a few runs were made in which the back pressure at the producing end of the core was maintained at pressures above and below 920 psia, the saturated vapor pressure carbon dioxide at the flood temperature of 75°F. These results which should be considered preliminary appear to indicate slightly better recoveries at the lower back pressures, when the displacment is by CO_2 vapor.

CONCLUSIONS

1. Our experimental results indicate that oil recovery by CO_2 flooding under similar conditions is higher with a liquid CO_2 flood than with supercritical CO_2 gas.

2. In liquid CO_2 floods, the oil recovery increases with increase of core temperature. In supercritical CO_2 floods, the opposite trend was observed.

3. In the limited number of runs performed, it would appear that liquid CO_2 floods give higher oil recoveries than CO_2 vapor floods. This may mean that application of back pressure to production wells to ensure that the carbon dioxide remains a liquid during the displacement is desirable.

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TABLE 1

Drive Mechanism and Reservoir Conditions

Temperature T(°F)	Injection Well Pressure (psia)	Production Well Pressure (psia)	Drive Mechanism
Above 88	Above 1070	--	Supercritical Gas
Above 88	Below 1070	--	Gas
Below 88	Above 1070	Above 1070	Liquid
Below 88	Above 1070	Below Ps*	Liquid and Vapor
Below 88	Below 1070	Below Ps*	Vapor

*Saturated vapor at T°F.

TABLE 2

The Effect of Temperature on Secondary Oil Recovery by CO_2 Flooding

Run No.	Flow Rate (ml.hr)	Core Temp (°F)	CO_2 Slug (pore volume) Liquid	Gas	Oil So (pv)	Oil Recovered Displ. (pv)	Blow down (pv)	Total (pv)	Percent oil-in-place
E-19-7	20	70	.150	--	.620	.244	.112	.356	.574
E-59-2	20	86	.137	--	.660	.268	.170	.438	.664
E-19-6	20	100	.153	.395	.630	.308	.124	.388	.616
E-19-26	20	130	.177	.691	.640	.288	.068	.356	.556

TABLE 3

Effect of Applied Back Pressure on Oil Recovery

Run No.	Back Pressure psig	So (PV)	CO_2 Slug (PV) (Liquid)	Oil Recovery (PV) Displ.	Blow Down	Total	Percent oil-in-place
E-89-6	1150	.696	.160	.226	.230	.456	65.5
E-89-4	1100	.696	.163	.235	.234	.469	67.4
E-89-1	850	.696	.169	.261	.144	.405	58.2
E-89-7	650	.696	.169	.278	.172	.450	64.7

TABLE 4

Cores and Materials

	E-19	E-59	E-89
Sandstone Core	Berea	Berea	Berea
Diameter	3.81 cm	3.81 cm	3.81 cm
Length	20.0 cm	20.2 cm	20.3 cm
Pore Volume	50 ml	47 ml	46 ml
Porosity	21.9%	20.4%	19.9%
Permeability			
Ka (brime)	72 md	72md	97 md
Ko (oil)	62 md	25 md	60 md

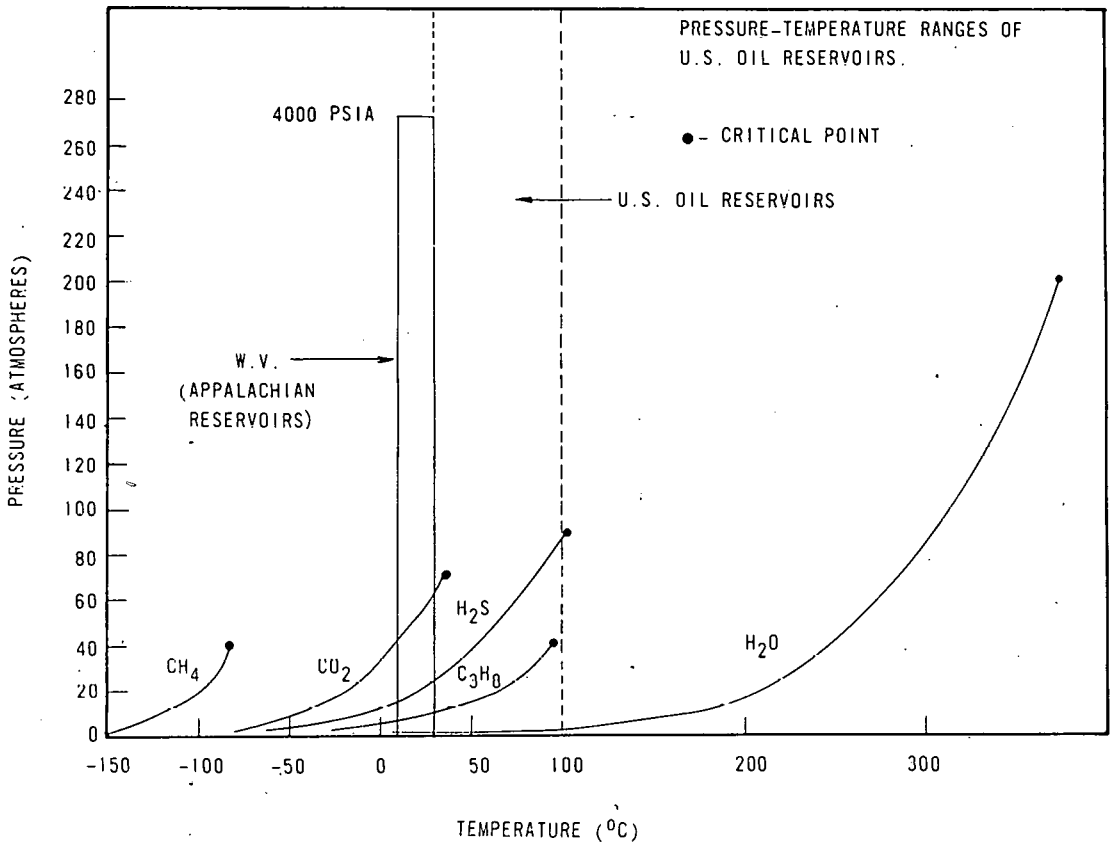
Oil: Hilly Upland Crude Oil (3.64 cps).

Brine: Two percent NaCl in distilled water.

Alcohol: Commercial grade Isopropanol.

O_2: Commercial grade cylinder with outlet tube reaching to bottom of inside cylinder for syphoning of liquid CO_2.

FIG. 1 - VAPOR PRESSURE OF PURE SUBSTANCES VS. TEMPERATURE.



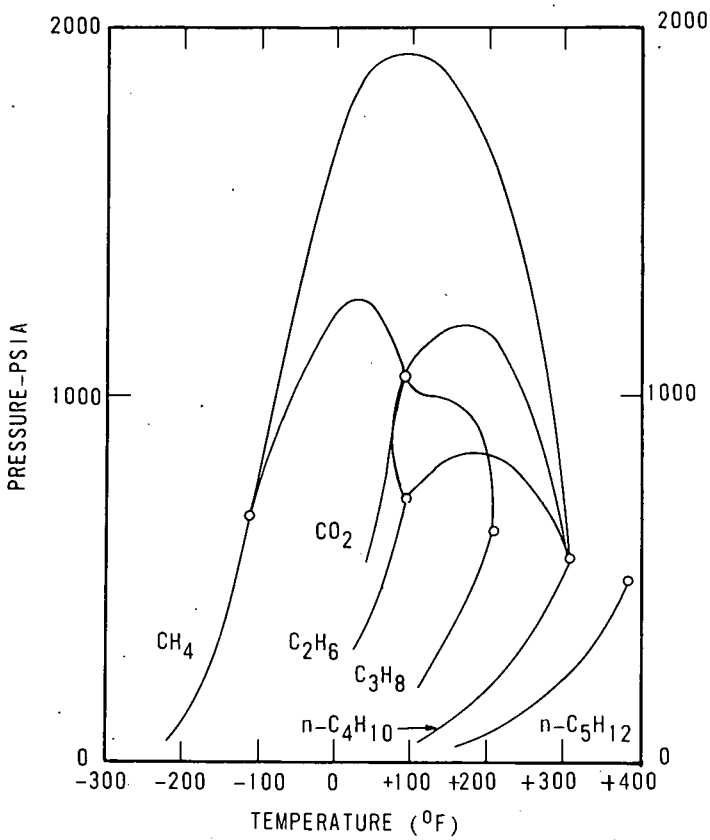


FIG. 2 - CRITICAL LOCII FOR CO_2-HYDROCARBON SYSTEMS.

CO_2 DISPLACEMENT
TEST APPARATUS

FIGURE 3

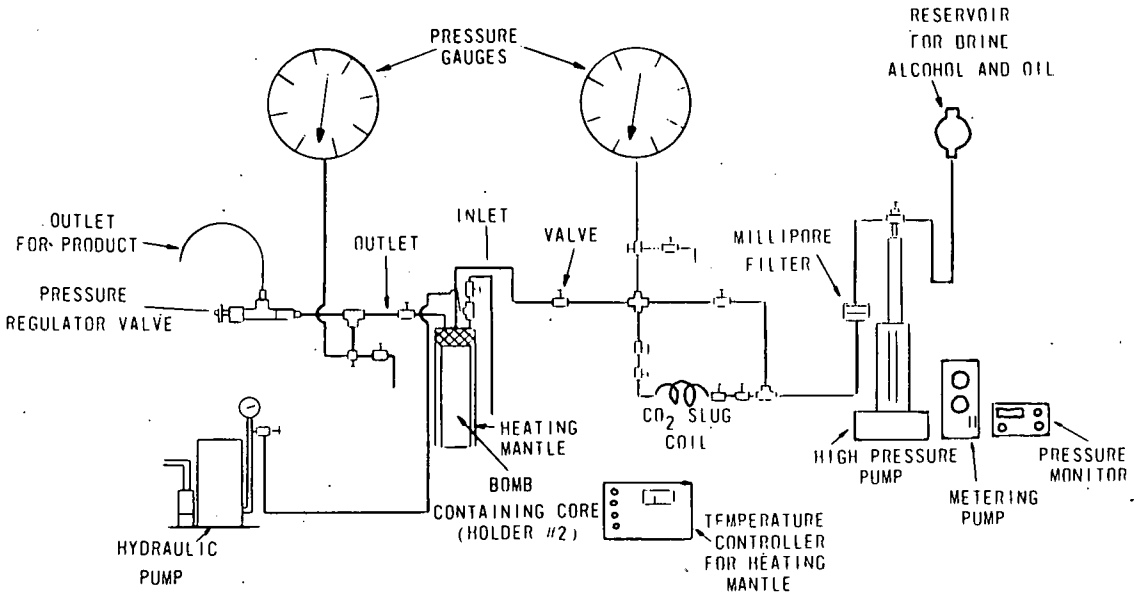
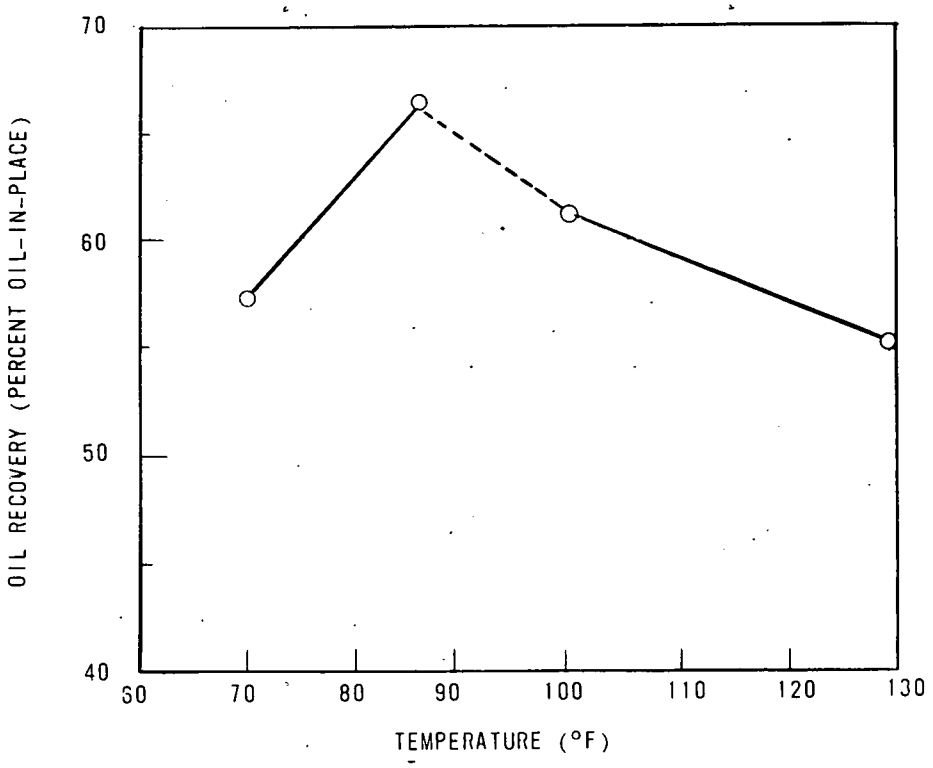


FIGURE 4

EFFECT OF TEMPERATURE ON SECONDARY OIL

RECOVERY BY CO_2



ENHANCED OIL RECOVERY BY CO_2 MISCIBLE DISPLACEMENT IN THE LITTLE KNIFE FIELD BILLINGS COUNTY, NORTH DAKOTA

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ABSTRACT

Gulf Oil Exploration and Production Company in conjunction with the Department of Energy will conduct a field test of the CO_2 miscible displacement process. The project will be conducted in the Mission Canyon Formation, a carbonate reservoir which is presently in an early stage of primary depletion. Location of the field is west-central North Dakota at the approximate center of the Williston Basin. A WAG-type injection sequence involving alternate slugs of water and CO_2 will be employed. The test will establish the incremental recovery by a miscible CO_2 flood in an oil reservoir that has not been extensively waterflooded.

Slim-tube displacement tests have been conducted and the results indicate that CO_2 will achieve multiple contact miscibility with Little Knife crude oil at reservoir conditions. Drilling operations for the first two wells should be completed by the end of 1979.

INTRODUCTION

The Little Knife Field CO_2 minitest will be a nonproducing five-acre field trial of the CO_2 miscible displacement process in a heterogeneous carbonate reservoir. The test will involve time-lapse logging to monitor saturation changes as

Prepared for DOE under Contract No. DE-AC21-79MC08383.

ternate slugs of water and CO_2 pass the observation wells. At e conclusion of drive water injection a pressure core taken behind the flood front will confirm the residual oil saturation. The test is designed to give the following information:

* Reduction in original oil saturation due to water injection;
* Reduction in waterflood residual oil saturation due to alternate CO_2/water injection;
* Extent of gravity segregation within the porous zone;
* Effect of stratification and crossflow;
* Influence of reservoir heterogeneity on fluid injection performance.

This information is needed to assess the potential for a full-scale fluid injection project in the Mission Canyon. Vertical and areal conformance of the injected slug will be determined in addition to the displacement efficiency. The volume of displaced oil that can actually be recovered will not be measured directly in the field. In lieu of actual production data the day-to-day evaluation of project performance will make use of a compositional numerical reservoir simulation model.

FIELD DEVELOPMENT

Little Knife Field is located near the center of the Williston Basin and south of the Nesson anticline in portions of Billings, Dunn, and McKenzie Counties (Fig. 1). Production is from the lower Mississippian Mission Canyon Formation, part of the Madison Group, at a depth of approximately 9800 feet. As presently delineated, the field is 12 miles long and 2 1/2 miles wide. Structural relief across the field is quite subtle averaging less than one degree.

The field was discovered in January, 1977, with the drilling of Gulf 1-18 State wildcat, Section 18, T145N, R97W, Dunn County, North Dakota. On initial test the well flowed 480 BOPD of 43° sour crude against a 14/64" choke with a GOR of 938 SCF/STB from eight feet of perforations. The associated gas contains about eleven percent H_2S. Two additional wildcats, drilled two and five miles further to the south, confirmed the major discovery. To date, the development drilling program has resulted in completion of 78 Mission Canyon producers and 5 abandoned holes. Little Knife Field is ultimately expected to encompass 100 wells based on 160-acre spacing.

Field cummulative production totaled 5,845,385 BO as of June 1, 1979. The field producing rate is restricted to ± 15,000 BOPD based on the current gas processing plant capacity of ± 17 MMSCFPD. Prior to construction of these facilities production was restricted on an individual well basis, as set forth by the North Dakota Industrial Commission on June 1, 1977: 1.) unlimited rate for 60 days, 2.) 200 BOPD for 90 days, 3.) 150 BOPD for 90 days and 4.) 100 BOPD each day thereafter. This schedule was maintained until July 26, 1978 when the first phase of gas plant opened, initially treating 6 MMSCFPD.

DATA BASE GENERATION

Selected wells were cored during the early stages of field development in an effort to fully define the productive interval. A preliminary visual examination of the cores showed the Mission Canyon to be a highly complex carbonate sequence. In light of the performance history of other Madison Group fields, it was felt that a detailed characterization study would be needed in order to fully exploit each of these zones. At this point, a comprehensive program to obtain additional reservoir data was formulated by both geologists and engineers. The expenditures for this work were reduced by coordinating it with routine drilling and well testing operations.

Initially, the open-hole logging suite consisted of the dual laterolog and compensated sonic logs. The compensated neutron-formation density log was later included when it was found that porosity derived from the neutron-density combination was in close agreement with core analysis porosity. The basic approach used for quantative log analysis has been to calibrate the interpreted results with special core analysis data available on specific wells. Anomalous log responses on individual wells were then normalized in accordance with the field-wide interpretation model.

Pressure drawdown and buildup tests are routinely run on most new Little Knife completions. The standard procedure includes approximately eight hours of flow with the bomb in the hole followed by sixty-four hours of shut-in. In general, these transient tests have yielded quantative information on skin damage, flow capacity, and reservoir pressure. As required by the state of North Dakota, static bottom-hole pressures are taken periodically on every producing well. The recording of these pressures was organized into two field-wide surveys conducted in February and November of 1978.

Nineteen Mission Canyon wells have been cored, fifteen within and four outside of field boundaries. In all, 3,074 feet of rock was cored and 2,885 feet recovered (94%) with an average length of 162 feet. Following routine analysis, cores were

'abbed and photographed in color using plane and ultraviolet :ght. Special core analysis work included capillary pressure, waterflood susceptibility, rock compressibility, formation resistivity factor, and acoustic velocity measurements. Cores were examined in detail with thin sections taken at each bedding, lithologic or subtle textural change, averaging one every five feet. Scanning electron microscopy is underway to examine pore throat geometries and distribution. Insoluable residue and paleontologic studies are being prepared at this time. The purpose of this detailed effort is to determine the depositional sedimentary environment and amounts and types of diagenesis forming the reservoir rock.

RESERVOIR GEOLOGY

Methods of study of Little Knife Field was divided into two portions: 1.) petrologic and petrographic core description and analysis and 2.) log correlation and reservoir mapping. These studies enabled the Mission Canyon Formation to be subdivided into attendant lithofacies, reservoir facies and log zonations. Log correlations delineated the presence of key beds and divide the section into five zones: A, B, C, D, and E (Fig. 2). Study of the complete Mission Canyon section was made possible by means of overlapping several cores from the field to form a composite section. This technique revealed the depositional environment to be a carbonate to anhydrite-shallowing upward regressive sequence, forming a lime mud to sabkha cycle. Most sediment accumulation was deposited in the subtidal realm with three recognizable subenvironments; upsection, they are: 1.) basin rhythmites, 2.) shallow open marine and 3.) shallow restricted marine. Rhythmites are composed of alternating laminations to very thin bedded, fine grained skeletal wackestone-packstone and slightly argillaceous pelletoidal wackestone-packstone, possibly formed in a deeper water basinal setting at the formation base. The shallow open marine subenvironment records a shallowing of water within the depocenter and the development of major carbonate cycles. Carbonate cycles are composed of medium to thick bedded, burrowed mudstone grading up into shallower high-energy deposition of skeletal packstone, and are referred to as major cycles. The restricted marine subenvironment reflects further shallowing and lowering of amounts of energy and circulation with subtle cycles still recognized. Minor carbonate cycles of medium to thick bedded, burrowed pelletoidal mud grade up into slight skeletal enrichments of skeletal wackestone, and form less noticeable cycles. These minor cycles eventually give way to complete restriction with only beds of burrowed, peletoidal mud being deposited.

The intertidal environment forms a thin veneer of variable thickness to end the pronounced period of subaqueous de-

position. Rock building consitituents included pelletoids, grapestone, clotted and lumpal micrite, ooids-pisoliths, calcispheres, local rip-up intraclasts and rare skeletal detritus of thin to thick beds of wackestone-packstone. Micritic mud, burrowing and vague boundaries suggest a low-energy intertidal environment. Early cementation is common leaving only small localized pods of porous intertidal rock throughout the area of investigation.

Pseudomorphs of anhydrite after possible salt hoppers, water table selenite gypsum crystals, now anhydrite, and localized laminated crust developments indicate the presence of higher salinities and subaerial exposure as a supratidal environment prograded into the deposystem. Anhydrite beds follow these first indicators, with several anhydrite types: 1.) mosaic chicken wire, 2.) mosaic thin bedded, 3.) laminated-medium bedded, 4.) burrowed replacive, 5.) ropy displacive and 6.) pseudomorphs of anhydrite after selenite gypsum crystals and possible salt hoppers. Most of the anhydrite types have felted textures. Thin interbeds of laminated dolomite is the only other lithology present and record storm washover ponds or where local embayments onto sabkha-like areas formed.

The field is formed across a broad low anticlinal flexure plunging northward along a north-south axis (Fig. 3). A typical log of central portions of the field, Zabolotny 4-3-1A, reveals multiple reservoir hydrocarbon accumulations (shaded areas) scattered throughout the B, C, and D zones (Fig. 2). These zones can be divided more simply into a lower reservoir sequence (zone D and rare basal portions of zone C) and an upper reservoir sequence (zones B and C) the latter susceptible to further subdivision. Limbs of the structure average one-half and one-quarter degree dips off the west and east flanks, respectively, and similarly off the nose to the north, feathering out each hydrocarbon accumulation progressively upsection.

Diagenetic modifications to specific restricted marine and open to restricted marine beds form the primary reservoir facies (Fig.4). These mud enriched beds have passed through the veil of diagenesis creating porous rock by being dolomitized. The upper reservoir sequence is thoroughly dolomitized bioturbated pelletoidal mudstone to wackestone, with pelletoid ghosts preserved as dolorhomb necklaces. The lower reservoir sequence is burrowed skeletal wackestone with the micritic matrix completely dolomitized, leaving calcareous skeletal detritus (calcite) floating in porous dolomite. Both reservoir sequences have undergone a dissolution leaching action during dolomitization with the end product a fine euhedral saccharoidal dolomite. The very fine grained micritic matrix was affected early while larger less reactive pelletoids and skeletal detritus were left to only be affected by latest stages of the

diagenetic transformation. Small, localized, lenticular stratigraphic traps of porous limestone are preserved as highest portions of the upper reservoir sequence within beds of intertidal suites of rock (uppermost zone B).

Cores have revealed discontinuous, vertical, planar and paper-thin fractures which extend only short distances before terminating. Fractures are not controlled by specific lithologies or facies and appear randomly throughout the section, except for anhydrite beds. No movement along fractures can be demonstrated and extend through skeletal and oolitic constituents without lateral offset.

The reservoir development and hydrocarbon accumulation present in Little Knife Field is primarily a composite diagenetic-structural feature associated with a smaller component of stratigraphic entrapment.

RESERVOIR ENGINEERING

The most relevant implication of the ABCDE zonation is the possibility that the Mission Canyon Formation is composed of multiple porosity developments. Individual well performance data was composited according to zone. Because of the large number of multi-zone completions, no attempt was made to allocate production back to a particular horizon. Instead, each well was classified either as a BC or a BCD producer. Static reservoir pressure was plotted as a function of both time and cumulative production (Figs. 5 & 6). Two isobaric maps, one for each completion type, were contoured using pressures recorded in November, 1978 (Figs. 7 & 8).

A review of performance and pressure data indicates that these two completion types are quite dissimilar. The BC completions experienced a rapid decline from an original pressure of 4378 to 3396 psi by November, 1978 (Fig. 10). The cumulative GOR has been relatively constant at 1100 SCF/STB. In general, the updip wells make only a trace of water. The flank wells produce at higher cuts and have very little productivity. The BCD wells exhibited an average virgin pressure of 4409 psi but had declined only 133 psi to 4276 psi during the same time period (Fig. 11). Again, the cumulative GOR has not moved above the solution GOR value. Water cuts for the BCD producers average less than five percent.

The BC completions are performing as a volumetric depletion reservoir still above the saturation pressure. Recent material-balance calculations appear to indicate a small amount of pressure support in these wells, possibly caused by a weak

water drive. If an aquifer is present in either the B or C zones, its effect would likely be minimal due to the limited areal continuity of these horizons. At a production rate of 12,000 BOPD, the average reservoir pressure should reach the bubble point of 2923 psi by the end of 1979.

Material-balance considerations clearly show the BCD wells to be acting under the influence of an active water drive. By inference, the aquifer would appear to be connected to zone D. Preliminary results of a recent production-logging program tend to support this conclusion. Selective production tests have established that zone D is porous throughout the field both above and below the oil-water transition zone. The indicated performance agrees with the geological interpretation of the lower reservoir sequence as a blanket-type deposit.

Zone characteristics are summarized in Table 1. Forty percent of the core analysis work performed has been by the whole-core method. Average permeability for the productive horizons ranges from 17 to 36 md. Several wells, however, produce at rates greater than would be expected from matrix flow alone. Average permeability as calculated from pressure buildup data is about 20 md. The majority of buildup tests conducted to date have been analysed by the conventional Horner method. Several of the anomalous tests exhibit a fractured shape when plotted on the appropriate type-curve, particularly those wells stimulated with acid. Indicated fracture lengths have been too small to estimate. Induced fractures and planes of weakness that are visible in several cores may be responsible for this behavior. Apparently, the stress imparted during drilling and completion operations causes the formation to fail and interconnects these minute cracks around the wellbore. In its natural condition, the Mission Canyon Formation does not appear to be dominated by fractures.

MINITEST SITE SELECTION

The proposed minitest site is in the central portion of the field, northwest of the section center, Section 3, T144N, R98W, Billings County. Injection will be confined to the lower reservoir sequence, zone D, at a depth of roughly 9800 feet (Fig. 12). Geological considerations for the selection of this location are based on: 1.) average reservoir facies, 2.) continuity of porosity, permeability and lithology and 3.) elevated structural position. Engineering considerations relating to the site selection process require the reservoir to be at a pressure of no less than the 3400 psi needed for multiple contact miscibility of CO_2 with Mission Canyon crude. At pressures lower than 3400 psi only a portion of the injected CO_2 will dissolve in the oil and a loss of displacement efficiency will result. By the time injection begins in 1980, indications are that zone D will have sufficient residual pressure to insure miscibility.

A west to east cross section (A-A') drawn through tions of the field nearest the minitest site demonstrates the prerequisite of good structural positioning with edge water on the flanks (Fig. 13). The reservoir facies is isolated within beds of dolomitized skeletal wackestone. Reservoir continuity is dependent upon the amounts of porosity and permeability developed by partial dolomitization. Three nearby cored wells provide answers to reservoir variability and were instrumental in the modeling process: 1.) Sabrosky 4-31-4C with excellent porosity and permeability, 2.) Hurinenko 1-2-2A with excellent porosity and intermediate permeability, and 3.) Miller 3-10-4B with good porosity and poor permeability (Fig. 14). Three recognizable pore throat geometries are identified within the reservoir: 1.) polyhedral pores, 2.) tetrahedral pores and 3.) interboundary-sheet pores, each progressively smaller in size, after Wardlaw (1976 a and b).

The final site selection was made by comparing sonic log porosity curves of the three cored wells, of known porosity, permeability, and lithology to the sonic logs of surrounding non-cored wells. Although the nearest well to the minitest site, Zabolotny 4-3-1A, was not cored, its sonic log porosity curve exhibits characteristics similar to the cored wells possessing average reservoir properties. The proposed minitest site is expected to meet all of the above mentioned criteria.

MINITEST DESIGN

The test pattern will consist of a single injection well offset by three observation wells arranged in an inverted four-spot configuration (Fig. 15). Initially, two wells are to be drilled, cored, completed and tested in the Mission Canyon D zone. Locations for the remaining two wells will be staked after the core and pressure data has been evaluated. If a significant permeability trend is discovered, the pattern will be skewed so that ideally the CO_2 arrival time will be the same for each observation well. Assuming that no major anisotropy is detected, the pattern will be as shown in Figure 15 to test the NE-SW regional permeability trend reported in several other Madison Group fields.

Three of the minitest wells will be cored through zones B, C, and D using a conventional core barrel to cut a 4" OD core. The in-situ orientation of each core will be recorded with downhole magnetic orienting equipment. This system gave good results on a recent coring operation. The fourth project well is to be cored through zone D using a pressure-retaining core barrel. This tool will cut a core approximately 9 feet in length and 2 1/2 inches in diameter and bring it to the surface at formation pressure. The major emphasis is to recover an undisturbed reservoir sample and measure the virgin fluid satu-

rations. Once at the surface, the inner barrel will be frozen in dry ice to prevent fluid-loss and oxidation.

Whole-core analysis methods will be employed for porosity, permeability (in each of two horizontal directions and vertically), and fluid saturation determinations. Selected portions of these cores will be used for relative permeability measurements. Procedures used for cutting and handling the cores will be consistent with preservation of the native wettability. The samples recovered under pressure will be analysed by a commercial laboratory using their modified whole-core technique.

The open-hole logging suite will include a dual laterolog, compensated sonic, and compensated neutron-formation density logs. Additionally, a fracture identification log will be run over the Mission Canyon interval. Porosity and fluid saturations will be calculated with the aid of a computerized log interpretation routine. The bottom-hole location of each wellbore will be determined with a dipmeter survey.

A string of 5 1/2" production casing will be set through the Mission Canyon and selectively perforated in zone D. Each well is to be equipped with a stainless steel wellhead and tubing set on a permanent packer. Permanent downhole pressure transmission equipment will be installed in all four wells. This system was selected for use instead of wireline bombs because it offers a continuous surface readout of reservoir pressure.

Reservoir characterization by means of transient pressure testing will be employed throughout the project life. Routine drawdown/buildup tests will be conducted as a part of the initial completions. Subsequent buildups will be recorded any time the well is sampled. Reservoir properties within the minitest area will be thoroughly investigated by pulse testing. Initially, a pressure pulse will be created by flowing one well and measuring the response in the other project well. When the second pair of wells are drilled, all four will become involved in the program. Both the mobility-thickness product, kh/u, and the porosity-thickness product Øch will be estimated for the interwell region. If anisotropic permeability is present within the pattern, its effect will be estimated. Following the pulse testing but prior to slug injection, an interference test will be conducted. By observing the reservoir pressure decline within the minitest pattern, the effect of drainage by offset producers will be quantified.

As the miscible front radiates away from the injector, a series of cased-hole logs will be run in each of the observation wells to monitor its progress. This time-lapse technique

uses a pulsed-neutron log to detect changes in fluid saturation around the wellbore. The tool responds directly to changes in water saturation as measured by the thermal neutron decay rate. Any increase in CO_2 saturation between subsequent logging runs is noted as a decrease in the apparent porosity. The end result will be a saturation history of the CO_2-swept region around each well. At the conclusion of injection, one additional core hole is to be drilled within the pattern. The pressure core taken will confirm the residual saturations behind the front.

The schedule for data acquisition during injection is as follows:

1. Monitor injection pressure and injection rate continuously.

2. Record bottom-hole pressure in each well continuously.

3. Sample fluid from observation wells when evidence of slug breakthrough is noted.

4. Sample fluid from offset producing wells once a month.

5. Run pulsed-neutron log in each observation well monthly until response is noted, then increase frequency as indicated.

6. Run pulsed-neutron log in the injection well before injection, after water injection, and after CO_2 injection.

ACKNOWLEDGEMENT

Thanks is given to the various members of Gulf Oil Corporation for their assistance in preparing this report.

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TABLE I—SUMMARY OF MISSION CANYON CORE DATA

Zone	Wells Cored	Samples*	Porosity (percent)	Permeability (md)	Lithology
A	2	19	4.0	9	Anhydrite
B	16	343	10.0	17	Limestone-Dolomite
C	13	211	9.2	36	Calc. Dolomite
D	8	162	10.2	17	Calc. Dol.-Dol. Limestone
E	3	198	10.4	9	Calc. Dol.-Limestone

* .1 md. cutoff

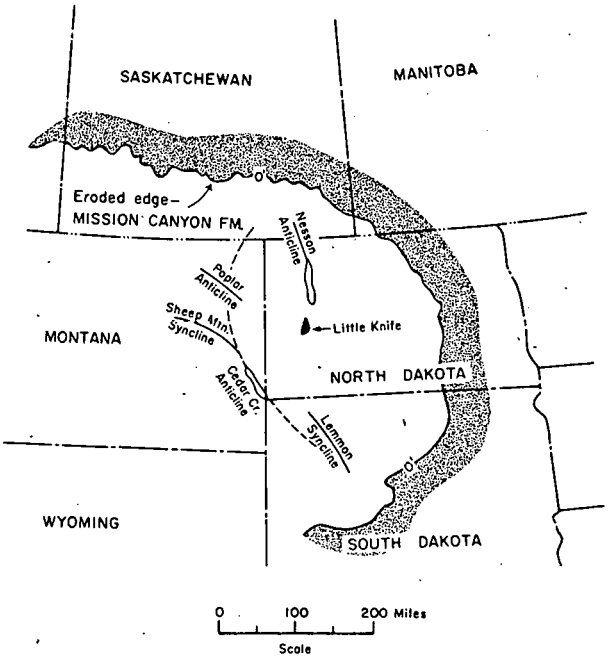


Fig. 1 — Index Map of Williston Basin (modified after Proctor and Macauley, 1968 and Wittstrom and Hagemeier, 1978, 1979).

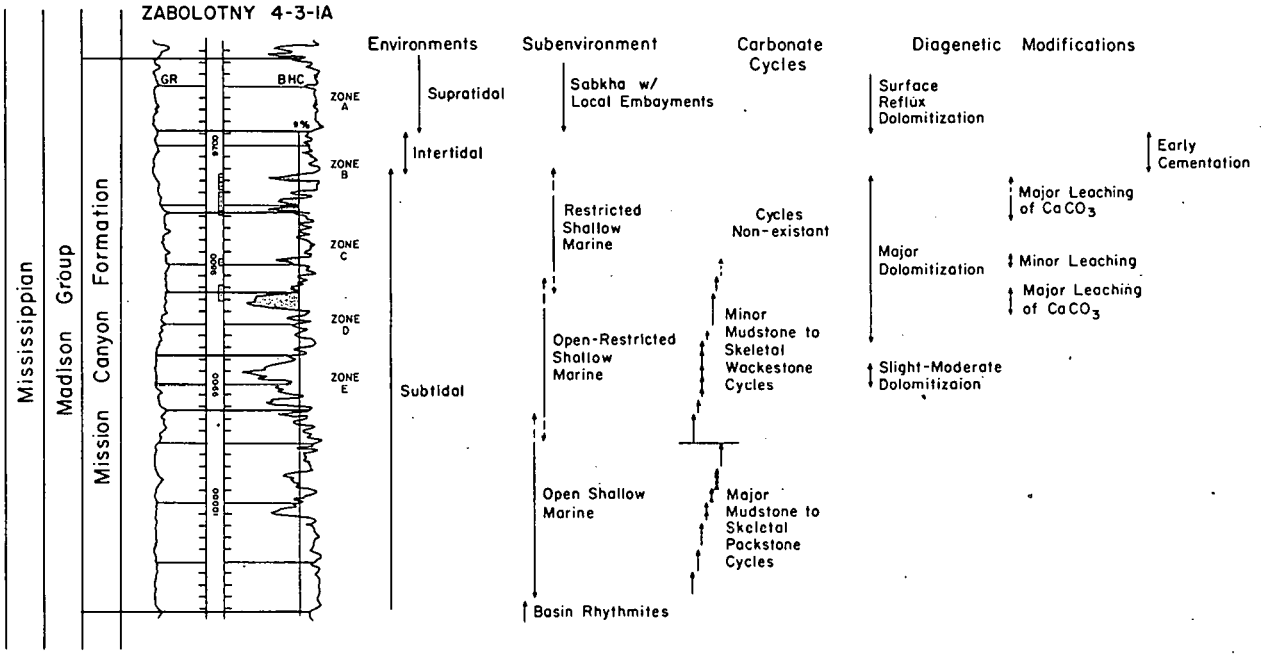


Fig. 2 — Type log of Mission Canyon Formation in central portion of Little Knife Field. Depositional environment and diagenetic modifications from a composite section of several cores.

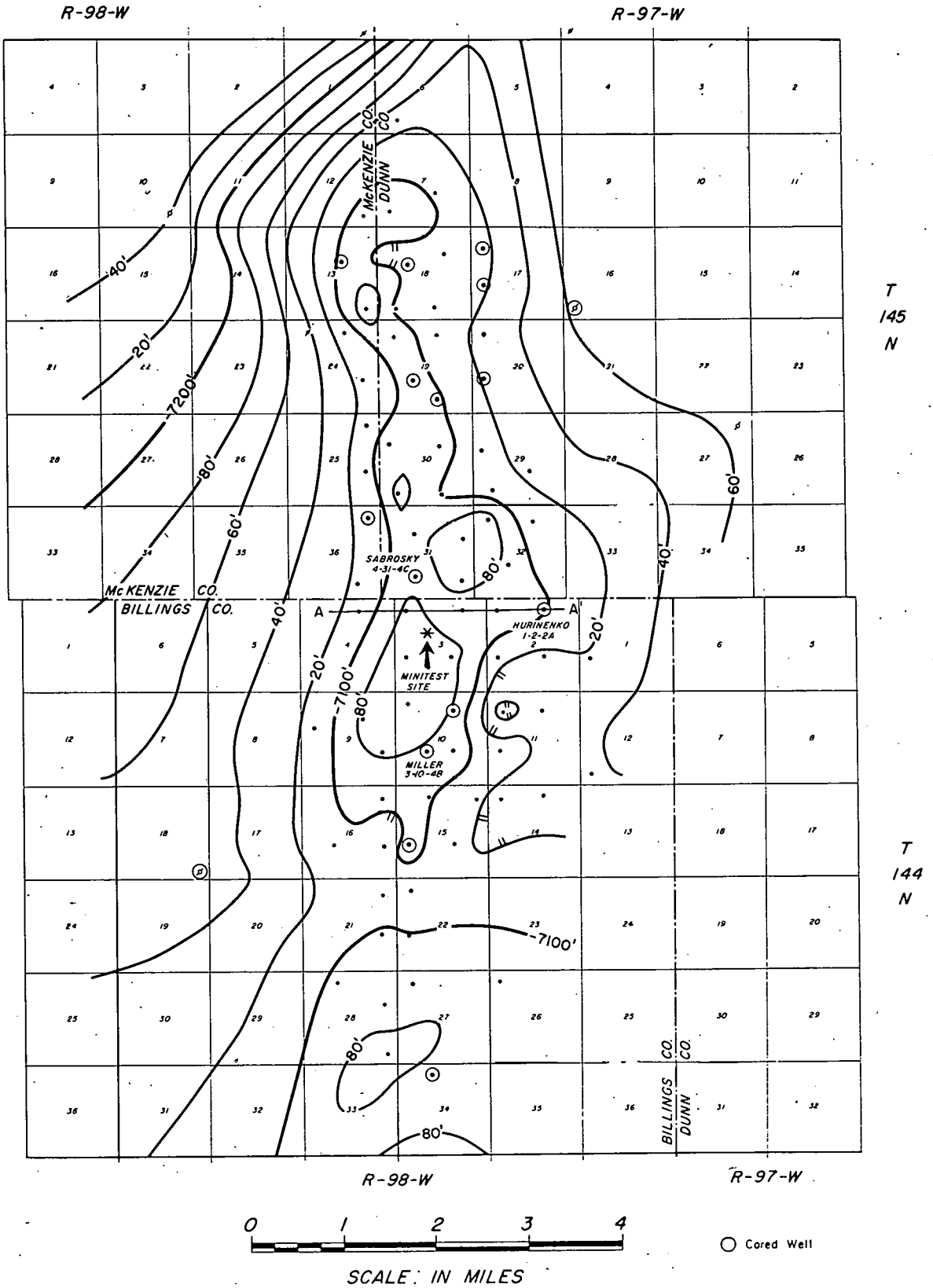


Fig. 3 — Top Mission Canyon Formation with west to east structural cross section A-A'. Asterisk marks proposed minitest site location. Contour interval = 20 ft.

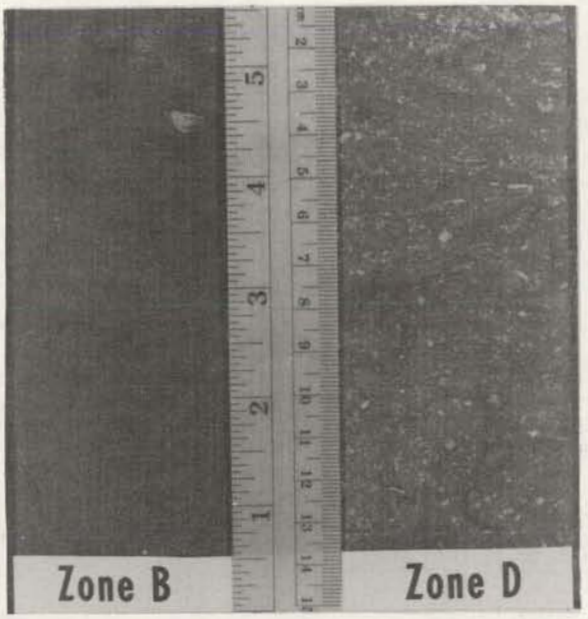


Fig.4—Core slabs of porous dolomite (Zone B) at 9733 ft. and calcareous dolomite (Zone D) at 9816 ft. from Sabrosky 4-31-4C. Scale is in inches and centimeters.

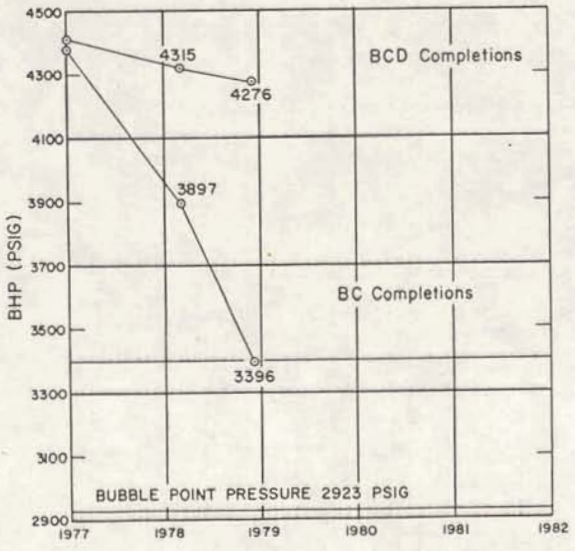


Fig. 5 —Mission Canyon Fm. BHP vs. time.

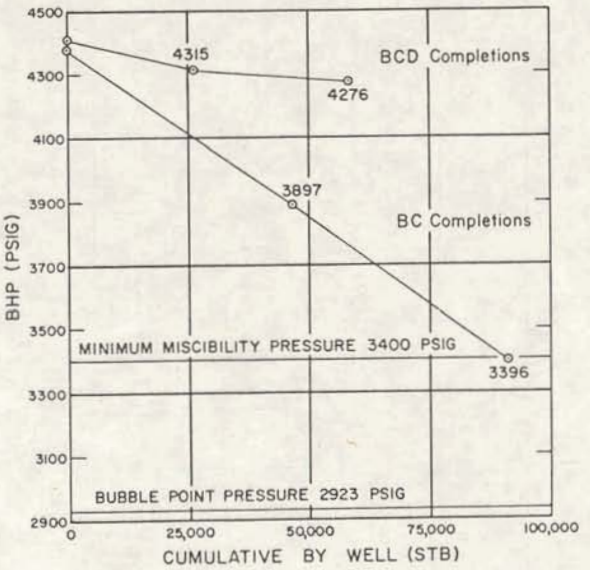


Fig. 6 —Mission Canyon Fm. BHP vs. cumulative production.

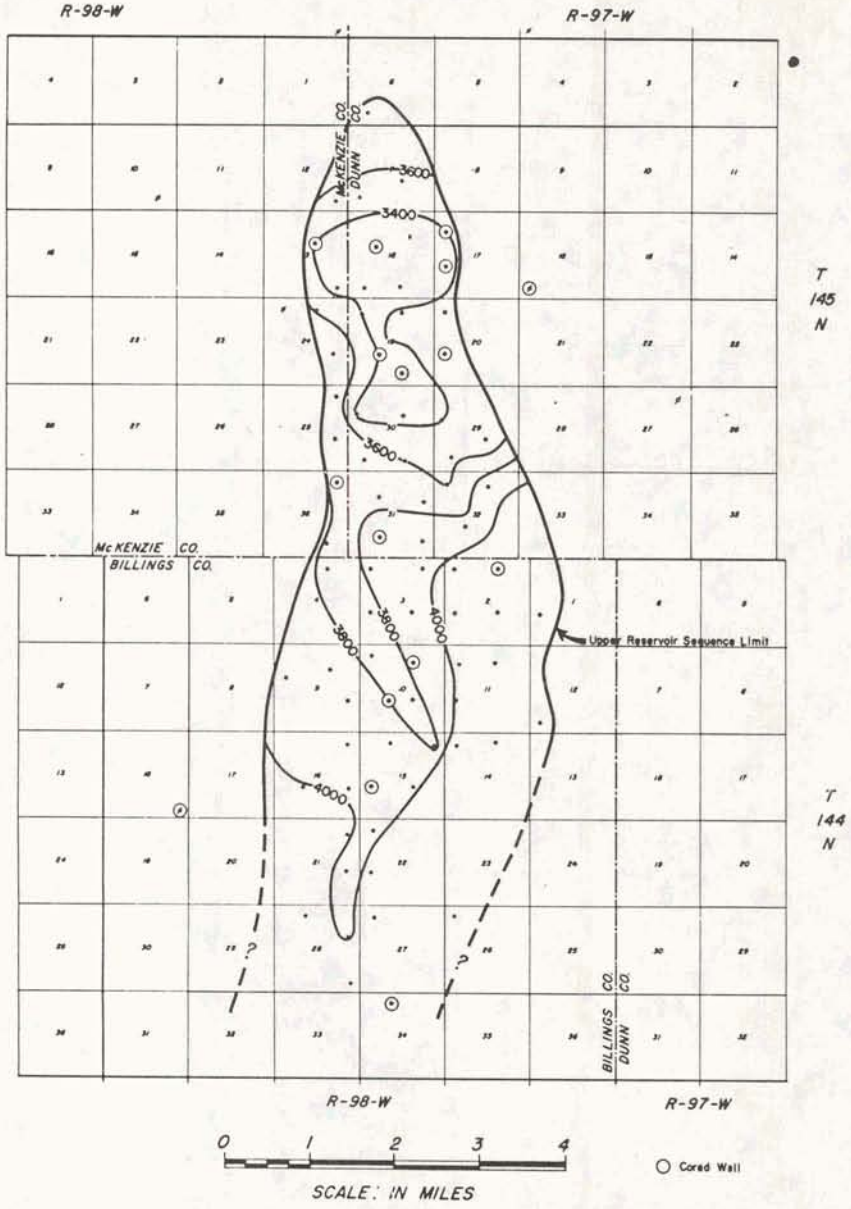


Fig. 7 — Isobaric map of BC-type completions from November, 1978 pressure survey. All pressures corrected to common datum.

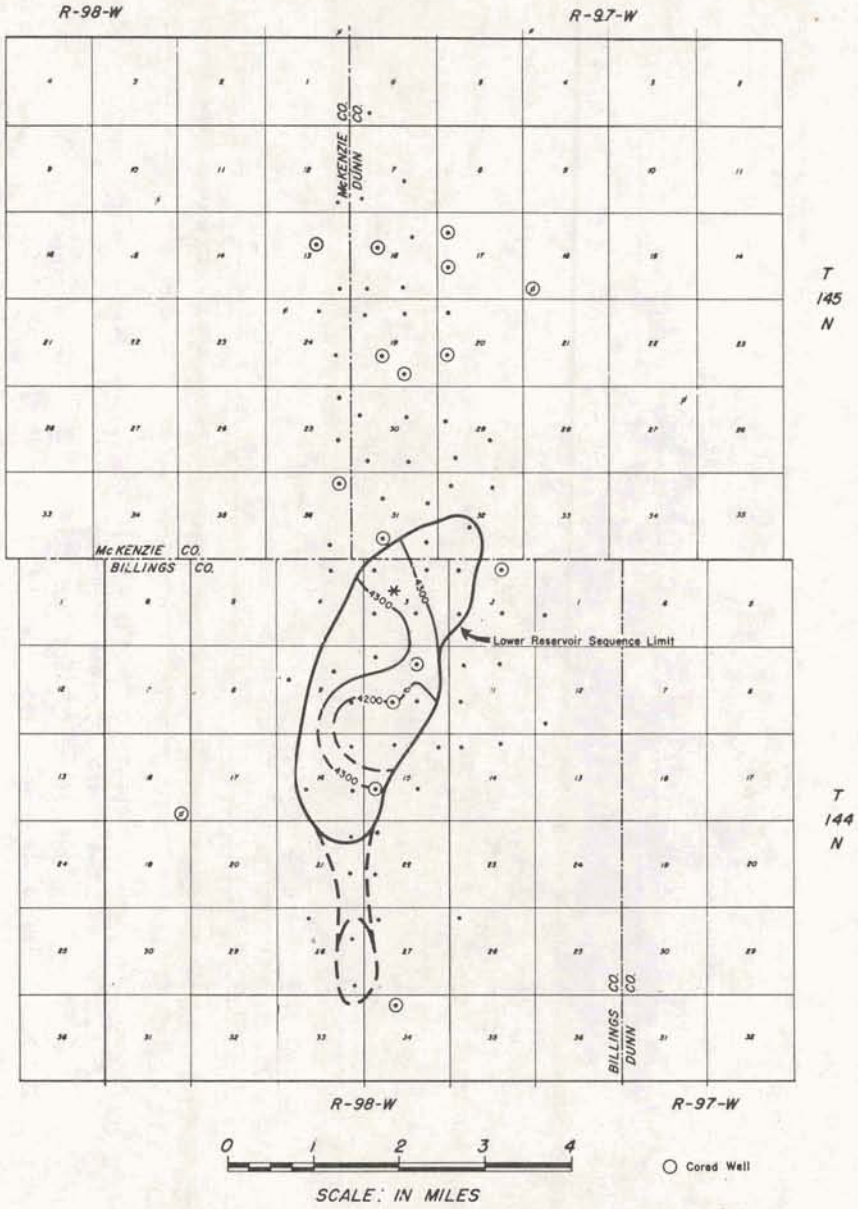


Fig. 8 — Isobaric map of BCD-type completions from November, 1978 pressure survey. All pressures corrected to common datum.

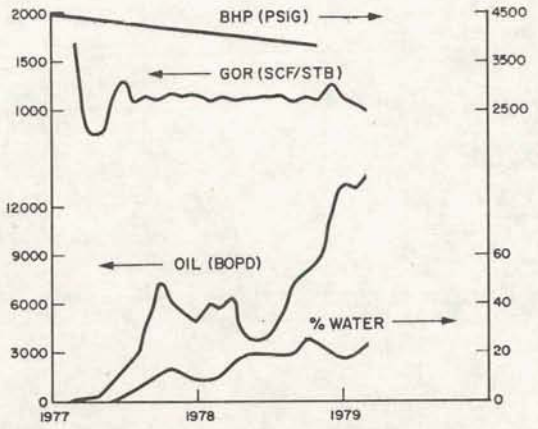


Fig. 9 — Mission Canyon performance (All wells).

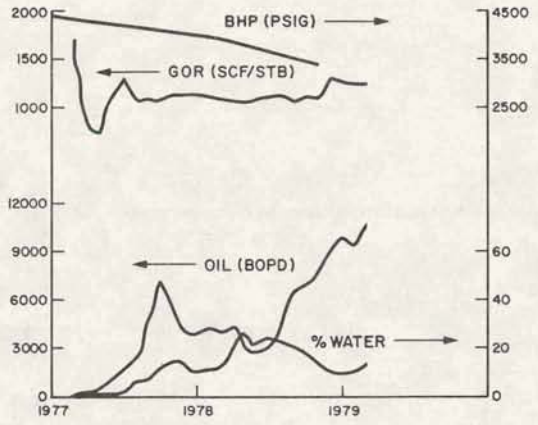


Fig. 10 — Mission Canyon B C- zones performance.

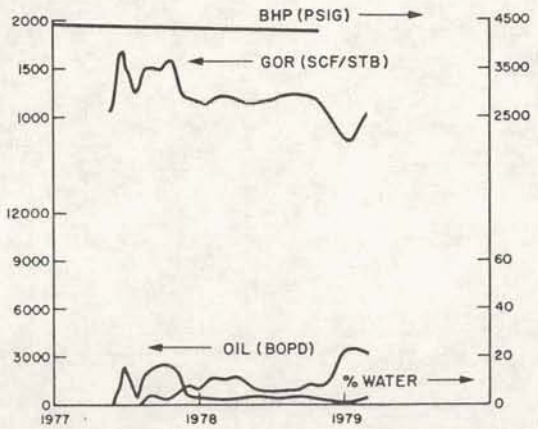


Fig. 11 — Mission Canyon B C D- zones performance.

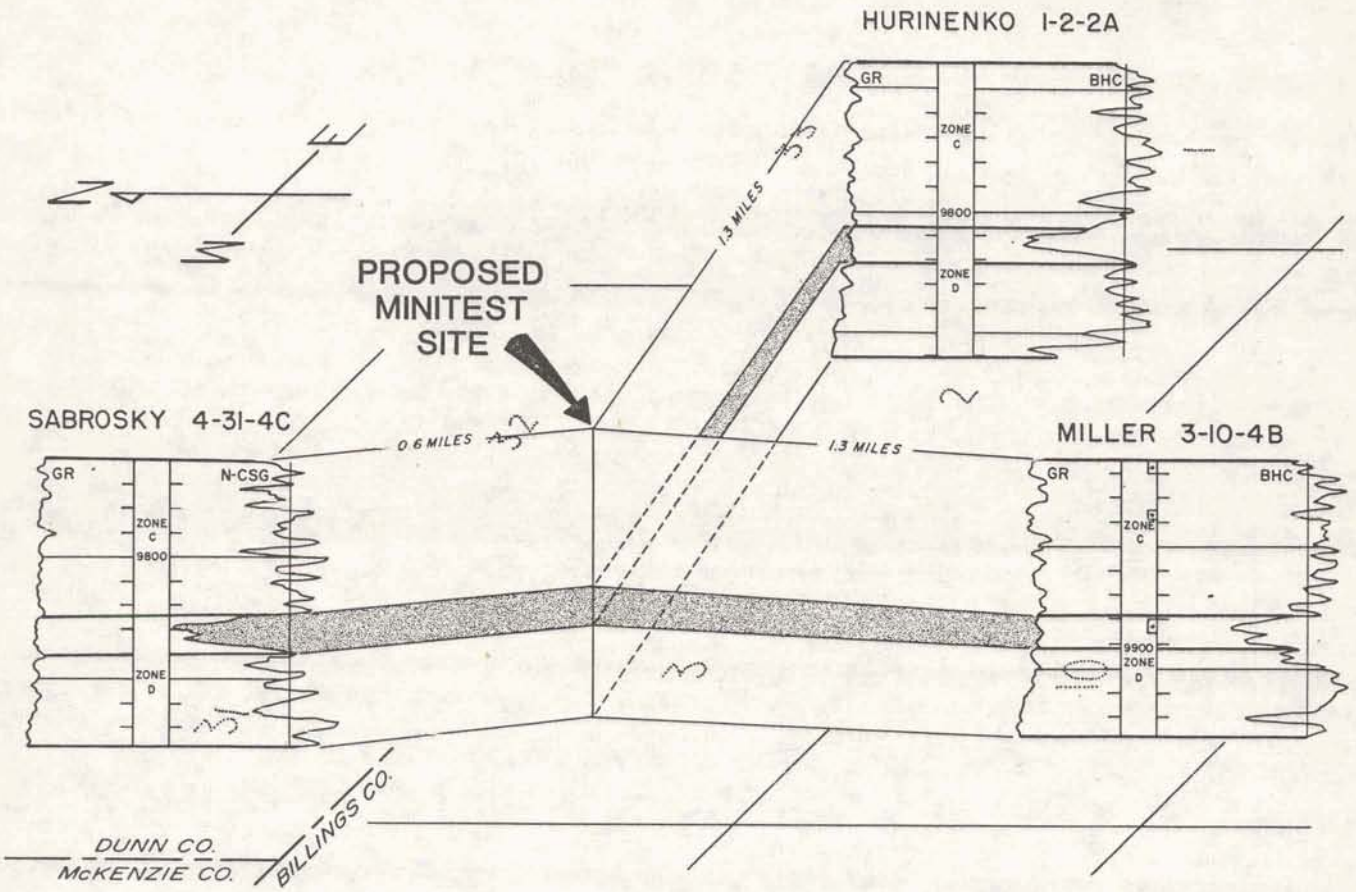


Fig. 12 — Stratigraphic fence diagram of cored wells nearest to proposed minitest site, zones C and D Mission Canyon Fm.

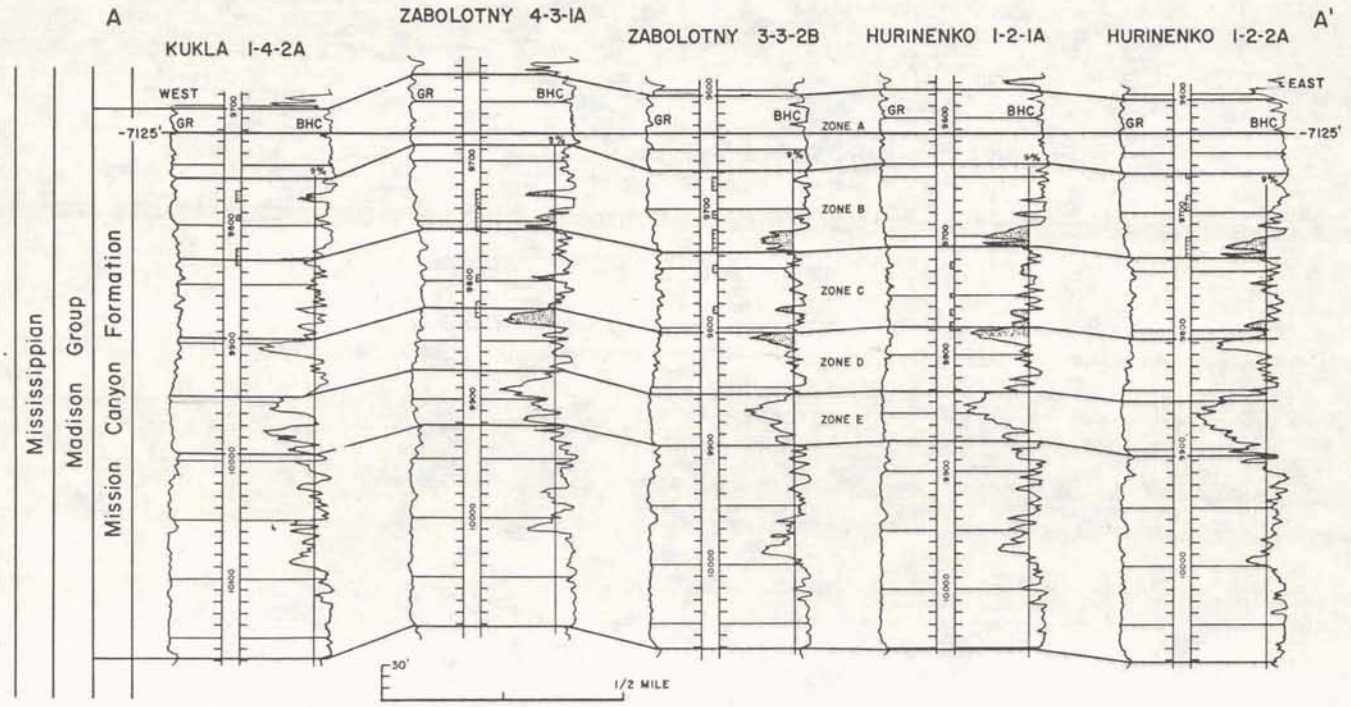
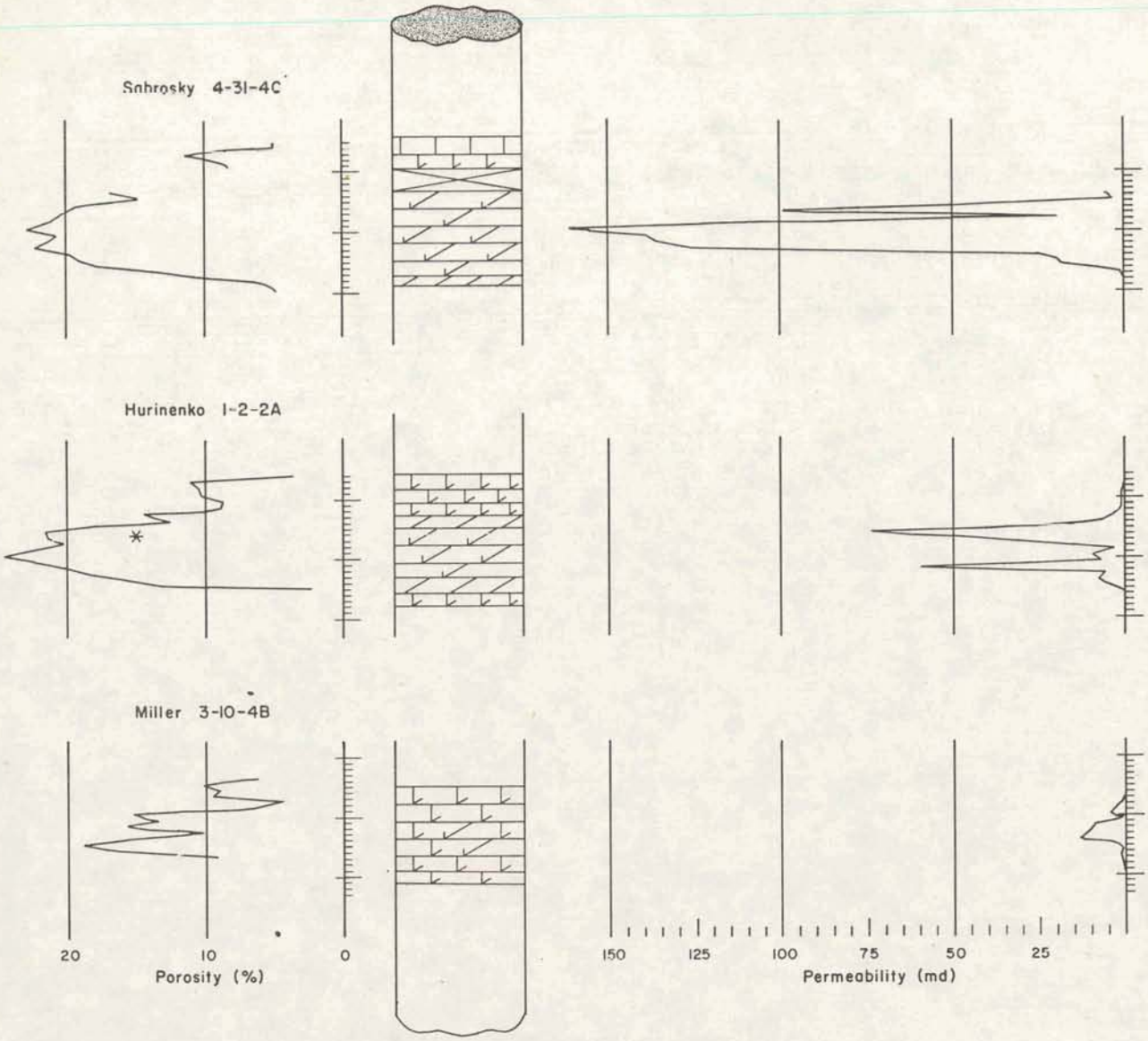
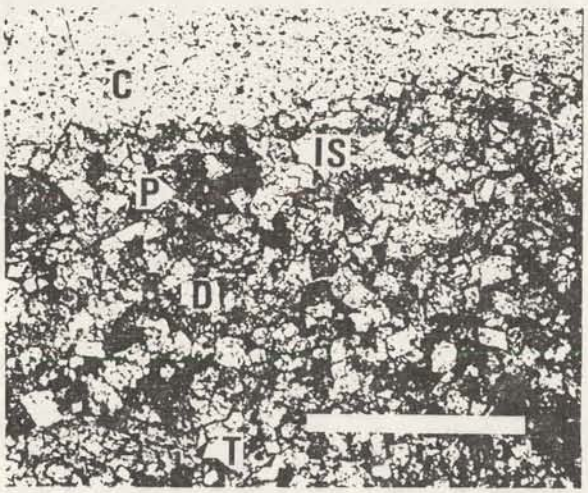
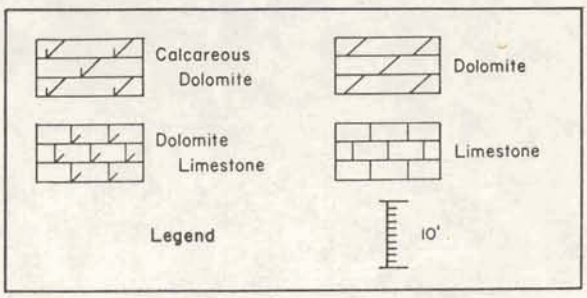


Fig. 13 — West to east structural cross section through Little Knife Field. Proposed minitest site location 1/3 mile southeast of Zabolotny 4-3-1A. Shaded areas denote hydrocarbon bearing beds.







← * Hurinenko 1-2-2A, 9806'. Note porosity in darkened areas, crinoid columnal (C) with matrix of dolorhombs (D) and associated pore throat geometries: P) enlarged polyhedral pores, T) smaller, triangular tetrahedral pores and IS) narrow interboundary–sheet pores.

Fig. 14 — Zone D porosity, lithology and permeability from cored wells. Photomicrograph (x-nicols) of reservoir rock—calcareous dolomite, originally skeletal wackestone. Scale is 0.25 mm.

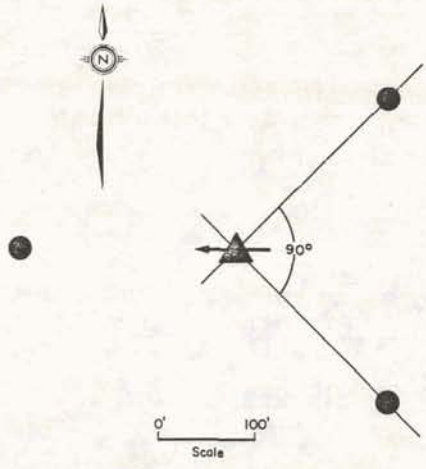


Fig. 15 — Miscible carbon dioxide minitest pattern.

THE MISCIBLE DISPLACEMENT OF RESIDUAL OIL USING SCALED PHYSICAL MODELS

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I. ABSTRACT

A contract for the study of carbon dioxide in the recovery of residual crude oil at the University of Southern California was initiated by an attempt to define the factors which govern the recovery of residual oil by the injection of unequivocal miscible agents in uniform porous media.

Although some experimental work has been reported concerning the displacement of residual oil by miscible fluids[1], most work on miscible displacement has been done using high initial saturations of the oil. The literature also revealed that only a few of the studies on miscible flooding employed scaled physical models with the result that the laboratory observations could not be reliably extrapolated to field operations. The overall disappointing results obtained in pilot and fieldwide miscible drives has been in part attributed to this omission.[2]

The initial experiments undertaken as part of this project were approximately scaled to simple prototype field operations to provide some conceptual information on the mode of displacement of residual oil by miscible fluids. They have revealed a significant effect of velocity on the mode and degree of displacement of the residual oil in prototypes studied to date. These results have permitted hypotheses to be formulated concerning the mode and efficiency of a low viscosity, miscible fluid, e.g., carbon dioxide, on the displacement of residual crude oil. These hypotheses will be tested in a sequentially planned series of experiments.

II. INTRODUCTION

Early scaled physical model studies[3] on solvent displacement of crude oil showed that the recovery of oil on breakthrough of solvent was affected by the mobility ratio in exactly the same manner as the latter affected immiscible displacements. Subsequent to breakthrough, however, miscible fluids recovered greater quantities of the oil because of diffusion of the miscible fluids into each other behind the displacement front.

Other investigations[4] revealed the role of the ratio of viscous to gravity forces. Over a rather wide range of viscous to gravity forces, recovery of oil, from systems containing high initial oil saturations, appeared to be independent of rate and geometry. At higher viscous-gravity

Prepared for DOE under Contract No. ET-78-C-05-5785.

ratios, numerous secondary fingers gave rise to significantly higher recoveries of oil. At low ratios, gravity tonguing dominated the system so that recovery was poor except when the velocity was so decreased molecular diffusion became significant and stabilized, even increased the recovery.

Shelton and Schneider[1] conducted some of the few straightforward experiments on recovery of residual oil by solvent injection although the experiments were not physically scaled. Their observations led to the conclusion that the recovery of residual oil is limited by some sort of shielding effect of the water which is related to capillary trapping of residual oil.

The foregoing works suggested to us that there were two parallel alternate paths for solvent to follow upon being injected into a porous media containing residual oil. Solvent could flow into the system displacing the mobile water until the saturation of the latter decreased and solvent saturation increased to levels where mixing of solvent and residual oil occurred. An alternate path, when gravitational force dominated the system, would be the development of a tongue of solvent which widened as a result of molecular diffusion and dispersion caused by the lithology of the system.

The purpose of these experiments was to attempt to define what operational factors and reservoir and fluid parameters caused one or the other mode of displacement to dominate the system. In order to accomplish this, scaled physical models were used which are theoretical facsimiles of the prototype reservoir. The work to date has investigated the role of frontal solvent velocities on one prototype. Additional work is in progress.

III. PHYSICAL MODEL SCALING

The principles of physical scaling of reservoir processes have been discussed in some detail by Geerstma, et al. in 1956[5], and still others developed scaling techniques for specific uses in prior years. The basic principle of physical scaling requires that the ratios of all the dominant forces acting to control the behavior of the prototype (e.g., viscous forces to gravitational forces, gravitational forces to diffusion, etc., in the real reservoir) bear the same relation to each other in the laboratory model as they do in the prototypical reservoir.

For scaling solvent displacement, the following equalities must be maintained:

$$\frac{\left(\frac{k\,\Delta\rho}{v\,\mu}\right)_P}{\left(\frac{k\,\Delta\rho}{v\,\mu}\right)_M} = \frac{\left(\frac{D}{v\,\ell}\right)_P}{\left(\frac{D}{v\,\ell}\right)_M} = \frac{\left(\frac{v\,\rho\,\sqrt{k}}{\mu}\right)_P}{\left(\frac{v\,\rho\,\sqrt{k}}{\mu}\right)_M}$$

where k is the permeability, $\Delta\rho$ the density difference between the fluids, v the linear velocity of the fluids, μ a characteristic viscosity of the fluids, D the diffusion constant, ℓ a characteristic length of the system, and M and P refer to the model and prototype respectively.

It has been assumed in reaching this conclusion that capillary effects and the Leverett J-function (essentially a distribution of pore sizes) are not significant in controlling the solvent displacement process. Obviously, this is an assumption of convenience since neither can be scaled appropriately. Shelton and Schneider[1] have presented some evidence however to suggest that relative permeability hysteresis (and therefore indirectly the capillary pressure and the J-function) does affect miscible displacement of tertiary oil. Pozzi and Blackwell[6] also showed that grain size distribution (and hence pore size distribution) effected miscible displacement in secondary recovery models. However, we have been able to rationalize that both of these factors will be modifying influences rather than primary influences on our screening studies of the results of miscible displacement of residual oil. Depending upon the results of current studies, however, such factors may have to be reckoned with.

The scaling for the dimensionless Reynold's Number, the third term above, and the dimensionless ratio of gravitational forces, the first term, cannot be simultaneously achieved. It was calculated that the fluid velocities used in the model flow at a Reynold's number of less than one when using the diameter of the grains as the characteristic dimension for the Reynold's number argument. This implies that flow within the core is still laminar or viscous[7] and therefore the neglect of the Reynold's Number scaling is believed justified. (In future experiments it too will be scaled at the expense of gravitational scaling which will be made possible by using model fluids of identical density thus eliminating the need for gravitational scaling.)

IV. RESULTS AND DISCUSSION

A one foot, 2.5 inch diameter lucite tube was packed with glass beads, saturated with water, flooded with the oil, then with water to reach a non-mobile oil saturation. The tertiary miscible flood was then initiated at controlled rates of injection. The porosity of the packs averaged 0.37, and the permeability 13 darcies. The residual oil saturation ranged from 20 to 24%. The prototype corresponding to this is a 10 acre line drive pattern with an injector/producer spacing of 467 feet, and an absolute permeability of 25 mds. Solvent-oil pairs were nonane-dodecane, hexane—dodecane, and dodecane-nonane.

The results of several of the experiments completed to date are presented graphically in Figures 1 to 6.

Consider Runs No. 15, 4 and 9 in which nonane (see Table I for viscosity and density of fluids) displaced residual dodecane at a slightly unfavorable viscosity ratio both with respect to the water and the residual crude oil. At the high velocity of Run No. 9 corresponding to a prototype velocity of 0.25 feet per day, water is substantially displaced ahead of the solvent. The first oil production occurs after the injection of 0.2 pore volume of solvent, and ultimately the solvent itself breaks through after the injection of 0.55 pore volumes. Higher velocities did not change the behavior.

The amount of water displaced corresponds to virtually all the mobile water, leaving a residual saturation of water of 24%. Also, practically 100% of the residual oil is recovered, but 75% of the recovered oil is produced after the first appearance of solvent in the effluent. At this velocity, then, it appears the slightly less viscous solvent frontally displaces the water but mixes with the bulk of the oil that is recovered. There is no evidence of any significant viscous fingering or gravity overlay of the solvent in the displacement of the water at this velocity.

At a significantly lower flow rate, corresponding to a prototype linear velocity of 0.017 feet per day (at the lower end of the rates that might be anticipated in reservoir processes), the mode of displacement is very different. Although water production is initiated immediately upon injection of the solvent, the water production reduces rapidly and ultimately only 0.25 pore volume of water is displaced leaving a residual water saturation of some 50%. Oil production starts after the injection of only 0.08 pore volume of solvent and somewhat more than half the residual oil is produced by the time solvent breaks through. Such breakthrough occurs after only 0.23 pore volume of solvent have been injected whereas at the higher rate breakthrough did not occur until 0.55 pore volume had been injected.

It was anticipated that at the low velocity, gravitational forces and diffusion would be more important than at the high velocity. However, the actual results, which were replicated, were not quite as anticipated. It was expected that at low velocities, when gravitational forces dominated the system, the solvent would form a gravity tongue, override the water and break through quite early. Continued injection was expected to see some small, sustained production of oil mixed with the solvent as the gravity tongue thickened as a result of diffusion and dispersion. Relatively early solvent breakthrough does in fact occur, compared to that observed at higher velocities, but a significant amount of neat oil precedes the solvent. This suggests that the entering solvent develops fan shaped front from which solvent is diffused and dispersed both downwards and horizontally causing trivial but sufficient increases in non-wetting phase saturation to mobilize the residual oil.

Pozzi and Blackwell's work[6] on solvent displacement of high oil saturations show somewhat similar performance in that the recovery of oil upon breakthrough of solvent increases as frontal solvent velocity decreases and/or the ratio of length to height in the system increases. However, in their experiments since the oil was mobile the admixture of solvent was not required to impart mobility to the oil.

In this low velocity experiment only about 60% of the residual oil is recovered (compared to the virtually 100% recovered at higher velocity) but over half of that oil is recovered prior to solvent breakthrough. A prototype velocity of .05 foot per day gave essentially the same results as the .017 foot per day velocity. Insufficient experiments were done to determine where the transition from one mode of displacement to the other occurred nor the abruptness of such a transition.

Although such low prototype velocities might be thought of as being losities at this time, it must be noted that the displacement efficiency of the solvent in displacing the residual crude oil is extremely high. Fifty percent of the residual oil (0.1 p.v.) is recovered upon the injection of only 0.3 p.v. of solvent whereas at the higher velocity more than twice the amount of solvent, 0.7 p.v., is required to obtain such recovery.

To increase insight into the phenomenon, the roles of nonane and dodecane were reversed with the dodecane now being the solvent. The viscosity ratios are now all slightly favorable. At a prototype rate of 0.05 foot per day, the displacement performance was almost identical to the displacement of dodecane by nonane at a rate of 0.25 foot per day. Apparently, the rather small improvement in viscosity ratio caused the viscous forces to dominate the system even at the lower viscosity.

A set of experiments were then done with hexane as the solvent and dodecane as the oil, increasing the unfavorable nature of the viscosity ratio by another factor of approximately 2. At the high velocity of 0.25 foot per day, the results were substantially the same as when displacing dodecane with nonane except that now the water recovery is slightly less and solvent breakthrough occurs slightly earlier.

At 0.017 foot per day, again, substantially similar results to those obtained with nonane displacement at the same velocity were obtained but the oil recovery decreases to 53% from 60%, and the solvent breakthrough occurs earlier at 0.15 pore volume injected compared to 0.23. The displacement by hexane is demonstrating somewhat greater tonguing and fingering than did the nonane. There is a suggestion of a trend in these results to the effect that as the viscosity ratio becomes more unfavorable, early solvent breakthrough and reduced recovery will occur at even the higher velocities.

V. EXTRAPOLATION OF RESULTS TO CO_2 FLOODING

Assuming that the results can be extrapolated, as suggested by the last paragraph of the preceding section it is informative to speculate on the significance of these results for miscible flooding when the solvent has a viscosity that is only a fraction of that of water. Even at high pressures, the viscosity of carbon dioxide will be significantly less than that of water. Under such conditions it may not be possible to achieve the stable displacement exhibited by experiments wherein the prototype velocity is in the range of what is usually expected, a few tenths of a foot per day. Instead, the mode of displacement may be hypothesized to be more closely related to that exhibited by the low velocity experiments because of the very adverse viscosity ratio of the carbon dioxide water system.

It might be noted that although there is some similarity in the results of the low velocity experiments reported herein (and now hypothesized to be similar to those at higher velocities when the viscosity ratio is very unfavorable) with the results of numerical simulation of carbon dioxide displacement of residual crude oil.[8] The similarity is in the early breakthrough of solvent, but there remains a significant difference. There is no evidence r the production of neat oil in the results of numerical simulation whereas here is significant production of oil before solvent breakthrough in these experimental results.

These results suggest that scaled model experiments could provide information for the design of a slug injection process which would efficiently recover a fraction of the residual crude. The carbon dioxide may be somewhat more efficient than a hydrocarbon solvent because the former will be able to diffuse through the continuous water phase to dissolve in bypassed residual oil.

However, if carbon dioxide can be secured cheaply enough, the higher recovery of crude oil suggested to be achievable by very high injection rates and close spacing may more than offset the cost involved of achieving such high fluid velocities within the reservoir.

VI. FUTURE WORK

The scaled model studies will be continued with hydrocarbon solvents to determine the effect of higher viscosity ratios, permeabilities and stratification on the results. Also, the configuration of the system will be changed to that of a rectangle and attempts made to trace the solvent paths by using dyed solvents. Finally, a three-dimensional scaled physical model will be prepared to investigate areal effects on the results.

Ultimately, two-dimensional model studies will be developed using carbon dioxide-crude oil systems. Although our current interpretation of the mechanism for crude oil mobilization and displacement does not give too much weight to the role of complex phase behavior in effecting displacement, provision is being made in the design of such models for the sampling of phases between inlet and outlet ports. The costs involved in constructing a three-dimensional scaled physical model for carbon dioxide displacement studies currently precludes our consideration of such a model.

VII. CONCLUSIONS

Miscible displacement of residual oil at prototype velocities of several tenths of a foot per day result in piston like displacement of the water followed by recovery of mixtures of solvent and oil at progressively high concentrations of the latter. Most of the residual oil is recovered. This behavior is observed regardless of whether the viscosity ratios are slightly favorable or unfavorable.

At very low prototype velocities, of a couple of hundredths of a foot a day, a significant amount of oil is produced prior to breakthrough of solvent; both occurring quite early. The amount of water displaced is only a fraction of the total in the system.

There is some evidence that as the viscosity ratio becomes more and more unfavorable, piston like displacement of the water will not be achieved except at reservoir velocities that are significantly greater than those usually attained. Although less than all the residual oil is recovered under such conditions, oil recovery is indicated to be achieved quite efficiently in terms of pore volumes of solvent injected.

Hypotheses relevant to the displacement of residual crude oil by carbon oxide have been generated from these experiments which will be tested by ditional scaled physical models.

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Table I

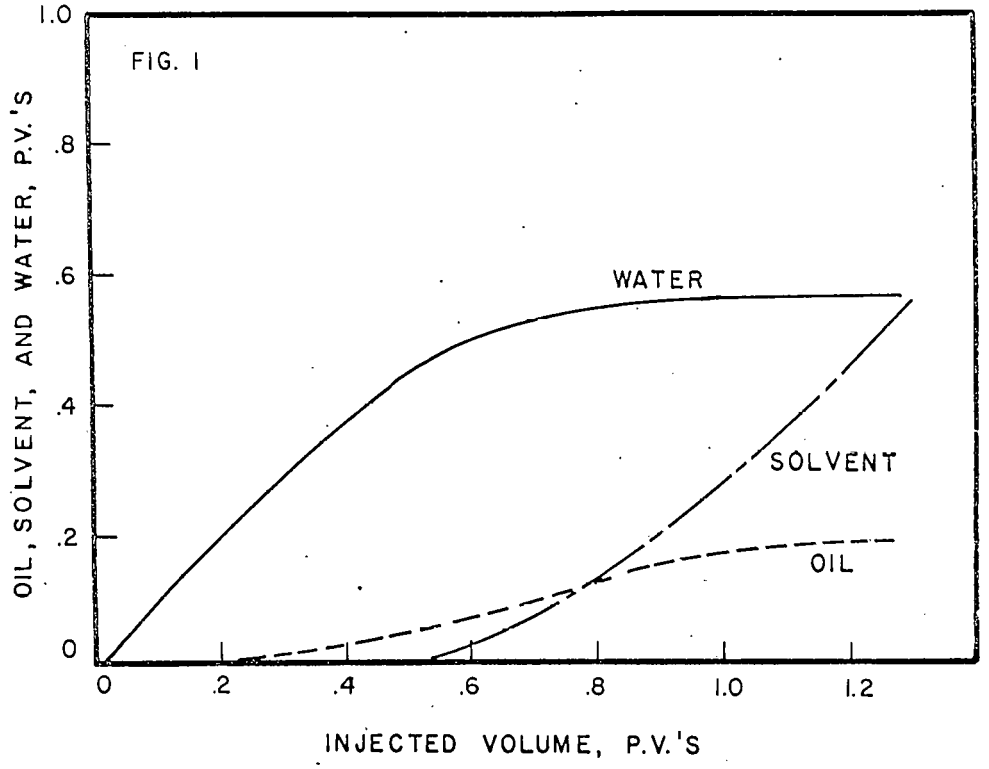
DENSITY AND VISCOSITIES

	Density* (g/cc)	Viscosity* (cp)
Hexane	.66	.33
Nonane	.72	.71
Dodecane	.75	1.35

*At room temperature

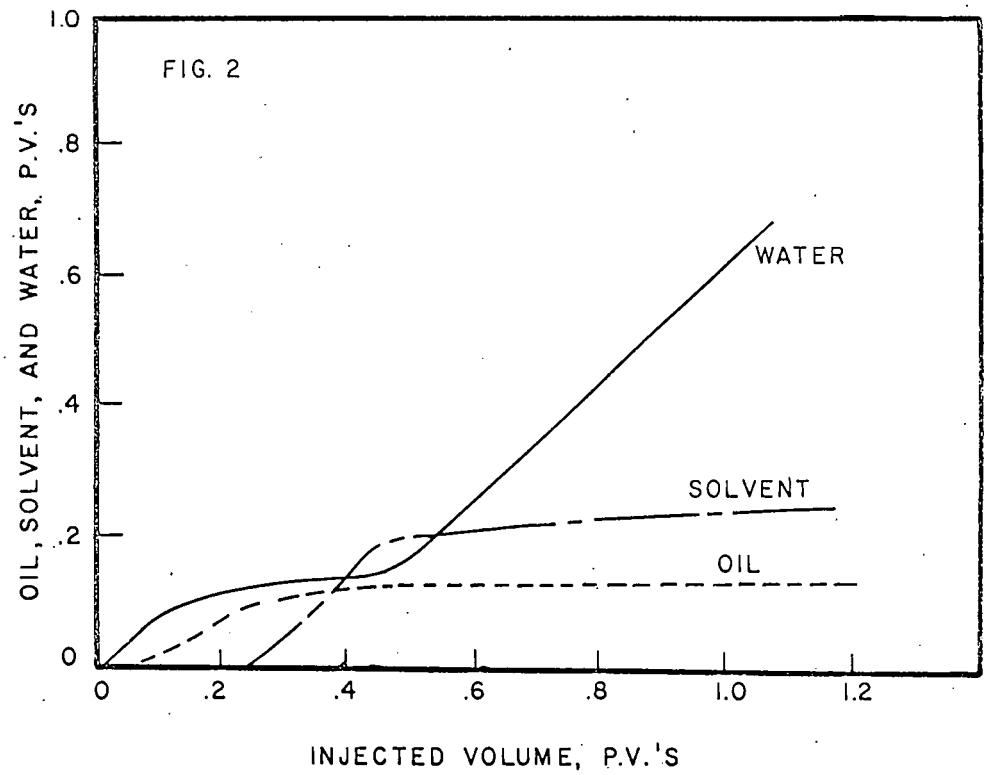
RUN NO. 9, NONANE DISPLACING DODECANE

PROTOTYPE VELOCITY = .25 FT/DAY



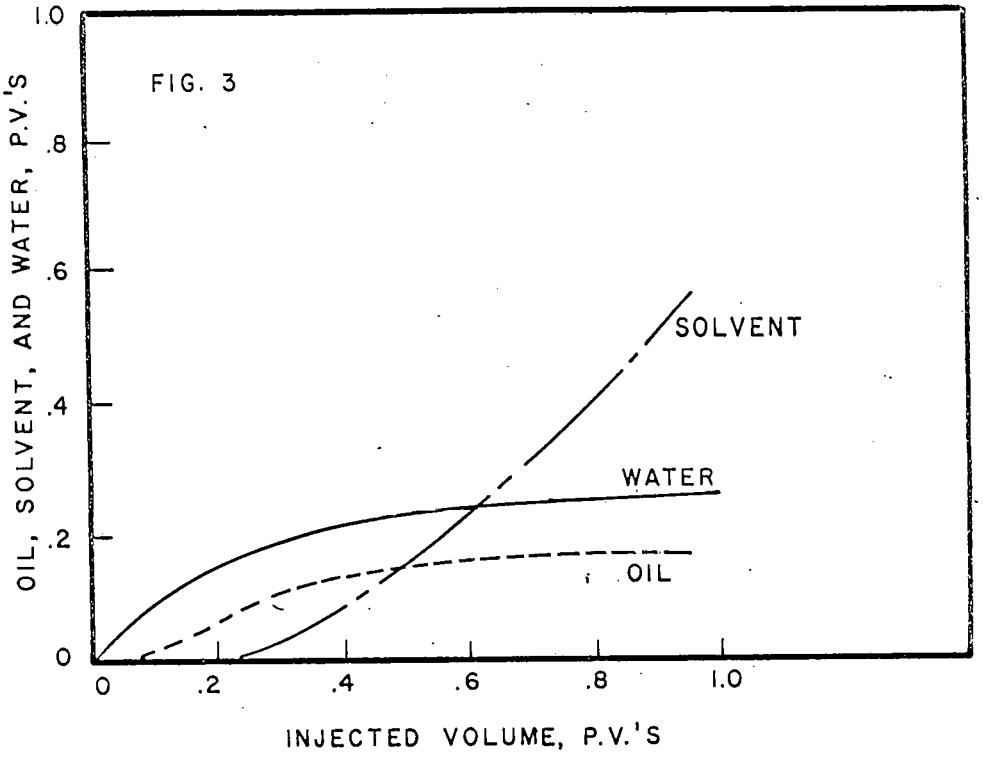
RUN NO. 4, NONANE DISPLACING DODECANE

PROTOTYPE VELOCITY = .05 FT/DAY



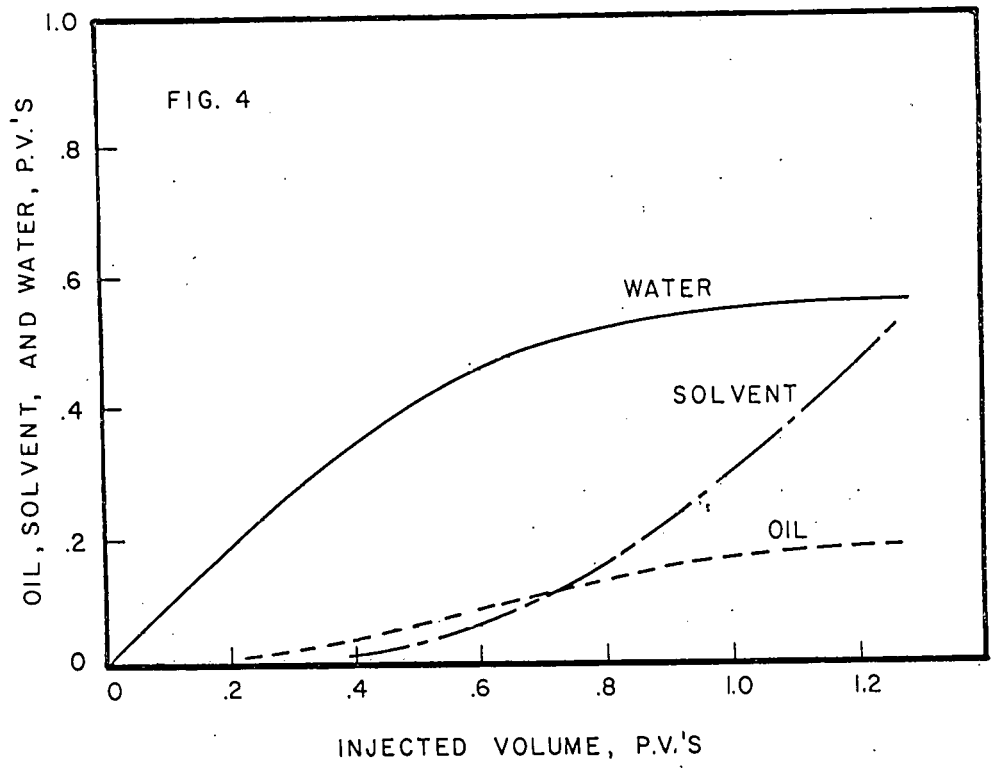
RUN NO. 15, NONANE DISPLACING DODECANE

PROTOTYPE VELOCITY = .017 FT/DAY



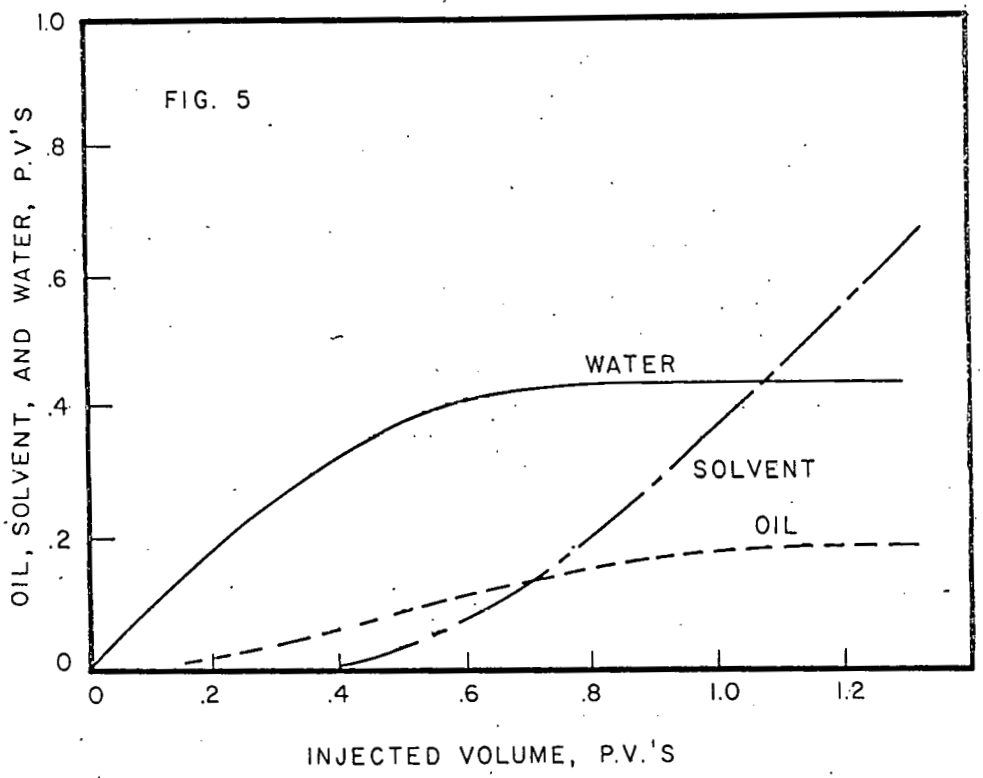
RUN NO. 7, DODECANE DISPLACING NONANE

PROTOTYPE VELOCITY = .05 FT/DAY



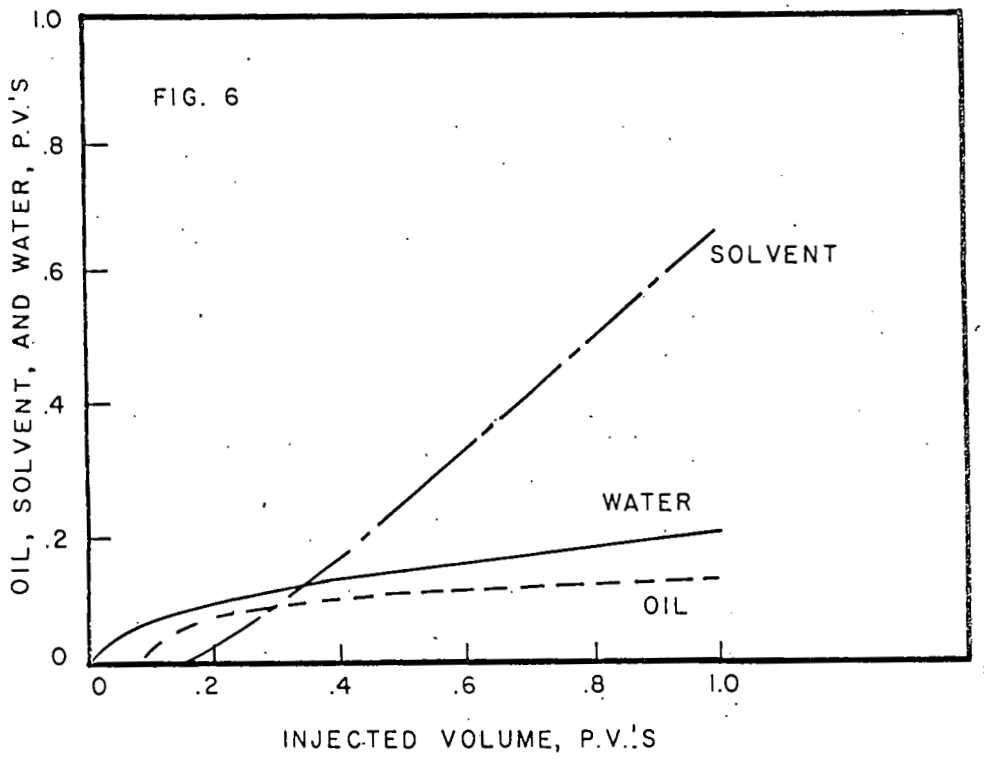
RUN NO. 17, HEXANE DISPLACING DODECANE

PROTOTYPE VELOCITY = .25 FT/DAY



RUN NO. 19, HEXANE DISPLACING DODECANE

PROTOTYPE VELOCITY = .017 FT/DAY



NATURALLY OCCURRING CARBON DIOXIDE SOURCES IN THE UNITED STATES

A Geologic Appraisal and Economic Sensitivity Study of Drilling and Producing Carbon Dioxide for Use in Enhanced Oil Recovery

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ABSTRACT

This study develops estimates of reserves for significant subsurface carbon dioxide accumulations, and investigates the effects of price variation on the profitability of producing these accumulations.

Several geographic provinces of the United States including central Mississippi, West Virginia, the Delaware-Val Verde Basins of West Texas and several locations in the Rocky Mountains contain large accumulations of high purity, naturally occurring subsurface carbon dioxide.

Four significant accumulations of carbon dioxide were chosen for in-depth geologic, reservoir, and economic analyses.

Original gas in place, recovery efficiencies, reserves, anticipated flowing pressures, and sustained flow rates were estimated.

Earning power sensitivity to variation in flow rate and reserve was studied to bracket a possible range of gas prices, utilizing estimated development and production costs, for each of the four areas.

Projections of the potential supply, profitability of drilling and producing, and preliminary analyses of potential demand for naturally occurring carbon dioxide are presented.

Prepared for DOE under Contract No. Ex-76-C-01-2025

INTRODUCTION

Preliminary estimates[1] indicate 5-10 billion barrels of enhanced oil may be recovered by carbon dioxide flooding, which may require on the order of 20-50 Tcf of carbon dioxide. Current research and field tests should help resolve some of the uncertainties concerning the process so that the economics of carbon dioxide miscible flooding can be appraised more reliably. Two critical questions, however, remain to be resolved:

- will the large volumes of carbon dioxide required be available?
- at what price will they be available?

GURC was requested under Task XV of its DOE contract to assist Pullman-Kellogg[2] in an assessment of naturally occurring carbon dioxide. GURC located and characterized the major source areas and estimated costs to drill and produce the carbon dioxide into a trunkline. Kellogg provided investment and operating cost estimates for compression, treatment, and transportation.

GURC's overall responsibility included three tasks:

- Evaluation of reservoir rock properties and gas composition for each potential carbon dioxide source,
- Estimate of costs for drilling and producing naturally occurring carbon dioxide reservoirs,
- Analysis of field utilization of carbon dioxide in EOR projects.

SOURCE DELINEATION

GURC developed a data base* of naturally-occurring carbon dioxide wells early in the study. Based in part on data originally published by the U.S. Bureau of Mines Helium Division[3], which included over 11,000 analyses of gas samples from oil and gas wells, the data base presently contains over six hundred records representing occurrences of natural carbon dioxide greater than 5 mole percent in 27 states.

Under subcontract to GURC, Daniel Analytical Services statistically analyzed the relationships of carbon dioxide with the geologic environment, major associated gases and minor associated gases[4]. Figure 1, a ternary diagram, generated to demonstrate the relationship of carbon dioxide, nitrogen and methane in natural gas samples, exemplifies the types of analyses performed by Danalyt.

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*This data base is available through the Office of Information Systems at the University of Oklahoma.

Initial delineation of areas containing potential reserves f carbon dioxide was then conducted using the gas quality and reservoir characteristics data in the Carbon Dioxide Data Base.

The regions considered include West Virginia, the Jackson Dome area in Mississippi, the Delaware-Val Verde Basins in West Texas, and 9 sub-areas of thc Rocky Mountains, as follows:

.. Southwest Colorado, McElmo Dome area
.. South Central Colorado, Sheep Mountain area
.. North Central Colorado, North Park Basin
.. Northeast New Mexico, Sierra Grande Arch area
.. Northwest New Mexico, San Juan Basin
.. Central Utah, Farnham Dome area
.. Central Utah, Gordon Creek area
.. Southeast Utah, Paradox Basin
.. Wyoming, Sweetwater and Uinta Counties area

Table 1 briefly characterizes the gas compositions, estimated productivity, and pressures of the more significant carbon dioxide source areas.

SELECTION CRITERIA FOR DETAILED STUDY

Three criteria were established to determine which of these source areas warranted detailed reservoir and economic evaluation:

(1) reserves apparently sufficient for pipeline consideration,

(2) proximity to miscible flood candidate reservoirs, and

(3) evidence of strong industry interest

On this basis, four areas were chosen for further geologic, reservoir, and economic analysis:

.. McElmo Dome area, southwest Colorado,
.. Sheep Mountain area, south central Colorado,
.. Northeast New Mexico, and,
.. Jackson Dome area, Mississippi

These areas, each representing a unique geologic environment and posing varying drilling and production conditions, are reasonably representative of the range of expected naturally occurring carbon dioxide sources in the United States.

IN-DEPTH ANALYSIS OF PRIMARY CO_2 SOURCE AREAS

The locations of several major carbon dioxide productive areas, examined in depth in GURC's report[5] on naturally occurring carbon dioxide are identified in Figure 2. Brief summaries of the potential reserve, gas purity, average deliverability per well and expected field capacity are included for each of the areas.

Additionally, areas containing significant oil reservoirs amenable to carbon dioxide flooding are identified on Figure 2. Estimates of potential oil recoverable by carbon dioixde flooding, carbon dioxide requirement in Mcf per barrel recovered, and potential "net new"* carbon dioxide requirements are summarized for three areas containing significant candidate reservoirs.

RESERVOIR ANALYSIS METHODOLOGY

Data obtained from exploratory programs in each area, including well logs, core analyses, and completion reports were utilized to develop estimates of porosity, gas saturation, net pay and OGIP in each area.

Field test data, including flow rates, flowing tubing pressures and pressure drawdowns were then analyzed. For each area a range of average sustained deliverabilities and flowing tubing pressures was estimated. Production was assumed to be by depletion drive for all areas investigated.

For each area, a set of well "models" spanning the probable variation in rock quality, OGIP, and sustained productivity was created. Flowing bottom hole pressure decline curves were constructed as a function of cumulative gas produced, allowing easy correlation with varying flow rates and recovery efficiencies. Individual well economics on these representative well models were then calculated.

A brief summary of four significant naturally occurring, carbon dioxide sources is presented below.

Southwestern Colorado - McElmo Dome Area

Exploration for carbon dioxide reservoirs in southwestern Colorado has focused on the McElmo Dome area in Montezuma County and the Doe Canyon-Dove Creek area of Dolores County. The two carbon dioxide productive zones in this portion of the Paradox Basin are the Leadville (Mississippian) and the Ouray (Devonian), found at depths of 6500-9000 feet subsurface. Analysis of produced gas from both formations indicates a composition of 96-99 percent carbon dioxide with 1-4 percent nitrogen.

At the time of our study 16 wells had been drilled in the area. Nine wells were completed as potential producers, while five were reported as dry holes. Data was unavailable for two wells.

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*"Net new" CO_2 = Total CO_2 injected - produced CO_2 recycled in reservoir.

Data indicates the reservoir has an areal extent of 100 productive sections, and from 75 to 100 feet net pay thickness with approximately 7 percent porosity. OGIP is estimated to range from 3.8 to 4.9 Tcf. Ultimate recovery (65-70% E_R) might reach from 2.6 to 3.4 Tcf. Sustained well deliverabilities are anticipated in the 3 - 12 MMcfd range, with flowing wellhead pressures from 600-850 psi. If flowing wellhead pressures in this range can be achieved, then only one stage of compression should be required for delivery into a pipeline at around 2000 psi.

South Central Colorado - Sheep Mountain Area

The Sheep Mountain area, located in Huerfano Co., Colorado, is carbon dioxide productive from two stratigraphic units. The Dakota (Cretaceous), and a smaller reservoir, the Entrada (Jurassic), produce gas composed of 97 to 99.6 percent carbon dioxide with minor amounts of nitrogen and methane present.

Data from fifteen wells supplied well control, with ten wells completed as potential producers and five wells reported as dry holes. Data was unavailable for six other wells in the area.

Based on available data the productive area of the Dakota reservoir ranges from 25 to 30 sections, with 75 to 125 feet of net pay and an average porosity of 17 percent. OGIP in the Dakota is estimated to be 1.9 Tcf to 3.8 Tcf. Ultimate recovery (65% E_R) might range from 1.3 Tcf to 2.5 Tcf. Per well average sustained deliverability is estimated to range from 3 to 12 MMcfd. The wells are expected to be produced at sufficient flowing pressures to enable delivery to a pipeline (1500-2000 psi), with only one stage of compression.

Northeast New Mexico - Bravo Dome Area

Several areas in northeastern and north central New Mexico, including locations near Bueyeros, Wagon Mound and Turkey Mound, have been recent exploration targets for commercial carbon dioxide reserves.

The most rewarding drilling activity to date has occurred on a large structural nose on the eastern flank of the Sierra Grande Uplift. Several stratigraphic units in the area have exhibited shows of carbon dioxide. The Glorieta (Permian), Tubb (Permian), and a granite wash member appear to be carbon dioxide productive.

Twenty-one of twenty-seven exploratory wells in the area were reportedly productive. Four wells were reported dry and no data was available on three other wells.

Recent exploratory drilling in the area indicates high grade carbon dioxide of 99.1 to 100 percent purity, with a maximum of .3 percent nitrogen and .2 percent hydrocarbon as contaminants.

The productive area appears to cover 880,000 acres, or roughly 38 townships, with an average of 40 to 60 feet net pay, and approximately 20 percent porosity. OGIP is estimated to range from 10.9 Tcf to 16.3 Tcf. The ultimate recovery (65% E_R) would then range from 7.0 Tcf to 10.6 Tcf. Anticipated sustained per well deliverabilities range from .3 MMcfd to 1.2 MMcfd, with flowing tubing pressures at least 140 psi. With sustained flowing tubing pressures in excess of 140 psi, two stages of compression may be sufficient for delivery to the pipeline.

Central Mississippi - Jackson Dome Area

Jurassic sediments in portions of Rankin, Madison, and Scott Counties, Mississippi, have tested sour gas over the past 20 years of exploration. A corridor of carbon dioxide and H_2S rich gas is located on the east-northeast flank of the Jackson Uplift and extends in an arc from north central Madison County through central Rankin County.

Two stratigraphic units, the Smackover (Jurassic) and the Norphlet (Jurassic) have indicated strong carbon dioxide potential during exploratory drilling and testing.

Wells in the area have tested carbon dioxide concentrations ranging from 65 to 99.6 percent from the Jurassic section. Jurassic gas in this area is associated with up to 10 percent H_2S and varied quantities of methane.

Seven wells of ten wells which have tested Jurassic formations in the area are apparently productive of carbon dioxide in excess of 98 percent purity.

Present control indicates the combined productive area of four structural features containing gas greater than 98 percent carbon dioxide is a minimum of 27 sections, and total net pay of the Jurassic section is 120 feet to 250 feet. With 13 percent average porosity, minimum OGIP (CO_2 > 98%) would range from 3.4 Tcf to 7.0 Tcf. Minimum ultimate recovery (60% E_R) would then range from 2.0 Tcf to 4.2 Tcf. Sustained per well deliverabilities from both the Smackover and Norphlet, individually, are expected

to range from 4 MMcfd to 16 MMcfd. Initial flowing tubing pressures are expected to range from 2,000 psi to 4,500 psi. It seems unlikely that dual completions will be made in these two formations.

ECONOMIC ANALYSIS

Drilling costs for carbon dioxide wells were found to be highly site specific and regionally variant due to topographic and geologic anomalies. Completed well costs were based on those reported by operators in each area. A dry hole "cost" was estimated in each area, based on historical dry hole ratios and estimated intangible well costs, for both exploration and development drilling phases. Lease bonus fees and estimated probable operating costs for carbon dioxide wells were obtained from industry personnel.

Investment and operating costs for surface processing equipment, composed of compression and dehydration facilities and a gathering system, were supplied by Pullman Kellogg. Each well was assigned a pro rata expenditure for surface processing equipment based on its production contribution to a 50 MMcfd module. Actual surface processing costs may vary considerably if two-phase flow is encountered at the surface.

Discounted cash flow economic evaluations considering lease bonus, exploration costs, drilling and development expenses, gathering, treating, and compression costs, and probable time delays (as discussed below) were calculated using a commercial computer package.[6]

Earning power was calculated on an after Federal income tax basis, with a tax rate of 48 percent and no depletion allowance for all cases. A 12.5 percent royalty was assumed.

Economics were calculated in constant value 1978 dollars and assumed that inflation in investment and operating expenses will not exceed escalation in wellhead gas price.

As might be expected the probable time delay between initial expenditures and initial carbon dioxide production, expected to be 5 to 6 years, had a negative impact on present value economics.

Economic results must be considered speculative and depend on sustained production history for confirmation.

In each of the four areas analyzed in detail, sensitivity of earning power to variation in sustained flow rate and reserve per well was studied considering three rate cases and three reserve cases, at two gas prices, $.25/Mcf and $.50/Mcf.

An example of the economic analysis methodology, the study of the Jackson Dome area, Mississippi is presented below.

Economics were calculated for three sets of model wells, which assumed average sustained producing rates of 4 MMcfd, 8 MMcfd, and 16 MMcfd. Economics for each set of the model wells were evaluated for per well reserves of 17 Bcf, 51 Bcf, and 152 Bcf. This range of per well reserve estimates is based on recovery efficiencies of 60 percent from a 640 acre drainage area and net pays of 25, 75, and 225 feet, respectively.

Capital expenditures for each well model are summarized in Table 2. Well operating costs and surface processing operating costs, including hydrate inhibition, drying and compressing the gas[2], are listed in Table 3. It is assumed that costs of purifying the carbon dioxide, i.e., removal of H_2S will be borne by the pipeline.

The investment schedule assumes capital expenditures will occur over a six-year period prior to actual carbon dioxide production. Investment for development drilling and surface processing equipment was scheduled over the final two years (years 5 and 6) prior to carbon dioxide production.

Results of discounted cash flow rate of return calculations, using the above reservoir input and gas prices of $.25/Mcf and $.50/Mcf, are presented in Figure 3.

SUMMARY ON NATURALLY OCCURRING CO_2 ACCUMULATIONS

The three areas surveyed in the Rocky Mountain province, the McElmo Dome area, Sheep Mountain area, and Bravo Dome area, potentially represent an aggregate carbon dioxide OGIP of 16.6 Tcf to 25 Tcf. Indicated carbon dioxide reserve from these areas is estimated to range from 10.9 Tcf to 16.5 Tcf. Peak pipeline delivery to west Texas oil fields will probably be on the order of 1.15 Bcfd.

Other carbon dioxide accumulations in Utah and Wyoming may eventually be developed, if demand is strong enough, and may significantly add to the indicated reserves in the Rockies.

OGIP carbon dioxide in the Jackson Dome area of Mississippi is estimated to be 3.4 Tcf to 7.0 Tcf. Ultimate recovery will probably range from 2.0 Tcf to 4.2 Tcf. Maximum transport of gas available for oil fields in Southern Mississippi and Louisiana is expected to be on the order of 150 - 200 MMcfd.

DEFINITION OF SYMBOLS

AFIT	=	after Federal income tax
Bcf	=	billion cubic feet
CAOF	=	calculated absolute open flow
DCF-ROR	=	discounted cash flow rate of return
E_R	=	recovery efficiency (fraction of OGIP)
Mcf	=	thousand cubic feet
MMcf	=	million cubic feet
OGIP	=	original gas in place
Tcf	=	trillion cubic feet
ϕ	=	porosity

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7. Campbell, J.A.: "Carbon Dioxide Resources of Utah", Report of Investigation No. 125, Utah Geological and Mineral Survey, Salt Lake City, Utah, (1978).

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TABLE 1

AREAS REPORTED TO HAVE SIGNIFICANT CO_2 DEPOSITS

State	Field/ Location	Gas Composition Mole Percent	Productive Stratigraphic Units	Expected* Sustained Deliverability MMcfd	Expected Range of Shut In Wellhead Pressures PSIG	Expected Range of Initial Flowing Wellhead Pressures PSIG	Expected Well Depths Feet
COLORADO (Southwest)	McElmo Dome Area, Dove Creek; Montezuma and Dolores Co's.	>96% CO_2 Balance N_2	Leadville, Elbert	3-12	2200-2800	600-850	6000-8000
COLORADO (South Central)	Sheep Mountain Area; Huerfano Co.	96-99% CO_2 Balance N_2, CH_4	Dakota, Entrada	3-12	700-1100	200-700	3400-7000
MISSISSIPPI (Central)	Jackson Dome Area Rankin & Madison Cos.	70-99% CO_2 Many Wells >98% CO_2 May Contain From Trace to 10% H_2S	Smackover, Norphlet	4-16	4000-6500	2000-4000	12000-17000
NEW MEXICO (Northeast)	Harding, Union, Mora, Colfax Cos.	92-99.7% CO_2 Balance N_2	Triassic-Santa Rosa Permian-Glorieta, Tubb	.1-2	250-700	50-500	1500-2800
UTAH (Central)	Gordon Creek Area; Carbon Co.	91-99% CO_2 Balance N_2, CH_4	Sinbad, Coconino	NA	3900-4200	NA	11000-12000
UTAH (Southwest)	Farnham Dome Area; Carbon Co.	98% CO_2	Navajo, Sinbad, Kaibab	NA	1000-1500	NA	2800-5000
WEST VIRGINIA (South Central)	Fayette & Kanawha Cos.	20-80% CO_2 Balance N_2, CH_4	Tuscarora	.1-2	1800-2900	NA	6000-9000
WYOMING (Southwest)	Church Buttes Area; Uinta & Sweetwater Cos.	83-86% CO_2 2% H_2S Balance N_2, CH_4	Madison	2-6	NA	Low	18000-19000

*Highly speculative; requires sustained production history for confirmation.

TABLE 2

INVESTMENT - JACKSON DOME AREA, MISSISSIPPI

FLOW RATE MMcfd	COMPRESSION B.H.P. REQUIRED	COMPRESSION INVESTMENT IN $ *	DEHYDRATION COST IN $	WELL COST IN $	DRY HOLE COST (PRO RATA) IN $ **	GATHERING SYSTEM COST IN $ ***	TOTAL $ I
4	516	279,100	32,000	2,500,000	360,000	250,000	3,171,100
8	1,032	558,100	64,000	2,500,000	360,000	250,000	3,482,100
16	2,064	1,116,200	128,000	2,500,000	360,000	250,000	4,104,200

* Based on $540.8/BHP.

** Pro rata dry hole cost assigned on intangible investment for 20 dry wells per 80 producing wells.

*** Gathering system based on 1 mile of 4" S.S. quality pipe. Also includes $65,000/well for hydrate control.

I Total excludes $64,000/640 acres lease fee.

TABLE 3

OPERATING COSTS - JACKSON DOME AREA, MISSISSIPPI

$/well/month = 300

¢/Mcf for compression from 565 psi - 2000 psi when required = 7.7

¢/Mcf for dehydration = .53

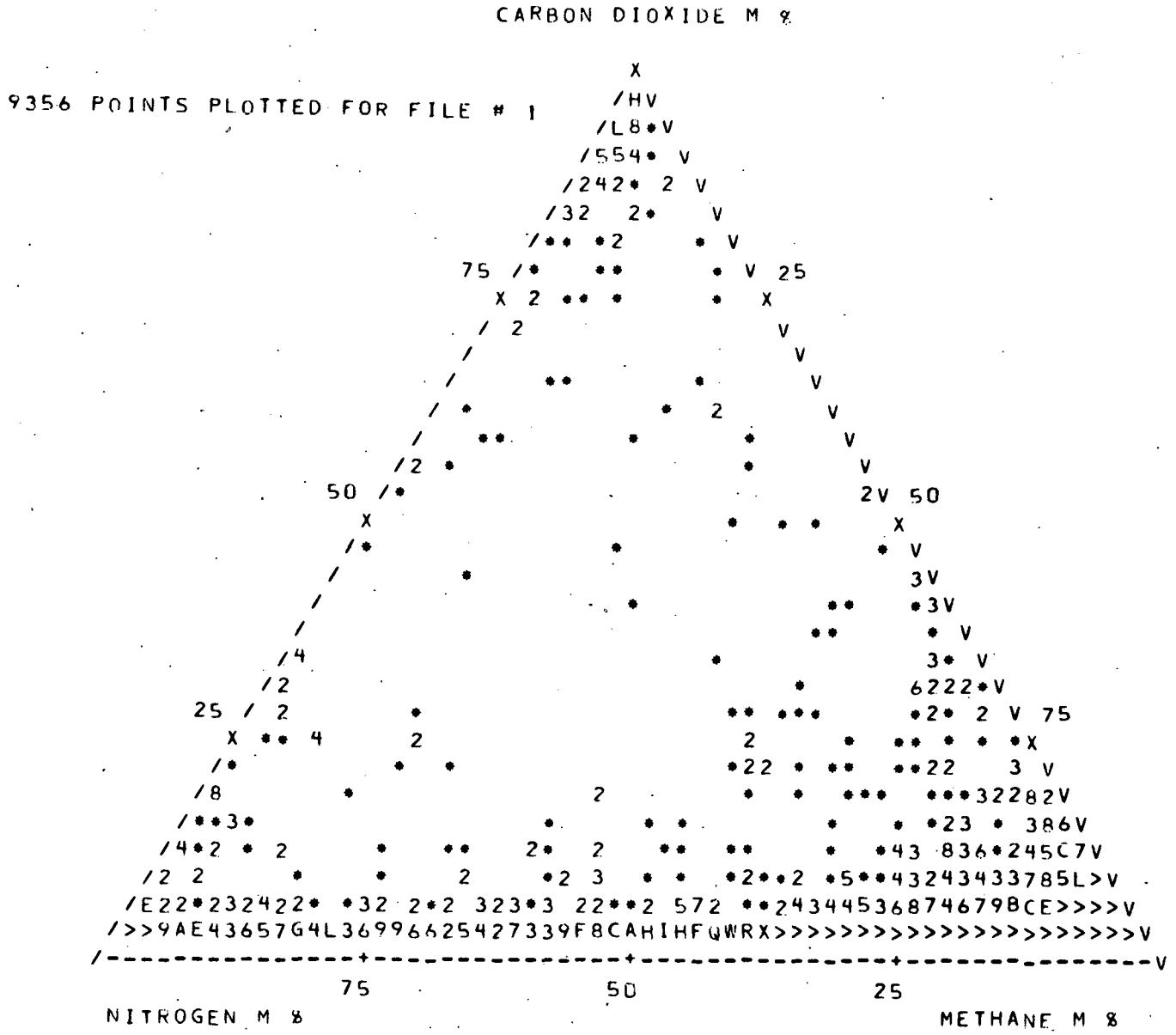
¢/Mcf for hydrate control = .4

TOTAL COST $/UNIT = .0863/Mcf

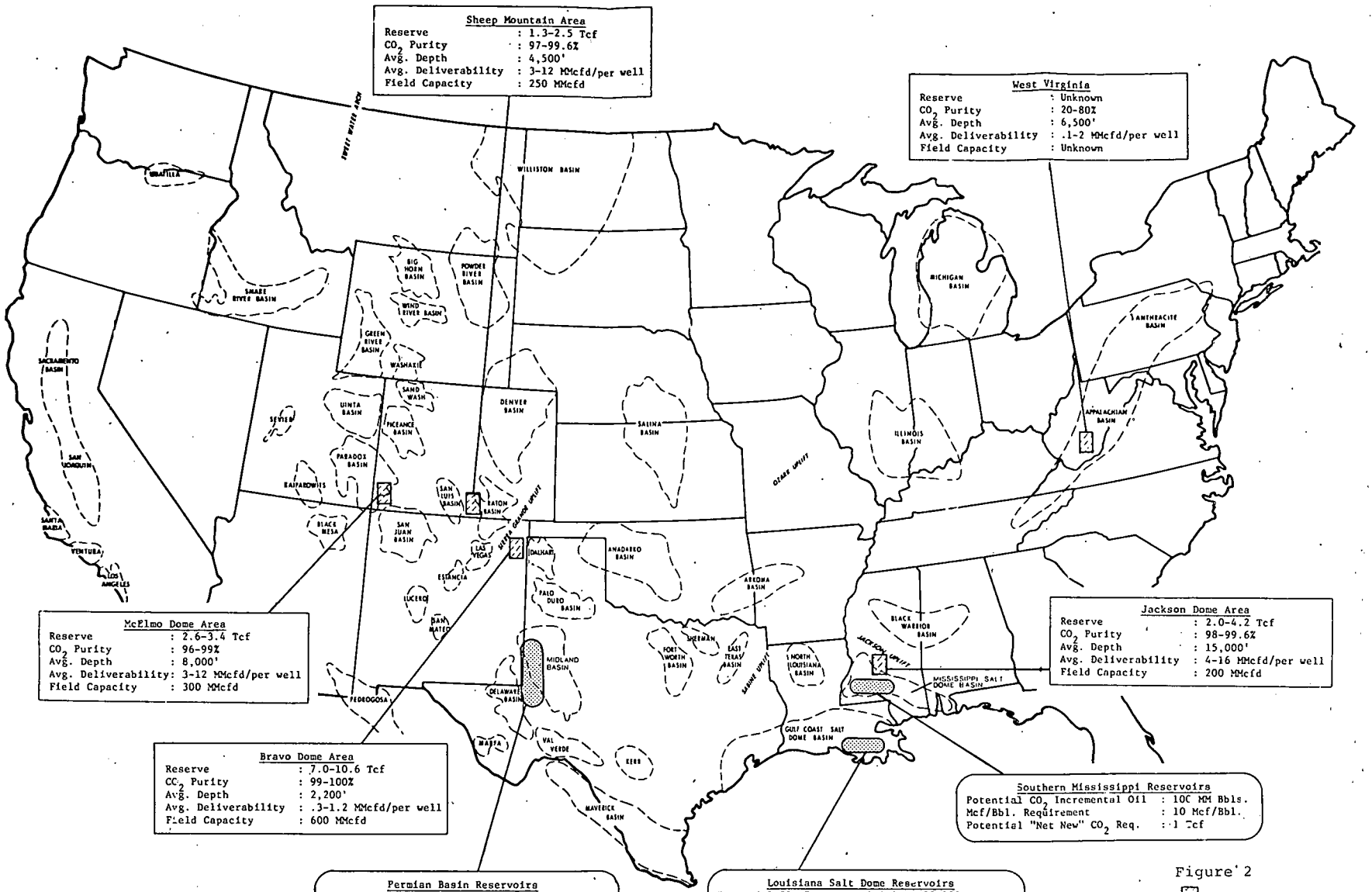
Figure 1

CARBON DIOXIDE-NITROGEN-METHANE RELATIONSHIP

Figure 1 is a ternary diagram summing up the indicated carbon dioxide, nitrogen and methane relationships. As expected, the greatest number of samples by far have a high methane content; however, a number of samples contain significant amounts of nitrogen or high carbon dioxide mole percentages. The strong nitrogen-methane correlation as discussed with Figure 1.5.3 is seen along the N_2-CH_4 axis. The tendency for high carbon dioxide containing samples to also contain nitrogen as noted in Figure 1.5.4 is shown, as well as the virtual absence of samples containing comparable amounts of carbon dioxide, nitrogen and methane.



MAJOR CO_2 PRODUCTIVE AREAS AND OIL RESERVOIRS AMENABLE TO CO_2 FLOODING



Sheep Mountain Area

Reserve	: 1.3-2.5 Tcf
CO_2 Purity	: 97-99.6%
Avg. Depth	: 4,500'
Avg. Deliverability	: 3-12 MMcfd/per well
Field Capacity	: 250 MMcfd

West Virginia

Reserve	: Unknown
CO_2 Purity	: 20-80%
Avg. Depth	: 6,500'
Avg. Deliverability	: .1-2 MMcfd/per well
Field Capacity	: Unknown

McElmo Dome Area

Reserve	: 2.6-3.4 Tcf
CO_2 Purity	: 96-99%
Avg. Depth	: 8,000'
Avg. Deliverability	: 3-12 MMcfd/per well
Field Capacity	: 300 MMcfd

Jackson Dome Area

Reserve	: 2.0-4.2 Tcf
CO_2 Purity	: 98-99.6%
Avg. Depth	: 15,000'
Avg. Deliverability	: 4-16 MMcfd/per well
Field Capacity	: 200 MMcfd

Bravo Dome Area

Reserve	: 7.0-10.6 Tcf
CO_2 Purity	: 99-100%
Avg. Depth	: 2,200'
Avg. Deliverability	: .3-1.2 MMcfd/per well
Field Capacity	: 600 MMcfd

Southern Mississippi Reservoirs

Potential CO_2 Incremental Oil	: 100 MM Bbls.
Mcf/Bbl. Requirement	: 10 Mcf/Bbl.
Potential "Net New" CO_2 Req.	: 1 Tcf

Permian Basin Reservoirs

Potential CO_2 Incremental Oil	: 2-8 B. Bbls.
Mcf/Bbl. Requirement	: 4-17 Mcf/Bbl.
Potential "Net New" CO_2 Req.	: 8-9C Tcf

Louisiana Salt Dome Reservoirs

Potential CO_2 Incremental Oil	: 50-300 MM Bbls.
Mcf/Bbl. Requirement	: 6 Mcf/Bbl.
Potential "Net New" CO_2 Req.	: .3-1.8 Tcf

Figure 2

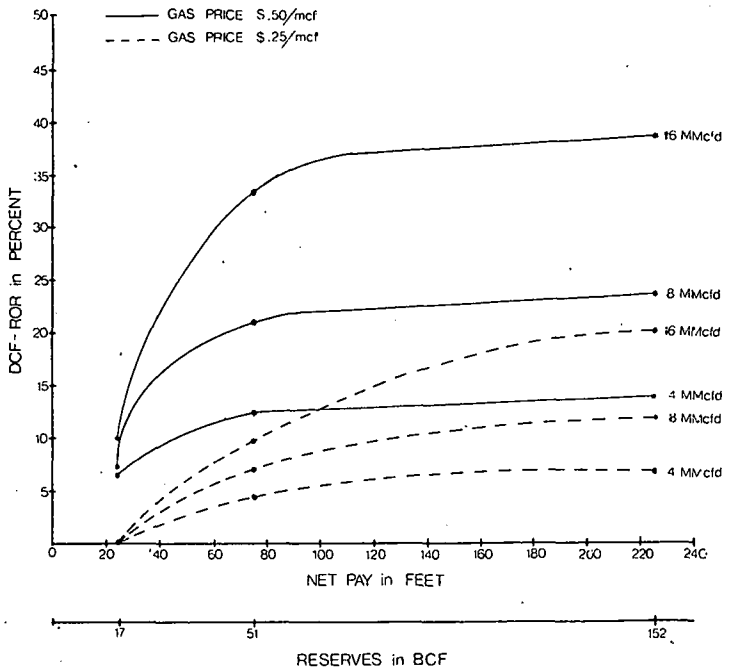
CO_2 PRODUCTIVE AREAS

OIL RESERVOIRS AMENABLE TO CO_2 FLOODING

O-1/13

Figure 3

AFIT DCF-ROR vs. PER WELL RESERVE FOR VARYING FLOW RATES AND GAS PRICE
JACKSON DOME AREA, MISSISSIPPI



8.1 Southwestern Colorado - McElmo Dome Area

8.1.1 Geologic Introduction

Exploration for CO_2 reservoirs in southwestern Colorado has focused on the McElmo Dome area in Montezuma County and the Doe Canyon-Dove Creek area of Dolores County. The two CO_2 productive zones in this portion of the Paradox Basin are the Leadville (Mississippian) and the Ouray (Devonian), found at depths of 6500-9000 feet subsurface. Both formations are composed of limestones and dolomites, with the Leadville indicating greater productivity.

Analysis of produced gas from both formations indicates a composition of 96-99 percent CO_2 with 1-4 percent nitrogen.

Exploratory wells, identified on Figure 6* appear to have delineated a productive area in the southern portion of the structure. Wells identified as 18, 22, 25, C, D, E, and F reportedly were completed as potential producers. Data is unavailable regarding CO_2 productivity in well numbers 16 and 27. Wells 17, 23, 24, 26 and 29 were reportedly plugged as dry holes. Productive area at the southern end of the structure is estimated to be roughly 100 sections, or 64,000 acres.

Although at least one productive well, identified as well A on Figure 6, has been completed in the northern Dove Creek portion of the structure, control is insufficient for accurate reservoir delineation in the northern area. Of the

*Location maps referred to in this and subsequent sections were adopted from maps provided by McNeill in his report, "A Study of the Natural Carbon Dioxide Occurrences in a Four-Region Area of the United States". Stippled areas on these maps are referred to by McNeill as follows, "... Areas of interest were outlined on the basis of lease ownership, unit outlines or anticipated reservoir configuration ...".

SOURCES AND DELIVERY OF CARBON DIOXIDE

FOR

ENHANCED OIL RECOVERY

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ABSTRACT

This paper presents results from a comprehensive study by Pullman Kellogg, with assistance from Gulf Universities Research Consortium (GURC) and National Cryo-Chemics Incorporated (NCI), of the carbon dioxide supply situation for miscible flooding operations to enhance oil recovery.

General observations from a survey of carbon dioxide sources within the geographic areas of potential EOR are presented.

The costs, such as purchase, production, processing, and transportation, associated with delivering the carbon dioxide from it source to its destination are discussed.

Specific cases to illustrate the use of the maps and cost charts generated in the study have been examined.

Prepared for DOE under Contract EX-76-01-2515

SOURCES AND DELIVERY OF CARBON DIOXIDE FOR ENHANCED OIL RECOVERY

Introduction:

The surge in the U.S. oil import coupled with increasing oil prices has created increased interest in enhanced oil recovery (EOR) techniques as means to obtain greater domestic oil production. Miscible flooding methods using carbon dioxide (CO_2) as a material capable of recovering additional quantities of oil from depleted, watered-out reservoirs has been investigated by laboratory tests and field tests. Preliminary estimates indicate that 5-10 billion barrels of oil could be produced from enhanced oil recovery by CO_2 flooding. This might require upwards of 40-50 trillion standard cubic feet of CO_2.

Future plans for EOR by CO_2 flooding will depend on the availability and the cost of CO_2. Pullman Kellogg recently completed a comprehensive evaluation of the supply and cost of CO_2 for EOR. The study was conducted for the United States Department of Energy under the Contract EX-76-C-01-2515, with the assistance from Gulf Universities Research Consortium (GURC) and the National Cryo-Chemics, Inc. (NCI). This paper presents the highlights of our final report[1] for the study. The objectives of the study were threefold and included:

1. Mapping of all significant sources of carbon dioxide on regional maps in a quantitative manner so that through the use of maps and legends a description of the sources in terms of quantity and quality might be available.
2. Evaluation of all the costs associated with delivering the carbon dioxide from its source to its destination. These include purchase, production, processing, and transportation costs.
3. Examination of specific cases to show examples of the use of the maps and cost charts generated.

Carbon dioxide sources and availability

The sources of CO_2, shown on four regional maps in Figures 1 through 4, consisted of natural deposits, industrial sources such as process and cement plants, natural gas treating plants, SNG plants, refineries and power plants. Each source is characterized as to type, and expected capacity. Table 1 summarizes available CO_2 from various sources in the four regions. Table 2 shows a summary of natural CO_2 surveyed. A description of each source is presented in the tabular form in the final report[1].

Comparison of supply and demand indicates that the potential peak CO_2 demand of 7-11 BSCFD (billion standard cubic feet per day) could be met from the total supply of 28.4 BSCFD; however, the source

of CO_2 is not always convenient to the candidate oil fields. GURC has estimated that 2 to 8 billion barrels of oil might be recovered from West Texas by CO_2 flooding, with a median estimate of 5 billion barrels. Assuming an average requirement of 10 MSCF/BBL, upwards of 50 trillion standard cubic feet (TSCF) could ultimately be required with a peak delivery rate of 6.3 BSCFD. A potential CO_2 shortage in the West Texas fields does exist as the potential demand of 6.3 BSCFD could have to be supplied from an estimated maximum availability of 6.0 BSCFD. The largest sources considered are carbon dioxide natural deposits in Colorado and New Mexico. Natural CO_2 reserves are expected to range from 20-28 TSCF with 12-18 TSCF possibly available for the West Texas oil fields.

Total demand of CO_2 for Mississippi and Louisiana could be on the order of 2.8 TSCF. From Table 1, based on current information, it is estimated that 3 TSCF of natural CO_2 could be available, all from the Mississippi Jackson Dome area. After satisfying local Mississippi demand there should be around 2 TSCF CO_2 available for transport (via pipeline) from Mississippi to South Louisiana. The potential South Louisiana demand of 1.8 TSCF can be met also from high purity CO_2 from ammonia and hydrogen plant vents. At current operating levels there is approximately 390 MMSCFD of available CO_2 with 98+% purity.

Cost of purchasing

The price that an oil reservoir operator may pay to the owner of the CO_2 source is influenced by CO_2 purity, demand of CO_2 for EOR and location to some degree. High purity CO_2 sources, such as, ammonia plant vents and SNG plants command higher prices for CO_2 than low purity sources like flue gas stacks from power plants and cement plants. Low purity sources will require significant clean-up before CO_2 from such sources can be used for EOR by miscible flooding. Wellhead prices for natural carbon dioxide will depend on purity, pressure of the source and on location of the source. The present cost of purchasing carbon dioxide from the sources studied varies from a low of \$1-2/Ton for sources such as power plant stacks to a high of \$15-20/Ton F.O.B. plant for a liquid CO_2 plant. These costs are summarized in the Table 3.

Cost of natural CO_2 production

Natural sources of CO_2 have perhaps the greatest potential as a future source of CO_2 for EOR projects. GURC made a geologic and economic analysis for estimating costs to drill and produce CO_2 from the natural sources. GURC's report [2] is summarized in a separate paper.

Cost of processing

Impure sources of CO_2 will require processing to upgrade the quality of CO_2 for EOR use. The aboveground sources of impure CO_2 include the flue gases of power plants and cement plants plus some off gas from natural gas processing plants. Naturally occurring deposits of CO_2 can also have sufficiently high concentrations of impurities to require purification. Examples of naturally occurring deposits that require processing are some of the deposits found in Mississippi, West Virginia and Wyoming. Impurities found in the sources include hydrogen sulfide (H_2S), methane (CH_4), sulfur dioxide (SO_2), and sulfur trioxide (SO_3). The impure CO_2 sources have large variations in gas compositions and initial conditions. The concentrations of the impurities in the various sources range from zero to 90+%. As well, the sources are available for purifying at pressures ranging from atmospheric to 1000+ psig.

CO_2 from Power Plant Stack Gas Costs

The purification costs and the investment costs for recovering CO_2 from power plant stacks are developed for CO_2 recovery rates from 50 to 500 MMSCFD using a chemically reactive system (MEA). The purification cost by the MEA system is compared with the purification cost by a physical solvent process (Selexol - Allied Chemical Process) at the recovery rate of 125 MMSCFD.

In the chemical reactive process, monoethanolamine (MEA) in dilute aqueous solution reacts reversibly with acidic constitutents such as CO_2 and H_2S in a sour gas stream. In the absorber these reactions form soluble carbonate and sulfide salts which decompose thermally in the stripper to release the acid gases. The physical solvent is primarily an organic compound containing minimal quantity of water and other ingredients. Absorption of the acid gases depends on their solubilities in the solvent. Therefore, the physical solvent system is particularly well suited for processing streams with high partial pressures of acid gases. Since there is no chemical reaction in the physical solvent system, the solvent can be regenerated by simply flashing the absorbed acid gas from the solvent at reduced pressure.

The economic analysis is based on 4th quarter, 1978 investment cost, 20-year project life, 20-year straight line depreciation, 100% equity capital and using discounted cash flow rate of return procedure (DCFRR). Figures 5 and 6 show that the recovery costs for 125 MMSCFD of CO_2 from flue gas vary from \$0.60/MSCF to \$1.00/MSCF for a MEA unit and from \$2.00/MSCF to \$3.00/MSCF for a Selexol unit using a 10%-25% DCFRR range. The purification cost includes the compression cost of recovered CO_2 (pressure of recovered CO_2 is 2000 psig). Figure 5 shows that the purification cost by MEA increases rapidly at CO_2 recovery rates below 100 MMSCFD. One reason for the higher purification cost in the Selexol unit is the necessity to raise the partial pressure of the CO_2 to enable absorption to occur. The additional capital and utility costs associated with the compression of flue gas make the Selexol unit economically undesirable for recovery of CO_2 from power plant stack gas.

CO_2 From Naturally Occurring Sources Costs

Naturally occurring sources of CO_2 are available at a variety of pressures and CO_2 concentrations. Thus the study examined cases with CO_2 concentrations from 10% to 90% with the pressure range of 250 to 1000 psig at various CO_2 production rates. The Selexol process is used for the purification of these sources. As well, a case of 10% CO_2 at 1000 psig using the MEA process is studied to compare it with the Selexol process. Natural sources containing 2% H_2S are also examined, using Selexol process, for cases of 50% CO_2 (48% CH_4) and 90% CO_2 (8% CH_4) at source pressures of 250 and 1000 psig and at various CO_2 production rates.

All cases of natural sources studied have 98% purity methane (CH_4) as an additional product. To provide only the CO_2 purification cost, credit is not take for the CH_4 produced. However, the CH_4 consumed as fuel for the gas turbines is considered as an expense. The economic analysis, using discounted cash flow rate of return procedure, indicates that the purification costs of CO_2 and H_2S-free natural sources varies from \$0.22-1.85/MSCF, depending on the feed gas pressure, CO_2 concentration in the feed, CO_2 recovery rate and the rate of return. Figure 7 shows the effects of the feed gas quality and pressure on the purification costs for CO_2 production rate of 125 MMSCFD at 20% DCFRR.

Comparison of purification costs, by MEA process and Selexol process, of natural sources with low CO_2 concentrations (10%, 1000 psig pressure) indicates that the investment cost for a MEA unit is significantly lower than that for a Selexol unit but the MEA unit has higher operating costs. The resulting gas purification costs for the MEA unit are slightly less than those for the Selexol unit.

Natural sources containing H_2S require the extra expense for the removal and disposal of H_2S from both the product CO_2 and CH_4 streams. The extra expense due to presence of H_2S translates to CO_2 purification costs 2-3 times those of similar sources without H_2S. If credit were given for the byproduct sulfur produced, the CO_2 purification costs would decrease slightly, but would still remain higher than these for sources without H_2S.

Cost of transportation

The study evaluated the costs of transporting carbon dioxide from the source area to the oil recovery site. Final delivery pressure is assumed to be 2000 psig. The three pipeline systems considered are:

1. The supercritical pipeline system (operating pressure greater than the critical pressure of CO_2, i.e. 1071 psia).
2. The subcritical pipeline system (operating pressure less than 1000 psig).
3. The liquid pipeline system.

In the supercritical pipeline system, a base compressor, located either at the natural CO_2 well site or at the production plant site, injects the CO_2 into the pipeline at 2000 psig. Intermediate pipeline booster compressors are required to maintain pressure in the range of 1400 to 2000 psig throughout the pipeline. The injection compressor, located at the oil recovery site, compresses CO_2 to 2000 psig at the end of the pipeline.

In the subcritical system, a base compressor located either at the natural CO_2 well site or at the CO_2 production site, injects the CO_2 into the pipeline at 700 psig. The intermediate pipeline booster compressors maintain a 400-700 psig pressure range throughout the pipeline. The injection compressor, located at the oil recovery site, compresses CO_2 to 2000 psig at the end of the pipeline.

The liquid pipeline system consists of liquefaction plant to produce liquid CO_2, a base pump to pump liquid CO_2 into the insulated pipeline and the injection pump to boost the liquid CO_2 pressure to 2000 psig at the oil recovery site.

The pipelines with capacities from 50 MMSCFD to 500 MMSCFD and with transmission lengths from 50 miles to 500 miles are examined. In order to select the best pipeline system, CO_2 transportation costs, based on various rates of return using discounted cash flow and utility financing methods are analyzed. Table 4 shows the results for the three pipeline systems considered, using flat terrain as the basis. Based on the results in Table 4, the obvious conclusion is that the supercritical pipeline system is the most economical mode of CO_2 transportation.

The graphs are developed to estimate CO_2 transportation costs for supercritical pipeline system, regardless of terrain and geographic effect. Estimated terrain adjustment factors are added directly to the base costs which, in turn, re-estimates the total fixed capital investment costs used in determining the CO_2 transportation costs. Graphs are presented in the report (1) for terrain adjustment factors such as: rugged terrain, rolling hill terrain, river crossing, and differential elevation between the CO_2 source and the oil recovery site.

CO_2 transportation costs incurred via the supercritical pipeline system vary considerably depending on flow rate, transmission length and return on investment. To illustrate, at a flow rate of 125 MMSCFD CO_2 and a rate-of-return on investment of 15%, the CO_2 transportation costs are \$.09/MSCF CO_2 and \$.84/MSCF CO_2 for a 50 mile and 500 mile supercritical pipeline system, respectively. In addition, at a flow rate of 250 MMSCFD CO_2 and a rate-of-return on investment of 15%, the CO_2 transportation costs are \$.07/MSCF CO_2 and a \$.59/MSCF CO_2 for a 50 mile and 500 mile supercritical pipeline system, respectively. Therefore, the results dictate the difficulty in predicting generalized CO_2 transportation costs. However, the preceding results demonstrate that the greater the CO_2 pipeline capacity and the shorter the pipeline transmission length, then the less expense involved in transporting CO_2, as expected.

Specific cases

The study evaluated three specific (typical) cases primarily to demonstrate the use of the information developed in the preceding discussions in evaluating the total cost of CO_2 for EOR. The total cost developed for the cases examined is for general guidance. The sources considered for these illustrations include natural sources, a power plant stack gas source and ammonia plant vent sources. Three cases selected are:

1. CO_2 supply to West Texas oil reservoir
2. CO_2 supply to South Mississippi oil reservoir
3. CO_2 supply to South Louisiana oil reservoir

CO_2 supply to West Texas Oil Reservoir

Oil fields in West Texas have a great potential for EOR by CO_2 miscible flooding. There is substantial industry interest for EOR in this area. GURC estimates that there is 2 to 8 billion BBL of oil that is recoverable by CO_2 flooding in West Texas. The following three CO_2 sources are considered to supply CO_2 for West Texas fields:

A. CO_2 from natural deposits in Southwest Colorado
B. CO_2 from natural deposits in Northeast New Mexico
C. CO_2 from power plant flue gas, Mitchell County, West Texas.

The associated costs, such as, purchase costs, production costs, purification costs, transportation costs are derived from the graphs and equations presented in our final report.[1] The results are tabulated below:

Basis

	Natural CO_2 from S.W. Colorado	Natural CO_2 from N.E. New Mexico	CO_2 from Power Plant
Net CO_2 Requirement MMSCFD	300	500	112
Total pipeline length, miles	500	320	105
Pipeline length in rugged terrain, miles	328	-	-
Pipeline length in rolling hill terrain, miles	165	316	75
Pipeline length in flat terrain, miles	-	-	30
River Crossings, miles	7	4	-
Elevation difference between source and the oil field, feet	3500	1750	Not appreciable

Cost of CO_2 for West Texas Oil Fields

	Natural CO_2 from S.W. Colorado $/MSCF	Natural CO_2 from N.E. New Mexico $/MSCF	CO_2 from power plant in Mitchell County, W. Tex $/MSCF
Purchase	-	-	0.09
Production	0.38	0.50	-
Purification	-	-	0.88
Compression	-	0.33	-
Transportation	0.68	0.24	0.11
Total $/MSCF	1.06	1.07	1.08

CO_2 Supply to South Mississippi Oil Reservoir

GURC estimates that in Southern Mississippi there could be 100 million barrels of oil potentially recoverable by CO_2 flooding. For this specific case, it is assumed that a source with CO_2 concentration of about 90% and with hydrogen sulfide concentration of 2% will be used. The basis for the total cost and the associated costs to deliver CO_2 to the EOR site for this case is summarized below:

Basis

Net CO_2 requirement: 117 MMSCFD
Total pipeline length: 80 miles
Pipeline in rolling hill terrain: 60 miles
Pipeline in flat terrain: 19 miles
River Crossings: 1 mile
Elevation difference between source and the oil field: Not appreciable

Costs	$/MSCF
Purchase	0.50
Compression	0.97
Transportation	0.10
Total	1.57

CO_2 Supply to South Louisiana Oil Reservoir

In Southern Louisiana, there could be 300 million barrels of oil that is potentially recoverable by CO_2 flooding. The most viable source of CO_2 for these fields in Southern Louisiana is high purity CO_2 available as a by-product from ammonia plants, located about 50 miles from these field. These ammonia plants in Louisiana are located on a 70 mile stretch along the Mississippi river. The basis for the total cost and the associated costs to deliver CO_2 to the EOR site for this case is summarized below:

Basis

Net CO_2 requirement: 151 MMSCFD
Total length of pipeline: 120 miles
River Crossings: 40 miles (to compensate for marsh land)
Flat terrain: 80 miles
Elevation difference between CO_2 source and an oil field: Not appreciable

Costs	$/MSCF
Purchase	0.35
Compression	0.45
Transportation	0.20
Total	1.00

These specific cases indicate that for oil fields in West Texas, natural CO_2 sources in Southwest Colorado and Northeast New Mexico appear to be the economical choice because of low CO_2 cost and sufficient supply. Power plant stack gas sources in the vicinity of the oil fields could be used as supplementary sources to the natural sources, but a single power plant source probably can not supply sufficient CO_2 for a complete EOR project.

Total cost of natural CO_2 contaminated with H_2S is high because of the high purification cost. If oil fields in Southern Mississippi use high purity CO_2 from Madison County deposits, purification costs can be reduced substantially.

Although CO_2 from ammonia plant vents is of high purity, compression costs and purchase costs can be substantial. Specific cases studied in this section indicate that the cost difference between CO_2 from power plants and ammonia plants is marginal due primarily to the high purchase cost for CO_2 from ammonia plants. Were this purchase cost to drop somewhat then ammonia plant sources would enjoy a substantial economic advantage over power plant sources.

Conclusions and Recommendations

The data collected on carbon dioxide availability, we believe, is the most comprehensive survey taken to date. The survey includes virtually all known significant sources of CO_2. Each source is mapped and tabulated to facilitate the location of potential CO_2 supplies for a given prospective CO_2 EOR project. We feel that the range of CO_2 demand reported in our final study report[1] spans the more likely values. One of the more significant conclusions drawn from these projections is the potential for a shortage of CO_2 that might develop in the West Texas oil fields. At best it seems that there is an even match between CO_2 supplies and potential demand for the area.

GURC has made a geologic appraisal and economic analysis of naturally occurring CO_2 sources of the McElmo Dome and Sheep Mountain areas in Colorado, Northeast New Mexico area, and Jackson Dome area in Mississippi. The effect of the well flow rate and the well reserve size on the DCFRR at CO_2 prices of $0.25 and $0.50 per MSCF is presented graphically in their report[2].

We have investigated various carbon dioxide removal systems for each characteristic source. The two systems that merit the most consideration are a chemically reactive MEA system and physical solvent Selexol system. We have determined that the Selexol system is more economical for most natural CO_2 sources whereas an MEA system is more economical for low concentration industrial sources such as power plant stacks. For those natural sources containing H_2S, a two-stage Selexol system, with a Stretford sulfur removal plant has been considered.

The transportation systems evaluated are supercritical, subcritical and liquid pipelines. In all cases, we find the supercritical pipeline operating with the range of 1400-2000 psig to be the most economical. Graphs have been developed to determine the costs for transporting various quantities of CO_2 over the range of 50-500 MMSCFD and for distances spanning 50-500 miles inclusive of terrain and elevation effects. Final delivery pressure for the CO_2 is set at 2000 psig.

Surprisingly, CO_2 from certain low purity, low pressure power plant stacks could be competitive with higher purity, higher pressure sources because of the general proximity of some power plants to the candidate oil fields. In other words, the expense of purification and compression of power plant stack gas is almost equivalent to the transportation and purchase costs borne by distant high purity sources.

It is difficult to draw general conclusions about the merits of one source of CO_2 supply over another. Each CO_2 EOR candidate oil reservoir operator is faced with a unique combination of conditions which migh direct him to consider using a variety of CO_2 sources. We cannot state which CO_2 source is best in a given situation. The final cost for CO_2 to an operator is the sum of several terms, any of which can have a significant influence on the final total. We hope and feel, however, that sufficient information is contained within our report[1] to enable someone to make a reasonable determination of the final delivered cost of CO_2 from any given source.

We highly recommend that if serious consideration be given to any particular CO_2 source listed in our report[1] that the owner of that source be personally contacted before any preliminary work begins. Market conditions are constantly changing which could affect the availability of the source under consideration. Additionally, some sources might have characteristics which could make the CO_2 difficult to purify or collect. Some owners might not be willing to enter into such a sale arrangement. The incentives for doing a little preliminary investigation are numerous.

References

1. Hare, M., Perlich, H., Robinson, R., Shah, M., Zimmerman, F., "Sources and Delivery of Carbon Dioxide for Enhanced Oil Recovery" U.S. DOE Contract No. EX-76-C-01-2515, December 1978. Report No. FE-2515-24.

2. Gulf Universities Research Consortium Report No., 165: "Naturally Occurring Carbon Dioxide Sources in the United States - A Geological Appraisal and Economic Sensitivity Study of Drilling and Producing Carbon Dioxide for Use in Enhanced Oil Recovery", January 1979.

TABLE 1.

AGGREGATE SOURCES OF CARBON DIOXIDE SURVEYED IN THIS REPORT - MMSCFD

	TOTAL	POWER PLANT	CEMENT PLANT	PROCESS PLANT	NATURAL DEPOSITS
REGION I					
Wyoming	1748.0	1403.3	27.2	317.5*	3-6 MMSCFD/WELL
N. Utah	458.1	378.0	29.1	11.0	40
N. Colorado	999.6	952.2	25.7	3.3	18.4
	3205.7	2733.5	82.0	331.8	58.4
REGION II					
S. Utah	105.0	55.0	0	0	50
S. Colorado	1075.0	393.6	31.4	0	600
New Mexico	2988.9	1510.1	38.0	440.8 *	650
W. Texas	2234.8	1421.9	253.0	237.9	322
	6003.7	3380.6	322.4	678.7	1622
REGION III					
E. Texas	10541.6	9831.2	316.6	393.8	0
Louisiana	1966.5	1520.6	0	445.9	not significant
Mississippi	970.1	542.5	191.0	111.6	125
	13478.2	11894.3	507.6	951.3	125
REGION IV					
West Virginia	4380.2	3556.8	0	793.6	29.8
CALIFORNIA	1284.2	1226.2	n/a	58.0	0
Grand Totals	28351.8	22791.2	912.0	2813.4	1835.2

*Includes Proposed SNG Plant

TABLE 2.

SUMMARY OF NATURAL CO_2 RESERVES SURVEYED

	BSCF CO_2
Region I	
Wyoming	3900
N. Utah	1600
N. Colorado	100
TOTAL	5600
Region II	
S. Utah	1000
S. Colorado	3900-5900
New Mexico	7000-10600
W. Texas	600+
TOTAL	12500-18100
Region III	
E. Texas	None
Louisiana	-
Mississippi	2000-4200
TOTAL	2000-4200
Region IV	
West Virginia	330
Los Angeles Area	None

TABLE 3.

CURRENT ESTIMATE OF

COST OF PURCHASING CO_2

	COST	
ABOVE GROUND SOURCES	$/TON	CENTS/1000 SCF
PROCESS VENTS (PURE, LOW PRESSURE)*	4-8	25-50
COMBUSTION VENTS (LOW PURITY, LOW PRESSURE)	1-2	6-12
AS LIQUID F. O. B. PLANT	15-20	85-115
NATURAL SOURCES		
WELLHEAD PRICE**	4-6 (10)	25-35 (10)

*AMMONIA, SNG, HYDROGEN PLANTS - NATURAL GAS, LPG, NAPHTHA FEEDSTOCKS, PROCESSES BASED ON PARTIAL OXIDATION OF FEEDSTOCKS OR GASIFICATION OF COAL SHOULD COMMAND A LOWER PRICE DUE TO LOWER PURITY.

**COLORADO AREA

TABLE 4

CO_2 TRANSPORTATION COSTS BASED ON "DCFRR" AND "UTILITY FINANCE" METHODS

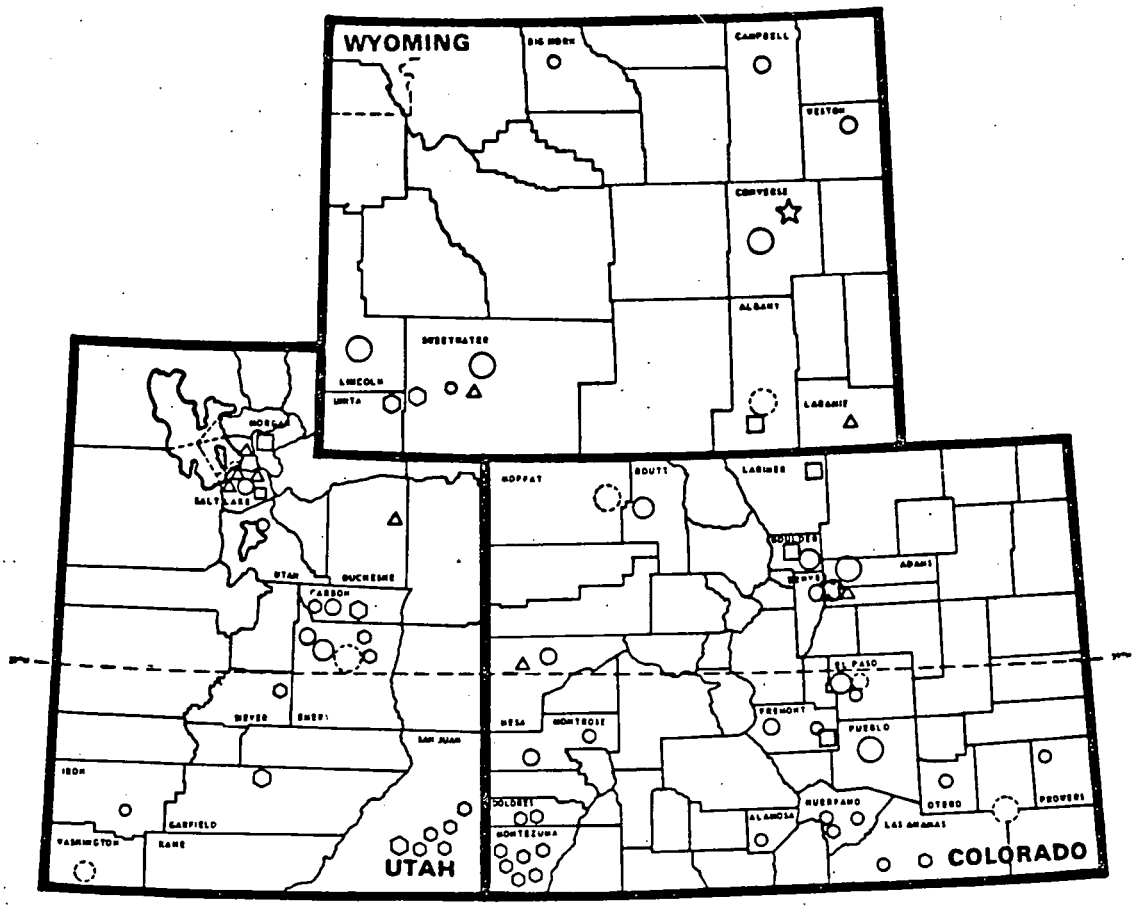
BASIS: Flat Terrain

	Pipeline Capacity (MMSCFD CO_2)	Pipeline Length (MILES)	Gas Cost Based On Discounted Cash Flow ($/MSCF CO_2) @10%	@15%	@20%	@25%	Gas Cost Based On Utility Financing ($/MSCF CO_2) @8%	@10%
Supercritical	50	50	0.12	0.17	0.22	0.27	0.13	0.14
		100	0.21	0.29	0.38	0.48	0.22	0.24
		300	0.61	0.83	1.09	1.38	0.61	0.69
		500	1.00	1.36	1.78	2.25	1.00	1.14
	125	50	0.07	0.09	0.12	0.15	0.07	0.08
		100	0.14	0.19	0.24	0.30	0.14	0.16
		300	0.39	0.52	0.67	0.83	0.39	0.44
		500	0.63	0.84	1.08	1.35	0.64	0.71
	250	50	0.05	0.07	0.09	0.11	0.05	0.06
		100	0.10	0.13	0.17	0.21	0.10	0.11
		300	0.25	0.35	0.45	0.57	0.26	0.29
		500	0.43	0.59	0.76	0.96	0.44	0.49
	500	50	0.04	0.05	0.07	0.08	0.04	0.05
		100	0.08	0.10	0.13	0.16	0.08	0.09
		300	0.24	0.31	0.39	0.48	0.24	0.27
		500	0.40	0.51	0.65	0.80	0.40	0.44
Subcritical	50	50	0.23	0.29	0.36	0.44	0.23	0.25
		100	0.41	0.52	0.66	0.81	0.41	0.45
		300	1.05	1.43	1.86	2.35	1.05	1.19
	125	50	0.16	0.20	0.24	0.29	0.16	0.17
		300	0.57	0.76	0.97	1.21	0.57	0.64
Liquid	50	100	0.92	1.15	1.42	1.72	0.93	1.01
		100	0.95	1.20	1.48	1.79	0.96	1.05
		100	1.01	1.27	1.58	1.92	1.01	1.11

REGION I

WYOMING, COLORADO, UTAH

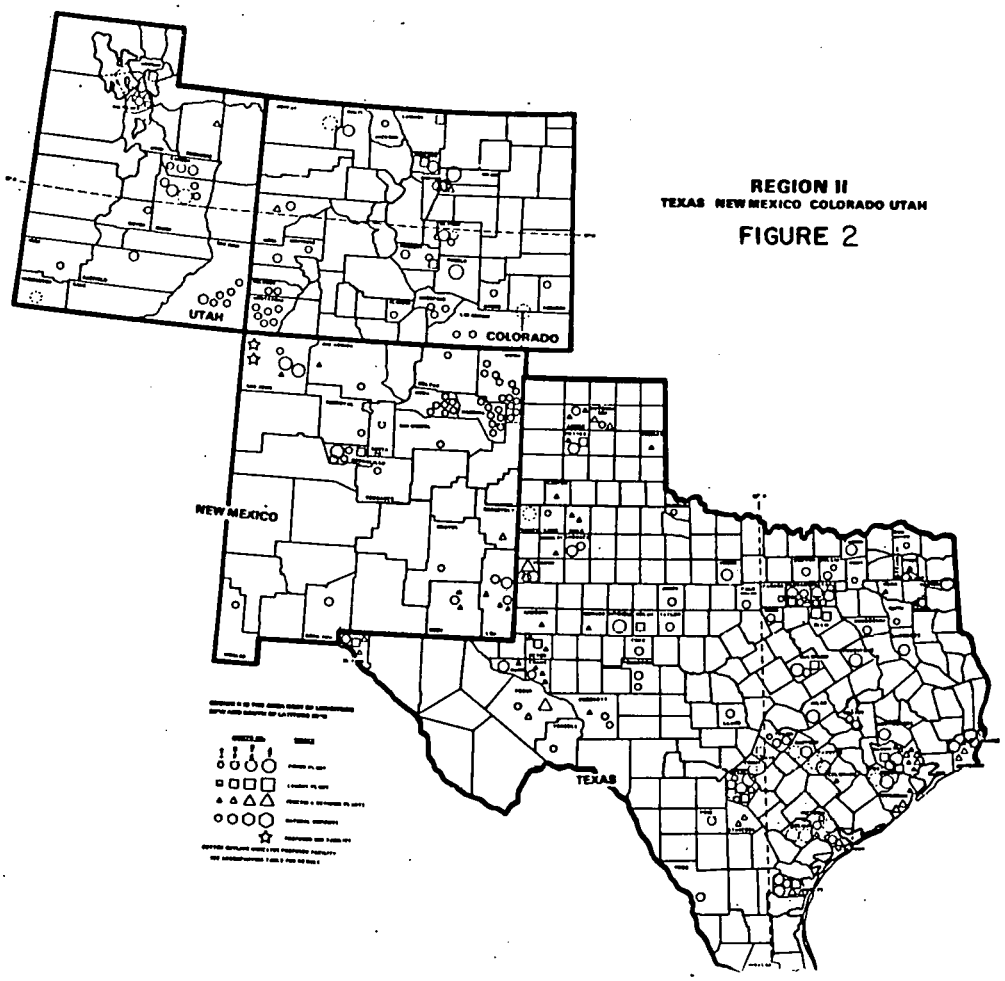
FIGURE I



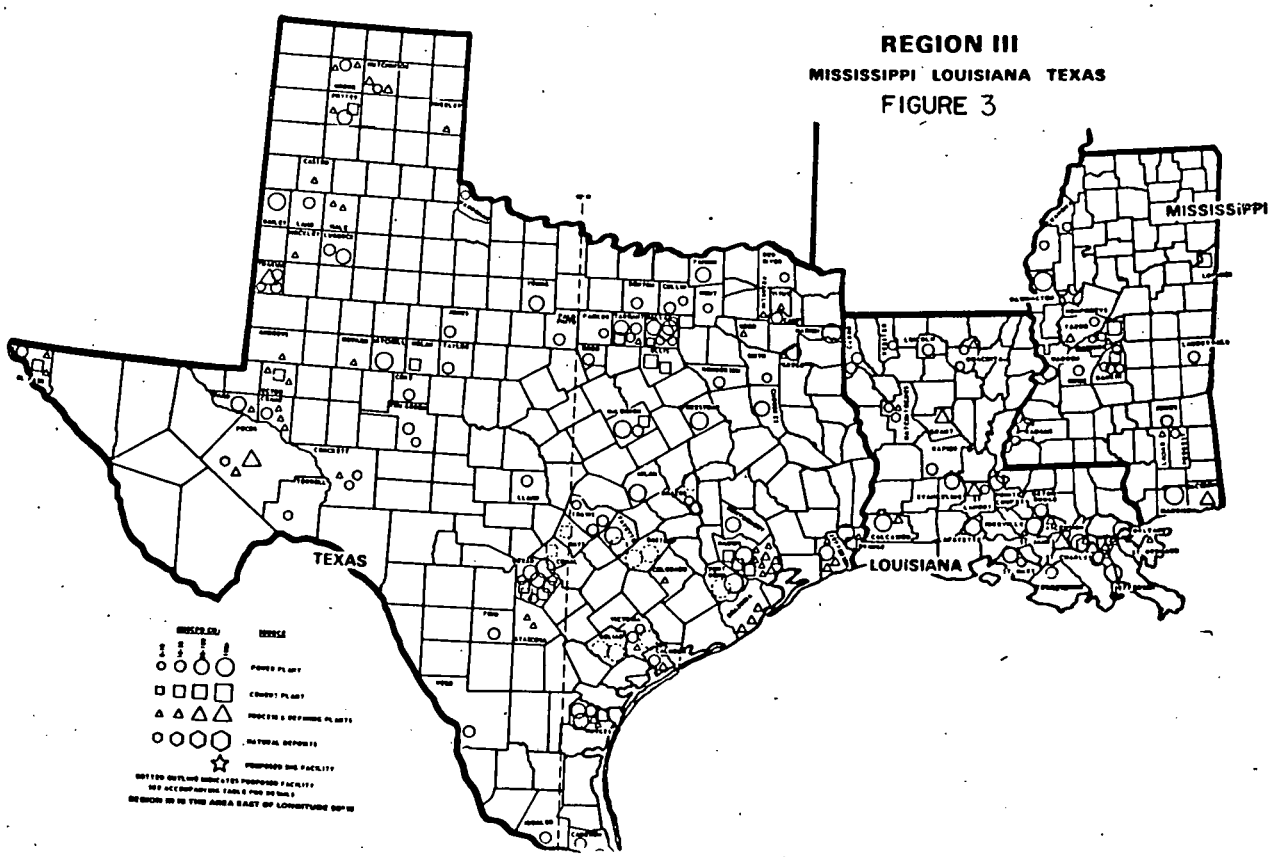
REGION I IS THE AREA NORTH OF LATITUDE 39° N

SYMBOL	SOURCE
○ ○ ○ ○	POWER PLANT
□ □ □ □	CEMENT PLANT
△ △ △ △	PROCESS & REFINING PLANTS
○ ○ ○ ○	NATURAL DEPOSITS
☆	PROPOSED SRC FACILITY

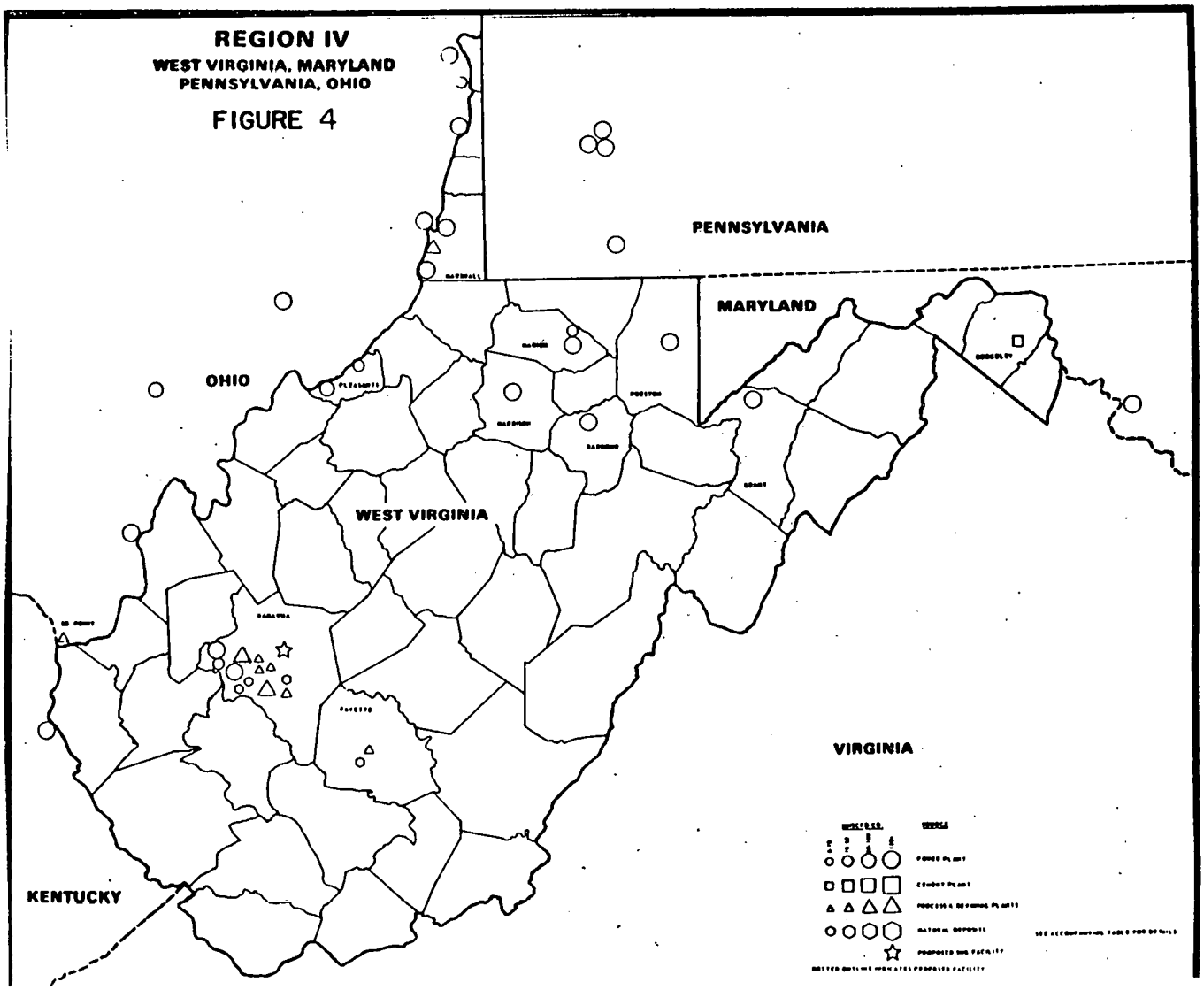
DOTTED OUTLINE INDICATES PROPOSED FACILITY
SEE ACCOMPANYING TABLE FOR DETAILS

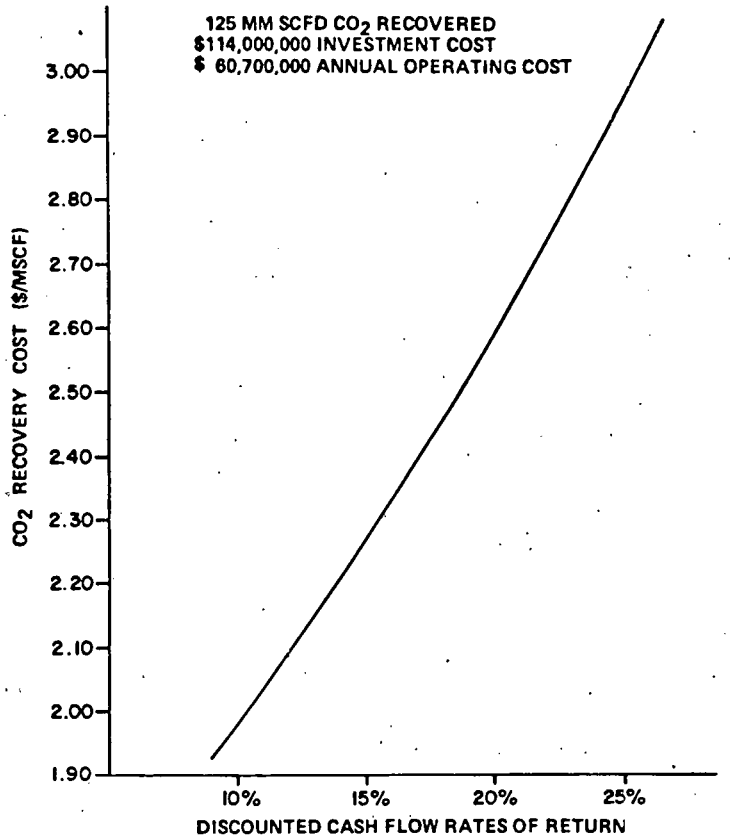


REGION II
TEXAS NEW MEXICO COLORADO UTAH
FIGURE 2



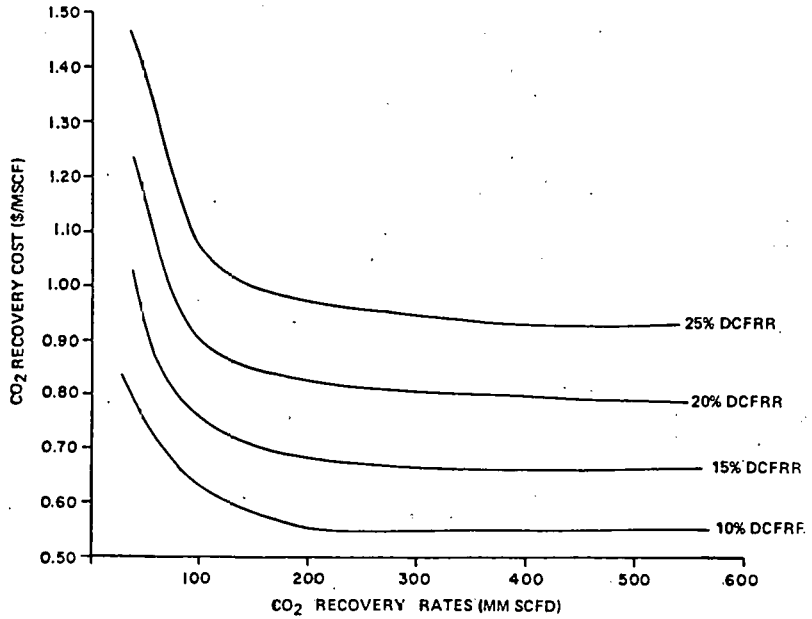
REGION III
MISSISSIPPI LOUISIANA TEXAS
FIGURE 3


REGION IV
WEST VIRGINIA, MARYLAND
PENNSYLVANIA, OHIO
FIGURE 4
PENNSYLVANIA
MARYLAND
OHIO
WEST VIRGINIA
VIRGINIA
KENTUCKY



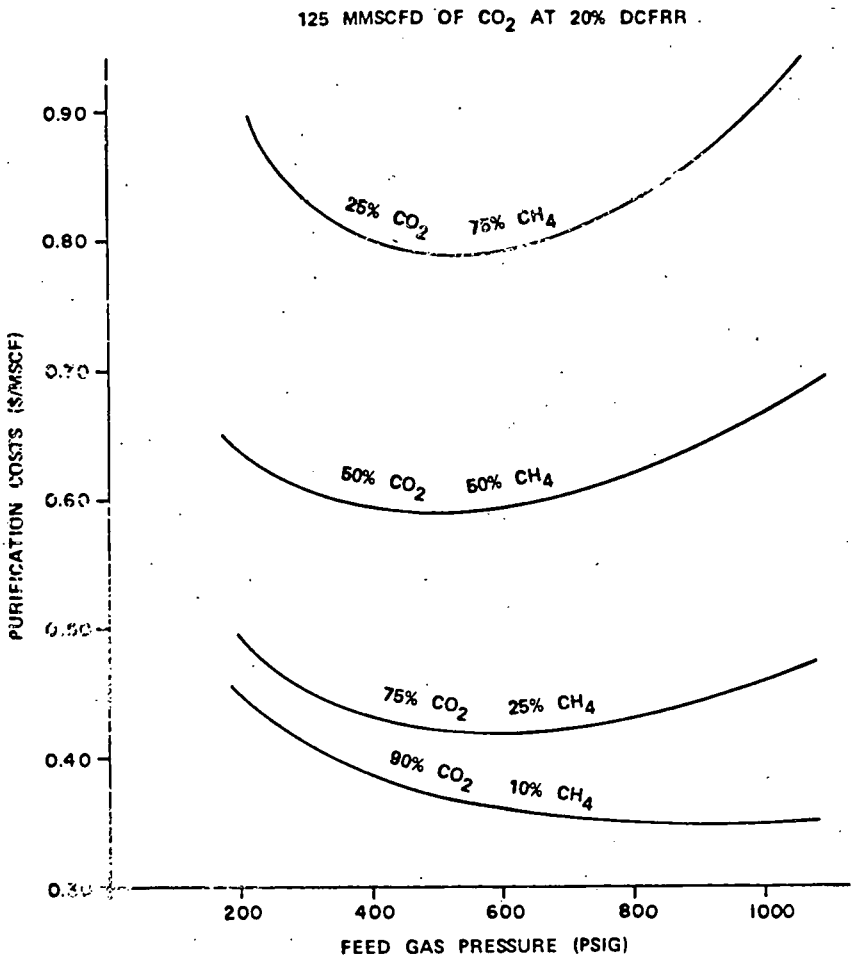
COST OF CO_2 RECOVERY FROM POWER PLANT FLUE GASES USING THE SELEXOL PROCESS VERSUS VARIOUS DISCOUNTED CASH FLOW RATES OF RETURN

FIGURE 6



COST OF CO_2 RECOVERY FROM POWER PLANT FLUE GASES USING THE MEA PROCESS FOR VARIOUS CO_2 RECOVERY RATES AND DISCOUNTED CASH FLOW RATES OF RETURN

FIGURE 5



PURIFICATION COSTS AT 20% DCFRR OF VARIOUS QUALITY FEED GASES AT A CO_2 PRODUCTION RATE OF 125MMSCFD VERSUS FEED GAS PRESSURE

FIGURE 7

ALTERNATIVE METHODS OF SUPPLYING CO_2 FOR ENHANCED OIL RECOVERY

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ABSTRACT

Previously conducted CO_2 supply studies have concentrated on identifying major sources of CO_2 in the United States and the transport of CO_2 from these sources to candidate EOR reservoirs. The emphasis in these studies was placed on collecting, processing and transporting CO_2 as a supercritical fluid.

Alternative methods of supplying CO_2 to enhanced oil projects are being studied by Science Applications, Inc. to identify means of reducing the delivery cost of CO_2. Discussions of the merits of transporting CO_2 as an ambient temperature, dense-phase fluid are presented.

This paper reviews the thermodynamic properties of CO_2, identifies energy conserving methods for achieving dense-phase fluid conditions for pipeline transport. The energy requirements and costs of pressurizing and transporting CO_2 as a more dense-phase fluid are compared to those associated with a higher temperature fluid.

The results indicate that substantial savings in investment and/or operating cost can be achieved if CO_2 is maintained at lower temperatures than those recommended in previous studies.

Prepared for DOE under Contract No. EW-78-C-21-8333

INTRODUCTION

This study was undertaken to explore alternative methods of supplying CO_2 from naturally occurring sources to enhanced oil recovery projects. In previously conducted studies (References 1-3), emphasis was placed on the transport of relatively large quantities of CO_2 in the supercritical state via pipeline. The thrust of this study is to explore alternative methods of processing, transporting, and storing CO_2. The rationale for the initiation of the study was that if efficient methods could be developed for processing and transporting smaller quantities of CO_2, then a larger number of reservoirs could be considered as candidates for CO_2 flooding.

The subject of this paper is the discussion of the impact of transporting CO_2 as an ambient-temperature, dense-phase fluid, as opposed to a relatively high-temperature, supercritical fluid as had been proposed in Reference 3. In contrast to that study, the approach described here is to analyze the thermodynamic properties of pure CO_2, and attempt to develop "low-energy paths" for accomplishing the required transport. Once attractive candidate paths are identified, the power and energy requirements are established. Finally, the costs associated with the selected paths are estimated and compared.

DISCUSSION

To understand the motivation for operating a pipeline in the denser phase of the supercritical region, it is helpful to review the thermodynamic properties of CO_2. A pressure-enthalpy (Mollier) diagram for CO_2 is shown in Figure 1. The four regions identified in the Figure are the liquid, two-phase, gas, and dense-phase-fluid. Dense-phase fluid is the description of the phase of CO_2 at pressures above the critical pressure (1,071 psia). The merits of operating in the region have been discussed previously (References 1, 2, and 4), and include the fact that high densities can be achieved, and that abrupt phase changes (two-phase flow) can be avoided. Within the dense-phase region there are areas that are inherently more attractive thermodynamically than are others. This fact is most easily understood by observing that the constant-entropy (S=constant) lines become more vertical as one progresses from the higher temperature to the lower temperature of the dense-phase region. This characteristic is due to the fact that CO_2 behaves more as a liquid than as a gas as the temperature is decreased, at a constant pressure. This characteristic is normally expressed in the equation of state by a reduction in the compressibility factor (Z). The impact of this thermodynamic characteristic is that it requires substantially less work (Δh) to increase the pressure of the fluid in the lower temperature, low-compressibility area of the dense-phase-fluid region.

To determine the relative merits of operating in the lower temperature, low-compressibility area of the dense-phase region the energy requirements and costs of the initial pressurization and pipeline transport of the CO_2 were compared to those associated with operating in the high temperature, high-compressibility area of the dense-phase region.

The candidate paths for the initial pressurization of the CO_2 are illustrated in Figure 2. For the case illustrated the CO_2 was assumed to exit from the producing wellhead at 200 psia and 140°F. In order to access the low-compressibility region without the aid of refrigeration it is necessary to compress CO_2 in the gas phase to a pressure which has a reasonably high saturation temperature. For this illustration that pressure was assumed to be 1000 psia which has a saturation temperature of approximately 80°F. The gas was initially cooled to reduce the compressor work (1 to 2) and compressed in the first stage of the compressor (2-3). It was assumed that a single-stage pressure ratio would be limited to approximately 3:1 a level consistant with high isentropic efficiency. The gas was then intercooled (3-4) and compressed in the second compressor stage. There is a departure of the paths in the second compression leg. The high-compressibility path continues in the near-isentropic manner to point 5. The low-compressibility path from the departure point (4') to point 6 consists of heat transfer and condensation of the CO_2. The remainder of the pressurization for this path is performed with CO_2 in the liquid then low-compressibility dense-phase fluid state. The reason for the departure paths is to reduce the pressurization work. This advantage can be visualized by comparing $\Delta h_2'$ to that portion of Δh_2 above the point of path departure (4'-5). As previously stated the reason for the departure being at a pressure of 1000 psia in that it represents the lowest pressure at which condensation can be reasonably achieved without the aid of refrigeration.

The compressor horsepower requirements associated with the two thermodynamic paths are shown in Figure 3 a plot of compressor horsepower per MSCFD vs CO_2 wellhead pressure. Two observations should be made. The first is that CO_2 reservoir pressure should be utilized where possible to reduce compressor power requirements. The second observation is that for the range of pressures between 400 and 1200 psia substantial reductions in compressor horsepower requirements can be achieved by utilizing the low-compressibility path. At low wellhead pressures the differences become smaller percentagewise due to relatively longer length of the commonly shared high-compressibility path.

Repressurization is required for long pipelines to overcome the frictional losses encountered by the fluid. The energy required for repressurization consist of the energy required by the compressor itself plus that required for any special thermal conditioning. A key assumption that was made during this phase of the analysis was that the pipeline would be buried sufficiently deep to eliminate temperature changes due to variations of ambient air temperature. For average values of soil conductivity constant ground temperatures are normally achieved at approximately four-foot burial depths. At this depth the ground temperature has a constant temperature equal to the annual mean ambient air temperature. The specific assumption made was that the ground temperature at the burial depth would never exceed 70°F. Most of the midcontinent regions of the United States have temperatures significantly lower than 70°. This fact makes the assumption of 70° ground temperature conservative. A second key assumption (sited in Reference 3) which was that the CO_2 would have to be heated to 130°F (at 1400 psia the assumed minimum pipeline operating pressure) to

provide a sufficiently high-compressibility factor to meet gas compressor manufacture's warrantee requirements. This requirement has the effect of not only increasing compressor work but significantly increased the temperature of the gas in the pipeline which in turn causes higher initial pressure losses.

A qualitative representation of the effect that these two key assumptions have on the temperature of the gas in pipelines is shown in Figure 4. The temperature of the CO_2 will asymptotically approach the ground temperature due to heat transfer to the ground and Joule-Thompson self cooling. In the high-compressibility case the temperature at the compressor discharge is 185°F. Whether the temperature of the gas closely approaches the ground temperature will depend on the length of the line between compressor stations which is a function of the rate of pressure loss. For the case plotted in Figure 4 the temperature is only slightly greater than ground temperature when the low pressure limit is reached. Prior to recompression the CO_2 must be reheated to meet the compressibility requirements prior to entry into the compressor.

If pressurization is accomplished in the low-compressibility area then the temperature of the CO_2 never departs significantly from ground temperature. For pipelines of equal diameter and capacity the pressure loss per unit length will be lower for the lower temperature more dense fluid.

These two approaches to repressurization can be analyzed by plotting the paths on a Mollier diagram as shown in Figure 5. The pump work required in the low-compressibility path is indicated by the Δh_p. The energy required to thermally condition the CO_2 (i.e. heat it to 130°F) will depend upon the temperature the CO_2 had reached just prior to the compressor station. One can see that in cases where the CO_2 temperature approaches the ground temperature that substantial amounts of energy are required to reheat the fluid to the required compressor inlet conditions.

To determine the impact of the above mentioned phenomana the operating characteristics were calculated for CO_2 pipelines of four different capacities. In all cases the maximum operating pressure of 2000 psia and a minimum operating pressure of 1400 psia were assumed. In one set of calculations the initial conditions of 2000 psia and 80°F were assumed (low-compressibility path). In the second set of calculations the initial conditions were assumed to be 2000 psia and 185°F (high-compressibility path). Modified Panhandle (Panhandle B) equations (Reference 5) were used to compute the pressure drop of the high-compressibility path. Both the Modified Panhandle equations and methods more suitable for product pipelines were used for the low-compressibility path. The heat transfer from the CO_2 was limited by the heat transfer coefficient at the outer wall of the pipe which was assumed to be 0.6 BTU/ft-°F-hr a value calculated for average soil conductivities. The pipeline diameter was held fixed for each line capacity. The values of the diameter were more nearly optimum for the low-compressibility case.

The results of the pressure loss and heat transfer calculations are shown in Table 1. The pressure loss is represented by the distance between compressor stations (i.e. the line length at which the low pressure limit had

been reached - Δp=600 psi). As a result of the higher density the low-compressibility path always resulted in longer distances between compressor stations (i.e. lower unit pressure losses) than the high-compressibility path. The differences in distances ranged from 17% for the 8 in. diameter pipeline to 150% for the 20 in. line. This variation in differences is caused by the fact that the smaller diameter pipeline transfers heat more rapidly than the large diameter pipe due to the higher surface-to-volume ratio of the smaller pipe. Additional evidence of the decreasing unit heat transfer rate with increasing pipe diameter is the higher final fluid temperatures of the larger diameter pipes.

The compressor power and thermal conditioning requirements for the four pipelines are listed in Table 2. The significant differences in compressor power (hp/mi) results from both the closer compressor spacing and the higher power required to compress the higher temperature fluid of the high-compressibility path. The differences in compressor requirements for the two paths are substantial ranging from a factor of 2 for the 8-inch line to almost a factor of 8 for the 20-inch line. The thermal conditioning requirements for the smaller pipelines are significant and tend to negate the beneficial effects that transferring heat to the ground had in reducing the pressure loss. It should be noted that these differences are not representative of pipelines whose designs had been optimized for the respective fluid conditions. The higher capacity lines designed for the high-compressibility conditions would require larger diameters to arrive at more optimum operating conditions.

As one would expect from the decreased energy requirements of the low-compressibility path, the estimated CO_2 transportation costs are lower for the low-compressibility pipeline than for the high-compressibility case. Table 3 summarizes the investment costs for two cases. The comparison is based on the standard pipeline diameter most appropriate to low-compressibility fluid transport at each of the four line capacities of 50, 125, 250, and 500 MMSCFD. Although the high-compressibility fluid pipelines would probably be different from the diameters chosen, the analysis is illustrative of the relative economic efficiency of the two transport alternatives.

The investment costs include pipeline and repressurization facilities. Pipeline investment was assumed to be $20,000/in-mile for both low-and high-compressibility cases. Repressurization costs were assumed to be $540/hp for both cases. As seen in Table 3 at the lower two capacities the investment costs per mile are roughly the same. The investment for the high-compressibility transport mode increases more rapidly with capacity than does the low-compressibility investment. At 500 MMSCFD, the investment for the high-compressibility system is 27% greater than the investment for the low-compressibility systems at the 20-in. pipeline diameter. The difference in investments is due principally to the closer spacing of compressor stations for the high-compressibility pipeline than that required for the low-compressibility pipeline.

The difference in operating costs between the two alternatives is much more pronounced than the difference in investment. Operating costs include repressurization station labor and supervision, and fuel for both repressurization and revaporization (needed only for the high-compressibility

transport of 50 and 125 MMSCFD). Table 3 shows that the high-compressibility system has significantly higher operating costs than the low-compressibility system. At 50 MMSCFD, the high-compressibility operating costs are 52% greater than the low-compressibility costs; and at 500 MMSCFD, the high-compressibility operating costs are 147% greater than the low-compressibility costs.

The cost analysis suggest that both investment and operating costs are lower for a dense-phase-fluid CO_2 pipeline than for a pipeline designed for a high-compressibility path. These results are only qualitative, however, since the same diameter pipe was assumed for both low- and high-compressibility cases. Though beyond the scope of this study, a more accurate economic comparison would involve selection of the cost-minimizing combination of pipe diameter, pressures, temperatures and pump stations. The analysis summarized in Table 3 is nonetheless useful as an indication of the potential economic benefits to be gained from operation of a CO_2 pipeline in an energy-conserving, low-compressibility mode. Of additional interest in this respect are the fuel costs of the two cases. Fuel cost accounts for from 29% to 43% of the operating cost for the high-compressibility pipeline, but fuel cost is only 3% to 16% of the operating cost for the dense-phase-fluid systems. Hence, the cost of the high-compressibility CO_2 transport system is more sensitive to rising energy cost than is the low-compressibility transport cost.

CONCLUSIONS

Substantial reductions in compressor work and thermal conditioning can be achieved by maintaining CO_2 in the lower temperature, dense-phase fluid region (above the critical pressure) in pipelines. The reductions in compressor work and thermal conditioning can translate into substantial reductions in investment and/or operating costs. These results are strongly dependent on assumptions regarding compressor operating characteristics. Specifically the stated need to provide the compressor a fluid having a compressibility factor of 0.5 ($T=130^{o}F$ at 1400 psia) or higher, places a severe thermodynamic penalty on CO_2 pressurization schemes and pipelines. The advantages of dense-phase fluid pressurization and transport should provide the motivation to explore means of pressuritizing CO_2 in the low-compressibility, more liquid area of the dense-phase fluid thermodynamic region.

ACKNOWLEDGEMENTS

The authors wish to acknowledge the generous assistance of R. A. Acebal, B. Amirijafari and S. G. Roberts in preparing the material presented in this paper.

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COMPARISON OF CO_2 PIPELINE

REPRESSURIZATION AND THERMAL CONDITIONING REQUIREMENTS

		Low Compressibility Path			High Compressibility Path		
Line Capacity (MMSCFD)	Nominal Diameter (in)	Distance Between Compressor Stations (mi)	Initial Temp (F)	Final Temp (F)	Distance Between Compressor Stations (mi)	Initial Temp (F)	Final Temp (F)
50	8	88	80	75	75	185	77
125	12	107	80	75	61	185	101
250	16	87	80	75	38	185	147
500	20	70	80	75	28	185	167

TABLE 1

NOTE: Compressor stations are located where pressure has declined from 2000 psia to 1400 psia

COMPARISON OF CO_2

PIPELINE REPRESSURIZATION POWER AND THERMAL CONDITIONING

TABLE 2

		Low Compressibility Path			High Compressibility Path		
Line Capacity (MMSCFD)	Nominal Diameter (in)	Distance Between Compressor Stations (mi)	Compressor Power (hp/mi)	Thermal Conditioning (BTU/mi/day)	Distance Between Compressor Stations (mi)	Compressor Power(hp/mi)	Thermal Conditioning (BTU/mi/day)
50	8	88	2.9	0	75	9.1	6.2×10^6
125	12	107	5.9	0	61	28.0	9.6×10^6
250	16	87	14.5	0	38	89.9	0
500	20	70	36.0	0	28	244.1	0

Note: Compressor stations are located where pressure has declined from 2000 psia to 1400 psia

SUMMARY OF TRANSPORTATION COSTS

TABLE 3

		Investment Cost Per Mile		Annual Operating Cost Per Mile	
Line Capacity (MMSCFD)	Nominal Diameter (in)	Low Compressibility	High Compressibility	Low Compressibility	High Compressibility
50	8	$162,000	$165,000	$11,700	$17,800
125	12	243,000	255,000	13,900	26,900
250	16	308,000	349,000	18,200	35,600
500	20	419,000	532,000	26,000	64,100

CARBON DIOXIDE THERMODYNAMIC PROPERTIES

PRESSURE-ENTHALPY (MOLLIER) DIAGRAM

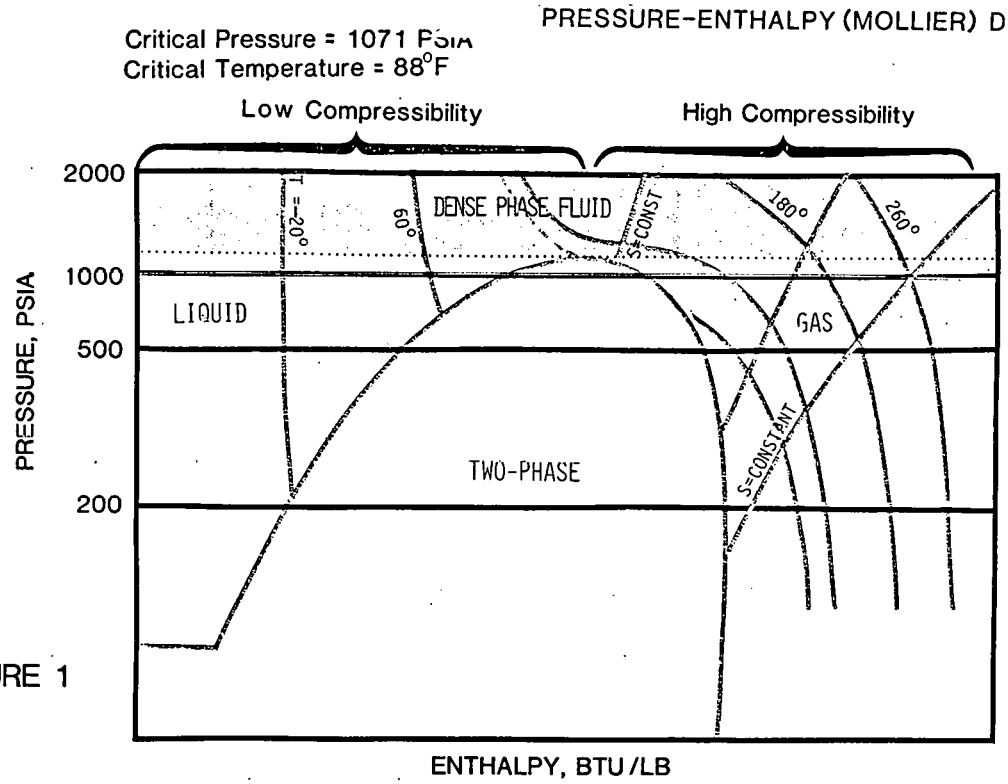


FIGURE 1

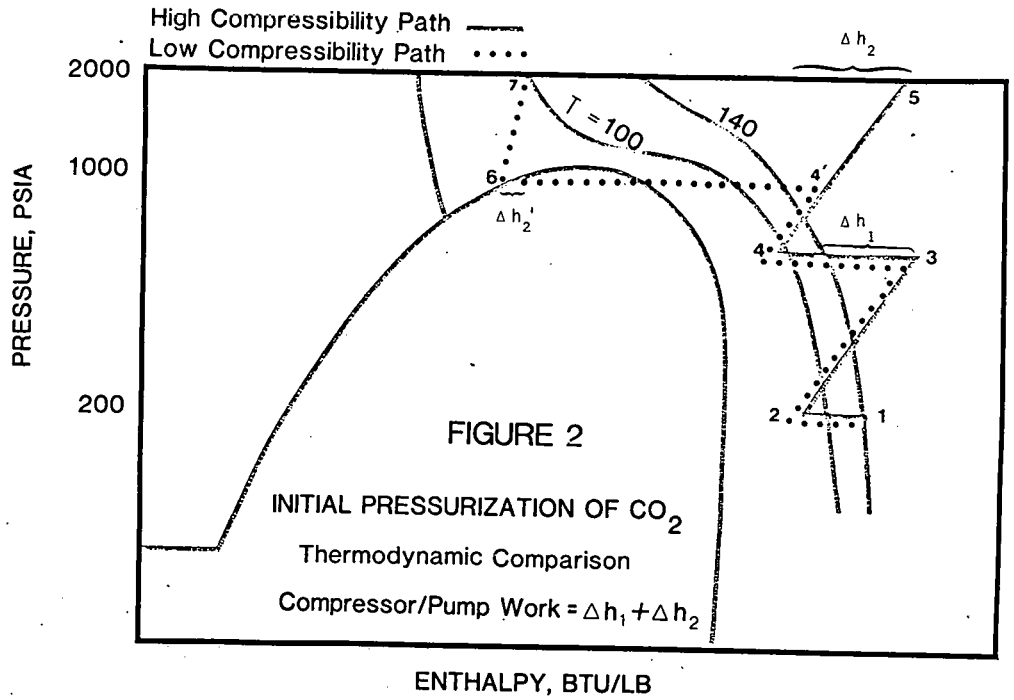
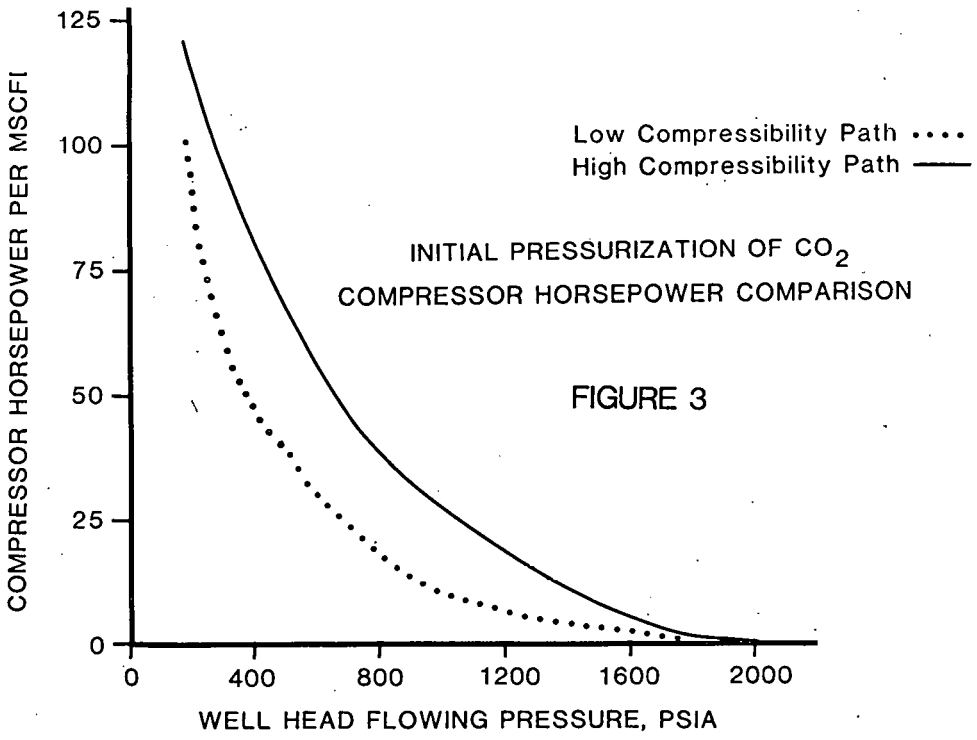


FIGURE 2

INITIAL PRESSURIZATION OF CO_2

Thermodynamic Comparison

Compressor/Pump Work = $\Delta h_1 + \Delta h_2$



INITIAL PRESSURIZATION OF CO_2
COMPRESSOR HORSEPOWER COMPARISON

FIGURE 3

TEMPERATURE DISTRIBUTION IN 50 MMSCFD CO_2 PIPELINES

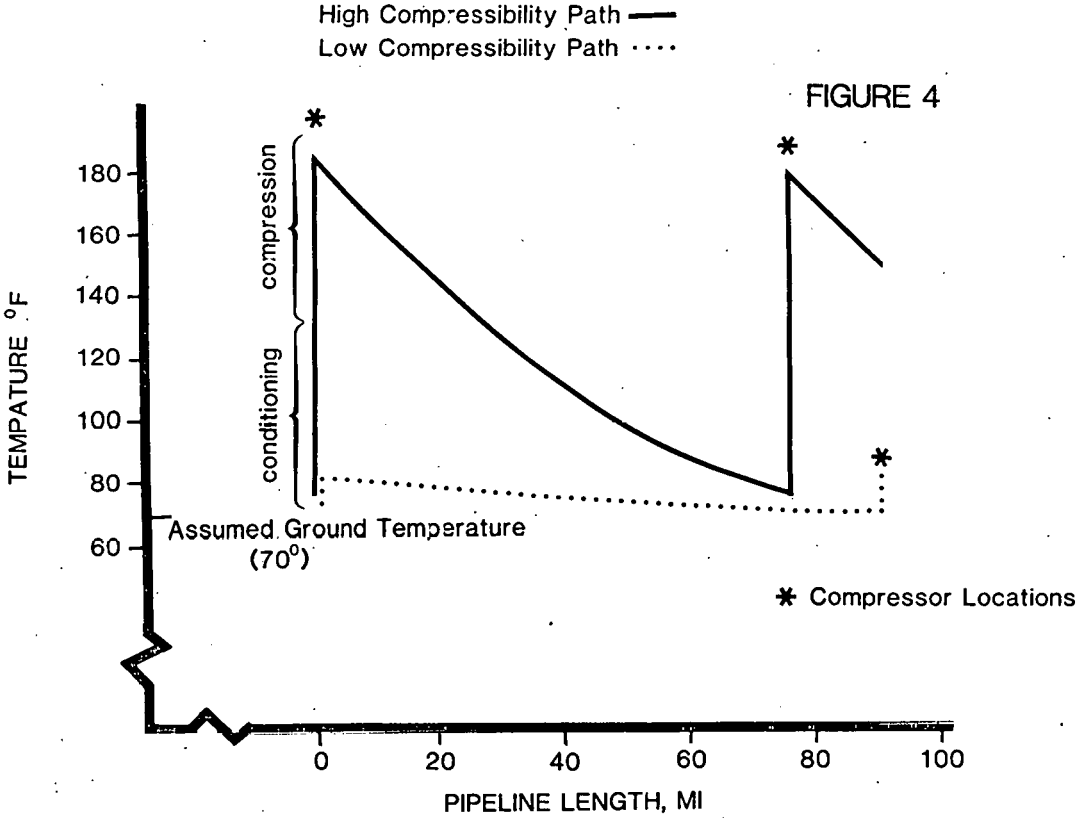


FIGURE 4

CARBONATE TARGET RESERVOIRS FOR CO_2 MISCIBLE FLOODING

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ABSTRACT

Gruy Federal has been contracted by the Department of Energy to interpret the results of field tests of the CO_2 miscible displacement process in carbonate reservoirs with collection and interpretation of information on other possible candidate reservoirs in the Permian Basin and the Rocky Mountain states. Furthermore, to obtain, through a cost shared drilling and coring program, reservoir information suitable for the design of CO_2 displacement projects in strategically located fields where significant potential for increased production exists.

This paper summarizes results to date on these contract tasks.

Prepared for DOE under contract no. DE-AC21-79MC08341

INTRODUCTION

The United States Department of Energy (DOE) has a goal that domestic industry achieve an incremental production of 124,000 barrels per day by 1985 from CO_2 injection projects. As a means of advancing toward that goal, Gruy Federal has been awarded a contract entitled "Target Reservoirs for Carbon Dioxide Flooding". The study is focusing on the potential in carbonate reservoirs located in the Permian, Williston, and other basins in the Western United States. This study has many parts and is still in the early phases. The sections are:

- Summary of available CO_2 field test data
- Summary of existing reservoir and geological data on carbonate reservoirs with selected characteristics
- Creating a list of priority candidate fields for CO_2 testing without regard to CO_2 availability (in this step)
- Select specific reservoirs from this list with the highest priority for commercial production under CO_2 injection. (In this step proximity of CO_2 sources is considered)
- Within these specific reservoirs select sites for coring to verify critical parameters
- Participate in the drilling, coring, logging, testing and the analysis of results to confirm estimates of current oil saturation and obtain information suitable to design a mini-CO_2 injection test program

This program is designed to provide a solid engineering foundation upon which field mini and pilot tests, and eventually full scale projects, can be implemented in carbonate reservoirs.

SUMMARY OF AVAILABLE FIELD TEST DATA

The tests of CO_2 miscible displacement in carbonate reservoirs are the most germane to the selection of carbonate reservoirs for field testing. For this reason we have selected the carbonate tests to study first. The following eight fields have been identified as having carbonate reservoirs in the contract area with past, existing, or proposed carbon dioxide injection:

1. Aneth (Ratherford Unit)
2. Crossett (North Cross Unit)
3. Kelly Snyder (SACROC)
4. Levelland (Levelland Unit)
5. North Cowden
6. North McElroy
7. Slaughter (Slaughter Estate Unit)
8. Wasson (Willard and Denver Units)

Seven of these fields are in the Permian Basin and the locations are given in Figure 1.

Table 1 summarizes the reservoir parameters collected to date, on a number of these projects. Gruy's study of these projects and proposed projects includes both an engineering and a geological summary and review.

For enhanced oil recovery projects, the importance of detailed understanding of the reservoir geology, particularly in carbonates, cannot be understated. Continuity of porosity stringers in carbonate reservoirs has been researched and reported by reservoir specialists (Ghauri, Osborne, and Magnuson, 1974; George and Stiles, 1978; Driscoll, 1974, and Barrett, Harpole, and Zaaza, 1977). Porosity continuity is now thought to be significantly less than previously assumed. For example, studies in the Wasson Field show only 55% of the porosity (pay) zones are continuous for a distance of 5000 feet (George and Stiles, 1978). This type of information is needed in the design of secondary/tertiary programs. Of the fields reviewed to date, only Crossett shows a decided pay continuity. This is the result of the lithology (Devonian silicious dolomite) where porosity development is relatively homogeneous.

SUMMARY OF EXISTING RESERVOIR AND GEOLOGICAL INFORMATION OF CARBONATE RESERVOIRS

SELECTION OF RESERVOIRS

The guidelines given to Gruy Federal for selecting reservoirs on which to gather information included the following:

Average permeability	$\geq$ 5 md
Average oil gravity	$\geq$ 36° API
Average oil viscosity	$\leq$ 10 cp
Average current oil saturation	$\geq$ 38%

In addition, no extremely high permeability stratigraphic thief zones should exist.

The Petroleum Data System (PDS) at the University of Oklahoma was used as a starting point for locating fields in the project area that met these criteria. The PDS data banks contain information on over 80,000 fields and reservoirs in the United States and Canada, and is immensely useful in studies like this. Access to PDS was gained through the General Electric Mark III Computer Network, an interactive time-sharing system. The PDS relies heavily on the International Oil Scouts Association's annual reviews, and official state statistical publications. Completeness of records for any field or reservoir depends largely upon the legislated reporting requirements for an area.

A search was performed seeking those fields which are listed as being carbonate, have produced oil with an API gravity greater than 35°, have a listed average permeability of greater than 4 md and for which no descriptor indicating fractures was listed in the file.

Current saturation greater than 38% and viscosity $\leq$ 10 cp were deemed to be unnecessary to screen on for obvious reasons and the information contained in these categories in PDS, for the project area, is minimal. This preliminary search yielded 244 reservoirs.

This search has been augmented by use of state and regional geological society publications, and other primary documents, on oil and gas fields in the project area. A total of 48 additional reservoirs have been added by this search, making the total located to date 292 reservoirs in 10 geologic provinces. The results by geologic province are summarized in Table 2. As can be seen from Table 2, the province with the greatest number of reservoirs meeting the criteria is the Permian Basin with 230. The Williston Basin with 32 is also significantly represented.

The productive formations represented within the Permian Basin, along with the number of fields, and two measures of field size are summarized in Table 3. The screening is not yet final because a few limey sands have been included, which are not strictly carbonate. These will be removed in later efforts. The two measures of field size are the number of wells and the sum of the latest annual production figures for fields producing from the listed formations. The Grayburg-San Andres formations of 18 fields in the Permian Basin with a combined latest annual production of over 68 million barrels and having about 6000 wells certainly fulfills the screening requirements better than any other.

Examination of the list of fields selected revealed that certain fields which are undergoing testing by major oil companies for commerical application of the CO_2 have been missed by this screening. Notable among these are Wasson, Levelland, Slaughter, North McElroy, and North Cowden. Table 4 lists the pertinent data (for this screening) contained in the PDS file on the major reservoir in these fields. As is apparent from Table 4 the major causes for missing these fields are oil gravity and average permeability requirements. In the interest of thoroughness, these requirements were relaxed slightly to investigate other "near misses". (Permeability as low as 2 md and oil gravity as low as 30° API). A total of 333 fields can be identified as being in the near miss category. However, most of these fields are rather small with only 60 having more than 50 wells.

SYNTHESIS OF EXISTING RESERVOIR DATA

The contract calls for data to be compiled on reservoirs that meet the selection criteria. The required data include stratigraphy, structure, mineralogy, porosity, permeability, gross thickness, net thickness, hydrocarbon and connate water content of the reservoirs, production data, PVT analysis, and well test data and analysis. Gruy is currently gathering these data on the

292 reservoirs selected to date. The PDS files have been extensively used, as well as primary data sources including:

1. State and regional geological societies publications for information on stratigraphy, structure, mineralogy, porosity, and permeability.

2. State regulatory tabulations on the gravity of produced oil, the amount of monthly or yearly production from a lease, and the recorded pressures, both from the original records and from commercial information companies.

3. Annual production compilations of the International Oil Scout Association.

Information of the crude oil contained in these reservoirs has been extracted from two sources:

1. The COIL file of PDS. This file was furnished to the repository by the Department of Energy.

2. Recent publications of the DOE which provided additional crude oil analyses.

CRUDE OIL CHARACTERIZATION

To assist in the characterization of the resource a brief examination of the 199 crude oil analyses collected to date from the fields and reservoirs selected has been made. Cluster analysis of the tabulated crude oil correlation indices for each oil reveal that the oils included in this sample can be grouped into 8 categories represented by the plots given in Figure 2. The number of oils falling into each category is given at the end of each line.

OTHER FEATURES OF THE SELECTED RESERVOIRS

Statistical plots of many reservoir parameters are now being made to consolidate the masses of date being collected. Sample plots of selected information are provided as Figures 2 through 5.

The pressure at which effective displacement occurs is commonly referred to as the miscible pressure, although this displacement is usually not, in the true sense, a completely miscible one. A recently proposed predictive technique for the minimum miscibility pressure MMP presented by Yellig and Metcalfe (1978) is being used to estimate the necessary miscible pressure for the subject reservoirs.

SELECTION OF TARGET RESERVOIRS

Armed with the knowledge gained in previous sections and utilizing data on available CO_2 supply, (extracted largely from the Pullman Kellog and GURC Final Reports, 1979) Gruy Federal will prepare a priority list of carbonate reservoirs in the project area for EOR by CO_2 injection. A criterion for priority

within this list will be the most expeditious use of available and potential CO_2 supplies.

The priority list will be upgraded to a refined list of reservoirs in which the CO_2 process has a high probability of success. This step will be accomplished through analysis of the results of the field test of CO_2 displacement in comparable reservoirs and a thorough characterization of the reservoirs that pass the selection criteria.

SELECTION OF SPECIFIC RESERVOIRS FOR CO_2 INJECTION TESTS

Once the list of priority target reservoirs has been compiled, Gruy Federal will discuss with the owners and operators of the fields our preliminary assessment of the potential for CO_2 displacement in their reservoirs. Receptivity of the owners and operators to a project to verify the critical reservoir parameters for CO_2 displacement, partially supported by the U. S. Department of Energy, will be guaged. The specific site selection for the field tests will be made with the assurance that the owner/operator of the field would be amenable to the project, and that the known reservoir parameters give the field a high priority for testing.

SELECTION OF SPECIFIC SITES FOR TEST WELLS

In choosing the location of preliminary test wells, Gruy Federal will work with the operators of the fields selected as sites for the field testing. Our purpose will be to ensure that the test wells will penetrate a representative portion of the target reservoir. Many EOR pilot projects have been initiated in relatively poor parts of the reservoir. Such tests are difficult to analyze and do not provide conclusive answers to critical questions about EOR techniques (Bassan et al, 1978).

Gruy's role in this part of the project will be to ensure acquisition of the information necessary to confirm reserve estimates and design a mini-field test of the CO_2 process.

DRILLING, CORING, AND TESTING ACTIVITIES

The primary objective of the logging, coring, and testing program will be to determine the existing oil saturation of the reservoirs, and the suitability of CO_2 displacement. Zones of particular interest will be those at waterflood residual saturation. A testing program to verify that water is the only mobile fluid would also be desirable. In order to best accomplish this objective, pressuring coring, a comprehensive logging program, and the testing program will be designed for each site to obtain maximum information.

RECOMMENDATIONS FOR CORING PROGRAM

Since principal objective of the core test is to determine the insitu oil saturation, it is essential to design the drilling and evaluation

program so that "losses" of reservoir fluids from the core and the zone immediately around the wellbore will be minimized. Because many of the fields are already under waterflood the reservoir pressure may be quite high. If a relatively heavy mud will be required to contain this pressure, a protective casing should be set just above the top of the pay to avert the possibility of lost circulation to upper formations. An additional benefit of the protective casing would be that better control of mud properties is possible.

To minimize flushing losses, the mud should be mixed to have a very low water loss with a weight consistent with a minimum overbalance required for safe drilling. Low circulation rates should be used and a tracer should be added to the mud system for subsequent detection of filtrate invasion in core samples. The mud resistivity should be matched with that of the formation water to aid in the log determination of "flushed zone" water saturations.

RECOMMENDATIONS FOR LOGGING PROGRAM

Our recommendation for a logging program will be a complete suite of open-hole logs, including:

1. a proper resistivity log for obtaining R_t, which should include one of the following: dual induction, induction-electrical, dual laterolog or laterolog;

2. two porosity logs, which should include two of the following: a formation density compensated (FDC) log, a compensated neutron (CNL), a sidewall neutron porosity (SNP) log, and/or borehole compensated (BHC) sonic log;

3. a microresistivity log for the determination of R_{xo};

4. gamma ray and self potential curves for correlation and assistance in determining clay content

This suite of logs should allow the most comprehensive open-hole log analyses to be performed.

Recommendations for testing will be prepared based on the log and core analysis data. The intent of testing would be to verify the residual and/or mobile oil information calculated from logs and core analysis.

CONCLUSIONS

This paper consists of a status report on the early phases of this contract study, (15 weeks after initiation) and it is envisioned that there will be much more to report in the actual presentation (27 weeks after initiation).

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TABLE #1
RESERVOIR PARAMETER FROM CO_2 DISPLACEMENT
PROJECTS IN "CARBONATE" ROCKS

	KELLY SNYDER FIELD SACROC UNIT	WASSON FIELD	WILLARD UNIT	DENVER UNIT	CROSSETT FLD NORTH CROSS UNIT	SLAUGHTER FIELD SLAUGHTER ESTATE UNIT	LEVELLAND FLD LEVELLAND UNIT	ANETH FIELD	NORTH COWDEN FIELD	NORTH McELROY FIELD
PHYSICAL RESERVOIR FEATURES										
FORMATION	CANYON	SAN ANDRES			DEVONIAN	SAN ANDRES	SAN ANDRES	PARADOX	GRAYBURG	GRAYBURG/ SAN ANDRES
LITHOLOGY	LIMESTONE	DOLOMITE			(C)	DOLOMITE	(E)	(E)		
STRUCTURE	ANTICLINAL	ANTICLINAL			STRATIGRAPHIC		(G)	(G)		
DEPTH, FT.	6700	5100			5300		4900	~ 5500	~ 5100	3000
WATER-OIL CONTACT, FT.	-4500				-3040				~ -1300	
AVG. GROSS THICKNESS, FT.	268		50-230	137	40-180 (88 EFFECTIVE)		GROSS 250 NET 100	140		150(NET)
LITHOLOGIC TYPE	(A)	(B)			CHALKY			(H)		
POROSITY TYPE	(J)	(D)			(D)			(I)		
FLUID AND ROCK PROPERTIES										
INITIAL RES. PRESS., PSIG	3122 @ 9300'		1805	1805	2400				1750 (EST)	755
RESERVOIR TEMP, ^oF	130° @ 4300'			105	106°					
OIL GRAVITY, ^oAPI	41		33	33	44 @ 60° F		30		34	32
BUBBLE POINT, PSIA	1850		2-65		2328					
SOLUTION GOR, CUFT/BBL	1000		9382		NOV 76 6000	JUN 1053				
OIL VOLUME FACTOR	1.5		1.312							
OIL VISCOSITY, CPS	0.35		1.18		0.38		1.9			
AVG. POROSITY OVER GROSS THICK., %	3.93		8.5	12	22		10.2	RANGE 10-12	8	15
AVG. PERMEABILITY, MD	19.9		3	5	5.5		2.1	RANGE 10-50	5	10
AVG. SWI, %	21.9				35		23.9			
WATER-OIL MOBILITY RATIO	0.3			15			(ENRICHED GAS) 1100			
CO_2 OIL MOBILITY RATIO	8.0				5					
CO_2 MISCIBLE PRESSURE, PSI		1250	1250		1650					
AVG. SOR, %		30	>30							
DRIVE MECHANISM										
PRIMARY	(M)	SOLUTION GAS			SOLUTION GAS		SOLUTION GAS		SOLUTION GAS	
SECONDARY	(N)	(O)			(P)	WATERFLOOD	(Q)	WATERFLOOD CO_2 TERTIARY	WATERFLOOD	
CURRENT STATUS	COMMERCIAL		(R)		COMMERCIAL	TESTING	CONT TESTING			

(A) CALCARENITE WITH MINOR AMOUNTS OF CALCIRUDITE & CALCILUTITE
(B) FINELY CRYSTALLINE
(C) SILICEOUS DOLOMITE
(D) PRIMARY-INTERGRANULAR
(E) LIMESTONE/DOLOMITE
(G) STRATIGRAPHIC/STRUCTURAL
(H) CALCARENITES/CHALKY DOLOMITE
(I) VUGGY/FINELY INTERCRYSTALLINE
(J) SECONDARY VUGGY
(M) FLUID EXPAN. & SOL. GAS
(N) CENTERLINE WATERFLOOD PATTERN AREA CO_2 - WAG
(O) LINE DRIVE WATERFLOOD SINCE 1965
(P) CO_2 INVERTED 9 SPOT
(Q) ENRICHED HYDROCARBON CO_2 TERTIARY
(R) REPORTED TERMINATED SPE EOR FIELD REPORT V4 NO.2 9/78

TABLE #1 CONTINUED

	KELLY SNYDER FIELD SACROC UNIT	WASSON FIELD			CROSSETT FLD NORTH CROSS UNIT	SLAUGHTER FIELD SLAUGHTER ESTATE UNIT	LEVELLAND FLD LEVELLAND UNIT	ANETH FIELD	NORTH COWDEN FIELD	NORTH MCELROY FIELD
			WILLARD UNIT	DENVER UNIT						
STATISTICAL DATA										
SURFACE AREA, AC	99,900	68,000	8010	27,8000	1120	(FF)	(Y)		38,000	30,000
PRODUCING WELLS	(S)				22	2 PILOT			2 PILOT	
SHUT-IN WELLS	398									
INJECTION WELLS	305		8		6	6 PILOT			6 PILOT	
TOTAL	1358				28	8 PILOT			8 PILOT	
ORIG. STOCK TANK OIL-IN-PLACE, STB	2113 MM	600 MM	(AA)	2,108 MM	53 MM					
CUM. OIL PRODUCTION, STB	JAN 937 MM	MAR 50.6 MM			(CC)			OCT 76 265 MM		
CUM. INJECTION	AS OF JAN-78		(BB)							
WATER, BEL	1,809 MM		1 MMB							
CO_2, SCF	346 MMM		3.8 MMM		27.7 MMM					
INCREMENTAL OIL FROM CO_2, STB					926 M	(GG)	(HH)			
CUM. CO_2 PRODUCTION, MMCF					363					
CURRENT PRODUCTION RATES	AS OF DEC-77									
OIL, BOPD	139,886	1974 31,500			(DD)	~ 80	OCT 76 23,700			
GAS, CF/D	136,807 M									
CO_2, CF/D	35,864 M	(T)			(EE)					
WATER, BBL/D	411,974					~ 320				
CURRENT INJECTION RATES	AS OF DEC-77									
WATER, BBL/D	596,191	1974 & 75 385 BWPD				~ 600				
CO_2, CF/D	146,903 M	1973 2300 RVBD			~ 17 MM					
OPERATOR	CHEVRON		ARCO	SHELL	SHELL	AMOCO	AMOCO		AMOCO	

(S) 648 (ART, LIFT)
11 (FLOWING)

(T) PEAK 100 RVBD 9% OF INJECTION

(AA) 55-70 MSTBO/AC

(BB) NOV. 72 TO FEB. 75

(CC) AP 1972 6.9 MM NOV. 76

(DD) AP 72 1480 NOV. 76 2000

(EE) NOV. 76 960 MCF/D
5.3% OF INJ.

(FF) PILOT - TWO 6.6 ACRE 5 SPOTS

(GG) TO JULY 11/AC FT.
PROJECTED 18'/AC FT.

(HH) PROJECTED 99/AC FT.

(Y) LEVELLAND UNIT 13,600
PROJECT AREA 1170

TABLE 2

NUMBER OF CANDIDATE FIELDS IN
PRELIMINARY SCREENING BY BASIN

Basin Name	Number of Fields
Anadarko Basin	5
Bend Arch	9
Big Horn	1
Denver	1
North Park	2
Paradox	10
Permian	230
San Juan Basin	1
Sweetgrass Arch	1
Williston	32
Total	292

TABLE 3

PRODUCING FORMATION OF FIELDS SELECTED
IN THE PERMIAN BASIN

Texas District 7B	Total No. Fields	Total No. Wells	Total Latest Annual Production
Bend	1	39	695,267
Caddo	1	19	88,880
Canyon Lime	1	54	5,239,574
Canyon Reef	2	14	114,554
Goen	1	7	76,282
Hope Lime, Upper	1	15	81,364
Noodle Creek	1	15	82,700
Odom Lime	1	65	952,396
Palo Pinto Reef	1	86	1,074,719
Strawn	1	4	45,361
Strawn Reef	2	158	820,241
Texas District 7C			
Atoka	2	24	17,990
Bend	1	24	120,698
Capps	1	6	31,334
Cisco Canyon	1	3	8,746
Clearfork	1	25	60,234
Crinoidal	1	26	1,030,455
Ellenburger	2	72	344,925
Goen	1	0	258
Menielle Penn.	1	25	341,190
Penn.	1	6	39,506
Pennsylvanian	2	39	263,123
Queen	1	111	508,902
Strawn	7	160	2,102,413
Texas District 8			
Canyon Reef	1	68	1,855,237
Cisco	1	3	11,651
Clearfork	4	997	4,930,751
Devonian	9	300	8,203,157
Devonian, North	1	31	179,790
Ellenburger	13	143	2,482,949
Fusselman	2	29	251,741
Grayburg	3	1868	14,834,577

TABLE 3

PRODUCING FORMATION OF FIELDS SELECTED
IN THE PERMIAN BASIN

Texas District 8 (con't)	Total No. Fields	Total No. Wells	Total Latest Annual Production
Holt	2	155	1,161,354
Penn.	1	26	305,941
Pennsylvanian	3	96	1,608,198
Permian	1	91	677,129
San Andres	7	2158	17,097,686
Seven Rivers	1	168	846,264
Silurian	2	58	836,962
Silurian-Devonian	1	38	578,992
Silurian-Montoya	1	19	154,859
Strawn	2	13	118,849
Wolfcamp	10	334	2,851,455
Texas District 8A			
Canyon	6	183	12,503,505
Canyon Reef	2	779	66,313,961
Cisco	2	53	4,346,179
Cisco Sand	1	38	67,873
Fusselman	4	47	1,336,065
Glorieta	2	66	195,938
Montoya	1	8	357,365
Pennsylvanian	7	646	18,223,778
Pennsylvanian Reef	1	9	70,683
Permian	1	353	2,002,037
San Andres	3	487	26,134,603
San Andres, Lower	1	19	48,547
Siluro-Devonian	1	7	168,521
Strawn	4	49	263,787
Strawn Sand	1	12	179,561
Wichita-Albany	1	14	128,263
Wolfcamp	3	56	4,461,079

TABLE 3

PRODUCING FORMATION OF FIELDS SELECTED
IN THE PERMIAN BASIN

New Mexico	Total No. Fields	Total No. Wells	Total Latest Annual Production
Abo	2	44	328,682
Abo Lower	1	1	17,510
Abo Reef	2	3	14,605
Abo Upper	1	1	3,545
Blinebry	1	26	285,924
Bough	1	23	188,846
Bough C	2	40	187,292
Cisco	1	9	7,568
Delaware	2	15	47,844
Devonian	12	128	1,629,018
Drinkard	1	17	100,405
Grayburg	3	641	1,414,602
Grayburg-San Andres	1	461	5,433,247
Grayburg San Andres	2	711	4,460,078
Lower Wolfcamp	1	38	93,698
Montoya	1	13	65,436
Paddock	2	4	18,629
Penn	2	18	67,501
Penn Bough C	1	146	945,612
Pennsylvanian	2	5	8,506
Permo Penn	1	10	1,217
Queen	1	137	228,679
San Andres	1	67	397,788
Seven Rivers	1	17	20,149
Strawn	2	4	60,094
Tubb Drinkard	1	44	323,584
Wolfcamp	9	154	1,047,699
Yates	1	4	11,735
Yates Seven Rivers	1	65	197,116
Yates Seven Rivers Que	1	43	98,727
Yeso	1	729	1,599,996

TABLE 4

SUMMARY OF INFORMATION CONTAINED IN PDS
ON FIELDS CURRENTLY BEING EXAMINED
FOR CO_2 DISPLACEMENT

Field/Pool	APIGRAV	AVPERM	LITHOLOGY	ϕ - Type
Levelland/ San Andres	29.0	3	Lime	11
McElroy, North/ Ellenburger	51	---	Dolomite	Frac. Vuggy
Slaughter/ San Andres	32.0	11	Dolomite	12.2
Wasson/ San Andres	34.0	20	----	11.5
North Cowden/ San Andres (Permian)	33	3	Dolomite	12.0

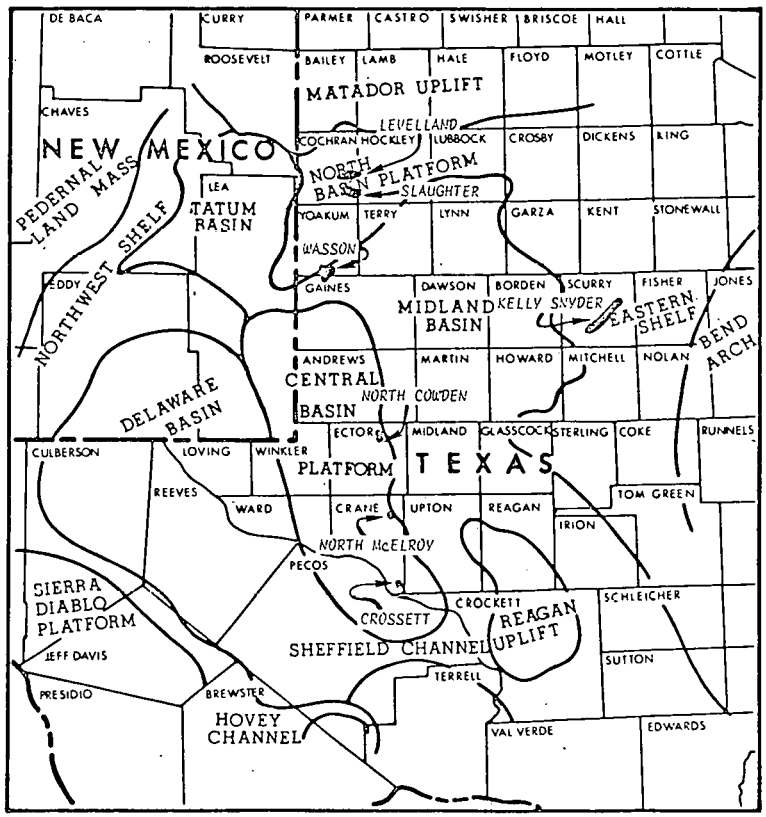


FIGURE 1

LOCATION OF FIELD TEST OF
CO_2 MISCIBLE DISPLACEMENT PROCESS
IN PERMIAN BASIN AREA

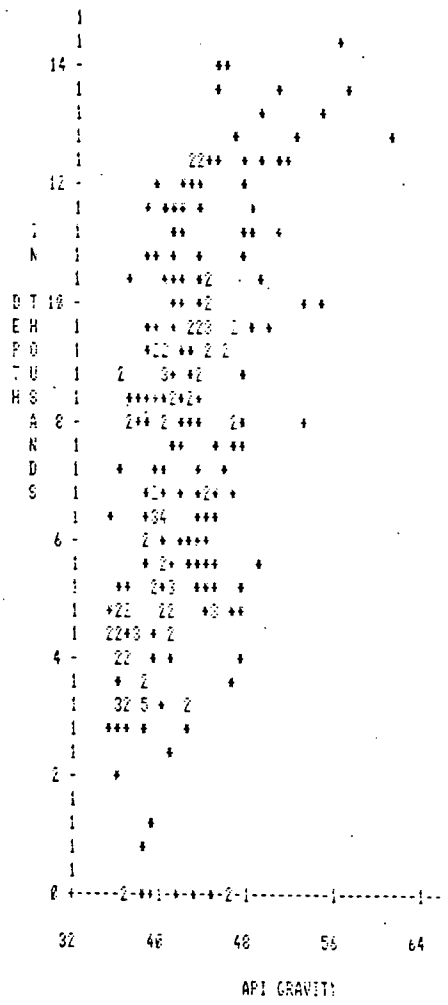


FIGURE 2

AVERAGE DEPTH VS AVERAGE API GRAVITY FOR ALL RESERVOIRS SELECTED

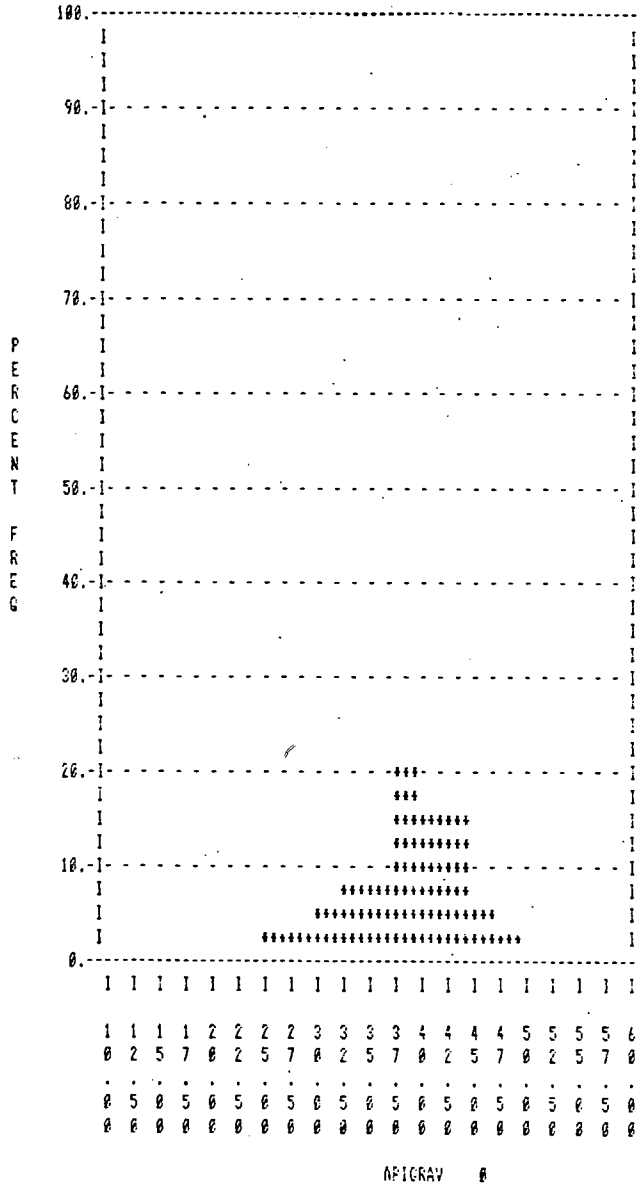


FIGURE 3

DISTRIBUTION OF AVERAGE API GRAVITY IN CARBONATE RESERVOIRS IN WEST TEXAS

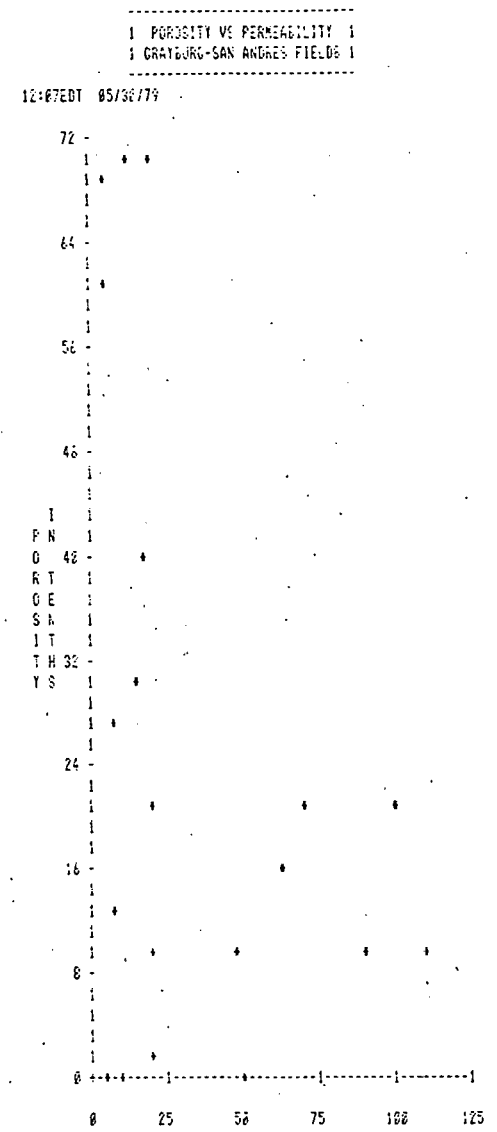
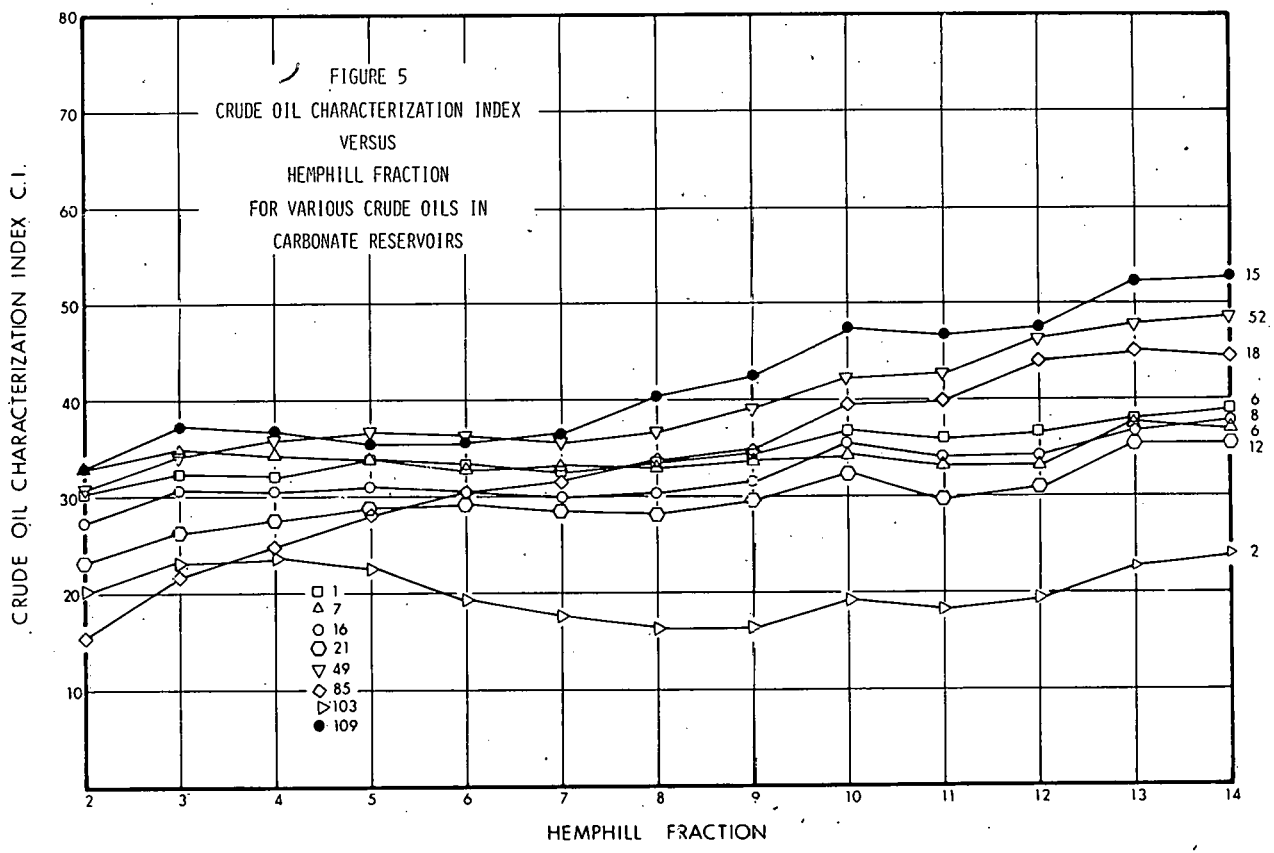


FIGURE 4

AVERAGE POROSITY VS AVERAGE PERMEABILITY FOR GRAYBURG-SAN ANDRES FIELDS SELECTED TO DATE



PROGRESS OF THE PILOT CARBON DIOXIDE FLOOD IN THE ROCK CREEK-BIG INJUN FIELD ROANE COUNTY, WEST VIRGINIA

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ABSTRACT

The Rock Creek Field, discovered in 1906, is the site of a pilot carbon dioxide flood designed and installed by Pennzoil Company with financial support from the Department of Energy. Conventional extra recovery methods have not provided sufficient production responses to be economical. In this field, 80% of the original stock tank oil-in-place or 150 million barrels of oil remain in the reservoir. This large amount of oil in place was one of the main reasons in designing and installing this pilot carbon dioxide project. The objectives of this pilot are to determine the oil recovery efficiency of a multiple contact carbon dioxide miscible flood and to define and evaluate operational and reservoir problems associated with this recovery method. As of April 1, 1979, 1.7 million barrels of water have been injected into the project. A short lived waterflood response that produced less than 600 barrels of oil per acre was experienced. This response was indicative of past waterflood attempts and failures. Carbon dioxide injection was started on February 20, 1979. As of April 1, 1979, approximately 10% of the designed 25,000 ton injection volume had been injected.

INTRODUCTION

The Rock Creek Field, discovered in 1906, is located in Roane County, West Virginia (see Figure No. 1). This field is the site of a pilot liquid carbon dioxide flood designed and installed by Pennzoil Company with financial assistance from the Department of Energy. The

repared for the Department of Energy, under Contract No. EF-76-C-05-5301.

pilot consists of two continuous five spot patterns encompassing a total of 19.65 acres. These dual five-spots are surrounded by thirteen back-up injection wells drilled as or converted to water injection wells with the sole purpose of containing the injected carbon dioxide. The total area encompassed by these thirteen back-up wells is 53 acres (see Figure No. 2). Prior to the start of carbon dioxide injection on February 20, 1979, the reservoir pressure had to be increased from 91 psia at the start of the project to 1000 psia in order to achieve miscible conditions. This pressure increase was achieved by injecting water into all of the nineteen injection wells. Water injection will continue into the back-up injection wells throughout the project life.

PROJECT DESIGN AND DEVELOPMENT

The pilot carbon dioxide flood in the Rock Creek Field was designed in 1975. The needed well work and plant construction began in 1976 and was completed in 1977.

The design of this project was based on successful laboratory miscibility tests and model studies utilizing known reservoir information. This design called for a pressure build-up phase prior to carbon dioxide injection to assure necessary miscible conditions within the reservoir at the carbon dioxide front. In the third quarter of 1978, the needed reservoir pressure of 1000 psia within the pattern area was achieved. The start of carbon dioxide injection was delayed until February 20, 1979 because of the need to workover a center producing well.

A detailed description of the reservoir lithology, laboratory tests, process design and project design was presented at the 1977 ERDA Symposium in Tulsa, Oklahoma. Published in Volume No. 1 of the proceedings, the paper, numbered C-3, is titled "Development of a Pilot Carbon Dioxide Flood in the Rock Creek-Big Injun Field, Roane County, West Virginia" by Larry G. Guckert and George P. SanFilippo. The parameters used in the original design of this project and presented in the aforementioned paper have since been revised. The information gathered from the coring and logging programs during the installation of the project was used to refine the reservoir parameters to values that more accurately represent the 19.65 acre pattern area. These parameters for each five spot are listed in Table I.

Due to the revision of the reservoir parameters, the volume of carbon dioxide needed for the project was also revised. Although the volume of carbon dioxide for optimum oil recovery has yet to be determined in the industry, field tests and various publications support effective carbon dioxide injection equal to 20-25 percent of the hydrocarbon pore volumes. The total hydrocarbon pore volume of the 19.65 acre pattern area was 392,770 barrels at the initiation of the project. Based on simulation work performed on the water injection phase of the project, the effective injection of carbon dioxide was taken as 50 percent. Since one ton of carbon dioxide existing at the

reservoir conditions of 73° F and 1000 psi equates to 7.65 barrels, percent of the revised designed carbon dioxide volume of 25,000 tons equivalent to 191,250 reservoir barrels or 24.3 percent of the hydrocarbon pore volume.

Another change from the original project design was the drilling of an observation well in one of the ten acre patterns. This well was drilled at the midpoint between injection well PI-6 and a pattern center producing well (see Figure No. 2). This well was completed with fiberglass casing cemented across the net sand interval in order to accommodate induction logging. This well will be logged periodically with an induction log to monitor the change in hydrocarbon saturation and with a compensated neutron log to determine the vertical distribution of the injected fluids. Also, this well will be equipped with bottom hole pressure monitoring equipment in order to keep an accurate record of this midpoint reservoir pressure.

FIELD OPERATIONS

Water Injection

Water injection into the back-up injection wells was initiated on October 16, 1976. As of April 1, 1979, the cumulative injection into these thirteen wells totaled 1,325,438 barrels. Water injection into these thirteen wells will continue throughout the life of the project.

Water injection into the six pattern injection wells commenced on April 22, 1977. As of April 1, 1979, the cumulative water injection into these six wells totaled 390,687 barrels. Figure No. 3 graphically presents the water injection history for the project. Water injection into these wells continued until pressure fall-off tests indicated that the average reservoir pressure within the pattern area was greater than 1000 psia.

Carbon Dioxide Injection

Carbon dioxide injection was initiated on February 20, 1979. As of April 1, 1979, 1,970.8 tons of liquid carbon dioxide have been injected. Based on material balance calculations, the effective carbon dioxide injection was 43 percent to April 1. Injection of liquid carbon dioxide will continue until approximately 40 percent of the total designed volume of 25,000 tons is injected. At that time the injection schedule will start alternating injection of water and liquid gas (WAG). The exact WAG schedule will be developed as project performance, carbon dioxide availability, and weather dictate.

Producing Wells

The two center producing wells responded to water injection during the second quarter of 1978 when oil production for the project peaked at a rate of 106 barrels per day. This oil production rate dropped sharply as the water-oil ratio approached a 100% water cut by December, 1978. This short response was indicative of producing a thin oil bank. The same type of response was seen in other pilot waterfloods in the field. Therefore, this response again proves that this reservoir will not significantly respond to waterflooding. The waterflood recovery as of April 1, 1979 was 565 barrels per acre. Figure No. 4 is a graphical presentation of the total production history for these two wells since the start of the project.

SUMMARY

Sufficient pressure to promote miscible carbon dioxide oil recovery was achieved in late 1978. The injection of the liquid carbon dioxide slug was initiated on February 20, 1979. The response to waterflooding within this project was similar to past waterfloods, indicating that this reservoir will not significantly respond to waterflooding.

Since the pattern producing wells are now producing near a 100 percent water cut, any additional oil recovery will be attributed to carbon dioxide injection. Therefore, the future oil production response of this project will demonstrate the feasibility of miscible carbon dioxide oil recovery in the Rock Creek Big Injun Field.

ACKNOWLEDGMENT

The authors wish to thank Pennzoil Company for the opportunity to prepare this paper and the following people for their help in its preparation: J. R. Blomberg, J. A. Crews, G. F. McCrady, S. J. Haught, and J. Whited.

TABLE I

	L. W. Shaffer No. 1 Five-spot	L. W. Shaffer No. 4 Five-spot
Area, acres	10.01	9.64
Average Øh	7.5073	7.4828
Primary Recovery, BPA	5,093	5,188
Secondary Recovery, BPA	3,225	2,818
Total Recovery, BPA	8,318	8,016
S_o - initial, %	53.8	53.8
S_w - initial, %	46.2	46.2
S_o - after primary, %	39.94	39.73
S_{or} - after secondary, %	34.13	34.63
Total Pore Volume, Bbls.	582,995	559,613
Hydrocarbon PV, Bbls.	198,976	193,794

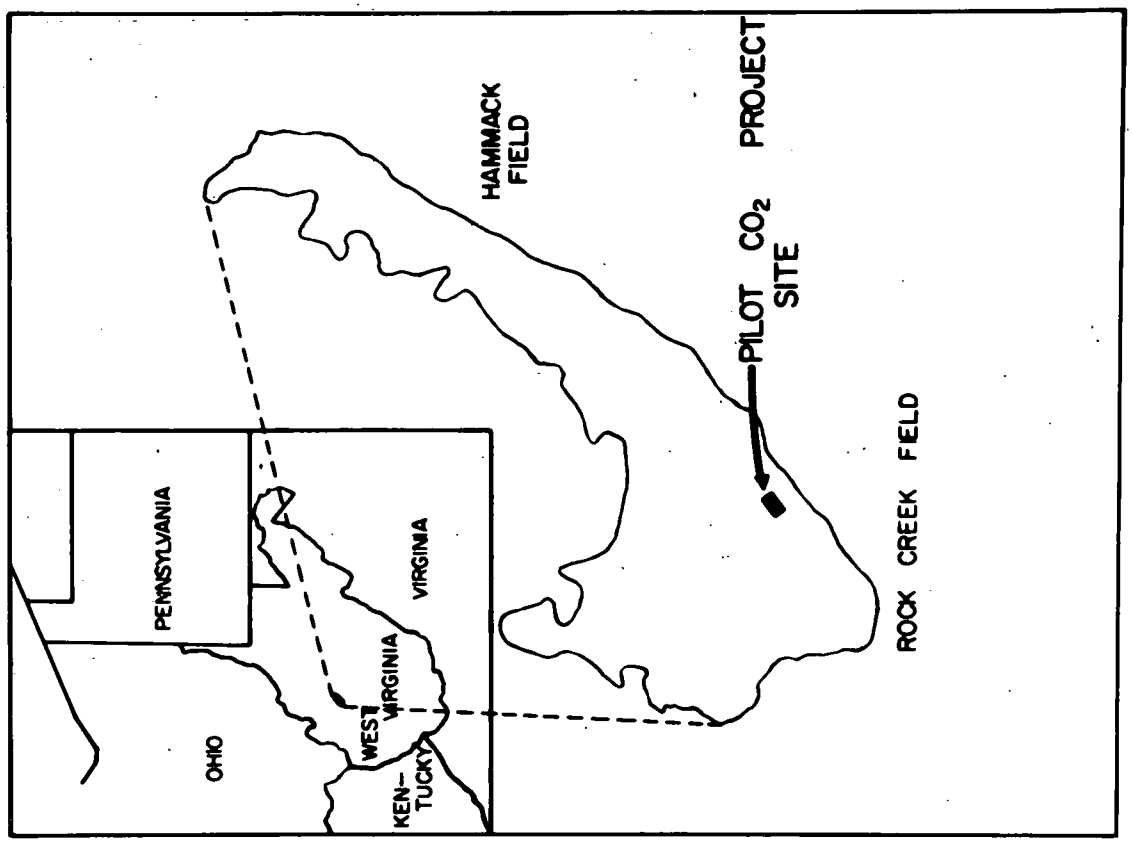


Figure No. 1 Location map of the Rock Creek CO_2 Pilot

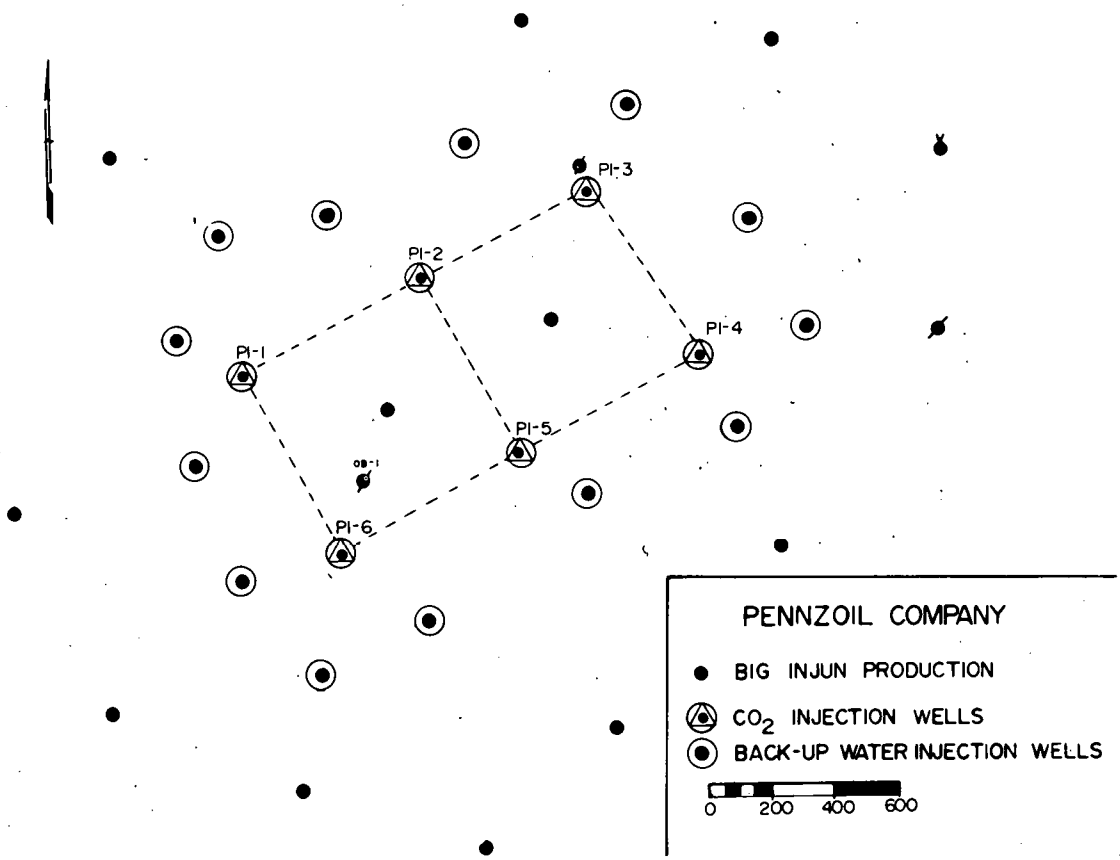


Figure No. 2 Rock Creek CO_2 Pilot Project

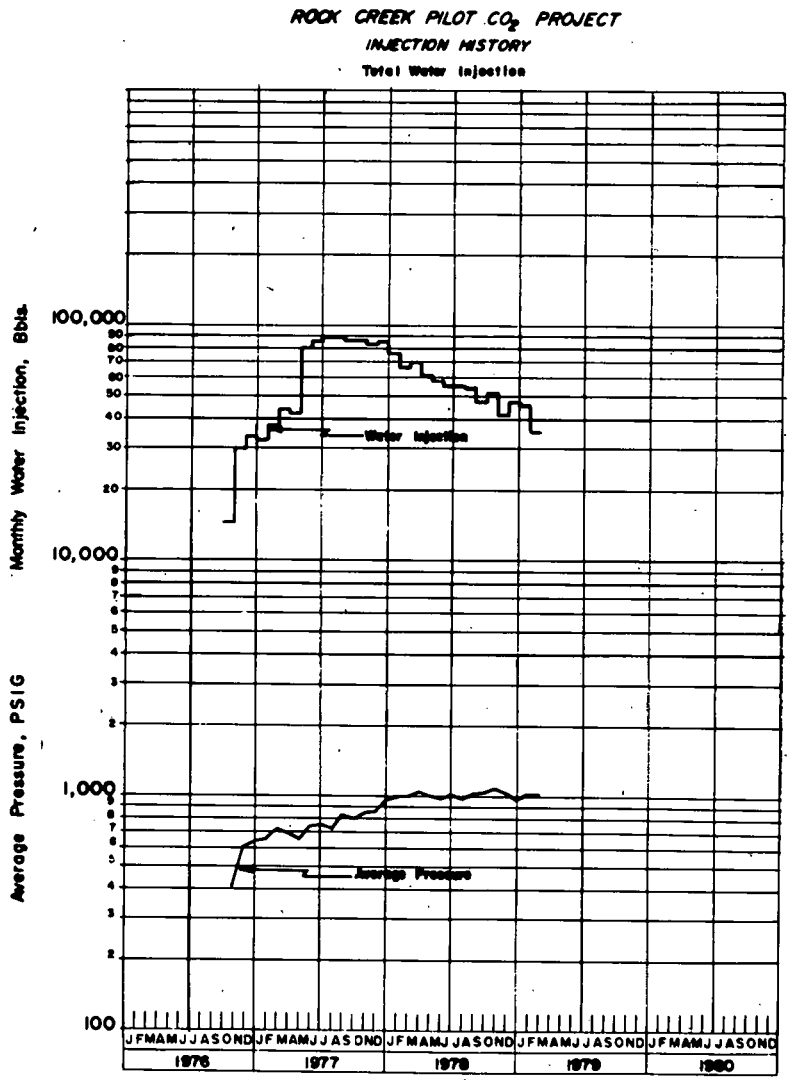


Figure No. 4 Production history of the Rock Creek CO_2 Pilot Project

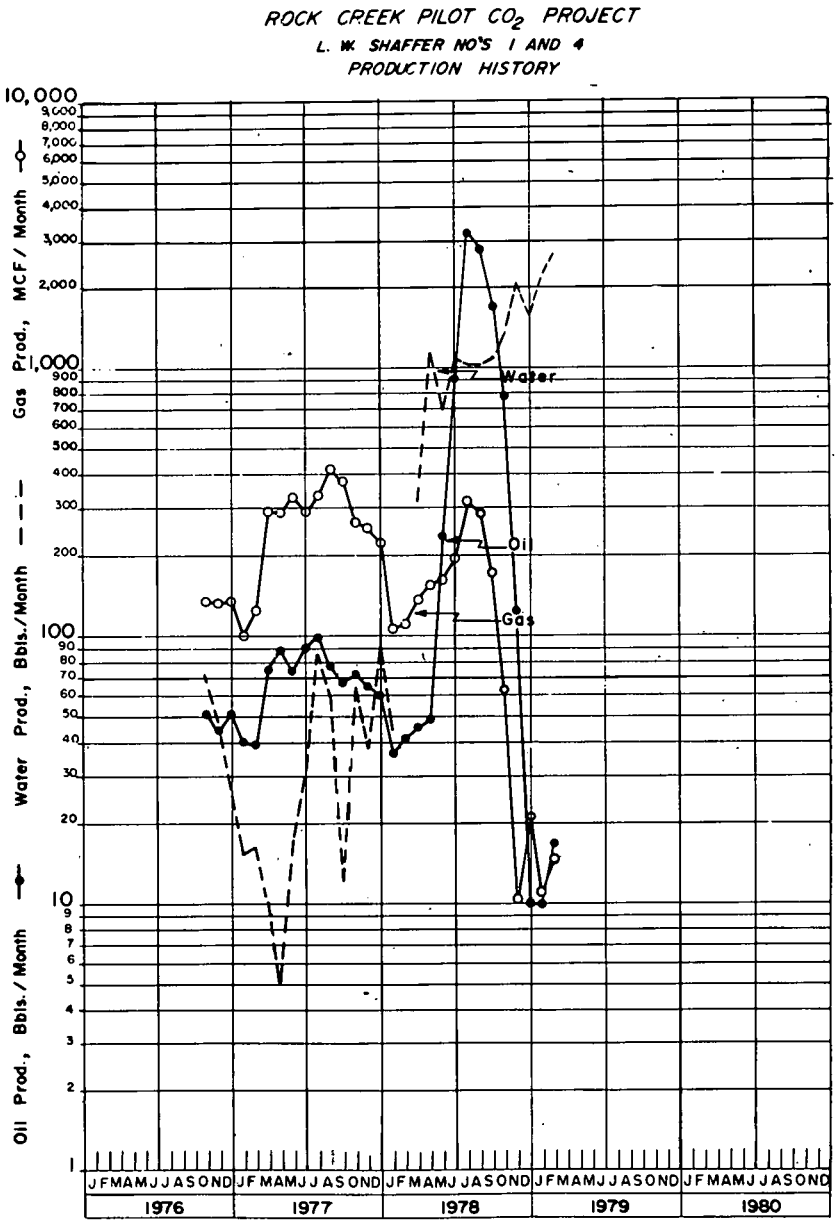


Figure No. 3 Injection history of the Rock Creek CO_2 Pilot Project

GRANNY'S CREEK CO_2 INJECTION PROJECT CLAY COUNTY, WEST VIRGINIA

by

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ABSTRACT

Columbia Gas Transmission Corporation, in conjunction with the Department of Energy, is conducting a field demonstration of oil recovery by CO_2 injection in Clay County, West Virginia. The objective of this test is to evaluate and demonstrate the effectiveness of using CO_2 injection to recover high gravity crude oil from shallow watered-out reservoirs.

The reservoir was repressured to approximately 1000 psi with water prior to CO_2 injection. The plant was completed and injection of CO_2 began on June 2, 1976. A total of 9800 tons of CO_2 was injected in several stages, alternating with water periodically for mobility control and better sweep efficiency. Injection of the CO_2 slug was completed on June 16, 1977. Water injection followed the CO_2 slug and continues to the present.

Oil production from the central producer peaked shortly after cessation of CO_2 injection and water production increased to about the same as before the project started.

Since it is felt that confinement was lacking in the original test, the current plans call for a "mini-flood" within the confines of the original 5-spot. This paper reviews the project to date and describes the progress to date of the "mini-flood".

Prepared for the Department of Energy,
under Contract No. EF-76-C-05-5302

INTRODUCTION & REVIEW

The Granny's Creek field is located in western Clay and southeastern Roane Counties, West Virginia, approximately 25 miles northeast of the city of Charleston, West Virginia. The field is approximately 5 miles long and 2 miles wide and contains approximately 3000 acres. Columbia has under lease approximately 1200 acres in the field and has produced approximately 3,000,000 barrels of oil from its leases.

The producing horizon in the Granny's Creek field is the Upper Pocono Big Injun Sand of Lower Mississippian Age. Production is primarily from three usually separate porous and permeable intervals that have been designated zones A, B and C. The A and B horizons are developed in the upper, coarse-grained part of the Injun sand and generally exhibit low to medium porosities and medium to high permeabilities. The C zone, on the other hand, is developed in the fine-grained, argillaceous sandstone that characterizes the lower part of the Injun sand in the Granny's Creek area, and generally shows very high porosity and low permeability. Oil production is controlled by both the structure of the field and by intraformational permeability and porosity pinch-outs.

The field was drilled in the period from 1916 to 1944 and at present is being waterflooded by Columbia on the southern 350 acres and in a pilot waterflood by Pennzoil in the northern part of the field.

The waterflood was initiated in 1964 by, a then subsidiary of Columbia Gas System, Preston Oil Conpany, with a 10 acre pilot project consisting of 6 water injection wells and 3 producers. Approximately 4000 barrels per acre of secondary oil was recovered with an approximate response time of 2 1/2 years.

Subsequently, in early 1975, the Columbia Gas System, acting in conjunction with the Morgantown Energy Research Center and the Pennzoil Company, drilled an additional well inside the pilot area as part of the Energy Research and Development Administration's continuing program for furthering the use of fracture systems for secondary recovery. In addition, residual oil saturation was determined and the feasibility of initiating a miscible flood process to recover additional oil was investigated.

Upon completion of the core analysis, log analysis, miscibility studies, fracture orientation determination and other important considerations, the reservoir conditions appeared to be favorable for tertiary recovery project utilizing a miscible flood technique.

Columbia began construction on the project in August 1975, with the resumption of water injection into the 6 original pilot water input wells in an attempt to repressure the reservoir to 1000 psi. Periodic bottom hole pressure tests were run on the inside producers to determine if this was being achieved. During the period from August 1975 to June 1, 1976, wells were reworked and CO_2 storage and injection equipment was ordered and installed.

During the preliminary testing and design phase of the project, three basic questions arose:

1. Is the residual oil saturation after waterflood high enough to warrant an attempt for tertiary oil?

2. How big a "slug" of CO_2 should be injected?

3. Should it be injected in one mass or in stages?

The first of these questions was answered by core analysis from a test well in the proposed pilot area as discussed above (an indicated 35%). On question #2 - based on the "state of the art" at the time, it was determined that a minimum of 4000 tons of CO_2 and a maximum of 8000 tons of CO_2 could be injected and give satisfactory results. This maximum and minimum was determined using the two prevailing methods of calculation; i.e., 200 scf/bbl. of oil, or 5% of the pore volume. The actual slug size was to be determined by observing and analyzing data as it was collected. On #3 - the "state of the art" also indicated that the CO_2 slug should be injected in one mass followed by alternate slugs of "carbonated" water.

CO_2 INJECTION

On June 1, 1976 approximately 300 barrels of natural gasoline was injected to promote miscibility and on June 2, 1976, CO_2 injection began.

While original plans called for the injection of 36 tons per day, the actual injection averaged 45-50 tons per day. During the latter part of July and early August, CO_2 was detected in the produced gas of both the inside and outside producers. After extensive testing and study, it was decided that enough CO_2 had been injected so that water could be injected without an adverse effect on the CO_2 slug. Subsequent to the injection of 1000 barrels of water per well, it was decided to alternate future injection of CO_2 with water, so that each well would follow the overall schedule listed below:

1) 800 Tons CO_2
2) 1000 Barrels Water
3) 500 Tons CO_2
4) 850 Barrels Water
5) 400 Tons CO_2
6) 680 Barrels Water
7) 300 Tons CO_2
8) 510 Barrels Water

This schedule was followed with little difficulty until mid December when the worst winter on record arrived. From mid December 1976 to mid March 1977, CO_2 was virtually nonexistent in Appalachia due to the natural gas crisis in the area. An attempt was made to inject water during this period, however, this was extremely difficult due to constant freeze-ups. As a result, reservoir pressure declined 400-500 pounds.

In mid March, CO_2 began to be available although it was necessary to bring it in from northwestern Ohio. Due to the distance involved, and the expense, we resumed injection with about 1/2 to 2/3 of the daily requirements of the project. However, this did arrest the decline in pressure and even increased it slightly.

When CO_2 became available again locally in April, it was decided that the remaining CO_2 would be injected in one slug rather than resuming the various cycles of the wells. It was also decided to add an additional 1000 tons of CO_2 after the 8800 tons in the original proposal had been injected.

CO_2 injection was completed on June 14, 1977 and water injection was resumed and has continued to date.

Cumulative injection of CO_2 per well is as follows:

#2020	#2022	#2023	#2025
2,364 Tons	2,794 Tons	2,264 Tons	2,456 Tons

Total: 9,878 Tons

We are currently injecting approximately 160 barrels of water per day or approximately 39 barrels per day per well.

PRODUCTION

Prior to June 15, 1976, all wells in the field except the 4 wells inside the pattern were pumped into a central tank battery and production allocated on the basis of pumping time. The 4 wells inside the pattern were shut-in for periodic BHP testing. On June 15, construction of lines and tank sites had been completed and the 12 wells involved in the project began producing into an individual tank for each well. Flow testing for different periods of time was initiated on the inside producers June 3, 1976, and continued until July 1, 1976.

From July 1, 1976 until August 30, 1976, these wells flowed 24 hours per day. On August 30, 1976, all of the inside producers, except well number 4254 had been shut-in and since that time have been used for reservoir testing only. During the fall of 1976, bottom hole pressure tests indicated a higher productive capacity in well number 4254 than the well was actually producing, although increases in production had been noted.

The well was therefore treated with carbon bisulfide, reconditioned and given a light fracture treatment in an effort to stimulate production. Production then increased from approximately 30 barrels per week to 60 barrels per week and was steadily climbing when winter arrived.

As pressure declined due to lack of sufficient injection media, production in the well declined to approximately 20 barrels per week. The cycle was repeated with the resumption of CO_2 injection. Since all indications pointed to a higher productive capacity for the well, the

decision was made to pump the well instead of allowing it to flow. Pumping equipment was installed in August of 1977.

Coincidentally, with the installation of pumping equipment and the resumption of water injection, oil production began declining and water production increased. This trend with minor fluctuation has continued to date.

While production increases were noted early in the wells outside the pattern, the most interesting one was well number 2046. Throughout 1976, this well had a bottom hole pressure in excess of 950 psi, yet flowed only 1-2 barrels per day. The well was tested and treated with carbon bisulfide to relieve paraffin blocks, to no avail. In May of 1977, the well was tubed and started to pump. Production then increased to approximately 23 barrels per day, again peaking in June and declining with the resumption of water injection.

The original proposal called for flowing the producing wells in order to maintain better reservoir control such as miscibility, sweep efficiency, reduce corrosion and prevent paraffin deposition. However, this soon proved to be inadequate to produce the wells to their capacity.

One of the most interesting aspects of the project was the low initial water volumes produced. In almost all wells, increases in initial oil production were noted with very little or no water production.

Since this project was installed in a "watered-out" section of our waterflood, it was expected that water production would come first, especially inside the pattern. This was not the case. Oil came first and only after CO_2 injection was completed did water production become significant.

Production in general has followed the same pattern. Increases in oil production with no increase in water followed by the reverse (decrease in oil production and increase in water production), when the CO_2 slug was complete and water injection resumed.

PROBLEMS

From an operational standpoint, three problems have

occurred: 1) the high pressure injection pump; 2) metering the liquid CO_2; and 3) the change over from CO_2 to water during injection cycles.

1. Although technically we were handling a liquid, the CO_2 had a tendency to vapor lock the pump, particularly in hot weather. Changes in insulation and piping design was the solution. Packing adjustment and the proper lubricating oil were critical due to the $0^{\circ}F$ operating temperature. Unlike a water pump, the packing on a CO_2 pump cannot be allowed to leak or ice will form and the packing will blow out. The proper lube oil must be used to keep vapor entrapment to a mimimum, and in general the plungers must be over lubricated or packing blow-outs will result.

2. The meters originally installed were water meters converted for CO_2 usage. However, these proved inaccurate and turbine meters were substituted with much better results.

3. While the water injection system was satisfactory during the life of the pilot waterflood, it proved unsatisfactory when the wells were periodically changed from CO_2 injection to water injection as outlined previously. This was due to the higher pressure necessary to inject water once the reservoir was pressured up.

This was especially true during the winter of 1976-77 when leaks and freeze-ups were a daily occurrence. However, when CO_2 injection was completed, these lines were tied into the water plant and the problem solved. Since these lines were all new, welded and wrapped, it is felt that they will be more than adequate for the life of the project. We have added to the water supply system and have replaced the filters, and associated equipment in the water plant in order to insure a larger and more reliable water supply and injection system. While all problems were not solved, we were able to maintain a much more reliable system during the past two winters.

One major problem that we anticipated was that of corrosion. While we have had our share of leaks, it has not been determined whether they were caused by CO_2. The

repairs have been no more frequent than when waterflooding.

We have had paraffin problems in certain wells and it has been necessary to steam the tubing when it gets serious enough to restrict production.

From a reservoir standpoint, the major problem is that of evaluating the project. It has been calculated that only 3%-6% of the injected CO_2 entered the pattern. If this is true, then oil recovery based on this volume is reasonable.

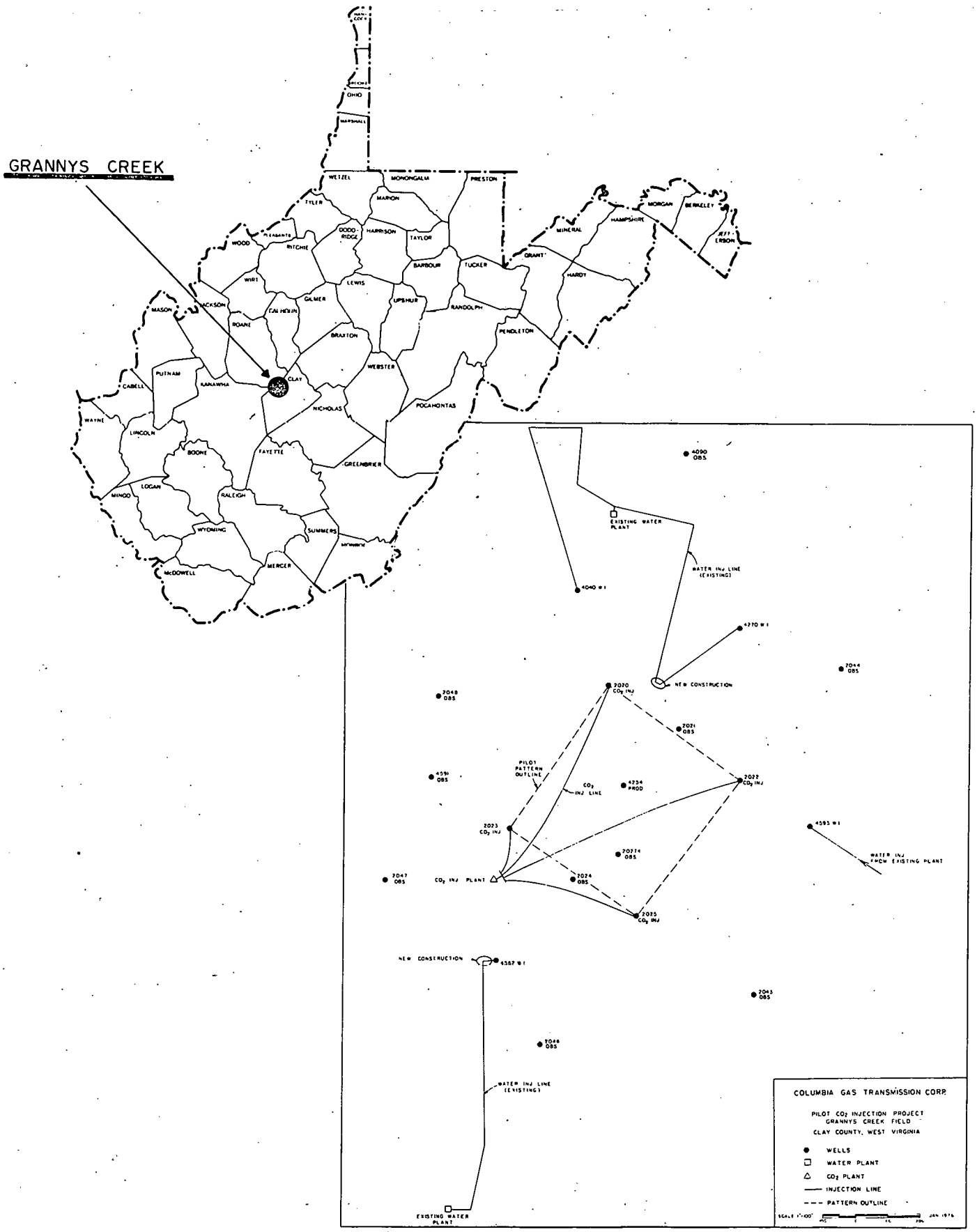
As a result of the many problems involved (mainly lack of confinement) and conflicting data derived, evaluation of the project became impossible. Most of 1978 was therefore spent trying to determine the best procedure to follow in obtaining the data necessary to make a final evaluation of the project. After many meetings with all parties involved, it was determined to modify the existing pattern and install a "mini-flood" within it.

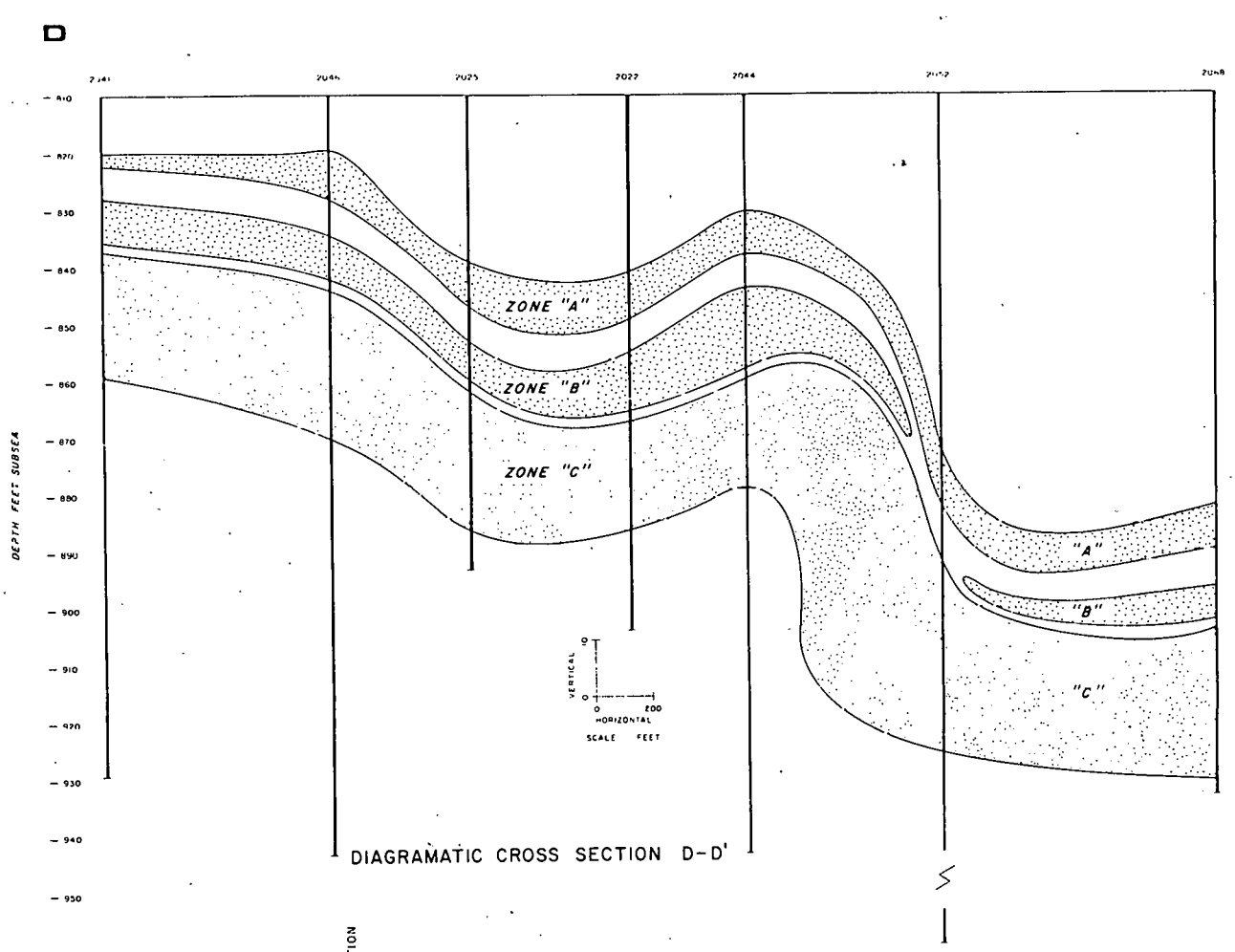
Under this plan, one test well inside the pattern (20274) would be converted to CO_2 injection and two test wells (4254 & 2024) would be converted to producers. One thousand tons of liquid CO_2 would be injected. Pressure build-up and fall-off tests would be conducted to determine communication and flow patterns. It would also be necessary to do certain construction work on wells and lines as well as adding gas separation and measurement equipment at the two producers. We would continue to inject water in the existing input wells and shut in all other producers in the first row of outside producers. It was felt that this plan would provide the confinement originally lacking in the project.

The above program was approved and work proceeded. To date all of the work outlined has been completed except injecting the CO_2.

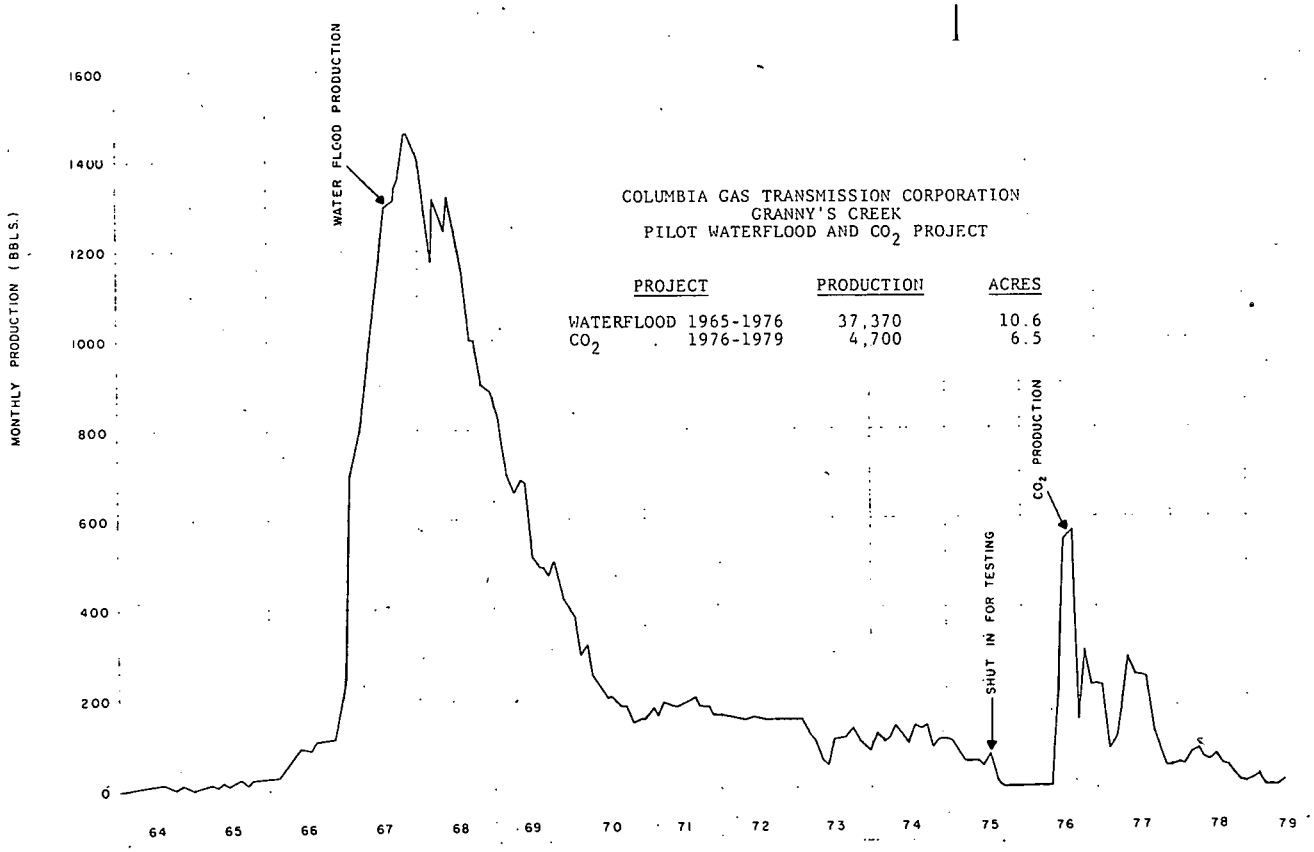
Since many problems were encountered with the repair and conversion to injection of the test well (20274) and delays were encountered in evaluating the pressure tests, it has been necessary to request additional funds from the government to avoid exceeding the contract.

This money has been requested but to date approval has not been received, however, approval is expected in the very near future.


GRANNYS CREEK
WETZEL
MONONGALIA
PRESTON
TYLER
MARION
MARSHALL
OHIO
WOOD
PLEASANTS
RITCHIE
DODDRIDGE
HARRISON
TAYLOR
BARBOUR
TUCKER
MINERAL
HAMPSHIRE
MORGAN
BERKELEY
JEFFERSON
GRANT
HARDY
WIRT
LEWIS
UPSHUR
RANDOLPH
GILMER
CALHOUN
JACKSON
MASON
ROANE
BRAXTON
PENDLETON
WEBSTER
CLAY
PUTNAM
CABELL
KANAWHA
NICHOLAS
POCAHONTAS
WAYNE
LINCOLN
BOONE
FAYETTE
GREENBRIER
LOGAN
MINGO
RALEIGH
WYOMING
SUMMERS
MONROE
MERCER
McDOWELL
4090 OBS
EXISTING WATER PLANT
WATER INJ LINE (EXISTING)
4040 W I
4270 W I
NEW CONSTRUCTION
7044 OBS
7048 OBS
2020 CO2 INJ
7021 OBS
PILOT PATTERN OUTLINE
4091 OBS
CO2 INJ LINE
4234 PROD
2022 CO2 INJ
2023 CO2 INJ
4593 W I
WATER INJ FROM EXISTING PLANT
7027A OBS
7047 OBS
CO2 INJ PLANT
7024 OBS
2025 CO2 INJ
NEW CONSTRUCTION
4587 W I
2043 OBS
7046 OBS
WATER INJ LINE (EXISTING)
EXISTING WATER PLANT
COLUMBIA GAS TRANSMISSION CORP.
PILOT CO2 INJECTION PROJECT
GRANNYS CREEK FIELD
CLAY COUNTY, WEST VIRGINIA
WELLS
WATER PLANT
CO2 PLANT
INJECTION LINE
PATTERN OUTLINE
JAN 1976

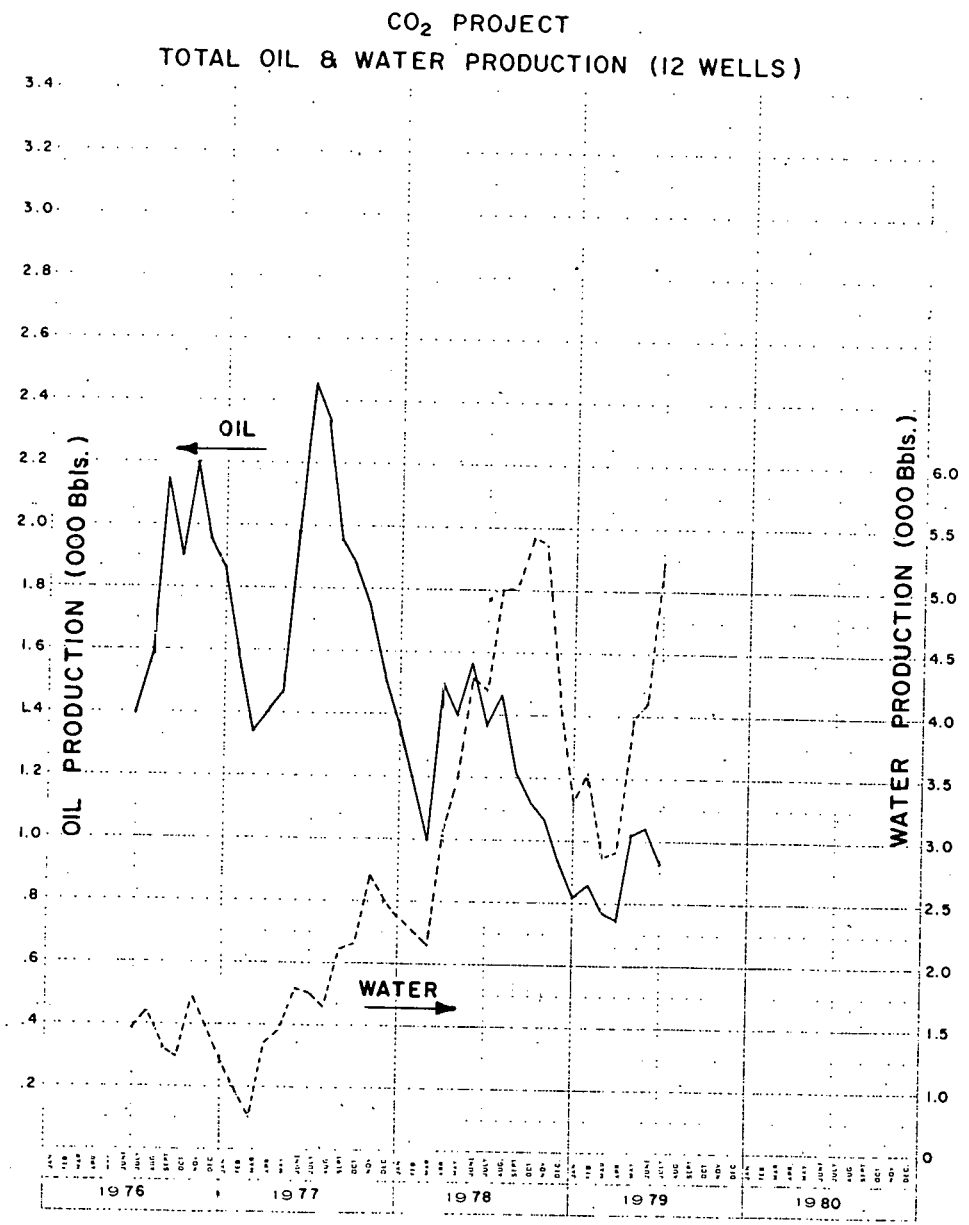


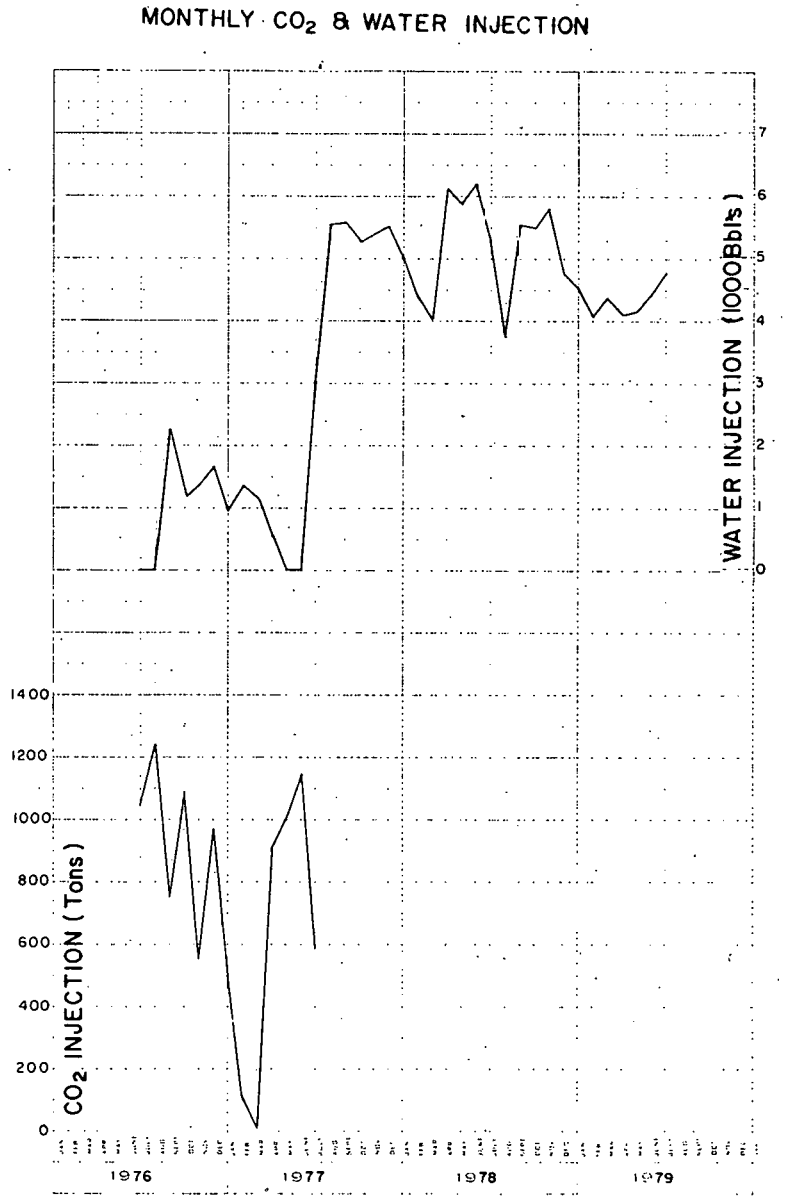
DIAGRAMATIC CROSS SECTION D-D'

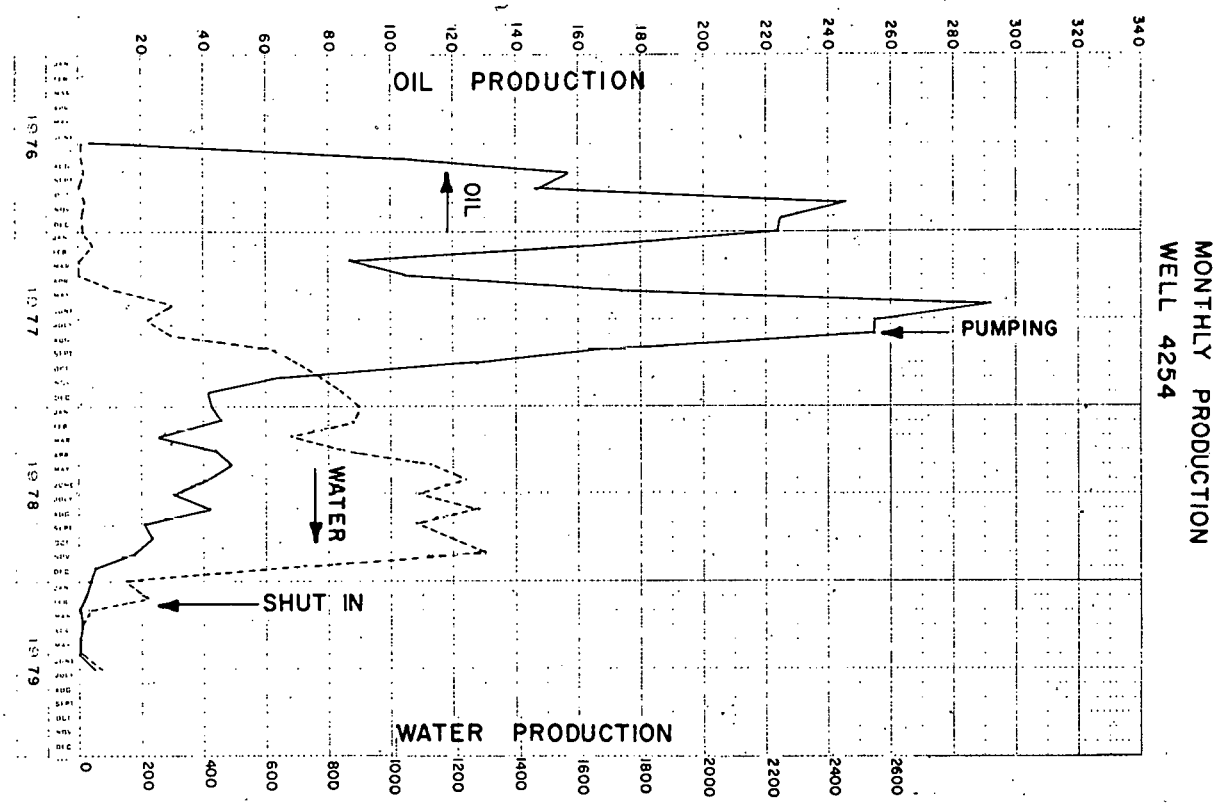


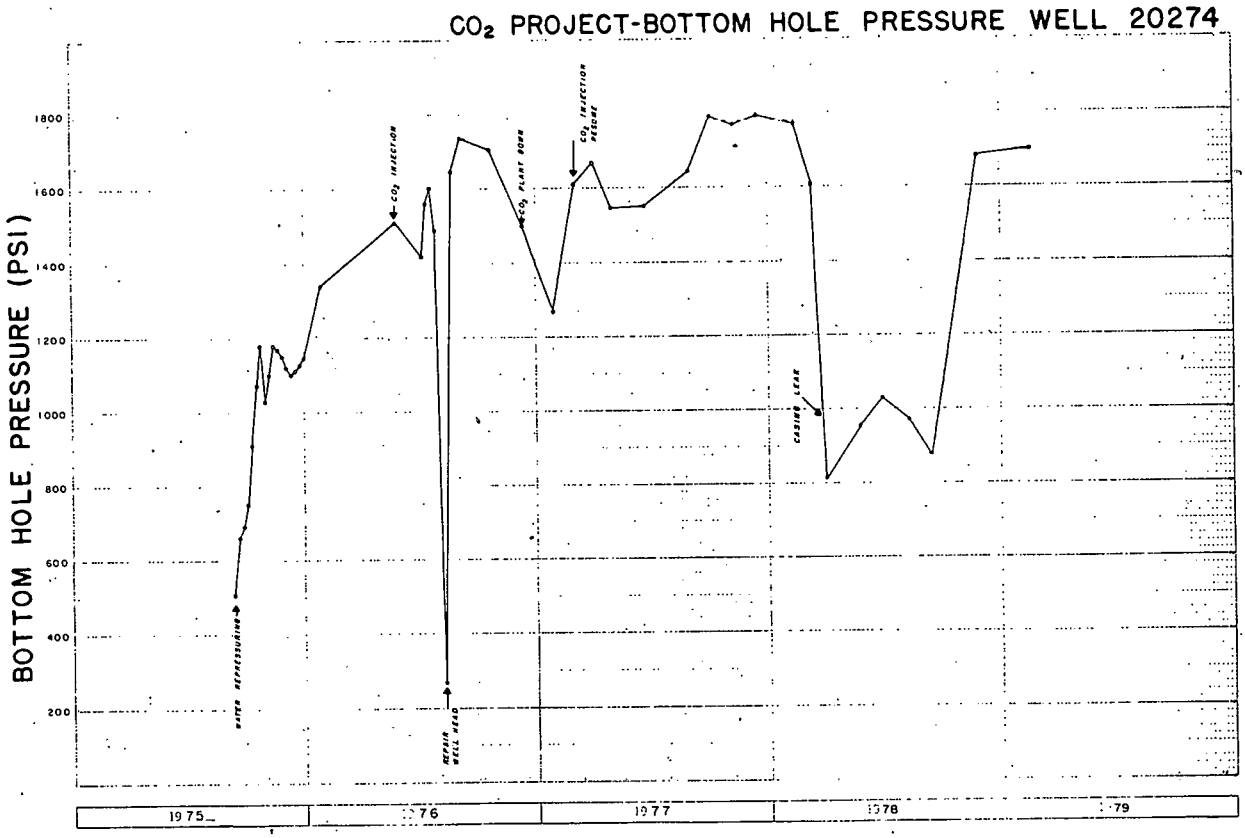
COLUMBIA GAS TRANSMISSION CORPORATION
GRANNY'S CREEK
PILOT WATERFLOOD AND CO_2 PROJECT

PROJECT	PRODUCTION	ACRES
WATERFLOOD 1965-1976	37,370	10.6
CO_2 1976-1979	4,700	6.5


CO_2 PROJECT
TOTAL OIL & WATER PRODUCTION (12 WELLS)
OIL PRODUCTION (000 Bbls.)
WATER PRODUCTION (000 Bbls.)
OIL
WATER
3.4
3.2
3.0
2.8
2.6
2.4
2.2
2.0
1.8
1.6
1.4
1.2
1.0
.8
.6
.4
.2
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0
1976
1977
1978
1979
1980


MONTHLY CO_2 & WATER INJECTION
CO_2 INJECTION (Tons)
WATER INJECTION (1000Bbls)
1400
1200
1000
800
600
400
200
0
7
6
5
4
3
2
1
0
1976
1977
1978
1979


OIL PRODUCTION
OIL
PUMPING
WATER
SHUT IN
WATER PRODUCTION
MONTHLY PRODUCTION
WELL 4254


CO_2 PROJECT-BOTTOM HOLE PRESSURE WELL 20274
BOTTOM HOLE PRESSURE (PSI)
1975
1976
1977
1978
1979

DO NOT MICROFILM
COVER





The University of Tulsa

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JOURNAL