BERC/TPR-77/1

**COMMERCIAL SCALE DEMONSTRATION
ENHANCED OIL RECOVERY BY MICELLAR-POLYMER FLOODING
M-1 PROJECT—DESIGN REPORT**

By

Marathon Oil Company

Prepared for ERDA Under Contract No. E(49-18)-2242

NOTICE

Date Published—April 1977

PORTIONS OF THIS REPORT ARE ILLEGIBLE. It
has been reproduced from the best available
copy to permit the broadest possible avail-
ability.

Bartlesville Energy Research Center
Energy Research and Development Administration
Bartlesville, Oklahoma

TECHNICAL INFORMATION CENTER
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Energy Research and Development Administration, nor any of their employees, nor any of their contractors, sub-contractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights.

This report has been reproduced directly from the best available copy.

Available from the National Technical Information Service, U.S. Department of Commerce, Springfield, Virginia 22161.

NATIONAL TECHNICAL INFORMATION SERVICE PAPER COPY PRICES EFFECTIVE JAN. 1, 1976

Page range	Domestic price	Page range	Domestic price	Page range	Domestic price	Page range	Domestic price	Page range	Domestic price	Page range	Domestic price
001-025	\$3.50	126-150	\$6.00	251-275	\$ 9.00	376-400	\$10.75	501-525	\$12.75	701- 800	\$18.75
026-050	\$4.00	151-175	\$6.75	276-300	\$ 9.25	401-425	\$11.00	526-550	\$13.00	801- 900	\$21.25
051-075	\$4.50	176-200	\$7.50	301-325	\$ 9.75	426-450	\$11.75	551-575	\$13.50	901-1000	\$23.75
076-100	\$5.00	201-225	\$7.75	326-350	\$10.00	451-475	\$12.00	576-600	\$13.75	1001-1100	\$28.25
101-125	\$5.50	226-250	\$8.00	351-375	\$10.50	476-500	\$12.50	601-700	\$16.25	1101-1200	\$32.75

For additional pages, add \$4.50 for each beginning 100 pages. Add \$2.50 per copy for foreign price.

Microfiche \$3.00 (domestic) \$4.50 (foreign).

COMMERCIAL SCALE DEMONSTRATION
ENHANCED OIL RECOVERY BY MICELLAR-POLYMER FLOODING

M-1 PROJECT
DESIGN REPORT

By

Bruce L. Knight, *Editor*

Contributing Authors

John M. Genziano
Floyd L. Legg
John S. Rhudy
Wayne O. Roszelle

Marathon Oil Company
Findlay, Ohio 45840

Prepared for the Energy Research and Development
Administration Under Contract No. E(49-18)-2242

Bruce L. Knight, *Project Coordinator*
Marathon Oil Company

William D. Howell, *Technical Project Officer*
Bartlesville Energy Research Center
Energy Research and Development Administration

NOTICE
This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Energy Research and Development Administration, nor any of their employees, nor any of their contractors, subcontractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights.

Date Published—April 1977

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
TECHNICAL INFORMATION CENTER

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

PREFACE

A contract was executed between the United States Energy Research and Development Administration (ERDA) and Marathon Oil Company, Findlay, Ohio, on September 30, 1976, for the purpose of a commercial scale demonstration of enhanced oil recovery by the MarafloodTM oil recovery process.

This commercial scale demonstration is known as the M-1 Project; it is located within Sections 15, 16, 21 and 22, T6N, R13W, Crawford County, Illinois. The M-1 Project area encompasses approximately 407 acres of Robinson Sand reservoir developed in the first decade of the century. The area covers portions of several waterfloods developed on 10-acre spacing in the 1950's that were approaching their economic limit. The project, as originally conceived, was confined to the M-1 Unit and contained 352 acres. The addition of producing wells on the south and west sides of the project increased its size to 407 acres. The inclusion of additional acreage into the project did not materially affect project reservoir engineering, which was based on leases within the unit boundary indicated on various exhibits in Part A of this report.

The Robinson Sand reservoir is a stream channel sandstone deposit of Pennsylvanian age at a depth of approximately 950 feet. Extensive reservoir studies were conducted to define the area and to determine flooding patterns to be developed to conduct the micellar-polymer project. Ultimately, a five-spot pattern configuration was selected using patterns of 2.5-acre spacing and 5.0-acre spacing to analyze relative system performance and economics.

TM Trademark of Marathon Oil Company, Findlay, Ohio

Critical to technical and economic success of the M-1 Project is extensive background work in the areas of reservoir engineering and fluid system design. Appropriate expertise within Marathon Oil Company was brought to bear on the problem of properly defining the M-1 Project reservoir and using advanced Company technology to design the most cost effective fluid system for the project. Technology applied to the M-1 Project represents the culmination of 15 years of field test experience in the Robinson Sand reservoir. When applied to a commercial scale demonstration such as the M-1 Project, it represents the industry's most advanced effort to economically produce tertiary oil using a micellar-polymer process.

Reservoir engineering and fluid system design aspects of the M-1 Project were nearing completion when the contract between Marathon Oil Company and ERDA was executed. In order that ERDA and the public could benefit from the work, Marathon proposed a special report be prepared to document details of all M-1 Project reservoir engineering and fluid system design efforts. This report, the Design Report, is the result of this proposal.

Reservoir engineering and fluid design aspects of the M-1 Project entailed the cooperative efforts of several persons at Marathon's Denver Research Center. Their efforts in this project are appreciated and acknowledged. Part A: M-1 Project Reservoir Engineering, was prepared by Marathon Oil Company's Production Technical Service Department, located in Denver, Colorado. The efforts of John M. Genziano and Floyd L. Legg are especially acknowledged. Part B: M-1 Project Fluid System Design, was prepared by the Company's Mara-

flood Services Department, also located in Denver. Special acknowledgement to Wayne O. Roszelle and John S. Rhudy is made for their work.

Bruce L. Knight
Project Coordinator

TABLE OF CONTENTS

	<u>Page</u>
PREFACE.	ii
<u>PART A: M-1 PROJECT RESERVOIR ENGINEERING</u>	
SUMMARY.	1
RESERVOIR DEFINITION AND MAPPING WORK.	6
General Geologic Description.	6
Sandstone Properties.	8
Basic Control Data.	9
Correlation Work.	12
Selection of Net Reservoir.	13
Mapping Work.	16
M-1 and 119-R Project Reservoirs.	18
AREA OF LOWER SAND STRINGER.	19
Reservoir Definition of Stringer.	19
Interference Testing.	23
Production Tests.	24
Computer Modeling	24
ANALYSIS OF PRODUCTION HISTORY	26
General Production History.	26
Data Analysis	28
Data Interpretation	31
Group I.	32
Group II	32
Group III.	35
Group IV	38
Oil Saturation.	39
M-1 and 119-R Projects - Waterflood Performance Comparison.	43
PORE VOLUME INTERPRETATION USING STREAMLINE MODELING	44
Definition of Objectives and Model Description.	44
Model Input and Operation	45
Data Interpretation	46
Peripheral Water Injection.	50

TABLE OF FIGURES

<u>Figure</u>		<u>Page</u>
A1	M-1 Project Location	52
A2	Location of Cross Sections	53
A3	Primary and Waterflood Wells	54
A4	Photomicrographs of Reservoir Sandstone.	55
A5	Photomicrographs of Reservoir Sandstone.	56

PART A: M-1 PROJECT RESERVOIR ENGINEERING

TABLE OF FIGURES (continued)

<u>Figure</u>		<u>Page</u>
A6	Photomicrograph of Reservoir Sandstone	57
A7	Comparison of Log and Core Data for Wells EE-17 and Q-6.	58
A8	Possible Sand Discontinuity in H. Martin Lease.	59
A9	Correlation Marker for Cross Section Work.	60
A10(a-c)	Cross Section A-A'	61
A11(a-b)	Cross Section B-B'	63
A12(a-b)	Cross Section C-C'	64
A13(a-c)	Cross Section D-D'	65
A14(a-b)	Cross Section E-E'	67
A15(a-b)	Cross Section F-F'	68
A16	Limited Extent of High Permeability Trend in Stacked Sand Area.	69
A17	Schematic of Random Occurrence of Non-Reservoir Rock	70
A18	Stiles Plot of Permeability Data	71
A19	Frequency Plot of Porosity Data.	72
A20	Correlation of Permeability and Porosity	73
A21	Net Sand Isopach	74
A22	Isoarithmic Permeability Map - Net Sand.	75
A23	Isogeometric Permeability Map - Net Sand	76
A24	Isoarithmic Permeability Map - Gross Sand.	77
A25	Isogeometric Permeability Map - Gross Sand	78
A26	Isoarithmic Permeability x Thickness Map (kh) Net Sand.	79
A27	Isoporosity Map - Net Sand	80
A28	Lorenz Coefficient - Gross Sand.	81
A29	Structure Contours on Coal Horizon (Sub-Sea)	82
A30	Isopach of Lower Sand Stringer	83
A31(a-b)	Cross Section G-G'	84
A32	Results of Core Test No. 1	85
A33	Results of Core Test No. 2	86
A34	Results of Core Test No. 3	87
A35	Iso-Oil Cut Map - Lower Sand Stringer Area	88
A36	Total Fluid Production Map - Lower Sand Stringer Area (contour interval 1 B/D/NF)	89
A37(a-d)	Well Performance Data.	90
A38	Core Analysis and Test Data for Well Bassom & Siler No. 12.	94
A39	Core Analysis of Well G-97	95
A40	Core Analysis of Well W. Mann No. 29	96
A41	Pre-Waterflood Cores with Low Measured Oil Saturation in Top.	97
A42	Pre-Waterflood Core Analysis - Iso-Oil Saturation.	98
A43	Model Segments for Streamline and Flood Front Work	99
A44	Streamlines for Segment I.	100

PART A: M-1 PROJECT RESERVOIR ENGINEERING

TABLE OF FIGURES (continued)

<u>Figure</u>	<u>Page</u>
A45	Streamlines for Segment II Without Peripheral Water Injection. 101
A46	Streamlines for Segment II With Peripheral Water Injection . . 102
A47(a-b)	Streamlines for Segment III Without Peripheral Water Injection. 103
A48(a-b)	Streamlines for Segment III With Peripheral Water Injection. . 105
A49	Streamlines for Segment IV 107
A50	Producer-Centered Pattern Confinement. 108
A51	Injector-Centered Pattern Confinement. 109

TABLE OF TABLES

<u>Table</u>	<u>Page</u>
A1	Average Reservoir Parameters 110
A2	Core Test No. 1 - Bassom & Siler Lease 111
A3	Core Test No. 2 - Bassom & Siler Lease 112
A4	Core Test No. 3 - R. A. Siler Lease. 113
A5	Results of Interference Testing. 114
A6	Cumulative Oil Production by Lease 115
A7	Pore Volume Data by Lease. 116
A8	Analysis of Lease Performance. 117
A9	Electric Log Interpretations 118
A10	Example Flood Front Results. 119
A11	Pore Volumes of Injector-Centered Patterns 120
A12	Pore Volumes of Producer-Centered Patterns 123
A13	Peripheral Water Injection Well Data 127
A14	Pore Volume Eliminated by Peripheral Water Injection 128

TABLE OF CONTENTS

	<u>Page</u>
<u>PART B: M-1 PROJECT FLUID SYSTEM DESIGN</u>	
SUMMARY	129
MARAFLOOD TM PROCESS TEST HISTORY	131
FLUID SYSTEM DESIGN.	135
Laboratory Testing Procedures.	135
Slug Design.	136
Feedstock.	137
Chemical Additives	137
Surfactant Concentration	137
Slug pH.	137
Sulfonate Molecule Cation.	138
Cosurfactant Type and Level.	138
Slug Size.	139
Polymer Design	139
REFERENCES	142

TABLE OF FIGURES

<u>Figure</u>	<u>Page</u>
B1 Alcohol-Viscosity Slug Behavior.	143
B2 Oil Recovery vs. Injected Slug Volume.	144
B3 Oil Recovery vs. Permeability.	145

TABLE OF TABLES

<u>Table</u>	<u>Page</u>
B1 Slug Composition	146
B2 Water Compositions	147
B3 Effect of Feedstock on Oil Recovery.	148
B4 Effect of Chemical Additives on Oil Recovery	149
B5 Effect of Slug Variables on Oil Recovery	150
B6 Core Flood Results Using Recommended Slug.	151

PART A: M-1 PROJECT RESERVOIR ENGINEERING

SUMMARY

The M-1 Project location is indicated on Figure A1. The project is situated in southeastern Illinois near the town of Robinson. This location is in Crawford County, approximately 50 miles southwest of Terre Haute, Indiana. The M-1 Project reservoir is a classic example of deposition by a meandering river with migrating point bars. Sand thickness varies from zero feet on the eastern edge of the project to about 60 feet in the center. Both multiple sand bodies stacked one above another and isolated sand lenses, found above and below the main sand, occur in the M-1 Project.

The M-1 Project contains 114 injection wells and 132 production wells in two nominal acreage development categories: 2.5-acre and 5.0-acre. These wells develop a total of about 407 acres of the Robinson Sand. The 2.5-acre wells are designated by a single letter and number (e.g., B-6), with the exception of E. C. Burch No. 5, XA-10, XA-12, XA-14 and AA-11, all of which are also included in the 2.5-acre area. The 5.0-acre wells are designated by two letters and a number (e.g., CC-15). However, wells Sally Carlisle No. 14, A. R. Smith Nos. 35 and 36 and Brubaker-Prier Fee No. 18 are also in 5.0-acre patterns.

Average reservoir parameters were determined for both the 2.5- and 5.0-acre sections of the project by integrating maps developed during this study. Following is a summary of average parameters for the net reservoir section:

<u>Parameter</u>	<u>2.5-Acre</u>	<u>5.0-Acre</u>	<u>Total Project</u>
Net Thickness, ft	29.3	25.5	27.8
Arithmetic Mean Permeability, md	100.3	107.0	102.8
Geometric Mean Permeability, md	75.5	79.3	76.9
Porosity, %	18.8	18.9	18.9
Lorenz Coefficient*	0.446	0.439	0.443

*based on gross section

Thin section and scanning electron microscope work show that pore throats of M-1 reservoir sandstone are restricted by kaolinite and calcite. This condition has reduced the permeability of the M-1 sand.

A sand stringer that underlies the main portion of the reservoir is present on the western edge of the project area (Bassom & Siler, A. Riker and northwest corner of the R. A. Siler leases). This lower sand stringer was not included as net reservoir based on the interpretations that: 1) it contains oil saturation at or below the laboratory-determined irreducible value; 2) it is generally of low permeability (approximately 15 md); and 3) there is a boundary composed of a zone of interbedded shale and sand (1-3 feet thick) between the main sand and this lower stringer.

Production performance of the leases within the M-1 Unit was studied in detail. Leases were organized into four groups. Group I contains the W. Mann, C. I. Weirich, H. Martin and Wakefield-Martin Community leases. Oil recovery and waterflood performance of Group I leases was taken as the norm to evaluate performance of other leases. Available production data indicate an average primary recovery of 17.9% of a pore volume (PV) and an average waterflood recovery of 12.7% PV.

Group II consists of the A. Riker and Bassom & Siler leases. The factor common to these two leases is the occurrence of the lower sand stringer mentioned above. When this stringer is excluded from net reservoir calculations, oil recovery performance for these leases is similar to Group I. This implies that the lower sand stringer contributed no measurable oil production during the primary and waterflood histories of these leases. Not all of the A. Riker lease has been developed; tertiary development ceased with the IT row because the net sand north of this row was judged to be too thin for economic development.

Group III consists of the J. N. Burch, Wakefield Heirs and R. A. Siler leases. These three leases had depressed oil recovery. The J. N. Burch lease did not perform well during primary production and was only partially developed for waterflooding. Waterflood performance was satisfactory in the area developed. Primary recovery from the Wakefield Heirs lease was somewhat below normal and waterflood recovery was well below normal. The R. A. Siler lease did not perform well during either primary or waterflood operations.

Group IV consists of two leases - the E. E. Martin and the S. Tohill A/C 3. Production from these leases came from both the main reservoir and lower sand lenses (not the lower sand stringer). Since this production was commingled in the wellbore, little confidence should be placed in these Robinson Sand recovery estimates.

The original connate water saturation in the M-1 area was probably in the range of 26 to 31% PV with an average of 28% PV. These values were taken from E-log analysis of waterflood wells that produced water-free oil on initial testing.

The present average oil saturation in the M-1 area may range from 40% to 45% PV based on connate water saturation values of 26 to 31% and an oil production material balance from the C. I. Weirich and Wakefield-Martin Community leases. A value of 40% PV is considered most representative for the project area. This is an average value on a project-wide basis and does not preclude localized anomalies of either higher or lower oil saturation.

Oil saturations below waterflood residual (12 to 20%) were noted in the upper section of several cores taken during waterflood development. These reduced saturations are probably the result of air repressuring operations. Other contributing factors could be gravity segregation and/or formation of secondary gas caps during the depletion phase of primary production.

Streamline and flood front modeling work have been done for the M-1 Project using a steady-state flow, unit mobility, piston-like displacement computer model. This work was used to estimate the pore volume for all patterns, including unconfined asymmetrical patterns, and to evaluate the effects of water injection at the project periphery. Data input to the streamline model included a net sand isopach and an isoporosity map, both generated during this study.

One conclusion reached from the streamline modeling work was that peripheral water injection will aid project confinement and decrease the amount of process fluids required for injection into the outside row of project injectors.

Fifteen existing wells are available for water injection; seven wells are active, three are not completed and five have been temporarily abandoned.

Following is a summary of pore volume calculations from streamline predictions for the injector-centered patterns. Any inverted pattern having a designated 2.5-acre injector was included in the 2.5-acre portion of the pattern; the same applied for a named 5.0-acre injector.

<u>Pattern Spacing</u>	<u>Injection Wells</u>	<u>Area Acres</u>	<u>Bulk Volume Acre-Ft</u>	<u>Pore Volume Bbls</u>
2.5-acre	85	247.9	7,268.8	10,627,513
5.0-acre	<u>29</u>	<u>159.1</u>	<u>4,058.7</u>	<u>5,947,610</u>
Total	114	407.0	11,327.5	16,575,123

Pore volume was also determined in the same manner for producer-centered patterns with the resultant total pore volume the same as for the inverted patterns. However, values of area and bulk volume for the two acreage categories differ due to different pattern boundaries predicted by the streamline computer model.

RESERVOIR DEFINITION AND MAPPING WORK

The reservoir in the M-1 Project has been geologically defined. A depositional model is presented that explains abrupt variations in reservoir thickness. Microscopic work performed on M-1 rock is described and control data available for microscopic reservoir definition are presented and discussed. Correlation work is exhibited that demonstrates reservoir continuity and exemplifies the growth, separation and coalescence of the various sand bodies comprising the reservoir. The procedure for net pay selection is presented with maps of reservoir parameters. Average values of reservoir parameters are tabulated separately for the 2.5-acre and 5.0-acre sections of the project.

General Geologic Description

The M-1 Project will be conducted in the Main Consolidated (Robinson) Sand of early Pennsylvanian age, which lies near the crest of the La Salle anticline. The name, Robinson Sand, has been given to the Main Consolidated oil sand that occurs between depths of 750 feet and 1000 feet throughout Crawford County, Illinois. The sand was named after the town of Robinson, which is approximately 10 miles northeast of the project site. Figure A1 locates the M-1 Project areally and geologically within the State of Illinois. Figure A2 presents the leases and wells comprising the M-1 Project. Figure A3 presents the primary and waterflood wells in the area.

The Robinson Sand satisfies the depositional model requirements of a meandering river with migrating point bars. That model is based on the fining-upward sequence of deposits associated with modern, relatively shallow meandering streams. It is characterized by a basal scoured surface followed by point bar

deposits, beginning with horizontally stratified or large scale cross-stratified medium grained sand at the base, and grading upward to ripple cross-stratified fine sand at the top. The point bar deposits represent lateral accretion in a meandering stream. They are overlain by vertical accretion deposits; that is, overbank silt and mud, deposited on the flood plain with evidence of alternating slow and rapid deposition. In addition to satisfying the requirements of the depositional model described, another line of evidence that suggests a fluvial depositional environment for the Robinson Sand is the absence of marine megafossils or microfossils, and the presence of abundant carbonized wood.

Considerable variation in sand thickness occurring over short lateral distances is characteristic of point bar-type deposits. Single sand bodies are seldom over 30 feet thick; thicker sands are usually caused by the merging of more than one sand body (stacked sands).

The M-1 Project reservoir is a classic case of this type of deposition. The main reservoir varies in thickness from zero feet at the pinch-out on the eastern edge of the project to 60 feet in the "stacked sand" section near the center of the project. This stacked sand section underlies the central 100 acres of the project and consists of two or more sand bodies "stacked" one above the other. Isolated sand lenses are found above and below the main sand in the M-1 Project. This is characteristic of meandering stream deposits. The isolated lenses are usually separated from the main reservoir section by 5 to 20 feet of shale. An exception to this trend is the lower sand stringer, confined to the western edge of the project, which is not separated by 5 to 20 feet of shale but rather by a thinner interval of shale and sand. The

characteristics of this lower sand stringer are presented in a later section entitled "Area of Lower Sand Stringer".

Sandstone Properties

The M-1 Project reservoir sandstone has been analyzed in detail using grain size analysis, x-ray diffraction methods, thin section study and scanning electron microscope (SEM) work. Eleven grain size analyses were run on selected samples from the project. The mean grain size is 3.527 phi units on the Wentworth scale, (0.088 millimeters), with a size breakdown as follows: 78% is larger than 0.0625 millimeters (sand); 13.5% is between 0.0625 and 0.002 millimeters (silt); and 8.5% is smaller than 0.002 millimeters (clay). The sand size fraction is unimodal with a mean grain size of 2.40 phi units (0.19 millimeters). Sand of this size is regarded as fine sand on the Wentworth Size Class scale. The Inclusive Graphic Standard Deviation (sorting) as calculated by the Folk-Ward equation is 1.9, placing the sandstone in the very poorly sorted category.

A heavy mineral analysis was run in conjunction with the grain size analysis. The heavy mineral content was negligible throughout the main sand with the exception of well E. E. Martin GG-19.

A set of thin sections and SEM photomicrographs have been examined that reveal the sand to be subangular, with a Powers roundness of about 2.5. The sand size fraction is composed of 95% quartz and 5% feldspar. The major cement is calcite and the minor cement is siderite. The SEM photos show that most of the clay is authigenic. As can be seen in the SEM photomicrographs in Figures A4 through A6, the pore throats are restricted by clay that has reduced the overall permeability (refer to Figure A6) of the sandstone.

Basic Control Data

The control data available for reservoir definition and mapping work can be broken into three categories: 1) primary development well data (well cards); 2) waterflood development well data (electric logs (E-logs) and cores); and 3) M-1 development well data (gamma ray logs, density logs and cores).

The primary development well reservoir data occur on well cards. A typical well card contains the following information:

- a) Date drilled
- b) Top and bottom of pay zones as picked by cable tool driller
- c) Initial oil production (first 24 hours)
- d) Total depth and/or plugback total depth (PBTD)
- e) Completion record
- f) Cleanout record
- g) Abandonment date

The well cards are useful sources for initial production data and provide completion, cleanout and abandonment records, but do not provide basic reservoir parameters.

The 61 wells drilled for waterflood development in the M-1 area were all cored and logged with a standard E-log combination of spontaneous potential (SP) and resistivity curves (16- and 64-inch normals). The E-logs and cores have been used extensively as a source of basic control data. The standard 10-acre five-spot pattern of waterflood wells has supplied a solid framework of data upon which to build. The 61 waterflood era cores were adequately described and a sample was taken from each foot of reservoir for laboratory measurements of permeability, porosity, oil saturation and water saturation. Permeabilities

were generally measured using low pressure air, and porosities by summing the fluids extracted from the sample. Oil and water saturations were determined using an electric retort.

Development wells drilled for the M-1 Project were all logged with a standard gamma ray log. Fifteen cores were also taken that supplement the 61 waterflood era cores. These cores were also analyzed for air permeability, porosity and oil and water saturations. The gamma ray logs provide a closely spaced network of reservoir thickness control. However, this log indicates only a gross sand thickness, not a net sand value. In an effort to better define the reservoir, a program using a gamma ray-density log was initiated that relogged 18 wells on the Wakefield-Martin Community and E. E. Martin leases. As a result of this work, a dispersed group of additional wells throughout the M-1 project was relogged using the gamma ray-density tool. The density logs provided infill data necessary to more confidently correlate non-reservoir, low porosity (inferred low permeability) trends found within the project. Figure A7 is an example of the gamma ray-density log run in injector EE-17 on the Wakefield-Martin Community lease. The gamma ray log alone provides a gross sand value with a slight indication of non-reservoir from 892-898 feet. However, the density log definitely shows the section from 892-898 feet as being a low quality section within the main reservoir sand. The E-log and core analysis of waterflood well Q-6, (also presented on Figure A7) 170 feet north of EE-17, confirm this premise (note 900-904 feet on core analysis and 898-904 feet on E-log). Another feature gained from the density log was improved definition of the top and bottom of the reservoir. Point A on the density log of well EE-17 (Figure A7) is the true top of the sand but without the density log, point B on the gamma ray, 2 feet

higher, would have been chosen. A further refinement was that the coal seam found at the base of the sand in well EE-17 was not recognized until the density log was run. Accordingly, this injection well was plugged back to isolate the coal from the main reservoir to prevent the possibility of fluid loss at the sand-coal interface.

The relogging of M-1 Project wells with a density tool presented several interpretation problems. One problem occurred because a sonde had to be selected that could be run down 4-1/2-inch O. D. casing to log the open hole section below the casing shoe. This requirement dictated that a compensated density log could not be used. The uncompensated dog-leg type sonde chosen was used to provide relative bulk density measurements (sand-shale) in a given well and was not used to calculate porosity. A second problem occurs when the sonde approaches the casing shoe and is forced away from the borehole wall. The result is a "spike" occurring on the density log that masks the bulk density reading at the top of the sand. If the casing shoe is located above the top of the sand as in the case of well EE-17 (Figure A7), the top is accurately investigated and recorded. The final problem with interpretation is the possible presence of siderite occurring in varying amounts as an intergranular cement. This causes an unadjusted porosity calculation to be very pessimistic. Since the concentration of siderite varies in a siderite-cemented zone, a constant correction for the grain density cannot be used. In this case, the gamma ray will give the best gross sand value.

In conclusion, E-logs and cores from the waterflood era provided the framework and gamma ray logs, density logs and additional cores supplied the infill data necessary to carry out the detailed reservoir study presented in this report.

Correlation Work

Continuity of the Robinson Sand in the M-1 Project was established by 20 cross sections that used logs from every M-1 producer and injector and all waterflood wells. A 5- to 7-acre area of possible sand discontinuity exists in the undeveloped portion of the H. Martin lease where the sand pinches out (see Figure A8). The complex lensing nature of the Robinson Sand can be seen on the cross sections. They also illustrate the stacked sand mentioned in the "General Geologic Description" section.

All correlation work was referenced to the closest continuous coal above the Robinson Sand. This coal lies about 100 feet above the top of the Main Robinson Sand (see Figure A9).

Six example cross sections are included in this report. Figure A2 shows the location of these cross sections and a discussion of each follows.

1) Cross section A-A', Figure A10 (a-c), begins at well B-0 in the J. H. Wasson lease. A 2-acre stacked sand area occurs in the extreme southwest part of the project. A single thin lens carries from well D-2 to well F-4 where a second lens merges between wells F-4 and G-5. A third lens converges between wells M-11 and N-12 at the base of the other two lenses. The basal third lens pinches out between wells Q-15 and N-94. The sand thickness remains fairly constant until the end of cross section A-A' at well QQ-15.

2) Cross section B-B', Figure A11 (a-b), begins at waterflood well No. 16 in the R. A. Siler lease. A correlative shale break can be followed through well Nos. 16 and I-1 to I-5. A basal sand lens pinches out between wells I-11 and I-13. An upper sand lens is stacked onto the main sand between wells I-13 and I-15. The sand thickness remains fairly constant until the end of cross section B-B' at well GG-19.

3) Cross section C-C', Figure A12 (a-b), begins at waterflood well No. 16 in the S. Carlisle lease. Two upper sand lenses are stacked onto the main sand between wells T-4, T-6 and T-8. The stacked sand continues until an upper lens pinches out between wells T-14 and NN-12. The main sand pinches out between wells NN-14 and the cored dry hole NN-16.

4) Figure A13 (a-c), cross section D-D', also illustrates the coalescing of sand lenses to form a continuous reservoir section. Cross section D-D' shows the western lens merging with the eastern lens between wells U-7 and T-8 and the eastern lens merging with the western lens between wells M-15 and waterflood well N-3. Although the lower sand stringer is noted by stippling on this and the following two cross sections, discussion will be limited to a subsequent section of this report.

5) Cross section E-E', Figure A14 (a-b), begins at well A-3 and continues north along the western edge of the project ending at well A-84. Two wells, F. L. Dewey A-98 and S. Carlisle No. 16, which are outside the M-1 Unit boundary, have been included in this cross section.

6) Cross section F-F', Figure A15 (a-b), cuts across the Bassom & Siler lease to the northeast and details the lower sand stringer.

Selection of Net Reservoir

Net reservoir determination is very important to tertiary recovery economics. All fluids are injected in relation to net reservoir, i.e., net sand thickness. Economics will be less than optimum if either too little or too much micellar solution is injected. Therefore, an intensive study was made to determine net reservoir for the M-1 Project.

This study revealed no general correlative permeability trends that can be carried for any great distance. In the case of the central 100 acres, the junction between the two stacked sand lenses is a clean sand-on-sand contact. The sand-on-sand contact may permit crossflow and should not severely hamper vertical conformance. In a small portion of the stacked sand area the upper lens is more uniform and permeable than the lower lens. The permeability ratio of the top lens to the bottom lens is 2:1. Figure A16 shows the higher permeability upper sand in wells G-97 and GI-3, but it also shows it is not present in the upper section of well C. I. Weirich No. 7 just 330 feet away. This demonstrates the limited areal extent of correlative permeability trends in the area where they should be most apt to occur.

Study of the core data showed that dispersed non-reservoir rock generally occurs randomly throughout the reservoir section. Such non-reservoir rock is that other than correlative shale streaks. Figure A17 schematically illustrates this dispersed non-reservoir rock.

Assuming that non-reservoir rock is randomly distributed, a Stiles plot prepared from the approximately 2,100 core samples should represent all possible permeability samples from every part of the area. In other words, if there were an infinite number of samples from each core, the Stiles plot (fractional kh versus fractional h) prepared using those data would be the same as the one prepared using the 2,100 samples taken from the 61 wells cored in the waterflood development and 15 wells cored during M-1 Project development. The Stiles plot is attached as Figure A18; it shows that 99% of the capacity (kh) is contained by 84% of the reservoir interval.

The porosity data were also statistically evaluated. Figure A19 is a frequency plot of these data sorted into classes that describes a normal statistical distribution except for the tail of low porosity values. Figure A20 is a correlation of average permeability for each class of samples versus class porosity. Figure A19 shows that a significant number of low porosity (less than 13%) samples exist in the project area and Figure A20 shows that they are correlative with the low permeability samples (i.e., where permeability is good, porosity is good).

After examining these statistical data, two parameters were considered for use in distinguishing between net reservoir thickness and gross reservoir thickness. They were a flow capacity cut-off and a permeability cut-off. A combined approach was selected that used a permeability cut-off such that most of the flow capacity was included in the net sand.

The permeability value selected as a cut-off was 10 md. This value includes over 99% of the flow capacity and is shown on the Stiles plot of the M-1 samples (Figure A18). The 10 md cut-off eliminates those samples containing less than 13.4% porosity, or in other words, eliminates the low porosity "tail" on the porosity distribution shown on Figure A19.

After it was decided that a 10 md cut-off was justifiable to separate net sand thickness from gross sand thickness, it was still necessary to develop a procedure to extrapolate the cut-off to uncored wells. This was done as follows:

- 1) The gross section was selected for each well using gamma ray and density log data.

- 2) The adjusted gross section was picked for each well by deleting correlative shale streaks shown by logs and not necessarily reflected by core analyses due to sampling techniques (i.e., shale was not sampled). In most cases the gross section and adjusted gross section are identical.
- 3) The ratio of net sand to adjusted gross sand was calculated for each cored well and the resulting 76 control points were mapped using isopercentage values to the nearest 1%.
- 4) The isopercentage values were interpolated for uncored wells and net sand values were calculated by multiplying this percentage value by the adjusted gross section determined from log analysis. These net sand values were then mapped, resulting in the net sand isopach (Figure A21) for the project.

The lower sand stringer present on the western flank of the project is not considered part of the net reservoir and is not included in the net sand isopach.

Mapping Work

Reservoir parameters other than net reservoir thickness have also been mapped.

These parameters include:

1) Arithmetic Mean Permeability - Net Sand	Figure A22
2) Geometric Mean Permeability - Net Sand	Figure A23
3) Arithmetic Mean Permeability - Gross Sand	Figure A24
4) Geometric Mean Permeability - Gross Sand	Figure A25
5) Arithmetic Mean Permeability x Net Sand Thickness	Figure A26
6) Porosity - Net Sand	Figure A27
7) Lorenz Coefficient - Gross Sand	Figure A28

These parameters were calculated for each well by inputting data from the 61 waterflood era cores and the 15 tertiary era cores into a data processing program. The average reservoir parameters by well were then input to a computer mapping program that generated maps that were subsequently smoothed by hand.

A structure map (Figure A29) was prepared using a thin coal horizon about 100 feet above the reservoir as the reference marker. Every well in the area having a wire line log (approximately 300) contributed control to this map.

Inspection of these maps and of the net sand isopach reveals that the permeability maps generally have the same trends as the net sand isopach. The porosity map does not obviously trend with any of the other maps even though statistically analyzed core data (Figure A20) indicate a correlation with permeability.

The Lorenz Coefficient map (Figure A28) indicates a high degree of heterogeneity in the A. Riker lease and much of the Bassom & Siler lease. These data were the initial "flag" that eventually resulted in elimination of most of the A. Riker lease from development. This is discussed later in the section entitled "Group II".

Average reservoir parameters were determined for both the 2.5-acre and 5.0-acre sections of the project by integrating these maps. Average parameters are summarized in Table A1.

M-1 and 119-R Project Reservoirs

The following is a summary of selected average M-1 Project reservoir parameters and 119-R Project reservoir parameters. The 119-R Project is located several miles north of the M-1 Project in the Main Consolidated Sand.

<u>Parameter</u>	<u>119-R Project</u>	<u>M-1 Project</u>
Net Thickness, ft	25.0	27.8
Arithmetic Mean Permeability, md	211.0	102.8
Average Porosity, %	19.3	18.9

The 119-R Project was initiated in 1968 and is essentially complete. Performance of the Maraflood process in this 40-acre tract of the Robinson Sand helped form the basis for expansion of the process to the commercial scale demonstration M-1 Project. A brief historical perspective of Maraflood process test history is given in the section entitled "Maraflood Process Test History" in Part B of this report.

The above data may be summarized as follows: The M-1 Project is being conducted in a thicker, less permeable, slightly less porous section of the Robinson Sand compared to the Henry reservoir in the 119-R Project area.

It should also be noted that the M-1 Project is being conducted in a typical Robinson Sand reservoir that has been profitably exploited for 70 years under primary depletion and secondary waterflooding operation.

AREA OF LOWER SAND STRINGER

A sand stringer that underlies the main portion of the reservoir is present on the western edge of the project area (Bassom & Siler, A. Riker and north-west corner of the R. A. Siler leases). It is separated from the main reservoir throughout the major portion of these leases by what is judged to be a thin impermeable zone of interbedded shale and sand. Since the contact between the main sand and lower sand stringer appears to be sand-on-shale and not sand-on-sand as in the stacked sand area, crossflow should be limited. In small areas where the main reservoir lies sand-on-sand with the lower sand stringer or where the zone of interbedded shale and sand may be fractured, potential for crossflow exists.

Reservoir Definition of Stringer

Correlation and mapping work show that the lower stringer is a bench-like deposit of sand. Sand occurring in this fashion is indicative of migrating sand waves that commonly occur in a non-marine, fluvial environment, i.e., in a fresh water river. Figure A30 is an isopach map of gross sand stringer thickness. Cross sections C-C', Figure A12 (a-b), D-D', Figure A13 (a-c), E-E', Figure A14 (a-b), F-F', Figure A15 (a-b), and G-G', Figure A31 (a-b) illustrate occurrence and character of the lower sand stringer. Conclusions drawn from the cross sections are as follows:

- 1) A zone of interbedded sand and shale generally separates the lower stringer from the main sand.
- 2) The main sand occasionally lies directly on top of the lower stringer as illustrated in wells V-0 and A. Riker A-84 from cross section E-E', Figure A14 (a-b).

- 3) The lower stringer is discontinuous as shown on Figure A13 (a-c) and Figure A15 (a-b).

Figure A31 (a-b) is another cross section (G-G') illustrating continuity and log character of the lower sand stringer; it includes logs from three post-waterflood era core tests drilled to improve reservoir definition. The location of this cross section is shown on Figure A2 with the location of the three core tests. This analysis shows that the lower sand stringer completely underlies the A. Riker lease, the western two-thirds of the Bassom & Siler lease and the northwest corner of the R. A. Siler lease.

Core Test (CT) No. 1 contained both the main sand and the lower sand stringer. In general, core analysis oil saturations were higher in the main sand than in the lower stringer but permeabilities were low in both sections. Results are summarized below and are shown in detail on Figure A32 and in Table A2.

	<u>CT No. 1</u>		
	<u>Interval, ft</u>	<u>$\bar{S}_o$, %</u>	<u>$\bar{k}$, md</u>
Main Sand	909-927	29.5	25.8
Lower Sand	927-940	23.6	14.7

CT No. 2 also contained both the main sand and lower sand stringer. Core analysis oil saturations were good in the main sand but were low in the lower stringer. Permeabilities were better in the main sand and in the bottom part of the lower stringer when compared to CT No. 1. Results are summarized below and are presented in detail on Figure A33 and in Table A3.

CT No. 2

	<u>Interval, ft</u>	<u>S_o, %</u>	<u>k, md</u>
Main Sand	922-941	31.4	72.0
Lower Sand	941-962	19.1	32.3
Bottom Section of Lower Sand	958-962	18.2	116.0

CT No. 3 did not contain the lower sand stringer. Core analysis oil saturations and permeabilities were good throughout the main sand section. Results are summarized below and are presented in detail on Figure A34 and in Table A4.

CT No. 3

	<u>Interval, ft</u>	<u>S_o, %</u>	<u>k, md</u>
Main Sand	886-914	32.1	100.6

Log suites consisting of a formation compensated density log (FDC), gamma ray, dual induction laterlog 8 and SP curve were run on all three core tests. Log-derived porosities agreed well with core porosities for the main sand but were not in agreement with core porosities for the lower sand stringer. The reason for the difference was found to be a high grain density in the lower zone. Measured values of about 2.95 g/cc on samples from the lower stringer compared to the conventional value of 2.65 g/cc for sandstone. The higher grain density was also apparent from heavy mineral separations that revealed extremely large heavy mineral residues in the lower sand stringer from the Bassom & Siler lease. The weight of the heavies represents 10.0 to 12.5% of the sand size fraction in the lower sand stringer. Siderite was the primary heavy mineral, approximately 90%, with minor amounts of dolomite and opaques. The high concentration of siderite dispersed throughout the sand in the lower stringer makes the standard grain density of 2.65 g/cc unusable in this zone.

If a 2.65 g/cc grain density were used in the Wylie equation to calculate porosity from a formation density log, the resulting porosity would be low by 10 to 11 porosity units.

An attempt was made to define water saturations from log data in the three core tests. Log-derived saturations did not consistently track core saturations and at times yielded oil saturation values less than those measured by core analysis. The problem with log interpretation could not be attributed to water resistivities (post-waterflood) because these were measured on samples from producing wells in the area. Values ranged from 0.25 to 0.53 ohm-m²/m.

Data taken from these core tests coupled with core analyses and core descriptions from the waterflood development wells (in particular Bassom & Siler No. 12) indicate:

- 1) The lower sand stringer contains an oil saturation at or below irreducible as determined by laboratory methods.
- 2) The lower sand stringer is generally of low permeability (approximately 15 md).
- 3) The main sand contains an oil saturation well above irreducible except in the region around well Bassom & Siler No. 12.
- 4) The main sand ranges in permeability from about 25 md near CT No. 1 to about 75 md near CT No. 2.
- 5) The boundary between the main and lower sands is generally composed of interbedded shale and sand about 1-3 feet thick. This boundary is judged to be impermeable where the interbedded zone exists and where it is not fractured.

Interference Testing

Interference testing was done in four locations within the area containing the lower sand stringer in an effort to better define reservoir permeability. The tests were conducted by injecting water into an injection well and observing the fluid buildup in offset production wells. Response was measured daily using an Echometer to determine height of the fluid column in the wellbore. A water gradient was applied to changes in fluid height to calculate pressure values. Analysis of pressure data was accomplished using a computer program that applies a least squares regression technique to calculate reservoir properties that best explain observed transient test data.

Interpreted results of the testing are summarized below and are presented in detail in Table A5.

<u>Test Area</u>	<u>Mobility k/u, md/cp</u>	<u>Storage øc, psi⁻¹</u>	<u>Remarks</u>
SS-3	5	6×10^{-7}	
Q-3	20	6×10^{-6}	
U-5	6	1×10^{-6}	
S-7	12	1×10^{-6}	No lower sand present

Data from injection into well SS-3 are of dubious quality due to low and erratic injection rates and the resulting low level of response in the observation wells. The data from wells Q-3, U-5 and S-7 appear to be of reasonable quality and mobility values are in relative agreement with core data in the area. Storage factors indicate little or no free gas saturation.

Production Tests

Production tests were run on 27 development wells in the A. Riker, Bassom & Siler and R. A. Siler leases. At the time of these tests, the lower sand stringer was open in many of the wells. Figures A35 and A36 present maps of the average oil cut and total fluid production normalized to net reservoir (main Sand) thickness. Inspection of these maps indicates:

- 1) Oil cuts in the interior of the Bassom & Siler lease were greater than normally found in a waterflooded reservoir. The lowest cuts generally coincide with the waterflood development except for wells V-2 and T-2, which are in the vicinity of well Bassom & Siler No. 12.
- 2) Total fluid withdrawal rates expressed in barrels per day per foot of net pay (B/D/NF) correlate with the permeability maps - Figures A22 through A25. An area of low fluid withdrawal in the interior of the Bassom & Siler lease coincides with an area of low permeability shown on the permeability maps. The same is true at the western edge of the R. A. Siler lease.

Computer Modeling

A two layer conceptual model was used to determine if oil banked in the more permeable, higher oil saturation main sand reservoir would flow down into the lower sand stringer. To approximate the Maraflood process, a stabilized oil bank was simulated at the injection well by simultaneously injecting oil and water into the main sand only. At breakthrough of the stabilized oil bank at the producing well, model predictions for oil saturations, pressures and oil migration were monitored. Effects from different vertical permeability values between the two layers, injection rate, oil cut of injected fluid and capillary pressure were also studied. Modeling work indicates that banked

oil, and probably injected slug and/or polymer, will migrate to the lower sand stringer if any vertical communication exists. Since the Maraflood process was not precisely simulated by this work, it is not known how much oil, if any, might flow to the lower stringer, nor is it possible to predict if any migrated oil would be recovered within the time frame of the project.

ANALYSIS OF PRODUCTION HISTORY

Production performance of the leases in the M-1 Unit has been studied in depth. Both primary and waterflood data have been reviewed by lease and individual well to define a norm and attempt to locate and explain areas of differing performance. Efforts have been made to estimate original connate water saturation in the area. Material balance calculations have been made using these estimates and oil production data. These calculations have yielded estimates of post-waterflood oil saturation.

General Production History

Most leases within the M-1 Project were developed expeditiously in 1906 with an occasional infill or replacement well being drilled as late as 1920. Cable tool rigs were used for this development. Drilling proceeded generally from north to south beginning initially with the A. Riker lease. Marathon, operating as the Ohio Oil Company, purchased most of the leases from the original development company during the period 1908-1915. By 1915, Company operated leases and surface acreage within the area consisted of the following: A. Riker - 80 acres; W. Mann - 140 acres; R. A. Siler - 70 acres; Bassom & Siler - 50 acres (this included a 0.5-acre tract named the C. L. Beckett); J. N. Burch - 40 acres; H. Martin - 40 acres; S. Tohill A/C 3 - 60 acres; and the J. C. Martin A/C 2 - 80 acres (presently known as the E. E. Martin). The Wakefield-Martin Community lease (40 acres) was operated by the Kewanee Oil Company until the Ohio Oil Company acquired it for waterflooding during the 1950's.

The time between 1906 and 1959 (when waterflooding began) is commonly referred to as the primary production history. Technically, this is a misnomer because secondary measures were applied locally before 1959. In any case, initial oil rates (when available), cumulative oil production by lease and subsequent well status changes constitute the interpretable data from this period.

The original reservoir drive mechanism was undersaturated solution gas, which dwindled quickly and led to initiation of other recovery means. By 1921, air and gas injection were being applied in Crawford County with water injection being added by 1924. Apparently, the standard practice was to apply a vacuum assist followed by air repressuring.

The S. Shire air repressuring project began in 1941 and included most leases in the M-1 Project. This project affected 976 acres with 128 producing wells and 20 air input wells, or "key" wells, which are tagged with a "K" (e.g., well W. Mann 16-K). Air repressuring followed the vacuum assist that had been going on for an unknown period. The Shire project was reputed to have not experienced excessive air bypassing. If bypassing had been excessive, an operator would have injected water with the air periodically to remedy the ineffective air injection.

The primary period in this locale ended in 1958 when waterflood development was initiated in the Mann Waterflood 39R (WF-39R). The Mann WF-39R was made up of the E. C. Burch, J. N. Burch, H. Martin, Wakefield Heirs and Wakefield-Martin Community leases and the Mann Unit. Included in the Mann Unit were leases and portions of leases as follows: 40 acres of the A. Riker; Bassom & Siler; C. L. Beckett; 29 acres of the R. A. Siler; the C. I. Weirich and 100 acres

of the W. Mann. The M-1 Unit for application of the Maraflood process was formed by including the Mann WF-39R leases except the E. C. Burch, and by adding the E. E. Martin lease.

The Mann WF-39R encompassed 470 acres; however, only 320 acres should be considered as developed under waterflooding. New development wells were drilled with rotary tools and were used to confine approximately 160 acres in the center of the flood where the thicker sand area is situated. There were only nine confined nominal 10-acre five-spot patterns in the Mann waterflood. Production wells for these patterns are as follows: W. Mann No. 27, C. I. Weirich Nos. 7 and 8, Wakefield-Martin Nos. 11, 12, 13 and 14 and H. Martin Nos. 11 and 12. The remainder of waterflood development involved an assortment of incomplete patterns on irregular spacing. Old primary development wells were utilized instead of drilling new producers in some areas.

Interpretable data from this period consist of oil production records by lease or unit and periodic well test information. Water injection data by well and well histories, including completion and stimulation data, are also available.

Data Analysis

Primary and secondary production data were studied by lease and individual well to determine normal and abnormal oil recovery performance. Tables A6 through A8 summarize production performance by lease for the area.

Cumulative oil production by lease listed in Table A6 is for the primary and waterflood periods. The primary period has been subdivided into two categories as follows: the period between 1906 and 1940 is classified under depletion even though a vacuum was applied during part of this time; the period from 1941 through 1958 is classified as air repressuring, although the entire area could not have benefited from air injection due to the location of "key" wells. Table A6 also summarizes cumulative oil production during waterflood operations that took place between 1959 and October 1, 1974, the effective date of the M-1 Unit. Production volumes are presented in Table A6 in stock tank barrels, which for practical purposes should be considered reservoir barrels because the oil formation volume factor (FVF) was between 1.0 and 1.1 reservoir barrels per stock tank barrel. This assumption is based on restored state PVT data from a Robinson Sand producing well and the use of Standing's correlation. A low FVF is also inferred from the need to apply vacuum early in the primary phase, indicating a highly undersaturated oil. In addition to the low FVF, any correction applied to cumulative oil would be influential only during the early portion of the 1906-1940 period. The application of the low FVF to only this early portion of production would not appreciably change interpretation of the data in this report.

Table A7 presents pore volumes used to normalize primary and waterflood production performance. A distinction is made in Table A7 between acreage considered developed under the primary phase and that developed for waterflood operations. It has been assumed for primary that the total lease area containing the main reservoir was developed. The waterflood development was incomplete in many leases.

Areas denoted by cross-hatching on Figure A3 represent reservoir assumed to be unaffected by waterflooding. On the A. Riker lease, for example, no water injectors were drilled north of well Nos. 1, 6, 4 and 3; therefore, this area has been deleted. Accordingly, the pore volume attributed to the waterflood phase in Table A7 excludes this 5-acre segment. Cross-hatched areas on the W. Mann, Bassom & Siler and Wakefield Heirs leases are likewise considered unaffected by waterflood due to a lack of either injectors or producers to sweep these areas. Similarly for the J. N. Burch lease; approximately the southwest half of the lease contained no producing wells.

The cross-hatched area on the H. Martin lease and the south 40 acres on the E. E. Martin lease represent a discontinuity between two different reservoir sections. H. Martin well No. 7, and presumably No. 6-K, did not encounter the same reservoir sections as did injection wells G-6 or K-6. The interpretation made is that one lens from the north pinches out while a lower lens from the south also pinches out in this cross-hatched area. This is the area in which M-1 development well D-12 was abandoned as a dry hole. Similarly on the south portion of the E. E. Martin lease, wells R-10 and R-11 were completed in a lower lens, not necessarily the same one as on the H. Martin lease, while the area shown as developed was completed in the main reservoir. The dry holes drilled during primary development proved no reservoir exists in the north 40 acres of the E. E. Martin lease.

The net pay map (Figure A21) and the porosity map (Figure A27) were used as a basis for values reported in Table A7. In addition, pore volumes are presented that include the lower sand stringer occurring in the A. Riker, Bassom & Siler and R. A. Siler leases.

Table A8 presents analysis of lease performance. Parameters presented in Table A8 are cumulative oil recovered on a pore volume basis from primary and waterflood operations, cumulative water injected on a pore volume basis, the ratio of cumulative fluid produced to the allocated injection, cumulative water-oil ratio (WOR) and average cumulative injectivity on a B/D/NF basis. Average parameters are shown for: 1) the group of leases considered to represent normal production performance (Group I); and 2) all leases in the M-1 Unit.

Individual well performance data are presented on Figure A37 (a-d). Individual well data include initial primary oil rates, initial waterflood test and peak oil rate test during the flood, cumulative waterflood oil, water, and water-oil ratio (WOR), waterflood average cumulative productivity on a B/D/NF basis and relevant comments. Most of these wells have now been plugged and abandoned and new wells drilled for tertiary development.

Data Interpretation

Leases within the M-1 Unit have been organized into four groups as shown in Table A8. Group I contains four leases with good oil recovery. Group II contains two leases where analysis of production performance is complicated by the presence of the lower sand stringer. Group III contains three leases with depressed oil recovery. Group IV contains two leases where allocation of production to developed pore volume is based on small portions of each lease due to production from lower sands (not lower sand stringer). As a consequence, little confidence should be placed in the Group IV results.

Group I. The leases in Group I are as follows: W. Mann, (Figure A37 (a) + (b)), C. I. Weirich (Figure A37 (c) + (d)), H. Martin (Figure A37 (c) + (d)) and Wakefield-Martin Community (Figure A37 (d)). Oil recovery and waterflood performance of this group is considered the norm by which to evaluate production performance of the other leases. Available data indicate an average primary recovery of 17.9% PV or 265 barrels of oil per acre-ft (BOAF). Average waterflood recovery was 12.7% PV or 186 BOAF. This totals 30.6% PV or 451 BOAF. These data are presented in Table A8.

The C. I. Weirich and Wakefield-Martin Community leases have the most complete record of production data within the M-1 Unit. Both primary and waterflood oil production data are available, and both leases were developed in their entirety for waterflood. Thus, these two leases form the basis for material balance work to estimate present oil saturation.

Oil production data are not available to compute a primary recovery from the H. Martin lease. In the case of the W. Mann lease, cumulative oil production data are available (1906-1958), but oil was produced from portions of this lease outside the M-1 Unit. This lack of data during the primary phase should not detract from the computed waterflood values.

Group II. The two leases in Group II are the A. Riker and Bassom & Siler, presented on Figure A37(b). The occurrence of the lower sand stringer is common to both leases. This stringer completely underlies the A. Riker lease and covers about two-thirds of the Bassom & Siler lease. This stringer has been described in a previous section of this report. Study of the stringer has shown that the lower oil saturations determined by core analysis do

not indicate an oil-water transition zone, but rather were coincident with the lower sand stringer that is correlative areally across the A. Riker and Bassom & Siler leases. In other words, it has been concluded that the lower oil saturations correlate with lithologic features rather than structural features. Since this lower sand stringer probably did not contribute significant primary or secondary reserves, and since it will probably be isolated by plugbacks of existing wells, it was deleted from the net sand calculation.

The Bassom & Siler lease was only partially developed for waterflooding as shown on Figure A3. This lease was not fully developed for waterflooding probably as a result of drilling wells Bassom & Siler No. 12 and D-94 and also because of the history of primary wells on the lease.

Bassom & Siler No. 12 was drilled for waterflood development and never produced because initial tests showed no oil production. It was shut in during July, 1960. The lower sand stringer was present but had been plugged back before testing. In fact, the lower sand stringer was plugged back in many of the waterflood injection wells in the area, including all injection wells on the A. Riker lease. These plugbacks are shown on Figure A3.

Figure A38 presents the E-log, core data and well test data from No. 12.

Bassom & Siler No. 2, an old primary well, also registered high water cuts under waterflood and was shut in during August, 1960, early in the waterflood history. Bassom & Siler D-94, a waterflood development well, was plugged at the conclusion of its drilling. It exhibited both low oil saturation and low permeability by core analysis. Six of the 11 primary wells drilled on the Bassom & Siler lease were plugged and abandoned within 12 years after

discovery. These wells are identified on Figure A3, which includes abandonment dates. A good correlation exists between these plugged wells and the area not developed for waterflooding. Primary wells were generally plugged for one of two reasons: 1) either the oil rate had declined to an uneconomic level; or 2) there were severe mechanical problems with the well. In the event of mechanical problems a replacement well would probably have been drilled. Since none were, it has been assumed that the oil volume had declined below the economic limit.

When oil recovery from Group II leases is computed using only the main sand reservoir, results are similar to the norm from Group I. Primary and secondary recoveries from the A. Riker lease are then 17.8% PV and 11.3% PV, respectively. These compare to the norms of 17.9% PV and 12.7% PV. The Bassom & Siler lease produced 15.6% PV and 15.5% PV primary and secondary oil when the lower sand stringer is excluded from the net sand calculation. The above average waterflood recovery probably results from not assigning enough area to waterflood development in this analysis. Since this lease was not fully developed for waterflood (see Figure A3), a subjective assignment of developed secondary reserves is required. Since these recoveries agree with the norm, it appears that the lower sand stringer did not contribute any significant oil to primary or waterflood production.

In addition to the presence of the lower sand stringer, the A. Riker lease also contains lower permeability reservoir than other leases in the area. This is shown by Figure A24, a map of average permeability based on gross reservoir section. The average permeability of the gross section ranges

from 20 to 50 md within the undeveloped interior of the A. Riker lease compared to an average of about 93 md (based on gross sand) for the entire M-1 Unit.

Reservoir permeability within the A. Riker lease is also exceedingly variable. The Lorenz Coefficient map (Figure A28) generally shows values in the range of 0.6 to 0.7 within the lease compared to an average of 0.44 for the M-1 Unit. As a consequence, the cumulative WOR under waterflood for the A. Riker lease was 11.6 compared to 8.5 for the entire unit. When the low permeability reservoir that occurs in correlative streaks in this area is eliminated, the results are reflected by low net sand values within the lease shown on the net sand isopach, Figure A21. Only one control point (XX-4) north of the TT row indicates a net sand thickness greater than 12 feet. Therefore, tertiary development was ended with the TT row because further development was judged uneconomic. Three UU wells were drilled north of the TT row for experimental work and will be considered for backup water injection as described in a forthcoming section of this report, "Peripheral Water Injection".

Group III. Leases in Group III are the J. N. Burch (Figure A37(c)), Wakefield Heirs (Figure A37 (a) + (d)) and the R. A. Siler (Figure A37(c)). The J. N. Burch lease produced only 10.2% PV of oil during primary production compared to 17.9% PV (Group I) for the C. I. Weirich and Wakefield-Martin Community leases. Waterflood production performance was satisfactory at 10.8% PV of oil when only reservoir developed for waterflooding is considered. In general, water-oil ratios are low and oil cuts are good from wells in this developed area. Approximately half of the lease (see Figure A3) was not waterflooded. This undeveloped area coincides with thin sand (less than 15 feet - refer to net

sand isopach, Figure A21) and early abandonment of primary wells. It is likely that thin sand precluded waterflood development. Poor primary performance is probably the result of low permeability reservoir, principally in the area that was not developed for waterflooding. This is inferred from the thin reservoir interval and the premise that low permeability quite commonly accompanies thin reservoir in fluvial deposits.

Primary recovery from the Wakefield Heirs was somewhat below normal - 14.1% PV versus the norm of 17.9% PV. Waterflood recovery was well below the norm (8.3% PV), although the computation utilized only area confined by injectors as was done for other leases, e.g., Bassom & Siler and J. N. Burch. However, when individual well performance was reviewed, only three wells did not respond satisfactorily to water injection. Most waterflood wells can be characterized by high initial oil cuts, good peak oil rates and oil cuts, low cumulative water-oil ratios and substantial cumulative oil production. Pattern development was irregular. Well No. 18, for example, represents the only complete 10-acre five-spot pattern. It recovered 20% of the total lease waterflood oil. In comparison, Well No. 9, which drained one-half of a 5-acre five-spot, produced about half the total oil that No. 18 produced. Well No. 10 is part of a very irregular pattern; however, it produced nearly as much oil as No. 18.

The three wells that did not perform satisfactorily during waterflood are Nos. 1, 4 and 20. Well No. 1 was outside the influence of the nearest injector, N-88, because a second producer, No. 9, was located between N-88 and well No. 1. Well No. 4 produced little oil, but it performed satisfactorily in terms of WOR and oil cut. Low cumulative volumes of oil and water may well

indicate wellbore damage; this was a common problem when old primary producers were utilized as waterflood producers. The completion techniques in 1906, e.g., uncemented casing and open hold shooting, limited potential for remedial work, and accordingly, the utility of well No. 4. Well No. 20 was drilled six years after water injection began in well P-97. Core analysis yielded low oil saturations but when chloride analysis indicated fresh water (injector) contact, it was concluded that the area of well No. 20 had already been swept by water.

It appears that depressed waterflood performance of the Wakefield Heirs lease is a result of poor areal sweep from irregular waterflood development. Most producers were unconfined. For example, Well No. 12 had injection from only two sides, by wells P-92 and P-97. Analysis of individual well data indicates no obvious problem with oil saturation on this lease.

The R. A. Siler lease did not perform well during either primary or waterflood operation. The normalized oil recovery was 7.5% PV of primary oil and 7.4% PV of waterflood oil. The northwest corner of the lease is underlain by the lower sand stringer described previously in this report, but the stringer is confined to such a small area that its influence, if any, on lease performance was probably minimal. Only one primary well (No. 2) was plugged and abandoned early, and it was immediately replaced by a new well, No. 13. This indicates mechanical problems rather than uneconomical oil production. Examination of individual well performance data from the waterflood shows that No. 13 in the southwest corner of the lease produced only 5,000 barrels of secondary oil before it was abandoned in 1966. The cumulative WOR for this well was 46. Well No. 1 in the northwest corner

of the lease produced 30,000 barrels of secondary oil at a cumulative WOR of 20. However, the third waterflood producer, located on the east side of the lease, R. A. Siler No. 18, produced 85,000 barrels of oil at a cumulative WOR of 4. The performance of these wells indicates that prior to waterflooding, the west side of the lease was at a lower oil saturation than the east side. CT No. 3 was drilled on this lease during 1976 as part of the lower sand stringer evaluation. It showed that the current oil saturation is normal in the main reservoir (no lower sand stringer present).

One reason for poor lease performance during primary and secondary operations could be the absence of a well producing from the central portion of the lease. This hypothesis is supported by the iso-oil cut map (Figure A35) prepared from well tests on M-1 development wells. Note the higher oil cuts (5-17%) from the center producers N-2, N-4 and N-6 compared to the reported oil cuts of a "trace" and "zero" for wells P-2 and L-2, respectively. Wells P-2 and L-2 are located near old wells No. 1 and No. 13, respectively, which produced at high water-oil ratios during waterflood operations. These production data show that if a saturation problem now exists within the R. A. Siler lease, it is probably a localized condition confined to small areas around the old locations of R. A. Siler Nos. 1 and 13 (now wells P-2 and L-2).

Group IV. The two leases in Group IV are the E. E. Martin (Figure A37(d)) and the S. Tohill A/C 3 (Figure A37 (c) + (d)). Primary production on both leases came from both the main reservoir and lower sand (not lower sand stringer of this report) lenses. Since this production was commingled, it is impossible to determine primary production from the main reservoir, the zone of interest in this study. Waterflood development also included multiple

sands. Since well test data were available, it was possible to attempt isolating portions of the lease where it was known that only the main reservoir was developed. The data reported in Table A8 are based on these attempts involving only portions of the leases shown on Figure A3. However, since only small portions of these leases are involved, little confidence should be placed in the results, even though examination of individual well performance data for each lease shows good oil production from those wells completed only in the main sand.

Oil Saturation

Determination of oil in place is important in evaluating a tertiary prospect. The approach used for this project was to: 1) estimate the original (connate) water saturation; 2) assume the remaining pore space was filled with oil; and 3) calculate oil presently in place by subtracting the oil produced during both primary and secondary production phases. This approach is similar to that presented by Gordon et al in "Determination of Residual Oil Saturation After Waterflooding", SPE Paper 3791, presented at the SPE Improved Oil Recovery Symposium, Tulsa, Oklahoma, April 16-19, 1972. Two leases, the C. I. Weirich and the Wakefield-Martin Community, were fully developed during primary and secondary operations and also have a complete history of oil production. The production from these leases was used as a basis to estimate oil saturation that is assumed to be representative for the entire M-1 Project.

Two sources of data are available for estimating connate water saturation in the M-1 Project. They are: 1) special core analyses from the Robinson Sand; and 2) electric logs from wells drilled during waterflood development.

There have been no special core analyses conducted on reservoir rock from the M-1 Project area. However, extensive work has been done on reservoir rock from other locales of the Robinson Sand. The end point water saturation value from air-brine capillary pressure measurements is commonly accepted as the irreducible water saturation for an oil-brine system, under the assumption that air acts as oil (non-wetting phase) displacing water (wetting phase). Average connate water saturation from this determination was 20% PV. End point saturations measured during water-oil relative permeability determinations (flushing fresh core with crude) on eight core plugs yielded an average irreducible water saturation of 24.5% PV.

Electric log data (64-inch normal) are available from 17 producing wells drilled for waterflood development in the area. Table A9 presents E-log interpretations from nine of these wells that initially produced essentially water-free oil. Table A9 shows that initial oil cuts in these wells ranged from 92-100%. One of these wells (Wakefield Heirs No. 18) has a reservoir section of 15 feet, which may inhibit log response and provide an inaccurate interpretation. The arithmetic average water saturation from the remaining eight wells (excluding No. 18) is 27.7% PV and ranges from 25.6-30.7% PV. Interpretations were made using the Humble soft reservoir formation factor equation with a water resistivity, $R_w = 0.17$. There are no data to suggest the use of a different value for either R_w or the formation factor relationship.

The remaining eight logged producers exhibited a mobile water saturation initially. Oil cuts ranged from 62% down to 10%. This mobile water condition is presumed to be a secondary condition resulting from invasion of surface

water or waters from strata above the main reservoir during primary production. Casing commonly remained uncemented during this period and migration of foreign waters into the pay zone was probably a common occurrence. Another contributing factor could be breakthrough of injected water. Producing wells were often drilled one or two years after injection wells to delay capital expenditures until the reservoir was pressured and responding to waterflooding. Four of the eight wells exhibiting a mobile water condition initially were serviced by at least one injector that was active the year before the producer was drilled. Inspection of the structure map (Figure A29) shows no apparent trend in structural relief that correlates with initial mobile water production. This reinforces the presumption that recorded mobile water production was a secondary condition.

The C. E. Weirich and Wakefield-Martin Community leases each produced approximately 29% PV of primary plus waterflood oil. Post-waterflood oil saturations can be calculated by the relationship

$$S_o = 1 - S_{wr} - 0.29$$

It has been shown by laboratory measurements that the irreducible water saturation (S_{wr}) could range from approximately 20% PV, as determined from capillary pressure measurements, to approximately 25% PV, based on fresh cores used for relative permeability measurements. It has also been shown that interpretation of E-logs from waterflood development wells that produced water-free oil yielded connate water saturations that ranged from about 25-31% PV. Since the laboratory data were not determined using M-1 reservoir rock, E-log values are probably more representative of in situ values. Accordingly, the present average oil saturation in the M-1 Unit may range from 40-45% PV (similar to the Henry 119-R Project area prior to tertiary production). A value of 40% PV is considered most representative for the

M-1 Project area. This value is an average and may not accurately represent localized conditions of low oil saturation such as those noted in the vicinity of wells Bassom & Siler No. 12 and R. A. Siler Nos. 1 and 13. In addition, since the reservoir has been waterflooded, oil saturation gradients exist, creating other localized areas of higher and lower oil saturation throughout the project.

Core analyses from waterflood development wells also furnish additional saturation data for the M-1 area. Of the 61 cores taken during waterflood development, 15 scattered cores yielded oil saturations below waterflood residual. Measured oil saturations in the range of 12 to 20% PV were noted in the upper 2-15 feet of main reservoir. Wells that exhibited this depressed oil saturation include G-97 and W. Mann No. 29 (Figures A39 and A40, respectively). It is possible that air repressuring operations were responsible for this reduced oil saturation because of the many years of air injection. Other contributing factors may include gravity segregation and the formation of secondary gas caps during the depletion phase of primary production. Wells characterized by low oil saturation are shown on Figure A41 along with the location of air injectors.

An iso-oil saturation map (drawn from pre-waterflood era laboratory-determined oil saturations from the main reservoir section) is presented as Figure A42. This figure provides at least two features of interest.

First, on the A. Riker lease, the trend in laboratory-measured oil saturation is 20-25% PV. This is low compared to the measured 40% PV value from cores on the C. I. Weirich lease. However, average (normalized) oil recovery

from the A. Riker lease during both primary and waterflood phases was close to the Group I norm. Similar oil recovery during waterflood and the dissimilar oil saturation from core samples prior to waterflood could be explained by different rock-saturation relationships for the A. Riker lease compared to the C. I. Weirich area.

Second, the general appearance of the iso-oil saturation map is similar to the net sand isopach (Figure A21) and very dissimilar to the structure map (Figure A29). This further supports the belief that oil saturations measured by core analysis may be principally controlled by lithologic features and not by structure.

M-1 and 119-R Projects - Waterflood Performance Comparison

The M-1 area has performed well under waterflood, producing over 1.5 million barrels of oil from about 320 acres. Group I leases in the M-1 have produced 186 BOAF compared to 180 BOAF from the 119-R Project area. For the total M-1 Unit, oil recovery has been approximately 170 BOAF.

PORE VOLUME INTERPRETATION USING STREAMLINE MODELING

Streamline and flood front modeling work have been done for the M-1 Project. This work was used to estimate the pore volume for unconfined and asymmetrical patterns, and to evaluate effects of backup water injection on the project periphery. A streamline network analysis computer program was used to accomplish this work; the study incorporated the net sand isopach and the isoporosity map resulting from this study. The status of available water injectors is presented and the economic benefits of water injection explored.

Definition of Objectives and Model Description

Streamline and flood front modeling work have been done for the M-1 Project. The objectives of this study were to: 1) aid in estimation of design pore volume for edge patterns, incomplete patterns and patterns with asymmetric geometry; and 2) evaluate the effects of peripheral water injection using existing wells. Drilling new wells specifically for backup water injection was not considered.

A streamline network computer program was used to generate streamline and flood front maps for a heterogeneous system. The reservoir can be heterogeneous in that porosity, permeability and/or thickness can vary in different areas of the system. The program generates a pressure surface for the heterogeneous two-dimensional network model. This model assumes that: 1) the system is in steady-state flow; 2) mobility ratio equals one; and 3) displacement is piston-like. The pressure surface, rock properties and Darcy's law are combined to follow a particle of fluid as it moves in the reservoir, thus defining the streamlines and flood front positions. The program uses a variable block

size grid system in which values of thickness, porosity and directional permeability may change from block to block. Flow rates are assigned to blocks containing wells and a pressure surface is generated. Streamlines are then traced by means of the pressure surface and reservoir properties. Time of flight along a streamline is calculated and flood fronts are plotted as a function of input well rates, which may be changed with time. Streamline map plots may be obtained for runs of interest.

Model Input and Operation

Four model segments were defined for this study. Figure A43 outlines these segments; they cover essentially the entire M-1 Project area. This modular approach was used rather than gridding the entire project area to economize on computer processing time.

A constant porosity was input for simplicity. A value of 20% was considered acceptable for modeling purposes. Trends in sand thickness were input as finite blocks of constant thickness using the net sand isopach map (Figure A21). This approximation procedure resulted in reasonable pore volume agreement between the model pattern volumes and the planimetered values from the net sand isopach.

Input rates were calculated using an injectivity factor of 5 B/D/NF per 150 md, or 0.033 B/D/NF per md. This method was used because it yielded reasonable flood lives and approximated the effect of areal permeability trends. This was judged to be the most practical approach in the absence of injection histories of Maraflood process fluids within the M-1 Project. Interpretation regarding flood life was done by comparing patterns within

the project; therefore absolute values of injectivity do not affect results - only relative differences are important.

Injection rates were computed from the product of injectivity factor and well node thickness and permeability. An isopermeability map, Figure A22, was used to estimate permeability for each well.

The model was run in the unbalanced injection-production mode. Producing well rates were implicit values calculated within the program to satisfy the mathematical relationship using injection well rates and a constant pressure applied to each producing well node.

Model runs were made for all four segments. In the case of Segments II and III, runs were made with and without peripheral water injection. Streamline maps resulting from these runs are shown as Figures A44 through A49.

Data Interpretation

It is necessary to select a time frame within which to work in order to use the flood front and streamline maps to estimate affected pore volume. For example, consider an injection well on the M-1 Unit boundary, such as MM-15. This well is offset by only two producing wells, NN-14 and LL-14. The existing reservoir pinch-out to the east has been incorporated into the model grid. As a result, all injection into well MM-15 will eventually reach a producing well somewhere within the project. However, if some of this injection reaches a producer 20 years in the future, the reservoir traversed by this injection is not considered effective project pore space. This is because most of the project will be flooded out before this pore space can

contribute production. A major problem in estimating proper time frame is that model times do not necessarily correspond to actual project flood times. The model may indicate floodout in four years at 1.5 PV fluid injection. In reality, it may take six years to reach 1.5 PV injection. Differences of this nature are due principally to difficulties in estimating actual injection rates without prior injection history for the specific reservoir and fluids being studied.

Since we were primarily interested in determining pore volume affected during the economic life of the project, and since most of the project is composed of regular confined 2.5- and 5.0-acre five-spot patterns, it is reasonable to define economic project life as that time required to flood out regular (uniform geometry) pattern development. Using this assumption, model time required to flood out a regular pattern becomes the time frame that bounds affected pore volume in the unconfined and edge patterns.

After tracing flood fronts in this study, it appears that most confined 2.5-acre patterns will flood out in about five years and that most 5.0-acre patterns will flood out in about 10 years. Table A10 presents data from example inverted five-spots showing flood front times, pore volumes injected and areal coverage.

The five-year and ten-year flood front positions, along with streamline configurations, were used to determine pore volumes. The procedure used was to overlay the net sand isopach (Figure A21) onto the streamline output. Subjective interpretation was necessary to align the computer output with the map containing well locations. Once overlain, confinement by streamlines and

cut-off time (flood fronts after either 5 or 10 years) was traced onto the net pay isopach.

The streamline model output was used as a guide for determining pore volumes for all patterns, both inverted and producer-centered. Regular patterns in which streamlines followed the geometric configuration did not require streamline cutoffs. Examples of regular geometry include patterns defined by wells GG-13 and T-12. Example patterns where the model served its purpose include well QQ-15, an unconfined edge injector, well S-15, where the 2.5- and 5.0-acre areas join and well I-1 where streamlines show the benefit of peripheral water injection. The streamline model output from Segment IV also revealed a 5.6-acre void space within the interior of the H. Martin lease that is not effective pore space. This area was not developed because a dry hole (D-12) was drilled within the area.

Figures A50 and A51 show outlines of producer-centered patterns and injector-centered patterns, respectively. There are 132 producers and 114 injectors in the M-1 Project. Tables A11 and A12 present pore volumes for inverted (injector-centered) five-spots and regular (producer-centered) five-spots, respectively. Brubaker-Prier Fee No. 18 is not included in Table A12. This well will be reactivated as a 5.0-acre producer, but reservoir quality near this well is marginal and no pore volume contribution is included. Porosity and bulk volume for each pattern were taken from the isoporosity map and net sand isopach - Figures A27 and A21, respectively. Patterns requiring the use of streamline cut-offs to determine affected pore volume are noted in each table.

Following is a summary of pore volumes determined for 2.5- and 5.0-acre portions of the project for injector-centered (inverted) patterns (Table A11). Any inverted pattern having a 2.5-acre injector was included in the 2.5-acre portion of the pattern.

<u>Pattern Spacing</u>	<u>Area Acres</u>	<u>Bulk Volume Acre-Ft</u>	<u>Pore Volume BBl's</u>
2.5-acre	247.9	7,268.8	10,627,513
5.0-acre	<u>159.1</u>	<u>4,058.7</u>	<u>5,947,610</u>
Total	407.0	11,327.5	16,575,123

A further breakdown of confined wells based on streamline model predictions (shown by Figures A50 and A51) is shown below:

	<u>2.5-Acre</u>	<u>5.0-Acre</u>
For Producer-Centered Patterns: (Figure A50)		
Confined Producers.	65	20
For Injector-Centered Patterns: (Figure A51)		
Confined Injectors.	78	19

A confined well is defined as a well surrounded by four unlike wells, i.e., to complete the five-spot pattern. This pattern is designated as either 2.5-acre or 5.0-acre development, although there are both larger and smaller patterns within each designated pattern size category (refer to Tables A11 and A12).

Peripheral Water Injection

The data presented on Figures A50 and A51 and in Tables A11 and A12 reflect:

1) the use of peripheral water injection; and 2) the use of well Sally Carlisle No. 14 as an active producer during operation of the M-1 Project. This well was still active in December, 1975 in the Shire waterflood.

There are 15 wells that were assumed available for water injection that affected model runs for Segments II and III. These wells were noted on Figure A43 and data are presented in Table A13. Seven wells, which were waterflood injectors, were accepting water satisfactorily based on May, 1976 data in Table A13. There are indications of operational problems in eight wells noted below.

Three wells, UU-1, UU-3 and UU-5 were drilled for experimental work and have not been completed. A review of cement bond logs indicates the possibility of communication behind the pipe due to a poor cement bond; this condition could be corrected by recementing. Accordingly, it is assumed these three wells will be available for water injection.

Five waterflood injectors, R-12, X-94, X-97, X-3 and X-12 have been temporarily abandoned during waterflood operation. The reason(s) for shut-in are not known. Possibly, these wells experienced mechanical or injectivity problems. Whatever the problem, it is assumed that these five wells will be available for water injection.

It is difficult to estimate the incremental oil that will be produced through the use of peripheral water injection. It is even more difficult to estimate

the increased rate at which oil will be recovered due to better confinement. However, using streamline work, it is possible to estimate reservoir volume eliminated by increasing confinement with water injection backup using the 15 wells noted above and producing Sally Carlisle No. 14. This was done by comparing Figure A45 with Figure A46, and Figure A47 (a-b) with Figure A48 (a-b). The pore volume eliminated by assuming water injection totals about 175,000 barrels as shown in Table A14. It is likely that Maraflood process fluids designed for this incremental pore volume would be ineffective. This is because that incremental pore volume is located on pattern fringes where effective slug size is small.

Elimination of 175,000 barrels of pore volume by confining edge patterns would result in a reduction of about 17,500 barrels of slug if a 10% PV slug size is arbitrarily assumed. It is believed the non-operational wells can be reconditioned and all 15 wells operated for economic water injection backup.

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A1. M-1 PROJECT LOCATION

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A2
 LOCATION OF CROSS SECTIONS

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A3
PRIMARY AND WATERFLOOD WELLS

PHOTO #1. SEM PHOTOMICROGRAPH OF M-1 ROBINSON SANDSTONE, 100X, WELL GI-3, 896 FEET. THIS IS A LOW POWER SHOT SHOWING SEVERAL TYPICAL M-1 SAND GRAINS. THE MOST OBVIOUS FEATURE IS THE KAOLINITE ■ AND CALCITE ★ PACKING THE PORE THROATS AND COVERING MOST OF THE GRAINS.

PHOTO #2. SEM PHOTOMICROGRAPH OF M-1 ROBINSON SANDSTONE, 1000X, WELL C T -3, 899 FEET. THIS PHOTO SHOWS A PARTIALLY DISSOLVED FELDSPAR GRAIN ■ . SOLUTION POROSITY ACCOUNTS FOR A MINOR PORTION OF THE OVER-ALL POROSITY BUT THE KAOLINIZATION OF FELDSPAR MAY SUPPLY THE COMPONENTS FOR THE AUTHIGENIC KAOLINITE IN PHOTO #1 AND PHOTO #5.

FIGURE A4. PHOTOMICROGRAPHS OF RESERVOIR SANDSTONE

PHOTO #3. SEM PHOTOMICROGRAPH OF M-1 ROBINSON SANDSTONE, 300X, WELL C T -3, 899 FEET. SAME AS PHOTO #2 BUT AT A LOWER MAGNIFICATION TO SHOW THE PARTIALLY DISSOLVED FELDSPAR GRAIN ■ BETWEEN THE SURROUNDING QUARTZ GRAINS.

PHOTO #4. SEM PHOTOMICROGRAPH OF M-1 ROBINSON SANDSTONE, 300X, WELL D-6, 910 FEET. THIS PHOTO SHOWS A TYPICAL M-1 PORE THROAT. THE PORE THROAT IS IN THE CENTER OF THE PICTURE. AUTHIGENIC KAOLINITE PLATLETS ■ COVER THE SIDE OF THE PORE THROAT AND DISCRETE CALCITE PARTICLES ★ ARE FOUND TO THE LOWER LEFT OF THE PORE.

FIGURE A5. PHOTOMICROGRAPHS OF RESERVOIR SANDSTONE

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

PHOTO #5. SEM PHOTOMICROGRAPH OF M-1 ROBINSON SANDSTONE, 1000X, WELL CT-3, 910 FEET. THIS IS A PHOTO OF A PORE THROAT FROM A SECTION OF THE RESERVOIR WHICH HAD A PERMEABILITY OF 9 MD. IN THIS PARTICULAR SECTION OF THE RESERVOIR THE COMBINATION OF CALCITE AND KAOLINITE HAVE NEARLY SHUT OFF THE PORE THROATS. THE CALCITE CAN BE SEEN IN THE PORE THROAT, RHOMBOID STACKS IN UPPER CENTER OF PHOTO ■. AUTHIGENIC KAOLINITE IS FOUND IN ITS TYPICAL "BOOKLET" FORM IN THE LOWER CENTER OF THE PHOTO ★.

FIGURE A6. PHOTOMICROGRAPH OF RESERVOIR SANDSTONE

Q-6
WAKEFIELD MARTIN COMM.
WATERFLOOD ELECTRIC LOG
& CORE ANALYSIS

EE-17
WAKEFIELD MARTIN COMM.
M-1 GAMMA RAY-DENSITY

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

FIGURE A7. COMPARISON OF LOG AND CORE DATA FOR WELLS EE-17 AND Q-6

MARATHON OIL COMPANY
MARAFLOOD PROCESS — M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

C-13
H. MARTIN
M-1 GAMMA RAY

D-12 DRY HOLE
H. MARTIN
M-1 GAMMA RAY

E-9
H. MARTIN
M-1 GAMMA RAY

FIGURE A8. POSSIBLE SAND DISCONTINUITY IN H. MARTIN LEASE

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

N - 94
W. MANN
WATERFLOOD ELECTRIC LOG

LL - 12
WAKEFIELD HRS.
M-1 GAMMA RAY

FIGURE A9. CORRELATION MARKER FOR CROSS SECTION WORK

FIGURE A10. CROSS SECTION A-A'

(a)

(b)

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A10. CROSS SECTION A-A'

(c)

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A11. CROSS SECTION B-B'

(a)

(b)

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

FIGURE A12. CROSS SECTION C-C'

(a)

(b)

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

FIGURE A13. CROSS SECTION D-D'

(a)

(b)

FIGURE A13. CROSS SECTION D-D'

(c)

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

FIGURE A14. CROSS SECTION E-E'

(a)

(b)

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

FIGURE A15. CROSS SECTION F-F'

(a)

(b)

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

G-97
R.A. SILER
WATERFLOOD ELECTRIC LOG

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

GI-3
C.I. WEIRICH
OBSERVATION WELL GAMMA RAY

7
C.I. WEIRICH
7 CONVERTED TO M-1
WELL M-11
ELECTRIC LOG

FIGURE A16. LIMITED EXTENT OF HIGH PERMEABILITY TREND IN STACKED SAND AREA

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

FIGURE A17. SCHEMATIC OF RANDOM OCCURRENCE OF NON-RESERVOIR ROCK

MARATHON OIL COMPANY
MARAFLOOD PROCESS — M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

FIGURE A18. STILES PLOT OF PERMEABILITY DATA

FIGURE A19. FREQUENCY PLOT OF POROSITY DATA

FIGURE A20. CORRELATION OF PERMEABILITY AND POROSITY

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A21
NET SAND ISOPACH

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A22
ISOARITHMETIC PERMEABILITY MAP
NET SAND

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A23

**ISOGEOMETRIC PERMEABILITY MAP
 NET SAND**

FIGURE A24

**ISOARITHMETIC
PERMEABILITY MAP - GROSS SAND**

FIGURE A25

**ISOGEOMETRIC
PERMEABILITY MAP - GROSS SAND**

FIGURE A26

**ISOARITHMETIC PERMEABILITY $\times$
THICKNESS MAP (KH) - NET SAND**

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A27
 ISOPOROSITY MAP - NET SAND

MARATHON OIL COMPANY
MARAFLOOD PROCESS — M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A28
LORENZ COEFFICIENT - GROSS SAND

FIGURE A30

**ISOPACH OF
LOWER SAND STRINGER**

FIGURE A31. CROSS SECTION G-G'

(a)

(b)

MARATHON OIL COMPANY
 MARAFLOOD PROCESS -- M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A32. RESULTS OF CORE TEST NO. 1

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A33. RESULTS OF CORE TEST NO. 2

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A34. RESULTS OF CORE TEST NO. 3

FIGURE A35

ISO-OIL CUT MAP

LOWER SAND STRINGER AREA

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

b	a
c	d

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A37(c)

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

b	a
c	d

22

FIGURE A37(d)

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

DATE	TEST BOPD/BWPD
6/59	Tr./63
4/60	0/57
5/60	0/54
7/60	0/54

TAILED IN ON 3/59

- 46 -

FIGURE A38. CORE ANALYSIS AND TEST DATA FOR WELL BASSOM & SILER NO. 12

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

THE OHIO OIL COMPANY
 R. A. SILER #G-97
 T. D. DRILLER 933'
 K. B. ELEV. 478'
 15-6N-13W

FIGURE A39. CORE ANALYSIS OF WELL G-97

MARATHON OIL COMPANY
MARAFLOOD PROCESS — M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

R. 13 W.

FIGURE A41

**PRE-WATERFLOOD CORES
 WITH LOW MEASURED
 OIL SATURATION IN TOP**

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A42

**PRE-WATERFLOOD CORE ANALYSIS
 ISO-OIL SATURATION**

MARATHON OIL COMPANY
 MARAFLOOD PROCESS — M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A44. STREAMLINES FOR SEGMENT I

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A45. STREAMLINES FOR SEGMENT II WITHOUT
 PERIPHERAL WATER INJECTION

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A46. STREAMLINES FOR SEGMENT II WITH
 PERIPHERAL WATER INJECTION

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A47(a). STREAMLINES FOR SEGMENT III WITHOUT PERIPHERAL WATER INJECTION

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A47(b). STREAMLINES FOR SEGMENT III WITHOUT PERIPHERAL WATER INJECTION

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A48(a). STREAMLINES FOR SEGMENT III WITH
 PERIPHERAL WATER INJECTION

MARATHON OIL COMPANY
MARAFLOOD PROCESS — M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A48(b). STREAMLINES FOR SEGMENT III WITH
 PERIPHERAL WATER INJECTION

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

FIGURE A49. STREAMLINES FOR SEGMENT IV

FIGURE A50

**PRODUCER-CENTERED
PATTERN CONFINEMENT**

FIGURE A51

**INJECTOR-CENTERED
PATTERN CONFINEMENT**

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE A1

Average Reservoir Parameters

Parameter	Maximum Value	Minimum Value	Mean Value		Total Project	No. Control Points
			2.5-Acre	5.0-Acre		
Net Sand, ft	60	0	29.3	25.5	27.8	302
Arithmetic Mean Permeability, md (Net Sand)	188	31	100.3	107.0	102.8	76
Geometric Mean Permeability, md (Net Sand)	143	24	75.5	79.3	76.9	76
Arithmetic Mean Permeability, md (Gross Sand)	188	14	90.7	97.9	93.3	76
Geometric Mean Permeability, md (Gross Sand)	143	4	59.5	63.0	60.8	76
Porosity, % (Net Sand)	21.0	16.4	18.8	18.9	18.9	76
Lorenz Coefficient (Gross Sand)	0.749	0.271	0.446	0.439	0.443	76

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE A2

Core Test No. 1
Bassom & Siler Lease

Depth, ft	Permeability k, md	Helium Porosity ϕ , %	Fluid Saturation, %	
			Oil	Water
909.7-.9	2.9	15.0	29.3	30.7
910.2-.3	0.87	12.7	31.1	54.3
911-915	Drilled			
915.3-.5	1.6	12.9	36.4	61.2
916.5-.7	24.0	18.3	24.6	59.0
917.5-.7	41.0	18.9	26.5	60.3
918.4-.6	124.0	20.4	34.4	46.6
919.2-.4	21.0	17.8	29.3	48.3
920.3-.6	15.0	18.1	24.8	49.7
921.6-.8	21.0	15.9	30.2	51.6
922.3-.5	29.0	17.5	23.4	56.6
923.2-.5	19.0	16.7	31.6	58.2
924.3-.5	8.1	16.0	27.5	49.4
925.4-.6	9.0	16.2	27.8	50.6
926.3-.5	69.0	20.1	32.9	40.8
927.5-.65	1.6	14.5	33.1	53.1
Average	25.8	16.8	29.5	51.4
928.5-.7	SHALE			
929.3-.5	4.4	21.5	25.6	44.6
930.3-.6	3.5	18.9	29.1	47.6
931.6-.8	0.08	8.8	10.2	90.9
932.7-.9	0.56	11.7	28.2	65.8
933.2-.5	31.0	18.1	32.6	37.6
934.5-.7	0.03	2.6	0	96.2
935.2-.5	51.0	17.7	28.2	39.0
936.3-.5	0.87	12.5	24.0	60.4
937.4-.6	0.45	11.8	11.9	60.2
938.7-.8	15.0	16.4	30.5	46.9
939.4-.6	12.0	16.6	30.1	52.4
940.4-.6	57.0	19.3	32.6	38.8
Average	14.7	14.7	23.6	56.7

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

TABLE A3

Core Test No. 2
Bassom & Siler Lease

Depth, ft	Permeability k, md	Helium Porosity ϕ , %	Fluid Saturation, %	
			Oil	Water
922.4-.6	0.49	12.9	27.9	41.1
924.6-.9	53.0	13.7	35.0	59.1
925.6-.8	81.0	17.4	29.4	57.5
926.5-.7	173.0	20.2	35.2	45.0
927.4-.6	206.0	21.2	37.2	38.2
928.4-.6	140.0	20.1	30.8	41.8
929.5-.7	186.0	20.9	30.6	39.0
930.4-.6	87.0	18.5	26.0	36.8
931.5-.7	44.0	18.0	32.3	39.5
932.1-.4	61.0	18.4	35.9	39.1
933.4-.6	129.0	20.6	21.4	29.6
934.3-.6	2.0	14.2	29.6	52.8
935.4-.6	21.0	18.0	30.9	47.6
936.6-.7	28.0	17.7	32.7	49.6
937.5-.7	95.0	20.2	32.9	36.2
938.3-.6	15.0	16.7	31.1	46.0
939.3-.6	21.0	17.9	28.4	41.9
940.3-.6	17.0	16.9	29.2	46.6
941.3-.5	8.6	16.3	39.2	44.8
Average	72.0	17.9	31.4	43.8
942.5-.7	1.7	4.3	5.6	100.0
943.3-.6	1.3	15.5	20.2	64.7
944.4-.6	3.5	15.5	25.6	60.0
945.3-.5	9.3	15.3	22.0	58.7
946.5-.8	10.0	23.9	26.3	46.4
947.5-.7	7.2	17.9	21.1	51.5
948.6-.8	6.8	15.7	20.4	56.1
949.3-.6	4.4	14.6	24.0	62.3
950.4-.6	1.2	13.9	26.0	86.5
951.5-.7	0.58	12.0	30.1	100.0
953.3-.6	0.94	13.1	16.8	74.0
954.2-.4	16.0	14.6	15.1	64.3
955.4-.6	1.6	14.5	17.3	66.2
956.2-.5	0.56	11.0	10.0	15.8
957.4-.7	0.40	12.7	11.8	59.0
958.4-.6	59.0	19.3	26.4	30.0
959.4-.7	139.0	21.7	16.1	62.3
960.5-.7	131.0	21.1	15.7	66.8
961.6-.7	156.0	22.1	14.0	66.0
962.6-.8	95.0	18.0	18.4	82.7
Average	32.3	15.8	19.1	67.9

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE A4

Core Test No. 3
R. A. Siler Lease

Depth, ft	Permeability k, md	Helium Porosity ϕ , %	Fluid Saturation, %	
			Oil	Water
886.6-.8	52.0	18.5	29.2	48.7
887.5-.8	312.0	22.7	18.7	60.9
888.4-.7	190.0	22.2	22.1	52.2
889.2-.5	154.0	22.4	26.2	29.1
890.2-.5	468.0	24.1	13.3	35.5
891.4-.6	127.0	21.7	21.6	39.2
892.4-.8	157.0	21.7	30.1	38.1
893.2-.5	22.0	17.8	36.1	56.7
894.4-.6	30.0	18.6	26.5	41.2
895.5-.7	49.0	18.8	32.3	43.0
896.6-.9	63.0	19.7	28.9	42.2
897.6-.8	59.0	19.3	42.3	58.7
898.4-.6	65.0	20.2	34.9	45.8
899.4-.6	127.0	20.8	46.2	50.5
900.3-.5	52.0	16.1	49.1	57.9
901.4-.6	148.0	20.1	41.6	42.6
902.3-.6	175.0	19.8	49.7	45.1
903.5-.7	15.0	16.8	46.9	43.4
904.3-.5	20.0	15.7	27.4	52.3
905.5-.7	46.0	18.5	32.1	47.5
906.4-.7	18.0	16.6	32.6	52.9
907.7-.9	94.0	20.9	29.2	41.8
908.5-.7	46.0	18.4	30.1	40.9
909.3-.5	45.0	18.2	36.3	44.5
910.2-.4	9.0	16.7	32.4	42.2
911.5-.7	78.0	20.1	21.9	48.2
912.2-.4	171.0	21.9	32.7	40.8
913.2-.4	50.0	20.4	34.7	54.2
914.2-.5	74.0	19.7	25.6	37.7
Average	100.6	19.6	32.1	46.0

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE A5

Results of Interference Testing

<u>Well</u>	<u>Status</u>	<u>Mobility k/u, md/cp</u>	<u>Storage øc, psi⁻¹</u>	<u>Remarks</u>
Q-3	Injector			
T-4	Observation	13.05	2.94×10^{-6}	
R-2	Observation	30.26	1.54×10^{-5}	
R-4	Observation	10.52	4.34×10^{-6}	
P-2	Observation	40.73	2.14×10^{-6}	Lower stringer present
P-4	Observation	25.43	1.43×10^{-5}	Lower stringer not present
Group Average		20.78	5.77×10^{-6}	
S-7	Injector			
S-5	Observation	10.50	1.24×10^{-6}	Lower stringer not present
R-6	Observation	10.57	1.06×10^{-6}	Lower stringer not present
R-8	Observation	20.32	9.81×10^{-7}	Lower stringer not present
T-6	Observation	7.32	2.03×10^{-6}	Lower stringer not present
T-8	Observation	14.76	8.70×10^{-6}	Lower stringer not present
Group Average		12.34	1.66×10^{-6}	
SS-3	Injector			
RR-2	Observation	5.15	2.09×10^{-6}	
TT-2	Observation	3.50	4.49×10^{-7}	
Group Average		4.78	6.47×10^{-7}	
U-5	Injector			
T-4	Observation	9.31	1.20×10^{-6}	
T-6	Observation	3.59	2.64×10^{-6}	Lower stringer not present
V-4	Observation	7.41	7.16×10^{-7}	
V-6	Observation	4.83	10.00×10^{-7}	
Group Average		5.83	1.34×10^{-6}	

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

TABLE A6

Cumulative Oil Production by Lease

Primary Production, STB

<u>Lease</u>	<u>1906-1940 (Depletion)</u>	<u>1941-58 (Air Repr.)</u>	<u>Total</u>	<u>Waterflood Production, STB (1959 - 10/74)</u>	<u>Total Production, STB (to 10/74)</u>
A. Riker	140,412	18,185	158,597	82,543	241,520
Bassom & Siler	211,229	24,027	235,256	109,005	344,261
R. A. Siler	96,461	26,314	122,775	120,157	242,932
C. I. Weirich	195,672	41,807	237,479	142,878	380,357
W. Mann	Not Available				Incomplete
J. N. Burch	112,769	26,222	138,991	89,331	228,322
H. Martin	Not Available			129,618	Incomplete
Wakefield-Martin Comm.	284,369	57,956	342,325	218,880	561,205
S. Tohill A/C 3	123,196	21,558	144,754	40,000 ¹	184,754
Wakefield Heirs	227,303	61,747	289,050	125,482	414,532
E. E. Martin	Not Available			48,000 ²	Incomplete

¹Includes estimated production since Marathon Oil Company sold S. Tohill A/C 3 in 1970.

²Includes estimated production since Marathon Oil Company sold J. C. Martin A/C 2 in 1970; tract was released in 1974 as the E. E. Martin for the M-1 Unit.

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE A7

Pore Volume Data by Lease

<u>Lease</u>	<u>Pore Volume, Bbls</u>	
	<u>Primary (Total Lease)</u>	<u>Waterflood (Allocated)</u>
A. Riker	889,532/1,298,689*	730,338/1,097,602*
Basson & Siler	1,504,121/2,106,918*	704,039/747,677*
R. A. Siler	1,630,266/1,687,753*	1,630,266/1,687,753*
C. I. Weirich	1,325,222	1,325,222
W. Mann	Not Available	3,200,175
J. N. Burch	1,360,598	826,692
H. Martin	1,255,341	1,085,150
Wakefield-Martin Comm.	1,908,468	1,908,468
S. Tohill A/C 3	Not Available	331,305
Wakefield Heirs	2,050,944	1,517,038
E. E. Martin	Not Available	222,461

*Main sand plus lower sand stringer

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE A8

Analysis of Lease Performance

<u>Lease</u>	<u>Oil Production, % PV</u>			<u>Cumulative</u>			
	<u>Primary</u>	<u>Secondary</u>	<u>Total</u>	<u>WOR</u>	<u>Inj. PV</u>	<u>Fluid Production ÷ Inj.</u>	<u>Injectivity B/D/NF</u>
<u>Group I</u>							
W. Mann	Not Available	14.5		7.8	1.46	0.873	3.93
C. I. Weirich	17.9	10.8	28.7	4.9	1.15	0.549	3.58
H. Martin	Not Available	11.9		7.6	1.64	0.623	4.73
Wakefield-Martin Comm.	17.9	11.5	29.4	7.7	1.42	0.742	5.07
Group Average	17.9	12.7	30.6	7.3	1.41	0.753	
<u>Group II</u>							
A. Riker	17.8	11.3	29.1	11.6	1.49	0.957	4.23
	12.2*	7.5*	19.7*				
Bassom & Siler	15.6	15.5	31.1	12.9	1.85	1.159	4.25
	11.1*	14.6*	25.7*				
<u>Group III</u>							
J. N. Burch	10.2	10.8	21.0	10.2	1.57	0.769	2.60
Wakefield Heirs	14.1	8.3	22.4	7.8	1.64	0.445	3.27
R. A. Siler	7.5	7.4	14.9	9.9	1.36	0.981	3.97
	7.3*	7.1*	14.4*				
<u>Group IV</u>							
E. E. Martin	Not Available	21.5		10.4	1.70	0.578	
S. Tohill A/C 3	Not Available	12.1		10.2	1.94	0.695	
Total Project	Not Available	11.6	N/A	8.5	1.49	0.781	4.33

*Normalized to main sand plus lower sand stringer

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE A9

Electric Log Interpretations

<u>Well</u>	<u>Initial Production</u>			<u>Porosity ϕ, %</u>	<u>F</u>	<u>R_t</u>	<u>Water Saturation S_w, %</u>	<u>Net Sand Thickness, ft</u>
	<u>BOPD</u>	<u>BWPD</u>	<u>Oil Cut, %</u>					
C. I. Weirich No. 8	14	trace	100	19.6	21	48	27.3	43
W. Mann No. 27	23	0	100	18.7	23	55	26.7	47
W. Mann No. 28	16	0	100	18.5	23.5	50	28.3	52
R. Siler No. 18	21	1	95	18.3	24	60	26.1	47
H. Martin No. 12	20	1	95	19.0	22.5	45	29.2	37
Wakefield-Martin No. 12	20	1	95	17.9	25	45	30.7	34
Wakefield-Martin No. 11	30	2	94	19.0	22.5	50	27.6	33
Wakefield Heirs No. 18	27	2	93	19.0	22.5	40	30.9	15
C. I. Weirich No. 7	23	2	92	18.0	25	65	25.6	42

Average S_w of wells excluding Wakefield Heirs No. 18 = 27.7%

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE A10

Example Flood Front Results

<u>Segment</u>	<u>Inverted Pattern</u>	<u>Pattern Size, Acres</u>		<u>Flood Front Time Years</u>	<u>Model Fluid Injection, PV</u>	<u>Area1 Coverage, %</u>
		<u>Nominal</u>	<u>Actual</u>			
I	Q-11	2.5	2.3	5	1.35	95
	MM-13	5.0	4.9	10	1.07	83
II	GG-15	5.0	6.5	10	1.73	95
	EE-13	5.0	6.2	10	1.33	97
III	M-5	2.5	3.0	5	1.25	89
	K-1	2.5	4.3	5	1.01	87
	M-1	2.5	2.5	10	0.99	86
	O-1	2.5	2.9	10	1.20	85
	SS-3	5.0	5.2	10	1.43	95
IV	G-7	2.5	2.4	5	1.96	100
	EE-11	5.0	5.8	10	1.31	87

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE A11

Pore Volumes of Injector-Centered Patterns

<u>Pattern</u>	<u>Porosity ϕ, %</u>	<u>Area, Acres</u>	<u>Bulk Volume Acre-Feet</u>	<u>Pore Volume PV, Bbls</u>
* SS-1	20.3	5.64	103.16	162,464
* SS-3	19.0	5.22	115.99	170,972
SS-5	18.6	5.15	84.99	122,640
* SS-7	18.5	4.60	80.27	115,206
* SS-9	18.5	5.77	183.60	263,508
* SS-11	19.1	5.06	137.08	203,122
* W-1	20.0	5.46	118.97	184,594
* W-3	19.3	4.18	83.52	125,054
* W-5	19.3	2.67	44.06	65,971
W-7	19.0	3.94	58.75	86,599
* W-9	19.1	2.95	60.15	89,129
* W-11	18.4	4.04	124.20	177,292
* W-13	18.1	3.85	133.63	187,643
* W-15	18.4	5.11	165.00	235,533
* QQ-13	18.3	6.48	175.47	249,117
* QQ-15	18.2	4.09	109.04	153,960
* U-1	19.2	2.85	56.29	83,846
U-3	18.1	2.35	41.10	57,713
U-5	18.5	2.54	36.99	53,089
U-7	18.7	2.53	53.41	77,484
U-9	18.7	2.46	85.35	123,821
U-11	18.5	2.54	112.66	161,693
U-13	18.4	2.51	106.17	151,555
* U-15	18.5	3.72	119.90	172,084
00-13	18.3	5.83	179.61	254,995
* 00-15	18.2	4.11	131.43	185,573

*Pattern Area determined by modeling

TABLE A11 (continued)

Pattern	Porosity ϕ , %	Area, Acres	Bulk Volume Acre-Feet	Pore Volume PV, Bbls
* S-1	18.5	3.35	73.37	105,303
* S-3	18.4	2.12	38.24	54,587
S-5	18.2	2.47	38.24	53,993
S-7	18.5	2.46	83.02	119,153
S-9	18.5	2.56	118.45	170,003
S-11	18.4	2.60	118.08	168,556
S-13	18.4	2.55	105.37	150,413
* S-15	18.3	4.71	183.93	261,128
* MM-13	18.2	5.59	123.96	175,026
* MM-15	18.2	4.11	86.23	121,753
* Q-1	19.1	3.52	76.38	113,178
Q-3	19.5	2.46	48.87	73,931
Q-5	19.0	2.51	67.59	99,629
Q-7	18.7	2.47	107.73	156,289
Q-9	18.8	2.52	118.50	172,832
Q-11	18.8	2.65	122.30	178,375
Q-13	18.8	2.51	101.68	148,301
* Q-15	19.1	2.44	108.36	160,565
* O-1	19.5	2.90	63.95	96,744
O-3	20.2	2.31	53.95	84,546
O-5	19.7	2.51	100.15	153,062
O-7	19.4	2.61	121.40	182,713
O-9	19.7	2.56	130.30	199,141
O-11	19.6	2.61	140.57	213,746
O-13	19.0	2.48	133.90	197,371
* O-15	19.1	4.27	186.53	276,396
* KK-13	18.7	5.60	103.18	149,688
* KK-15	18.5	5.47	113.42	162,784
* M-1	19.2	2.59	75.14	111,924
M-3	19.2	2.59	77.15	114,918
M-5	18.9	2.52	109.99	161,274
M-7	18.5	2.56	122.08	175,213
M-9	19.0	2.60	130.67	192,610
M-11	19.2	2.62	117.79	175,452
M-13	19.0	2.53	139.52	205,655
* M-15	19.5	2.58	103.46	156,515
* K-1	18.0	4.25	91.55	127,844
* K-3	18.2	1.97	66.92	94,488
K-5	18.3	2.63	85.43	121,286
K-7	18.7	2.58	93.91	136,240
K-9	18.5	2.55	69.92	100,351
K-11	19.0	2.60	66.85	98,538
K-13	20.3	2.60	77.46	121,990
* K-15	19.6	3.61	113.74	172,949
II-13	19.0	5.81	141.50	208,574
II-15	19.1	5.70	137.60	203,893
II-17	18.9	5.17	89.19	130,776

TABLE A11 (continued)

Pattern	Porosity ϕ , %	Area, Acres	Bulk Volume Acre-Feet	Pore Volume PV, Bbls
* I-1	17.4	3.42	65.73	88,728
* I-3	17.2	2.48	56.64	75,579
I-5	18.3	2.51	76.61	108,764
I-7	18.8	2.51	73.94	107,842
I-9	18.5	2.44	67.48	96,849
I-11	18.6	2.48	58.23	84,025
I-13	19.3	2.48	50.80	76,063
* I-15	19.2	5.18	162.03	241,350
GG-13	18.7	5.96	199.96	290,091
GG-15	18.9	6.01	211.66	310,349
* GG-17	19.0	5.00	133.09	196,177
* GG-19	19.5	7.42	179.32	271,277
* G-1	17.6	3.06	54.07	73,828
G-3	17.0	2.54	52.25	68,910
G-5	18.1	2.58	70.71	99,291
* G-7	18.3	2.52	74.88	106,308
* G-9	18.3	2.50	52.81	74,975
* G-11	18.4	2.92	52.02	74,257
G-13	18.7	2.79	30.24	43,871
* EE-11	19.0	5.38	126.85	186,979
* EE-13	18.4	5.84	234.94	335,370
EE-15	18.9	6.01	214.07	313,883
* EE-17	19.0	5.00	101.26	149,259
* E-1	18.6	2.10	37.38	53,939
* E-3	18.3	2.56	28.42	40,348
E-5	18.5	2.52	39.94	57,323
* E-7	18.9	2.29	67.96	99,647
* E-9	18.7	2.78	62.44	90,585
* C-1	18.8	5.12	148.89	217,157
* C-3	18.9	3.15	44.48	65,219
* C-5	19.4	2.98	41.96	63,152
* C-7	19.5	2.89	44.80	67,774
* C-9	19.4	3.33	52.11	78,428
* C-13	19.3	3.47	77.03	115,337
* CC-11	19.9	3.99	115.99	179,070
CC-13	19.9	7.52	214.22	330,722
* CC-15	19.5	5.68	110.38	166,984
* CC-17	19.5	5.93	121.23	183,398
* A-11	19.4	3.36	63.99	96,308
* A-13	19.5	3.02	83.71	126,637
* A-15	19.7	2.66	94.69	144,717

Total 16,575,123

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE A12

Pore Volumes of Producer-Centered Patterns

<u>Pattern</u>	<u>Porosity φ, %</u>	<u>Area, Acres</u>	<u>Bulk Volume Acre-Feet</u>	<u>Pore Volume PV, Bbls</u>
* TT-2	18.8	4.03	74.87	109,198
* TT-4	18.4	2.59	56.09	80,067
* TT-6	18.1	2.57	37.52	52,686
* TT-8	18.5	2.90	76.18	109,336
* TT-10	19.1	3.29	93.25	138,176
* SC-14	20.5	3.06	55.15	87,710
* RR-2	19.3	6.16	139.51	208,887
* RR-4	19.5	6.87	120.67	182,551
* RR-6	19.0	6.11	96.30	141,948
* RR-8	18.5	5.65	160.89	230,914
* RR-10	18.2	5.88	188.97	266,817
* RR-12	18.7	5.39	154.06	223,502
* RR-14	18.2	2.72	57.00	80,481
* V-0	20.0	2.04	44.18	68,550
V-2	19.0	3.08	60.91	89,783
V-4	18.9	2.60	44.69	65,527
V-6	19.0	2.55	38.82	57,221
V-8	19.0	2.65	55.03	81,115
V-10	18.6	2.36	85.79	123,793
V-12	18.6	2.42	100.76	145,395
* V-14	18.3	2.64	102.96	146,174
* PP-12	18.5	5.12	147.99	212,400
PP-14	18.4	6.20	202.40	288,920
* PP-16	18.2	3.08	88.19	124,520
* T-0	18.8	1.36	27.12	39,555
T-2	18.2	2.86	52.28	73,817
T-4	18.1	2.55	42.47	59,636
T-6	18.3	2.59	52.80	74,961
T-8	18.8	2.55	96.55	140,819
T-10	18.7	2.53	110.84	160,801
T-12	18.5	2.29	96.71	138,801
* T-14	18.5	3.14	127.20	182,561
* NN-12	18.2	5.49	171.48	242,122
* NN-14	18.1	7.04	191.17	268,441

*Pattern area determined by modeling

TABLE A12 (continued)

Pattern	Porosity ϕ , %	Area, Acres	Bulk Volume Acre-Feet	Pore Volume PV, Bbls
* R-0	18.5	1.47	34.79	49,932
R-2	19.0	2.84	63.40	93,453
R-4	18.5	2.45	39.20	56,261
R-6	18.3	2.37	70.21	99,678
R-8	18.7	2.46	108.79	157,827
R-10	18.9	2.32	109.20	160,116
R-12	18.9	2.53	110.73	162,359
* R-14	19.1	2.76	111.17	164,729
* P-0	18.6	1.37	32.09	46,305
P-2	19.7	3.10	60.81	92,938
P-4	20.0	2.47	65.03	100,901
P-6	19.2	2.67	112.13	167,022
P-8	19.4	2.46	110.32	166,037
P-10	19.9	2.46	122.25	188,735
P-12	19.4	2.29	104.97	157,985
* P-14	19.1	2.78	135.09	200,173
* LL-12	18.6	6.58	266.91	327,428
* LL-14	18.5	7.04	106.47	152,809
* N-0	19.4	1.80	50.79	76,442
N-2	19.9	2.72	63.28	97,694
N-4	20.1	2.37	88.90	138,627
N-6	20.0	2.39	109.55	169,978
N-8	19.1	2.53	126.48	187,415
N-10	19.8	2.02	114.48	175,851
N-12	18.8	2.54	140.34	204,686
* N-14	19.4	2.92	152.81	229,987
* JJ-12	19.1	6.54	196.52	292,199
JJ-14	18.9	5.66	100.74	147,711
* JJ-16	18.8	4.95	114.25	166,634
* L-0	18.5	1.49	39.74	57,036
L-2	18.5	2.10	53.74	77,129
L-4	18.8	2.32	91.79	133,876
L-6	18.5	2.17	97.50	139,935
L-8	18.5	2.29	99.96	143,466
L-10	18.3	2.05	73.96	105,002
L-12	19.7	2.51	92.35	141,141
L-14	19.7	1.98	87.02	132,995
* J-0	18.0	1.55	29.76	41,558
J-2	17.5	2.90	59.89	81,310
J-4	18.1	3.12	90.21	126,673
J-6	18.8	2.67	87.33	127,371
J-8	18.7	3.02	85.79	124,459
J-10	18.7	2.64	69.86	101,349
J-12	19.6	2.93	64.74	98,442
* J-14	19.7	2.72	87.55	133,805

TABLE A12 (continued)

Pattern	Porosity ϕ , %	Area, Acres	Bulk Volume Acre-Feet	Pore Volume PV, Bbls
* HH-12	19.1	6.49	183.76	272,292
HH-14	19.1	5.66	189.23	280,397
HH-16	19.2	5.85	149.62	222,864
* HH-18	18.9	5.17	124.82	183,019
* HH-20	19.5	2.08	44.86	67,865
* H-0	17.4	1.38	28.45	38,404
H-2	16.9	3.00	58.03	76,083
H-4	17.4	2.50	69.66	94,033
H-6	18.8	2.29	75.41	109,986
H-8	18.6	2.50	66.46	95,901
H-10	18.5	2.26	53.34	76,555
H-12	18.6	2.29	40.13	57,907
* H-14	19.1	2.69	60.74	90,003
* FF-12	18.8	6.33	200.86	292,955
FF-14	19.0	5.65	236.99	349,328
FF-16	18.9	5.67	158.97	233,093
* FF-18	18.6	4.54	114.03	164,545
* FF-20	19.5	2.26	37.71	57,049
* F-0	18.5	1.67	27.59	39,598
F-2	17.5	2.71	43.09	58,501
F-4	17.7	2.51	32.04	43,996
F-6	18.6	2.53	69.82	100,749
F-8	18.5	2.46	60.54	86,889
* F-10	18.4	1.94	36.01	51,403
F-12	18.6	1.66	22.43	32,366
* F-14	19.0	2.17	27.33	40,285
* D-0	19.0	1.38	34.21	50,426
D-2	18.6	3.26	62.47	90,143
D-4	19.0	2.64	32.47	47,861
D-6	19.2	2.59	64.22	95,658
D-8	19.2	2.44	53.70	79,988
* D-10	19.0	1.29	24.98	36,821
* DD-10	19.3	3.44	57.70	86,394
DD-12	19.6	6.16	224.16	340,851
DD-14	18.6	5.90	204.91	295,683
* DD-16	19.5	6.27	154.72	234,062
* DD-18	19.3	3.64	68.54	102,625
* B-0	19.0	1.07	42.95	63,309
* EB-5	19.0	2.49	55.96	82,486
* B-4	19.5	1.41	16.65	25,188
* B-6	19.5	1.59	18.17	27,488
* B-8	19.5	1.52	20.35	30,786
* B-10	19.5	1.96	15.40	23,297
* B-12	19.5	2.45	63.51	96,079
* B-14	19.8	2.50	90.05	138,324
* B-16	20.2	3.74	90.83	142,341

TABLE A12 (continued)

<u>Pattern</u>	<u>Porosity ϕ, %</u>	<u>Area, Acres</u>	<u>Bulk Volume Acre-Feet</u>	<u>Pore Volume PV, Bbls</u>
* AS-35	20.1	2.14	46.47	72,916
* AS-36	19.7	4.76	76.90	117,528
* XA-10	19.5	0.95	15.37	23,252
* XA-12	19.5	1.80	38.09	57,623
* XA-14	19.5	1.31	47.48	71,828
* AA-11	19.4	0.57	20.90	31,456
			Total	16,575,123

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE A13

Peripheral Water Injection Well Data¹

<u>Lease-Well</u>	<u>Status</u>	<u>Rate (BWPD) @ Pressure(psig)</u>	<u>Cumulative Injection Thousand Bbls</u>	<u>Remarks</u>
<u>SEGMENT II</u>				
A. R. Smith P-12	Active	104 @ 705	678	
A. R. Smith Q-12	Active	58 @ 700	782	
Brubaker-Prier R-12	Shut In		489	No water since 1/69
<u>SEGMENT III</u>				
W. Mitchell X-88	Active	217 @ 580	209	No well record available
S. Carlisle X-91	Active	106 @ 625	556	Old No. 11 conversion
F. Dewey X-94	Shut In 2/75		818	When shut in, avg. rate 282 BWPD
F. Dewey X-97	Shut In 8/75		706	Hole in csg, tbg & pkr set @ 763' in 1971; when shut in avg. rate 135 BWPD
R. A. Siler X-3	Shut In 2/75		688	Hole in csg, tbg & pkr set @ 875' in 1969; when shut in, avg. rate 238 BWPD @ 600 psig
R. A. Siler X-6	Active	161 @ 625	838	
J. Wasson X-9	Active	79	502	
J. Wasson X-12	Shut In 9/75		431	Hole in csg, tbg & pkr set @ 886' in 1967; when shut in avg. rate 258 BWPD @ 600 psig
J. Wasson A-12	Active	32 @ 600	1,169	Hole in csg, tbg & pkr set @ 845' in 1967
UU-1	Not completed			Csg set through & cem; poor bond below 800'; M-1 development well
UU-3	Not completed			Csg set through & cem; poor bond below 600'; M-1 development well
UU-5	Not completed			Csg set through & cem; poor bond below 800'; M-1 development well

¹Data current to May, 1976

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE A14

Pore Volume Eliminated by Peripheral Water Injection

<u>Segment</u>	<u>Water Injection Wells</u>	<u>Inverted Pattern</u>	<u>Eliminated Pore Volume, Bbls</u>
II	P-12, Q-12, R-12	CC-13	0
		CC-15	1,794
		CC-17	14,796
		EE-17	10,103
		Subtotal	26,693
III	UU-1, UU-3, UU-5 X-88, X-91, X-94 X-97, X-3, X-6 X-9, X-12, A-12	SS-1	1,150
		SS-3	2,000
		W-1	12,080
		U-1	27,912
		S-1	1,562
		Q-1	19,192
		O-1	2,660
		M-1	455
		K-1	17,931
		I-1	17,936
		G-1	4,929
		E-1	10,884
		C-1	27,364
		C-3	2,000
		Subtotal	148,005
		Total	174,748

PART B: M-1 PROJECT FLUID SYSTEM DESIGN

SUMMARY

The M-1 Project is a commercial scale demonstration of the Maraflood oil recovery process being conducted on 407 acres in Crawford County, Illinois. This project is the culmination of 15 years of laboratory and field testing of the process. The initial fluid system laboratory design work for the project began in December, 1973. However, most of the fluid system design work for this reservoir was done during 1976. A large number of laboratory experiments, nearly all of which were disc floods using reservoir rock, reservoir crude and synthetic reservoir water, were conducted to determine the most cost effective micellar-polymer system for recovering oil from this reservoir. Disc floods entail the preparation and radial flooding of thin sections of cylindrical core material. Injection takes place into a "well-bore" drilled in the center of the disc, with fluid flow being directed radially outward toward the edge of the disc, where "produced" fluids are collected.

The typical micellar solution (slug) composition for the M-1 Project is shown in Table B1 and discussed below. The slug will be manufactured in Marathon's Robinson Refinery. It will contain 10 wt % active sulfonate. The target slug pH is 7.0 and will be maintained between 6.5 and 7.5.

Some chemicals will be added at the field injection site. These include approximately 500 ppm citric acid as an iron chelating agent during initial slug injection and primary hexanol as cosurfactant. Slug viscosity will be

maintained below 40 cp. If the viscosity cannot be maintained below this value using only hexanol, isopropyl alcohol will be used to reduce viscosity as required.

Laboratory data indicate tertiary oil recoveries in excess of 70% can be obtained with 8-10% PV of a pilot plant slug similar in composition to the formulation in Table B1 when displaced by Dow PUSHER 700 polymer through high permeability discs. Dow 700 polymer will be used for the mobility buffer in the M-1 Project. The mobility buffer configuration used to obtain satisfactory laboratory oil recovery with 10% PV slug was:

10% PV	1100 ppm Pusher 700 polymer
50% PV	615 ppm Pusher 700 polymer
30% PV	117 ppm Pusher 700 polymer
50% PV	produced water

The mobility buffer configuration for the M-1 Project is based on the design used in another large scale application of the Maraflood process in the Robinson Sand. The field design is as follows:

11% PV	1156 ppm Pusher 700 polymer
19% PV	800 ppm Pusher 700 polymer
32% PV	625 ppm Pusher 700 polymer
12% PV	411 ppm Pusher 700 polymer
11% PV	200 ppm Pusher 700 polymer
10% PV	100 ppm Pusher 700 polymer
10% PV	50 ppm Pusher 700 polymer
35% PV	produced water

The field design requires the use of 25% more polymer than used in the laboratory.

MARAFLOODTM PROCESS TEST HISTORY

The Maraflood process employs micellar-polymer systems to mobilize tertiary oil and displace it through the reservoir in a flowing regime that behaves in a miscible-like manner under certain conditions. The micellar slug is designed to displace oil at its leading edge and must in turn be displaced without loss of mobility control at its trailing edge. Aqueous-based polymer solutions are used for mobility control behind the slug.

Since 1962, thousands of core flood experiments have been conducted and more than 1,000 micellar solutions have been formulated and evaluated in Marathon Oil Company laboratories. Most systems were ruled out for field application due to poor laboratory results. As experience increased, better systems were taken to the field for testing.

Field testing of the process was initiated with the Dedrick pilot flood in November, 1962. This test was in the Robinson Sand on the Dedrick lease in Crawford County, Illinois. This reservoir was originally developed in the early 1900's and had not been waterflooded prior to micellar solution injection.

In January, 1964, testing was extended to a similar Robinson Sand reservoir on the Wilkin lease. This reservoir had been waterflooded and producing water cuts were in excess of 97% at the initiation of slug injection. Results of these two tests and other field testing by Marathon Oil Company in the Robinson Sand have been documented in the literature.¹

Additional testing was conducted in the same reservoir on the Henry lease beginning with two inverted 0.75-acre patterns. Because of mobility control problems in the earlier tests, micellar slug was displaced with Dow PUSHER 500 polymer solution. Encouraging oil displacement and recovery were obtained from this test.² These results led to the 40-acre 119-R Project. This test, initiated in September, 1968, used both Marathon-manufactured and commercial sulfonates and Dow PUSHER 700 polymer as the mobility buffer.

A primary objective of the 119-R Project was to obtain a field recovery factor that could be scaled to full field utilization of the process. Encouraging oil production response and projected ultimate recovery resulted in a concerted effort to develop more cost effective micellar fluids.³

The major chemical cost was for high quality surfactant from commercial sources. Research conducted at Marathon's Denver Research Center ultimately resulted in a process in which crude oil is sulfonated directly and micellar solution produced in a single process. Laboratory tests using crude oil sulfonate slugs established superiority in cost effectiveness of these micellar solutions compared to slugs formulated from commercial sulfonates.

A pilot plant was constructed at the Denver Research Center to manufacture sufficient slug volumes from various crude oil feedstocks to determine oil displacement in the field. Mini-Test #1 was the first field test using slug manufactured by direct sulfonation of crude oil. A mini-test is not a production test. Micellar-polymer fluids are injected into one well, displacing reservoir fluids away from the vicinity of the injection wellbore. Oil displacement is estimated from analysis of cores taken from various locations

around the injection well. Slug injection in this single well test began in March, 1973, using mini-testing technology developed by Marathon.⁴ The test demonstrated that crude oil sulfonate slug could bank and displace oil efficiently enough to warrant larger scale oil production testing.³

At the conclusion of this test a decision was made to build a slug manufacturing unit in Marathon's Robinson, Illinois, refinery to furnish micellar solution for southeastern Illinois oil properties owned by Marathon. This unit was completed in September, 1975. The plant was started up and slug was available for injection into the first large project on October 1, 1975. This project, known as the 219-R Project, encompasses 116 acres adjacent the 119-R Project discussed above.

During 1975 and 1976, field work was underway on a 400-acre commercial scale project to be conducted in the Robinson Sand. This project, known as the M-1, was undertaken to demonstrate economic feasibility of the Maraflood process when applied to a large waterflooded reservoir. The slug manufacturing unit in the Robinson Refinery is producing the micellar solution being transported to the field site by pipeline. To guarantee a supply of polymer for mobility control, a long term contract was signed with The Dow Chemical Company. Dow Pusher polymer was selected over other commercially available polymers on the basis of availability, price, laboratory core flood evaluation and successful utilization of this material in previous Illinois field tests. Negotiations with ERDA resulted in a contract being executed between Marathon and ERDA on September 30, 1976.

During 1976, work was continuing at the Denver Research Center to design a fluid system for injection into the M-1 Project. This section of the Design Report presents results and variables investigated in this study.

FLUID SYSTEM DESIGN

Surfactants used for M-1 Project fluid system design were manufactured at the Robinson Refinery and in the Denver Research Center pilot plant. Sulfonate manufactured in these units has been used in micellar-polymer systems for another reservoir in the Robinson Sand. Even with the background acquired in using this sulfonate to design fluids for a similar reservoir, it was necessary to investigate a number of variables to obtain the most cost effective micellar-polymer system for the M-1 Project. Restraints placed on the design were: 1) slug would be manufactured in the Robinson Refinery unit; 2) slug viscosity would not exceed 40 cp; and 3) based on considerations discussed in the previous section of this report, the mobility buffer would utilize Dow polyacrylamide.

Laboratory Testing Procedures

Laboratory fluid design tests were conducted under conditions simulating the reservoir. All flooding tests utilized samples of reservoir rock taken from a series of four 6-inch diameter cores cut from the M-1 Project reservoir. From the time the cores were cut until they were prepared for flooding, they were handled so as to minimize alteration of their properties. Cores were shipped and stored in containers under reservoir crude or water. They were cut to a thickness of 2 inches and trimmed for laboratory use with minimal exposure. Discs were cleaned by cold solvent flushing with isopropyl alcohol, toluene and hexane before drying in a vacuum oven at temperatures not exceeding 120°F. They were then resaturated with synthetic reservoir brine and actual reservoir crude oil and waterflooded to the tertiary condition prior to

laboratory experiments. These handling and cleaning procedures closely duplicated those for discs that had not been cleaned, but were simply restored to the tertiary condition using fresh crude oil and synthetic reservoir brine. The synthetic reservoir brine used in this work was based on an average analysis of waters taken from four producing wells within the project area. Ionic content of the produced water is shown in Table B2.

Water used to mix polymers for this work is a synthetic fresh water based on analysis of an available supply water that was 80% zeolite treated to reduce hardness and polymer requirement. Ionic content of this treated fresh water is also shown in Table B2.

Crude oil used in laboratory experiments was taken from four different 10-gallon samples gathered from the project area. This is a sweet Illinois crude having a gravity of 36⁰ API and a viscosity of 5-6 cp at the reservoir temperature of 72⁰ F.

All laboratory experiments were conducted at a controlled temperature of 72⁰ F. Micellar-polymer fluids were injected into a 1/8-inch diameter wellbore drilled in the center of the discs. Injection was at a constant rate to give a median frontal velocity of 0.3 ft/day.

Slug Design

Variables investigated during slug optimization work include feedstock, chemical additives, surfactant concentration, pH, sulfonate molecule cation and cosurfactant type and level. All laboratory oil recovery results shown in

tables and figures include a recovery factor normalized to an oil saturation after waterflooding of 40% PV. This value corresponds to the average oil saturation believed to exist in the M-1 Project.

Feedstock. Studies were conducted using various feedstocks in the pilot plant sulfonation unit located in Denver. Oil recovery results of this work are shown in Table B3. Feedstocks are denoted by letters A-G. Based on oil recovery, slug viscosity and economic considerations, feedstock F was chosen for the slug manufacturing unit.

Chemical Additives. Slug formulations incorporating various chemical additives were investigated. Results of this study are shown in Table B4. Based on results in Table B4, chemical additives were not considered further for use in the M-1 Project slug.

Surfactant Concentration. Studies were conducted to determine effect of surfactant concentration on oil recovery. Results showed that within certain limits of surfactant concentration, when total injected surfactant (surfactant concentration multiplied by slug pore volume) was held constant, oil recovery was essentially independent of surfactant concentration. Use of very high surfactant concentrations resulted in slugs with unacceptably high viscosities. A 10 wt % active sulfonate concentration was selected for this project to keep slug viscosity below 40 cp.

Slug pH. Early laboratory work indicated that oil recovery was adversely affected when using low pH slugs (pH of 3-6). However, acidic slugs are desirable because at low pH iron hydroxide precipitation that can cause

injectivity problems is minimal. Floods were performed with slugs in the 6-9 pH range. Results are shown in Table B5. Results indicated that optimum recovery occurred near pH 7. Corrosion of copper and brass is not significant at this value. The target pH of 7.0 is based on oil recovery and corrosion results. About 500 ppm citric acid will be added to the initial injected slug to prevent hydroxide precipitation of any iron in solution at this pH.

Sulfonate Molecule Cation. Sulfonate produced in Marathon's sulfonate manufacturing facility utilizes ammonium cation. The question arose whether sodium, a more costly cation, could improve oil recovery. Slugs were tested that utilized only ammonium, a mixture of ammonium and sodium and only sodium as sulfonate molecule cation. Laboratory results (Table B5) do not indicate a strong preference for sodium. The use of ammonium for sulfonate molecule cation is based on economic considerations.

Cosurfactant Type and Level. Oil recovery is dependent upon amount of oil soluble alcohol added to the slug. The highest oil recoveries were achieved using hexanol as cosurfactant (Table B5).

Use of hexanol as the only cosurfactant may result in a slug viscosity higher than the desired 40cp. Isopropyl alcohol can be added with hexanol to reduce slug viscosity and/or increase hexanol tolerance. Addition of water soluble isopropyl alcohol as necessary to reduce viscosity did not adversely affect oil recovery.

The actual level of cosurfactant addition depends on plant operating conditions. Manufactured slug properties may vary slightly over the project life and amount of added cosurfactant may be varied accordingly. Slug viscosity as a function of alcohol content over the stable range of the slug selected for laboratory tests is shown on Figure B1. The upper stability limit shown on this figure represents the level of alcohol addition above which the slug separates into two phases. Behavior of the slug actually injected into the project may be similar to behavior on Figure B1.

Slug Size

Oil recovery is dependent on amount of slug injected. Figure B2 shows oil recovery of the recommended slug at various injected slug volumes for both Pusher 700 and Pusher 500 polymers. This figure indicates that, using Dow 700, 8-10% PV slug is necessary to obtain a laboratory recovery of 70%.

Injected slug volume in the M-1 Project will be selected based on previously developed field-laboratory oil recovery correlations, relevant economic considerations and certain laboratory data.

A summary of the core flood results shown on Figure B2 is included in Table B6. The curves on Figure B2 represent a non-linear regression of data in the slug size range 6-14% PV.

Polymer Design

Dow partially hydrolyzed polyacrylamide was selected for the M-1 Project mobility buffer. Tests were run using both Pusher 500 and Pusher 700 polymers

at concentrations giving sufficient oil recovery in Robinson sandstone.

Final results using the two polymers are shown in Table B6.

Figure B2 shows runs in which recommended slug was flooded at various volumes using both Pusher 500 and Pusher 700 polymers at a mobility buffer configuration of 10% PV of 1100 ppm polymer, 60% (minus slug size) PV of 615 ppm polymer, 30% PV of 117 ppm polymer and followed by 50% PV produced water. This figure shows definite oil recovery improvement with Dow 700. In addition, two runs using Dow 500 at 1.5 times the above concentrations are also shown on this plot. This additional concentration does not increase recovery over lower Dow 500 concentrations.

Data on Figure B2 were obtained from discs with permeabilities greater than 100 md. Effect of permeability on oil recovery as a function of polymer type was studied because the M-1 Project reservoir has a geometric mean permeability of 77 md. Results of this work are shown on Figure B3. This figure indicates oil recovery is reduced as permeability decreases and the difference in recovery between the two polymers approaches the laboratory experimental error for permeabilities below the geometric mean value for the M-1 Project reservoir.

The lines on Figure B3 represent linear least squares fits of the data. Based on laboratory disc flood data discussed in this report and field injectivity tests (discussed in regular project operating reports) that indicated acceptable injectivity for the 700 series polymer, Pusher 700 polymer was selected for use in the M-1 Project.

The specific polymer design for the M-1 Project is based directly on the design currently being used in another large scale application of the Maraflood

process in the Robinson Sand. The field design is as follows:

11% PV	1156 ppm Pusher 700 polymer
19% PV	800 ppm Pusher 700 polymer
32% PV	625 ppm Pusher 700 polymer
12% PV	411 ppm Pusher 700 polymer
11% PV	200 ppm Pusher 700 polymer
10% PV	100 ppm Pusher 700 polymer
10% PV	50 ppm Pusher 700 polymer
35% PV	produced water

The field design requires the use of 25% more polymer than used in the laboratory for most work discussed in this report. The use of additional volumes and higher average concentrations of polymer in the field results from experience in past projects indicating laboratory displacements do not accurately simulate drive water breakthrough at producing wells in field situations.

REFERENCES

1. Gogarty, W. B. and Davis, J. A., Jr.: "Field Experience with the Maraflood Process," SPE 3806, Presented at Improved Oil Recovery Symposium, Tulsa, Oklahoma (April 16-19, 1972).
2. Gogarty, W. B. and Surkalo, H.: "A Field Test of Micellar Solution Flooding," SPE 3439, J. Pet. Tech. (September 1972) 1161-1169.
3. Earlougher, R. C., Jr., O'Neal, J. E. and Surkalo, H.: "Micellar Solution Flooding: Field Test Results and Process Improvements," SPE 5337, Presented at Rocky Mountain Regional Meeting of Society of Petroleum Engineers of AIME, Denver, Colorado (April 1975).
4. Jones, S. C. and McAtee, R. W.: "A Novel Single-Well Field Test of a Micellar Solution Slug," J. Pet. Tech. (November 1971) 1371-1375.

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

FIGURE B1. ALCOHOL-VISCOSITY SLUG BEHAVIOR

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

FIGURE B2. OIL RECOVERY VS. INJECTED SLUG VOLUME

MARATHON OIL COMPANY
MARAFLOOD PROCESS — M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-19) - 2242
Design Report

FIGURE B3. OIL RECOVERY VS. PERMEABILITY

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE B1

Slug Composition

Slug as Produced in Marathon's Robinson Refinery

<u>Component</u>	<u>Typical Level</u> <u>Wt %</u>	<u>Typical Range</u> <u>Wt %</u>
Active Sulfonate	10.0	9.2 - 10.8
Inorganic Salt	2.5	2.0 - 4.0
Water*	80.0	75.0 - 82.0
Unreacted Oil	7.5	5.0 - 15.0
	<u>Target Level</u>	<u>Range</u>
Slug pH	7.0	6.5 - 7.5

Chemicals To Be Added At Field Site

<u>Component</u>	<u>Typical Level</u>	<u>Typical Range</u>
Citric Acid, ppm**	500	400 - 600
Hexyl Alcohol, Vol %	0.8	0.4 - 1.0
Isopropyl Alcohol, Vol %	0.0	0 - 1.5

*Water - Palestine supply water, see Table B2

**Citric acid to be added only to initial 2,000 Bbls injected slug

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE B2

Water Compositions

<u>Ion</u>	<u>Formation Water¹</u> mg/l	<u>Fresh Water²</u> mg/l	<u>Polymer Makeup Water³</u> mg/l
Bicarbonate	1,172	241	241
Chloride	9,081	39	39
Sulfate	88	90	90
Calcium	166	80	16
Magnesium	118	20	4
Sodium	<u>5,950</u>	<u>31</u>	<u>134</u>
Total Dissolved Solids	16,575	501	524

Synthetic Waters Used for Laboratory Floods

<u>Compound</u>		
CaCl ₂	461	44
MgCl ₂	463	15
Na ₂ SO ₄	130	133
NaHCO ₃	1,614	332
NaCl	<u>13,903</u>	<u> </u>
Total Dissolved Solids	16,571	524

¹ Average analysis for Wells FF-12, JJ-12, PP-12 and RR-9

² Palestine supply water

³ 80% zeolite treated Palestine water

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE B3

Effect of Feedstock on Oil Recovery

Run No.	Feedstock	Injection Sequence	Core Permeability k, md	Oil Saturation After Waterflood Sor, % PV	Oil Saturation After Chemical Flood Sor _c , % PV	Recovery of Oil in Place %	Recovery if Sor = 40% PV %
1	A	1	513	41.8	24.7	40.9	38.3
2	B	1	88	32.4	15.4	52.5	61.6
3	B	1	89	30.5	13.2	56.7	67.0
4	C	1	194	26.1	18.0	31.0	54.9
5	C	1	66	37.6	18.8	50.0	53.0
6	D	2	154	35.6	18.6	47.9	53.6
7	D	2	161	35.0	19.4	44.6	51.5
8	E	2	134	37.0	13.9	62.4	65.3
9	E	2	58	31.9	14.2	55.6	64.6
10	F	2	100	34.3	9.4	72.5	76.4
11	F	2	44	36.7	9.7	73.6	75.8
12	G	2	89	38.0	15.1	60.4	62.3
13	G	2	65	33.9	14.1	58.4	64.7

Injection Sequence 1:

10% PV slug
 10% PV 1100 ppm Pusher 700 polymer
 50% PV 615 ppm Pusher 700 polymer
 30% PV 117 ppm Pusher 700 polymer
 50% PV produced water

Injection Sequence 2:

10% PV slug
 10% PV 1650 ppm Pusher 500 polymer
 50% PV 932 ppm Pusher 500 polymer
 30% PV 175 ppm Pusher 500 polymer
 50% PV produced water

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE B4

Effect of Chemical Additives on Oil Recovery

<u>Run No.</u>	<u>Additive</u>	<u>Core Permeability k, md</u>	<u>Oil Saturation After Waterflood S_{or}, % PV</u>	<u>Oil Saturation After Chemical Flood S_{orc}, % PV</u>	<u>Recovery of Oil In Place %</u>	<u>Recovery if S_{or} = 40% PV %</u>
14	None	54	35.8	16.4	54.1	58.9
15	None	60	36.6	19.8	45.8	50.4
16	A	41	42.1	20.5	51.4	48.9
17	A	19	35.8	18.2	49.0	54.4
18	B	312	33.3	21.9	34.2	45.3
19	B	18	27.7	17.9	35.2	55.2
20	C	303	35.7	16.1	55.0	59.8
21	C	52	31.9	18.9	40.8	52.8

All runs in this table performed with an injection sequence of:

10% PV slug
 10% PV 1100 ppm Pusher 500 polymer
 50% PV 615 ppm Pusher 500 polymer
 30% PV 117 ppm Pusher 500 polymer
 50% PV produced water

MARATHON OIL COMPANY
 MARAFLOOD PROCESS - M-1 PROJECT
 Crawford County, Illinois
 Contract No. E(49-18) - 2242
 Design Report

TABLE B5

Effect of Slug Variables on Oil Recovery

Run No.	Variable	Core Permeability k, md	Oil Saturation After Waterflood Sor, % PV	Oil Saturation After Chemical Flood, Sorc, % PV	Recovery of Oil in Place %	Recovery if Sor = 40% PV %
	<u>pH</u>					
22	8.8	125	37.0	13.5	63.4	66.1
23	8.0	217	42.9	14.7	65.8	63.3
24	6.9	126	30.0	11.8	60.6	70.5
25	6.0	67	40.3	17.5	56.5	56.2
	<u>Cation</u>					
26	NH ₄	104	37.2	13.2	64.5	67.1
27	NH ₄ + Na	73	34.0	13.0	61.9	67.6
28	Na	62	29.5	12.1	58.9	69.6
	<u>Cosurfactant</u>					
29	Amyl Alcohol 1.50%	107	36.9	16.0	56.6	59.9
30	Hexyl Alcohol 1.55%	134	37.0	13.9	62.4	65.3
31	Amyl Alcohol 1.25%	67	40.3	17.5	56.5	56.2
32	Hexyl Alcohol 1.25%	70	31.7	13.3	58.2	66.8

All runs in this table performed with an injection sequence of:

10% PV slug
 10% PV 1650 ppm Pusher 500 polymer
 50% PV 932 ppm Pusher 500 polymer
 30% PV 175 ppm Pusher 500 polymer
 50% PV produced water

MARATHON OIL COMPANY
MARAFLOOD PROCESS - M-1 PROJECT
Crawford County, Illinois
Contract No. E(49-18) - 2242
Design Report

TABLE B6

Core Flood Results Using Recommended Slug

Run No.	Slug Inj. % PV	Mobility Buffer PUSHER Polymer*	Core Permeability k, md	Oil Saturation After Waterflood Sor, % PV	Oil Saturation After Chemical Flood Sor _c , % PV	Recovery of Oil in Place %	Recovery if Sor = 40% PV %
33	6.0	700	135	34.4	14.5	57.9	63.8
34	6.0	700	104	37.9	8.9	76.5	77.8
35	6.0	500	112	35.5	17.0	52.1	57.5
36	8.0	700	217	41.0	10.8	73.8	73.1
37	8.0	700	105	42.1	12.7	69.9	68.2
38	8.0	500	64	34.0	18.1	46.9	54.8
39	10.0	700	173	40.4	10.8	73.1	72.9
40	10.0	700	296	39.3	10.1	74.4	74.9
41	10.0	700	175	38.2	10.2	73.2	74.4
42	10.0	700	117	35.8	10.2	71.4	74.5
43	10.0	500	130	42.8	15.7	63.3	60.7
44	10.0	500	182	44.1	15.8	64.2	60.6
45	10.0	1.5 x 500	104	36.7	13.5	63.1	66.2
46	10.0	1.5 x 500	164	43.0	17.2	60.1	57.1
47	12.0	700	261	38.9	8.1	79.2	79.8
48	12.0	700	357	38.2	12.5	67.3	68.8
49	12.0	500	299	41.0	12.5	69.5	68.7
50	14.0	700	154	45.6	9.3	79.5	76.6
51	14.0	700	180	42.3	2.9	93.0	92.6
52	14.0	500	315	39.2	13.6	65.2	65.9
53	10.0	700	78	41.0	15.3	62.7	61.7
54	10.0	700	60	38.2	17.0	55.6	57.6
55	10.0	700	37	37.9	13.7	63.9	65.8
56	10.0	700	21	39.6	17.0	57.1	57.6
57	10.0	500	97	39.7	15.4	61.2	61.5
58	10.0	500	84	41.0	12.6	69.2	68.4
59	10.0	500	26	34.7	20.4	41.1	48.9
60	10.0	500	36	35.9	16.3	54.5	59.2

*All runs except 45 and 46 use Injection Sequence 1 (Table B3). Runs 45 and 46 use Injection Sequence 2 (Table B3).