Energy

G E O T H E R M A L

DOE/NV/10081--3-Pts.1-2

DE85 016048

DOE/NV/10081-3(Pts.1-2)
(DE85016048)

SWEET LAKE GEOPRESSURED-GEOTHERMAL PROJECT

Volume III

Annual Report for the Period February 1982--March 1985

By
C. O. Durham, Jr.
F. D. O'Brien
R. W. Rodgers

Work Performed Under Contract No. AC07-80NV10081

**Magma Gulf-Technadril
Houston, Texas**

**Technical Information Center
Office of Scientific and Technical Information
United States Department of Energy**

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.

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.

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.

Price: Printed Copy A20
Microfiche A01

Codes are used for pricing all publications. The code is determined by the number of pages in the publication. Information pertaining to the pricing codes can be found in the current issues of the following publications, which are generally available in most libraries: *Energy Research Abstracts (ERA)*; *Government Reports Announcements and Index (GRA and I)*; *Scientific and Technical Abstract Reports (STAR)*; and publication NTIS-PR-360 available from NTIS at the above address.

SWEET LAKE
GEOPRESSURED-GEOTHERMAL PROJECT
MAGMA GULF-TECHNADRIL/DOE AMOCO FEE

VOLUME III
FINAL REPORT

ANNUAL REPORT
for the period
February 1982 - March 1985

C.O. DURHAM, JR., F.D. O'BRIEN, & R.W. RODGERS
Editors

Magma Gulf-Technadril
430 Hwy. 6 South, Suite 208
Houston, Texas 77079

Prepared for the
U.S. Department of Energy
Division of Energy Technology
Under Contract DE-AC08-80NV10081

i. nofelio

PREFACE

This is Volume III, the final report to the U.S. Department of Energy on the Magma Gulf-Technadril Inc. geopressured well testing project of the Amoco No. 1 (Sweet Lake) well in Cameron Parish, Louisiana. This report presents the results of the testing of Sand 3 (15,245 - 15,280 feet in depth) which occurred from November 1983 to March 1984 and evaluates these new data in comparison to results from the testing of Sand 5 (15,385 - 15,415 feet in depth) which occurred from June 1981 to February 1982. It also describes the reworking of the production and salt water disposal wells preparatory to the Sand 3 testing as well as the plug and abandon procedures requested to terminate the project.

The period treated in this report extends from the termination of the Sand 5 test in February 1982 to the final plug and abandon completed in November 1984. The present report effectively serves as the annual reports for the third and fourth years of the project from February 11, 1982 to completion of the contract, concluded with submission of this report in March, 1985. During a major portion of this period operations were suspended for lack of funding to rework the wells preparatory to additional testing.

Two previous reports have been published by the Department of Energy:

Volume I: "Drilling and Completion Test Well and Disposal Well" (DOE/NV/10081-1) - which serves as the annual report for the period December 1, 1979 to February 27, 1981.

Volume II: "Surface Installations, Reservoir Testing" (DOE/NV/10081-2) - which serves as the annual report for the February 28, 1981 to February 10, 1982.

In addition Gas Research Institute has published a final report on the auxiliary research investigations concerning the project which were funded by that organization. This report is entitled "Geopressured Well Project, Sweet Lake, Cameron Parish, Louisiana" Final Report, February 1980 - September 1982 (GRI - 79/0125).

The present report summarizes the contents of these previous publications, however, for detailed information and reports the previous publications should be consulted.

The present volume contains two parts: Part 1 includes the text and accompanying plates, figures and tables; Part 2 consists of the appendixes including auxiliary reports and tabulations.

PART I

Preface	ii
Table of Contents	ix
Summary	x
Text	1
Figures	103
Tables	185
Plates	208

PART II

Title and Index	210
Appendices	212

TABLE OF CONTENTS

1.0	Project History, Objectives and Administration	1-16
1.1	Project History	1
1.2	Project Objectives	4
1.3	Project Administration	7
1.4	Contract Subcontractors	9
2.0	Well Facilities	17-33
2.1	Well Location	17
2.2	Site Preparation	17
2.3	History of Well Designs	18
2.4	Disposal Well	29
3.0	Geology	34-51
3.1	Regional Geologic Setting	34
3.2	Geology of the Sweet Lake Area	34
3.3	Test Well Geology	36
3.4	Reservoir Description	38
3.5	Petrophysical Analysis	41
3.6	Core Analysis	44
3.7	Organic Geochemistry	50
3.8	Disposal Well Cores	51
4.0	Description of Surface Facilities	52-66
4.1	Test Wellhead	52
4.2	Flow Control System	52
4.3	Brine/Gas Separator System	54
4.4	Brine Filter System	54
4.5	Salt Water Disposal Wellhead	55
4.6	Production Gas System	55
4.7	Surface Tankage	56
4.8	Pressure Relief Systems	56
4.9	Instrumentation	57
4.10	Scaling/Corrosion Monitoring Systems	62
4.11	Electrical System	62
4.12	Instrument Air System	62
4.13	Fresh Water System	63
4.14	Waste Water Disposal	63
4.15	Control Room Trailer	63

4.16 Site Laboratory	63
4.17 Modes of Operation	63
4.18 Safety	64
4.19 Gas-Water Ratio Measurements	64
4.20 Proposed Surface Generating System	65
5.0 Reservoir Testing	67-78
5.1 Preliminary Operations	67
5.2 Sand Zone 5	67
5.3 Hiatus In Operations	70
5.4 Sand Zone 3	71
5.5 Results and Conclusions	74
6.0 Chemical Analysis	79-83
6.1 Brine Analysis	80
6.2 Gas Analysis	80
6.3 Solubility of Methane	81
6.4 Other Chemical Aspects	82
6.5 IGT Conclusions	82
7.0 Environmental Monitoring	84-94
7.1 Air Quality	84
7.2 Water Quality	86
7.3 Microseismic Monitoring at Sweet Lake	88
7.4 Subsidence	93
8.0 Economics	95-98
8.1 Introduction and Earlier Cost Estimates	95
8.2 The 1984 Project Total Costs	96
8.3 Analysis of Project Costs	96
9.0 Abandonment and Site Restoration	99-102
9.1 Background	99
9.2 Plug and Abandon Test Well	99
9.3 Plug and Abandon Disposal Well	101
9.4 Site Restoration	101

LIST OF FIGURES

No.	Title	Page	of Reference
1-1	Joint Venture Personnel-Drilling	103	8
1-2	Joint Venture Personnel-Testing	104	8
2-1	Drillsite Location in Southwest Louisiana	105	17
2-2	Vicinity and Production Well Map	106	17
2-3	Production Well Design Including 1983 Recompletion	107	18,27
2-4	Disposal Well Design Including 1983 Recompletion	108	27
3-1	Sweet Lake Structure Map - Original 1979 Version	109	35,38
3-2	Isothermal Map - Top of <u>Miogypsinoides</u> Zone	110	35
3-3	Thickening Index Diagram	111	37
3-4	Cross Section of <u>Miogypsinoides</u> Sand	112	39
3-5	East - West Cross Section Sweet Lake	113	
3-6	Structure Map - Current Interpretation	114	39
3-7	Induction Log of <u>Miogypsinoides</u> Sand	115	39
3-8	Schlumberger Salinity - Resistivity Chart	116	
3-9	Mud Resistivity Correction - Dunlap	117	43
3-10	Salinity Correction Chart I - Dunlap	118	43
3-11	Salinity Correction Chart II - Dunlap	119	43
3-12	New SP Chart - Silva and Bassiouni	120	43
3-13	Dual Induction Log of <u>Miogypsinoides</u> Sequence Showing Cored Intervals	121	44
3-14	EDS Analysis - Feldspar	122	45
3-15	EDS Analysis - Drilling Mud	123	45,46
3-16	EDS Analysis - Illite	124	45,46
3-17	Quartz Overgrowths and Feldspar Grains	125	46
3-18	Feldspar Grains Showing Dissolution Porosity	125	46
3-19	Quartz Overgrowth Development	126	46
3-20	Drilling Mud Contamination Bridging Intergranular Pore	126	46
3-21	Illite Coating	127	46
3-22	Illite Partly Occluding Pore Throat	127	46
3-23a	Summary of Organic Analyses; C ₁ -C ₇ Hydrocarbon	128	50
3-23b	Summary of Organic Analyses; C ₄ -C ₇ Hydrocarbon	129	50
3-23c	Summary of Organic Analyses	130	50
3-24	Visual Kerogen Assessment	131	51
4-1	Sweet Lake Site Plot Plan	132	52
4-2	Process and Instrumentation Drawing	133	52,56,57,59,60,61
4-3	Process and Instrumentation Drawing	134	52,55,56,59,61
4-4	Test Wellhead and Casing Spools Diagram	135	52
4-5	Test Wellhead - Casing Spools Photographs	136	52
4-6	Gray Choke Valve Manifold Diagram	137	53
4-7	Brine/Gas Separator System Photographs	138	54
4-8	Salt Water Disposal Wellhead and Casing Spools Diagram	139	55
4-9	Salt Water Disposal Wellhead Photograph	140	55
4-10	Inhibitor Pilot Plant Photograph	141	56
4-11	Gas Content of Discharge Brine Compared to Separator Pressure	142	65

No.	Title	Page	of Reference
5-1	Sweet Lake Log of <u>Miogypsinoidea</u> Sand Zone Showing Sands Sands 5 and 3	143	67
5-2	Preliminary Calculations by J. D. Clark of Sand 5 Reservoir Drawdown Test	144,145	68
5-3	Drawdown Curve - Sand 5	146	68
5-4	Drawdown Curve - Sand 5	147	68
5-5	Pressure Build-Up Curve - Sand 5	148	69
5-6	Bottom Hole Pressure Projections for Sand 5 Prior to Planned Perforation of Second Zone	149	71
5-7	Time Anticipated for Single Zone Flow Following Perforation	150	71
5-8	Drawdown Curve - Sand 3	151	73
5-9	Potential Fault Traces	152	77
5-10	Flow Angle of Reservoir	153	74
6-1	Relationship Between Alkalinity and Brine pH	154	81
7-1	Fresh Water - Saltwater Interface in Chicot Aquifer and Base of Fresh Water in S.W. Louisiana	155	86
7-2	Altitude of 1000 mg/l, 3000 mg/l, and 10,000 mg/l Dissolved Solids Surface	156	86,88
7-3	Trilinear Plot of Dissolved Constituents in Natural Waters in Southwestern La.	157	87
7-4	Geologic and Physiographic Features of Southwestern Louisiana	158	88
7-5	Map of Test Site Area Showing Parameter Observation Stations	159	84,88
7-6	Characteristic Seismographs Recommended by Sweet Lake Test Network	160	89
7-7	Time History of Seismic Activity, Sweet Lake Test Well	161	90
7-8	Seismic Activity and Changes in Well Pressure, Sweet to 7-12 Lake Test Well	162-166	91
7-13	Seismic Activity and Changes in Well Pressure, Sweet to 7-17 Lake Disposal Well	167-171	91
7-18	Seismic Activity and Changes in Well Pressure, Sweet Lake Test Well	172	91
7-19	Seismic Activity After Reservoir Limit Testing, Sweet Lake Test Well	173	91
7-20	Locations of Seismic Activity, Sweet Lake Area July 1980 - January 1983.	174	91
7-21	Locations of Seismic Activity During Reservoir Limit Test	175	91
7-22	Distribution of Computed Depths of Seismic Activity	176	91
7-23a	Rainfall at Lake Charles Airport, June 1981 - December 1983	177	92
7-23b	Rainfall at Lake Charles Airport, January 1984	178	92
7-24a	Events on Non-Thunder Days, Located with Three or More Stations 1981 - 83	179	92
7-24b	Events on Non-Thunder Days, Located With Five or More Stations, 1981 - 1983	180	92
7-24c	Events on Non-Thunder Days, Located With Five or More Stations, 1984	181	92
7-25a	Events on Non-Thunder, Non-Rain Days Located With Three or More Stations, 1981-83	182	92
7-25b	Events on Non-Thunder, Non-Rain Days Located With Five or More Stations, 1981 - 83	183	92
7-26	Seismic Monitoring Network	184	92

LIST OF TABLES

No.	Title	Page	of Reference
3-1	Gas Shows	185	37
3-2	Summary of Micropaleontology	186	38
3-3	Calculated and Measured Porosity	187	47,75
3-4	Calculated and Measured Permeability	188	41,47,75
3-5	Calculated and Measured Salinity	189	42
3-6	X-Ray Diffraction of Test Well Sidewall Cores	190	
3-7	Porosity and Permeability of Test Well Diamond Cores	191	47
3-8	Porosity and Permeability of Test Well Sidewall Cores	192	47
3-9	Ultraviolet Reflectance Summary	193	51
3-10	Porosity and Permeability of Disposal Well Sidewall Cores	194	51
4-1	Calibration of Halliburton Liquid Turbine Meters	195	65
4-2	Comparative Gas/Water Ratio Measurements	195	65
5-1	Porosity and Thickness Used to Calculate Original Water In Place	196	76
6-1	Typical Brine Composition, Sand 5	197	80
6-1a	Typical Brine Composition - Sand 3 Compared to Sand 5	198	80,81
6-2	Typical Gas Analysis	199	80,81
6-2a	Typical Gas Analysis - Sand 3 Compared to Sand 5	200	81
6-3	Brine Analysis - Sand 3 - Sample Nov. 23, 1983 Scan, Inc.	201	80
6-3a	Brine Analysis - Sand 3 - Sample Nov. 30, 1983 Scan, Inc.	202	80
6-4	Brine Analysis - Sand 3 - Scan, Inc. Compounded to Rice University Analyses	203	80
6-5	Gas Composition as a Function of Reservoir Pressure	204	82
7-1	Coordinates of Microseismic Monitoring Stations	205	88
8-1	History of Cost Estimates 1979 - 84	206	95,96,97
8-2	Estimated Gas Production, Income and Pay-Out Schedule, 1975	207	96

List of Plates

No.	Title	Page	of Reference
I	Sand 5, Flow Test Data	208	40,64,67, 68,69,70,72
II	Sand 3, Flow Test Date	209	33,40,67,73

Appendices

No.	Title	Page of Page Reference
A.	Sand Zone 5 Flow History	212 68,70
B.	Sand Zone 3 Flow History	226 73
C.	Engineering Interpretation Miogypsinoides Geopressed Reservoirs MG-T/DOE Amoco Fee No. 1 Well Sweet Lake Area Cameron Parish, Louisiana July 1984; J. Donald Clark, P.E.	234 68,76
D.	IGT Test Activities On The MG-T/DOE Amoco Fee No. 1 Well During August 1981; C.G. Hayden, P.L. Randolph, T.L. Osif; Prepared by Institute of Gas Technology.	289 50,65
E.	Well Test Analysis MG-T/DOE Amoco Fee No. 1 Sweet Lake Project Sand Zone #3, January 1984; Prepared by Dowdle Fairchild and Ancell, Inc.	320 76
F.	Distribution of Cores	337
G.	Gas Water Ratio Measurements, Sept. 1981.	343 79
H.	Separator Water Flush; Weatherly Laboratories, Inc.	351
I.	Reservoir Fluid Analysis For Magma Gulf-Technadril, MG-T/DOE Amoco Fee No. 1 Well, Sand Zone No. 3, Weatherly Laboratories Inc.	363
J.	Gas Analysis as a Function of Separator Pressure; Weatherly Laboratories, Inc.	389
K.	A Base Line For Determining Local, Small - Scale Vertical Movements In Louisiana by Drukell B. Trahan.	411 94
L.	Plug and Abandon Correspondence and Permits - Production and Salt Water Disposal Wells.	431 99

SUMMARY

The Sweet Lake geopressured test site was located in northern Cameron Parish in southwestern Louisiana where the six hundred foot upper Frio (Miogypsinoïdes) gross sand sequence occurs at depths below 14,000 feet.

The first geothermal leases in Louisiana were taken on the prospect by Magma Gulf Company in 1975.

The prospect was submitted to ERDA in 1976 as a site for a proposed production test and was competitively selected in 1977.

Initial DOE funding supported seismic analysis which depicted the sand as localized in a graben dipping and widening westward.

Additional leases were obtained by Magma Gulf from Amoco Production Co. in 1978 for a specific drillsite with a sand top at 15,060 feet with reservoir temperatures of 299° F., pressure of 12,060 psi. and salinity exceeding 100,000 ppm.

The drilling and testing proposal was submitted by Magma Gulf-Technadril Inc. Joint Venture, and the contract with DOE was signed in December 1979.

Drilling of production well with total depth of 15,740 feet including a sidetracked hole occurred from August 22, 1980 to February 26, 1981 and disposal well with a total depth of 7440 feet occurred from September 19, 1980 to October 13, 1980.

Well casing and surface facilities were designed to accommodate an anticipated flow of 40,000 barrels per day.

Two of the seven sands in the sequence (numbered from the top) were tested: Sand 5 (15,387 - 414 feet in depth) from June 1981 to February 1982 and Sand 3 (15,245 to 15,280 feet in depth) from Nov. 1983 to March 1984. Sand 5 has a porosity exceeding 20% and permeability over 300 md. with its estimated 10,800 millidarcy feet representing 49% of the hydraulic capacity of the total seven sands. Sand 3 is the second rated sand with over 17% of total hydraulic capacity.

Maximum flow rate of 34,000 barrels per day from Sand 5 confirmed the capacity of the production and disposal wells and the surface facilities to accommodate such rates. However, limited reservoir capacity could maintain continuous flow of exceeding 5,000 barrels per day with surface pressure of 2,000 psi. and surface temperatures of 238°F. Maximum flow from Sand 3 slightly exceeded 6,000 barrels per day and was capable of sustaining 2,000 barrels per day with a surface pressure of 290 psi. and surface temperature of 160°F.

Drawdown tests indicated barriers close to the well but with a reservoir extent exceeding four miles in one direction. The barriers were ascribed to bounding graben faults or alternatively to permeability

barriers, but similarities in Sand 5 and 3 results favor the bounding fault conclusion particularly since it conforms to the graben interpretation based on independent seismic data.

Initial measurements of solution gas content were erroneously low. Subsequently, long term measurements of separated gas averaged 19 to 20 standard cubic feet per barrel of water with total methane content ranging from 23 to 27 SCF/B. Analyses indicated that the brine is saturated although other interpretations by recombination studies indicated saturation at 34 SCF/B (Weatherly Laboratories).

Average carbon dioxide content of 8 to 10% precluded sale to nearby pipelines. Cleaning equipment was too costly in terms of the limited gas supply so the gas was flared.

Proposals to produce electricity by a portable generator were not approved by DOE, being considered state of the art and hence not experimental.

Sand 5 testing terminated because of pressure buildup in the disposal well which was ultimately cleaned and plugged back to a shallower zone. Meanwhile tubing breaks in the production well necessitated replacing the tubing. Funding problems for these repairs resulted in the long shut-in period between from early 1982 to late 1983.

Sand 3 testing was terminated on DOE orders to conserve funds. The production and disposal wells were plugged and abandoned, the surface facilities dismantled with the separator moved to the Gladys McCall site and the site returned to the surface owner in November 1984. Submittal of the present final report concludes the contract.

*Back up
blank*

1.0 PROJECT HISTORY, OBJECTIVES AND ADMINISTRATION

1.1 PROJECT HISTORY

Gulf Geothermal Corporation (GGC) was incorporated in 1973 to investigate the geopressed-geothermal potential resources of the Texas and Louisiana coastal plain. Previously, in the final report of the Geothermal Resources Research Conference of 1972, chaired by Walter J. Hickel, special attention had been given to geopressed water as an energy resource among other types of geothermal energy. The report emphasized the need for resource assessment including exploration, reservoir development, and production methods. Electrical power generation was considered as the most important use, with space heating, mineral production, and water desalination as additional important uses. Problems considered included production technology, the legal regulation of geothermal fluid production, mineral rights, and environmental issues including subsidence, seismic activity, groundwater and disposal problems.

Gulf Geothermal Corporation began its evaluation of the geopressed-geothermal resources of Texas and Louisiana in 1973, beginning with initial studies in South Texas. Areas having the highest subsurface temperature and pressure and greatest thickness of reservoir sands were identified using every available deep well log. A geothermal curve with mud weight and sand occurrences was plotted for each area using a profile designed by the Company. These studies sought to identify drillable prospects where the opportunity to drill and produce was most assured. The only areas of interest were those where previously drilled wells depicted desirable temperatures, pressure and sand conditions. Once identified, these areas had also to qualify as environmentally suitable and available for acquisition. A further restriction was the need for shallow sands suitable for water disposal.

Although GGC was not organized until May 1973, two of its principals, Dr. C. O. Durham, Jr. and Mr. W. A. Romans, both geologists, had attempted to raise funds for a proprietary investigation of Gulf Coast geothermal resources beginning in 1970. Their interest was sparked by Dr. Paul H. Jones, whose U. S. Geological Survey deep basin hydrology study was located in its early years at Louisiana State University, where Dr. Durham was Director of the School of Geoscience, and also served as major professor for Dr. Jones PhD. dissertation program on the subject.

By the time funding to organize GGC became available in 1973, Durham and Romans had already accumulated considerable geologic and technologic information through their own efforts supportive of the potential of Gulf Coast geopressed-geothermal energy, and had individually participated in various local and national conferences including a House Republican hearing on the subject in 1972, and a seminar sponsored by the United Nations in 1973.

By the fall of 1973, GGC expertise on the subject attracted the attention of the Library of Congress, which was assembling information to be used by

the House McCormick subcommittee on energy to prepare a bill to foster investigation on geopressed and hot, dry rock geothermal resources. The bill ultimately passed as the Geothermal Research and Development Act in 1974. Cost estimates for wells obtained by GGC for its in-house studies from Goldrus Drilling Company of Texas and Ben-Holt Company of California were relayed to Congress with permission of these companies.

Subsequently, in February 1974, Durham and Romans were invited to testify on the needs for geopressed-geothermal research, and they proposed a six year \$27.4 million program. Fortunately, GGC work was well advanced because the other two testimonials were in direct contradiction. Representatives of Shell Oil Company testified that appropriate geothermal resources did not exist in Texas and Louisiana, whereas representatives of Dow Chemical Company testified to the tremendous potential of the resource.

As a result of that impasse GGC testimony that the company had already identified appropriate reservoirs (contrary to Shell), but that these were definitely not universally distributed (contrary to Dow) was important to demonstrate the need for the type of government-sponsored research program that GGC recommended and that ERDA ultimately implemented.

Gulf Geothermal Corporation had largely completed its investigations by the middle of 1974, as originally planned, but was unable to lease any properties until a joint venture with Magma Power Company was implemented. At that time, a lease form was developed incorporating earlier legal findings of GGC, the newly issued federal geothermal lease form, and geothermal legal expertise of Magma Power Company supplied by Mr. Joseph Aidlin.

In 1974, GGC and Magma Power Company formed a joint venture to lease these prospects. Over 100,000 acres in six areas of Texas and Louisiana were leased; among them was the pioneer geothermal lease in the Gulf Coast on the Brazoria, Texas prospect (February, 1975), and a portion of the Sweet Lake, Louisiana prospect (July, 1975).

Following the acquisition of leases, Magma Gulf Company was incorporated in 1975 in order to secure private drilling partners. However, in February, 1976, when the U. S. Division of Geothermal Research established as an outcome of the 1974 hearings, announced plans to drill such wells with Federal funds, acquisition of private funding proved impossible.

Magma Gulf Company entered the PRDA DGE 76-4 competition in May, 1976, by proposing a test well in the upper Frio Sweet Lake prospect in Cameron Parish, Louisiana, and a test well in a Wilcox prospect near Katy, Texas, in Waller County. Although leased and also available, the Brazoria prospect was not included because it was Upper Frio, as was Sweet Lake, and a geologic diversity was a self-imposed requirement for the proposal. The Katy prospect in Texas was proposed to demonstrate high volume production from higher temperature sand (355°F.) of Wilcox age with probable low permeability, while the Sweet Lake prospect in Louisiana was

proposed to demonstrate high volume production from lower temperature sand (290°F.) of Frio age with probable high permeability.

The Magma Gulf proposal for Sweet Lake was selected by DOE in July, 1977, the Katy prospect was eliminated, and the contract was signed between DOE and Magma Gulf in June, 1978. As submitted, the proposal included a Phase I geologic study of the Sweet Lake prospect to be conducted prior to proceeding to drilling a test well. The Phase I geologic study and a study of available seismic data completed in 1978 confirmed that the Sweet Lake prospect contained a geopressured-geothermal reservoir ideal for testing. Additional leases were acquired by Magma Gulf Company in 1979 to provide the most suitable available well site. The site was moved approximately one mile further west from the original proposed site as a result of seismic interpretation of the configuration of the faults bounding the graben. A drilling and testing plan was completed and organized as the basis for the technical proposal which was submitted as the Phase II drilling and testing of the aquifer under contract ET-78-C-08-1561. This comprehensive proposal was submitted to DOE in June 1979, outlining a two-year project. Subsequently, a joint venture was formed between Magma Gulf Co. and Technadril, Inc. to perform this work. In order to implement the program, DOE executed a contract (NO. DE-AC08-80NV10081) in December 1979 with Magma Gulf-Technadril, Inc. (MG-T), to conduct the drilling, completion, and testing of one geopressured-geothermal test well and one disposal well. A contract was also executed between MG-T and the Gas Research Institute (No. 5014-321-0290) to provide funds for important corollary aspects of the program during the drilling and testing phases.

Project management was in place beginning in early January 1980, and proceeded to implement the program plans. A delay in the approval of the final Environmental Impact Statement resulted in delay in beginning the test site preparations. This compounded conditions in the drilling industry, so that a delay was also encountered in acquiring substitute drilling rigs at the later date, and, most importantly, tubular goods. It was management's opinion that no drilling point should be reached without the necessary materials actually being on site. It was felt that this would prevent possible problems and delays occurring during the drilling operations.

Site preparation proceeded smoothly, and, with the final availability of all tubular goods, Resource Drilling Rig 12 moved on site in August 1980. The test well was spudded August 22, 1980, and drilling operations were completed on February 26, 1981 with the setting of the 5 1/2" production tubing. The well was drilled to a total depth of 15,740 feet with a random sidetrack at 12,564 feet. The salt water disposal well was spudded on September 19, 1980 and completed drilling operations on October 12, 1980. The salt water disposal well was drilled to a total depth of 7,440 feet.

During the drilling operations phase, plans for the construction of the surface testing facilities were designed and fabrication began. As soon as drilling operations were completed, modification of the site for the installation of the surface testing equipment was implemented. Installation of the surface testing equipment was completed in May 1981, and preparations were begun for perforating the test well and the beginning of the several flow testing phases.

The test well was perforated on June 19, 1981, and the initial flow test to clean the well, determine that the disposal well would accept the brine, and demonstrate that all surface facilities operated properly was begun. This test continued until June 22; part of the design criteria for this test was a constant flow rate to facilitate the reservoir interpretation. A reservoir limit test was performed during June and July 1981 and lasted a total of 17 days. The first long term testing phase at Sweet Lake continued for 208 days, lasting from June 17, 1981 to February 10, 1982 (Plate I).

Negotiations with United Gas Co. began in 1981 for the sale of natural gas from the Sweet Lake well. One of the considerations, although not a primary one, for the location of the test well had been the immediate proximity of one of United's pipelines which crossed the site. Although United Gas was interested in purchasing the produced gas, no agreement could be reached due to the CO₂ content of the gas. The maximum CO₂ content allowable under United Gas contracts was 2%, which was much less than that being produced at Sweet Lake (approximately 10%). Money for purchase of gas clean-up equipment was not available, and the quantity of CO₂ allowed under the contract could not be changed. Therefore, no contract for gas sales was ever negotiated.

In February 1982 the salt water disposal well sanded up necessitating a recompletion of that well. During this time a leak was discovered in the 5 1/2" tubing of the test well. The Sweet Lake site was shut in from March 1982 until August 1983 awaiting an administrative decision from the DOE as to whether to continue testing or to terminate the project.

In August 1983 it was decided to continue the testing of additional sands in the Sweet Lake well. The 5 1/2" tubing was repaired, the well perforated in a shallower sand and a second series of flow tests was begun. An initial flow test, followed by a reservoir limit test and a long term flow test were begun in November 1983 (Plate II). The long term flow test continued for 122 days until March 13, 1984, when the well was shut-in. The shut-in was not necessitated by mechanical problems but rather by budgetary ones. A decision was made by DOE to terminate the project in June 1984.

During this period a proposal by MG-T to develop and install surface facilities at its own expense to demonstrate electric power generation at the site was rejected by DOE. An RFP to plug and abandon the site was issued in June 1984. The test well and salt water disposal well were plugged and abandoned, and site cleanup and restoration were completed in November 1984.

1.2 PROJECT OBJECTIVES

The initial paragraph of Magma Gulf's proposal to DOE in May, 1976, stated:

"Economic analyses by Magma Gulf Company indicate that the energy resources of geopressured-geothermal reservoirs cannot be successfully operated unless large volume water production can be sustained (over 1,000 GPM). Yet this possibility has been challenged by knowledgeable engineers and geologists who cite low permeability and geopressured formation collapse as inhibiting factors. However, until sustained high volume production is demonstrated, all other questions are academic."

Magma Gulf believed that the proposed production well had an excellent chance to produce such volumes, and the completion and production testing schedules were designed to demonstrate it.

In addition to permitting experiments in high flow rates that were essential to geopressed-geothermal energy development, other critical experiments also proposed to be performed sequentially were:

- (1) Drilling and utilization of disposal wells;
- (2) Determination of methane content, and demonstration of its separation for commercial purposes;
- (3) Experimentation with pressure turbines; and,
- (4) Utilization of heat energy in a binary or flash system.

The proposal was outlined to accomplish all of the primary goals which were listed on page 7 of ERDA PRDA DGE 78-4 as follows:

During drilling and coring, data can be acquired concerning "the characteristics of the geopressed geothermal reservoirs, including permeability and porosity, extent and distribution of sands and shales, degree of undercompaction, and rock composition; as well as the aquifer; fluid properties including in situ temperature, composition, natural gas content, and pressure."

During well testing information will be obtained on "the behavior of fluid and reservoir under conditions of fluid production at moderate and high rates, including pressure-time behavior at different flow rates, fluid characteristics under varying production conditions, other information related to the reservoir production drive mechanisms, and physical and chemical changes that may occur under production conditions."

Magma Gulf also proposed to transfer its existing geothermal leases on the Sweet Lake and Katy sites to ERDA for the duration of the project. It proposed to manage and operate a program designed to accomplish the following sequentially:

- (1) In the case of Sweet Lake, secure and analyze seismic data to determine a specific drill site;
- (2) Prepare detailed plan and cost estimates for the program;
- (3) Drill and test one or two production wells by turn-key sub-contract;
- (4) Drill accompanying disposal wells by turn-key subcontract;
- (5) Test the production capacity of wells under varying flow conditions for a 6 month period. Simultaneously, disposal well capability would be tested, and gas extraction by high pressure gas separators demonstrated;
- (6) Design and placement of a high pressure turbine and binary heat conversion system.

It was also obvious that many peripheral tests and investigations could be conducted from the samples obtained from the test well. It was anticipated that ERDA (DOE) would wish for as many investigators as possible to have access to the wellsite and the information that would be obtained.

In its 1979 proposal to the DOE the well drilling and testing program was designed to determine the following parameters:

Reservoir permeability, porosity, thickness, rock materials properties, depth, temperature, and pressures.

Reservoir fluid content, specific gravity, resistivity, viscosity, and hydrocarbons in solution.

Reservoir fluid production rates, pressure, temperature, production decline, and pressure decline.

Geopressured well and surface equipment design requirements for high-volume production and possible sand production.

Specific equipment design for surface operation, hydrocarbons distribution, and brine disposal.

Possibilities of reservoir compaction and/or surface subsidence.

Specifically, flow testing of the geopressured-geothermal test well was planned in three separate phases as follows: (1) Phase 1 - Initial Flow Test - Reservoir Confirmation Test (ca 1-2 days), (2) Phase II - Reservoir Limit Determination Test (ca 10-20 days), and (3) Phase III - Long Term Demonstration Flow Testing at Commercial Design Rates (ca 150+ days). The successful completion of these testing phases would obviously result in continued production and sale of natural gas, and facilitate further evaluation of thermal and hydraulic energy recovery potential from geopressured-geothermal brines.

Eaton Industries of Houston recommended that the flow characteristics of the well be tested initially in a test loop prior to the planning and construction of permanent testing and production facilities. The test loop was designed to conduct flow directly from the production well to the disposal well(s) but had a bypass line for securing fluid and gas samples.

Following 60 days of testing with the test loop, this facility would be dismantled. Testing results would be used to design a permanent facility which would then be installed to permit a prolonged period of production.

The foregoing plan was designed to provide answers to the critical questions concerning geopressured energy that were listed earlier. Satisfactory demonstration might have led to early private development of these resources.

This testing plan presented the necessary background information, and the specific details of testing designed to achieve these goals; however, it should be noted that the primary emphasis of the testing described was

directed to the recovery of natural gas (primarily methane) from geopressured geothermal brines, and high-volume brine disposal.

In addition to the achievements of the primary goals, the testing plan was designed to accumulate sufficient data to: (1) characterize and define adequately the nature, size, and thus potential, of the reservoir, (2) characterize analytically the brine and natural gas produced, (3) confirm the adequacy of the test well and surface facilities design, and (4) define the extent of scaling/corrosion problems associated with the long-term high-volume production and disposal of geopressured-geothermal brine, and to minimize and control such scaling/corrosion. Finally, the effects (if any) of testing the subject geopressured-geothermal well on the environment were to be monitored through concurrent and separate measurements and studies of subsidence, seismicity, and the quality of the air, surface water, ground water, and eco-systems in the area.

1.3 PROJECT ADMINISTRATION

Program administration was furnished by both Magma Gulf Co. and Technadril, Inc. through a Joint Venture Executive Committee. Purpose of the committee was to ensure implementation of all aspects of the project and determine any necessary changes or modifications in the program plans and objectives.

1.3.1 MANAGEMENT ORGANIZATION

The Joint Venture Executive Committee consisted of three members: Dr. C. O. Durham of Magma Gulf Co. served as Chairman and Program Coordinator to ensure that the program operated according to plans, schedules and budgets and served as liaison with the DOE. J.I. Marshall of Technadril, Inc. served as Deputy Chairman to oversee costs and schedules. R. W. Rodgers of Magma Gulf Co. served as Project Manager to provide overall supervision of the project. Reporting to the Project Manager were deputy project managers, assigned to specific aspects of the project.

Key Personnel

Magma Gulf Company

Dr. C. O. Durham, Jr.
Chairman of Joint Venture Executive Committee
President of Magma Gulf Company
Program Coordinator for Sweet Lake Project

R. W. Rodgers
Member of Joint Venture Executive Committee
Operations Project Manager for Sweet Lake Project

K. S. Hoffman
Deputy Project Manager - Research for Sweet Lake Project.

Technadril, Inc.

- J. I. Marshall
Deputy Chairman of Joint Venture Executive Committee
President of Technadril, Inc.
- C. S. Adkins, Jr.
Deputy Project Manager - Drilling & Construction for Sweet Lake Project
- A. L. Wyand
Deputy Project Manager - Administration for Sweet Lake Project
- C. D. Mitchell
Site Manager for Sweet Lake Project - Drilling phase
- Larry Durrett
Deputy Project Manager - Testing Phase
- Jonne Berning
Site Manager - Testing Phase
- Frank O'Brien
Administrative Deputy and Technical Director

The management program as outlined in Section 1.3.1 (Figure 1-1) remained in effect until the completion of the drilling phase of the project. At this time it became necessary for R. W. Rodgers to return to his University duties. Dr. C.O. Durham acted as Project Manager during the testing phase. In addition Larry Durrett of Technadril, Inc. became testing Manager and Jonne Berning of Technadril, Inc. became Site Operations Manager. Frank O'Brien of Technadril served as Deputy Administrator acting for J. I. Marshall and A. L. Wyand during the completion phase, and served as Technical Director during the testing phase (Figure 1-2). Carl Guillot served as consultant for the design and construction of the surface facilities. J. Don Clark served as consultant for reservoir testing.

1.3.2 REPORTING

As a part of its contract for the Sweet Lake project, Magma Gulf-Technadril submitted periodic management and technical reports (Vol. I - 1982, - Vol. II - 1984) to the Department of Energy.

Before operations began, drilling plans for the project test well and disposal well were submitted to the DOE as a Drilling and Testing Plan in July 1980. This plan was a revised version of the plans submitted in 1979 as part of the Magma Gulf proposal. Additionally, MG-T submitted a Management Plan which included Milestone and Status schedules, manpower plans, and Policies and Procurement procedures.

Monthly reports included the Cost Management Report for comparison to the Cost Plan, Government-Owned Property Inventory, Project Status Report, and a Contract Management Summary Report. Beginning with the

start of site activities and continuing through the drilling and testing phases a Technical Progress Report (Drilling Report-Testing Report) was filed daily with the DOE. This report was a summary of the project for the previous 24 hours, and a forecast of any major scheduled activities.

Beginning in 1981 a weekly Cost Management Report was forwarded from the Sweet Lake site to the Houston offices and then submitted to the DOE Las Vegas Operations office. This cost form included the Contract Estimated Cost, Current Cost, Estimated Cost to Complete, and Overrun - Underrun Costs.

As a part of the Management Program weekly Progress Review meetings were held with key personnel to review progress and forecast schedules and potential problems.

Periodically, Design Review Meetings were held to review the status of major aspects of the program. These included, for example, a review of the drilling and completion plans, testing procedures, coring procedures held in conjunction with the Rock Mechanics investigations group, reservoir modeling, and chemical analysis. One of the results of these meetings was the inception of the Pilot Plant program for chemical inhibitor injection and chemical analysis.

Technical Progress Reports have been filed which serve as the annual reports. These are Drilling and Completion - Test Well and Disposal Well, Vol. I, June 1982, and Surface Installations and Reservoir Testing Vol. II, April 1984. This report, Final Summary and Analysis, Vol. III, 1984, serves as the final report for the drilling and testing of the Sweet Lake geopressured-geothermal reservoir, but all 3 volumes are necessary for a detailed understanding of the project.

1.4 CONTRACT SUBCONTRACTORS

The following list represents the major important subcontractors for the project with total costs of \$10,729,045. Additionally, some 30 vendors supplied lesser services, supplies, and equipment.

1.4.1 SUBCONTRACTORS - UNDER DOE CONTRACT - DRILLING

Amoco Production - Tubing	Houston, Tx. \$18,020
Analytical Stress Relieving - Stress tests - welding	Houston, Tx. \$11,000
Baker Packers - Packers	Houston, Tx. \$47,450
Benton Casing - Casing crews	Houma, La. \$52,824

Big Diamond Trucking - Hauling-cuttings, drilling mud	Lake Charles, La. \$272,686
Brown Pipe & Supply - Tubing-recompletion test well	Houston, Tx. \$58,000
Brown Oil Tools - Tools	Houston, Tx. \$99,248
Brown Tool & Supply - Tools	Lafayette, La. \$128,087
Byrom & Co. - Drilling consultants	Houston, Tx. \$34,582
Chickasaw Distributors, Inc. - Casing	Dallas, Tx. \$956,138
Christensen Diamond Products Co. - Diamond coring	Salt Lake City, Utah \$10,951
Completion Technology - Completion recommendations	Houston, Tx. \$3,245
Crosby Valve - Safety valves	Providence, RI. \$10,119
Dave's Welding Service - Welding	Schriever, La. \$24,800
Jeff Davis Electric Coop - Electrical power	Jennings, La. \$29,651
Dia-Log - Wireline services	Houston, TX. \$28,956
Dresser Magcobar - Drilling fluids	Houston, Tx. \$695,599
J. F. Eggleston - Drilling consultant	Carencro, La. \$19,648
Energy Resource Management - Work over procedures	Houston, Tx. \$4,000
FMC Corporation - Part of production wellhead Disposal wellhead	Dallas, Tx. \$191,600
Franks Casing Crew Casing crew	Lafayette, La. \$27,400

The Foxboro Co. - Instrumentation	Houston, Tx. \$11,233
Geograph Pioneer - Wireline services	Houston, Tx. \$83,549
Gearhart Owens, Inc. - Logging	Lafayette, La. \$27,010
G&G Valve & Supply, Inc. - Valves	Lake Charles, La. \$62,985
Goldrus Drilling Co. - Rig and crews-disposal well	Houston, Tx. \$241,340
Grant Tubular Corporation - Casing	Houston, Tx. \$244,023
Gray Tool Co. - Chokes and upper section test wellhead	Houston, Tx. \$62,846
Greene's Pressure Testing - Test blow-out preventers	Lafayette, La. \$23,385
Halliburton, Co. - Cementing	Houston, Tx. \$414,851
Richard Hanks Welding Service - Welding	LeCompte, La. \$41,014
Russell Lee Jacobs - Blowout insurance	Houston, Tx. \$47,112
T. J. LeMarie's Welding Welding	Abbeville, La. \$6,500
Lincoln Big Three - Welding gases	Baton Rouge, La. \$6,469
N. L. McCulloch - Bridge plug	Lake Charles, La. \$12,667
McKinley Oil Field Service - Construction	Longview, Tx. \$20,745
NOWSCO - Disposal well cleanout	Lake Charles, La. \$2,100
Oceanography International - Sand detectors	College Station, Tx. \$15,500

Oil Field Rental Service Co. - Rental tools	Houston, Tx. \$130,077
Oil Technology Services - Quality assurance - tubing	Houston, Tx. \$158,977
Oil Quip, Inc. - Tubulars	Houston, Tx. \$567,920
Oilwell - Tubulars	Houston, Tx. \$133,636
Ortego Oil & Supply - Rig fuel	Opelousas, La. \$221,564
Otis Engineering - ESD System	Dallas, Tx. \$70,019
Otis Pressure Control - Packer-recompletion-wireline serv.	Houston, Tx. \$17,402
Patterson Truck Line - Hauling	Houston, Tx. \$6,967
Petroleum Well Service - Drilling consultants	Sour Lake, Tx. \$73,872
Projects Design - Drafting	Houston, Tx. \$17,179
Quality Inspection and Control, Inc. - Pipe inspection	Houma, La. \$8,179
Mike Queenan Equipment - Construction equipment	Lake Charles, La. \$27,080
Resource Drilling, Inc. - Rig and crews-test well	Houston, Tx. \$2,056,434
Rig Housing - Site office	Lafayette, La. \$9,308
Rig Water, Inc. - Rig water	Church Point, La. \$12,937
Sandair - Air compressors	Houston, Tx. \$28,007
Schlumberger - Logging, sidewall coring, perforating test well and disposal	Houston, Tx. \$347,978

Security Bits - Drill Bits	Houston, Tx. \$22,190
Smith Pipe & Supply Co. - Casing	Houston, Tx. \$158,556
South Central Bell - Site telephones	Shreveport, La. \$12,586
Southwestern Bell - Telephone	Houston, Tx. \$3,012
Sperry-Sun, Inc. - Logging - Well surveys	Houston, Tx. \$16,450
Taylor Instruments - Control instruments	Houston, Tx. \$16,486
Tong Rentals - Rental tools	Lafayette, La. \$18,858
Totco - Surveys	Norman, Ok. \$7,004
Tri State Oil Tool - Drilling tools	Houston, Tx. \$45,585
Universal Engineering - Field construction	Sulphur, La. \$87,677
Universal Tubular - Tubing Coating	Corpus Christi, Tx. \$3,384
O'Dell Vinson Oil Field Contracting - Site preparation	Lake Charles, La. \$1,098,355
Warren Automatic Tool Co. - Drilling monitors	Houston, Tx. \$38,866
Washington Maritime - Disposal services	Lake Charles, La. \$161,974
Watson Electric - Electric contracting	Jennings, La. \$135,727
Willis Co. - Chokes	Pasadena, Ca. \$14,162
Wilson Down Hole Services - Fishing tools	Houston, Tx. \$35,143
Welex - Logging - Perforating test well	Houston, Tx. \$34,837

1.4.2 SUBCONTRACTORS - DOE CONTRACT - TESTING

Air Power Service Co. - Air Compressors	Houston, Tx. \$24,240
Accumin Analysis - SEM core photos Photomicrographs of thin sections	Houston, Tx. No charge
Aymonds Welding - Welding	Iowa, La. \$8,318
Baker Sand Control - Sand production and control	Houston, Tx. \$1,800
J. Donald Clark, Consultant - Reservoir limit analysis	Houston, Tx. \$17,352
Ken Davis, Assoc. - Perforation - completion recommendations	Baton Rouge, La. \$4,700
Diamond Pittsburgh Paint - Paint - surface equipment	Sulphur, La. \$6,009
Dowdle, Fairchild, and Ancell - Reservoir modeling	Houston, Tx. \$6,400
Engineering Speciality Services, Inc. - Design of surface facilities	Houston, Tx. \$50,388
Intercomp Research & Engineering, Inc. Reservoir modeling	Houston, Tx. Separate DOE contract
Kaye Instruments - Control instruments	Bedford, Mass. \$17,730
Kodiak Fabrication Ind. Inc. - Separator skid	Houston, Tx. \$252,345
McNeese University (Karkalits-Hankins) Chemical analysis	Lake Charles, La. \$11,600
Jack Matson Consulting Engineer - Scale and corrosion chemistry inhibitor chemistry	Houston, Tx. \$6,840
F. S. Millard, Consultant - Log interpretation	Houston, Tx. \$750

Milton Roy - Inhibitor pumps	Philadelphia, Pa. \$16,905
Mobile Quarters - Control trailer	Rayne, La. \$24,720
Moody Price - Instruments	Baton Rouge, La. \$7,082
Panelmasters Intl. - Control panels	Houston, Tx. \$18,731
Pilgrim Steel - Flare	Glassboro, N. J. \$11,626
Pioneer Centrifuging Co. Inc. - Filters	Liberty, Tx. \$71,842
Puffer Sweiven - Instruments	Stafford, Tx. \$13,268
Reservoir Data, Inc. - Monitoring bottom-hole pressure and temperatures	Houston, Tx. \$106,039
Rice University (Mason Tomson) - Scale and corrosion chemistry pilot plant monitoring	Houston, Tx. \$6,000
Russell Sensat Welding - Welding	Ragley, La. \$29,960
Systems Science and Software - Reservoir Behavior	LaJolla, Ca. Separate DOE contract
University of California - Lawrence Livermore Laboratory Brine Injection	Livermore, Ca. Separate DOE Contract
Weatherly Laboratories, Inc. - Gas recombination analysis	Lake Charles, La. \$12,400

1.4.3 SUBCONTRACTORS - (GRI CONTRACT TO MG-T)

Core Laboratories - Core analysis	Houston, Tx. \$10,305
Hartax, Int. - Geochemistry	Baton Rouge, La. \$31,393

IDL -
Mud Log

Houston, Tx.
\$58,800

Paleo-Data, Inc. -
Paleontology

New Orleans, La.
\$25,773

1.4.4 SUBCONTRACTORS - INDIRECT - THROUGH DOE CONTRACT TO L.S.U.

Louisiana State University -
Clay Diagenesis

Baton Rouge, La.

Louisiana State University -
Energy Program Office
Environmental Monitoring

Baton Rouge, La.

U.S. Geological Survey -
Clay and formation water analysis

NSTL Station, Miss.

U.S. Geological Survey -
Thermal Conductivity

Menlo Park, Ca.

2.0 WELL FACILITIES

2.1 WELL LOCATION

The Sweet Lake well site is located approximately 15 miles southwest of Lake Charles in Cameron Parish, Louisiana (Figure 2-1). The site is just south of State Highway 384 in a 5 acre test site on fee land leased from AMOCO by Magma Gulf Co. The site is in the South 1/2, Section 13, Township 12 South, Range 8 West. The surface rights have been leased to the Precht family which has conducted rice farming operations at the site for the past fifty years. Throughout the duration of the project close communication was maintained between Magma Gulf-Technadril personnel, representatives of AMOCO, and members of the Precht family. Every effort was extended to ensure the surface lessees that operations at the Sweet Lake site would not unduly interfere with normal farming operations. This close cooperation was maintained through the termination of the project when the site was restored and returned to the owners and lessees.

2.2 SITE PREPARATION

The existing road from Louisiana Highway 384 to the turnaround (Figure 2-2) was graded and covered with 6 inches of shell. The turnaround area, site manager's trailer location, was also graded and covered with shell. This turnaround was used as a staging and storage area during the site preparation and start-up operations. The site manager's trailer and a guard station were located at the turnaround to control access to the site. This was particularly necessary since all drill cuttings and drilling fluids had to be hauled to a waste disposal site, as no reserve pits could be used at the site. The State of Louisiana required that the disposal of such materials must be closely monitored.

The access road from the turnaround to the well site was graded and covered with one layer of Dupont 3401, 4 ounce pervious TYPAR. This material was then covered with 12 inches of shell which was rolled and compacted prior to placement of the boards. Due to the delays caused by unavailability of tubular goods, the shell road was used without the board covering until it was time for rig start-up operations. The board road was three ply consisting of a bottom ply laid 14 feet wide containing 17 mud boards. The second ply contained cross ties placed on 9 inch centers. The top ply contained 12 board runners set on vehicular track spacing. The first two plies were used board lumber, and the top ply was new board lumber nailed with a minimum of four 60P nails per board.

The test well site was approximately 250 feet by 325 feet in area. The areas of heavy traffic were underlain with Dupont 3401 TYPAR, and covered with 12 inches of shell. These areas were covered with three ply boarding, with the bottom ply laid on 12 inch centers and the middle and top plies laid on 9 inch centers. In the area of the rig substructure a fourth ply laid on 9 inch centers was also used. All the boards were 3 X 9 scant good hardwood. The two bottom plies were used lumber and the top ply and top plies in the area of the rig substructure were new boards. The top layers were nailed with a minimum of four 60P nails per board. Prior to laying the boards in the area of the rig substructure, ninety 12 inch pilings were driven with a diesel hammer to refusal and then cut off at ground level.

A ring levee was constructed around the turnaround area which was low enough to protect, but not interfere with, farming operations. A three feet high ring levee was then constructed along the north side of the board run access road to the well site, and then around the test well site. Subsequently the ring levee was also constructed around the disposal well site. The levee system and parallel drain ditch drained to a low point from which excess water could be pumped into a local drain ditch or picked up by vacuum truck for off-site disposal. The levee and drain ditch were constructed to protect the well site from flooding, and to protect the local farming operations from any possible contamination. One 36" X 80' culvert and two 15" X 30' culverts with gates were constructed beneath the access road in order to facilitate irrigation, and not interrupt the rice farming operations.

In compliance with the lease requirements, no reserve pits were used. Instead, drilling fluids, solids, and excess surface water were hauled by truck to a State of Louisiana approved disposal site located nearby.

2.3 HISTORY OF WELL DESIGNS

The initial well design and cost estimate for Magma Gulf for the Sweet Lake design and disposal wells was prepared by Louis Records and Associates of Lafayette, Louisiana. This design was based on information supplied to Records by Magma Gulf using data from the three deep wells drilled near the proposed site by Union of California. The well designs and cost estimates ultimately included by Magma Gulf Co. in its 1979 proposal to DOE were prepared by Eaton Industries of Houston, Texas. DOE representatives requested Magma Gulf to arrange through its parent, Magma Power Co., for Dr. Ben Eaton of Eaton Industries to visit the Geysers with the view of incorporating pertinent techniques in the second Pleasant Bayou well. Ultimately, through supplementary funding by DOE of Magma Gulf's DOE contract ET-78-C-08-1561, Eaton prepared the well designs and cost estimates submitted to DOE in Magma Gulf's 1979 proposal.

After the contract was signed with the DOE in 1979, the Eaton plans were modified by Magma Gulf - Technadril, and submitted as the Drilling and Testing Plan for the Sweet Lake project to the DOE in July 1980.

2.3.1. WELL DESIGN

The Sweet Lake test well, MG-T/AMOCO Fee No. 1 was designed to demonstrate both flow testing to define the geopressured-geothermal reservoir and to permit long term flow at commercial design rates. The well, which is depicted in Figure 2-3, was drilled to a total depth of 15,740 feet with a random sidetrack at 12,564 feet.

The 13-3/8 inch casing was set at 4,050 feet and cemented from that depth to the surface. The 9-5/8 inch casing was cemented in at 10,230 feet. A 7-5/8 inch string, run as a liner, was cemented in at 15,065 feet, and then tied back to the surface and cemented in the 9-5/8 inch casing to 5,600 feet.

The production tubing consisted of a 5-1/2 inch liner cemented in place (Plugged Back Total Depth of 15,660 feet to 14,558 feet Top of Liner). A Polished Bore Receptable (PBR) was set on top of the liner at 14,534 feet. A 4-1/8 inch I.D. seal assembly was inside the PBR. The 5-1/2 inch tubing was hung off in the tubing hanger.

The 5-1/2 inch tubing was filled with about 300 barrels of 10.0 ppg salt water. The annulus between the 5-1/2 inch tubing and the 7-5/8 inch casing was filled (ca 190 bbls) with a calcium bromide packer fluid with a 13.4 ppg density at 70°F. As the well heated up the calcium bromide expanded, the density was reduced to about 12.5 ppg, and it was necessary to bleed off about seven barrels of the fluid from the annulus to avoid excessively high pressures.

The 5 1/2" production tubing was coated internally by Universal Tubular Services - Spincote with their product SC850 after final threading and before shipment to the well. The purpose of the coating was twofold, first to protect the tubing from corrosion and scale adhesion and second to reduce friction losses/pressure drop.

Both purposes were achieved - there were no significant scale deposits on the tubing and the only corrosion was at certain joints where the coating had been mechanically abraided off. There was no evidence of subsurface pitting or blistering after two years of service. It did appear that the coating could be removed by high local flow rates or erosion where joint design could cause local cavitation.

The original application of Spincote 850 was found to be defective during installation and the tubing was removed, blasted clean, and recoated to the uniform proper thickness and then reinstalled. The coated liner had been cemented in place and could not be reworked. The only operational problem was the breaking free of some of the thicker coating on the 5 1/2" liner during perforation. Even this thicker material was unaffected by subsequent operations and there was no flow blockage.

2.3.2 DRILLING HISTORY

The following is a summary of the design well drilling history. A complete drilling history and detailed well history are included in Vol. I Drilling and Completion Test Well and Disposal Well. On August 16, 1980, Resource Drilling Company's Rig No. 12 began moving on location at the Sweet Lake site. Rigging up was completed, and on August 19, began driving the 30" conductor casing to 126' below ground level. The flow lines were nipped up and the well was spudded on August 22, 1980.

INTERVAL TO 20" CASING POINT

The 24" hole interval to 835' was drilled in 2 days using a Magcogel mud which was gradually increased from 8.7 to 9.4 lb./gal. At 835'

the hole was logged and then circulated and conditioned preparatory to running the 20" casing.

Thirteen joints of 20" 133 lb. K-55 B.T.C. and 9 joints of 20" 169 lb. K-55 B.T.C. were then run to 824'. The cement was set and then the 30" and 20" casing were cut. The 20" 3000 lb. FMC OCT casing head was welded and then tested to 1250 psi. The cement and float collar were then drilled out.

INTERVAL TO 13 3/8" CASING POINT

The 17 1/2" hole to 4050' was drilled in 3 days with a 9.2 lb./gal Magcogel and caustic mud. A gyro survey was run with a 3/4° deviation at 3,500'. The hole was circulated and conditioned preparatory to running casing. Forty-five joints of 13 3/8" 72 lb. L-80 B.T.C. casing, a float shoe and float collar, and 69 joints of 13 3/8" 72 lb. N-80 B.T.C. casing were run to 4,050'. The casing was cemented to the surface with 887 sacks returned. The 13 3/8" casing was hung with 200,000 lb. on OCT Type C-29 slips and then cut. The 13 5/8" 5000 lb. X 20" 3000 lb. OCT C-22 casing head was tested to 1,400 psi. The cement and float shoe were drilled, and a leak-off test to 14.0 lb./gal. mud weight equivalent was made.

INTERVAL TO 9 5/8" CASING POINT

The 12 1/4" hole to 10,230' was drilled in 16 days with no problems. The mud weight was gradually increased from 9.0 lb./gal. to approximately 10.0 lb./gal. until a depth of 10,102' was reached. At this point the mud weight was rapidly increased to 11.2 lb./gal., and then to 13.1 lb./gal. at 10,221'. Refer to the Magcobar mud report in Volume I for a detailed review of the mud characteristics. The hole was then circulated and conditioned preparatory to logging. Schlumberger ran Dual Induction, Formation Density, Gamma Ray, Neutron, Sonic and Dipmeter logs. Twenty-four sidewall cores were attempted across the geopressured transition zone with 16 cores recovered. Bottoms up were circulated and 40 units of gas were recorded. The hole was then circulated preparatory to running casing.

Eight joints of 9 5/8" P-110 47 lb./ft., and 225 joints of 9 5/8" N-80 47 lb./ft. casing were run to 10,230'. The 9 5/8" casing was then cemented, and allowed to set up for 16 hours. The pipe was then pulled. The pipe slipped and the cement was allowed to set another 6 hours. A temperature survey was run with the cement top determined at approximately 6,400'. The 9 5/8" casing was then pulled to 810,000 lb. and stretched 54". A gyro survey was run from 11,000' to 3,987' with a horizontal displacement equal to 51.33' at N39° 18' W.

Hard cement and 10' of formation was then drilled to 10,240', and the casing shoe tested to 1,500 psi. A leak-off test with 14.0 lb./gal. mud equivalent to 16.8 lb./gal. tested O.K.

INTERVAL TO 7 5/8" CASING POINT

While drilling the 8 1/2" hole to the 7 5/8" casing point unstable hole conditions resulted in the drill bit being stuck at 13,556'.

After washover and fishing operations, the hole was plugged back at 11,015'. A random sidetrack was then started at 10,645'.

After setting the 9 5/8" casing the hole was drilled to 11,155' with 13.8 lb./gal. mud gradually increased to 14.5 lb./gal. At 11,155' 851 units of trip gas were recorded. A drilling break was noted at 11,728' to 11,732'. A directional survey was run at 11,987' and the instrument was lost in the hole. The drill pipe was rabbitted and junk drilled from 11,960' to 11,987'. Drilling continued to 12,460' where a survey was attempted at 12,457'. The survey was misrun and drilling continued to 12,064', where another survey was run. Drilling continued to 12,872', and the hole reamed from 12,800' to 12,872'.

Drilling continued with a drilling break at 12,808' to 12,894'. Some slight movement was noted, and the hole was circulated and mud weight increased to 15.3 lb./gal. Maximum gas was recorded at 1,080 units, with background gas at 280 units. The mud weight was increased to 15.5 lb./gal., and the background gas dropped to 19 units. Drilling continued to 13,126', where 10 stands of pipe were pulled and the hole was not taking mud. Bottoms up were circulated with excessive large cuttings and 440 units of gas. The 15.6 lb./gal. mud weight was cut to 14.2 lb./gal. The gas was circulated out of the hole and the drill pipe was pulled. Went in the hole and washed from 13,050' to 13,126', and drilled to 13,140'. The hole was circulated to clear bottoms up. Maximum gas was recorded at 1,400 units, with 12,900 Cl₂.

Drilling continued to 13,273' where circulation with 15.8 lb./gal. mud was lost. Circulation pressure was reduced to attempt to regain circulation. The pipe was slugged twice, and 33 stands of pipe were pulled slowly back into the 9 5/8" casing. Circulation was attempted at 10,230', but returns were lost. The mud weight was cut from 15.8 lb./gal. to 15.6 lb./gal., and waited for the hole to heal. The hole was allowed to heal for 5 1/2 hours and then circulation was resumed slowly. Bottoms up at 10,230' were circulated with 43 units of gas. Went back in the hole with 18 stands of pipe and circulated bottoms up at 11,964'. There were excessive shale cuttings and 472 units of gas. Went in the hole with 10 stands of pipe, and again circulated bottoms up with less shale and 294 units of gas. Went in the hole with 1 stand of pipe and started to take weight. The hole was reamed to 13,273', with some excess shale noted, and 199 units of gas recorded. The hole was then drilled to 13,335' with only 16 units of gas recorded. The hole was then drilled to 13,554' with 15.6 lb./gal. mud with no further problems.

At this point, 13,554', a 20 stand short trip was made to 11,700' in order to pressure test the hole. The well started to swab in with 15.6 lb./gal. mud. The bit was lowered back to bottom and drilled to 13,556'. For over half an hour 15.8 lb./gal. mud was circulated, and then the well started flowing. The Cameron annular BOP was closed with 800 psi on the casing and 50 psi on the drill pipe, and the well was circulated through the choke. The 13 3/8" Cameron annular BOP started leaking. The rams were closed and the well killed. The mud was cut to 8.5 lb./gal. with gas and 27,000 ppm Cl₂. The rams were opened and circulation was attempted, but the pipe was stuck. A

Schlumberger temperature survey was run from the surface to 13,550'. A CBL-VDL-GR log was run from 13,527' to 10,000', and a second temperature survey was run from 13,530' to 9,000'. The bit appeared to be stuck at 13,520'. Mud was pumped through the drill pipe for half an hour at 650 lb. at 20 strokes per minute, and at 1,050 lb. at 28 strokes per minute. The formation broke down at 1,250 psi.

A 1 13/16' junk shot was run to 13,531' and fired to remove the bit jets. The drill string was then cemented. The annulus started to flow 30 minutes after placing the cement, and after 12 hours pressure increased to 400 psi on the drill pipe and to 210 psi on the annulus. The pressure on the drill pipe was bled to 0 psi, and after 6 hours the pressure on the annulus increased to 300 psi.

Another temperature survey was run from 12,924' to 8,000' and a CBL-VDL-GR log was run from 13,500' to 8,000'.

A Gyro directional survey was run, and the temperature log was rerun from 10,530' to 8,000'. A Dialog string shot and free point indicator were run. A comparison of the logs and free point indicator showed the pipe stuck at 11,000' and free at 10,472'. The well was shut in and the annulus pressure increased to 100 psi. The drill pipe was pressured to 1,500 psi and 1 bbl. of fluid was injected at a bbl./min. rate. The pressure declined to 520 psi on the drill pipe and increased to 210 psi on the casing. The 5" drill pipe was perforated from 12,520' to 12,591' with five 0.33" holes using a 21 1/8" Hyperjet gun. The well was then circulated. The 5" drill pipe was again perforated from 12,585' to 12,586' with five 0.33" holes using a 2 1/8" Hyperjet gun. The well was again circulated.

The pipe was worked for 1 hour attempting to re-establish circulation and the pipe parted at 4,712'. The well started to flow and it was shut in with 160 psi on the casing. Fifty stands of pipe were chained out of the hole. Went back in the hole and screwed into the fish at 4,712'.

A free point indicator was run and showed the pipe stuck at 9,350' inside the 9 5/8" casing.

The drill pipe was perforated at 10,120'. The drill pipe was then perforated at 9,350', but circulation still could not be established. The drill pipe was then pulled to 320,000 lb. to 9,290' before the fish came free and circulation was established. The hole was circulated and the mud conditioned and cut from 15.1 lb./gal. to 14.0 lb./gal. to stop mud loss.

The hole was then re-entered with fishing tools to wash out and around the stuck drill pipe. The drill pipe was screwed into at 9,354'. A free point indicator and collar locator with string shot was run and the pipe was backed off at 10,147'. The hole was then circulated to 10,147' and 27 joints of drill pipe and 2 damaged joints with perforations were recovered.

While washing over the fish at 10,235' the well started flowing. The drill pipe was shut in with 100 psi, and the casing with 260 psi. The mud weight was increased from 14.1 lb./gal. to 15.1 lb./gal. The shut

in pressure increased to 800 psi on the drill pipe and 900 psi on the casing. The well was then circulated through the choke while washing over the fish from 10,235' to 10,363'. The circulated mud was cut from 15.6 lb./gal. to 15.3 lb./gal. with 360 units of gas. The hole was circulated clean and the fish re-engaged. A free point and string shot were run which showed the pipe free at 11,000' in torque and free at 12,000' in tension. The 5" drill pipe was backed off at 11,015'. The fish and wash pipe were pulled back into the 9 5/8" casing and then pulled out of the hole. An open hole plug was cemented at 11,015' on top of the fish.

The hole was then reamed from 10,550' to 10,579' and cement drilled from 10,579' to 10,602'. The shoe and formation tested to 16.8 lb./gal. equivalent. Schlumberger ran a borehole geometry log from 10,608' to 10,234'.

SIDETRACKED INTERVAL TO 7 5/8" CASING POINT

On November 11, 1980, a random sidetrack was begun by drilling with a Dynadrill from 10,645' to 10,725'. A survey showed a deviation of 1 3/4° at 10,523'. The hole was then drilled to 11,891' with periodic surveys to check hole inclinations.

The bottom-hole assembly and all surface equipment were checked and tested, and the hole drilled to 12,203'. The hole was circulated and the mud weight raised to 15.4 lb./gal. The hole was then drilled to 12,614'. The hole was then drilled to 12,723' where the pipe became stuck briefly. The hole was then reamed from 12,164' to 12,723', and drilled to 12,894'. The directional survey showed a 4° deviation. The hole was slowly reamed from 12,804' to 12,894', and drilled to 13,077'. The hole was drilled to 13,155', and then drilling continued to 13,550'. The hole was then drilled to 13,680', where a trip was made to change the stabilizer positions. Deviation at this point was 6 3/4°.

Drilling was continued to 14,146', with a drilling break at 13,858'. The surface equipment was tested and the hole drilled to 14,480'. The hole was then drilled to 14,725', and reamed from 14,591' to 14,651'. The hole was then drilled to 14,856'. The top of the Camerina II sand was noted at 14,856'.

Drilling continued to 15,065', with the first appearance of the microfossil Miogypsinoides at 14,958'. The hole was circulated and conditioned preparatory to logging. The top of the Miogyp sand was at approximately 15,065'. Deviation at 15,065' was 8 1/2°.

Schlumberger ran ISF-Sonic, CNL-FDC-GR, and Dipmeter logs. Forty-eight sidewall cores were attempted from 12,875' to 15,065'. Forty-two were recovered, data from 26 was retrieved, and 6 cores were lost in the hole.

251 joints of 7 5/8" 39 lb. SFJ casing was run to 15,065', and then cemented.

A 4 3/4" drill collar assembly was lowered to tag the cement top at 9,750'. The cement was drilled from 9,750' to 9,814'.

Five inch drill pipe was then run in the hole to the float collar at 14,980'. The float collar, 84' of cement, the float shoe, and 5' of formation were drilled to 15,070'. The casing shoe was tested to 17.0 lb./gal. equivalent.

INTERVAL TO 5 1/2" LINER POINT (TOTAL DEPTH)

A 6 1/2" 533F bit was lowered to bottom and drilling continued to 15,144'.

The Schlumberger RFT tool was run with a pressure differential of 1 lb./gal. or 800 psi. Pressure in the sand at 15,144' was indicated at 11,990 psi.

After conditioning the hole a 4 1/8" X 2 1/8" 60' core barrel was run into the hole. The diamond bit was a 6" X 2 1/8" type MC-20. The hole was cored from 15,144' to 15,185' when the core barrel jammed. The core was pulled after coring 41' of section with 36' of recovery.

A 6 1/2" bit was lowered to 15,144' and a 6" rat hole was reamed to 15,182'. The 6" bit was pulled and the second core barrel was lowered. The hole was cored from 15,185' to 15,204' when the barrel again jammed. When the diamond bit was removed there was evidence of junk on top of the bit, but there was no damage to the bit. Nineteen feet of section was cored with 17' of recovery in the second coring run.

A rat hole was reamed from 15,144' to 15,204', then drilled from 15,204' to 15,234'. The hole was then drilled from 15,234' to 15,389'.

The hole was cored from 15,389' to 15,408'. Nineteen feet of section were cored with 17' of recovery. The hole was then reamed and drilled from 15,408' to 15,435'.

A 6 1/2" hole was then drilled from 15,435' to 15,600'.

The fourth coring run was then made from 15,600' to 15,634' with 32' of recovery. A J-33 bit was then used to ream a rat hole from 15,600' to 15,634' and then drill from 15,634' to 15,740' - total depth.

Schlumberger ran an ISF-Sonic-GR log to total depth. A maximum recording thermometer recorded 300°F bottom-hole temperature. An FDC-CNL-GR log was run, and again the maximum recording thermometer recorded 300°F. A dipmeter log was run, and the maximum bottom-hole temperature recorded at 300°F. Deviation at total depth, 15,740', was 18 1/2°.

Eight joints of 5 1/2" 25.5 lb./ft. FL4S casing were run as a liner with shoe, float collar, polished-bore receptacle, liner, hanger, and tie-back sleeve. The 5 1/2" liner was run to 15,735' on the drill pipe and cemented. The float collar was at 15,661 PBTD. The top of the 7 5/8" tie-back sleeve was at 14,535'.

Two hundred forty-seven joints of 7 5/8" casing with an 8.58' stem into the liner tie-back sleeve was run and set at 9,815'. The string which had had 1 joint of FJP casing 43.15' from the stem to the float collar, and 2 joints of FJP to the cross-over (1.12') and 243 joints of X-line casing was run and cemented.

The cement did set up for 46 hours before an attempt to pre-stress the 7 5/8" casing was made. The casing pulled free with only 30,000 lb. of tension. Schlumberger ran a temperature survey and located the plug at 8,995', with cement to 8,780'.

The 7 5/8" tie-back string was then cemented again. The cement set for 18 hours and a Schlumberger Temperature Survey showed the cement top inside the 7 5/8" casing at 9,438'. Waited on cement approximately 24 hours and pulled 65,000 lb. above the pipe weight. There was a slight movement of the pipe. The pipe was set back in the PBR with 35,000 lb. and continued to wait on the cement. After an additional 8 hours the casing moved with 60,000 lb. of pull.

Again the 7 5/8" casing was stressed and it pulled free at 40,000 lb. above the weight of the string. The hole was circulated and Halliburton cemented the 7 5/8" tie-back string. After 18 hours a Schlumberger Temperature Survey located cement inside the casing at 9,570'.

After an additional 63 hours of waiting on the cement, 81 hours in all, the 7 5/8" casing was pulled with 650,000 lb. and the slips set. The 7 5/8" casing was cut and a 9" - 10,000 psi Tubing Spool, and double studded adapter flange 9" - 10,000 psi X 13 5/8" - 10,000 psi were installed. The casing hanger was tested to 7,000 psi.

A 6 1/4" bladed mill was used to drill the cement plug at 9,546', and drilled cement to 9,596'. Cement was then drilled to 9,622'. A 6 1/4" bit was used to drill cement to 9,825', and the 7 5/8" casing was gauged in the hanger spool. The slips had swagged the pipe inward to 6,375'. The bit was run in the hole with 2 7/8" tubing and the 7 5/8" casing cleaned from 12,719' to 14,536'. No cement was found at the top of the 5 1/2" liner at 14,534'.

The hole was circulated at the liner top, and the 7 5/8" casing, 7 5/8" tie-back sleeve, and top of the 5 1/2" liner were tested to 2,000 psi with 15.2 lb./gal. mud. A 6 3/8" mill and 7 5/8" casing scraper were used to scrape the casing. A Type M-14 Packer and jars, and 6 drill collars were run in the hole, and the packer was set at 14,419'.

A dry test of the 5 1/2" liner top was made with a 4,300 psi differential. The tubing was displaced with 42.5 bbl. of water, and the tie-back tested with 2,908 psi. differential. Schlumberger ran temperature and CBL-VDL logs from 15,661' to 9,450'.

A Brown Oil Tools 5 7/16" Polishing Mill was run into the PBR at 14,558'. A Dummy Seal Assembly was run to 14,536'. The casing side of the seal was tested to 2,000 psi, and the tubing side to 3,500 psi.

Halliburton pumped 30 bbl. of HEC Polymer Spacer and 400 bbl. of 10 lb./gal. brine filtered to 25 microns. Continued to filter the brine water to 25 microns for several hours.

A Polishing Mill was run in the hole to 14,534' and dressed the PBR from 14,534' to 14,558.

The 5 1/2" FL4S 23.0 lb./ft. tubing was run. The landing collar was hubbed up and the annulus tested to 2,000 psi. The casing and seal assembly were tested to 6,000 psi. Twenty bbl. of spacer and 265 bbl. of 13 lb./gal. packer fluid were placed in the annulus. The BOP's were picked up, and landing joint backed out and the blanking plug installed in the hanger. The BOP's were nipped down. The Christmas tree was nipped up, and all flanges and valves tested to 10,000 psi.

The rig was released at 1400 hours on February 27, 1981.

2.3.3 COMPLETION AND PERFORATION

The original plan for completion of the test well, as specified in the Drilling and Testing Plan of July 1980, was to complete in the lowermost sand of the Miogysinoïdes sequence, unless wireline log data and/or core analysis suggested otherwise. As has been discussed in the geology section of Volume 1, Drilling and Completion, both log and core analysis indicated a higher porosity and permeability in one of the sands of the seven sand sequence (15,387-15,414 feet) than in the lowermost sand (15,520-15,572 feet). A decision was made, following extensive discussion, to perforate initially the 15,387-15414 foot interval. The high porosity and permeability indicated that this one sand would contain approximately 50% of the total hydraulic capacity of the Miogypsinoides sequence. In addition, this sand appeared to be relatively discrete in relation to the remaining sands. The lack of communication between this sand and the other sands would help to ensure reliable reservoir performance testing.

Information concerning the well was supplied to Ken Davis and Associates in order to obtain their recommendations on the perforation interval. Their recommendation agreed with the independent decision made by Magma Gulf-Technadril to perforate and test the one sand, Sand 5. The report by Ken Davis and Associates was included in Vols. I and II as an appendix. A temperature log was run from the surface to total depth on June 13, 1981. This log was run at the request of the U.S. Geological Survey to provide information concerning heat flow and geothermal gradients in the Gulf Coast. The 27-foot interval (15,387-15,414 feet) was perforated on June 16, 1981 with a Schlumberger Hyperdome gun at 4 shots per foot. The completion efficiency, as calculated by Reservoir Engineering Consultant J. Donald Clark, was 97%. The original reservoir pressure was 12,052 psia, the initial surface pressure 4,749 psia, and the original reservoir temperature 299°F.

The bottom-hole temperature recorded during wireline logging was 300°F. After applying the AAPG correction factor, a temperature of

330°F was expected at TD, or a temperature of approximately 320°F in Sand 5. The actual reservoir temperature was much closer to that recorded during logging. As there had been over 8 hours between the time circulation was stopped and the logging, the borehole apparently had approached equilibrium in that time. The AAPG correction factor was in error in this case.

2.3.4 INTERRUPTION OF TESTING

After perforation of the test well and perforation and acidizing of the salt water disposal well the flow testing of Sand 5 was begun in June of 1981. The three phases, including clean-up and reservoir determination, reservoir limit, and long-term flow testing continued until February 1982 (Plate I). At this time the salt water disposal well sanded up due to backflow of sand and had to be recompleted in a shallower sand (Fig. 2-4).

2.3.5 RECOMPLETION OF TEST WELL

After recompletion of the salt water disposal well in March 1982, it was discovered during April 1982 that the test well had developed a tubing leak. It was decided to put a plug above the perforations in the test well in order to determine the location of the tubing leak. Energy Resource Management found debris in the tubing which was possibly some of the plastic coating from the tubing along with some seals. The well was flowed for a short time to dislodge the material and the leak appeared to seal itself due to thermal expansion of the tubing. While further trying to dislodge the debris 28 feet of fishing tools and 739 feet of wireline were lost in the hole. The fish was recovered in May and the well was flowed. Bottom was tagged at 15,401 feet, approximately 14 feet below the top of the perforations in Sand 5, indicating that sand and/or scale had back filled the hole. A Pengo bridge plug (Fig. 2-3) was set at 15,385 feet, with cement above it. The new PBTD was at 15,351 feet.

The location of the leak in the 5 1/2 inch tubing was then attempted using a Pengo fluid density tool. A new technique of trying to force a few gallons of CaBr_2 fluid from the annulus and detect the location with the density tool proved unsuccessful.

Use of a Cesium 137 radioactive tracer in combination with a noise tool was attempted. A Iodine 137 tracer was also used, but no leaks could be discerned using the tracers. Possible leaks were located with the tool at 5,978', 7,497', and 8,090'. All were at collars as determined by a Casing Collar Locator log. Bottom was also noted at 15,142' rather than 15,351', perhaps due to scale build-up.

Halliburton then attempted to seal the leak at 5,965+ feet by spotting 2 1/2 gallons of HYPOSEAL mixed with 10 gallons of fresh water injected at a flow rate of .27 gals./minute. No discernible results were obtained, and another attempt was made using 12 gallons of HYPOSEAL at a flow rate of .825 gals/minute. Again there was no discernible result. During this operation the dump bailer (30 feet in

length with a 2 1/2 inch threaded lockup) was lost from the wireline at 6365'.

Attempts to retrieve the dump bailer were abandoned in July 1982 because no further funding was available from DOE for a rig which was determined necessary to solve the problem. The tool remained in the hole until retrieved after start up operations began in August 1983.

During the intervening 12 months Magma Gulf-Technadril submitted plans and procedures along with cost estimates to the DOE for implementing the recovery and recompletion of the test well.

In August 1983, Pride Rig No. 834 moved on site to begin recovery operations. Bottom was tagged at 14,451', after washing at 14,520'. The top of the fish was located at 15,105 feet and pushed to 15,144'. The complete fish was then recovered in good condition after being in the well for almost a year.

The well was then tested with a 4 3/8 inch Halliburton RTTS packer. The packer was moved to various depths and checked for pressure leaks. After testing it was clear that there were two leaks; one below 14,448' in the seal assembly, and a second at about 5,980'. There was the possibility of a third leak above 75' in the tubing hanger.

The Pride rig which was not big enough to handle the 5 1/2" tubing was released and Petrostar Rig No. 2 was moved on site to pull the 5 1/2 inch tubing.

The 5 1/2 inch tubing was worked and moved approximately 24 inches. A pull of 415,000 pounds was made and it was determined with a free point that the seals were stuck.

An internal cut was made in the 5 1/2 inch tubing at 14,456' or 64' above the stuck seal assembly. The cutting tool twisted and part of the 2 7/8 inch drill pipe assembly had to be fished from the hole. 334 joints of C-95 X line 5 1/2 inch tubing were recovered along with the Baker Model L sliding sleeve and the BOT seal assembly. The hole was then washed to 15,345 feet.

A preliminary check of the 5 1/2 inch tubing indicated that it was clean and in good condition. There was some pin-end corrosion on joints with FL4S connections that were deep in the well. The 334 joints were visually inspected with 25 rejects because of problems with pins and boxes. Of 201 joints hydrostatically tested to 10,000 psi there were 53 rejects because of bad pin ends. Of 120 joints tested for drift there were no rejects. It was ultimately necessary to scrap only 5 joints of the original 334. Additional joints of P-110 X line treated with Spincote 850 epoxy coating were acquired to recomplete the test well. A detailed analysis of the tubing condition was completed by Oil Technology Services, Inc. (TD-06)

The well was again washed to 15,346' to clean out any scale which might have formed. Wellex then ran gamma ray and CCL logs in preparation for perforating. Total depth was 15,322'. An Otis WBR packer was set at 14,508'. Fluids were displaced with clean 10.5 ppg.

Ca CL₂ packer fluid with D-302 corrosion inhibitor added. The well was then pressure tested to 5,000 psi with no problems.

The well was then perforated at 15,260 - 15,280', and 15,245 - 15,255' with 4 shots per foot. Bottom was at 15,312'. After perforating, bottom hole pressure at 15,245' in Sand 3 was 11,887 psia, with a temperature of 293°F. The surface pressure was 3,660 psia. The well was then flowed at a rate of 2800 B/D to the blow down tanks in order to clean the well in preparation for testing of Sand 3.

2.4 DISPOSAL WELL

2.4.1 INTRODUCTION

The disposal well for the Sweet Lake test site (MG-T/DOE AMOCO SWD well) was designed to demonstrate the feasibility of successfully disposing large quantities of geopressured-geothermal brine (up to 40,000 barrels per day). These feasibility studies included injectivity tests, side wall core analysis, the effects of chemical inhibitors, as well as the chemical effects of the produced brine on the long-term capabilities of the disposal well and sands.

The salt water disposal well was spudded on September 19, 1980 and completed drilling operations on October 13, 1980. This well, which is depicted in Figure 2-4, was drilled to a total depth of 7,440'. A detailed history of the well is presented in Volume I.

The 13-5/8 inch casing was set at 1,375 feet and cemented back to the surface. The 9-5/8 inch casing was set at 7,436' and cemented back to 1,970'. The Plugged Total Depth (PBDT) inside the 9-5/8 inch casing was 7,350'.

This well was completed with a Baker Model F packer set at 6,254'. It should be noted that the first packer failed to set and was pushed to PBDT. The production tubing in this well was 7-inch 23# K-55. The 7" x 9-5/8" annulus was filled with an inhibited brine solution with a density of 9.5 ppg.

2.4.2 DRILLING HISTORY

On September 18, 1980, the Goldrus Drilling Co. Rig No. 4 began moving on location at the Sweet Lake site. Rig up operations were completed on September 19, and the 20" conductor pipe was driven to a depth of 93'.

INTERVAL TO 13 3/8" CASING POINT

A 17 1/2" hole was drilled to the 13 3/8" casing point in 3 1/2 days. The drilling fluid was a Barite, Gel, and caustic mud that was gradually increased from 8.7 lb./gal. to 8.9 lb./gal.

Schlumberger ran Induction and Borehole Geometry logs from 1,375' to 96'. The hole was circulated, and 20 joints of 72 lb. N-80 and 10 joints of 68 lb. K-55 13 3/8" casing were run and cemented. The 20" and 13 3/8" casing were cut, and the 13 5/8" Bradenhead was welded in

place and tested to 1,100 psi. A Gyro survey was run from 1,280' to 100'. Location relative to the surface was 3.51' N 81° 59'W. The BOP's were tested to 5,000 psi, and the Hydril to 3,500

INTERVAL TO 9 5/8 CASING POINT (TOTAL DEPTH)

A 12 1/4" bit was used to tag the cement at 1,290', and the plugs and cement were drilled to 1,375'. A 12 1/4" hole was drilled to total depth of 7,436' using a drilling fluid that was gradually increased from 9.0 lb./gal. to 9.2 lb./gal. The formation was then drilled to 4,757'. Surveys were run at 1,888'; 2,392'; 2,908'; 3,410'; 3,910'; 4,155'; and 4,600'. The maximum deviation was 3/4° at 4,600'.

The hole was then drilled to 6,316'. A survey at 6,159' showed 1/2° deviation. Drilling continued to 6,580' when the stabilizers balled up and the pipe stuck. This was caused by drilling with a high viscosity mud which was the result of not having reserve pits available. The hole was then drilled to 7,440'. A survey at 7,170' showed 0° deviation.

After total depth of 7,440' was reached, the hole was conditioned preparatory to logging. Schlumberger ran an ISF/Sonic log from 7,458' (Schlumberger wire line reading) to 1,383'. FDC-CNL-GR and Borehole Geometry logs were also run from 7,458' to 1,383'. Sidewall cores were taken from 7,400' to 6,700'. Thirty-four cores were attempted and recovered. The cores were taken at selected points throughout the interval of prospective injection sands. The hole was then cleaned up and circulated preparatory to running casing.

Two hundred and two joints of 9 5/8" casing, consisting of 13 joints of 43.5 lb. S-95; 105 joints of 43.5 lb. L-80, N-80, and S-95; 35 joints of 40lb. S-95, P-110, and N-80; and 49 joints of 47 lb. AR-95; were run and cemented. The Schlumberger temperature survey showed the top of the cement at 1,970'. The 9 5/8" casing was hung with 9 5/8" 510,000 lb., cut off and the 9 5/8" casing spool installed.

The top of the plug was drilled, and the mud was displaced with water. The cement was drilled from 6,637' to 7,350'. Schlumberger ran a CBL-VDL log from 7,350' to 1,850'.

The fresh water in the hole was circulated and conditioned with 100 barrels of water with detergent to clean the casing. The water and detergent were displaced with 9.5 lb./gal. brine inhibited to prevent corrosion.

A casing caliper log was run from 7,350' to the surface and a Gyro directional survey was run. The coordinates were 277.3° azimuth, inclination 0.55, and total deviation 13.27' from surface.

A Baker F-1 packer was run in the hole to 6,250', but would not set. The packer had released from the tool. A new seal assembly was run in the hole and the packer was pushed to 7,348'. A decision was made not to risk fishing for the packer, and a new packer was ordered.

The second Baker F-1 packer was run in the hole but prematurely set at 1,233'. The packer was milled over 12' with an 8 3/5 x 6 7/8 milling shoe after engaging the packer and pulling 20,000 lb. to recover. The packer started moving down the hole. The pipe was pulled out of the hole but failed to recover the packer. The bottom-hole assembly was changed and the packer was pushed to 7,330'. Thirty thousand pounds were set down on the spear and the pipe was pulled, but failed to recover the packer. Went back in the hole with fishing tools, engaged the packer and recovered it.

The Baker F-1 packer was then run into the hole, and this time was set at 6,254' with no problems. A Baker 6" x 4.875 190-40 seal assembly was run in the hole to 6,255'.

The 7" casing completion string was run and spaced out. The FMC-OCT TC-1A-EN hanger was installed with 130,000 lb. on the hanger. The casing and packer seal assembly were tested to 1,500 psi.

The 11" 5,000 x 9" 5,000 Christmas tree flange was installed on top of the 9 3/4 FMC OCT TC-1A-EN hanger and capped with the 9" 5,000 x 6" 5,000 spool and 6' blind companion flange.

The tanks were cleaned and the rig was released at 2400 hours, October 12, 1980.

2.4.3 SALTWATER DISPOSAL WELL COMPLETION

Wireline log data and sidewall core analysis indicated that the salt water disposal well contained numerous sand intervals between 2,500-7,500' that were excellent for brine disposal. Porosities were 25-30% and air permeabilities averaged around 1 darcy, with a range of 200 to 2100 md.

Plugging and pressure build-up due to calcium carbonate precipitation were postulated to inhibit disposal. It was therefore decided to perforate an interval larger than the calculated minimum interval necessary to dispose of 40,000 B/D.

The sands selected were between 7,000-7,300', and were the lowermost in the section. Additional sands above these would then be available if necessary.

Information was again submitted to Ken Davis and Associates for perforation interval selection. Their recommendation agreed with the intervals chosen by Magma Gulf-Technadril. This report was included as Appendix II in Vol. II. Approximately 200' of sand were perforated in June, 1981 with a Schlumberger gun at 4 shots per foot.

2.4.4 SALTWATER DISPOSAL WELL ACIDIZING

The disposal well was not acidized immediately following its perforation. However, immediately after flowing from the test well began, the pressure increased to 800 psia. The flow was diverted back

to the blowdown tanks, and Halliburton acidized the disposal well as follows:

- 1) 48 bbl 15% HCl = 15% Pen-5 + 2% HAI-55
- 2) 96 bbl reg. HF + 15% HCl + 15% Pen-5 + 2% HAI-55
- 3) 24 bbl 15% HCl + 15% Pen-5 + 2% HAI-55
- 4) 12 bbl MAT - OWG (Plugging Agent)
- 5) 48 bbl 15% HCl + 15% Pen-5 + 2% HAI-55
- 6) 96 bbl reg. HF + 15% Pen-5 + 2% HAI-55
- 7) 48 bbl clay fix water

Pen-5 and HAI-55 are inhibitors. This acid treatment successfully cleaned the disposal well such that back pressure was reduced to a nominal value, less than 100 psi at full flow.

After a short time back pressure in the disposal well again increased. The disposal well was acidized a second time. 24,000 gallons of HCL acid were pumped in 4,000 gallon increments, alternated with 4,000 gallons of HF acid. A total of 20,000 gallons of HF acid was pumped. An injectivity test was run to determine the results of the second acid treatment. An injection rate of 13 bbls. per minute at 300 psi, was followed by an injection rate of 16 bbls. per minute at 400 psi. The second acidizing treatment was very successful with a resulting disposal well head pressure of approximately 50 psig at a brine flow rate of 16,000 B/D. No further problems with back pressure were encountered until the disposal well began sanding up after periods of shut-in of the test well in February of 1982.

2.4.5 RECOMPLETION SALTWATER DISPOSAL WELL

On February 12, 1982 back pressure in the disposal well increased to 800 psig. Fine sand had backflowed through the perforations. The top of the sand was at 6,902' which was 98' above the top of the perforated zones. PBD in the disposal well was 7,365', so approximately 462' of sand had flowed through the perforations.

NOWSCO came on site to use a coiled tubing Nitrogen jet to clean the disposal well. 230' of sand were removed with the top of the sand then at 7,132'. While jetting part of the coiled tubing was lost in the hole. While trying to retrieve the coiled tubing the disposal well sanding up to a depth of 2,600'. This increased sanding was probably initiated by the jetting operation and the loss of tubing preventing circulation and repressuring of the well.

The well was cleaned by jetting Nitrogen and milling the coiled tubing. The well was then cleaned to a depth of 4,530'. The 7 inch production tubing was cut at 4,500' and pulled from the hole. A NL McCullough Model S drillable bridge plug was set at 4,627', with 11' of cement above it. A Baker Model F packer was set at 2,016' (Fig.2-). The well was then perforated from 3,976' to 4,425' with 4 shots per foot, opening 230' of sands. An injectivity test equivalent to a flow rate of 24,000 B/D was then run. It was determined that acidizing would be necessary to sustain a high rate (24,000 B/D) of flow, but

would not be necessary at the lower expected flow rate from the Sand 3 flow test. No problems with back pressure were encountered during the subsequent flow testing. A history of disposal well surface pressure during the testing of Sand 3 is presented in Plate II.

3.0 GEOLOGY

The geological interpretation of the Sweet Lake prospect was originally based on seismic, gravity, and regional well log data. Subsequent to the drilling of the test well, information from the Sweet Lake well and other sources led to some modification of the original interpretation of the geology. However, these data plus reservoir modeling studies have confirmed the original basic geologic model of the Sweet Lake prospect.

3.1 REGIONAL GEOLOGIC SETTING

During the Cenozoic Era, the continental margin of southwestern Louisiana has progressively built Gulfward through processes of sedimentation. The upper slope and outer shelf are normally characterized by instability with a tendency to form gigantic slumps. Simultaneous sedimentation results in contemporaneous growth faults with abnormally thick deposits of deeper water facies on the basin side, contrasted to shallower water or deltaic deposits on the shoreward side. As a shelf edge moves intermittently basinward, continental facies of massive sands of relatively even thickness and low dip are superposed on the earlier faulted and tilted shales and sands of variable thickness.

In southern Louisiana, these sediments of geosynclinal thickness have been superposed on the deeply buried, thick Louann salt bed which has responded to differential sedimentation by lateral migration into salt ridges, massifs, and ultimately, in some cases, into piercement domes. Early formation of localized basins and ridges by salt migration influenced the geographical location of thicker and thinner sedimentary accumulations, which in turn, reinforced the continued migration of the salt. Thus, sedimentary depocenters and embayments bounded by contemporaneous growth faults developed in areas where salt evacuation was pronounced.

The shelf edge extended east-west through Beauregard Parish, 50 miles north of the prospect, during deposition of the early Eocene Wilcox Formation. Today it is 160 miles to the south, some 145 miles off the present coastline. The Sweet Lake area was occupied by unstable outer shelf and slope conditions with associated growth faults at an intermediate time during the deposition of the upper Frio Camerina zone of upper Oligocene or lower Miocene age.

3.2 GEOLOGY OF THE SWEET LAKE AREA

The Sweet Lake geopressured-geothermal prospect was identified and leased by Gulf Geothermal Corporation in 1974. Its successor, Magma Gulf Company, submitted the prospect for drilling and testing in response to a 1976 request for proposals from ERDA. The proposal was accepted in 1977 with funding under contract No. ET-78-C-08-1561 for a geologic study utilizing existing seismic data in the area.

3.2.1 INTERPRETATION FROM PREVIOUS STUDY

The geological interpretation made by Magma Gulf under the above mentioned contract was based on 17 deep well logs and 27 miles of

seismic lines. The conclusion of this study was that the Sweet Lake prospect is in a basin located on the north flank of an east-west salt ridge containing the Hackberry, Big Lake, and Sweet Lake structures. The structural interpretation is shown in Figure 3-1. The south side of the basin is bounded by a fault downthrown to the north. This converges eastward with a major east-west fault, downthrown to the south, to form the eastern termination of the basin. The prospect thus lies in a graben, bounded by two major growth faults and unbounded an unknown distance to the northwest. Structural dip is northwesterly into the basin, which opens toward the south flank of the South Lake Charles structure several miles distant to the north. The surface terrain in the prospect area is formed by late Pleistocene deltaic deposits. In the subsurface, alternating massive sands and clays extend to an average depth of 9000 feet, and overlie the thick shales of the Anahuac Formation. The Anahuac is in turn underlain by the Frio Formation, the upper member of which is termed the Camerina zone. Several sands occur within this zone, the thickest being the basal Miogypsinoides sand, named for a key microfossil.

The Miogypsinoides sand was identified in logs from the entire area studied, but it is thicker and structurally lower in the graben formed by the two major faults. Only three wells penetrated the Miogypsinoides in the graben, all in the eastern end. The seismic study indicated that the dip was approximately 17° northwest, so that the Miogypsinoides sand would be present below 18,000 feet in the western part of the graben. The drill site was located close to the three control wells that penetrated the Miogypsinoides sand; the top of the sand was estimated to be at 15,000 feet.

The geothermal gradient in the Sweet Lake area was estimated using bottom-hole temperatures, corrected by the AAPG correction factor. A temperature of 300°F was estimated for the test well at the midpoint of the sand based on the calculated gradient (Figure 3-2).

The geopressed zone begins at a depth of 8,740 to 9,400 feet in the wells in the Sweet Lake area; this is essentially at the base of the massive sands. The mud weights from these wells indicated that the minimum expected pressure at the top of the Miogypsinoides sand would be 8,700 to 10,800 psi.

Porosity, as calculated from a sonic log and a density log, was expected to be approximately 22%. No data on permeability were available at the time that this early study was made. Salinity had been calculated from well logs and ranged from 46,000 to 100,000 ppm. It should be noted that these estimates were made before the recent research into calculation of salinity from well logs, and the resultant new methods of calculating salinity were developed.

In general, the geology of the Sweet Lake prospect was fairly well defined by this early study. The reservoir was known to be in a graben which terminated to the east and was open an unknown distance to the west. The Miogypsinoides sand was expected at a depth of 15,000 feet in the test well, approximately midway between the two bounding faults in the eastern portion of the graben. The net sand volume in the reservoir was estimated at .6 to 1.0 cubic miles.

3.3 TEST WELL GEOLOGY

This section concerns the test well geology based on information accumulated during drilling. The two major tools used during this phase of the project were mud logging and micropaleontology. The use of wireline logs is discussed in section 3.5 Petrophysical Analysis.

The expected geology consisted of thick Miocene sands to a depth of approximately 9000 feet. The thick Anahuac shale lies below these sands, and the top of the geopressured zone was expected to be close to the top of the Anahuac. This thick shale extends down to the top of the Miogypsinoides sand and contains a few sands in the 5000+ feet shale section, including the Marginulina and Camerina sands. The top of the Miogypsinoides sand was expected at a depth of +15,000 feet. Mud logging and micropaleontology were useful correlation tools during the drilling phase. Significant departures from the expected stratigraphy or fossil content that would have indicated a structure other than what was inferred would have been quickly noted. No such evidence was observed, but the mud logging and micropaleontology provided important daily correlation data, and information for determining casing points and coring intervals.

3.3.1. MUD LOGGING

Mud logging services were provided by Integrated Drilling and Logging, Inc. (IDL). The mud logging included:

- Monitoring drilling rate
- Monitoring pore pressure
- Examining and describing well cuttings
- Monitoring mud temperature and mud weight
- Monitoring gas content
- Collecting well cutting samples
- Recording auxiliary information, such as weight on bit, bit number and type, and rpm.

The mud loggers began monitoring and recording this information when the well had reached a depth of 6000 feet. Samples of well cuttings were collected by rig personnel prior to that time. The mud loggers remained on site until the total depth of the sidetrack hole (15,750 feet) was reached.

One of the primary purposes of measuring the drilling rate was to make an estimate of porosity. IDL measures the penetration rate by mechanical means and converts the data to a porosity estimate. This information, along with the lithologic description, was useful in correlation. In addition, the porosity estimates were in good agreement with the measured porosity from diamond and sidewall cores.

Measurement of the pore pressure was crucial, since at least 5000 feet of hole were to be drilled in geopressured strata. Knowledge of the pore pressure was important so that the mud weight could be adjusted correctly to prevent under - or overbalancing.

Well cuttings were sampled at thirty-foot intervals. The cuttings were examined and described, and a lithologic log was constructed. This information was telecopied from the site daily and was used in correlation with three key control well logs. This enabled the geologist to identify the particular part of the formation that the well drilled through at a given time. Since the test well was located in a graben in which there was sparse well control, the exact location of the major bounding faults was not precisely known. Prior to the drilling of the well, some concern had been expressed that the well bore might cross one of these faults. The daily correlation of the mud log and the control well logs confirmed that the well did not cross a major fault. A thickening diagram (Figure 3-3) prepared for the test well and the three control wells demonstrated a substantial amount of thickening and thinning of the stratigraphic section between the four wells. The changes in thickness did not indicate a major fault, but could possibly indicate some minor faulting that was not directly evident from correlation. Despite the thickening and thinning of the stratigraphic section, the top of the Miogypsinoides sand was encountered very close to the predicted depth.

Two gas shows were reported in the original hole, at depths of 10,785 to 10,804 and 12,885 to 12,915 feet. The first show was in a very thin sand stringer and the second was in the first Camerina sand. Both shows were described as fair; a tabulation of all recorded parameters is presented in Table 3-1. Neither of these shows were observed in the sidetrack hole, most likely because the mud weight was heavier.

The mud loggers collected three sets of well cutting samples at thirty-foot intervals. One set was used for micropaleontological analysis and the other two were donated to universities. In addition, canned samples were collected every sixty feet for organic geochemistry studies.

Mud logging was funded by Gas Research Institute Contract No. 5014-321-0290.

3.3.2 MICROPALAEONTOLOGY

The micropaleontological analysis of the well cuttings were performed by Paleo-Data, Inc. The identification of the microfossils in the well cuttings was an important correlation tool. Cuttings were sampled at thirty-foot intervals and shipped to Paleo-Data, where they were washed and examined microscopically. The fossils were identified and the cuttings were described lithologically. The important correlation fossils were reported to MG-T as soon as they were identified.

The fossil picks were compared to those of two key control wells, the Union of California Pan Am Fee #1 and #2, providing an additional check on the position in and the thickening or thinning of the stratigraphic section. Again, if the well bore had crossed a major fault, it would most likely be immediately evident by a change in the microfossil assemblage. No such changes were observed, but this does not preclude the possibility of minor faulting in this area.

The important correlation picks are summarized in Table 3-2. The entire report submitted by Paleo-Data is in Appendix C-1 of Volume I. The picks appear to be slightly deeper in the sidetrack hole than in the original hole; this is primarily because these depths are not true vertical depths.

Micropaleontology was very important in picking the top of the Miogypsinoides sand, since the planned coring program included obtaining a core as close to the shale/sand transition zone as possible. The Miogypsinoides fossil in the control wells appeared 30 to 100 feet above the top of the sand; thus, once the fossil was identified drilling should cease and coring begin. Paleo-Data personnel were on site as the well neared the Miogypsinoides sand, and the microfossil was identified from cuttings at approximately 4:30 p.m. on Christmas Day, 1980.

The fossils present in the well indicate that the depositional environment in Miogypsinoides time was most likely outer shelf to upper slope, a water depth of 300 to 1500 feet. The classification of marine environments are those used by Paleo-Data, and are fairly standard zonations.

Micropaleontology was funded by Gas Research Institute contract No. 5014-321-0290.

3.4 RESERVOIR DESCRIPTION

The reservoir geology was determined from well logs, seismic data, and reservoir engineering. A fairly accurate interpretation of the reservoir was made from well logs, gravity, and seismic data before the Sweet Lake test well was drilled. The prospect was located in a graben, with approximately 3,000 feet of throw on the northern fault and 1,000 feet on the southern fault. The structure map in Figure 3-1 shows that the two major faults converge approximately two miles east of the test well location, and diverge westward. A splinter fault was hypothesized to run northeast from Section 18, T12S, R8W. It was not known whether this fault actually existed at the Miogypsinoides depth, or, if so, whether it extended far enough to the northeast to enclose the reservoir. These questions were later resolved by reservoir engineering interpretations of flow tests; this is fully discussed in Section 3.4.3.

The graben was estimated to be approximately 1.5 to 2 miles across at the test well location, although due to the lack of well control, and the fact that the seismic lines were unmigrated, this could not be precisely defined. The expected thickness of the Miogypsinoides sequence was on the order of 800 feet; assuming the sand covered the entire area within the graben, this would give a volume of approximately 0.6 to 1.0 cubic miles. A splinter fault which was observed on the seismic lines to the east of the test well site separates one of the control wells, the Union of California Sweet Lake #1, from the other control wells. Although this fault had been observed on the seismic lines, there was no evidence from well correlation to support it directly.

The final description of the reservoir evolved in three stages: first, the drilling of the test well; second, information from other new wells drilled in the area; and third, interpretation of reservoir engineering studies. The reservoir description is discussed in three stages in the following sections.

3.4.1 DATA FROM TEST WELL

The Sweet Lake test well completed drilling operations in early February 1981. The final set of logs allowed a detailed correlation with control wells. A cross-section of the Miogypsinoides sequence is presented in Figure 3-4. This cross-section shows that the correlation of the individual sands within the Miogypsinoides sequence between the four wells is extremely good. There are seven individual sands in the Miogypsinoides sequence, and each set of these sands, with the same characteristics, is present in each of the four wells. There is some change in thickness, but this is geologically reasonable and expected, and could easily be explained by depositional differences.

The primary conclusion from the study of the test well log was that the Miogypsinoides sand was most likely a sand that blanketed the area inside the graben. The preservation of the sand character from one well to another indicated good communication, and no evidence of major faulting was observed.

3.4.2 DATA FROM NEW WELLS IN THE AREA

The evidence from seismic lines indicated that the Miogypsinoides sand was very deep (below 18,000 feet) in the western portion of the graben. In fact, the two deep wells to the west of the Sweet Lake test well did not penetrate the Miogypsinoides sand. In the summer/early fall of 1982, Rio Bravo Oil Company drilled a deep (16,569 foot) well approximately 1.5 miles due west of the Sweet Lake test well. This well did not penetrate the Miogypsinoides; in fact, the TD of the well is barely below the second Camerina sand. The cross-section in Figure 3-15 shows that the Camerina sands and the intervening shale thickens considerably to the west. If the underlying strata thickened at the same rate, the Miogypsinoides sand would lie well below 18,000 feet in the western portion of the graben, and may even approach 19-20,000 feet at the extreme western edge. A revised structure map (Figure 3-6) was constructed to show the structure of the top of the Miogypsinoides as it is now interpreted. This map shows a strong northwest dip into the graben. The Miogypsinoides sand is inferred to be present to the west, with no major faults separating the test well from the western portion of the graben.

3.4.3 DATA FROM RESERVOIR ENGINEERING STUDIES

The specifics of the flow testing and the interpretation of the accumulated data are discussed in detail in section 5.0 Reservoir Testing. Drawdown tests, buildup tests, and the changes in reservoir interpretation due to these tests are presented in that section. The purpose of this section (3.4.3) is to summarize the overall conclusions of the reservoir engineering studies and to present a final description of the Sweet Lake reservoir.

Two of the seven sands in the Miogypsinoides sand package were tested, Sand 5 and Sand 3 (Figure 3-7). The reasons for the perforation of these particular sands are discussed in section 2.3.3 Completion and 2.3.4 Recompletion. The reservoir pressure testing of Sand 5 occurred during July 1981, and that of Sand 3 in November-December

1983. (Plates I & II.) Each of these tests was analyzed by two different reservoir engineering consultants. The Sand 5 test was analyzed by J. Donald Clark, consultant, (Appendix C) and by Intercomp Resource Development and Engineering. The Sand 3 test was analyzed by Clark, (Appendix) and by Dowdle Fairchild and Ancell, Inc. (Appendix E). Each of these tests indicated that there were barriers close to the wellbore, although the nature of the barriers could not be determined.

The final conclusions reached by Dowdle Fairchild and Ancell were that both Sand 3 and Sand 5 had barriers within 250 feet of the wellbore. Computer modeling using the assumption of close barriers, produced history matches that were almost exact. The model involved two barriers for each sand, equidistant from, but on opposite sides of, the wellbore. An interesting point is that the barriers in Sand 5 are slightly farther from the wellbore than are those of Sand 3. This is consistent with a structural model of minor faulting, with the faults crossing the wellbore just below the Miogypsinoides sands. This would be in agreement with the fact that no direct evidence of faulting was observed from the well log correlation.

However, according to Dowdle Fairchild and Ancell, an alternate model could be devised that would also match the pressure history very closely but would not involve barriers such as faults. In this model, the sand would cover the entire graben, but there would be a substantial decrease in permeability close to the well. It is geologically unlikely that the well just happened to be drilled into the highest permeability zone of each sand, but it is also unlikely that the well happened to drill into the exact center of two faults. Thus the computer modeling cannot be accepted verbatim.

One very likely explanation is that there is minor faulting in the graben. The similarity in sand characteristics between the test well and control wells precludes major differences in deposition, and the fact that the Miogypsinoides sand is also present outside the graben indicates that this is an extensive sand. In addition, pressure testing indicated that although there are close barriers, the reservoir is open in one direction at least 4 1/4 miles. Minor faulting, however, would not have been evident from the seismic lines or well log correlation, and is geologically reasonable. The abundance of major faults in this area suggests that there may be accompanying minor faults.

Although it is unlikely that the Sweet Lake test well drilled into the exact midpoint between two faults, there is some margin of error in the computer modeling. The conclusion by the geologists is that the gross structure is well represented by the structure map in Figure 3-6. The major bounding faults of the graben were not observed during pressure testing due to barriers that are within 250 feet of the wellbore. These barriers are most likely minor faults that are not directly observable through any other tool. The faults probably cross the wellbore below the base of the Miogypsinoides sand, and probably die out before crossing the wellbores of the control wells. The amount of throw on these faults cannot be estimated. The reservoir is open in one direction, however, for at least 4 1/4 miles. This direction is to the northwest, and there is no evidence that the reservoir is enclosed.

3.5 PETROPHYSICAL ANALYSIS

The logs of both the test well and disposal well were analyzed to estimate porosity, permeability, and salinity. The logs used included SP, resistivity, gamma ray, borehole compensated sonic, compensated neutron, formation density, and Saraband. The results of the log analysis are compared to the core analysis in section 3.6 Core Analysis.

3.5.1 TEST WELL LOGS

Petrophysical properties of the test well logs were calculated by three different firms: Magma Gulf, Intercomp, and Frank Millard, consultant. The results of these three separate analyses are discussed in the following sections.

3.5.1.1 POROSITY AND PERMEABILITY

Results from all porosity calculations are presented in Table 3-3. Reference to this table will facilitate following the discussion of the various porosity calculations.

The Magma Gulf geologists calculated porosity in two ways; first, from the sonic log, and second from averaging the Schlumberger-calculated Saraband porosity. The Saraband porosity is significantly lower, ranging from 12.1 to 19.0%. This porosity is known to be a few percent lower than measured porosities. The sonic porosity ranges from 14.1 to 22.9%.

Frank Millard, a well log analyst, studied the entire suite of Sweet Lake logs and submitted a report on his findings. His complete report is in Appendix E of volume 1. Part of this report included a porosity estimate based on the neutron-density crossplot. These numbers are comparable to the sonic log porosities and range from 14.6 to 23.2%.

Intercomp used a digitized tape prepared by Schlumberger and an in-house computer analysis to estimate porosity. These porosities, again are comparable to both the sonic and the neutron-density estimates, and range from 13.9 to 20.8%.

Sand 5 had the highest porosity, followed closely by Sand 3. These figures were taken into consideration when the perforation intervals were chosen.

Permeability is a more difficult parameter to estimate, as no logging tool has yet been developed which can measure permeability and gives adequate estimates as far as relative permeabilities are concerned. The absolute values are often quite different from the actual measured values. Intercomp again used their own computer analysis to estimate permeability. All permeability results are presented in Table 3-4.

The estimates of air permeability from the Saraband log range from 130 to 2960 millidarcys. The Intercomp air permeabilities range from 48 to 2703 millidarcys, and, in most cases, are comparable to the Saraband-derived values. However, these numbers are somewhat misleading as the air permeability values are much higher than the values of permeability to water.

An estimate of permeability to water was made, using the Saraband air values as the input data. The resulting water permeabilities, shown in Table 3-4, range from 20-400 millidarcys. These numbers are basically an order of magnitude lower than the corresponding air values, but are much closer to the actual values obtained from reservoir engineering.

3.5.1.2 SALINITY

Salinity calculations from log data have been notoriously inaccurate in the past. Recent research has yielded various new methods for calculating salinity, most of which appear to yield values closer to reality than the old SP method. All salinity information is presented in Table 3-5.

A brief discussion of how each of the nine sets of calculated salinities was obtained is necessary before the results can be evaluated. Reference to Table 3-5 will be helpful in following the discussion.

In order to calculate salinity, the water resistivity and temperature must be known. Entering these two numbers on a chart such as that in Figure 3-8 yields salinity. The following methods are thus basically different ways of calculating water resistivity.

In the first method the SP salinity is that calculated using the conventional equation, which has proved to be greatly in error for geopressed reservoirs. The equation used is:

$$R_{we} = R_{mf} (10 \text{ ssp} / (60 + .133 T_f))$$

where

R_{we} effective water resistivity
 R_{mf} mud filtrate resistivity
 SSP static spontaneous potential
 T_f formation temperature

The calculated R_{we} is then used in the chart in Figure 3-10. This equation yielded estimates of salinity of 60,000 to 78,000 ppm, which is less than half the actual salinity. These calculations demonstrate the unreliability of using the conventional SP equation to calculate salinity.

A second method is that termed the R_{wa} method. This method relies on true resistivity and porosity to calculate water resistivity. The equation used is:

$$R_{wa} = R_t \phi^2 / .81$$

where

R_{wa} apparent water resistivity
 R_t true resistivity
 ϕ porosity

The salinities calculated using this method ranged from 58,000 to 120,000 ppm, which are somewhat better than the conventional SP estimates, but are still low compared to the measured values.

The third method used is that termed the K_f , which was developed by Dunlap (1980). K_{fI} and K_{fII} refer to refinements of this model (Dunlap, 1981). The K_f method concentrates on determining a better value for R_{mf} , which is then used in the conventional SP equation.

The equation used is:

$$R_{mf} = K_f R_m$$

where

R_{mf}	resistivity of mud filtrate
R_m	resistivity of mud
K_f	dimensionless constant

The constant K_f is determined from the chart in Figure 3-9. K_f depends on the type and the density of the mud. The calculated R_{mf} is used to calculate R_{we} from the SP equation. The values obtained from this calculation range from 130,000 to 160,000 ppm, which are very close to the measured values.

Dunlap (1981) has made two refinements to this model (Figures 3-10 and 3-11). The first accounts for geologic age, while the second is an unattributed correction factor. The values obtained from these corrections range from 100,000 to 140,000 ppm, and 100,000 to 150,000 ppm, respectively. The values are slightly lower than the uncorrected values and, as such, are less an approximation of the Sweet Lake salinities, but are still within 10% of the correct value. This is a remarkable improvement over the conventional SP calculation.

A fourth method is to use the conductivity to calculate true resistivity. The equation used is:

$$R_t = \frac{1000}{C}$$

where

R_t	true resistivity
C	conductivity

The calculated R_t is then used in the R_{wa} equation to calculate apparent water resistivity. The values calculated by this method had the largest range, from 68,000 to 200,000 ppm. The salinities calculated by this method are apparently inconsistent.

The fifth method used was that developed by Bassiouni and Silva (1981). This method uses the quantity R_{sh}/R_{mf} at T_f along with the SP value to determine the quantity R_{mf}/R_w at 75° (Figure 3-12), where R_{sh} is the resistivity of the shale. From the quantity R_{mf} at 75°, and obtaining R_{mf} at 75° from the well log data, R_w at 75° can be calculated and salinity obtained. The values obtained from this method were extremely low, only 11,000 to 15,000 ppm. This suggests that the Bassiouni method is not accurate in reservoirs similar to Sweet Lake.

Salinity was also obtained directly from the Saraband log computed by Schlumberger, and ranged from 68,000 - 125,000 ppm.

These are low compared to the actual values, but not as low as the conventional SP. The Saraband calculations may be more accurate for hydro pressured reservoirs.

Finally, Intercomp also estimated salinity using an in-house computer analysis. Values ranged from 100,000 to 175,000 ppm. These are fairly good estimates.

Overall, it appears that the K_f method developed by Dunlap provides the most accurate estimation of salinity in geopressured reservoirs.

The proper determination of salinity is necessary in order to determine the quantity of methane gas in the brine. Increased salinity appears to decrease or limit the amount of methane saturation, thus affecting the total gas available from the geopressured-geothermal brine.

3.5.2 DISPOSAL WELL LOGS

The disposal well logs were not analyzed to the same extent as the test well logs. It was sufficient to note that there were multiple thick sands to the total depth of the well, and that these sands had high porosities, on the order of 25-30%. The permeabilities, as calculated from the Saraband log, also appear to be high; some of the air permeabilities from the sidewall cores were on the order of 1-2 darcys. This information led to the conclusion that the disposal sands would adequately handle the volume of brine expected at peak production rates.

3.6 CORE ANALYSIS

Four conventional 2" diamond cores were obtained from the Miogypsinoides sand interval under the supervision of Christiansen Diamond Products, Inc. The cored intervals are shown in Figure 3-13 and are as follows:

<u>Core No.</u>	<u>Cored Interval</u>	<u>Recovered Interval</u>	<u>Core Length</u>
1	15,144-15,184	15,144-15,179	38.0 feet
2	15,185-15,201	15,185-15,197.5	12.5 feet
3	15,389-15,411	15,389-15,405	16.0 feet
4	15,600-15,634	15,600-15,632	32.0 feet

Core Laboratories, Inc. of Houston handled the core at the site. The core was wrapped in plastic bags and transported to Houston, where samples were obtained for porosity and permeability analysis. After these samples were taken the core was preserved in resin and aluminum foil. This was done to minimize the loss of fluids and other changes in the core before distribution. Various aspects of core analysis are discussed in the following sections.

3.6.1 STRUCTURE

Some sedimentary structures had been observed in the cores, notably cross-bedding. Since the majority of the core was to be cut and distributed to various research projects, a method of permanently recording the sedimentary structures was sought. The Coastal Studies Office at Louisiana State University pioneered a whole-core X-ray technique. This X-ray radiography illuminates such structures as cross-bedding and burrows, and provides a permanent record.

Technical Welding Laboratories was suggested to MG-T as a laboratory which had experience in this type of work. The core, which was wrapped in resin and aluminum foil, did not have to be exposed to air in order for this to be done. This was a definite advantage, as the other firms contacted would have had to remove the preservation material and encase the core in plaster of paris. Technical Welding Labs X-rayed the core in March, 1981. The core was returned to Core Labs without damage, and the X-ray radiographs were given to MG-T.

Although some of the X-rays are dim, the sedimentary structures are indeed evident. Cross-bedding is present throughout the core, and other structures which may possibly be burrows are also present.

3.6.2 LITHOLOGY

In general, the Miogypsinoides reservoir rock is a tan to gray, fine-grained, well-consolidated sandstone. There are shale layers that separate the individual sands, the thickest of these being 45 feet thick. Since these shales correlate well between the test well and control wells, it is thought that the individual sands are indeed discrete.

Scanning electron micrography, X-ray diffraction, grain size analysis, and conventional porosity and permeability analyses were performed on the core. The results of these analysis are discussed in the following sections.

3.6.2.1 SCANNING ELECTRON MICROSCOPE ANALYSIS

A small portion of Core No. 3 was given to Accumin Analysis for scanning electron micrography. This analysis was performed in part to determine whether there would be problems with sand production during flow testing. An abundance of clays in the pore space or as cementing material would indicate a potential problem. On the other hand, a cementing material such as quartz overgrowth would indicate minimal potential sand movement.

X-ray diffraction of the core showed that it consisted of 75% quartz, 19% feldspar, 4% illite, 2% mixed layer clay (illite/smectite) and a trace of kaolinite. Three energy dispersive spectra were obtained, which are shown in Figures 3-14, 3-15, and 3-16. Figure 3-14 is the EDS spectrum of a feldspar grain. There are peaks at the Al, Si, and K energies, showing this to be a typical potassium feldspar. Figure 3-15 shows peaks at Al, K,

Ca, Ba, Fe, and Au. This grain is thus most likely drilling mud, and the indication of gold is probably from the preparation material. Figure 3-16 shows the EDS spectrum of an illite grain. There are peaks at Al, Si, and K, but the relative strengths indicate that this is not another feldspar grain.

X-ray diffraction of three of the 44 sidewall cores obtained from the test well (7,020 feet, 7,050 feet, and 7,090 feet) showed that these sands consisted primarily of quartz (89-97%), with some feldspars and a trace of calcite. The results of this analysis are presented in Table 3-6.

Six scanning electron micrographs were taken of Core No. 3. These are presented in Figures 3-17 to 3-22. It was from these micrographs that it was conclusively determined that the cementing material was quartz overgrowth. The small amount of clays present should not have caused, and indeed did not cause, significant sand production.

Figure 3-19 is a general view showing quartz overgrowths and feldspar grains. The quartz overgrowth was caused by the recrystallization of quartz under pressure and the hexagonal nature of the recrystallized quartz can be clearly seen in this photograph.

The Miogypsinoidea sand has a very high porosity, considering the depth. Much of this porosity must be due to the high geopressure, but a contributing factor can be seen in Figure 3-18. The feldspar grains have been partly dissolved, and this dissolution porosity will add to the primary porosity. It is not known how much this actually contributes, but all of the feldspar grains in the micrographs show this dissolution porosity to some extent.

Figure 3-19 is again a general view, showing quartz overgrowth development and feldspar grains. The hexagonal nature of the quartz grains can again be noted.

There was some drilling mud contamination in the core, as had been noted by the EDS spectrum in Figure 3-15. Figure 3-20 shows this drilling mud bridging an intergranular pore. This contamination would probably not extend farther than a few inches from the borehole.

As has been noted previously, the location of the clays was a primary concern, and one of the major reasons for doing the SEM analysis. The last two SEM micrographs show the clay quite clearly. Figure 3-21 is a high-magnification photograph of the illite coating. Note that the illite takes the form of very fine hairs. This same effect can be seen in Figure 3-22, with the illite partly occluding the pore throat. These fine illite hairs would move during water production, but since they are not an inherent part of the cementation, this would not cause the quartz and feldspar grains to move. Figure 3-22 also shows an excellent example of the hexagonal nature of the quartz overgrowths.

3.6.3 BENCH CONDITION POROSITY AND PERMEABILITY

Core Laboratories, Inc. was responsible for bench condition porosity and permeability measurements. These were kept to a minimum, as the maximum amount of core possible was to be reserved for other research. As a result, a total of five analyses were made, two on Core No. 1, and one on each of the remaining cores.

The results of these analysis are presented in Table 3-7. The horizontal permeability (air) ranges from a low of 4 md to a high of 3670 md. It should be noted that the 4 md sample was from Core No. 4. This core was taken from the lowest sand in the section, which was not considered to be a highly productive sand. The silt content increased substantially in the lower part of the Miogypsinoïdes section.

The vertical permeability (air) ranged from a low of 2.6 md to a high of 3526 md. The lowest value however did not correspond to the lowest value of the horizontal permeabilities. Instead, the sample that had 32 md horizontal permeability had a vertical permeability of only 2.6 md. This indicates that there were silty stringers within the sands that may have prevented vertical communication.

The measured porosities ranged from 14.3 to 24.3%. These agree very well with the porosities calculated from the log data. A comparison of log and measured data for porosities and permeabilities can be found in Tables 3-3 and 3-4, respectively.

Forty-four sidewall cores were obtained from the test well. These were taken over most of the stratigraphic section, from 6,490 to 15,075 feet. As these samples were above the Miogypsinoïdes sand, they could not be used to evaluate the reservoir. However, the information was useful in evaluating variations between the hydro-pressured and geopressured formations, and in comparing core analysis to wireline log analysis. The porosity and permeability analysis results are presented in Table 3-8.

3.6.4 SIEVE ANALYSIS

The same samples that were used for porosity and permeability analysis were used for grain size analysis. The results of these analyses show that the median grain size is .0065 to .0127 inches (fine-grained to medium-grained). The complete Core lab report is included in Vol. I Appendix A.

3.6.5 DISTRIBUTION OF CORE MATERIAL

A total depth of 96 feet of core was divided among nine research projects. Requests for core material were filled as far as possible; limitations may have occurred because the amount of core recovered was much less than the amount requested. Core material was given to the following people and organizations:

Amoco Production
Hartax, Inc.
Institute of Gas Technology
Lawrence Berkeley Laboratory
Louisiana Geological Survey
Rice University
Terra Tek
U. S. Geological Survey
University of Texas

G. Pittman
George Hart
Walter Rose
Dmitri Sverjensky
Don Bebout, Ray Ferrell
Mason Tomson, John Oddo
John Schatz
Tom Kraemer
Ken Gray

Subsequently, the core given to Lawrence Berkeley Laboratory was returned, due to a lack of funding at LBL.

The complete list of core distribution is included as Appendix F.

3.6.6 ROCK MECHANICS

The production of fluid from a reservoir reduces pore fluid pressure and may cause surface and subsurface subsidence. The compaction of the reservoir rock is important as a mechanism to maintain pore pressure. As the pore pressure is reduced through geopressured-geothermal brine production, the effective stress increases. This stress increase causes formation compaction, which may be time dependent or non-time dependent. An increase in stress would tend to increase and/or maintain pore pressure, but also decreases porosity and permeability, which would have a detrimental effect on brine production. Investigation of the rock mechanics of the reservoir rock should thus yield information on long-term reservoir behavior, and also provide numerical values of certain parameters which could be used directly in reservoir engineering calculations.

The rock mechanics of the Sweet Lake geopressured-geothermal reservoir were investigated by the University of Texas at Austin under the direction of Dr. K. E. Gray. This work was funded by GRI Contract No. 5014-321-0290. Core samples from all four diamond cores were provided to Dr. Gray according to his specifications. Both types of rock behavior were investigated and reported on; first, non-time dependent (compaction) testing, and second, time dependent (creep) testing. The following sections describe this work. More details are contained in University of Texas Report CESE-DRM-88.

3.6.6.1 COMPACTION MEASUREMENTS

Prior attempts to quantify compaction drive and subsidence have generally utilized simplistic models. This project was undertaken to derive a more realistic model of reservoir behavior. The necessary tests to provide data to develop this model include uniaxial compaction and hydrostatic loading tests. Deformation behavior, porosity changes, permeabilities, and acoustic velocities were measured under increasing and decreasing effective pressures during each series of tests. The results of these tests lead to several conclusions:

- 1) As the effective stress increases to a maximum, the bulk

compressibility decreases by approximately 55-65%.

2) Bulk compressibilities at atmospheric pore pressure are higher than bulk compressibilities at elevated pore pressure under the same effective stress. This indicates that matrix compressibility is a significant factor, which has often been ignored in the past.

3) Porosity is reduced by approximately 1-3% under increasing effective stress, but permeability is reduced by 30-45%.

4) The uniaxial compaction coefficient changes in the same direction as bulk compressibility. Under the same effective stress, the uniaxial compaction coefficient is typically one-half to one-third the value of bulk compressibility.

5) Compaction is more pronounced in the early stages of reservoir fluid production than in later stages.

The above conclusions indicate that compaction of the reservoir rock will contribute to pore pressure maintenance and fluid production at the beginning of production. Over the long term, however, the reduction in porosity and permeability and the decreasing effectiveness of compaction to pore pressure maintenance will significantly decrease the contribution of rock compaction to the reservoir drive mechanism.

3.6.6.2 CREEP MEASUREMENTS

The compaction measurements discussed in the previous section described a more or less elastic response of the reservoir rock to changing effective stress. However, in order to completely describe the behavior of the rock under changing stress, the time dependent nonelastic response of the rock must also be considered. This response is described as the "creep" of the rock.

Nine creep tests were performed on samples from the Sweet Lake cores, under three sets of loading conditions: 1) hydrostatic-elevated pore pressure; 2) hydrostatic-zero pore pressure; and 3) differential-zero pore pressure. Five of these samples showed creep, and four showed sufficient creep for data analysis.

Two models have been developed to explain this creep behavior, a delayed elastic and a non-linear strain hardening model. Both of the models adequately fit the data, and at this time one cannot be chosen over the other.

The delayed elastic model notes that the volume strain increases with time at a constant stress. However, this strain approaches a constant value in a finite time. Accordingly, the most simple explanation is to consider the rock as possessing a composite elastic response to applied stress. This composite response is partly an immediate response and partly a response that is delayed in time. A quantitative description has been derived to explain this behavior.

Alternately, the creep behavior may be described by a strain hardening model. This model considers the local shear stresses set up around spherical pores in a hydrostatic stress field. In this case, the volume creep strain rate depends on the volume creep strain and the effective stress. A mathematical model has been derived to explain creep behavior under a strain hardening law, and is fully discussed in the text of the complete report (Gray, et al, 1982). In general, creep curves generated by this model also show a good fit to measured data. Neither the delayed elastic nor the strain hardening model can be described as the preferred model at this time.

3.7 ORGANIC GEOCHEMISTRY

Organic geochemical analysis was undertaken by Hartax, Int. under GRI Contract No. 5014-321-0290. As stated in the Hartax report, this project investigated:

- 1) the quality, type (gas vs. oil), state of thermal maturity, and the areal and stratigraphic distribution of any hydrocarbon source rocks penetrated by this well;
- 2) the crude oil-parent source rock relationships of any reservoired oil or gas encountered during the drilling of this well as a means of determining whether or not such shows represent indigenous hydrocarbons sourced from contiguous shales or migrated hydrocarbons generated in older and/or more mature source facies;
- 3) the local geochemical controls influencing hydrocarbon generation, migration, and reservoired petroleum composition (source material, thermal maturation, secondary thermal and nonthermal alteration, etc.) in this specific area; and
- 4) the quantity of methane gas which may be contained in, and producible from, the geopressured methane-rich aquifer systems potentially encounterable at depth in the local area.

These items were investigated using standard organic geochemical techniques, including C₁-C₇ hydrocarbon analysis, C₁₅ liquid/chromatographic separation, total organic carbon analysis, visual kerogen assessment, and vitrinite reflectance analysis. Discussion of these various techniques is included in the Hartax report summary, Appendix D of Volume I.

Well cuttings were collected for organic geochemical analysis by the IDL mud loggers. Bagged cuttings were collected at thirty-foot intervals from the surface to 6,000 feet by rig personnel, and canned cuttings were collected at sixty-foot intervals by IDL from 6,000 feet to total depth of the sidetrack hole. The samples were sent to GeoChem Laboratories, Inc. for the actual analysis, and the results were submitted to Hartax, Int. for interpretation. A summary of all analyses is presented in Figure 3-23 A, B, and C.

The analyses show that the sediments penetrated by the Sweet Lake well can be divided into five distinct zones. Zone C can be divided into 3 subzones, with the zonation as follows:

Zone A	surface to 3,000 feet
Zone B	3,300 feet to 6,400 feet
Zone C	6,400 feet to 9,100 feet

Subzone C ₁	6,400 feet to 7,350 feet
Subzone C ₂	7,350 feet to 8,500 feet
Subzone C ₃	8,500 feet to 9,100 feet
Zone D	9,100 feet to 14,100 feet
Zone E	14,100 feet to 15,720 feet

Only the bottom zone, E, covers the interval containing the *Miogypsinoidea* sand. This was therefore the zone of primary interest to MG-T.

3.7.1 THERMAL MATURITY

The Zone E sediments grade from a slightly calcareous shale through siltstone to a coarse quartzose sand. The thermal maturity of three samples from the *Miogypsinoidea* sand is an immature Maturation Index Stage 2- to 2, as shown in Figure 3-24. The result of the vitrinite reflectance analysis (Table 3-9) also indicates immature thermal maturation. However, the increase in the C₁₅₊ paraffin-naphthene and aromatic hydrocarbon contents in the C₁₅₊ bitumen indicate that the reservoir may have been infused with oil sourced from underlying rocks.

3.7.2 HYDROCARBON SOURCE

The sediments analyzed from Zone E indicate a moderately immature poor oil and associated gas source. Any oil or gas present must have been sourced from underlying rocks. Discussions with Hartax and Geochem indicate that source rocks have not yet been identified in Gulf Coast sediments, as the sediments have not been buried deeply enough or long enough to become thermally mature and to have produced indigenous hydrocarbons. The lack of thermally mature sediments in the area obviously raises the question of the source of the hydrocarbons in the Sweet Lake reservoir.

3.8 DISPOSAL WELL CORES

No diamond core was obtained from the disposal well, but 29 sidewall cores were collected. These cores were taken to confirm adequate porosity and permeability for disposal of geopressured brine. As shown in Table 3-10, porosity ranged from 25 to 30% and air permeability from 200 to 2000 md, with an average of 1000 md. These results indicated that these shallow sands would be capable of accepting large quantities of brine.

4.0 DESCRIPTION OF SURFACE FACILITIES

A plot plan on the Sweet Lake site is given in Figure 4-1, and surface facility process and instrumentation drawings are shown in Figures 4-2 and 4-3. Reference to these three figures will be useful in following the description of the surface facilities.

This facility design was established after flow testing at Pleasant Bayou. Pleasant Bayou facilities were more experimental in orientation, whereas Sweet Lake surface facilities were oriented to a flow rate of 40,000 barrels per day, semi-commercial operation, 300°F, and with connections for power generation and gas sales. The Sweet Lake design has in fact been further optimized at the Gladys McCall well site.

4.1 TEST WELLHEAD

A schematic diagram of the test wellhead and casing spools is shown in Figure 4-4, and photographs of the test wellhead, including the twin flow wings, and the casing spools are shown in Figure 4-5.

The primary on/off flow control of the test well was through a redundant series of 5 1/8" Gray gate master valves. One of the master valves was hydraulically-operated and was part of the Emergency Shutdown (ESD) system described below in 4.9 Instrumentation. The uppermost Gray gate valve, or swab valve, on top of the "Y" block was used for wireline operations. All valves were packed with a special high temperature grease. As a further safety precaution, a manual wire drum operation was added to one of the master valves. During periods when the automatic shutdown system had been bypassed (for example, with a wireline in the hole) this manual remote system permits the valve to be closed without being close to the wellhead.

The brine flow split near the top of the wellhead into two flow wings for balance and to reduce thrust, and was then recombined near the base of the wellhead. It then flowed through heavy-wall 10,000 psi piping to the Gray choke skid.

The test wellhead was rated for 10,000 psi; however, the maximum expected surface pressure was 5,000 psi. The test wellhead was ordered from FMC. However, FMC could not complete manufacture and the upper portion of the wellhead was manufactured by Gray under another DOE contract and transferred to MG-T.

4.2 FLOW CONTROL SYSTEM

The use of the terms "flow control system" herein is something of a misnomer in that the brine flow from the test wellhead was not actually controlled automatically, but rather was directed through two banks of manually-operated adjustable choke valves in series. The choke valves were used to set the brine flow at or near the desired rate; the flow rate then varied with variations in the upstream pressure unless the choke valve settings were readjusted manually. Thus the pressure was dropped in two stages. The first stage reduced pressure to less than 5000 psi, which was the design rating of the

Halliburton turbine meter. The second stage of chokes dropped pressure to that desired in the separator, 300-1000 psig.

4.2.1 GRAY CHOKE VALVES

The Gray choke system and wellhead were acquired from DOE as a result of FMC not being able to complete the wellhead.

The Gray choke valve manifold, which was rated at 10,000 psi, is shown in Figure 4-6. Brine flow from the test wellhead entered the manifold, and then was directed through one or both adjustable choke valves arranged in parallel before reaching the manifold outlet. The choke valves were sized such that the entire design flow rate of 40,000 B/D could be passed through only one of the parallel choke valve legs and the other acted as a spare. This arrangement precluded the necessity of shutting in the test well to repair or replace one of these choke valves.

It should be noted that the 4 1/16" gate valves on the inlets of the two Gray choke valves were a part of the hydraulically-operated ESD system described below in 4.9 Instrumentation. When low pressures (less than 5,000 psi at the surface) were identified at Sweet Lake, it was determined that the Gray chokes could be eliminated.

4.2.2 WILLIS CHOKE VALVES

The brine flowed from the Gray choke manifold through heavy-wall 8-inch piping and a Halliburton turbine meter to a parallel bank of two Willis choke valves, which was planned for secondary flow control. One Willis choke valve was sized for 0-5,500 B/D, and was utilized primarily during the initial flow tests at relatively low flow rates. The second Willis Choke valve in this parallel arrangement was sized for 0-45,000 B/D.

The series arrangement of the Gray and Willis choke valve systems was necessitated by design criteria of (1) maximum wellhead pressure of 10,000 psi, (2) injection of scaling/corrosion inhibitor at relatively high pressure, with a maximum inhibitor pump discharge pressure rating of 7,500 psi, and (3) a flow measurement requirement at high pressure, with a maximum pressure rating of 5,000 psi on the turbine meter. At the time of installation, a higher pressure rating turbine meter was not available commercially.

The Gray chokes were removed later when low pressures were observed and the valves were needed at the Gladys McCall well. They were replaced by a straight piece of heavy wall pipe, and later a Gray ESD valve was added. Thus, the Willis chokes finally served as primary flow control.

The Willis chokes required a great deal of maintenance due to erosion. Their angular design required a number of adjacent pipe right angles, and erosion damage was experienced at these points.

4.3 BRINE/GAS SEPARATOR SYSTEM

As the pressure was decreased across the choke valves from the wellhead pressure of about 5,000 psi to about 1,000 psi, natural gas as well as other gases (e.g. carbon dioxide) was released from solution in the brine. The two-phase gas-liquid flow was then directed into the brine/gas separator system for the gas separation and recovery sequence of the process. Photographs of the separator system are shown in Figure 4-7.

The brine/gas separator vessel (V-301), construction details of which are given in Volume II, was a horizontal cylindrical vessel with an internal diameter of 54-inches and a length of 30-feet tangent-to-tangent. The separator system was designed for a 40,000 B/D brine flow rate containing 1.2 MMSCF/D of gas. The design operating pressure and temperature were 1,000 psig and 300°F, respectively. The maximum working pressure of 1,440 psig at 105°F could be reduced to 1,290 psig at 350°F. These pressures were selected to permit injection of gas into a commercial pipeline system and to permit the disposal of effluent brine into the disposal well without the necessity of installing pumping facilities. On the other hand separator pressure could be reduced to 100 psig if required by low well head pressure, which has been necessary at times.

The brine/gas flow from the Willis choke valves was directed into the separator inlet, and then downward by a splash plate at the inlet. The linear velocity across the separator was 0.32 feet/sec at the design flow rate of 40,000 B/D, and thus residence time in the separator was about 100 seconds. Obviously, the linear velocity was lower, and the residence time longer, at flow rates of less than 40,000 B/D.

The gas and water vapor thus separated from the brine flowed upward and out the top of the separator. Pressure control on the separator system was maintained through a split-range pressure indicator/controller, which adjusted the gas flow primarily to the future gas pipeline system, and secondarily as required to the flare system. However, during all testing phases all gas produced was sent to the flare since the necessary gas cooling and drying facilities had not been provided, and the connections to a commercial gas transmission pipeline system were not made.

The brine level in the separator was controlled by a liquid level indicator/controller, which set the rate of brine flow out the bottom of the separator. Although no oil was expected, the separator was also equipped with a 2-foot vertical baffle plate, so that oil/brine separation could be made in the vessel with only minor external additions should minor quantities of oil be produced. Some heavier liquids were produced- see Section 6 of this report.

Sand drains were included in the separator, but since no sand was produced, they were not used except for occasional cleaning of the separator.

4.4 BRINE FILTER SYSTEM

The brine from the separator system was filtered before flowing to the disposal well. The Pioneer Centrifuging Company brine filter system, consisted of five skid-mounted filters with parallel inlets, and outlet

headers, valves, gauges, bleed valves, cover davits, and other accoutrements. Crossover tees and blinds were included to allow operation of the five filters in parallel banks of three filters and two filters in series. The filter tubes used initially were for 50 micron size separation, but were also available in 5, 10, 25, 75, and 100 micron sizes. These filter cartridges were of throw-away design. A local pressure gauge on each indicated the need for replacement. Principal species filtered were iron and scale (calcium carbonate). Virtually no sand was observed.

4.5 SALT WATER DISPOSAL WELLHEAD

A schematic diagram of the salt water disposal wellhead and casing spools is given in Figure 4-8, and a photograph of the installed wellhead is shown in Figure 4-9. This wellhead was furnished by FMC Corporation.

4.6 PRODUCTION GAS SYSTEM

As was discussed previously, the gas and water vapor from the separator could be sent via split-range pressure control on the separator first to the gas pipeline system, and alternately as required to the field flare. Because the gas pipeline was not installed, both lines were connected together to go to the flare.

4.6.1 FIELD FLARE SYSTEM

As shown in Figure 4-3, the field flare system consisted of a water knock-out pot with level controller, a 30-foot Pilgrim Steel flare stack, a flame front generator ignition and pilot system, and a propane storage tank.

Gas and water vapor was routed to the water knock-out pot from which condensed water was sent via level control to surface blowdown tanks for disposal. The gas from the water knock-out pot was then burned in the flare. The 30-foot flare stack included a 4-inch X 8-foot tip, and was designed to withstand sustained winds of 125 mph. The flame front generator ignition and pilot system consisted of sending a regulated mixture of propane and air to the flare tip with manual electric ignition of the pilot from a remote panel. Because of the long pipe runs involved, the pilot system did not work reliably. The flare was locally lighted, using a rag on a pole or a fireworks rocket.

4.6.2 GAS PIPELINE SYSTEM (NEVER COMPLETED)

It would have been necessary to install additional surface facilities before the gas production could be sold to a gas transmission company. These facilities would have included a forced-draft air cooler to cool the gas from about 300°F to about 125°F, a water knock-out pot to remove the water thus condensed, a gas/triethylene glycol contactor for water removal, a 40-gph triethylene glycol regenerator, and piping from the site to the chosen gas pipeline. It might also have been necessary to install a gas/diethanolamine contactor, and a 10-gpm diethanolamine regenerator for reduction of the carbon dioxide concentration in the gas stream. Because it was not economic, a gas sales line was never contracted.

4.6.3 INHIBITOR INJECTION SYSTEM

As may be seen in Figure 4-10, the scaling/corrosion inhibitor injection system consisted of two 60-gallon inhibitor storage tanks with gauge glasses, three 30-gph Milton Roy positive displacement injection pumps with pulsation dampners and a maximum discharge pressure of 7,500 psig, and associated pressure relief valves, gauges and piping.

The system was designed so that two different inhibitors could be injected simultaneously at different concentrations into the brine line, with the third pump available as a common spare. The inhibitor injection rate was varied with a micrometer dial on the pump; the pump calibration curves were determined by plotting actual volume pumped per unit time as a function of the micrometer setting.

Inhibitors from the pump discharges were injected through separate piping into the 8-inch brine line between the Gray choke valves and the turbine flow meter.

Initially, 10 ppm of the scaling inhibitor AMP-20 were injected; however, the specific inhibitors, combinations thereof, and concentrations were reduced to about 1 ppm as a result of information gained from the inhibitor pilot plant program. A corrosion inhibitor was not required due to low experienced corrosion rates.

4.7 SURFACE TANKAGE

The blow-down pit utilized commonly in both oilfield drilling and geopressured-geothermal operations was not provided at the Sweet Lake site, primarily for environmental reasons and lease restrictions. Fluids not suitable for injection were piped to, and had to be contained in, four rectangular open top surface tanks with a total capacity of only 700 barrels (refer to Figures 4-2 and 4-3). There were three tanks with a 100-barrel capacity and one tank with a 300-barrel capacity. The use of these small tanks increased the cost of Sweet Lake drilling and operating significantly.

It was necessary to transport brine and other substances from the blowdown tanks with vacuum trucks to approved disposal areas. One such disposal area was located approximately 4 miles from the site. The blow-down tanks were not drained at the site. The brine from the tanks, however, could, be pumped to the disposal well through the use of the portable pump, if the brine was suitable; i.e., neither contaminated nor diluted with fresh water.

Although the blow-down tankage was indeed very limited, it was nonetheless considered adequate for the anticipated needs, and did not limit operations during the testing period.

4.8 PRESSURE RELIEF SYSTEMS

There were basically two types of pressure relief systems in the surface facilities design: first, there were conventional pressure relief or pop

valve systems which relieve at preset pressure settings, and second, various pressure sensors which relieve the abnormal pressure situation by actuating the Emergency Shutdown (ESD) system. This, in turn, closed gate valves upstream of the Gray choke valves and/or on the test wellhead, and would shut-in the well.

Pressure sensors which actuate the ESD system and shut-in the test well, their locations and respective pressure settings follow (refer to Figure 4-2):

8-Inch Brine Line Between Gray Choke Valve Manifold and Turbine Flow Meter

High Pressure Setting	-	5,000 psig
Low Pressure Setting	-	1,500 psig

10-Inch Brine Line Between Willis Choke Valve Manifold and Gate Valve Block for Separator Bypass

High Pressure Setting	-	1,500 psig
Low Pressure Setting	-	200 psig

Brine/Gas Separator Vessel (V-301)

High Pressure Setting	-	1,290 psig
Low Pressure Setting	-	200 psig

8-Inch Brine Line to Disposal Well (Downstream of PCV-121 Manifold)

Low Pressure	-	100 psig
--------------	---	----------

Conventional pressure relief valves, their locations, and pressure settings are as follows:

6-Inch Separator Bypass Line	-	1,935 psig
6-Inch Brine Filter Inlet Line	-	1,290 psig
Brine/Gas Separator Vessel (V-301)	-	1,290 psig

These pressure relief systems were designed to adequately protect the integrity of the surface facilities, and thus facilitated safe testing operations.

4.9 INSTRUMENTATION

4.9.1 BOTTOM-HOLE PRESSURE AND TEMPERATURE MEASUREMENTS

Wireline bottom-hole pressure and temperature measurements were made during the initial phases of testing by Reservoir Data personnel. Because the expected relatively high bottom-hole temperature (320° - 330°F) exceeded the limits of the Hewlett Packard gauge, a modified GRC-512 pressure element was used in the test well, although the

actual temperatures would have permitted the use of the Hewlett-Packard gauge. A Hewlett-Packard Quartz Gauge was used in the salt water disposal well. These temperature and pressure measurements were required for reservoir modeling studies to define the reservoir. For much of the testing, no downhole measurements were made and surface pressure measurements were sufficient.

4.9.2 FLOW MEASUREMENT

Flow measurement was made with both flow-proportional Halliburton turbine meters and by instruments measuring pressure drop across conventional orifice plates. A Komax mixing device was later added at GRI and IGT suggestion.

Large turbine meters (0-50,000 B/D) were in the brine lines downstream of the Gray choke valve manifold and the separator liquid outlet. A 0-10,000 B/D turbine meter was also arranged in parallel with the larger turbine meter on the separator liquid outlet line. Start-up piping was provided such that the 0-10,00 B/D turbine meter could be utilized during the early stages of the initial flow test at relatively low flow rates (i.e. 3,000-5,000 B/D) when the separator was bypassed. A 0-2 MM SCF/D turbine meter was installed in the production gas line, which ultimately would have been connected to a commercial gas pipeline, and a positive displacement meter was added later to confirm measurements. Operation at low flow rates has made meter range selection a problem.

The output from these turbine meters was displayed on the control panel in the control room trailer in the form of (1) a six-digit totalizer with manual reset, (2) flow indicators, and (3) strip-chart flow recorders

Conventional 0-2 MM SCF/D orifice plates for flow measurements were located in the total separator overhead gas line and in the gas line to the flare. These gas flows were displayed on strip-chart recorders in the control room trailer. A low range positive displacement gas meter was installed at the flare because of early problems with the orifice plates. The positive displacement meter served as a check on the orifice plates. Orifice meter calibration was also a difficulty magnified by two-phase, multi-component flows.

4.9.3 PANEL-MOUNTED INDICATORS/CONTROLLERS AND STRIP/CHART RECORDERS

The instrumentation that was used for primary control and monitoring of process variables on an hour-to-hour- basis were two panel-mounted indicator/controllers, and eight 30-day two-pen electronic strip-chart recorders located in the control room trailer. A listing of this instrumentation is given below.

<u>Instrument</u>	<u>Service</u>	<u>Range</u>
PR-100	Test Wellhead Pressure	0-5,000 psig
PR-102	Brine Line Pressure - Downstream of Primary Choke Valves	0-5,000 psig
FR-100	Brine flow from the Test Wellhead	0-50,000 B/D

PR-123	Disposal Wellhead Pressure	0-1,000 psig
TR-102	Brine Temperature from test Wellhead	150-350°F
TR-110	Brine Temperature to Disposal Wellhead	150-350°F
AR-100	Sand Production Rate from Test Well	Variable
AR-101	Sand Production Rate - Downstream of Filters	Variable
LIC/LR-100	Brine/Gas Separator Level	0-100%
FR-104	Brine Flow to Disposal Wellhead - Low Range	0-6,000 B/D
FR-105	Brine Flow to Disposal Wellhead - High Range	0-50,000 B/D
PIC/PR-117	Brine/Gas Separator Pressure	0-1,500 psig
FR-102	Total Separator Gas Production	0-2 MM SCF/D
FR-103	Production Gas to pipeline	0-2 MM SCF/D
FR-108	Production Gas to Flare	0-2 MM SCF/D

4.9.4 LOCAL INDICATOR/CONTROLLERS

The surface facilities control system also contained two local indicator/controllers. One of these indicator/controllers (PC-121-refer to Figure 4-2) maintained pressure on the brine line to the disposal wellhead, and was intended only for operations which bypassed the separator.

The second local indicator/controller (LIC-107-refer to Figure 4-3) released the high liquid level in the water knock-out pot on the production gas line to the flare.

4.9.5 SAND DETECTORS

Sand production rate was monitored with two Oceaneering International Sand Systems sand detectors. One sand detector monitored the actual sand production rate from the test well, and the second sand detector, located down-stream of the brine filters, monitored sand content of the brine flowing to the disposal well-head.

The sand detector system consisted basically of (1) a preamplified acoustical probe in the brine flow line and probe cables, (2) panel-mounted signal processing electronics, and (3) panel-mounted strip-chart recorders for data display and sand production quantification.

When a probe was struck by a particle of sand in the brine stream, an acoustically-sensitive crystal in the probe converted the acoustical "pinging" of the impinging sand into an electronic signal, which was processed by the electronic circuitry and then the signal output was displayed on a strip-chart recorder.

The sand detectors had five sensitivity ranges, which were calibrated individually. Sand concentrations as low as 30 ppm could be detected.

Based on data available, very little sand production was expected from the MG-T/DOE AMOCO Fee No. 1 test well. The instruments never gave a reading, and production inspection of components confirmed this lack of sand production. Sand found in the disposal well came from backflow of that well.

4.9.6 EMERGENCY SHUTDOWN (ESD) SYSTEM

The ESD system was an Otis "Wellhead Control and Emergency Shutdown System." The system consisted basically of variable sensors (pressure, temperature, flow level, sand production rate, etc.), a control panel, a hydraulic fluid pumping system, and hydraulic operators on key process gate valves. The Sweet Lake ESD control panel, located in the control room trailer, actuated a master valve on the wellhead, and the gate valves upstream of the choke valves. A detailed description of this system is presented in Volume II.

The hydraulic fluid system was a skid-mounted air pressurized dual pump (one spare) system that pressurized the hydraulic fluid to 3,000 psig. Upon receipt of signals from the sensors, the hydraulic system actuators closed the gate valves upstream of the Gray choke valves and a master valve on the test wellhead.

Once the hydraulic system was pressurized, air consumption should have been nil. However, minor leakage from the system required frequent operation of the air compressors. Additionally, nitrogen accumulators on the skid provided for four full cycles of opening and closing each valve. Once a given valve opened, the closing of the valve returned hydraulic fluid to the reservoir on the skid. The air compressors required extensive maintenance on a regular basis. A liquid nitrogen tank provided additional backup to the air system, in the unlikely event that the instrument air system became depleted. The sensors which actuated the ESD system on the Sweet Lake surface facilities are shown in Figure 4-2.

4.9.7 DIGISTRIP DATA LOGGER

In addition to strip-chart recording of key process variables these variables as well as certain others were logged digitally on one of two 32-point Kaye Instruments Digistrip Data Loggers. These data loggers, which were mounted in the control panel in the control room trailer, could be programmed to print out the digital data at practically any desired frequency. While the data logger was utilized in monitoring and testing operations, its primary function was to provide permanent

records of process variable data. The following variables were logged on the Digistrip.

PU-100	Test Wellhead Pressure
PU-101	Test Wellhead Casing Annulus Pressure
PU-102	Brine Line Pressure - Downstream of Primary Choke Valves
PU-106	Brine Line Pressures - Downstream of Secondary Choke Valves
PU-116	Brine/Gas Separator Pressure
PU-120	Brine Line Pressure - Downstream of Filters
PU-123	Disposal Wellhead Pressure
FU-100	Brine Flow from Test Wellhead
FU-102	Total Separator Gas Production
FU-103	Production Gas to Flare
TU-102	Brine Temperature from Test Wellhead
TU-105	Brine/Gas Separator Inlet Temperature
TU-110	Brine/Gas Separator Temperature
TU-112	Brine Temperature to Disposal Wellhead
TU-113	Total Separator Gas Temperature
TU-08	Gas Temperature to Pipeline
LU-101	Brine/Gas Separator Level
AU-100	Sand Production Rate from Test Well
AU-101	Sand Production Rate - Downstream of Filters

4.9.8 ALARM SYSTEMS

Numerous high and/or low pressure, temperature, flow, level, and sand production rate alarm systems were provided as may be seen in Figures 4-2 and 4-3. The alarm annunciator panel was mounted in the control panel in the control room trailer.

4.9.9 PROCESS GAS CHROMATOGRAPH

A process gas chromatograph was utilized to alternately analyze both the production gas stream and the brine stream to the disposal wellhead on approximately 30 minute time cycles.

The concentrations of methane, ethane, propane, isobutane, normal butane, isopentane, normal pentane, hexanes plus, and carbon dioxide were determined in the production gas stream with carbon dioxide being a key component.

The methane, ethane, and carbon dioxide concentrations were determined in the residual brine stream to the disposal well. The methane concentration was, of course, indicative of production gas lost to the brine stream due to brine/gas separator inefficiency. This instrument was shared with Gladys McCall. Maintenance and reliability were severe problems due to the supplier's corporate problems. It was supplemented with Draeger tubes for H₂S and CO₂, used both by operators and consultants such as SCAN. Draeger tube results were consistent and reliable.

4.10 SCALING/CORROSION MONITORING SYSTEMS

Scaling and corrosion were monitored in the main surface facilities through coupons mounted in (1) the brine line down-stream of the Willis choke valves, (2) the brine line downstream of the separator to the disposal well, and (3) the production gas line to the gas pipeline. The coupons in the brine lines were manifolded such that they could be removed and inspected during testing operations; however, the coupon in the production gas line could not be removed unless the separator was bypassed, or the test well was shut in.

Subject to experience gained during the first few weeks of testing, it was planned that these coupons would be removed, inspected, and weighed at approximately weekly intervals. The composition of the scale was also determined by periodic analysis of the material. This system confirmed that no significant scale formed, and that corrosion occurred only at isolated points in connection with erosion. Therefore the frequency of coupon analysis was reduced.

4.11 ELECTRICAL SYSTEM

The primary source of electricity at the Sweet Lake site was derived from the Jefferson Davis 7620 VAC line on Highway 384 directly north of the site. Four buried 25,000 volt conductor cables run from the Jefferson Davis line to feed three 50 KVA 120/240 volt transformers. These transformers were connected in a closed delta system with one spare 25,000 volt conductor in the event of failure of one of the other three conductors. This spare conductor had to be used due to the cutting of one conductor by unrelated construction.

The electric power left the transformers to one master 400 amp, 3 pole fusible double-throw disconnect. This disconnect was used for both commercial power distribution and generator power. A 75 KW auxiliary diesel-driven generator was available to feed critical services in the event of loss of commercial electricity. The generator was manually started locally when needed by stored compressed air.

Electricity from the master switch was fed in lines through two runs of 2-inch conduit. One conduit run fed the control room trailer and its equipment. The second conduit run fed the instrument air compressors, inhibitor injection pumps, inhibitor pilot plant and miscellaneous services such as outside lighting, etc.

4.12 INSTRUMENT AIR SYSTEM

The instrument air system was a skid-mounted Air Power Service Company package unit. The system consisted of two 55 SCF/M at 100 psig discharge Ingersoll-Rand compressors driven by two 20 HP TEFC electric motors, with associated aftercoolers, dryers, and filters. These unlubricated compressors required excessive maintenance, perhaps precipitated by the frequent starts due to leaked-off air pressure.

4.13 FRESH WATER SYSTEM

Water at the site was supplied by a 500-foot deep water well that was used initially to supply water for drilling operations. Water was supplied at the surface by pressurizing the annulus of the well with air, which flowed water to a 500-gallon head tank located near the control room trailer. A small booster pump was used to supply the control room trailer. If needed, large quantities of water could be supplied directly at about 80 psig. As this water had been contaminated by algae, bottled drinking water was used. Fire protection was provided via manual extinguishers, and could be supplemented by pumped fresh water.

4.14 WASTE WATER DISPOSAL

There were no waste water facilities which would permit direct disposal at the site. Waste water, brine from sampling systems, etc. had to be contained in surface tankage, and then transported via vacuum truck to a nearby approved disposal site. Sanitary wastes were treated and discharged on site.

4.15 CONTROL ROOM TRAILER

Process monitoring and control operations were centered in a 44-foot x 12-foot control room trailer, from which the Operators and Site Operations Manager worked. All of the panel-mounted instruments described previously under Instrumentation were contained in this trailer. A separate conventional trailer served as the site office.

4.16 SITE LABORATORY

A small skid-mounted portable laboratory constructed from a transport container was on-site near the control room trailer. The laboratory, which measured 8-feet x 11 feet, contained laboratory bench tops and cabinets, electrical outlets, running water and a sink.

Simple analytical tests on brine samples (e.g., pH, alkalinity, chloride, suspended solids, total dissolved solids, etc.) could be performed daily (at least initially) by the Operators. The laboratory was also available as required for use by other organizations working at the site.

4.17 MODES OF OPERATION

Maximum flexibility of testing operations was designed into the surface facilities. The following modes of flow testing operations were conducted.

- Test Well Direct to Surface Tankage
- Test Well Direct to Disposal Well
- Test Well Through Filters to Surface Tankage
- Test Well Through Separator to Disposal Well (Bypassing Filters)
- Test Well Through Separator and Filters to Disposal Well.

4.18 SAFETY

The principal mode of well safety was via automatic shut-in of the master valves on loss of power, loss of air, or certain out-of-range process variables. Operator intervention was not required. Some of these shut-ins were manually bypassed during start-up.

When the ESD valves were blocked, for example during wire line operations, the blocking action could be removed remotely via cable-actuated valves.

A permanent kill line was installed, so that mud could be added to the system at a distance from the wellhead.

4.19 GAS-WATER RATIO MEASUREMENTS

In all of the geopressed-geothermal wells tested to date, there have been questions as to whether the brines were undersaturated, saturated, or supersaturated with respect to methane gas. This question arose at Sweet Lake as well, primarily during the early part of the Testing Phase when faulty equipment yielded an unexpectedly low methane content.

Wet gas/water ratios of 13-15 SCF/B were reported during early testing (June - July, 1981) of the Sweet Lake well; in fact, a value of 8.5-9 SCF/B was reported during the Initial Flow Test in mid-June (Plate I). These early gas/water ratio measurements were determined to be erroneously low through a systematic study of both gas and brine measurement mechanisms.

4.19.1 GAS MEASUREMENTS

Early gas production measurements were made using concentric orifice plates and strain-gauge differential pressure instrumentation. The gas production rates thus determined were not initially considered suspect because consistent (albeit low) measurements were obtained using several orifice plates of different bores, as well as different differential pressure instruments calibrated at several different ranges. A detailed analysis of this topic were presented in Appendix 6-1.

However, a Rockwell positive displacement meter was installed for gas rate measurements on July 29, 1981 (Plate I), and measurements thus obtained were about 113% higher than those obtained with the orifice plates. The positive displacement meter was then removed, tested, and found to be accurate to within about 1%. The gas measurements with the orifice plates were thus determined to be erroneously low.

Inspection and systematic study of all components of the orifice plates-differential pressure instrumentation systems demonstrated that the measurement errors were attributable to the following:

Calculation Errors	- 12%
Improperly Designed and Constructed Orifice Plates (Plates not beveled to create proper sharp knife-edge)	- 27%
Steam Condensation Upstream of Orifice Plates	- 61%

The orifice measurement problems at Sweet lake have included precise orientation, flow direction, dimensioning, mechanical problems, and two phase flow peculiarities.

Comparitive wet gas/water ratios determined using both orifice plates-/differential pressure instrumentation and positive displacement meters for gas rate measurements, and turbine meters for brine measurements are given in Table 4-2. It should be noted that the ratios given in Table 4-2 are production wet gas/water ratios, and that gas lost in the brine to the disposal well (about 2-3 SCF/B at 300 psig separator pressure - refer to Figure 4-11) must be added to arrive at the total gas/water ratio.

4.19.2 BRINE MEASUREMENTS

Brine flow rate measurements were made with a Halliburton turbine meter which was piped upstream of the separator to obtain immediate flow response from the wellhead, and to avoid the time lag down-stream of the separator. Unfortunately, full stream flow (i.e., free gas and dissolved gas in addition to brine) was measured up-stream of the separator.

The indicated full stream flow rate was determined to be about 26-44% higher than the brine flow rate from the separator (refer to Table 4-1). This erroneously high indicated flow rate when used in gas/water ratio calculations will result in ratios of 5-6 SCF/B lower than the actual ratios.

Calibration test run data for the Halliburton turbine meters utilized for brine flow rate measurements are given in Table 4-1. It can be seen from these data that the turbine meters when measuring brine only are accurate to within less than 1%.

Samples were sent to Weatherly Laboratories for recombination studies. The results indicated that the brine should contain 34 SCF/B at saturation, which would mean that the Sweet Lake brine was undersaturated. The theoretical curves of Blount, Haas, and others, however, indicate that the Sweet Lake brine was saturated with respect to methane. These curves probably represent more an order of magnitude rather than a precise value, and so cannot be used to determine whether or not the brine was saturated. These data can be viewed in two ways. First, if the Weatherly data are accepted, the Sweet Lake brine was undersaturated. Alternatively, there are some, particularly at IGT, who view the Weatherly data with some skepticism. Their studies indicate that the Sweet Lake brine was at or near saturation. See Appendix D.

4.20 PROPOSED SURFACE GENERATING SYSTEM

Because the produced natural gas had CO₂ and H₂S concentrations in excess of pipeline standards, and because the cost of gas treatment equipment was not economic, no gas was ever sold from Sweet Lake. Instead MG-T proposed installation, at its expense of a hybrid power plant. This plant would burn produced gas as in an internal combustion reciprocating engine. The engine would drive an electric generator, and in addition, waste heat from the engine (both exhaust and cooling water) would be added to the separated brine

and input to an Organic Rankine Cycle system.

However, DOE had made up its mind to terminate the Sweet Lake Project, and the proposal was forthwith rejected. The bladeless turbine to utilize pressure energy was never tested.

5.0 RESERVOIR TESTING

The Miogypsinoides sequence in the Sweet Lake test well contained seven sands. Two of these sands, 5 and 3, were tested, in that order. In each case a short initial clean-up flow was followed by a build-up test. A reservoir limit determination test was then conducted. When this test had been run long enough to observe reservoir barriers, the downhole pressure testing equipment was removed. The well was then put on long-term production at various rates (Plates I and II).

5.1 PRELIMINARY OPERATIONS

5.2 SAND ZONE 5.

Sand 5 was selected as the first zone to be tested, primarily because of the abnormally high permeability. This sand, as shown in Figure 5-1, is separated from the other sands in the Miogypsinoides sequence by shale both above and below. For these reasons, this sand was thought to be ideal for the first test.

Information concerning this well was supplied to Ken Davis and Associates in order to obtain their recommendations on the perforation interval. Their recommendations agreed with that made by MG-T, to perforate and test only the one sand initially.

The original plan for completion of the test well, as specified in the Drilling and Testing Plan of July 1980, was to complete in the lowermost sand of the Miogypsinoides sequence, unless wireline log data and/or core analysis suggested otherwise. As noted above, Sand 5 (15,387-15,414 feet) did have porosity and permeability far superior to any of the other sands. These parameters indicated that Sand 5 would contain about 50% of the total hydraulic capacity of the Miogypsinoides sequence. Sand 5 also appeared to be relatively discrete in relation to the remaining sands. The lack of communication between this sand and the other sands would help to ensure reliable reservoir performance testing. Following extensive discussion, the decision was made to perforate and test initially the one interval.

Sand 5 was perforated on June 16, 1981 with a Schlumberger Hyperdome gun at 4 shots per foot. The completion efficiency, as calculated by Reservoir Engineering Consultant J. Donald Clark, was 97%. The original reservoir pressure was 12,052 psia, the initial surface pressure 4,749 psia, and the original reservoir temperature 299° F.

5.2.1 INITIAL FLOW TEST

The Initial Flow Test was planned for a period of approximately two days and was intended primarily to clean the test well, to determine that the disposal well would accept brine, and to demonstrate that all surface facilities were operating properly. The test began at 6:18 p.m. on June 19, 1981, and ended at 8:04 p.m. on June 22, a total of 3.03 days. Part of the design criteria for this test was a constant flow rate to facilitate reservoir interpretation.

During this time, 10,574 barrels of brine were produced, at an average rate of 3,444 B/D. The variation in the flow rate (2,820-4,680 B/D) was due primarily to restrictions in the disposal well which necessitated diverting the flow to the blowdown tanks. Acid treatments improved the flow restrictions in the disposal well, and there was no further pressure build-up in the disposal well (Plate I).

Reservoir Data Inc., equipment and personnel were on site during the Initial Flow Test and Reservoir Limit Test to measure and record bottom-hole and surface pressures in the test well. This information was used by Reservoir Engineering Consultant J. Donald Clark, (Appendix C) and Intercomp Resource Development and Engineering, in reservoir engineering calculations. These calculations (Figure 5-2) indicated that the radial exploration of the reservoir during this initial test reached 7,810 feet. A first approximation of water permeability was 339 md, fairly close to the predicted value of 400 md. Two permeability barriers were noted during this test, at 452 feet and 1,153 feet from the well bore. Indications of the barriers can be seen in the drawdown curves in Figure 5-3 and 5-4. A preliminary interpretation of these barriers concluded that they may be the major sealing faults, sand pinchouts, thinning, minor faulting, or simply a decrease in permeability. The most unlikely explanation was that the barriers were the major faults; subsequent testing confirmed that this explanation was not reasonable.

The first measurements of gas production rates yielded an estimate of dissolved methane content of 7-8 SCF/B, indicating that the brine was grossly undersaturated with respect to methane gas. A wet gas/water ratio of 25-30 SCF/B had been expected. However, these first measurements were proved to be greatly in error due to metering problems. Both brine and gas samples were taken during this test for analysis.

Before the Initial Flow Test, concern had been expressed about possible vertical elevation changes in the test wellhead, disposal wellhead, and separator as these systems were heated by flowing brine. The three systems were monitored with a transit during this test, and no elevation changes were detected. The temperature of these systems reached 215° F.

A detailed chronology of events of the Initial Flow Test is presented in Appendix A.

5.2.2 BUILD-UP TEST

At the conclusion of the Initial Flow Test, the test well was shut in prior to beginning the longer Reservoir Limit Test. This build-up period allowed the reservoir to return to near-original pressure which was important for reliable reservoir engineering calculations. Additionally, the build-up itself provided data useful in reservoir interpretation.

The bottom-hole pressure in the test well had decreased to 11,141 psi at the end of the Initial Flow Test and the start of the Build-up Test. At the end of the eight-day build-up test, on June 30, the reservoir pressure had increased to 11,974 psi. This was 78 psi less than the original pressure. The rate of pressure build-up can be seen on the plot in Figure 5-5, and also in Plate I. The rate of pressure increase had become minimal after eight days, and it was determined that the reservoir would not return to original pressure in the near future, if at all. Accordingly, the Reservoir Limit Test commenced on June 30, 1981.

5.2.3 RESERVOIR LIMIT TEST

The Reservoir Limit Test was intended primarily to attempt to determine the limits of the geopressed-geothermal brine reservoir at Sweet Lake. This information was necessary to determine the economic potential of long-term production. The reservoir is limited on two sides by major faults, which had been documented through well log and seismic interpretation. A third major fault that would enclose the reservoir to the west, had been postulated, although there were no well log data to support this postulation. If the fault did exist, however, its effect would have been observed within 10 to 20 days during the test. The absence of this fault would therefore indicate the presence of a large reservoir.

The Reservoir Limit Test began at 6:15 p. m. on June 30, 1981 and ended at 5:00 p.m. July 17, a total of 17 days. The average flow rate was 13,350 B/D, and approximately 226,300 barrels of brine was produced. The flow rate varied from a high of 16,000 B/D at the start of the test to near 10,000 B/D at the end. The decrease in the flow rate was due to the nearby barriers, which restricted the flow. The average flowing temperature during the test was 265° F. The bottom-hole pressure dropped from 11,974 psi to 7,804 psi (Plate I). This was equivalent to a surface pressure of approximately 700 psi. The surface facilities did not function with greatest efficiency at wellhead pressures of less than 700 psi. This was considered to be the lowest desirable pressure, and the flow rate was reduced accordingly to maintain this pressure.

RDI personnel and equipment were on site continually throughout this test. Bottom-hole pressures were measured using a Hewlett-Packard quartz gauge. Data collected by RDI were then used to calculate effective permeability, skin effect, completion efficiency, and distance to barriers.

5.2.4 LONG-TERM TEST

The purpose of the originally planned long-term testing was to demonstrate that brine could be produced at relatively high rates (around 40,000 B/D) from a geopressed-geothermal well on a sustained basis, that natural gas dissolved in the brine can be recovered, and that the brine can be disposed of at these high flow rates in shallow aquifers.

It was evident from the results of the Reservoir Limit Test that Sand 5 alone could not sustain a production rate of 40,000 B/D for any significant length of time. Perforation of additional sands to attain this rate was not a viable alternative at the time, and thus the decision was made to continue testing Sand 5 at variable rates. Documentation of the daily flow rates and surface pressures is presented chronologically in Appendix A, and in Plate I.

The long-term testing of Sand 5 continued for 208 days, from July 17, 1981 to February 10, 1982. The flow rate during this time varied considerably, from a high of 38,000 B/D to a low of 1,000 B/D. Approximately 1.1 million barrels of brine were produced during this test. The test well had been shut in only for routine maintenance up until February 10, when the disposal well suddenly sanded up and would not accept brine. It is probable that this sanding up was due to backflow resulting from brief periods of shutting in the test well to test new operators and train.

A low range positive displacement gas meter was installed at the flare because of early measurement problems with orifice plates. Orifice meter calibration was also a difficulty magnified by two-phase, multi-component flow.

During this long-term production period of more than seven months, most of the purposes of the designed Long-Term Test were met. Funds were very restricted during most of this time, however, which necessitated operation at only 5,000 B/D in order to "preserve the well." The short periods of high flow rate demonstrated that the surface facilities and disposal well were capable of handling high flow rates.

Approximately 20 SCF/B of methane gas were recovered from the brine during this test and flared (Plate I). The recovery of dissolved gas was more than adequately demonstrated.

5.3 HIATUS IN OPERATIONS

From February 10, 1982 to November 11, 1983 the Sweet Lake production well was shut in. At first, the shut-in was necessitated by the fact that the disposal well had sanded up. In March and April of 1982 the disposal well was cleaned and reperforated. Immediately after the reperforating, however, a leak was detected in the test well tubing. Flow testing could not be resumed until the cause of the leak was identified and rectified.

During this time meetings were held to discuss the future testing of the Sweet Lake reservoir. One question that was of great interest at the time was whether different sands in a sequence such as the Miogypsinoides would have significantly different chemical characteristics and different associated gas content. Differences would indicate that the sands were indeed discrete throughout the reservoir, whereas the same chemistry would indicate that there was communication between them.

The ultimate goal of Sweet Lake reservoir testing had been to perforate all sands in order to achieve maximum flow rate. Therefore, plugging off sands and testing them individually was rejected as an option at this time. An

alternate scenario was devised by Intercomp Resource Engineering and Development to obtain a pure sample from a second zone while two zones were open. This proposed test was based on the idea that if the first zone produced brine at a high enough flow rate to draw down the bottom-hole pressure substantially, and if the second zone was perforated immediately following this drawdown, the brine production from the well would come initially from the second zone. The difference in reservoir pressures would be enough to prevent brine from the first zone from reaching the surface for a period of up to 14 days, depending on the flow rate.

The first and second zones referred to were Sands 5 and 4, respectively. Sand 5 had been perforated and tested, and it was proposed to perforate Sand 4 (15,305 to 15,355 feet) immediately following a drawdown of Sand 5. Figure 5-6 illustrates Intercomp's suggested procedure for flowing prior to perforation of Sand 4. At the time this procedure was suggested, the well was flowing at 2000 B/D, which was allowing a build-up of formation pressure. Intercomp's scheme was to shut in the well for four days prior to perforation, in order to set up the perforation gun. Following the shut-in, the well would be flowed for four days at 15,000 B/D in order to draw the well down to approximately 7800 psia bottom-hole pressure.

Figure 5-7 shows Intercomp's calculation of how long Sand 4 would be able to flow without interference from Sand 5 (the "first zone"). An initial bottom-hole pressure of 7900 psia was used. The time to first zone flow was calculated for four flow rates; 500, 1000, 1500, and 2000 B/D. Any of these flow rates would evidently provide enough time to analyze the flow from Sand 4. Since Sand 4 has a much lower permeability than Sand 5, it would hold a higher pressure for a longer time, thus restricting the original sand from flowing.

This scenario was never tested. The well was shut in due to disposal well problems and a subsequent tubing leak in the production well. When these problems were resolved, and perforation of the new zone was approved, it was discovered that the production well had had a backflow of sand, and that both Sands 5 and 4 were now blocked by sand. During remedial work using a small rig, more tubing leaks were discovered, which necessitated employing a large rig to pull the tubing. The new PBTD of the well was 15,351 feet. The lower zones were then blocked with a bridge plug, and Sand 3 was perforated on November 11, 1983.

It was subsequently concluded that the above calculations could not be reproduced.

5.4 SAND ZONE 3

Sand 3 was selected to be perforated primarily by default. All zones beneath this were unavailable, and the remaining zones had more or less comparable porosity and permeability. The lowermost of the three remaining zones was chosen for testing so that the remaining two sands (upper sands) would be available for testing later, with no danger of being blocked off by sand from Sand 3.

This zone was perforated in two intervals, the first from 15,260 to 15,280 feet, and the second from 15,245 to 15,255 feet. The original reservoir pressure was 11,887 psia (15,245 feet), the initial surface pressure 3,660 psia, and the original reservoir temperature 293°F.

5.4.1 INITIAL FLOW TEST

The Initial Flow Test was planned for a period of 24 hours, primarily to clean the well and to ensure that the disposal well was accepting brine properly through its new perforations. Reservoir Dynamics, Inc. (RDI) equipment and personnel were onsite, and rigging up for downhole pressure and temperature measurement began immediately after perforation.

The well was opened up at a rate of 2800 B/D at 11:50 a.m. on November 12. At first, the flow was into the blowdown tanks. After "bottoms up" had been reached, the flow rate increased to 4000 B/D. The first formation brine out of the well was quite clean, without traces of drilling mud or sand production (Plate I).

The brine production was diverted to the separator and back to the blowdown tanks at about 8:00 p.m. on November 12. The separator system was started up at a pressure of 300 psig with production gas being burned in the flare. Brine production was switched from the bottom of the separator to the disposal well at about 10:00 p.m. November 12. The disposal well functioned successfully, with a wellhead pressure of only 35-40 psig at a brine production rate of 4,000 B/D.

The Initial Flow Test was concluded at 11:50 a.m. November 13, at which time the well was shut in. The first results from this test indicated that the flow from this zone would be very restricted. The bottom-hole pressure decreased from 11,883 to 10,133 psia with a flow rate of only 4,000 B/D during 24 hours. Obviously, the well could not sustain even that rate for any significant period of time.

5.4.2 BUILD-UP TEST

The Build-up Test of Sand 3 began at 11:50 a.m. November 13, 1983. A leak was detected at 7:00 p.m. on pressure instrumentation piping external to the wellhead. The downhole equipment had to be removed in order to repair this leak, which was accomplished on November 14. Downhole equipment was not rigged up again until November 21, so that measurement of the downhole pressure build-up was not made. Reservoir engineering calculations thus could not be made on this part of the test.

This test concluded at 8:50 a.m. November 22, for a total of 9.875 days. The bottom-hole pressure had returned to 11,794 psia, which was 93 psi lower than the original reservoir pressure.

5.4.3 RESERVOIR LIMIT TEST

The results of a second reservoir limit test on a sand in the Mio-gypsinoides sequence were important to compare to the first. It was hoped that the results of this test would resolve some of the questions raised by the first test. The barriers observed during the first test were thought not to be the major faults, but rather some minor faults or other sort of barrier. Would a second sand in the same sequence have barriers in the same places? If so, it would tend to confirm that the barriers were perhaps faults, which affected the entire sequence. If not, then perhaps the barriers were stratigraphic.

ation imposed; that is, pinchouts or permeability variations that differ between individual sands. If the barriers were different, then the shape of the total Miogypsinoides reservoir would be very complex, as each individual sand would have a different shape. There were also questions that concerned the chemistry of the brine. Would the chemistry of the brine be the same in the two sands, and, indeed, should it? It was possible that there would be differences that would point to a lack of communication between the two sands.

The Reservoir Limit Test commenced at 8:50 a.m. November 22, and concluded at 7:30 a.m. December 7, when RDI was released, a total of 15 days. The data collected by RDI was provided to the reservoir engineering consultant for interpretation. However, the behavior of Sand 3 precluded any rigorous calculations. The drawdown curve, shown in Figure 5-8, shows that there are no reliable straight-line portions. Radial flow was not achieved, and so permeability could not be calculated.

This test of Sand 3 can actually be divided into two separate phases. The Primary Drawdown Phase, from November 22-29, was an essentially constant-flow phase designed primarily to determine the limits of the Sand 3 reservoir. The downhole pressure dropped from 11,794 to 10,065 psia in that seven-day period (Plate II). The brine production rate was essentially constant, at 2,046 B/D, for a total production of 14,322 barrels. The wet gas/water ratio was 24 SCF/B.

The second phase, the Reservoir Depletion Phase, was actually a combination of the second half of the Reservoir Limit Test and all of the Long-Term Test. Downhole pressure and temperature measuring equipment remained in place for the first eight days of the Reservoir Depletion Phase. The information gathered during this time was used by reservoir engineers to match reservoir behavior. The brine production rate was varied during this phase in order to study gas composition as a function of reservoir pressure. The average production rate during this phase was 2,684 B/D.

5.4.4 LONG-TERM TEST

The Long-term Test can essentially be thought of as the Reservoir Depletion Phase, as described above. Downhole pressure measuring equipment was removed on December 7, 1983. The well continued to produce brine at relatively low rates until 6:44 p.m. on March 13, 1984, after 114 days of testing. The shut-in was not necessitated by any mechanical or reservoir conditions, but rather by economic ones. A total of 276,608 barrels of brine had been produced from Sand 3 at that time, a total of 122 days. This period, along with the long-term production testing of Sand 5, demonstrated that all surface facilities operated properly, and that dissolved methane could be removed from the brine effectively. Other types of testing had been planned, including perforating all zones to achieve high flow rates and using the brine directly, or the heat from the brine, to grow aquatic cultures such as shrimp or fish, but the lack of funds prohibited this.

A chronology of the Testing of Sand 3 is presented in Appendix B.

5.5 RESULTS AND CONCLUSIONS

The reservoir testing was designed primarily to determine the shape and permeability of the reservoir; i.e. how long would the reservoir produce brine and at what rates. The calculations pertinent to those determinations were those of distance to boundaries, effective permeability, and initial water in place.

5.5.1 BOUNDARIES

During the Initial Flow Test of Sand 5, the radial exploration of the reservoir reached 7,810 feet. Two permeability barriers were observed, at 452 feet and 1,753 feet from the wellbore. The reservoir was explored to a radial distance of 22,467 feet during the Reservoir Limit Test of Sand 5. Permeability barriers calculated during this test were interpreted to be 318 feet, 645 feet and 1,289 feet from the wellbore. It is difficult to say which of the barriers of the Initial Flow Test matched which of the barriers of the Reservoir Limit Test, which only emphasizes the degree of inaccuracy and leeway in interpretation that is involved in these calculations. However, both sets of results indicated that there were barriers much closer to the well than had been expected.

The location of these barriers indicated that the reservoir was more or less pie-shaped, with a flow angle of 25° (Fig. 5-10). While the reservoir was restricted in two directions, it was thought to be open an unknown distance in the third direction. This direction was interpreted as being to the northwest, which would match more closely the original geologic interpretation. Since no enclosing barrier was observed, the postulated fault to the west apparently did not exist.

Confirmation of the reservoir shape was made by Intercomp. Computer history matches of the drawdown and build-up tests were made, and a good match was achieved with a flow angle of 26° . Equally valid matches, however, could be made using different assumptions. As mentioned previously, a reliable interpretation could not be made of the tests made on Sand 3. Since the well never achieved radial flow, there was no straight-line portion of the drawdown curve. This meant that calculation of the permeability was impossible, which in turn meant that the distance to barriers could not be calculated. Computer matches could be made, however, mainly by trial and error, to simulate the drawdown behavior. Dowdle Fairchild and Ancell made such a computer history match. The seven-day constant flow test of Sand 3 was used in this analysis. The variable parameters in the history match were reservoir permeability, distance to the faults, and angle of the faults. The conclusion of this computer simulation was that there were two barriers (faults), each 225 feet from the well. The flow angle in this case is 60° . Again, the reservoir was interpreted to be pie-shaped, and open to the west.

There is an equally valid alternate description. The above description, with two faults 225 feet from the well and open at an angle of 60° , assumes that the rock properties are constant throughout the reservoir. As there is no geological reason why this must be so, a second description can be made based on varying rock characteristics.

(In fact, it is highly likely geologically that rock parameters vary to some degree). This second model assumes that there is a change in permeability 175 feet from the well. The computer simulation using this description fits the data equally well as does the first interpretation.

The conclusions of the testing of both Sands 5 and 3 are that there are barriers in the reservoir, close to the well bore. The nature of the barriers, whether due to faulting or a permeability decrease, for example, cannot be determined from the reservoir engineering data. An interpretation must be made on the geologic reasonableness of the descriptions.

5.5.2 EFFECTIVE PERMEABILITY

The permeabilities that were expected in each of the seven Miogypsinoïdes sands have been discussed in Section 3.5 Petrophysical Analyses. Actual versus estimated permeabilities are shown in Table 3-4. An approximate permeability to water was estimated, which was fairly close for Sand 5. In this case, the estimate for K_w was 400 md, while the permeability calculated from reservoir engineering was 339 md.

The comparison for Sand 3 was not as good. A water permeability of 140 md had been estimated. The permeability used in the successful computer simulation, however, was only 42 md, an order of magnitude lower. If the alternate reservoir description is accepted, the permeability drops from 42 md to 7 md at a distance of 175 feet from the wellbore. Thus there is a large disparity between the estimated and effective values for Sand 3. Part of this discrepancy is probably due to the fact that no core was taken from Sand 3, so a measured air permeability could not be used to estimate water permeability. The Saraband log was used to estimate permeability, and any log calculation of permeability is unreliable. Therefore, the computer history match value of 42 md may be close to the actual value of permeability for Sand 3.

5.5.3 INITIAL WATER IN PLACE

During the Reservoir Limit test of Sand 5, some 300,000,000 barrels of water in place were explored. Assuming a porosity of 22% (an average of the values in Table 3-3), and assuming that the reservoir thickness remains constant at 27 feet, Sand 5 covers an area of approximately 11,330 acres. Obviously, since no enclosing boundary was detected, the reservoir is larger than this.

The Reservoir Limit Test of Sand 3 explored about 20,000,000 barrels of water. Since this sand had a much lower permeability than Sand 5, the same length of testing explored a much smaller area. It is probable, however, that Sand 3 approaches the same areal extent as Sand 5.

An approximation of the total water in place can be calculated, although it must be emphasized that this is only an approximation. The model assumes that the sand thickness remains constant, which may or may not actually be the case. Assuming that each of the seven sands

cover an area of 10,000 acres, and using the thickness and porosities in Table 5-1, the total water in place is 1865.2 MM bbl. There are many drawbacks to this calculation, such as the fact that the reservoir thickness may not remain constant, or the porosity may change, or not all sands may extend for 10,000 acres. However, assumptions must be made in order to approximate the water volume, and these assumptions are reasonable under the circumstances. This calculation gives an estimate of the water in place, but of course only a fraction of this is recoverable.

5.5.4 ADDITIONAL INTERPRETATIONS

J. Donald Clark (Appendix C), Intercomp Resource Development and Engineering, and, later, Dowdle Fairchild and Ancell (Appendix E) worked directly under the auspices of MG-T. Other interested parties, not working for MG-T, also analyzed the reservoir engineering data and made interpretations. Two of these are Systems, Science, and Software (S-Cubed) and the University of Texas. These interpretations are discussed in the following sections.

5.5.4.1 S-CUBED

The interpretation by S-Cubed was based on analysis of the build-up data of the Sand 5 test. The reservoir characteristics determined from this analysis were used in the reservoir simulator MUSHRM to history match the drawdowns of the Initial Flow Test and Reservoir Limit Test. The conclusions reached were much different than those of Clark and of Intercomp and DFA. A complete discussion of how these conclusions were obtained can be found in Garg (1982).

S-Cubed states that there is a zone of relatively high permeability (162 md) near the wellbore, but that this extends only to a radius of 200 feet from the wellbore. The far field permeability is quite low, only 11.9 md. The claim is made that no barriers were observed during the drawdown tests. Obviously, if these lower permeabilities are correct, the radial distance explored and volume of water explored will be correspondingly lower.

This description of S-Cubed parallels the alternate description of the Sand 3 test made by Dowdle Fairchild and Ancell, which has been discussed in a previous section. It appears that valid computer simulations can be made using a variety of interpretations. For simplicity, the interpretation which involves a high near-wellbore permeability and a low far field permeability will be referred to as the "permeability description." The interpretation that proposes the existence of faults and constant permeability will be referred to as the "fault description." The validity of the two opposing descriptions is discussed in Section 5.5.5 Reservoir Description.

5.5.4.2 UNIVERSITY OF TEXAS

An analysis was made by Andrade et al (1982) on the same Sand 5

test. This analysis concluded that the permeability was constant but low, 17.1 md. Again, no barriers were interpreted. This analysis accepts the position of the major bounding faults of the graben, approximately 1 mile on each side of the well, and further states that to see the effects of these faults as a slope change on a pressure drawdown curve would take more than six months.

There are some discrepancies in the data used for this study, however, which may render the conclusions invalid. A gas content of 11 SCF/B was used to determine fluid properties, while the actual content was more than twice this amount. Also, this analysis basically ignores the early flow time data, which is important in barrier determinations. This report is not useful in the interpretations of the Sweet Lake reservoir because of these discrepancies.

5.5.5 RESERVOIR DESCRIPTION

Two distinct sets of interpretations have been made on the flow tests of Sands 5 and 3, and have been termed the fault description and the permeability description. The fault description is the primary interpretation made by the reservoir engineers working directly for MG-T. They also proposed an alternate description, which correlates with the interpretation made by outside engineers; this is the permeability description.

The fault description maintains that the restriction of the reservoir (both Sands 5 and 3) was caused by faults. The faults limit the angle of flow, and the reservoir was essentially wedge-shaped, open an unknown distance in one direction. These faults are 225 feet from the wellbore in Sand 3 and approximately 160 feet from the wellbore in Sand 5. The faults would thus intersect the well just below TD (Figure 5-9). The faults must be oriented as shown in Figure 5-9 as there was no indication of a fault crossing the well either from the drilling or log data.

There are problems with this interpretation, however. It required that the throw on the faults be such that sands do not match up on either side, or that the faults acted as seals. It also seems too coincidental that the well could have been drilled exactly midway between two faults. These problems provided the reason for the alternate description.

The permeability description involves a change in rock properties. Instead of a constant permeability with faults restricting the flow, this interpretation states that there was higher permeability near the well, but low permeability further from the well. This permeability change occurred at 175 feet from the wellbore in Sand 3 and 200 feet from the wellbore in Sand 5. In that respect this was the opposite of the fault description because the area of high permeability widened with depth instead of narrowing. However, it must be noted that a difference of 50 feet one way or the other is probably within the limits of accuracy of the calculations. The barriers were essentially vertical in either description.

Geologically, this description was as accurate as the fault description. There was no reason to expect permeability to remain constant throughout a reservoir; in fact, it probably constantly changed. The high measured permeabilities seem to contradict the low calculated values, but this may have been due to inaccuracies in estimating water permeability from air permeability, and the fact that the estimated values did not account for stress.

Again, however, there were some aspects to this description that do not seem reasonable. It seems too much to expect that the well managed to penetrate both sands in the high permeability zone, and that this zone had almost the same radius in both sands. It is difficult to picture a depositional environment in which this would occur. In this respect, faults are much easier to explain. The area surrounding the test well was highly faulted, and the test well itself was in the center of a graben bounded by major faults with hundreds of feet of throw. It was entirely reasonable to expect that there would be minor faulting associated with these major faults. These minor faults would probably not show up on the seismic lines, because the displacement would be short in comparison to the wavelength of the seismic waves. There was the problem of the well being in the exact middle of the two faults, but perhaps the limits of accuracy of the calculations would allow some leeway in the placement of the faults.

One interpretation could not be conclusively chosen over the other at this point in time. Computer simulations of drawdown tests using each of the two reservoir descriptions matched the actual data equally well. Data from the other sand zones may have helped to resolve this question. If one description of the reservoir had to be chosen, the most likely interpretation is the fault description. Minor faulting fitted in well with the geologic setting of the surrounding area, and the fact that the barriers moved closer to the well with depth also supports this theory. The reservoir would thus have been bounded on two sides by faults and open in one direction, to the west. An enclosing boundary for the reservoir was not observed.

The actual geology of the reservoir at Sweet Lake was probably much more complex than that which has been modeled. It is quite likely that aspects of both reservoir model descriptions were actually present in the reservoir.

6.0 CHEMICAL ANALYSES

The chemical and physical analyses of fluids from the Sweet Lake well were carried out by several independent groups: the Magma Gulf-Technadril plant operations staff, Professors Hankins and Karkalitz of McNeese State University, Professor Mason Tomson of Rice University and Professor Jack Matson of the University of Houston, Weatherly Laboratories, Institute of Gas Technology, and Scientific Consulting and Analysts.

One of the original testing objectives of the Sweet Lake Project and indeed of the entire geopressure program was to "characterize" the resource - what are the physical and chemical properties of the geopressured brine and associated gas. It must be noted that there was not a separate "chemical testing program" but rather that the resource was produced, and sampled and analyzed during production.

Sampling and analytical testing of brine and gas samples were performed using frequency, specific analyses, equipment, methods and techniques given in "Standard Sampling and Analytical Methods for Geopressured Fluids", prepared by McNeese State University, September, 1980, B.E. Hankins, Editor.

The objectives of chemical testing at Sweet Lake were to:

- determine brine chemistry
- determine gas chemistry
- determine the ratio of produced gas to produced brine
- determine the degree of gas saturation in the reservoir brine
- determine any changes in these properties with time or production
- provide input for the scaling and corrosion control programs
- optimize gas recovery

It is important in understanding the chemical testing results to review the overall testing scheme as described below.

The initial flow period from Sand Zone 5 was from June 1981 through February 1982. Very early results during June 1981 showed a very low (less than 10 standard cubic feet per barrel of brine) gas to water ratio. Although it was later established that these gas to water ratio measurements were too low by a factor of about 3 - see Appendix G for details, nonetheless, important testing decisions were made based on these inaccurate conclusions. The impact of such information was critical, and it became very important to know whether all other zones were similarly undersaturated. Subsequently a scheme that would allow testing of Sand Zone 5 and Sand Zone 3 simultaneously, yet permitting an initial isolated sample of the new brine from Sand 3, was devised as described in Section 4. Plans were made to perforate Zone 3, and by chemical sampling, determine if it was undersaturated similarly to Zone 5.

Before the plan could be implemented, however, some radical changes in instrumentation were made confirming a much higher gas content (of 25 standard cubic feet per barrel) than had been previously measured. Furthermore, the DOE determined that funds were too short to permit further mechanical work, and the flow was curtailed from August 1981 through February 1982, at which time the disposal well sanded up. Insufficient

funds to fix the well were available so it remained non-operational until August 1983. At that time, the production well was repaired in November 1983 and Sand Zone 5 was plugged off without further testing, and Zone 3 was perforated and tested instead.

The November 1983 test of Zone 3 was intended to be quite short since its flow potential was known to be small. The principal purpose was to verify whether Zone 3 and Zone 5 were similar in chemistry and methane saturation and in reservoir geometry. The approved plan was, in a few weeks to open all sands and examine their joint flow potential.

However, as soon as the well had been repaired in December 1983 and flow resumed, the DOE became aware of further funding problems, and advised MG-T that other tests would not be conducted. Instead, the flow from Zone 3 was continued at a low level until plugging. Thus, from a chemical test point of view, important results were achieved, but a comprehensive test was not accomplished.

6.1 BRINE ANALYSIS

Results have been reported previously in the Proceedings of the Fifth Geopressured-Geothermal Energy Conference, 1981.

This section will discuss the chemical analyses of the brine and gas produced, with particular emphasis on the relation of these analytical results to the solubility of methane. (Scaling and corrosion, and the inhibitor system designed to prevent them, were discussed in Section 4.0.) The results of these analyses are presented in Table 6-1. Karkalits and Hankins (1981) have noted that the calcium concentration is high compared to other geopressured-geothermal wells, and thus indicates a potentially severe scaling problem. The high concentration of total dissolved solids lowers the solubility of methane in the brine. The amount of dissolved methane was, in fact, lower than the value predicted before testing, primarily because of the higher concentration of dissolved solids. These sample analyses were confirmed by independent measurements made by Matson and Tomson, MG-T operators, and IGT personnel. It should be noted that analyses made by separate contractors were very consistent, and that the analyses were also quite consistent through time. See Tables 6-1A, 6-3, 6-3 A and 6-4.

Refer to Section 3.5.1.2 of this report for a discussion of brine salinity as predicted from well logs.

6.2 GAS ANALYSIS

The results of the analyses of gas samples are presented in Table 6-2. The gas is, as expected, predominately methane, with minor amounts of other hydrocarbons, 8-10% carbon dioxide, and a trace of H_2S . Most observers would classify the mixed gas as "sweet". This analysis is quite similar to analyses of gas obtained from other geopressured-geothermal wells, except that the low temperature Wells of Opportunity seem to have a lower CO_2 content.

A Beckman process gas chromatograph was shared between Sweet Lake and Gladys McCall sites. Because of maintenance and reliability problems, data gathered from the chromatograph were erratic and only confirmatory in nature.

Another critical chemical problem was the high CO₂ content (ca 9%) in the produced gas. No nearby pipeline company would accept this gas, and it had to be flared for the duration of testing. It should be noted that gas with an equivalent CO₂ content is being sold at Brazoria and at Gladys McCall. Further, the available brine flow rate was too low to justify installation of equipment to reduce the CO₂ content to acceptable levels. The absence of gas sales in essence increased project direct costs, and significantly reduced enthusiasm for the project. Because gas sales could not be achieved, the objectives of the Sweet Lake test program were adjusted. There was no way to optimize CO₂ content for gas sales purposes since all physically achievable concentrations were unacceptable for sale. The objective became to flow as long as possible and to note corresponding differences in chemistry as a result of pressure, temperature, and time. Table 6-2 shows the effects of Zone 3 pressure drawdown, with a seeming increase in CO₂ percentage, and decrease in methane percentage as pressure is reduced from 10,000 psi to 7,600 psi. No correlations with time or temperature are statistically reliable.

A similar analysis of gas and brine composition from Zone 5 is presented in Table 6-2.

It is interesting to note that in the less important chemical species there were differences in brine chemistry composition between Zone 3 and Zone 5, but the differences were not such as to affect solubility, scale or corrosion. It was expected that the chemical composition of the brines would be similar but not necessarily identical. (See Tables 6-1 A and 6-2 A) The relationship of brine pH and alkalinity is presented in Figure 6-1.

The testing program at Sweet Lake produced only preliminary data concerning the topic of "aromatic liquids" which have recently been produced at several geopressured wells. Data is presently being compiled by Dean Keeley at the University of Southwestern Louisiana at Lafayette, Louisiana.

6.3 SOLUBILITY OF METHANE

In all of the geopressured-geothermal wells tested to date, there has been some question as to whether the brine was undersaturated, saturated, or supersaturated with respect to methane gas. This question arose at Sweet Lake as well, primarily during the early part of the Testing Phase when faulty equipment yielded an unexpectedly low methane content. After the metering problems were solved, the methane content ranged from 23-27 SCF/B. This was still lower than expected, although part of this was due to the higher salinity of the brine.

Samples were sent to Weatherly Laboratories for recombination studies. The results indicated that the brine should contain 34 SCF/B at saturation, which would mean that the Sweet Lake brine was undersaturated. The theoretical curves of Blount, Haas, and others, however, indicate that the Sweet Lake brine is saturated with respect to methane. These curves probably represent more an order of magnitude rather than a precise value, and so cannot be used to determine whether or not the brine is saturated. These data can be viewed in two ways. First, if the Weatherly data are accepted, the Sweet Lake brine is undersaturated. Alternatively, there are some, particularly at IGT, who view the Weatherly data with some skepticism. Their studies indicate that the Sweet Lake brine is at or near saturation. This question has not been completely resolved.

Appendix I, Reservoir Fluid Analysis, is the results of analysis of a "recombined reservoir fluid sample" showing that from Zone 3 a gas content of 19.98 SCF/STB corresponds to a bubble point of 8800 psia at the 293°F reservoir temperature. Even at this date, there remains substantial controversy between the Weatherly results and those of IGT described below in 6.5.

6.4 OTHER CHEMICAL ASPECTS

MG-T in-home analysis of the gas water ratio measurements prepared in September 1981. The objective of that analysis is to discuss certain early measurement results at Sweet Lake, some errors in measurement, and the preventive measures taken to preclude further such errors.

Appendix H contains the Weatherly Laboratories analysis of water flash. Two of these analyses of separator water flash at 50 psig and at 250 psig are strikingly different and clearly demonstrate an important result of the geopressure program - namely that gas phase composition is strongly dependent on separator pressure. Table 6-5 presents gas composition as a function of reservoir pressure and Appendix J presents gas analysis as a function of separator pressure.

One could control the relative concentration of CO₂ in the overhead gas. The higher the separator pressure, the more CO₂ stays in solution and the lower its concentration in the overhead gas stream. A clear trade-off then is the total amount of gas per barrel removed in the separator. The lower the separator pressure, the more total gas is removed from solution, but the higher its CO₂ concentration. If one has just single stage separation and no CO₂ removal system, the separator pressure can be reduced to produce the maximum acceptable CO₂ concentration acceptable to the gas sales pipeline.

It has been hoped that there would be some correlation between the geochemical analysis and core analysis performed on cores, and the chemistry of the brine and gas produced. The only correlation made is that the CO₂ present in the gas is related to the carbonate present in the formation. Further, the core analysis concluded that the formation was well cemented and sand production would not be a problem in the test well.

6.5 IGT CONCLUSIONS

- "1. Reservoir brine is probably at or near saturation with natural gas.
- "2. At the times of sample collection by IGT, partitioning of gaseous species between gas and brine outputs for the separator was reasonably consistent with that from separators used on wells of Opportunity tested by Eaton Operating Company and the separators used for the 1980 testing of the Pleasant Bayou Well No. 2.
- "3. Total CO₂ content of produced brine, including bicarbonate ions and carbonate precipitates, is lower than experienced on Wells of Opportunity, as it would be expected due to the high Ca⁺⁺ content of produced brine.

- "4. Partitioning of CO₂ between the gas output of the separator, CO₂ in solution in brine on the disposal well, bicarbonate ions in brine to the disposal well and CaCO₃ precipitates, is dependent upon details of inhibitor injection in relation to separator pressure and temperature.
- "5. Solids retrieved from below perforations in the production well contained about 7 percent by weight plastic lining from the production casing and about 6.5 percent by weight carbonates and other salts soluble in HCl.

"The major significance of the IGT work reported herein is the suggestion that reservoir brine may well be at or near saturation with natural gas. At the same time, this result is not definitive due to lack of precision, time dependent metering of gas and brine flow rates required to establish correlation of changes in total produced gas/brine ratio with the observed changes in chemical composition of produced gas.

"The above conclusion regarding partitioning of gaseous species between separator outputs was qualified as "reasonably consistent" with prior experience. This qualification is due to a) lack of an onsite gas chromatograph and hardware for prompt acid liberation of CO₂ from separator brine samples, b) the discrepancy between quantities of gas liberated from brine samples in the field vs. samples analyzed later in IGT's Chicago laboratory, and c) the change of 70 psi in separator pressure provided to IGT on the basis of calibration of the pressure gauge several days after collection of IGT's last sample.

"Comparison of recombination data by Weatherly Laboratories with expectations from laboratory studies of methane solubility in brine, in the context of prior similar comparisons for Wells of Opportunity, provided a surprising results: Namely, the recombination data points agreed with solubility calculated on the basis of only the NaCl content of produced brine. Differences at actual data points were a maximum of about 3 SCF/STB and consistent with differences observed on Wells of Opportunity. In contrast, expected gas solubility assuming total dissolved solids are equivalent to that weight of NaCl is less than the recombination measurement at 10,270 psia by 7 to 11 SCF/STB.

"During mid August 1981, operator installation of a positive displacement meter and changes in the orifice meter run resulted in about doubling reported gas production rates. However, it is IGT's judgement that accuracy of gas and brine rate measurements is not yet adequate to warrant a conclusion regarding actual produced gas/brine ratio in comparison with the values of 23 to 27 SCF/STB calculated on the basis of 166,500 mg/ of dissolved solids and the range of 31 to 35 SCF/STB calculated from the 117,000 mg/ NaCl content and extrapolated from recombination studies."

Basically, IGT believes that on-site measurements were not sufficiently accurate to determine whether the reservoir brine is saturated with natural gas. Weatherly's findings imply that the brine was undersaturated (contained much less gas than equivalent saturated brine.)

7.0 ENVIRONMENTAL MONITORING

From the inception of the first proposals to test the geopressured-geothermal aquifers of the Gulf Coast region both Gulf Geothermal Corp. and Magma Gulf Co. had been concerned about the effects of such brine production on the environment. In order to determine the effects, if any, Magma Gulf had proposed monitoring the tests to determine the effects of resource testing on subsidence, seismicity, and both surface and subsurface water.

After the contract for the Sweet Lake Project was signed in 1979, Louisiana State University personnel, working under a separate contract with the DOE, began preliminary investigations at Sweet Lake, and then submitted an environmental monitoring plan to the DOE. According to the specifications of the plan, field stations (Fig. 7-5) were established to monitor air quality, subsidence, and seismicity within the Sweet Lake prospect. Additionally, three wells were drilled (Fig. 7-5) to monitor subsurface water, and sampling stations to monitor surface water were established.

7.1 AIR QUALITY

An ambient air quality and meteorological monitoring station was established approximately one mile northwest of the production well site (Figure 7-5).

The air quality monitoring station was installed and operated by Core Laboratories, Incorporated, of Lake Charles, Louisiana on behalf of the State of Louisiana. The instrumentation necessary for monitoring air quality and meteorology was installed by Core Laboratories during July, 1980. The station provided continuous records of hydrogen sulfide, sulfur dioxide, non-methane hydrocarbons, and total hydrocarbons in accordance with previously stated EPA guidelines. The following is a description of instrumentation used to monitor air quality and meteorology at the Sweet Lake test site.

1. Sulfur dioxide (SO_2) was monitored using a flame photometric technique designated as an EPA equivalent method. The sulfur dioxide was measured when the monitor was equipped with a hydrogen sulfide scrubber allowing the measurement of sulfur dioxide in an activated state.
- (2) Hydrogen sulfide was monitored by the same analyzer used to monitor sulfur dioxide, but equipped with a sulfur dioxide scrubber which allows the specific measurement of hydrogen sulfide. This method has been approved by the EPA.
- (3) The monitoring of total hydrocarbons and non-methane hydrocarbons was accomplished by the use of the Meloy Model HC 500-2C Hydrogen Analyzer, which is an approved EPA method. This analyzer uses a flame ionization detector. The analyzer contains a high temperature oxidizer to oxidize non-methane hydrocarbons allowing only methane hydrocarbons to be measured. The analyzer compares the methane hydrocarbons to the total hydrocarbons, determining the non-methane hydrocarbons.

- (4) Meteorological data (wind direction, wind speed, temperature and rainfall) was collected using Texas Electronics equipment. These sensors exceed all EPA specifications for PSD monitoring.

The ambient air monitoring instrumentation conformed to EPA standards and where applicable, instrumentation was designated as reference or equivalent or utilized designed methods of analysis.

Air quality and meteorological data at the Sweet Lake site were reported by Core Labs on a monthly basis. The monthly reports included the following tables and graphs for each of the four pollutants monitored:

- Maximum and average concentrations
- Day of month versus concentration
- Thirty highest 3-hour average concentrations
- Wind direction versus average concentration
- Hourly averages

Sulfur dioxide and non-methane hydrocarbons were the only pollutants monitored for which NAAQS have been established by the EPA.

Neither primary nor secondary NAAQS for sulfur dioxide were exceeded during the six month period. The highest 24 hours average concentration during 1980 was 14 micrograms/in³ reported on September 12. The highest 24 hour concentration during 1981 was 23 micrograms/in³ reported on March 12. The wind direction was generally from the northwest (270° to 360°) when SO₂ was reported. The sulfur dioxide was generally recorded during the day from 7:00 a.m. to 5:00 p.m. Lake Charles, the nearest metropolitan area, is located 12 miles north-northwest (337°) of the site. Sulfur, a smaller industrial center, is located 18 miles northwest (315°) of the site.

Standards for non-methane hydrocarbons were exceeded on an average of four days each month in 1980, and twenty-three days each month during January and February 1981. The highest concentrations of non-methane hydrocarbons during the NAAQS period in 1980 was 8,747 micrograms/m³ on Dec. 4. The highest concentration in 1981 was 10,933 micrograms/m³ and occurred on February 3. The extremely high concentrations occurred only from September 1980 through February 1981, and came primarily from the test well direction (90° to 157°) which was .7 mile from the monitoring station.

Total hydrocarbons were recorded at the monitoring site each day and ranged from 0 to 2,692 micrograms/m³ over a 24 hour period. The time of day when both methane and non-methane hydrocarbons were reported was basically the same each day, from 8:00 p.m. to 9:00 a.m. The wind direction from which the hydrocarbons came varied but were generally from the southeast to the northwest (135° to 292°).

Hydrogen sulfide was reported in minor amounts at the Sweet Lake site from July to December 1980. The average 24 hour concentration was between 0 and 2 micrograms/m³ during the six month period. During 1981 the average concentration was less than 1 microgram/m³. There was apparently no relationship between hydrogen sulfide concentrations and wind speed, direction, or time of day. Air quality monitoring was discontinued at the Sweet Lake site at the end of 1981 as there were no continuing problems

associated with the site and further monitoring was deemed unnecessary.

Throughout the period of drilling, construction, and test, there were no incidents of air pollution and no off site environmental impact on air quality.

7.2 Water Quality

Closure of the Sweet Lake geopressured-geothermal test site will lead to the eventual termination of water quality monitoring there. LSU will continue monitoring for a minimal period of time to detect potential contamination which may have lagged behind actual abandonment. It is doubtful that enough production or subsurface injection has taken place to adversely impact the natural waters in the area. Historically subsurface injection from other sources has been shallower and possibly volumetrically greater so that, if detected, natural water contamination by brine may not be blamed solely on geopressure-geothermal production.

Expansion of the water quality data base will be crucial. Changes in water quality from brine contamination can only be assessed after careful examination of natural characteristics. For this, reason reliance has been made on statistical and graphical methods which group parameters into origin-related families and which trace the changes through time of major and key constituents. In addition, data have been presented which may relate natural water quality characteristics to geologic variability. Permeability anomalies may allow salt-water intrusion or fresh water recharge to a tested aquifer. These phenomena have been distinguishable to some degree in the analyses.

Extensive research was done in the late '60s on the water quality characteristics of groundwaters in the state and in southwestern Louisiana (Harder, et al., 1967 and Winslow, et al., 1968). A concentrated effort was made to establish the position of the saltwater interface but little was done to establish the rate of movement. By comparing data from the present project with data obtained in earlier studies, observations can be made regarding this very important phenomenon.

The regional position of the freshwater-saltwater interface and the limits of fresh water are depicted in Figure 7-1 and total dissolved solids contents with depth are depicted in Figure 7-2. From these diagrams, the approximate TDS concentrations of ground water in the vicinity of the Sweet Lake test site can be interpolated. The values so derived represent the chemical characteristics of these waters prior to 1967-68. A comparison with more recent data should indicate any changes caused by movement of the saltwater interface.

The base of fresh water at Sweet Lake in 1967 was at a depth of approximately 600 ft. MSL. Chloride concentration in project observation wells in November, 1983 from a depth of -200 to -500 ft. MSL were below the laboratory detection limit of 1.0 mg/l. The maximum concentration of chloride in these wells during the period of sampling was 118.0 mg/l. The Sweet Lake test site may be in an area of very active ground-water recharge as indicated by an anomalously deep saltwater interface shown by the altitude of the 3,000 mg/l dissolved solids surface (Fig. 7-2).

A common method of illustrating the general chemical characteristics of natural waters is the trilinear plot (Piper, 1944). The trilinear diagram is divided into three fields which represent the relative concentrations of major cations, anions, and cation-anion pairs (Fig.7-3). In the lower left triangle, the percentage reacting values (PRV'S) of major cations (CA, MG, HCO_3) are plotted. The intersecting rays from these two fields into the central diamond indicate the relative concentrations of the most common cation-anion pairs (e.g. NaHCO_3 , NaCl , CaCO_3 , etc.). The local field, designated A (Fig.7-3) contains the PRV's of major dissolved constituents in project brines, average seawater, and surface waters in the southwestern Louisiana marshlands. A single point, plotted at B, represents water from drainage of the Sweet Lake site. C is a grouping of surface and subsurface waters at Parcperdue and D represents shallow groundwaters from Sweet Lake and Rockerfeller Refuge. Also indicated are the general characteristics of waters in the major southwestern Louisiana aquifers defined by Harder et al. (1967).

A definite gradation is indicated from seawater and brines to surface waters to ground waters in the anion triangle and the central diamond. This illustrates the relative HCO_3 enrichment in fresh surface and shallow subsurface waters. The grouping of all Parcperdue near-surface waters substantiates a conclusion made earlier in the DOE geopressured-geothermal environmental monitoring phase that shallow groundwaters underlying the Parcperdue test site are hydrologically connected to the surface; recharge probably occurs in the Vermillion River west of the prospect.

All near-surface waters at Parcperdue fall within the range of concentrations reported by Harder et al. (1967) to be characteristic of the Chicot aquifer. This aquifer is probably commonly connected to the surface and receives sufficient recharge to maintain a relatively high Ca to Na ratio. Ground waters from Sweet Lake and Rockerfeller Refuge plot very close to the limit separating Evangeline aquifer waters from blended Chicot-Evangeline waters. The lower chloride contents of these waters may indicate a low rate of saltwater intrusion into these aquifers, however, TDS contents are high, which may indicate a diagenetic process whereby chloride from seawater is taken out of solution.

Diagenetic processes are probably responsible for the variations indicated in the cation and anion triangles. A relative decrease in the concentration of magnesium with depth is indicated for seawater, ground waters and brines. This is probably due to the role of magnesium in cation exchange reactions.

A number of natural and man-induced processes may be responsible for the spatial and temporal variations which have been illustrated by the environmental monitoring data. Water quality variability may be due to saltwater intrusion, waste dispersion, or natural diagenetic processes. Furthermore, oil-field brines may find their way into shallow subsurface waters up faults or by molecular diffusion through semi-permeable shale membranes.

The saltwater interface has been shown (Harder, et al., 1967) to follow a northwest-southeast trend in southwestern Louisiana. Although some local variation may be due to fluid production (oil, gas, or ground water), the regional variability is probably related to Pleistocene and older deltaic

progradation as elements of these systems tend to be tangent to the strike of the saltwater interface (Fig. 7-4). The anomaly which causes displacement of the interface to the south on the 3,000 mg/l dissolved solids surface (Fig. 7-2) may be due to an area of recharge to the north or may be a relatively impermeable volume of sediment through which the flow of saline water is impeded.

Present water quality characteristics at the geopressured-geothermal test sites are consistent with those found in earlier studies (Harder, et al, 1967; Winslow, et al., 1968). Harder, et al (1968) calculated the rate of movement of the saltwater interface at limited, selected points in southwestern Louisiana. The rate of movement was found to be best illustrated by a 1 to 5 mg/l per year change in chloride content. L.S.U. data seem to substantiate that claim; however, it has also been shown that TDS content may increase at a faster rate due possibly to diagenetic processes; movement of the saltwater interface in some areas may be masked.

Brine contamination may come from two sources, if detected. Subsurface injection of oil-field brines is a common practice in south Louisiana. Brine contamination may occur through the rupturing of well casings or, after disposal, by migration up faults or through leaky aquitards. Another possible source of brine contamination may be natural due to movement from brine origin up deep faults or by slow leakage through semi-permeable shale membranes. The over pressuring of some brines in the subsurface may facilitate such a mechanism although movement will be very slow and diagenetic processes will significantly alter the composition of fluids during their migration.

A trilinear analysis of natural waters may contribute greatly to an understanding of mixing and diagenetic processes. One goal of this program is to determine the parameter most affected by these processes. Preliminary analysis indicates that magnesium may play a major role in the diagenesis of ground waters. Sulfate content may be of secondary importance. Mixing diagrams will be employed in future studies to determine and try to separate variations caused by saltwater intrusion and/or brine migration.

7.3 MICROSEISMIC MONITORING AT SWEET LAKE

The Louisiana Geological Survey (LGS) and Louisiana State University (LSU) conducted base-line seismic studies at the DOE Parcperdue, Sweet Lake, and Rockerfeller Refuge prospects to investigate microseismicity associated with geopressured-geothermal fluid production. These monitoring programs were designed, first, to establish the nature of the local seismic activity prior to production and, second, to determine if well activities induce changes in the rate of local fault movement. This section describes the results obtained from microseismic monitoring at Sweet Lake through April, 1984.

The Sweet Lake microseismic monitoring network consisted of eight permanent field stations (Fig. 7-5) which were maintained by the University subcontractor, Woodward-Clyde Consultants. Location coordinates are given in Table 7-1. Data collected at each field station were multiplexed and transmitted over telephone lines to the central recording facility in Baton Rouge, Louisiana.

At the central recording facility, all data were continuously recorded on

magnetic tape. Parallel with the magnetic tape recording system, selected station data were recorded on three drum recorders. Drum records were scanned daily to detect possible seismic activity. Upon detection of a possible natural seismic event, all station data were played back from the magnetic tape into hard copy format through an oscillograph. Station data were further reviewed and analyzed in hard copy format such that hypocenter locations and other characteristic information could be obtained. Data reduction was accomplished using a modified version of the earthquake location program FASTHYPO.

CHARACTERISTICS OF SEISMIC WAVE ARRIVALS

Seismic events recorded by the seismic monitoring network at Sweet Lake were not representative of microearthquakes recorded by networks in other environments. Microearthquakes in other environments have been typically characterized by a P-wave arrival, an S-wave arrival and, in some instances, a surface wave arrival. At Sweet Lake, however, typically only one arrival has been observed. This arrival is usually impulsive and has a frequency of 5 to 15 Hz (Figure 7-6). The arrivals appeared to be travelling with a velocity of about 0.35 km/sec. This velocity is similar to the velocity of fundamental mode Rayleigh waves computed using a velocity model derived for a portion of the Gulf Coast in Texas. As the sediment velocities in southern Louisiana are similar to those in coastal Texas, it has been concluded that the recorded arrivals may likely be fundamental mode Rayleigh waves.

P- and S-wave arrivals were observed for seismic events that can be identified as explosions detonated for geophysical surveys. The P-wave velocity determined from these near-surface events is about 1.5 km/sec.

LOCATION OF SEISMIC EVENTS

Microearthquakes were located using a modified version of the computer program FASTHYPO (Herrmann, 1979). This program uses an iterative least squares procedure to minimize the root mean square residual of the travel times. Input to the program usually consists of arrival times for P- and S- waves and a plane layered velocity model. Because P- and S- waves were not observed for microearthquakes detected by the seismic network at Sweet Lake, a procedure was adopted using the Impulsive Rayleigh wave arrivals to locate the events. Arrival times of the Rayleigh waves were treated as P-wave arrivals and a half-space with a velocity of 0.342 km/sec was used as the velocity model. Locations determined by this method must be considered uncertain, but for events within the array they were probably fairly accurate.

Depth was left unconstrained in the location procedure. Most calculated depths range from 0 to about 8 km, but the significance, if any, of depths based on surface wave arrivals is not clear, at best. Impulsive wave arrival times can be read with a precision of better than 0.1 sec in most cases. Differences in the calculated travel times for two events located in the center of the array but at depths of 0 and 4 km, respectively, would be on the order of 4 sec for a half-space with a velocity of 0.342 km/sec.

Thus, calculated depths cannot be explained as the result of uncertainties in arrival time readings. If the larger travel times are compensated by changing the velocity of the half-space rather than the depth, a velocity decrease of about 20% would be required. Another possibility is that energy recorded as a Rayleigh wave travelled along part of its path as a body-wave. In this case the different travel times would result from the different percentage of travel path that was transversed as a body-wave. The depths computed in this case may not be meaningful, but relative depths would be correct in a qualitative sense.

MAGNITUDES

Magnitudes were calculated on the basis of event duration. Duration is measured as the time from the onset of the arrival to the point at which the arrival recedes into background noise. The formula used for magnitude calculation is:

$$m_D = -2.22 + 1.18 \log(D)$$

This formula was derived for use in the Mississippi embayment by the Tennessee Earthquake Information Center. Its applicability to the southern Louisiana region has not been tested. While magnitudes that are computed may not be valid in terms of their absolute values, they do give a sense of the relative size of events.

Magnitudes calculated for microearthquakes recorded by the Sweet Lake network indicated that all detected events were small. Calculated magnitudes were typically less than 1 (m_D) for the events detected.

Another measure of the size of microseismicity recorded at the Sweet Lake site may be found in felt reports of the local residents. Local blasts, using charges of up to twenty-five pounds of explosives have been routinely detonated in the course of seismic prospecting in the immediate site area. These blasts are often felt by local residents. Felt reports consist of both an awareness of the seismic waves by residents in the course of daily activities, and effects on household objects coinciding with that awareness. There does not appear to have been any felt reports for the microearthquakes occurring at the Sweet Lake site.

SEISMICITY AND WELL PRODUCTION

Microearthquakes were first detected by the monitoring network at Sweet Lake in June, 1981. This activity followed approximately one year of seismic quiescence as observed on network records. The detection level of the network may, however, have changed during that time. In late May and early June of 1981, station gains and filter settings were adjusted to increase the sensitivity of the network. While some very small events may have been missed prior to June, 1981 activity similar to that detected beginning in June, 1981 would have been evident on the records if it occurred. No such activity was detected in a detailed review of the network records.

The time history of seismic activity at Sweet Lake is characterized by a constant background level of seismicity that is punctuated by bursts of earthquakes (Figure 7-7). These bursts usually consist of at least five events, and in one case thirty-five events, that occurred, within 15 km of

the wells during one day. The first such burst of activity occurred four days prior to perforation of the disposal well (Figure 7-8). The next burst occurred two days after the disposal well was perforated. No activity occurred near the time of perforation of the production well.

Other bursts of activity may have correlated in time with large rapid changes in the fluid pressure as measured at the wellhead of the production and disposal wells (Figures 7-8 through 17). Most bursts occurred with a time delay of two to three days with respect to the measured pressure change, but some preceded the change by less than a day.

There may be correlation between the level of seismic activity in June, 1981 and the activity at the wells (perforation, flow and reservoir limit testing) (Figure 7-18). However, seismic activity continued beyond the end of the Initial Flow Test in February of 1982. In fact, some of the largest bursts of activity occurred after the reservoir limit test ended (Figure 7-18). Letter reports describing activity at the wells subsequent to the termination of the flow test (Magma Gulf-Technadril, 1982) suggest that some of the bursts of seismicity were related to well activity (Figure 7-19). While the largest burst of seismicity, on Julian Day 107, is not related to drilling or flow activity, a large pressure increase was noted at the wellhead of the disposal well on the next day (day 108). There was no correlation between seismicity bursts and well activity after April, 1982 because the well was shut-in until September, 1983.

SPATIAL DISTRIBUTION OF MICROEARTHQUAKES

The spatial distribution of all earthquakes within about 10 km of the wells does not show any clear relation to the locations of growth faults inferred for depths of 12,000 to 15,000 ft (Figure 7-20). Examination of only events that occurred during the reservoir limit test has lead to the same conclusion (Figure 7-21). Even the bursts of seismicity that were tightly clustered in time did not show distinct spatial clustering about or along known structures, but they do appear to be distributed in spatial clusters about the well and within the area covered by the network. There does not appear to be any overall spatial migration of activity with time, however, the spatial clustering of activity occurring as bursts of seismicity has indicated potential locational constraints or preferences probably defined by specific changes occurring in the subsurface.

All well recorded events within 6 km of the wells have computed depths between 0 and 8 km (Figure 7-22). This suggests that microearthquakes were occurring within the range of depths at which the influence of fluid withdrawal and injection was to be expected. The spatial distribution of the microearthquakes as a function of depth may be related to the relative confinement of the reservoir fluids at both the depths of the withdrawal and injection. The geopressured/geothermal brine that was withdrawn from the production well occurs in a graben that is bounded by growth faults. Withdrawal from this reservoir could affect the fluid pressures at the graben boundaries, and perhaps of other aquifers at similar depths. On the other hand, the injection of fluid in the disposal well occurs in relatively unbounded sands. Faults at this level are thought to have significantly smaller displacements with respect to the reservoir thickness. Hence, the more dispersed distribution of the shallower activity may have been the result of its unbounded character.

DISCUSSION

After examination of the apparent large number of events being detected at the Sweet Lake site, it was decided to compare the event detection record to the climatological data of the area. A strong correlation was found in the records of seismicity when compared to the records of thunderstorm activity and rainfall, as reported by the N.O.A.A. National Weather Service Office in Lake Charles, Louisiana, and also by a digital rain gauge installed on Precht Road, about one mile west of the well site. For the period of data collection beginning in January, 1981, a complete history of weather activity shows that days in which large numbers of small microseisms were detected correspond well in time to thunderstorm activity and/or rainfall. In fact, it is quite apparent from the weather data that the sudden onset of microseismic activity in June, 1981 could be a result of the violent thunderstorms and heavy rainfall that began to occur then. We speculate that the "microseismicity" detected during these violent thunderstorms is caused by the coupling of loud air waves with the ground. In addition, for many of these suspect events, a "glitch", or sudden offset in the seismic traces, occurred simultaneously across all stations just prior to the event traces, suggesting that electromagnetic interference from lightning was causing the glitch and thunder was causing the "microevent." Figures 7-23a and b show the rainfall as recorded at Lake Charles Municipal Airport through January, 1984, the last month for which data have been issued. We have separated non-thunder related local events from the rest of the existing data set in Figure 7-24 a, b and c, and Figures 7-25 a and b show all events which occurred on days when neither thunder nor rain were detected. We cannot be certain that all events which occurred during thunderstorms were in fact caused by thunder. However, during the time period June to September, 1983, 88.4% of all detected events were coincident in time with periods of thunderstorm and/or rain, and none of these had detectable P- or S- wave arrivals, leading us to believe that none of them were tectonic in nature. We must conclude, therefore, that although seismic events of curious character have occurred in or near the seismic network on days when it was not raining, the exact number of naturally occurring events cannot be determined due to the above-mentioned contamination of the data set by weather-related "psuedo-events." Most of the events which occurred on days having good weather appear on seismograms as Rayleigh waves traversing the network from origins far outside the network.

Of all suspected naturally-occurring local seismic events detected during this time period, only two (Figure 7-26, event A & B) have a seismic signature typical of known earthquakes which occur in other parts of the country -- that is a clearly discernable P (Primary compressional/dilatational) wave followed by an S (Secondary shear) wave. Event A may be a foreshock of a larger ($M_b = 3.8$) event B which occurred October 16, 1983 in the Sweet Lake area.

Since the Sweet Lake DOE MG-T Amoco Fee #1 test well was shut in during June and July and only minor (non-pumping) work was performed at the well site prior to the occurrence of the event on September 11, 1983, or the main shock of October 16, 1983, it would seem unlikely that these events were related to well activity. Additionally, the computed depths of these two events (7.0 km and 12.5 km, respectively) were considerably below the production horizon.

CONCLUSIONS:

After three years of microseismic monitoring, our contractors have presented us with locations for over 1000 microseismic events. Through the course of data analysis, two problems have been encountered, and are currently being studied in detail. The first one is that almost all of the best located events are of the impulsive Rayleigh wave type. It must be pointed out that locations using only Rayleigh wave arrivals are not as reliable as those using body waves. Furthermore, the depths that go with the locations are extremely questionable. It is because of this that attributing events to particular inferred growth fault locations at depth is impossible. We are currently working on methods of arriving at more reliable event locations and depths.

The second problem has been that coincident rainfall and seismic activity has been observed at all three wells. At this time, it is yet unclear whether these slow moving (290 m/sec - 350 m/sec) impulsive Rayleigh wave events can be attributed to meteorological disturbances or indeed are of earth origin. Unfortunately, this slow velocity range is also occupied by acoustical transmissions through the air, and significant coupling of atmospheric acoustic and earth Rayleigh waves is highly probable. If, in fact, most of the observed signals are of earth origin, it is extremely difficult to separate them from atmospheric acoustic events, such as thunderstorm activity, associated with times of rainfall and frontal passage

Sweet Lake had two flow testing periods, the first was for seven months in 1981-1982, and a second from November, 1983 until the end of March, 1984. Continuous seismic monitoring during this entire period has shown no believable correlation of events with flow testing. All activity seems to have been at intermittent intervals throughout the three years. Microseismic monitoring will continue until spring 1985, one year after shut-in, to access any long term effects that may have resulted from the Sweet Lake testing project.

7.4 SUBSIDENCE

The effect of geopressure geothermal production on subsidence rates will only be assessed after careful examination of historical production of oil, gas, and ground water in the area surrounding each test site. Due to a potential subsidence lag following production, consideration must be given to some minimum backlog of data. For our purpose, an arbitrary period of 6 years has been chosen. In addition, cumulative production from each field has been considered. Subsidence monitoring is incomplete at the Sweet Lake test site.

Historical land surface subsidence in the Sweet Lake area was determined in a related study whereby regional movements were adjusted to movement of the Monroe uplift in northeastern Louisiana. The historical profile follows Highway 27 from Iowa, La. to Creole, La. Maximum subsidence is illustrated for the portion of the profile north of the point which corresponds both to the position of the prairie-coastal marshland boundary and the Sweet Lake salt dome. The absence of pronounced subsidence south of this boundary may be a result of water saturation since the land surface is at or below sea

level. Sediment dewatering may have been curtailed or subsidence to the north of the boundary may be an anomalous response to compaction of a buried Pleistocene Red River fluvial system. On the other hand, natural subsidence may have been counteracted by movement associated with the Hackberry-Sweet Lake salt ridge. A report by D. B. Trahan of Louisiana Geological Survey has discussed regional consideration (Appendix K).

The important considerations in oil-field subsidence analyses are (Geertsma, 1973):

- 1) The reduction in reservoir pressure.
- 2) The rate and degree of pore pressure reduction.
- 3) The uniaxial compaction coefficient.

The reduction in reservoir pressure is a function of the mobility, solubility, density and compressibility of fluids as well as reservoir boundary conditions. Pore pressure reductions depend on the permeability distribution, locations of wells and the production rate. The compaction coefficient depends on rock type; (the number, size and shape of grain contacts in sandstones), degree of cementation, porosity and depth of burial.

The effect of geopressure-geothermal development on subsidence rates will not be instantaneous. A lag in the transfer of stresses to the surface is expected for geopressure-geothermal development and for other fluid production activities. The effect of historical fluid production may be apparent in our data. Modeling studies which take into consideration the production histories of the producing fields, changes in pressures, depths and volumes of production, etc. will be attempted in the future. Some of the data necessary for such an analysis are presented here, although much more will be necessary. Ground-water production may also cause subsidence of the land surface, however the mechanism for compaction is different than that for deeper oil and/or gas reservoirs. In the most cases, changes in pressure in shallow aquifers has been small due to a relatively steady recharge into these aquifers. Subsidence can occur if the peizometric head is lowered significantly due to a low water budget (ie., discharge exceeds recharge). Therefore, future work will also center on an analysis of these conditions.

Although subsidence monitoring is continuing at all sites as scheduled, subsidence rates may also reflect greater historical fluid production in these areas. The best future efforts would be aimed at the use of models which take into consideration the production from individual wells and fields. Correlations could be made with fluid volumes, reservoir geometries, and pressure changes during production. Some of these data have been obtained as a key element of the program, but only for the geopressured-geothermal wells. Data for other wells and fields in the Sweet Lake area are presently being procured.

8.0 ECONOMICS

8.1 INTRODUCTION

In 1974, Gulf Geothermal Corp. was invited to testify before the House Energy Subcommittee concerning the drilling and testing of geopressured-geothermal aquifers of the Gulf Coast province. Rationale for the proposal was based on methane gas recovery as well as the as yet untapped thermal and hydraulic energy potential. At that time exploration for natural gas had not kept pace with demand resulting in a gas shortage. Based on GGC studies over the previous three years and studies by the U. S. Geological Survey and Louisiana State University L.S.U. the potential for a new economic energy resource lay in these Gulf Coast aquifers.

Subsequently, GGC joined with Magma Power Co. to acquire leases in Texas and Louisiana. Leases were acquired on some 100,000 acres in Texas and Louisiana at costs ranging from \$0.50 to \$2.00 per acre. In order to promote privately funded drilling and testing, Magma Gulf Company was organized in 1975. Midway in its solicitation of industry partners, ERDA announced plans for Federal funding of a similar project which caused Magma Gulf's proposed partners to defer contemplated support. Consequently, Magma Gulf was forced to submit its proposal in ERDA competition in order to salvage its past investments. Two specific sites were presented to ERDA in 1976 for proposed drilling and testing. Selection by ERDA of the Sweet Lake site resulted in the 1979 site specific proposal to the DOE to test the upper Frio Miogypsinoides reservoir. The proposal was modified after negotiations with the DOE, and the contract was signed in December 1979.

8.1.1 THE 1974 PROPOSAL

The cost estimated by Gulf Geothermal Corp. of drilling and testing a single geopressured-geothermal well was approximately \$3,500,000. The salt water disposal well costs were estimated at \$800,000, and testing costs at approximately \$900,000. The construction and installation of surface production facilities for the commercial generation of electricity was estimated at approximately \$4,500,000 (Table 8-1). Total cost of the project for exploration, lease acquisition, drilling, testing, environmental monitoring, and construction of electrical generating facilities for the three sites was \$27,400,000.

8.1.2 THE 1976 PROPOSAL

The proposal to ERDA by Magma Gulf Co. presented cost estimates for wells in both Texas and Louisiana. The Louisiana test well was estimated at \$3,000,000, with the disposal well costing \$510,000. A six month testing schedule was estimated at \$200,000. Total costs were estimated at approximately \$4,000,000.

8.1.3 THE 1979 PROPOSAL

In Phase II of DOE contract DE-AC08-78ET01561 Magma Gulf presented three alternate proposals to the Department of Energy along with estimated gas production, income, and pay out schedules (Table 8-2). The proposals were: I. based on day-rate drilling costs, II. based on combination day-rate and turn-key costs, and III. based on a lump sum turn key cost. Using the day-rate proposal the test well costs were estimated at \$3,517,800. The disposal well costs were estimated at \$1,407,800. Testing costs were estimated at \$1,757,090. Total costs were estimated at \$8,351,189. plus fees. -These costs for drilling and testing were based on then current costs as presented to Magma Gulf Co. by Louis Records and Assoc. of Lafayette, La., and Eaton Industries of Houston, Tx.

8.1.4 THE 1979 REVISED CONTRACT

Subsequently, the Magma Gulf-Technadril Inc. joint venture was formed and instructed by DOE to negotiate a day rate contract. The contract for drilling and testing the Sweet Lake site was negotiated in September 1979 and the contract signed in December 1979. The revised contract allocated \$3,446,308. for the test well, \$781,051. for the salt water disposal well, \$2,150,233. for testing, and \$1,439,213. for all other costs to be incurred.

In the 1979 proposal Magma Gulf Co. had proposed the initial testing phases to be done using a test loop designed by Eaton Industries. These testing phases would include the Initial Flow Test and Reservoir Limit tests, lasting approximately 60 days. If these tests indicated the presence of an extensive reservoir the test loop would then be dismantled and long-term surface testing facilities installed.

As a result of discussions with the DOE, the 1979 revised contract eliminated the construction of the test loop and provided for construction of the long term test facilities in order to conduct all testing phases.

8.2 THE 1984 PROJECT ACTUAL COSTS

The test well total costs were \$8,067,124. Salt water disposal well costs were \$1,505,592. Testing costs including construction and installation of surface facilities were \$2,286,164. Costs to workover both wells were \$1,184,445. Project administrative costs were \$2,383,805. Plug and abandonment and site restoration costs were \$225,000. Total project costs were \$16,152,154. (Table 8-1).

8.3 ANALYSIS OF PROJECT COSTS

8.3.1 PERCENTAGE COST INCREASES

When Magma Gulf presented its Phase II proposal to DOE in June 1979, project costs were estimated based on prices which were current and firm as of April 1979. These costs were audited by DCAA in August 1979. The contract was not signed until December 1979. Project

management was in place in late December 1979, however, no site preparation work could begin until the final EPA assessment was completed in February 1980. Procedures for acquiring drilling rigs and tubular goods commenced in January of 1980. However, this was the time when the Iranian crisis caused abnormal price increases for petroleum with resultant heavy drilling. Due to these conditions in the drilling industry during this time, no firm commitment for a rig for the test well, or pipe, was available until August of 1980.

This delay of some 16 months from proposal to start-up was a time of high cost inflation. By the time the well was completed and ready for testing in 1981, for example, fuel costs has increased 81.9% over 1979 prices, cementing services had increased 36.1% over 1979, and perforating costs had increased 41.6% over 1979 costs. (All percentage cost increases are based on IPAA Cost Study Committee Index, World Oil, June 1984.) Project costs were likewise affected with an increase over prior 1979 estimates for casing and tubing costs of 14.8%, fuel cost increase of 49.1%, wellhead equipment cost increase of 21.7%, cement and cementing services cost increase of 16.8%, drilling mud increase of 17.1%, payments to drilling contractors cost increase of 15.2%, and other expenditures average cost increase of 16.2%.

8.3.2 SPECIFIC COST INCREASE ITEMS

INTRODUCTION

The following are the major, easily defined, causes for increases in the total project costs. As seen in Table 8-1, the percentage ratios allocated to each major area of cost did not deviate greatly from the original estimates, except in the drilling and completion of the test well due to these problems.

Drilling time -

The original proposal and contract had estimated 60 days to drill the test well. Due to a subsurface blowout, the hole had to be sidetracked necessitating an increase of 43 days in test rig expense. Additionally, \$160,000. of drilling tools were lost and not recoverable as a result of the blowout. The time needed for redrilling, fishing and recovery for the test well is presented in Vol. I - Drilling and Completion of the Sweet Lake project.

Cementing -

More time was required than anticipated to complete the 7 5/8 inch completion string. This completion required 3 cementing attempts due to problems with the cement hardening properly.

Location expenses -

In order to comply with the requirements of the surface lessee a longer board road had to be constructed than originally planned.

Rig unavailability had necessitated using a larger rig than planned. This larger rig required a stronger site foundation (driving 90 12 inch pilings) and larger pad. These added requirements increased costs by \$740,000.

Environmental -

In order to comply with the lease with AMOCO, no mud pits could be constructed at the site. This necessitated additional solids control equipment and the hauling of all cuttings and liquids to an approved disposal site. The costs for disposal alone were an additional \$425,000. which had not been anticipated in the original proposal.

Mud and Completion Fluid -

Increased costs of mud chemicals, and mud and solids controls requirements resulted in an increase of \$669,285. in these costs.

Coring and tubing -

The delay in start-up resulted in an increase in tubular costs. Additionally, problems with plastic coating of the 5 inch production tubing caused all the tubing to have to be recoated. Although the coating company absorbed these costs, an additional 7 days of rig time increased rig costs by \$245,000.

Work over -

These costs were necessitated as a result of the salt water disposal well sanding up and the resultant clean out and reperforation of the disposal well. The leak in the 5 1/2 inch tubing of the test well necessitated pulling the 5 1/2 inch tubing and recompleting the test well.

Extension of the Contract -

The extension of the project resulted in higher costs in project operating and administration, although these costs are not the result of anticipated problems.

9.0 SWEETLAKE ABANDONMENT & SITE RESTORATION

9.1 INTRODUCTION

After the U. S. Department of Energy determined that it could not afford to complete testing of the Sweet Lake well the DOE directed MGT on June 7, 1984, to plug and abandon both the production and the salt water disposal wells. Earlier, on March 12, 1984, the DOE issued a limited stop work order.

Magma Gulf-Technadril planned to retrieve the production tubing and all possible casing to reduce total costs. Plugging and abandonment procedures were then conducted in strict compliance with all State of Louisiana and Federal regulations, with constant adherence to the best safety considerations. Appendix L contains State requirements and permits.

For both wells the State of Louisiana was kept advised of progress and notified at the appropriate inspection points. All deviations from the original approved plan were reviewed and approved by the state.

9.2 PLUG AND ABANDON TEST WELL

At the conclusion of the testing period which was shortened due to the unavailability of DOE funds, a decision was made to plug and abandon the wells, restore the site, and return it to the fee owner, Amoco Production Company. Before the wells were plugged, all possible efforts were made to find additional funding so that the testing program could be completed and extended. Additional sources of government and industry funding were solicited, to no avail. The well's low flow rate was subeconomic, and the general conclusion was that no geopressured gas wells could pay back their capital cost.

The first step in the P & A process was preparation of a plan and budget which were submitted to the DOE for approval in January 1983. That plan was not prepared for immediate execution but was for general budget planning purposes. Two plugging scenarios were envisioned; an ideal case and a less optimistic version. The principal difference being whether or not the 5 1/2" production tubing could be readily retrieved from the packer. A second consideration was whether the rig contractor (P & A contractor) would be allowed to keep all the tubular goods.

Plugging and abandonment of the test well was performed in three distinct steps separated in time by several months.

The well was shut in on March 12, 1984 with a surface pressure of 1,200 psia. At the time of shut in, it was not known whether the well would be reopened, so just the master valves were closed. Later, when it appeared unlikely that Sweet Lake would be flowed in the near future, on April 12, 1984 a retrievable pump through plug was pumped down the well.

It had been hoped that this retrievable bridge plug set at the packer would be sufficient to provide the extra safety margin desired. However, after setting this retrievable bridge plug on a wireline, the plug leaked and it was not possible to depressurize the upper tubing portion for any length of time. Neither positive pressure in flow through the plug nor negative pressure reduced the leak.

Later, during preparation of the plugging contract, it was determined that transition to the selected contractor would be simpler if the well were completely killed. A cement plug was then set on the leaking packer. This plug was then set between 14,780 ft. and 15,280 ft., using 10 barrels of 'Class H' cement, and the well was killed without further leakage.

P & A specifications were prepared for both the production and the disposal well as one contract on two alternative bases. The potential contractors could bid a reduced price based on retaining the casing for resale or turning it over to DOE. While bids were being received, DOE determined that if the savings were significant the contractor should keep the tubular goods, since DOE had no immediate need for them.

The successful contractor was W.L. Estis of Lafayette, with a fixed price bid of \$99,000. Bids were taken in June, and notice to proceed was given to Estis on July 11, 1984. However, Estis became delayed on other wells, and did not move to the Sweet Lake site until August 13, 1984.

The Estis Well Service Rig 20 was rigged up on August 13, 1984. The first several days were relatively non-productive. On August 14, Estis could not get the wireline below 740 feet due to thick mud. August 15 - 17 was spent going in the hole with 2 3/8" tubing and a 3 1/2" casing scraper breaking circulation down to 9,705 feet. On August 18, they had cleaned out to 14,495 feet and reversed mud out of the hole.

On August 19, a 4 1/4" jet shot was run in the hole to 14,000 feet to cut the 5 1/2" casing, and 10 lb/gallon calcium chloride was circulated. On August 20, casing jacks exerting 400,000 lb pull were applied to the casing, but it would not come free. Another 4 7/16" jet shot was run in the hole stopping at several depths, and finally stopping at 7,475 feet.

On the 21st, the jet cutter was run to 14,000 feet and fired, while pulling on the tubing with 376,000 pounds. The jet cutter had to be pumped below 7,476 feet. On retrieval, the jet cutter and weight joint were left in the hole. Two additional jet cutter runs, followed by 424,000 pound pull, did not cut the tubing, leaving a total of 3 joints of 2 3/8" weight tubing in the hole.

A Bowen internal casing cutter was run on August 24th, with a "cut" at 13,800 feet, but no movement of the casing occurred using 376,000 pounds of pull. On the 25th, 400,000 pounds was sufficient to move the pipe, and 135 stands were removed. By the 26th, all 2 3/8" tubing had been removed and the well reverse circulation had been performed.

The first 30 joints of 5 1/2" were retrieved on August 27, 15 days into the operation. 60 more joints were retrieved on the 28th. The 29th yielded 74 more joints and on the 30th, a total of 265 joints totaling 13,877 feet were removed. On the 31st, a total of 346 joints totaling 13,877 feet were removed.

On September 1, after circulation, a plug of 40 sacks of Class H cement plus 35% silica flour plus retarder was pumped down the 2 3/8" tubing. 21 barrels back flowed and plugged the tubing. Another 50 sack plug was set at 13,800 feet. On August 4th, the 2 3/8" tubing was laid down, and the absence of pressure on the 9 5/8" X 7 5/8" annulus was confirmed.

On September 5, the 7 5/8" casing was cut below the slips and fell 6 feet. The casing was worked to determine the free point, apparently at about 3,500 feet. On the 6th, a jet cutter was run in but would go no deeper than 2,300 feet and became stuck. The 7 5/8" was cut at that point and two joints of 7 5/8" were laid down. On the 7th, the rest of the 7 5/8" was removed, a total of 61 joints, totalling 2,365 feet.

Operations to remove the 9 5/8" casing began on September 9. The casing was cut at 2,330 feet with a Bowen casing cutter. 58 joints were removed on September 10, but the connections could not be broken. Therefore, the 9 5/8" was cut above each collar.

A back pressure valve was set in the remaining 13 5/8" at 1,950 feet. A plug of 195 sacks of Portland Type #1 cement with 2% retarder was set from 2,565 feet to 2,165 feet (200 feet inside 7 5/8", 200 feet inside 13 5/8"). On September 12, the 9 5/8" hanger spool was removed, and cement samples confirmed the plug set and cured properly. On the 13th, a 68 sack plug (15 barrels) of Portland Type #1 cement in a 14.6#/gallon slurry was set from 110 feet up to 10 feet, and rig-down began.

On September 14, the rig cut off the 30", 20" and 13 3/8" casing 5 feet below grade in the production well. A steel plate was welded on the 30".

9.3 PLUG AND ABANDON DISPOSAL WELL

On September 14, the rig moved to the disposal well.

On September 18, a pull of 160,000 pounds released the 7" casing in the disposal well. On the 19th, 4 joints were removed using up to 254,000 pound pull. Joint 3 was collapsed. It was necessary to back off some joints to continue removal. Joint 13 was also collapsed.

By September 19, a total of 38 joints had been removed totaling 1,475 feet. On the 20th, a cement plug of 58 sacks Portland Type #1 cement with 2% retarder (weight 14.2 ppg) was set via tubing at 1,320 feet to 1,120 feet. Then the 9 5/8" was cut by a jet shot at 1,100 feet, but could not be pulled with 440,000 pounds. On the 20th, the free point was found at 500 feet, and the 9 5/8" was again cut at 450 feet. This time a 40,000 pound pull was required. The casing joints were tight and each joint had to be cut. A 108 sack plug of Portland Type #1 cement with 2% retarder was set at 550 feet. A similar 58 sack plug was set from 110 feet to 10 feet.

On the 22nd, the 13 3/8" and 20" casing were cut. A 1/2" plate with 1/2" needle valve was welded to 20" drive pipe 40" below grade.

9.4 SITE RESTORATION

Site restoration work began in June, when a final decision was made to plug and abandon the wells, and was completed by November 1984. The separator had already been moved to the Gladys McCall site to become a second stage separator.

Dismanteling of Sweet Lake surface equipment began Tuesday, July 10. All equipment was removed and stacked to one side. All materials were removed in a manner to permit possible reuse.

At DOE request, arrangements for storage and protection at the proposed Superior Hulen site were made and all material was trucked there from Sweet Lake. Inspection of the internal high and low pressure pipe was completed as these sections were removed. No corrosion and/or scale deposits were noted on the pipe walls. Loose scale was found in the 10" section of the high pressure pipe from the Willis chokes to the inlet of the separator. This deposit was uniform on the bottom and about 1" thick. All other lines were in excellent condition with the exception of these deposits. Technadril-Fenix and Scisson inventoried and signed for all the equipment on December 1, 1984.

Site cleanup was on a fixed price competitive bid basis, with the contractor required to dispose of all materials. The selected contractor was Ashy Enterprises, and the contract was awarded August 28, 1984.

Because of lease restrictions, no pits had been used on site. Metal tanks had been used, and all drilling fluids had been properly disposed of during drilling operations.

Cleanup included removal of boards and shell, leveling of ring levees, removed of contaminated soil and grading.

Procedures for cleanup were agreed to by the surface leasee, and cleanup operations were reviewed frequently. Cleanup of the test well site began as soon as the P & A rig moved to the disposal well site.

Ring levees were filled in and all fences and posts were removed. Shell on top of the pads were bulldozed up and truck transported to the Gladys McCall site. The cement walls around the production well cellar were removed, and the power cables between the site and Highway 384 were pulled up. All cement piling and piers were removed. All water wells were plugged according to state requirements.

All septic tanks were emptied and removed. Board removal began on September 18. All drilled footings and concrete pads were removed. All 112 wooden pilings were cut off 3' below grade with a drag line.

Figure 1-1

SWEET LAKE PROSPECT
TESTING PHASE ORGANIZATION

June 1981

Figure 1-2

DRILLSITE LOCATION IN SW LOUISIANA

Figure 2-1

Vicinity Map and General
Plan Sweet Lake Geothermal
Production Test Well,
Cameron Parish, Louisiana

MG-T/DOE AMOCO FEE NO.1 WELL SWEETLAKE FIELD WILDCAT CAMERON PARISH, LOUISIANA

RECOMPLETION OCTOBER 30, 1983

**All 5-1/2" tubing is plastic coated and therefore the ID and Drift are reduced by 1/8 (0.125) inch from nominal.

Fig. 2-3

**MG-T/DOE AMOCO FEE NO.2
SALT WATER DISPOSAL WELL**
RECOMPLETION APRIL 6, 1982

Fig. 2-4

Figure 3-1 Sweetlake Structure Map (Original)

95%

Figure 3-2 Isothermal Map - Top of Miogypsinoides Zone

MG-T/DOE
AMOCO FEE #1

UNION OF CAL.
PAN AM FEE #2

UNION OF CAL.
PAN AM FEE #1

UNION OF CAL.
SWEET LAKE #1

Figure 3-3 Thickening Index Diagram

CROSS-SECTION OF MIOGYP SAND Sweet Lake Project

HORIZONTAL NOT TO SCALE

Figure 3-4 Cross-section of Miogypsinoides sand

25%

Figure 3-5 East-West Cross Section Sweet Lake

Figure 3-6 Structure Map Based on Current Interpretation

SP (MV)	-160.0	40.00	ILD (OHMM)		CILD (MM/M)
			0.0	10.00	
			SFLA (OHMM)		
			0.0	2.000	
			SFLA (OHMM)		4000.
			0.0	10.00	

Figure 3-7 Induction Log of Miogyp Sand
MG-TDOE Amoco Fee #1

Figure 3-8 Salinity-Resistivity chart, Schlumberger

MUD RESISTIVITY CORRECTION CHART
H. F. DUNLAP — AUGUST 1980

Figure 3-9 Mud Resistivity Correction, Dunlap

GEOLOGIC AGE SALINITY CORRECTION

H.F. DUNLAP , FEBRUARY 1981

9509

Figure 3-10 Salinity Correction I

SALINITY CORRECTION CHART II

H.F. DUNLAP , MARCH 1981

95%

Figure 3-11 Salinity Correction II

NEW SP CHART
SILVA AND BASSIOUNI JUNE 1981

9590

Figure 3-12 New Sp Chart Silva and Bassiouni

Figure 3-13

Dual induction log of the Miogypsinoides sequence in the MG/T DOE Amoco Fee #1
 Black intervals are cored intervals.

30-JAN-81 14:45:01 STANDBY
RATE: 2039CPS TIME 51LSEC
00-20KEY:18EV/CH PRST OFF
A:K-SPAR B:
FS= 1040 MEM: A FS= 200

CURSOR (KEY)=02.14

EDAX
INT

Figure 3-14 EDS Analysis, Feldspar

30-JAN-01 15:08:20 STANDBY
 RATE: 510CPS TIME 312LSEC
 00-20KEY:10EV/CH PRST OFF
 A: DRILL MUD? B:
 FS= 064 MEM: A FS= 200

Figure 3-15 EDS Analysis, Drilling Mud

Figure 3-16 EDS Analysis, Illite

Figure 3-17

General view showing quartz overgrowths and feldspar grain (100X)

Figure 3-18

Close up of feldspar grain showing dissolution porosity (2000X)

Figure 3-19

General view showing overgrowth development + feldspar ? (100X)

Figure 3-20

Possible drilling mud contamination ? bridging intergranular pore (500X)

Figure 3-21
Illite Coating (1000X)

Figure 3-22
Illite partly occluding pore throat (200X)

C₁-C₇ HYDROCARBON

SWEET LAKE LOUISIANA GEOTHERMAL TEST WELL
CAMERON PARISH, LOUISIANA

SUMMARY OF ORGANIC ANALYSES

C₄-C₇ HYDROCARBON

Figure 3-23B

SWEET LAKE LOUISIANA GEOTHERMAL TEST WELL
CAMERON PARISH, LOUISIANA

SUMMARY OF ORGANIC ANALYSES

Figure 3-23C

TABLE VI
VISUAL KEROGEN ASSESSMENT WORKSHEET

[illegible]

VL0M = very little organic material.

Figure 3-24 Visual Kerogen Assessment

Figure 4-2

Process and Instrumentation Drawing

Figure 4-3
Process and Instrumentation Drawing

Figure 4-4
Test Wellhead and Casing Spools

TEST WELLHEAD

CASING SPOOLS
FIGURE 4-5

FIGURE 4-6
GRAY CHOKE VALVE MANIFOLD

Figure 4-7
BRINE/GAS SEPARATOR SYSTEM

SALT WATER DISPOSAL WELLHEAD AND CASING SPOOLS

FIGURE 4-8

Figure 4-9

SALT WATER DISPOSAL WELLHEAD

Figure 4-10

Inhibitor Pilot Plant

Figure 4-11 Gas Content of Brine - Separator Pressure

Figure 5-1
Sweet Lake Log of Miogypsinoidea Sand Zone Showing Sands 5 & 3

RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST
FOR

GEOTHERMAL-GEOPRESSURED WELL
PRELIMINARY CALCULATIONS

Test date: June 19-22, 1981 Type Test: Drawdown Lease and Well No. M6-T/DOE
Producing Formation: Mississippian (Upper Mississippian or lower Mississippian) Field: Sweet Lake
Hole size: _____ Casing Size: 5 1/2 Tubing Size: 5 1/2 State: Louisiana - Cameron Ph
Cumulative Production: _____ Gas Gravity: _____ Z: _____
Constant Rate Production: 3000 (bbls/day) Water Salinity: 165000 PPM Total Solids
Total Production Life: _____ days Porosity: 0.21-0.24 Gas-Water Ratio: _____ ft³/bbl
Reservoir Temperature: 199 °F Net Pay: 27 ft. Perforations: 15,387-15,414 ft
μg _____ cps μv .30e cps Bv 1.06e R.B./B. Bg _____ R.B./MCF
C₁ 4.7e X10⁻⁶ C₂ _____ X10⁻⁶ C₃ 4.29e X10⁻⁶ C₄ 1.5e X10⁻⁶
= 22 psi/cycle P at 1 hour: 11,896 Sg _____ Sv 1.00 Pi 12,053 psia @ 15,337 ft.
Pf _____ psia

I. Calculation of kh (md-ft) and k (md):

$$kh = 162.6 (Q)(B)(\mu) / (\Delta p)$$

$$kh = 162.2 (3000) (1.06) (.30) / (22) = 7050.9 \text{ md-ft}$$

$$k = (7050.9) \text{ md-ft} / (27) \text{ ft} = 261.1 \text{ mds}$$

II. B_g = (P_b)(T_f)(Z)(1000)/(5.61)(520)(P_R) =

$$B_g = () () () (.34279 / ()) = \text{Res. bbl / MCF}$$

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP_{skin}

$$s = 1.151 \left[\left(\frac{P_i - P_{1hr}}{\Delta p} \right) - \log \left(\frac{k}{\phi \mu C_T r_w} \right) + 3.23 \right]$$

$$s = 1.151 \left[\left(\frac{(12,053) - (11,896)}{22} \right) - \log \left(\frac{(261.1)}{(.23)(.30)(4.7e)(.0525)} \right) + 3.23 \right] = 4.1$$

$$\Delta P_{\text{skin}} = (0.87)(s)(m) = \text{psi}$$

$$\Delta P_{\text{skin}} = (0.87)(.214)(22) = 4.1 \text{ psi}$$

IV. Diffusivity, η

$$\eta = .006328 (k) / (\phi \mu C_T) =$$

$$\eta = .006328 (261.1) / (.23)(.30)(4.7e) 10^{-6} = 5030.571 \text{ ft}^2/\text{day}$$

Figure 5-2

6/25/81
J.D.C.

Fig 5-2
Preliminary calculations
by J.D. Clark of Sand
5 Reservoir Drawdown Test

RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST (CONT'D)

Test Date: June 19-22, 1981; Type Test: Drawdown Lease and Well No. MG-T/DOE Amoco Fee No.1

Calculation of Productivity Index (B/D-psi) and Completion Efficiency, CE

$$J \text{ (actual)} = \frac{Q_w}{P_i - P_f} = \frac{(3000)}{(12053 - 11896)} = \underline{19.108} \text{ Bbls./D-psi}$$

$$J \text{ (ideal)} = \frac{Q_w}{(P_i - P_f) - \Delta P_{\text{skin}}} = \frac{(3000)}{(12053 - 11896) - (4.1)} = \underline{19.621} \text{ Bbls./D-psi}$$

$$CE = \frac{J \text{ (actual)}}{J \text{ (ideal)}} = \frac{(19.108)}{(19.621)} = \underline{.9739} \text{ OR } \underline{97.39} \%$$

Distance to Barriers or Discontinuities, $d = 2\sqrt{rk}$

$$d = 2\sqrt{(5030371)} \times \sqrt{t} = (4486) \sqrt{t}$$

time t days	$\sqrt{t}$	d , ft.	$\frac{d}{(psi/cycle)}$	Flow Angle	Jones Y Function	Bbls. of Aquifer Explored or tested
.0035	.0592	265.4	22	(3000) 360°	.859409	255 880
.007	.0837	375.3	44	180°	.859409	255 880
.105	.3240	1454	165	48°	.214852	1 023 522
.23	.4796	2151	135	-		
.50	.7071	3172	229	-		
.92	.9592	4303	161	-		
2.70	1.643	7371	600 (3720)	-	.0245025	8,974,825
3.031	1.741	7810	negative slope.	-		

$$(7758)(.23)/(1.06) = 1683 \text{ Bbl./A. Ft.}$$

$$(265.4)^2 \pi / (43560) = 5.08 \text{ Ac.}$$

$$(5.08 \text{ Ac.})(2774)(1683 \text{ Bbl./A. Ft.}) = 230,840 \text{ Bbls.}$$

Figure 5-2 (con't)

Fig 5-2 (con't)

12250

Reservoir Data Inc.

2314 McGall Street, Houston, Texas 77092, C-130 883-9258

PA = 124053 psi @ 1537 ft
Temp. 299°F

12500

12600

12800

13000

13200

13400

13600

13800

14000

14200

14400

14600

14800

15000

15200

MC-1/DOE AMOCO F-1E No. 1
Sweet Luke Prospect
Cameron Parish, Louisiana
Early Time Drawdown Plot

6-29-81

J.D. Clark

Figure 5-3
Drawdown Curve - Sand 5

Time Origin is 05/18/81 15:25:00 Logarithmic plot in Days

959/2

9590

Figure 5-6

Figure 5-7

Magma Gulf Technidril
Amoco Fee No. 1

Figure 5-9
Potential Fault Traces

95%

Fig 5-10

FLOW ANGLE OF RESERVOIR

Figure 6-1 RELATIONSHIP BETWEEN ALKALINITY
AND THE BRINE pH

FRESHWATER - SALTWATER INTERFACE IN THE CHICOT AQUIFER, SOUTHWESTERN LOUISIANA

(After Harder, Kilburn & Whitman, 1967)

BASE OF FRESH WATER IN SOUTHWESTERN LOUISIANA

(After Harder, Kilburn & Whitman, 1967)

SCALE

FIGURE 7-1

ALTITUDE OF 1000 MG/L DISSOLVED SOLIDS SURFACE
(After Harder, Kilburn & Whitman, 1967)

ALTITUDE OF 3000 MG/L DISSOLVED SOLIDS SURFACE
(After Winslow, Hillier & Turcan, 1968)

ALTITUDE OF 10,000 MG/L DISSOLVED SOLIDS SURFACE
(After Winslow, Hillier & Turcan, 1968)

FIGURE 7-2
156

FIGURE 7-3. TRILINEAR PLOT OF DISSOLVED CON-
STITUENTS FROM NATURAL WATERS IN SOUTHWESTERN
LOUISIANA.

- A. COASTAL WATERS AND BRINE.
- B. SWEET LAKE DRAINAGE.
- C. PARCERDUE SURFACE WATERS AND GROUND WATERS
- D. SWEET LAKE AND ROCKEFELLER REFUGE GROUND
WATERS.

GEOLOGIC AND PHYSIOGRAPHIC FEATURES OF SOUTHWESTERN LOUISIANA

(AFTER JONES, TURCAN & SKIBITZKE, 1954)

(FIGURE 7-4)

Area map of Sweet Lake geopressured-geothermal test site showing locations of parameter observation stations.

HWS

SFY

JCF

HWN

**CHARACTERISTIC SEISMOGRAPHS
RECOMMENDED BY SWEET LAKE NETWORK**

(FIGURE 7-6)

TIME HISTORY OF SEISMIC ACTIVITY
SWEET LAKE TEST WELL

EVENTS WITHIN 15km OF WELL
5 OR MORE STATIONS USED IN SOLUTION

(FIGURE 7-7)

Figure 7-8

Figure 7-9

Figure 7-10

165

Figure 7-11

891

Figure 7-14

Figure 7-15

170

Figure 7-16

171

Figure 7-17

Figure 7-18

LOCATIONS OF SEISMIC ACTIVITY
SWEET LAKE TEST WELL

JULY 1980 - JANUARY 1983

Figure 7-20

LOCATIONS OF SEISMIC ACTIVITY DURING RESERVOIR LIMIT TEST
SWEET LAKE TEST WELL
JUNE 1981 - FEBRUARY 1982

Figure 7-21

Figure 7-22

RAINFALL AT LAKE CHARLES AIRPORT, JUNE 1981 - DECEMBER 1983

Figure 7-23a

RAINFALL AT LAKE CHARLES AIRPORT, JANUARY, 1984

Figure 7-23b

EVENTS ON NON-THUNDER DAYS, 1981 - 1983
 LOCATED WITH 3 OR MORE STATIONS
 WITHIN 15 KM OF WELL SITE

Figure 7-24a

EVENTS ON NON-THUNDER DAYS, 1981 - 1983
 LOCATED WITH 5 OR MORE STATIONS
 WITHIN 15 KM OF WELL SITE

Figure 7-24b

EVENTS ON NON-THUNDER DAYS, 1984
LOCATED WITH 5 OR MORE STATIONS
WITHIN 15 KM OF WELL SITE

Figure 7-24c

EVENTS ON NON-THUNDER, NON-RAIN DAYS, 1981 - 1983
LOCATED WITH 3 OR MORE STATIONS
WITHIN 15 KM OF WELL SITE

Figure 7-25a

25%

EVENTS ON NON-THUNDER, NON-RAIN DAYS, 1981 - 1983
 LOCATED WITH 5 OR MORE STATIONS
 WITHIN 15 KM OF WELL SITE

Figure 7-25b

95%

Figure 7-26

95%

Show No.	1	2
Date	9/28/80	10/16/80
Interval	10,785 - 10,804	12,885 - 12,915
Drill Rate		
Before	9.7	8.3
During	50	43
After	17.7	9.0
Porosity Rate		
Before	10	10
During	25	25
After	20	12
Hot Wire		
Before	12	10
During	192	1080
After	18	-
Chromatograph		
Methane	2.8	20
Ethane	.14	4.6
Fluorescence	Dull yellow orange	Dull yellow
Chlorides		
Before	1800	3100
During	2200	27,900
After	-	8200
Mud Weight		
Before	14.2	14.9
During	14.2	13.2
After	14.2	15.5

Table 3-1 Gas Shows

	Original Hole	Sidetrack Hole
Marginulina idiomorpha	11,100	11,130
Marginulina vaginata	11,310	11,220
Marginulina howei	11,550	11,670
Camerina A	12,510	12,570
Miogypsinoidea A	NDE	14,970

Table 3-2 Summary of Micropaleontology

Sand	Depth	O, Sonic Log	O, Saraband	O, Neutron-Density	O, Intercomp	O, Measured
1	15080-15144	18.1	12.3	15.2	16.3	16.6
2	15170-15240	15.4	12.1	14.6	13.9	16.3
3	15250-15285	19.2	15.4	20.6	20.4	NA
4	15305-15355	18.3	15.3	18.8	18.1	NA
5	15385-15415	22.9	19.0	23.2	20.8	24.3
6	15460-15505	14.1	12.2	15.0	15.7	NA
7	15520-15600	16.4	12.9	17.3	16.3	NA

Table 3-3 Calculated and Measured Porosity

Sand No.	Depth	Saraband (air)	Intercomp (air)	Measured (air)	Estimated (water)	Effective (water)
1	15080-15144	175	275	30	20	
2	15170-15240	143	48	122	20	
3	15250-15285	700	1011	NA	140	42
4	15305-15355	750	690	NA	140	
5	15385-15415	2960	2703	3670	400	343
6	15460-15505	130	90	NA	20	
7	15520-15600	280	143	NA	30	

Table 3-4 Calculated and Measured Permeability

Sand No.	Depth	SP	Rwa	Kf	KfI	KfII	Conductivity	Bassiouni	Saraband	Intercomp	Measure
1	15080-15144	60,000	58,000	130,000	100,000	100,000	140,000	11,000	76,000	100,000	NA
2	15170-15240	60,000	68,000	130,000	100,000	100,000	68,000	11,000	68,000	100,000	NA
3	15250-15285	68,000	105,000	145,000	120,000	125,000	140,000	13,000	98,000	125,000	161,800
4	15305-15355	75,000	120,000	145,000	120,000	125,000	155,000	14,000	125,000	175,000	NA
5	15385-15415	78,000	75,000	160,000	140,000	150,000	200,000	15,500	125,000	175,000	165,000
6	15460-15505	65,000	68,000	140,000	123,000	128,000	68,000	12,500	74,000	175,000	NA
7	15520-15600	78,000	120,000	160,000	140,000	150,000	140,000	15,500	103,000	175,000	NA

Table 3-5 Calculated and Measured Salinity

Sample Depth	7020'	7050'
Mineral Percent		
Quartz	54	89
Feldspars	7	11
Calcite	7	trace
Bartie (mud contaminant)	32	

Table 3-6 X-ray diffraction of test well sidewall cores

Depth	15144.0-15144.4	15152.0-15152.4	15191.0-15191.4	15403.0-15403.5	15604.1-15604.5
Permeability (air),md					
Horizontal	27	32	122	3670	4.29
Vertical	34	2.65	83	3526	5.23
Porosity, %	16.6	14.3	16.3	24.3	18.8
Water % pore	48.5	39.3	71.2	81.2	49.3
Gas % Bulk	8.6	8.7	4.7	4.6	9.5
Grain density	2.66	2.67	2.64	2.65	2.66

Table 3-7 Porosity and Permeability Analysis of Test Well Diamond Cores

Depth	Permeability, md	Porosity, %
6490	680	29.1
7020	500	30.7
7050	480	29.0
7070	410	28.4
7090	980	30.8
7120	920	30.7
9400	Shale	
9420	Shale	
9440	Shale	
9510	Shale	
9580	Shale	
9600	Shale	
9630	Shale	
9700	Shale	
9710	Shale	
9720	Shale	
10050	Shale	
10200	Shale	
10220	Shale	
13085	Shale	
13120	480	24.6
13835	250	23.3
13856	365	24.1
13875	7.5	19.5
13926	2.4	17.6
13945	65	22.7
14035	58	22.1
14055	35	21.2
14305	22	20.4
14345	Shale	
14445	Shale	
14475	Shale	
14595	0.9	16.5
14632	1.4	17.4
14645	Shale	
14846	14	20.0
14856	Shale	
14868	Shale	
14923	4.2	17.1
14952	8.8	19.5
14990	Shale	
15045	11	20.0
15050	Shale	
15070	26	20.5
15075	62	22.0

Table 3-8 Porosity and permeability of test well sidewall cores

Depth	Population	Number of Readings	Minimum Reflectance (% Ro)	Maximum Reflectance (% Ro)	Mean Reflectance (% Ro)	Std. Div. (% Ro)
15300	(1)	29	0.18	0.43	0.32	0.054
	(2)	4	0.49	0.58	0.53	0.037
	(3)	14	0.72	0.97	0.86	0.070
	(4)	13	1.02	1.73	1.31	0.231
15660	(1)	15	0.17	0.38	0.28	0.061
	(2)	29	0.82	1.06	0.94	0.068
	(3)	16	1.11	2.35	1.52	0.339

Table 3-9 Vitrinite Reflectance Summary

Depth	Permeability, md	Porosity, %
7090	640	26.9
7110	1890	29.4
7160	600	24.9
7170	540	24.8
7200	680	26.8
7210	1150	30.2
7230	6.8	21.2
7240	220	25.3
7270	1820	28.0
7300	420	26.5
7320	1880	28.8
7330	2120	30.4
7340	2080	30.1
7410	640	25.6
7420	625	25.5

Table 3-10
Porosity and permeability analyses of disposal well sidewall cores

TABLE 4-1

MG-T/DOE AMOCO FEE NO. 1 WELL
SWEET LAKE PROSPECT
CALIBRATION OF HALLIBURTON LIQUID TURBINE METERS
SEPTEMBER, 1981

DATE	08/28/81	08/28/81	08/31/81	09/02/81	09/04/81
NOMINAL TEST RUN RATE, B/D	2,000	2,000	5,000	5,000	5,000
TEST RUN NO.	1	2	1	2	3
CALIBRATION TANK VOLUME, BBLs	158.4	152.0	152.0	152.0	152.0
TIME REQUIRED TO FILL TANK, MIN.	118.22	111.42	43.30	45.32	42.75
BRINE PRODUCTION RATE, B/D MEASURED	1,930	1,964	5,055	4,830	5,120
BRINE PRODUCTION RATE, B/D DETERMINED FROM TURBINE METER	1,925	1,964	5,055	4,861	5,086
% ERROR	- 0.2	0.0	0.0	+ 0.64	- 0.64
FULL STREAM PRODUCTION RATE, B/D*					
DETERMINED FROM TURBINE METER	2,777	2,766	6,385	6,672	6,535
% ERROR	+ 43.9	+ 40.8	+ 26.3	+ 38.1	+ 27.6

* NOTE: Full Stream Rate can only be utilized as an indication of relative brine rate since the Turbine Wheel is turned by both free gas and dissolved gas in addition to brine.

TABLE 4-2

MG-T/DOE AMOCO FEE NO.1 WELL
SWEET LAKE PROSPECT
COMPARATIVE GAS/WATER RATIO MEASUREMENTS
SEPTEMBER, 1981

DATE	GAS PRODUCTION, SCF/D		BRINE PRODUCTION, STD/D	GAS/WATER RATIO	
	POSITIVE DISPLACEMENT OR TURBINE METER	DP CELL ORIFICE		POSITIVE DISPLACEMENT OR TURBINE METER	DP CELL ORIFICE
NOMINAL 2,000 B/D TEST RUN					
Aug. 28	42,393	40,600	1,907	22.2	21.3
Aug. 29	42,238	39,574	1,867	22.6	21.2
Aug. 30	44,735	41,205	1,892	23.6	21.8
NOMINAL 5,000 B/D TEST RUN					
Sept. 2		104,239	4,899		21.3
Sept. 4		108,763	4,561		23.8
Sept. 5		113,918	4,991		22.8
Sept. 6		111,305	4,858		22.9

Table 5-1 Porosity and thickness used to calculate original water in place.

Sand No.	Thickness	Porosity	Water in Place, MM bbl
1	41	15.7	286.9
2	42	14.5	271.5
3	27	18.9	227.5
4	25	17.6	196.2
5	27	22.0	264.8
6	41	14.3	261.4
7	51	15.7	356.9
Total	254		1865.20

Table 6-1

SUMMARY OF TESTING - SWEET LAKE PROSPECT
TYPICAL BRINE COMPOSITION

	PPM
ALKALINITY	256 - 390
TOTAL DISSOLVED SOLIDS	156,900 - 166,500
CHLORIDES	92,340 - 100,100
SODIUM	42,000 - 46,000
CALCIUM	11,000 - 12,560
MAGNESIUM	630 - 760
POTASSIUM	1,690 - 1,740
SILICA	112 - 120
STRONTIUM	840 - 970
IRON	52 - 59

Table 6-1A

SUMMARY OF TESTING

SWEETLAKE PROSPECT

TYPICAL BRINE COMPOSITION

	SAND ZONE	
	NO. 3, MG/L	NO. 5, MG/L
ALKALINITY	256 - 281	256 - 390
CALCIUM	12,500 - 13,400	11,000 - 12,560
CHLORIDES	99,650 - 99,900	92,340 - 100,100
IRON	55.8 - 63.5	52 - 59
MAGNESIUM	700 - 720	630 - 760
POTASSIUM	860 - 990	1,690 - 1,740
SILICA	92 - 93	112 - 120
SODIUM	41,750 - 41,800	42,000 - 46,000
STRONTIUM	1,180 - 1,220	840 - 970
TOTAL DISSOLVED SOLIDS	168,400 - 168,900	156,900 - 166,500

Table 6-2

SUMMARY OF TESTING - SWEET LAKE PROSPECT
TYPICAL GAS ANALYSIS

	<u>% MOL</u>	
METHANE	88.77	
ETHANE	1.73	
PROPANE	0.35	
ISOBUTANE	0.04	
NORMAL BUTANE	0.06	
PENTANES AND HEAVIER	0.24	
NITROGEN	0.22	
CARBON DIOXIDE	8.59	
HYDROGEN SULFIDE	15 - 30	PPMV

Table 6-2A

SUMMARY OF TESTING
SHEETLAKE PROSPECT
TYPICAL GAS ANALYSIS*

	SAND ZONE	
	NO. 3, % MOL	NO. 5, % MOL
METHANE	89.43	88.77
ETHANE	1.50	1.73
PROPANE	0.20	0.35
ISOBUTANE	0.01	0.04
NORMAL BUTANE	0.02	0.06
NITROGEN	0.20	0.22
CARBON DIOXIDE	8.54	8.59
HYDROGEN SULFIDE	12-20 PPMV	15-30 PPMV

*AT BRINE/GAS SEPARATOR PRESSURE OF 300 PSIG.

Table 6-3

SCAN
 Scientific Consulting and Analysis, Inc.
 P.O. Box 6642
 Lake Charles, LA. 70606

December 9, 1983

Revised Chemical analysis
 Production Brine
 MG-T/DOE Amoco Fee # 1 Well
 Sweetlake Project
 Sand Zone # 3-15248-15285 ft.
 Sample Collected 11-23-83

Alkalinity	281 mgHCO ₃ ⁻ /L	
Alpha (gross)	71 pCi/L	**
Ammonia	105 mgNH ₃ /L	
Arsenic	<.001 mgAs/L	
Barium	110 mgBa/L	**
Beta (gross)	1050 pCi/L	
Boron	50.6 mgB/L	
Cadmium	.004 mgCd/L	
Calcium	12,500 mgCa/L	**
Chloride	99,650 mgCl/L	
Chromium	.05 mgCr/L	**
Copper	.050 mgCu/L	
Dissolved Solids	168,900 mg/L	
Fluoride	.45 mgF/L	
Gamma (gross)	-----	
Iron	63.5 mgFe/L	
Lead	.008 mgPb/L	
Magnesium	700 mgMg/L	**
Manganese	9.9 mgMn/L	
Mercury	<.001 mgHg/L	
pH	5.20	
Potassium	990 mgK/L	
Radium	210 pCi/L	
Radon (gas)	.3 pCi/L	
Silica	92 mgSiO ₂ /L	
Sodium	41,800 mgNa/L	
Specific Conductance	160,000 mhos/cm	
Specific Gravity	1.1103	
Strontium	1220 mgSr/L	**
Sulfate	<1 mgSO ₄ ⁼ /L	
Sulfide	3 mgS ⁼ /L	
Suspended Solids	.25 mg/L	
Zinc	2.25 mgZn/L	

Table 6-3A

SCAN

Scientific Consulting and Analysis, Inc.

P.O. Box 6642

Lake Charles, LA. 70606

DEC 12 1983

MAIL ROOM

Alkalinity	256 mgHCO ₃ /L
Alpha (gross)	80 pCi/L
Ammonia	170 mgNH ₃ /L
Arsenic	.014 mgAs/L
Barium	130 mgBa/L
Beta (gross)	1130 pCi/L
Boron	52.6 mgB/L
Cadmium	.007 mgCd/L
Calcium	13,400 mgCa/L
Chloride	99,900 mgCl/L
Chromium	.05 mgCr/L
Copper	.085 mgCu/L
Dissolved Solids	168,400 mg/L
Fluoride	.78 mgF/L
Gamma (gross)	-----
Iron	55.8 mgFe/L
Lead	<.05 mgPb/L
Magnesium	720 mgMg/L
Manganese	10.8 mgMn/L
Mercury	<.001 mgHg/L
pH	6.10
Potassium	860 mgK/L
Radium	224 pCi/L
Radon (gas)	-----
Silica	93 mgSiO ₂ /L
Sodium	46,750 mgNa/L
Specific Conductance	155,000 mhos/cm
Specific Gravity	1.1079
Strontium	1180 mgSr/L
Sulfate	<1 mgSO ₄ /L
Sulfide	.27 mgS/L
Suspended Solids	.56 mg/L
Zinc	1.47 mgZn/L

December 9, 1983

Chemical Analysis

Production Brine

MG-T/DOE Amoco Fee # 1 Well

Sweetlake Project

Sand Zone # 3 (15248-15285 ft.)

Sample Collected 11-30-83

Table 6-4

ANALYSIS OF PRODUCTION BRINE FROM SAND ZONE NO. 3MG-T/DOE AMOCO FEE NO. 1 WELLSWEETLAKE PROJECTNOVEMBER 23, 1983

	<u>SCAN, Inc.</u>	<u>Rice University</u>
Alkalinity, mg HCO_3^-/L	281	264
Calcium, mg/L	13,400	12,200
Chloride, mg/L	99,650	92,300
Total Dissolved Solids, mg/L	168,900	--
Iron, mg Fe/L	63.5	65
Silica, mg SiO_2/L	92	120
Sulfate, mg/L	< 1	56
Sulfide, mg/L	3	--
Lead, mg/L	0.008	--
Chromium, mg/L	0.13	--
Copper, mg/L	0.050	--
Fluoride, mg/L	0.45	--
Magnesium, mg/L	700	--
Manganese, mg/L	9.9	--
Mercury, mg/L	< 0.001	--
Potassium, mg/L	2,220	--
Sodium, mg/L	41,800	--
Strontium, mg/L	740	--
Zinc, mg/L	2.25	--
Boron, mg/L	50.6	--
Alpha (Gross) pCi/L	710	--
Beta (Gross) pCi/L	1,050	--
Radium, pCi/L	210	--
Radon, pCi/L	0.3	--
Suspended Solids, mg/L	0.25	--
Conductivity, mhos/cm	160,000	246,400
Hardness, mg/L as CaCO_3	--	34,300
Phosphonate, mg/L (Inhibitor)	0.9	--
pH	5.2	--

Table 6-5

MG-T/DOE AMOCO FEE NO. 1 WELL

SWEETLAKE PROJECT

SAND ZONE NO. 3

GAS COMPOSITION AS A FUNCTION OF RESERVOIR PRESSURE*

<u>RESERVOIR PRESSURE, PSIA</u>	<u>10,720</u>	<u>10,550</u>	<u>10,400</u>	<u>10,118</u>	<u>9,030</u>	<u>8,780</u>	<u>8,554</u>
METHANE, % MOL	91.8	91.6	91.6	91.2	89.9	90.6	90.5
ETHANE, % MOL	1.8	1.8	1.8	1.8	1.8	1.8	1.6
CARBON DIOXIDE, % MOL	5.8	5.9	5.9	6.2	7.5	6.9	7.2
<u>RESERVOIR PRESSURE</u>	<u>8,310</u>	<u>8,024</u>	<u>7,824</u>	<u>7,625</u>	<u>7,614</u>	<u>7,603</u>	
METHANE, % MOL	90.7	90.5	90.5	90.8	90.5	90.0	
ETHANE, % MOL	1.6	1.6	1.6	1.5	1.5	1.6	
CARBON DIOXIDE, % MOL	7.0	7.2	7.4	7.0	7.3	7.5	

* BRINE/GAS SEPARATOR PRESSURE WAS 500 PSIG.

Table 7-1

SWEET LAKE MICROSEISMIC MONITORING
NETWORK STATION COORDINATES.

	<u>Latitude</u>	<u>Longitude</u>
CPT	30°N02'37"	93°W12'47"
CPF	30°N00'04"	93°W08'02"
CLB	30°N01'16"	93°W08'43"
SFY	30°N00'50"	93°W10'56"
HWN	30°N01'05"	93°W05'19"
WLR	30°N03'34"	93°W07'41"
JCF	30°N02'16"	93°W07'01"
HWS	29°N59'33"	93°W05'17"

TABLE 8-1
COST ESTIMATE HISTORY
SWEET LAKE PROJECT

	1974		1976		1979		1979		1984	
	GGC PROPOSAL HOUSE ENERGY COMMITTEE		MAGMA GULF PROPOSAL ERDA		MAGMA GULF PROPOSAL DOE (OPTION 1)		MAGMA GULF-TECHNADRIL DOE CONTRACT		MAGMA GULF-TECHNADRIL PROJECT TOTAL	
TEST WELL	3,500,000	36.0%	3,000,000	78.6%	3,517,800	42.1%	3,446,308	44.1%	8,067,124.49	49.9%
DISPOSAL WELL	800,000	8.2%	500,000	13.1%	1,407,800	16.9%	781,051	10.0%	1,505,592.12	9.3%
TESTING	900,000 ¹	9.4%	200,000 ³	5.2%	291,550	3.5%	356,784	4.6%	1,272,134.90	7.9%
WORKOVER									1,184,445.00	7.3%
SURFACE FACILITIES	4,500,000 ²	46.4%			1,465,540	17.5%	1,793,449	22.9%	1,514,051.74	9.4%
ADMINISTRATION - OVERHEAD			66,967	1.8%	1,567,201	18.8%	1,439,213	18.4%	2,383,805.38	14.8%
P & A - SITE RESTORATION			50,000	1.3%	102,000	1.2%	costs included above		225,000.00	1.4%
TOTALS	9,700,000		3,816,967		8,351,891		7,816,805 ⁴		16,152,153.63 ⁵	

1. Includes production well testing and other long term tests not included in other proposals
2. Includes commercial electrical generating facilities
3. 6 month test does not include surface facilities
4. Does not include 7.9%
5. Does not include 5.0% fee

TABLE 3

MAGMA GULF COMPANY - ANALYSIS OF CAMERON PARISH GEOPRESSURED AQUIFER
ESTIMATED GAS PRODUCTION, INCOME AND PAY-OUT SCHEDULE

TABLE 8-2

stop reimbursement
at pay-out

SWEET LAKE
GEOPRESSURED-GEOTHERMAL PROJECT
MAGMA GULF-TECHNADRIL/DOE AMOCO FEE

VOLUME III

FINAL REPORT

PART 2
APPENDICES

ANNUAL REPORT
for the period
February 1982 - March 1985

C.O. DURHAM, JR., F.D. O'BRIEN, & R.W. RODGERS
Editors

Magma Gulf-Technadril
430 Hwy. 6 South, Suite 208
Houston, Texas 77079

Prepared for the
U.S. Department of Energy
Division of Energy Technology
Under Contract DE-AC08-80NV10081

Part 2
Appendices

No.	Title	Page	of Reference
A.	Sand Zone 5 Flow History	212	68,70
B.	Sand Zone 3 Flow History	226	73
C.	Engineering Interpretation Miogypsinoides Geopressed Reservoirs MG-T/DOE Amoco Fee No. 1 Well Sweet Lake Area Cameron Parish, Louisiana July 1984; J. Donald Clark, P.E.	234	68,76
D.	IGT Test Activities On The MG-T/DOE Amoco Fee No. 1 Well During August 1981; C.G. Hayden, P.L. Randolph, T.L. Osif; Prepared by Institute of Gas Technology.	289	50,65
E.	Well Test Analysis MG-T/DOE Amoco Fee No. 1 Sweet Lake Project Sand Zone #3, January 1984; Prepared by Dowdle Fairchild and Ancell, Inc.	320	76
F.	Distribution of Cores	337	
G.	Gas Water Ratio Measurements, Sept. 1981.	343	79
H.	Separator Water Flush; Weatherly Laboratories, Inc.	351	
I.	Reservoir Fluid Analysis For Magma Gulf-Technadril, MG-T/DOE Amoco Fee No. 1 Well, Sand Zone No. 3, Weatherly Laboratories Inc.	363	
J.	Gas Analysis as a Function of Separator Pressure; Weatherly Laboratories, Inc.	389	
K.	A Base Line For Determining Local, Small - Scale Vertical Movements In Louisiana by Drukell B. Trahan.	411	94
L.	Plug and Abandon Correspondence and Permits - Production and Salt Water Disposal Wells.	431	99

Appendix A SAND ZONE 5 FLOW HISTORY

- 6/16/81 Schlumberger perforating equipment rigged down and moved off the wellsite at 12:40 pm. This marks the official beginning of the Testing Phase. Surface pressure stabilized at approximately 4000 psig after an initial surge of 4200 psig. Reservoir Data (RDI) equipment moved onto the wellsite at 1:30 p.m. and RDI personnel began rigging up. RDI completed rigging up for bottom-hole pressure and temperature measurements at 8:00 pm and began going in the hole at 10:15 p.m. with an HP gauge.
- 6/17/81 RDI reached the target depth of 15,337 feet at 1:08 a.m. Descent rate was approximately 135 feet/min. Stabilization of the HP gauge began at this time with a bottom-hole pressure of 12,250 psia. The bottom-hole pressure began to stabilize at 12,064 psia at 6:00 a.m. The HP gauge malfunctioned for unknown reasons at 9:00a.m. and was pulled out of the hole by 12:00 p.m., at an ascent rate of 102 feet/min. At 1:40 p.m. a GRC-512 gauge with integral temperature measurement capability was installed on the wire line and this gauge started into the hole at 1:55 p.m. The desired depth of 15,400 feet was reached at 4:20 p.m., at a descent rate of 106 feet/min. Stabilization of GRC gauge was begun.
- 6/18/81 The GRC gauge had not stabilized by 1:30 a.m., after 9 hours in the hole. Decision was made to abandon this gauge and change to an HP gauge. Due to problems with the RDI computer, the new gauge did not start into the hole until 7:53 P.M. The gauge was on bottom (15,337 feet) at 9:40 p.m.
- 6/19/81 By 2:00 p.m., the HP gauge had been equilibrating for 16 1/2 hours, and the bottom-hole pressure was still decreasing at about 4 psi/hour. The reservoir engineer, Don Clark, felt that he could correct his calculations for this decrease, and so the decision was made to begin the Initial Flow Test. At 2:35 p.m. the well was opened up and it immediately blew out a line on the inhibitor system. This was corrected and the Initial Flow Test began at 6:18 p.m. at a rate of 2900 B/D, with the brine going to the blow down tanks for clean-up. Bottoms came up at 8:45 p.m., at 300 barrels production. By 9:00 p.m., the production rate had increased to about 4,680 B/D, and surface pressure was 4600 psig. Samples were filtered through 45 micron filters at 11:00 p.m. Clay and lignosulfonate drilling mud were noted, but no sand.
- 6/20/81 By 1:30 a.m., the filtered brine samples showed enough improvement to switch production through the surface facilities to the disposal well. Purging of the separator with nitrogen was begun at 1:45 a.m. and completed at 3:00 a.m. Brine production was switched to the separator at 4:15 a.m. At 5:30 a.m. some difficulty developed in flowing to the

allowed to decrease to 14,000 B/D and then remained constant. Bottom-hole pressure was 8040 psia and surface pressure 965 psia at 11:00 p.m.

- 7/6/81 Flow rate varied between 13,500 - 14,500 B/D. Well shutin for short time at 11:09 a.m. Bottom-hole pressure was 8033 psia and surface pressure was 958 psia at 11:00 p.m.
- 7/7/81 Flow rate decreased around noon to 12,000 B/D and then remained constant for remainder of day. Bottom-hole pressure 7981 psia and surface pressure 912 psia at 11:00 p.m.
- 7/8/81 Flow rate remained constant 12,000 B/D. Bottom-hole pressure 7950 psia and surface pressure 900 psia at 11:00 p.m.
- 7/9/81 Flow rate dropped from 12,000 B/D to 11,500 B/D at 7:00 p.m. Bottom-hole pressure 7924 psia and surface pressure 850 psia at 11:00 a.m.
- 7/10/81 Flow rate continued at 11,500 - 12,000 B/D. Separator pressure was decreased to 300 psia at 7:00 p.m. After 1 1/2 hours, the separator level decreased to 0%. Numerous attempts were made between 9:00 p.m. and 7:00 a.m. to get the pressure and level set. Bottom-hole pressure was 7878 psia and surface pressure 767 psia at 11:00 p.m.
- 7/11/81 Flow rate continued to vary between 11,500 - 12,000 B/D. Separator pressure could not be maintained at 300 psia, since the reservoir pressures were too low. Bottom-hole pressure was 7850 and surface pressure 756 psia at 11:00 p.m.
- 7/12/81 Flow maintained at 11,500 B/D. Bottom-hole pressure was 7,858 psia and surface pressure 745 psia at 11:00 p.m.
- 7/13/81 Flow maintained at 11,500 B/D. Bottom-hole pressure was 7844 psia and surface pressure 745 psia at 11:00 p.m.
- 7/14/81 Flow rate decreased from 11,500 B/D to 11,000 B/D at 3:00 p.m. Glacial acetic acid was added in addition to the AMP-20 inhibitor. Bottom-hole pressure was 7835 psia and surface pressure 736 psia at 11:00 p.m.
- 7/15/81 Flow rate decreased to 10,500 B/D between 1:00 - 5:00 p.m. but was maintained at 11,000 B/D for the remainder of the day. Bottom-hole pressure was 7817 psia and surface pressure 726 psia at 11:00 p.m.
- 7/16/81 Flow rate maintained at 11,000 B/D. Bottom-hole pressure was 7804 psia and surface pressure 711 psia at 11:00 p.m.
- 7/17/81 Reservoir Limit test was completed today. RDI began out of the hole at 5:45 p.m. and was out of the hole at 8:00 p.m.

Last bottom-hole pressure reading was 7806 psia at 5:00 p.m. Surface pressure still being measured by Pannex surface gauge. Flow rate was maintained at 11,000 B/D. AMP-20 concentration decreased to 7 ppm. Surface pressure was 717 psia at 11:00 p.m.

- 7/18/81 Flow rate maintained at 11,000 B/D. Surface pressure was 704 psia at 11:00 p.m.
- 7/19/81 Flow rate maintained at 11,000 B/D. Surface pressure was 704 psia at 11:00 p.m.
- 7/20/81 Flow rate varied between 11,000 - 10,000 B/D, but was 10,500 B/D at end of day. Surface pressure was 700 psia at 11:00 p.m.
- 7/21/81 Flow rate maintained at 10,500 B/D. Surface pressure was 696 psia at 11:00 p.m.
- 7/22/81 Flow rate had decreased slightly on its own to 10,300 B/D. Flow rate was cut back at 11:00 a.m. and decreased gradually over the next few hours until it stabilized at 2400 B/D at 9:00 p.m. Surface pressure was 1999 psia at 11:00 p.m. Lowest surface pressure was 691 psia at 9:00 a.m.
- 7/23/81 Flow rate decreased at 9:15 a.m. to 1100 B/D. Surface pressure was 2752 psia at 11:00P.M.
- 7/24/81 Flow rate varied between 1100 - 1000 B/D. Surface pressure was 3071 at 11:00 p.m.
- 7/25/81 Flow rate varied between 1100 - 2075 B/D. Surface pressure was 3203 psia at 11:00 p.m.
- 7/26/81 Flow rate varied between 1632 - 2075 B/D. Surface pressure was 3282 at 11:00 p.m.
- 7/27/81 Flow rate varied between 1260 - 2856 B/D. Surface pressure was 3402 at 11:00 p.m.
- 7/28/81 Well shut in at 9:03 a.m. to remove RDI spools and install a positive displacement meter in the flare gas line.
- 7/29/81 Valves were changed out and the well was opened at 7:00 p.m., at a rate of 2000 B/D. Surface pressure was 3594 at 11:00 p.m.
- 7/30/81 Flow rate 2000 B/D for most of day. Rate increased to 10,000 B/D at 9:20 a.m. and decreased to 2000 B/D at 12:20 p.m. Surface pressure was 3463 at 11:00 p.m.
- 7/31/81 Flow rate varied between 2000-2400 B/D. Surface pressure was 3463 at 11:00 p.m.

8/1/81 Flow rate 2300 B/D. Surface pressure was 3524 psia at 11:00 p.m.

8/2/81 Flow rate decreased to 2100 B/D at 9:00 a.m. Surface pressure was 3564 psia at 11:00 p.m.

8/3/81 Flow rate 2200 B/D from 9:00 a.m. to 1:00 p.m., and 2100 B/D for remainder of day. Surface pressure was 3598 psia at 11:00 p.m.

8/4/81 Flow rate dropped to 2000 B/D at 1:00 p.m. Surface pressure was 3650 psia at 11:00 p.m.

8/5/81 A new orifice plate was installed at 7:00 p.m. Flow rate maintained at 2000 B/D. Surface pressure was 3674 psia at 11:00 p.m.

8/6/81 Flow rate reduced to 1400 B/D at 9:10 p.m. Surface pressure was 3729 psia at 11:00 p.m.

8/7/81 Flow rate maintained at 1400 B/D. Surface pressure was 3798 psia at 11:00 p.m.

8/8/81 Well was shut in at 10:00 a.m. to install a new orifice flange.

8/9/81 Well opened at 8:00 p.m. Flow rate varied from 1450 - 1400 B/D. Surface pressure was 3950 psia at 11:00 p.m.

8/10/81 Flow rate maintained at 2000 B/D. Surface pressure 3875 at 11:00 p.m.

8/11/81 Well shut in at 7:00 a.m. to insert two new orifice flanges. Flow began again at 5:00 p.m. at a rate of 2,000 B/D and a pressure of 3896 psia. Flow rate was increased to 34,000 B/D at 8:00 p.m. Surface pressure had dropped to 1095 psia at 11:00 p.m.

8/12/81 Flow rate decreased to 25,000 B/D at 3:00 a.m. and then to 24,000 B/D. Surface pressure was 708 psia at 11:00 p.m.

8/13/81 Flow rate decreased to 20,000 B/D at 5:00 a.m. Well was shut in between 11:00 a.m. and 7:00 p.m. Initial rate of 18,000 B/D decreased to 16,500 by midnight. Surface pressure 727 psia at 11:00 p.m.

8/14/81 Flow rate decreased to 13,500 B/D by 5:00 a.m., then reduced to 2000 B/D at 11:00 a.m. Rate varied between 2000 - 2200 B/D for remainder of day. Surface pressure 2484 at 11:00 p.m.

8/15/81 Rate variable in morning, from 1200 - 2300 B/D. Rate increased to 20,000 B/D from 3:00 - 5:00 p.m. and reduced to

2100 B/D by 6:00 p.m. Surface pressure 3072 psia at 11:00 p.m.

8/16/81 Flow rate increased from 2100 B/D to 15,000 B/D at 10:00 a.m., and then to 18,000 B/D at 7:00 p.m. Surface pressure 673 psia at 11:00 p.m.

8/17/81 Well flowed at 20,000 B/D while Schlumberger rigged up for perforating. At 8:30 p.m. the wireline hit an obstruction at 15,417. Schlumberger pulled out of the hole and Otis was called for a bailer to bring up a sample.

8/18/81 Well shut in all day

8/19/81 Well shut in all day. Surface pressure 3600 psig.

8/20/81 Well shut in all day.

8/24/81

8/25/81 Well opened at 7:00 p.m. at flow rate of approximately 3000 B/D.

8/26/81 Flow rate 2800 B/D. Surface pressure 3788 psia at 11:00 p.m.

8/27/81 Flow rate 2800 B/D. Surface pressure 3762 psia at 11:00 p.m.

8/28/81 Flow rate 2800 B/D. Surface pressure 3752 psia at 11:00 p.m.

8/29/81 Flow rate 2800 B/D. Surface pressure 3755 psia at 11:00 p.m.

8/30/81 Flow rate 2800 B/D. Surface pressure 3753 psia at 11:00 p.m.

8/31/81 Flow rate increased to 5000 B/D at 3:00 p.m. and then to 13,500 at 9:00 p.m. Surface pressure 3753 psia at 11:00 p.m.

9/1/81 Flow rate gradually increased to 15,000 B/D at 7:00 a.m. Well shut in between 1:00 p.m. and 5:00 p.m. Flow rate 6000 B/D, gradually decreased to 4800 B/D. Surface pressure 2590 psia at 11:00 p.m.

9/2/81 Flow rate 5000 B/D. Surface pressure 2759 psia at 11:00 p.m.

9/3/81 Well shut in from 7:00 a.m. to 7:00 p.m. to replace leading ring gasket. Well opened up at flow rate of 5,000 B/D. Surface pressure 2970 psia at 11:00 p.m.

9/4/81 Flow rate 5000 B/D. Surface pressure 2810 psia at 11:00 p.m.

9/5/81 Flow rate 5000 - 5200 B/D. Surface pressure 2723 at 11:00 p.m.

9/6/81 Flow rate 5100 - 5200 B/D. Surface pressure 2688 psia at 11:00 p.m.

9/7/81 Well shut in.

9/8/81 Well shut in.

9/9/81 Flow rate increased from 2800 B/D to 15,000 B/D at 9:00 a.m. Rate decreased to 14,000 at 5:00 p.m., 13,500 at 7:00 p.m., and 13,000 at 9:00 p.m. Surface pressure 1328 at 11:00 p.m.

9/10/81 Flow rate gradually decreased from 13,000 B/D at 1:00 a.m. to 11,500 B/D at 1:00 p.m. Rate increased to 14,000 B/D at 5:00 p.m. and then decreased to 10,000 B/D at 9:00 p.m. Surface pressure 1294 psia at 11:00 p.m.

9/11/81 Flow rate 10,000 B/D. Surface pressure 1115 psia at 11:00 p.m.

9/12/81 Flow rate 10,000 B/D. Surface pressure 997 psia at 11:00 p.m.

9/13/81 Flow rate 10,000 B/D. Surface pressure 868 psia at 11:00 p.m.

9/14/81 Flow rate 10,000 B/D. Surface pressure 851 psia at 11:00 p.m. Addition of glacial acetic acid discontinued.

9/15/81 Flow rate 10,000 B/D. Surface pressure 830 psia at 11:00 p.m.

9/16/81 Flow rate dropped from 10,000 B/D to 9750 B/D at 300 a.m., and dropped again to 9500 B/D at 5:00 p.m. Surface pressure 815 psia at 11:00 p.m.

9/17/81 Flow rate varied between 9000 - 10,000 B/D. Inhibitor (AMP-20) concentration decreased at 5 ppm. Surface pressure 753 psia at 11:00 p.m.

9/18/81 Flow rate dropped from 10,000 B/D to 9500 B/D at 11:00 a.m. Surface pressure 730 psia at 11:00 p.m.

9/19/81 Flow rate 9500 B/D. Surface pressure 700 psia at 11:00 p.m.

9/20/81 Flow rate 9500 B/D, decreased to 9200 B/D at 7:00 p.m. Surface pressure 700 psia at 11:00 p.m.

9/21/81 Flow rate 9500 B/D. Surface pressure 685 psia at 11:00 p.m.

9/22/81 Flow rate 9500 B/D. Surface pressure 675 psia at 11:00 p.m.

9/23/81 Flow rate 9500 B/D. Surface pressure 560 psia at 11:00 p.m.

9/24/81 Flow rate 9500 B/D. Surface pressure 540 psia at 11:00 p.m.

9/25/81 Flow rate 9750 B/D. Surface pressure 533 psia at 11:00 p.m.

9/26/81 Flow rate 9750 B/D. Surface pressure 520 psia at 11:00 p.m.

9/27/81 Flow rate dropped from 9750 B/D to approximately 5000 B/D at 11:00 a.m. Rate varied from 5200 - 5500 B/D thereafter. Surface pressure 1447 psia at 11:00 p.m.

9/28/82 Flow rate increased to 9750 B/D by 9:00 a.m. Surface pressure 515 psia at 11:00 p.m.

9/29/81 Flow rate dropped from 9750 B/D to approximately 5000 B/D at 11:00 a.m. Rate varied from 5200 - 5500 B/D thereafter. Surface pressure 1497 psia at 11:00 p.m.

9/30/81 Flow rate varied between 4900 - 5500 B/D. Surface pressure 1861 psia at 11:00 p.m.

10/1/81 Well shut in at 10:00 a.m. due to Emergency Shutdown System malfunction. Well opened up at 5:00 p.m., at a rate of 4400 - 4600 B/D. Inhibitor concentration now 3 ppm AMP-20. Surface pressure 2065 psia at 11:00 p.m.

10/2/81 Flow rate increased from 3600 B/D to 5200 B/D at 11:00 a.m. Surface pressure 2065 psia at 11:00 p.m.

10/3/81 Flow rate 5000 - 5200 B/D. Surface pressure 2015 psia at 11:00 p.m.

10/4/81 Flow rate 5000 - 5200 B/D. Surface pressure 2010 psia at 11:00 p.m.

10/5/81 Flow rate 4600 - 5200 B/D. Surface pressure 2146 psia at 11:00 p.m.

10/6/81 Flow rate 4800 - 5200 B/D. Surface pressure 2063 psia at 11:00 p.m.

10/7/81 Flow rate 4900 - 5200 B/D. Surface pressure 2042 psia at 11:00

10/8/81 Flow rate 4900 - 5200 B/D. Surface pressure 2048 psia at 11:00 p.m.

10/9/81 Flow rate 5000 - 5200 B/D. Surface pressure 2044 psia at 11:00 p.m.

10/10/81 Flow rate 5000 B/D. Surface pressure 2040 psia at 11:00 p.m.

10/11/81 Flow rate 5000 B/D. Surface pressure 2075 psia at 11:00 p.m.

10/12/81 Flow rate 5000 B/D. Surface pressure 2075 psia at 11:00 p.m.

10/13/81 Well shut in at 9:00 a.m. to repair leak on turbine meter and to check for corrosion in welds.

10/14/81 Well shut in for repairs.

10/23/81 Well shut in.

10/24/81 Well opened up at 3:00 p.m. at rate of 5000 B/D. Surface pressure 3310 at 11:00 p.m.

10/25/81 Flow rate 5000 B/D. Surface pressure 2900 psia at 11:00 p.m.

10/26/81 Flow rate 5000 B/D. Surface pressure 2725 psia at 11:00 p.m.

10/27/81 Flow rate 5000 B/D. Surface pressure 2645 psia at 11:00 p.m.

10/28/81 Flow rate 4800 - 5000 B/D. Surface pressure 2598 psia at 11:00 p.m.

10/29/81 Flow rate 4800 B/D. Surface pressure 2554 psia at 11:00 p.m.

10/30/81 Flow rate 4800 - 5000 B/D. Surface pressure 2508 psia at 11:00 p.m.

10/31/81 Flow rate 4800 - 4900 B/D. Surface pressure 2474 psia at 11:00 p.m.

11/1/81 Flow rate 4800 - 4900 B/D. Surface pressure 2463 psia at 11:00 p.m.

11/2/81 Flow rate 4800 - 5000 B/D. Surface pressure 2423 psia at 11:00 p.m. Inhibitor concentration now 1 ppm AMP-20.

11/3/81 Flow rate 4900 - 5000 B/D. Surface pressure 2371 psia at 11:00 p.m.

11/4/81 Flow rate 4800 - 5000 B/D. Surface pressure 2371 psia at 11:00 p.m.

11/5/81 Flow rate 5000 B/D. Surface pressure 2355 psia at 11:00 p.m.

11/6/81 Flow rate 5000 B/D. Surface pressure 2347 psia at 11:00 p.m.

11/7/81 Flow rate 5000 B/D. Surface pressure 2346 psia at 11:00 p.m.

11/8/81 Well shut in at 3:00 a.m. due to leak on choke skid.

11/9/81	Well opened up at 1:00 p.m. at 4900 - 5000 B/D. Surface pressure 2866 psia at 11:00 p.m.
11/10/81	Flow rate 5000 - 5100 B/D. Surface pressure 2524 psia at 11:00 p.m.
11/11/81	Flow rate 5000 - 5400 B/D. Surface pressure 2408 psia at 11:00 p.m.
11/12/81	Flow rate 5000 - 5400 B/D. Surface pressure 2308 at 11:00 p.m.
11/13/81	Flow rate 5200 B/D. Surface pressure 2272 psia at 11:00 p.m.
11/14/81	Flow rate 5200 B/D. Surface pressure 2238 psia at 11:00 p.m.
11/15/81	Flow rate 5200 - 5300 B/D. Surface pressure 2221 psia at 11:00 p.m.
11/16/81	Flow rate 5100 - 5200 B/D. Surface pressure 2208 psia at 11:00 p.m.
11/17/81	Flow rate 5200 - 5300 B/D. Surface pressure 2203 psia at 11:00 p.m.
11/18/81	Flow rate 5200 B/D. Surface pressure 2190 psia at 11:00 p.m.
11/19/81	Flow rate 5100 - 5200 B/D. Surface pressure 2180 psia at 11:00 p.m.
11/20/81	Flow rate 5200 B/D. Surface pressure 2185 psia at 11:00 p.m.
11/21/84	Flow rate 5100-5200 B/D. Surface pressure 2180 psia at 11:00 p.m.
11/22/81	Flow rate 5200 B/D. Surface pressure 2180 psia at 11:00 p.m.
11/23/81	Flow rate 5200 B/D. Surface pressure 2175 psia at 11:00 p.m.
11/24/81	Flow rate 5200 B/D. Surface pressure 2180 psia at 11:00 p.m.
11/25/81	Well shut in at 9:00 a.m. to replace the Willis choke body. Well opened up at 3:00 p.m. at rate of 4800 - 4900 B/D. Surface pressure 2358 psia at 11:00 p.m.
11/26/81	Flow rate 4600 - 4800 B/D. Surface pressure 2324 psia at

11:00 p.m.

11/27/81	Flow rate 4600 - 5000 B/D. Surface pressure 2296 psia at 11:00 p.m.
11/28/81	Flow rate 4700 - 4900 B/D. Surface pressure 2279 psia at 11:00 p.m.
11/29/81	Flow rate 5000 - 5200 B/D. Surface pressure 2198 psia at 11:00 p.m.
11/30/81	Flow rate 3800 - 5200 B/D. Surface pressure 2188 psia at 11:00 p.m.
12/1/81	Flow rate 5000 B/D in morning. Well shut in between 1:00 p.m. - 7:00 p.m. Flow rate 5200 - 5400 B/D in evening. Surface pressure 2279 psia at 11:00 p.m.
12/2/81	Flow rate 5100 - 5200 B/D. Surface pressure 2197 psia at 11:00 p.m.
12/3/81	Flow rate 5000 - 5100 B/D. Surface pressure 2175 psia at 11:00 p.m.
12/4/81	Flow rate 5000 B/D. Surface pressure 2175 psia at 11:00 p.m.
12/5/81	Flow rate 5000 B/D. Well shut in at 7:00 p.m. due to power failure.
12/6/81	Well opened at 1:00 p.m. at approximately 5000 B/D.
12/7/81	Flow rate 4800 - 5000 B/D. Surface pressure 2294 psia at 11:00 p.m.
12/8/81	Flow rate 4800 B/D. Surface pressure 2276 psia at 11:00 p.m.
12/9/81	Flow rate 4800 - 5000 B/D. Surface pressure 2255 psia at 11:00 p.m.
12/10/81	Flow rate 4700 - 5000 B/D. Surface pressure 2189 psia at 11:00 P.M.
12/11/81	Well shut in at 11:30 a.m. to repair choke skid.
12/12/81	Well opened up at 7:00 p.m. at 5000 B/D. Surface pressure 2756 psia at 11:00 p.m.
12/13/81	Flow rate 4600 - 5200 B/D. Surface pressure 2352 psia at 11:00 p.m.
12/14/81	Flow rate 5000 - 5200 B/D. Surface pressure 2260 psia at 11:00 p.m.
12/15/81	Flow rate 5000 - 5600 B/D. Surface pressure 2166 psia at 11:00 p.m.

12/16/81 Flow rate 5100 - 5200 B/D. Surface pressure 2125 psia at 11:00 p.m.

12/17/81 Flow rate 5100 - 5200 B/D. Surface pressure 2110 psia at 11:00 p.m.

12/18/81 Flow rate 5100 B/D. Surface pressure 2115 psia at 11:00 p.m.

12/19/81 Flow rate 5100 B/D. Surface pressure 2115 psia at 11:00 p.m.

12/20/81 Flow rate 5100 B/D. Surface pressure 2090 psia at 11:00 p.m.

12/21/81 Flow rate decreased from 5100 B/D to 2500 B/D at 3:00 p.m. Surface pressure 2575 at 11:00 p.m.

12/22/81 Flow rate B/D. Surface pressure 2780 psia at 11:00 p.m.

12/23/81 Flow rate 2400 - 2600 B/D. Surface pressure 2873 psia at 11:00 p.m.

12/24/81 Well shut in at 7:00 a.m.

12/25/81 Well shut in.

12/26/81 Well opened up at 11:00 a.m. at 2100 - 2200 B/D. Surface pressure 3320 psia at 11:00 p.m.

12/27/81 Flow rate 2000 - 2100 B/D. Surface pressure 3254 psia at 11:00 p.m.

12/28/81 Flow rate 2000 - 2200 B/D. Surface pressure 3232 psia at 11:00 p.m.

12/29/81 Flow rate 2000 - 2200 B/D. Surface pressure 3258 psia at 11:00 p.m.

12/30/81 Flow rate 2000 - 2200 B/D. Surface pressure 3258 psia at 11:00 p.m.

12/31/81 Flow rate 2100 B/D. Surface pressure 3245 psia at 11:00 p.m.

1/1/82 Flow rate 2100 B/D. Surface pressure 3278 psia at 11:00 p.m.

1/2/82 Flow rate 2100 B/D. Surface pressure 3283 psia at 11:00 p.m.

1/3/82 Flow rate 2100 B/D. Surface pressure 3286 psia at 11:00 p.m.

1/4/82 Flow rate 2100 B/D. Surface pressure 3300 psia at 11:00 p.m.

1/5/82 Flow rate increased from 2100 B/D to 4000 B/d at 7:00 p.m., and increased gradually to 5000 B/D by 11:00 p.m. Surface pressure 2798 psia at 11:00 p.m.

1/6/81 Well shut in to replace Emergency Shutdown System.

1/7/82 Well opened up at 9:00 p.m. at 3000 B/D. Surface pressure 3355 2355 psia at 11:00 p.m.

1/8/81 Flow rate increased from 3000 B/D to 4600 - 4900 B/D at 1:00 p.m. Surface pressure 2897 psia at 11:00 p.m.

1/9/82 Flow rate 4400 - 4800 B/D. Surface pressure 2761 psia at 11:00 p.m.

1/10/82 Flow rate 4200 - 4600 B/D. Surface pressure 2686 psia at 11:00 p.m.

1/11/82 Flow rate 4200 - 5200 B/D. Surface pressure 2665 psia at 11:00 p.m.

1/12/82 Flow rate 3800 - 4800 B/D. Surface pressure 2625 at 11:00 p.m.

1/13/82 Flow rate 4300 - 5400 B/D. Surface pressure 2500 psia at 11:00 p.m.

1/14/82 Well shut in at 4:00 a.m. due to malfunction in Emergency Shutdown System. Well opened up at 9:00 p.m. at 5000 B/D. Surface pressure 2795 psia at 11:00 p.m.

1/15/82 Flow rate 5000 B/D. Surface pressure 2620 psia at 11:00 p.m.

1/16/82 Flow rate 5000 B/D. Surface pressure 2615 psia at 11:00 p.m.

1/17/82 Flow rate 5000 B/D. Surface pressure 2510 psia at 11:00 p.m.

1/18/82 Flow rate 5000 B/D. Surface pressure 2465 psia at 11:00 p.m.

1/19/82 Flow rate 5000 - 5100 B/D. Surface pressure 2445 psia at 11:00 p.m.

1/20/82 Flow rate 5100 B/D. Well shut down between 11:00 a.m. and 5:00 p.m. to correct Emergency Shutdown System problems. Surface pressure 2482 psia at 11:00 p.m.

1/21/82 Well shut in between 1:00 a.m. and 5:00 a.m. due to power failure. Flow rate 5000 - 5100 B/D. Surface pressure 2532 psia at 11:00 p.m.

1/22/82 Flow rate 5000 B/D. Surface pressure 2475 psia at 11:00 p.m.

1/23/82 Flow rate 5000 B/D. Surface pressure 2479 psia at 11:00 p.m.

1/24/82 Flow rate 5000 B/D. Surface pressure 2466 psia at 11:00 p.m.

1/25/82 Flow rate 5000 B/D. Well shut in between 11:00 a.m. and 3:00 p.m. and between 5:00 p.m. and 9:00 p.m. for maintenance work. Surface pressure 2482 psia at 11:00 p.m.

1/26/82 Flow rate 5000 B/D. Surface pressure 2460 psia at 11:00 p.m.

1/27/82 Flow rate 5000 B/D. Well shut in at 9:00 a.m., opened up between 11:00 a.m. and 1:00 p.m., and shut down at 1:00 p.m. to clean out separator.

1/28/82 Well opened up at 7:00 p.m. at a rate of 5000 B/D. Surface pressure 2831 psia at 11:00 p.m.

1/29/82 Flow rate 4800 - 5200 B/D. Surface pressure 2590 psia at 11:00 p.m.

1/30/82 Flow rate 5200 B/D. Surface pressure 2500 psia at 11:00 p.m.

1/31/82 Flow rate 5100 - 5200 B/D. Surface pressure 2470 psia at 11:00 p.m.

2/1/82 Increased flow to 10,000 B/D. at 8:00 a.m. Reduced flow to 7000 B/D at 10:30 a.m. Surface pressure 2103 psia at 11:00 p.m.

2/2/82 Increased flow at 8:30 a.m. to 8900 B/D. Reduced flow to 7000 B/D at 3:45 p.m. Increased to 8000 B/D at 9:00 p.m. Surface pressure 1850 psia at 11:00 p.m.

2/3/82 Flow rate decreased to 5000 B/D. at 1:00 p.m., dropped to 4000 B/D at 5:00 p.m., and increased to 16,000 B/D at 7:00 p.m. Rate decreased gradually to 13,500 B/D by 11:00 p.m. Surface pressure 925 psia at 11:00 p.m.

2/4/82 Flow rate decreased to 10,000 B/D by 5:00 p.m. and constant thereafter. Surface pressure 937 psia at 11:00 p.m.

2/5/82 Well shut in at 10:00 a.m. Well opened up at 7:00 p.m. at 5000 B/D. Surface pressure 1978 psia at 11:00 p.m.

2/6/82 Flow rate 5000 B/D. Surface pressure 2130 psia at 11:00 a.m.

2/7/82 Flow rate 5000 - 5300 B/D. Surface pressure 2186 psia at 11:00 a.m.

2/8/82 Well shut in.

2/9/82 Flow rate increased to 9000 - 10,000 B/D at 11:00 a.m., then decreased to 5400 B/D at 3:00 p.m. Surface pressure 2499 psia at 11:00 p.m.

2/10/82 Well shut in at 7:00 a.m. due to sanding of disposal well.

Appendix B SAND ZONE 3 FLOW HISTORY

11/11/83 15,260 - 15,280 foot interval of Sand 3 perforated at 3:00 p.m. Surface pressure 3650 psia immediately following perforation. Second interval (15,245 - 15,255 feet) perforated at 7:50 p.m. RDI began rigging up immediately.

11/12/83 RDI reached top of perforations (15,245 feet) at 6:30 a.m. Original reservoir pressure 11,887 psia, original temperature 293°F. Surface pressure 3660 psia with 10.5 ppg calcium chloride in the well. Well opened up to blowdown tanks at 11:50 a.m. Flow rate 2800 B/D Bottoms-up reached at 2:30 p.m. Flow rate increased to 4000 B/D. Flow diverted to separator at 8:00 p.m. Brine production switched to disposal well at 10:00 p.m.

11/13/83 Well shut in at 11:50 a.m. Initial Flow Test of Sand 3 completed. Bottom-hole pressure 10,133 psia. Leak necessitated removing wireline equipment at 8:15 p.m. Build-up test began.

11/14/83 Build-up test continuing. Surface pressure 4444 psia.

11/15/83 Build-up test continuing. Surface pressure 4498 psia.

11/16/83 Build-up test continuing. Surface pressure 4514 psia.

11/17/83 Build-up test continuing. Surface pressure 4530 psia at 11:00 p.m.

11/18/83 Build-up test continuing. Surface pressure 4549 psia at 11:00 p.m.

11/19/83 Build-up test continuing. Surface pressure 4573 psia at 11:00 p.m.

11/20/83 Build-up test continuing. Surface pressure 4587 psia at 11:00 p.m.

11/21/83 Build-up test continuing. Surface pressure 4587 psia at 11:00 p.m. RDI began rigging up at 6:00 p.m.

11/22/83 RDI began measurements at 3:52 a.m. Bottom-hole pressure 11,799 psia at that time. Well opened at 8:50 a.m. Bottom-hole pressure at start of test 11,794 psia, surface pressure 4592 psia. Flow rate 2300 B/D. Bottom-hole pressure 10,949 psia at 11:00 p.m., flow rate 2225 B/D at that time.

11/23/83 Power failure at 5:30 a.m. Readings begun again at 9:00 a.m. Flow rate 2100 B/D. Bottom-hole pressure 10,664 psia at 11:00 p.m.

11/24/83	Flow rate 2100 B/D. Bottom-hole pressure 10,495 psia at 11:00 p.m.
11/25/83	Flow rate 2100 B/D. Bottom-hole pressure 10,370 psia at 11:00 p.m.
11/26/83	Flow rate 2100 B/D. Bottom-hole pressure 10,258 psia at 11:00 p.m.
11/27/83	Flow rate 2000 B/D. Bottom-hole pressure 10,170 psia at 11:00 p.m.
11/28/83	Flow rate 2000 B/D. Bottom-hole pressure 10,094 psia at 11:00 p.m.
11/29/83	Flow rate increased to 4900 B/D at 3:00 p.m. Bottom-hole pressure 8860 psia at 11:00 p.m.
11/30/83	Flow rate increased to 5300 B/D at 11:00 a.m. and then to 5700 B/D at 3:00 p.m. Bottom-hole pressure 8079 psia at 11:00 p.m.
12/1/83	Flow rate 5400 - 5900 B/D. Bottom-hole pressure 7637 psia at 11:00 p.m.
12/2/83	Flow rate 4600 - 5300 B/D. Bottom-hole pressure 7593 psia at 11:00 p.m.
12/3/84	Flow rate 4300 - 4600 B/D. Bottom-hole pressure 7564 psia at 11:00 p.m.
12/4/83	Flow rate 3900 - 4300 B/D. Bottom-hole pressure 7590 psia at 11:00 p.m.
12/5/83	Flow rate 3,000 B/D. Bottom-hole pressure 7862 psia at 11:00 p.m.
12/6/83	Flow rate 2800 B/D. Bottom-hole pressure 7970 psia at 11:00 p.m.
12/7/83	RDI released at 7:30 a.m. Last bottom-hole pressure 7975 psia at 7:00 a.m. Flow rate decreased to 2600 B/D at 8:00 p.m. Surface pressure 1120 psia at 11:00 p.m.
12/8/83	Flow rate 2625 - 2650 B/D. Surface pressure 1081 psia at 11:00 p.m.
12/9/83	Flow rate 2600 - 2675 B/D. Surface pressure 1070 psia at 11:00 p.m.
12/10/83	Flow rate 2600 B/D. Surface pressure 1058 psia at 11:00 p.m.
12/11/83	Flow rate 2550 - 2600 B/D. Surface pressure 1046 psia at 11:00 p.m.

12/12/83	Flow rate 2550 B/D. Surface pressure 1032 psia at 11:00 p.m.
12/13/83	Flow rate 2475 - 2500 B/D. Surface pressure 1022 psia at 11:00 p.m.
12/14/83	Flow rate 2450 - 2475 B/D. Surface pressure 1007 psia at 11:00 p.m.
12/15/83	Flow rate 2450 B/D. Surface pressure 994 psia at 11:00 p.m.
12/16/83	Flow rate 2300 - 2600 B/D. Surface pressure 1006 psia at 11:00 p.m.
12/17/83	Flow rate 2300 - 2350 B/D. Surface pressure 1007 psia at 11:00 p.m.
12/18/83	Flow rate 2300 B/D. Surface pressure 999 psia at 11:00 p.m.
12/19/83	Flow rate 2250 - 2300 B/D. Surface pressure 989 psia at 11:00 p.m.
12/20/83	Flow rate 2775 B/D. Surface pressure 989 psia at 11:00 p.m.
12/21/83	Flow rate 3500 B/D. Surface pressure 787 psia at 11:00 p.m.
12/22/83	Flow rate 3550 B/D. Surface pressure 665 psia at 11:00 p.m.
12/23/83	Flow rate 3625 B/D. Surface pressure 576 psia at 11:00 p.m.
12/24/83	Flow rate 3400 B/D. Surface pressure 554 psia at 11:00 p.m.
12/25/83	Flow rate 3350 B/D. Surface pressure 541 psia at 11:00 p.m.
12/26/83	Flow rate 3250 B/D. Surface pressure 530 psia at 11:00 p.m.
12/27/83	Flow rate 3200 B/D. Surface pressure 530 psia at 11:00 p.m.
12/28/83	Flow rate 3850 B/D. Surface pressure 323 psia at 11:00 p.m.
12/29/83	Flow rate 2900 - 3100 B/D. Surface pressure 318 psia at 11:00 p.m.
12/30/83	Flow rate 3500 B/D. Surface pressure 315 psia at 11:00 p.m.
12/31/83	Flow rate 3400 B/D. Surface pressure 318 psia at 11:00 p.m.
1/1/84	Flow rate 3350 B/D. Surface pressure 314 psia at 11:00 p.m.
1/2/84	Flow rate 3300 B/D. Surface pressure 314 psia at 11:00 p.m.
1/3/84	Flow rate 3250 B/D. Surface pressure 313 psia at 11:00 p.m.
1/4/84	Flow rate 3225 B/D. Surface pressure 310 psia at 11:00 p.m.

1/5/84	Flow rate 2500 - 2600 B/D.	Surface pressure 308 psia at 11:00 p.m.
1/6/84	Flow rate 2525 - 2740 B/D.	Surface pressure 308 psia at 11:00 p.m.
1/7/84	Flow rate 2400 - 2600 B/D.	Surface pressure 309 psia at 11:00 p.m.
1/8/84	Flow rate 2420 - 2580 B/D.	Surface pressure 302 psia at 11:00 p.m.
1/9/84	Flow rate 2310 - 2770 B/D.	Surface pressure 297 psia at 11:00 p.m.
1/10/81	Flow rate 2440 - 2580 B/D.	Surface pressure 299 psia at 11:00 p.m.
1/11/84	Flow rate 2388 - 2580 B/D.	Surface pressure 304 psia at 11:00 p.m.
1/12/84	Flow rate 2412 - 2496 B/D.	Surface pressure 307 psia at 11:00 p.m.
1/13/84	Flow rate 2364 - 2424 B/D.	Surface pressure 302 psia at 11:00 p.m.
1/14/84	Flow rate 2376 - 2400 B/D.	Surface pressure 306 psia at 11:00 p.m.
1/15/84	Flow rate 2352 - 2388 B/D.	Surface pressure 304 psia at 11:00 p.m.
1/16/84	Flow rate 2352 - 2400 B/D.	Surface pressure 298 psia at 11:00 p.m.
1/17/84	Flow rate 2316 - 2388 B/D.	Surface pressure 303 psia at 11:00 p.m.
1/18/84	Flow rate 2160 - 2400 B/D.	Surface pressure 298 psia at 11:00 p.m.
1/19/84	Flow rate 2304 - 2400 B/D.	Surface pressure 294 psia at 11:00 p.m.
1/20/84	Flow rate 2316 - 2340 B/D.	Surface pressure 294 psia at 11:00 p.m.
1/21/84	Flow rate 2244 - 2320 B/D.	Surface pressure 296 psia at 11:00 p.m.
1/22/84	Flow rate 2196 - 2352 B/D.	Surface pressure 298 pia at 11:00 p.m.
1/23/84	Flow rate 2196 - 2328 B/D.	Surface pressure 301 psia at 11:00 p.m.

1/24/84	Flow rate 2000 - 2352 B/D.	Surface pressure 296 psia at 11:00 p.m.
1/25/84	Flow rate 2220 - 2292 B/D.	Surface pressure 291 psia at 11:00 p.m.
1/26/84	Flow rate 2196 - 2256 B/D.	Surface pressure 295 psia at 11:00 p.m.
1/27/84	Flow rate 2800 B/D.	Surface pressure 294 psia at 1:00 p.m.
1/28/84	Flow rate 2800 B/D.	Surface pressure 292 psia at 11:00 p.m.
1/29/84	Flow rate 2800 B/D.	Surface pressure 296 psia at 11:00 p.m.
1/30/84	Flow rate 2184 - 2232 B/D.	Surface pressure 294 psia at 11:00 p.m.
1/31/84	Flow rate 2208 - 2220 B/D.	Surface pressure 291 psia at 11:00 p.m.
2/1/84	Flow rate 2195 - 2268 B/D.	Surface pressure 290 psia at 11:00 p.m.
2/2/84	Flow rate 2064 - 2280 B/D.	Surface pressure 288 psia at 11:00 p.m.
2/3/84	Flow rate 2088 - 2268 B/D.	Surface pressure 295 psia at 11:00 p.m.
2/4/84	Flow rate 2100 - 2232 B/D.	Surface pressure 294 psia at 11:00 p.m.
2/5/84	Flow rate 2064 - 2268 B/D.	Surface pressure 286 psia at 11:00 p.m.
2/6/84	Flow rate 2088 - 2208 B/D.	Surface pressure 298 psia at 11:00 p.m.
2/7/84	Flow rate 2001 - 2422 B/D.	Surface pressure 298 psia at 11:00 p.m.
2/8/84	Flow rate 2100 - 2196 B/D.	Surface pressure 293 psia at 11:00 p.m.
2/9/84	Flow rate 2112 - 2208 B/D.	Surface pressure 291 psia at 11:00 p.m.
2/10/84	Flow rate 2124 - 2172 B/D.	Surface pressure 289 psia at 11:00 p.m.
2/11/84	Flow rate 2112 - 2160 B/D.	Surface pressure 287 psia at 11:00 p.m.
2/12/84	Flow rate 2040 - 2172 B/D.	Surface pressure 292 psia at 11:00 p.m.
2/13/84	Flow rate 2136 - 2160 B/D.	Surface pressure 295 psia at 11:00 p.m.

2/14/84	Flow rate 2112 - 2148 B/D.	Surface pressure 290 psia at 11:00 p.m.
2/15/84	Flow rate 2112 - 2148 B/D.	Surface pressure 290 psia at 11:00 p.m.
2/16/84	Flow rate 2052 - 2136 B/D.	Surface pressure 294 psia at 11:00 p.m.
2/17/84	Flow rate 2016 - 2184 B/D.	Surface pressure 291 psia at 11:00 p.m.
2/18/84	Flow rate 2000 - 2136 B/D.	Surface pressure 295 psia at 11:00 p.m.
2/19/84	Flow rate 1900 - 2184 B/D.	Surface pressure 291 psia at 11:00 p.m.
2/20/84	Flow rate 1992 - 2412 B/D.	Surface pressure 289 psia at 11:00 p.m.
2/21/84	Flow rate 1884 - 2292 B/D.	Surface pressure 296 psia at 11:00 p.m.
2/22/84	Flow rate 2088 - 2124 B/D.	Surface pressure 293 psia at 11:00 p.m.
2/23/84	Flow rate 2064 - 2124 B/D.	Surface pressure 294 psia at 11:00p.m.
2/24/84	Flow rate 2750 B/D.	Surface pressure 292 psia at 11:00 p.m.
2/25/84	Flow rate 2880 B/D.	Surface pressure 288 psia at 11:00 p.m.
2/26/84	Flow rate 2844 B/D.	Surface pressure 287 psia at 11:00 p.m.
2/27/84	Flow rate 2064 - 2088 B/D.	Surface pressure 287 psia at 11:00 p.m.
2/28/84	Flow rate 2040 - 2076 B/D.	Surface pressure 291 psia at 11:00 p.m.
2/29/84	Flow rate 1944 - 2244 B/D.	Surface pressure 294 psia at 11:00 p.m.
3/1/84	Flow rate 1344 - 2652 B/D.	Surface pressure 297 psia at 11:00 p.m.
3/2/84	Flow rate 2028 - 2064 B/D.	Surface pressure 299 psia at 11:00 p.m.
3/3/84	Flow rate 2028 - 2106 B/D.	Surface pressure 296 psia at 11:00 p.m.
3/4/84	Flow rate 1995 - 2112 B/D.	Surface pressure 296 psia at 11:00 p.m.

3/5/84	Flow rate 2028 - 2088 B/D.	Surface pressure 293 psia at 11:00 p.m.
3/6/84	Flow rate 2004 - 2088 B/D.	Surface pressure 295 psia at 11:00 p.m.
3/7/84	Flow rate 2040 - 2088 B/D.	Surface pressure 286 psia at 11:00 p.m.
3/8/84	Flow rate 2028 - 2076 B/D.	Surface pressure 286 psia at 11:00 p.m.
3/9/84	Flow rate 2004 - 2064 B/D.	Surface pressure 292 psia at 11:00 p.m.
3/10/84	Flow rate 2016 - 2052 B/D.	Surface pressure 281 psia at 11:00 p.m.
3/11/84	Flow rate 2028 - 2052 B/D.	Surface pressure 282 psia at 11:00 p.m.
3/12/84	Flow rate 1956 - 2076 B/D.	Surface pressure 296 psia at 11:00 p.m.
3/13/84	Flow rate 2052 - 2100 B/D. Surface pressure 288 psia at 5:00 p.m. Well shut in at 6:44 p.m., after 114 days of flow. Surface pressure 1095 psia at 11:00 p.m.	
3/15/84	Well shut in.	Surface pressure 1811 psia at 11:00 p.m.
3/16/84	Well shut in.	Surface pressure 1931 psia at 11:00 p.m.
3/17/84	Well shut in.	Surface pressure 2037 psia at 11:00 p.m.
3/18/84	Well shut in.	Surface pressure 2037 psia at 11:00 p.m.
3/19/84	Well shut in.	Surface pressure 2133 psia at 11:00 p.m.
3/20/84	Well shut in.	Surface pressure 2219 psia at 11:00 p.m.
3/21/84	Well shut in.	Surface pressure 2297 psia at 11:00 p.m.
3/22/84	Well shut in.	Surface pressure 2368 psia at 11:00 p.m.
3/23/84	Well shut in.	Surface pressure 2435 psia at 11:00 p.m.
3/24/84	Well shut in.	Surface pressure 2498 psia at 11:00 p.m.
3/25/84	Well shut in.	Surface pressure 2557 psia at 11:00 p.m.
3/26/84	Well shut in.	Surface pressure 2612 psia at 11:00 p.m.
3/27/84	Well shut in.	Surface pressure 2664 psia at 11:00 p.m.
3/28/84	Well shut in.	Surface pressure 2703 psia at 5:00 p.m.
3/29/84	Well shut in.	Surface pressure 2750 psia at 3:00 p.m.

4/13/84

Final Report from Sweet Lake site.
1150-1200 psia.

Surface pressure

APPENDIX C

Engineering Interpretation
Miogypsinoides Geopressured Brine Reservoirs
MG-T/DOE AMOCO Fee No. 1 Well
Sweet Lake Area
Cameron Parish, Louisiana
July 1984

J. Donald Clark, P.E.
Consulting Petroleum Engineer
5959 West Loop South, Suite 232
Bellaire, Texas 77401

Submitted to: Dr. Clay Durham, Project Manager
Magma Gulf-Technadril
430 Hwy 6, South-Suite 208
Houston, Texas 77079

INDEX OF GRAPHS AND TABLES MG-T/DOE Amoco Fee No. 1 Well

Figure No. 1	Structure Map
Figure No. 2	Cross Section

NO. 5 SAND

Figure No. 3	First Flow Test (Semi Log) (Enlarged Scale)
Figure No. 3A	First Flow & Buildup Test
Figure No. 3B	Field Interpretation Graph
Figure No. 4	R.L.T. 1st D.D.
Figure No. 4A	R.L.T. 1st D.D.
Figure No. 5	Horner Plot
Figure No. 6	No. 1 B.U.
Figure No. 6A	No. 1 B.U.
Figure No. 7	2nd Flow Test Graph
Figure No. 8	R.L.T. No. 2 Flow Test
Figure No. 8A	R.L.T. No. 2 Flow Test
Figure No. 9	Graph Exploration D.D.
Figure No. 10	R. Water Explored vs. Time
Figure No. 11	Temp. & Pressure Gradients
Table No. 1	Reservoir Fluid Summary
Table No. 2	Composite Laboratory Data
Table No. 3	Exploration Drawdown Calc.
Table No. 4	Tabulation of Temp. & Press. by Depth

NO. 3 SAND

Figure No. 12	Pressure Drawdown & B.U. Graph
Figure Nos. 13 & 13A	Drawdown Data Sheets
Figure No. 14	B.U. Data Sheets
Figure No. 15	Extended Drawdown Test (7.2 Days)
Figure Nos. 16 & 16A	Calculation Data Sheets
Figure No. 17	Log-Log Explored Water
Figure No. 18	Extended Drawdown Test (15 Days)
Table No. 5	Exploration Drawdown Calc.
Table No. 6	Reservoir Fluid Summary
Table No. 7	Composite Laboratory Data
Figure No. 19	Flowing Pressure & Temperature Gradients
Table No. 8	Tabulation of Gradient Stop Data

Exploration Drawdown Tests on the Miogypsinoides
Geothermal-Geopressured Sands found in the
MG-T/DOE AMOCO Fee No. 1 well, Sweet Lake Area
Cameron Parish, Louisiana

1

ABSTRACT

The MG-T/DOE AMOCO Fee No. 1 well was the second well drilled for the Department of Energy for the purpose of testing deep Gulf Coast geopressured brine sands for evaluating the energy potential of gas in solution as well as the hydraulic and geothermal possibilities. The tests were designed to maintain continuous and accurate readings of down hole sand face and surface well head pressure and temperature. A full well stream flow meter was installed to record simultaneous the flow rate with the pressure and temperature records. Surface gas-water separating equipment was designed and installed in such a manner that a complete and continuous record of the produced fluids were maintained.

The tests produced an excellent amount of basic production drawdown data for engineering interpretation. Only a very small portion of this data, even though pertinent, is contained in this report. The report goes into considerable detail to explain the method and results of each phase of the tests and is supported by graphs and calculation data forms.

The deeper No. 5 sand was interpreted as having very good productivity of some 8300 md.-ft., with average permeability to water of around 307 mds. The well is restricted by close in permeability barriers that reduces the flow area around the well to less than 48 degrees. All reservoir limits were not seen during the measured test period and some 303 million barrels of brine was explored. The well was not capable of sustained flow rates in excess of 10,000 barrels of brine per day due to a restricted flow area around the well.

The No. 3 sand was found to have fair permeability but relatively small. The sand was interpreted as a lenticular sand deposit containing approximately 11 million barrels of brine. The sand was producing around 2000 BWPD with 288 psi surface flowing tubing pressure when test was completed.

The reservoir brines in the two sand zones were found to be under saturated with gas at original reservoir temperature and pressure. The No. 3 sand had 24.5 cubic feet of dry gas in solution at a bubble point pressure of 8800 psia. The No. 5 sand was estimated to have 22.2 cubic feet of dry gas in solution at an estimated bubble point pressure of 6340 psia. The No. 3 sand produced approximately 349 thousand barrels of brine during nearly 4 months on flow testing. The No. 5 sand produced 1.063 million barrels of brine and 23,600 MCF of dry gas during its test period.

Engineering Analyses of Exploration Drawdown Tests
 Miogypsinoides Sands, MG-T/DOE AMOCO Fee No. 1 Well
 Sweet Lake Geothermal-Geopressure Prospect

J. Donald Clark, P. E.
 Petroleum Engineering Consultant

INTRODUCTION

The MG-T/DOE AMOCO Fee No. 1 well was drilled and completed in the Miogypsinoides sands of the Camerina Zone of the Upper Frio Formation. The well is located in the structurally high southeastern portion of a graben bounded by faults to the North, East and South, as shown on Figure No. 1. The Miogyp sands are found at depths between 15,000 and 15,640 feet. There are eight potentially productive sands in the Miogyp sequence that were considered for geothermal-geopressure testing. Results of flow tests conducted on the No. 5 and No. 3 sands are covered by this report.

This testing program was designed to determine and demonstrate, through long-term flow testing, the technological and economic feasibility of recovering dissolved methane from brine, and recovery of thermal and hydraulic energy associated with geopressure-geothermal aquifers. In order to establish the economics, it is necessary to determine the amount of gas in solution, the corrosive chemistry of the brine, the productivity and extent of the brine aquifer. The majority of the energy for brine production depends on the expansibility of the existing aquifer.

No. 5 Sand Selected for First Flow Test

The No. 5 Sand was selected as the first zone to be flow-tested. Figure No. 2 is a log cross-section depicting the eight Miogyp sands. Selection of more than one sand or reservoir, would introduce additional problems in drawdown analysis. Permeability barriers might appear in one sand and not in another. Chemistry of the fluids could differ and cross flow could occur between zones. These natural differences between various sands make test interpretations difficult. Therefore, the fifth sand was selected because of a high permeability, determined from core analyses, and relative uniformity of the section as indicated on an electric log. These data indicate a sand zone capable of producing maximum flow at rates of 40 or 50 thousand barrels of brine per day.

The No. 5 sand, found between 15,387 and 15,444 feet, has a net effective sand thickness of approximately 27 feet. Cores from this interval found permeability (to air) as high as 3.6 darcy's with porosities around 23.4 percent. The sand was believed to be a "blanket" type sand for the area, and is sealed above and below by solid shale.

The flow test was designed to support various engineering conclusions as to the well and sand productivity, by yielding a maximum amount of production and pressure data. Aquifer size and geometric configuration are needed for predicting future production capabilities. A lengthy constant-rate flow test, with concurrent accurate recordings of sand face flowing pressure, is basic for engineering requirements needed to insure early radial-flow interpretation. The high permeability and transmissability of the reservoir required method planning to properly place the well on flow.

Initial Flow Test

An initial flow test was designed for a low rate of approximately 5000 barrels of formation brine per day, for a period of 2 to 3 days. The flow-rate was to be maintained as constant as possible. Surface equipment will record all changes in surface temperatures and pressures. Total flow rates were to be measured and recorded both before and after separation. This test allows for correction of any surface producing equipment and measuring devices prior to extended flow testing.

The initial flow test started at 6:12 PM on June 19, 1981 and ended at 8:04 PM on June 22, 1981. Approximately 10,574 barrels of reservoir brine were produced during this 3.031 day flow period. Average rate of production was 3488.6 barrels of brine per day. Approximately 2.2 cubic feet of gas remained in each separated barrel of brine. Producing rates varied from 2820 to 4680 BPD with a separator gas-water ratio of about 20 scf/bbl. This corresponds to about 22.2 scf/bbl total for each barrel of brine.

Sand face pressures were obtained by using the Hewlett-Packard quartz-crystal surface-recording bottomhole pressure element. The original reservoir pressure was 12,062 psia at a reservoir temperature of 299°F. This pressure was measured at the center of perforations at a depth of 15,400 feet. Normal reservoir pressure at this depth is about 7195 psia, or 4867 psi less than the measured geopressure of the reservoir.

Engineering Interpretation of the First Flow Test

Figure No. 3 is an enlarged scale plot of the recorded drawdown pressures for the first 2.52 hours (0.105 days) of constant flow rate. The high rate of reservoir fluid transmissability necessitated a sensitive quartz crystal type pressure element and large scale graphing for interpretation. Figure No. 3-A depicts the complete pressure drawdown history for this primary flow test. Flow rates were varied after .105 days and thereby effected the later drawdown slopes.

The earlier portion of the drawdown test on Figure No. 3 has the well flowing at about 2820 barrels of water per day. The rate of drawdown was 22 psi per log cycle, allowing a calculation of 8301.3 md.-ft. of productivity as the Kh value. Formation permeability to the reservoir fluid for a 27 foot sand was 307.5 mds. This is comparable to the measured air permeability of 3.6 darcys from the reservoir core.

The observed skin effect was very small (plus 0.056). This allows a completion efficiency of 99.32 percent. This high completion efficiency resulted from the method of perforating the well, combined with the high sand productivity. A 30 foot perforating gun was used to perforate all 27 feet of the sand at the same instant with a negative pressure differential between the well bore and reservoir of approximately 1000 psi. This perforating method seems to insure instantaneous cleaning of the perforations. No sand production was detected during any of the flow testing.

The first permeability barrier was detected at a distance of 311 feet from the well bore, with a slope change from 22 to 44 psi per cycle at 0.0035 days. The second permeability barrier was detected at 440 feet from the well bore. A subsequent permeability barrier was found at a distance of 1703 feet from the well bore. This particular barrier is represented by a drawdown slope of 165 psi per cycle. The flow angle around the well was estimated at 48 degrees. These permeability barriers represent the two graben faults shown on Figure No. 1. Note that these two faults form an angle similar to that calculated from the slope changes. The formation brine explored to 0.105 days, and calculations based on the slope of 165 psi per cycle indicates a capacity of 1.579 million barrels. A triangular area of 48° extending 1703 feet from the well would approximate a productive area of 27.9 acres. Reservoir brine that could occupy this acreage with 27 feet of net sand and pore space of 1698 bbls. per acrefoot is equivalent to 1.279 million barrels. The drawdown test method using the slope of 165 psi per cycle gave an explored volume of 1.579 million barrels of water. This checks reasonably with the geometric pore volume.

Figure 1 is a contour map constructed on top of the Miogyp No. 1 sand, and places the graben faults farther apart than would occur at the Miogyp No. 5 sand depth. The faults were drawn with dips of 45° . Thus, the faults would each move some 300 feet closer to correspond to the Miogyp sand interval. (Note, this was also required by INTECOMP's reservoir simulator when they attempted the history match).

Attached calculation data sheets, Figure 4 and 4A, present detailed fundamental calculations. Figure No. 3 is a semi-log interpretation of the initial drawdown-pressure-plot. The production rates varied from a high of 4680 BPD to a low of 2820 BPD during the 3.031 day flow test. Changing choke sizes and resultant flow rates are depicted on the pressure drawdown, and on the calculation data sheets. Estimated production was 10,574 barrels of brine during the 3.031 days of flow time. The final sand face flowing pressure was recorded at 11,141 psia. The distance explored during this initial test was 9154 feet radially from the well bore. The total aquifer volume explored was approximately 13,850,000 barrels.

Reservoir Fluid Analysis

Reservoir fluid samples were taken from the separator prior to shutting in the well during the first flow test. Weatherly Laboratories personnel gathered and analyzed the recombined sample for chemical and physical characteristics. Surface samples were collected during a 4 hour testing period. The gas-liquid ratio of separator liquid measured on this test, at 8.1 cubic feet of separator gas per barrel, was used for one recombination. The resultant reservoir fluid exhibited a bubble point of 2006 psia at the measured reservoir temperature of 299°F . This suggests that reservoir fluid exists as an undersaturated brine at reservoir conditions of 299°F . temperature, and 12,062 psia pressure. The reservoir fluid analysis is summarized in Table No. 1.

The 8.10 separator gas-water ratio converts to a total dry gas ratio of 9.4 cubic feet per barrel, and 9.6 cubic feet per barrel wet gas-water ratio at a bubble point pressure of 2006 psia. Gas required for a saturated brine at the original reservoir pressure of 12.062 psia, at a temperature of 299°F . is 34.5 standard cubic feet. Table No. 2 tabulates composite laboratory data for the 2006 psia saturated reservoir brine. The water formation factor of 1.0509 standard barrels per reservoir barrel and water viscosity of 0.379 cps, was used in basic reservoir calculations. The compressibility of the reservoir brine was 2.78×10^{-6} bbl. per bbl. per psi. The total dissolved solids analyzed at the well site, by Dr. John Oddo of Rice University, was 165,000 PPM., with a salinity of 140,600 PPM.

Corrected Reservoir Fluid Analysis

Later production tests conducted with minor changes in metering devices required corrections to be made to the June, 1981 production statistics. Production testing between August, 1981 and February 8, 1982, reported wet gas to water ratios from lows of 12.41 cubic feet per barrel to a high of around 30.06 cubic feet per barrel of separator brine. This allows estimates of approximately 20 cubic feet of separator dry gas at 15.025 psia and 60°F . per barrel of separator water at 520 psig and 242°F . as used by the Weatherly Laboratory report. At a saturation pressure of 6340 psia, the viscosity of the reservoir brine and it's gas in solution would probably drop from .395 cps to .379 cps. The formation volume factor would change from 1.0761 to 1.0693 at a bubblepoint pressure of 6340 psia. A formation factor of 1.0459 at 12,062 psia would change to 1.0509 for conversion to original reservoir barrels from standard barrels at 15.025 psia and 60°F .

Initial Pressure Buildup Test

The well was shut in at 7:57 PM on June 22, 1981, and pressure buildup measurements were recorded. The final flowing pressure was 11,141 psia. A production rate below 2500 BPD and increasing pressure at the time the well was shut in effected the rate of the plotted pressure buildup. The pressure difference between the initial instrument pressure of 12,053 psia, at a datum of 15,337 feet, and the final flowing pressure is 912 psi.

The initial buildup slope is 17.6 psi per cycle, with a final prior flow rate of 2820 BWPD. This slope gives a Kh value of 1,376.7 md.ft. and a permeability of 384.3 mds. This value is higher than that interpreted from the original flow test, and is caused by a pressure buildup at the sand face during the reduced final flow rate. This created a reduction in initial buildup slope when the well was shut in. The skin effect was also effected by these well-flow mechanics.

There is an anomalous increase in pressure at 0.002 days on the graph where pressure increased from 11,254.59 psia to 11,267.62 psia in a 10 second reading. The buildup slope increased from 17.6 psi per cycle to 35.2 psi per cycle at this same time. The 2 to 1 increase in slope for the first permeability barrier was expected since it occurred this early in the drawdown test interpretation. No positive explanation for this anomaly will be presented at this time. The curving of the buildup slope to 370 psi per cycle was created by the variations in the flow rates prior to closing-in the well. Figure 6 and 6A contain calculations from the buildup test.

The buildup plot (Figure 3A), prior to 1 day of shut-in time, begins to show the effect of the short 3.031 days of prior flow time. The curve should have steepened with a longer flow time instead of decreasing and forming the "S" type configuration. The Horner Type (Figure 5) has the same effect, but is not quite as prominent. Note that the extrapolation of the final slope is less than the original pressure of 12,053 psia. The final buildup pressure of 11,974.21 psia, occurred at 18:15:30 PM on June 30, 1981, just before the second flow period began. The well had been shut in for 8.4708 days at this time, and was still 79 psi below the original pressure.

The use of the Horner Type pressure buildup graph must be used with caution in engineering interpretation. This type psuedo time graph is very sensitive to prior flow time. The interpretation is only valid over a builup time of about one-fourth of the prior flow time. This time factor for validating interpretations becomes longer with low permeability and shorter with high permeability.

Second Flow Test, No. 5 Sand Interval

The second flow test was planned to explore for whichever came first, the reservoir limits or 20 days of flow analyses. The first flow test depicted the permeability barrier locations of the geological graben type structure and defined the restricted flow area around the well bore. The second test was planned for a constant flow rate of approximately 15,000 barrels of water per day. Flow began at 6:15 PM on June 30, 1981. An initial measured flow rate was 17,500 BWPD for the first 33 minutes. The pressure-time data is presented graphically on Figure No. 7. The well was not completely opened to final choke size within the first 4.9 minutes. This eliminates interpretation of data for the first 320 feet around the well bore. A smooth straight radial flow drawdown slope is desired for support of a good test.

The flow rate of 17,500 barrels of brine per day and the time consumed to arrive at the flow rate prevented gaining the radial flow slope. This was obtained by taking one-half of second flow slope of 253 psi per cycle or 126.5 psi per cycle. This slope gave a Kh value of 8959 md.-ft. and 332 mds. for average permeability. Permeability of 332 mds. is reasonably close to 308 mds. obtained from the initial cleaning flow test.

A flow meter was installed in the surface flow line and connected to the RDI computer. This installation was made to record flow rates simultaneously with sand face pressures. The software design failed to average meter counts over nine to ten second intervals as planned. This caused fluctuation in plotted data, but it did record the trend of the brine flow rates on the semi-log plot with surface and bottom hole pressures. This record of production rates with sand face flowing pressures are very valuable in attempting exploration drawdown calculations of the explored volumes of the aquifer. Other records of production were recorded at one to two hour intervals and corrected to standard volume on the daily report. This aided in later corrections of RDI data.

The main purpose of this test phase was an attempt to determine reservoir volume or limits. Production choke adjustments were made during the first 3.5 days to maintain, if possible, a constant flow rate of 15,000 BWPD. These adjustments are readily noted on both the surface and the sand face pressures plotted on the semi-log graph (Figure No. 7). The effective flow angle around the well had been reduced to 25.2 degrees at the end of 3.5 days. Surface flowing pressure dropped below 1000 psia. The radial distance explored by this time was in excess of 10,000 feet. The explored volume of reservoir fluid was in excess of 24 million barrels of brine. After 3.5 days, production rates were allowed to drop while trying to maintain a surface flowing pressure at/or above 800 psia.

Sand-face pressures were continuously measured and recorded in excess of 17 days, before pulling the pressure instruments from the well bore. Surface pressures were monitored throughout the remainder of production testing. The 17 days of down hole pressure recordings, gives an explored distance of 22,520 feet. The volume of brine explored was 303.0 million barrels. Total productive limits were not defined, but the drainage flow angle was reduced below 25 degrees.

Summary of Initial Flow and Buildup Tests

Tests depict permeability barriers, relatively close to the well bore, creating a restricted drainage area for the aquifer reservoir. Productivity was high at approximately 8301 md.-ft., with permeability to the reservoir fluid averaging 308 mds. The reduction of the flow area to an angle of about 48 degrees conforms to a general faulted graben type of geological structure shown in Figure No. 1. The rapid rate of pressure drawdown suggested that the original exploration drawdown test plan be revised, and shortened to approximately 20 days, or to the detection of reservoir limits. Final limits are defined as that time when steady-state flow is observed, or when the pressure loss per day, per reservoir barrel of fluid produced, becomes constant.

The permeability barriers detected during the original flow test may or may not be sealing faults. The two main graben faults are positive, the small splinter fault might have been deleted, or the sand might have been pinching out updip of the well. It takes only 302 acres with 27 feet of net pay to support 13,850,000 barrels of explored reservoir brine. A distance explored in 2.7 days is 8640 feet, which would result in an area without barriers of 5384 acres, or approximately 246.8 million barrels of brine.

Exploration Drawdown Test

The No. 2 drawdown test planned for rates of 15,000 barrels of water per day, primarily would be used to gather data on the explored volume of the No. 5 sand aquifer. The diffusivity or pressure transmissability rate of around 7.5 million square feet per day, would prevent detecting close-in barriers while bringing the well up to 15,000 or more barrels per day. The flow test voids the first slope because 4.9 minutes were required to get the flow rate

to 17,500 BWPD. Primary data would give the increasing explored volumes of aquifer with producing time. The Calculation Data Sheet Figure No. 8 & 8A and log-log graph Figure No. 10, depict the explored volumes for the 17 days that reservoir sand face pressures were being recorded.

Figure No. 7 is a semi-log plot of flowing surface and sand face pressures, and the brine producing rate. The computer software for the flow meter was not accurately calibrated or set to average the meter rates. The data is sufficient to depict the declining flow rate with sand face pressure loss. The plotted pressures are averaged over approximately 9 seconds of pressure readings, allowing a smooth plot of points forming a solid pressure decline line. Therefore, a mean average rate, corrected to standard barrels per day, was used in calculating water explored. The standard rates of production were used with the sand face drawdown slopes determined from the pressure drawdown plot. A summary of these calculations are listed on the calculation data sheet, Figure No. 8A.

The well was not capable of maintaining the high rate of production as originally scheduled. The exploration drawdown test allows calculation of the volume of reservoir that can be determined as a function of flow time with declining rates of production. Table No. 3 contains these calculations as a function of cumulative flowing time. Figure No. 10 plots the log of water explored versus the log of time. When linear type permeability barriers exist the data falls on a 45 degree linear plot for each barrier. Lenticular time pinchout barriers are similar to the plotted data depicted here.

The pressure element was removed from the well bore, and production testing was continued until February, 1982. Total estimated production from the No. 5 sand is 1,063,000 barrels of salt water, and 23,600 MCF of dry gas. The saturation pressure for 22.2 cubic feet of dry gas in solution in a standard barrel of reservoir brine, is about 6340 psia. The saturation pressure is lower than required to flow the reservoir brine to the surface. Therefore, no free gas saturation is expected to occur in the reservoir.

Permeability to brine above 300 mds. is extremely high for Gulf Coast Sands located below 12,000 feet in depth. Productivity of 8301 md.-ft. is well above normal for most zones in this area. Therefore, the inability of this well to sustain rates in excess of 10,000 barrels of brine per day over any prolonged period, is due to a restricted flow area around the well bore. The well is capable of flowing in excess of 30,000 barrels per day for a very short time period. The flow angle reduction to 25 degrees after about 1 day of flow time, does not allow this well to meet even close-to-economical-considerations at the most optimistic gas prices obtainable to date.

Figure No. 11 is a graphical plot of the pressure and temperature well bore gradients conducted during June 17-18, 1981. These data were obtained prior to flowing the well with completion fluid in the well bore. GRC surface recording down hole pressure and temperature elements were used for recording these data.

Miogypsinoïdes No. 3 Sand, Cleaning Flow Test

The Miogyp No. 5 sand was effectively sealed off, and on November 11, 1983, the Miogyp No. 3 sand was perforated by Wellex. The Miogyp No. 3 sand zone consists of two sand stringers. The first stringer is between 15,248 feet and 15,261 feet, and the second stringer is between 15,265 feet and 15,285 feet. Net sand estimates show 7 feet in the upper stringer and 17 feet in the lower stringer, or 24 feet of net effective total sand. There were no core analysis available on this selected flow test interval, but log evaluation would indicate about 20 percent porosity. The sand was perforated between 15,245 feet to 15,255 feet and 15,260 feet to 15,280 feet. The total sand interval was not perforated for production, therefore, skin effect calculations should show a positive value.

Reservoir Dynamics, Inc. ran into the well bore after midnight on November 12, 1983, with the Panex surface recording down hole pressure and temperature gauges. Instruments were at a depth of 15,246 feet, or about the top of perforations, by 7:26 AM, Saturday, November 12, 1983. The measurements recorded at 8:00 AM were 11,886.87 psia pressure, and 293.8°F with a corresponding surface pressure of 3659.97 psia. The pressure elements were moved up the well bore to 15,200 feet to the designated test datum. The pressure at 11:40:00 AM at 15,200 feet was 11,873.54 psia, with 293.2°F temperature and 3660.83 psia surface pressure.

There was some pressure loss when the well was opened to the production line choke, and at 11:45:50 AM, November 12, 1983, the pressure at the datum depth was 11,832.17 psia, with 293.2°F temperature. Surface pressure was down to 3615.08 psia. These are pressure readings at the time the production control choke was opened. The well bore was full of a 10.5 pound per gallon completion fluid. The well was opened to the blow down tanks at a flow rate of about 2800 barrels per day. Completion fluid was all produced at about 2:30 PM and the production rate increased to about 4000 BWPd. There was no noticeable drilling mud or sand produced when the reservoir brine reached the surface, and formation brine continued to be clean during the entire flow test period. The disposal well was able to handle the 4000 BWPd with about 35 to 40 psig well head pressure. The test was conducted for about 24 hours.

The well was shut in at 11:49:30 on November 13, 1983, with a flowing datum pressure of 10,133.00 psia, 291.9°F. temperature and 3201.26 psia surface pressure. The maximum surface flowing temperature was 182°F. Pressure buildup readings were aborted at 20:15 PM when a leak developed in the pressure instrumentation piping, external to the wellhead. The datum pressure had increased to 11,173.76 psia with a corresponding surface pressure of 4160.47 psia. This is 699.78 psi below the original pressure of 11,873.54 psia. The total pressure drawdown at the datum, was 1,740.54 psi during the 24 hour flow period.

Interpretation of Cleaning Flow Test (No. 3 Sand)

Pressure drawdown and buildup plots are depicted graphically on Figure No. 12. The plots are mirror images, supporting the theory of a virgin well test. Note that at 0.007 days, or 10 minutes on flow, the plot exhibits a curving decline in pressure. The inverse of this curving is seen on the buildup plot starting earlier in about .0028 days, or 4 minutes. This is a common curve that is seen when completing in lenticular type sand pinch-outs. In other words, the completion zone is thinning in net effective sand as well as in permeability pinching out, reducing the drainage pattern around the well.

Attempts were made to gain a straight line slope to get an average sand permeability. A slope of 162 psi per cycle was drawn between .0007 days to .03 days and permeability calculated at 41.89 mds. This would be an explored distance of 60.7 feet to 397.5 feet respectively, which allows the 24 feet of estimated sand thickness in the well bore to meet radial flow conditions. This same data would give a calculated skin factor of a minus 3.27, or a pressure improvement of 460 psi. This is an impossibility, and shows that a slope of 162 psi per cycle is much too large for radial flow. This would suggest the sand zone has a much higher average permeability. The rate of pressure diffusivity, or transmissability, is very large, and the sand was thinning too fast to gain a straight line flow or buildup pressure slope. This does not mean that the well just happened to be completed in the thickest part of the sand zone. It does mean that the thinning in at least one radial direction is much greater than possible increasing net sand in another radial direction. In general, the well is completed in one end of a lenticular type sand pinch-out and does not show linear type permeability barriers.

The distance explored using the diffusivity calculated, would be considered less than actual. A different approach to determine reservoir limits is required. Variations in sand thickness and permeability give distance values that are highly speculative. Interpretations will require calculation of the explored volume of brine to determine future value of this sand interval.

There appears to be a drawdown slope of 1270 psi per cycle between 0.56 and 1.00 days. This slope occurred after the production rate was increased to 4000 BWPD. The explored water ranged between 1.578 to 2.819 million barrels during this flow period. If permeability is assumed at 42 mds., the distance explored was 1717 feet to 2295 feet for this same time period. A radial distance of 2295 feet is equivalent to nearly 380 acres. This would support 13.52 million barrels of water should 24 feet of net sand be used as a mean average. That is 4.80 times greater than the explored maximum of 2.819 million barrels. Assuming a higher permeability, would result in an even greater variance.

This short cleaning flow test, of about 24 hours, indicates the well is completed in one end of a lenticular type sand zone, probably of a sand bar type. The restrictions of the flow area around the well is very effective and at this early time would suggest a poor well for the purpose originally planned. Figures No. 13 and 13A give the detailed calculations for the prior comments.

Pressure Buildup Analysis

The pressure buildup data is also plotted in on Figure No. 12 with the prior cleaning drawdown pressures. You will note the inverse but similar (mirror image effect) pressure curve when compared to the drawdown plot. Again there were no apparent straight line radial buildup slopes that could be interpreted. The calculation data sheet, Figure No. 14, uses a slope of 170 psi per cycle as a best guess. This gives 1,321 md.-ft. for productivity, Kh ; 55 mds. permeability, and a negative skin factor of 3.59. The negative skin factor is again not possible with only a portion of the total interval perforated. In order to eliminate negative skin, the permeability should be the order of 200 mds., with a drawdown or buildup slope of less than 30 psi per cycle.

The dashed line is drawn hypothetically from the last measured pressure to the pressure of 11,801.51 psia. The pressure instrument was returned to the well bore some 8.8 days later. The pressure buildup plot and the drawdown plot depict a lenticular type of sand, with the well completed close to one end of the sand bar type reservoir.

Miogypsinoides No. 3 Sand, Extended Flow Test

The well remained shut in from 11:49:30 AM, November 13, to 8:47:00 AM on November 22, 1983. Pressure elements were rerun into the well to 15,200 feet, and pressure recordings were started at 3:52:40 AM on November 22. The first readings were 11,799.32 psia at datum depth with a temperature of 293.6°F. Surface pressure was 4601.90 psia. Datum pressure built slowly, and at 7:30:10 AM it was 11,801.51 psia, with 4604.97 psia at the surface. This represents a shut in period of 8.8199 days. The pressure returned to within 68.32 psi of the original depth pressure of 11,869.83 psi.

There was an accumulation of free gas in the upper tubing in the well bore and an attempt was made to open the valve slightly to allow some of this gas to bleed off. The purpose was to attempt to get a radial drawdown flow slope, that was missed on the first test. The bottom hole pressure was 11,801 psia when the gas bleed off was attempted at 7:30 AM on November 22, 1984. The pressure dropped to a low of 11,672.22 psia by 7:51:40 AM and was back to 11,795.17 psia at 8:43:30 AM. The pressure remained relatively stable for the next 13 minutes and at 8:46:30 was 11,795.27 psia when the flow test was started.

The well was opened to start the exploration drawdown flow test at 8:47:00 AM with a datum pressure of 11,795.24 psia and a datum temperature of 293.9°F. The surface wellhead pressure was 4602.20 psia. This 6 psi loss in pressure during bleed off of gas and start of flow should have a negligible effect on the drawdown slope.

Interpretation of Extended Flow Test (Miogyp No. 3 Sand)

Figure No. 15 depicts the pressure drawdown at the sand face and the metered flow rate for the first 7.2 days of the extended flow test. The attempt to get the early straight line radial drawdown slope failed. It is possible that uniform sand thickness around the well bore was not sufficient to gain an interpretable radial flow plot. The slight "hump" in the pressure plot seen on Figure No. 15 occurred within the first seven minutes of flow time. This was caused by the method and mechanics of opening the production control choke, free gas in upper part of well bore and liquid flow reaching the choke.

A slope of 165 psi per cycle has been drawn through the early pressure plots. The metered rate of production was about 2250 barrels of reservoir brine per day at this time. Figures 16 and 16A are the calculation data sheets using this data. The resulting productivity, or Kh , value was 813.2 md.-ft. The permeability using 24 net effective feet is 34 mds. These data would give a negative skin effect of 4.68, which is not realistic for this type of perforating and completion. This would give a 265 percent completion efficiency for perforation of a portion of the total sand zone at four shots per foot. This again supports a permeability to the reservoir brine much higher than depicted on the calculation sheets, Figure Nos. 16 and 16A. Instead of 34 mds., the permeability is probably in excess of 150 mds.

The drawdown plot, curving continuously for 7.2 days, does not present any linear type barrier detection. The exploration drawdown type analysis is required for engineering interpretation of this type of basic data. This method allows the integration of pressure decline at the sand face and the flow rate for interpretation of transient or steady state flow. This is then used in energy balance calculations or volume of water explored as a function of flow time. The calculation for explored volumes of reservoir aquifer is contained in Table No. 5. This explored volume of water is also depicted graphically on the log-log plot, Figure No. 17. The volume of reservoir brine explored during this

flow test is between 10 to 12 million barrels. The reservoir limits were approached between 5.13 to 7.2 days.

The distance explored, average permeability and average net sand cannot be determined accurately from this test. The size of the aquifer explored is relatively proven to be less than 12 million barrels. The productivity is well supported and is shown with continued production.

Addition Flow Tests, Miogyp No. 3 Sand

Flow testing continued after the 7.2 days of exploration drawdown testing. The pressure element remained at pressure datum and the rate was increased above 6500 BWPD. The production rate, bottom hole and surface flowing pressures are depicted on Figure No. 18 for a total of 15 days of total flow time. The increased flow rate is depicted by the sharp decrease in flowing pressures on Figure No. 18. The well was not capable of supporting the higher production rates for any sustained flow period.

The flow meter went out of service between 5:50 AM and 9:00 AM on November 29, 1983. The next valid data was after the rate was raised to 5697 BWPD. The flowing bottom hole pressure dropped from 10,074 psia to 8835 psia by midnight. The pressure readings and production rates, thereafter, were not sufficiently stabilized to allow additional exploration drawdown calculations. The lowest flowing sand face pressure recorded with pressure element in the well bore was 7546.73 psia at 10:40 AM on December 4, 1983. The production rate at this time was 4684 BWPD and still dropping.

The dry gas in solution at 8800 psia, bubble point pressure, was 24.50 cubic feet per barrel. The gas in solution at 7547 psia is 22.99 cu. ft/bbl. or about 1.51 cubic feet evolved. The radius around the well bore that would see the pressure below 8800 psia would be only a few feet. Theoretically a loss in produced gas-water ratio should have occurred during this period. This would be due to gas coming out of solution and remaining a free gas below the critical gas saturation necessary for gas flow. It is possible that we were unable to measure gas volume sufficiently to gain this accuracy for this determination.

The pressure and temperature elements were removed from the well on December 7, 1983. The well was flowing at around 3200 barrels of fluid per day at a surface temperature of 209°F while making flowing pressure gradient stops coming out of the well bore. These details are recorded on Table No. 8 and graphically depicted on Figure No. 19. The flowing pressure gradient was 0.456 psi per foot and very uniform. The temperature plot shows a variable temperature gradient and depicts a condition where there is variation in rate of temperature loss within the well bore. This rate of temperature loss will become more uniform with longer flow time.

The Miogyp No. 3 sand zone was finally shut in prior to abandonment at 6:44 PM on March 13, 1984. The well was flowing about 2015 standard barrels of water per day with 288 psia surface flowing tubing pressure at 178°F temperature. Separator pressure was 248 psig and the water disposal well head pressure was 65 psig. The cumulative brine produced was reported as 348,919 barrels on the daily test report.

The flow rate on December 31, 1983 was approximately 2780 SBWPD with 315 psia surface tubing pressure at 183°F. This is a loss of 760 barrels of water per day rate while maintaining around 300 psig well head pressure over the final 73 days of final flow.

Summary, Miogypsinoides No. 3 Sand

The production drawdown test conducted on the Miogyp No. 3 Sand presented data that was interpreted as coming from a lenticular bar type sand zone containing approximately 11.1 million standard barrels of reservoir fluid. In this case, the reservoir fluid is a brine having approximately 160,000 ppm total dissolved solids. The original pressure measured at the top of the sand zone at a depth of 15,246 feet was 11,886.67 psia at 293.8°F temperature. The brine contains about 24.50 cubic feet of gas (15.025 psia and 60°F) per standard barrel of reservoir water. The dry gas gravity is 0.9432 (air = 1). The bubble point pressure (saturation pressure) determined by Weatherly Laboratories was 8800 psia at 293°F temperature. During the 15 day flow period the bottom hole measured temperatures reached 301.2°F, which would give the mean reservoir temperature.

The sand thickness was not sufficiently uniform around the well bore to allow a radial flow calculation of Kh . The net sand at the well was estimated at around 24 total feet. Conditions necessary for a zero skin effect would require permeability to the reservoir fluid of about 200 mds. This is the estimate of permeability that would appear realistic. The original viscosity of the reservoir fluid is 0.342 cps., with a fluid compressibility of 2.57×10^{-6} bbl. per bbl. per psi. About 89 percent of the dry gas in solution in the reservoir brine can be separated at the surface under normal conditions.

Steady state flow occurred in the reservoir after about 5.13 days of transient flow. Steady state is defined as the flow condition where the pressure drop per day per reservoir barrel of produced fluid becomes constant. This condition occurred before reaching the flowing bubble point pressure at the sand face.

The production rate was increased to above 6000 BWPD during the 7th day on flow and the flowing sand face pressure dropped below the 8800 psia bubble point pressure. The final week of flow occurred between March 6 and March 13, 1984 with the well producing around 2000 BWPD, at +300 psig flowing tubing pressure. The flowing sand face pressure was estimated at 7225 psia producing +19.5 cubic feet of separator gas. The flowing well bore pressure gradient at 0.456 psi per linear foot was used to make this estimate. The data depicts future production rates declining while maintaining around 300 psi well head flowing pressure. The future brine production rates would decline asymptotic to a no flow condition.

The future gas rates would also depict an asymptotic decline from about 40 MCF per day, with little or no change in produced gas to water ratio. Calculations indicate that less than 3 cubic feet of gas per barrel of reservoir brine would evolve from solution in the reservoir. The 3 s.c.f. would occupy less than 0.2 percent of the reservoir pore space. This would not be a sufficient free gas saturation to support relative permeability for free gas flow.

The Miogyp No. 3 sand reservoir volume is estimated to be about 7,505 acre feet. The reservoir area, assuming 12 feet of average net sand, would support 625 acres. If 8 feet of average net sand is assumed, the area would approximate 938 acres of productive zone. The total production from the reservoir was approximately 3.14 percent of the total reservoir fluid volume. The production rate of 2,000 barrels of brine per day and less than 40 MCF of marketable gas per day is well below any foreseeable economic for this type well.

FIGURE NO. 1

95%

FIGURE NO. 2
 Cross-section of Mlogyp sand, Sweet Lake prospect.
 Datum is top of first sand.
 Note that Pan Am Fee #1 is a gamma ray log.

FIGURE No. 4
RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST
FOR
GEOTHERMAL-GEOPRESSURED WELL

18

No. 1
MG-T/DOE

Test date: June 19-22, 1981 Type Test: Drawdown Lease and Well No. AMOCO Fee No. 1
Producing Formation: Micogypsinoidea No. 5 Sand Field: Sweet Lake Area
Hole size: _____ Casing Size: _____ Tubing Size: 5 1/2" State: Louisiana (Cameron Ph)
Cumulative Production: 0 Gas Gravity: 632 Z: _____
Constant Rate Production: 2820 (bbls/day) Water Salinity: 165,000 PPM Total Solids
Total Production Life: - days Porosity, ϕ : .23 Gas-Water Ratio: 22.2 ft³/bbl
Reservoir Temperature: 299 °F Net Pay: 27 ft. Perforations: 15,387 - 15,414 ft
 μ_g _____ cps μ_w .379 cps B_v 1.0509 R.B./B. B_g _____ R.B./MCF
 C_T 3.23 $\times 10^{-6}$ C_g _____ $\times 10^{-6}$ C_v 2.78 $\times 10^{-6}$ C_r 1.5 $\times 10^{-6}$
 m 22 psi/cycle P at 1 hour: 11,896 S_g _____ S_w 1.00 P_i 12,053 psia @ 15,337
 P_f 11,141 psia @ 3,031 days

I. Calculation of kh (md-ft) and k (md):

$$kh = 162.6 (Q)(B)(\mu) / (\Delta P)$$

$$kh = 162.6 (2820) (1.0509) (.379) / (22) = 8301.3 \text{ md-ft}$$

$$k = (8301.3 \text{ md-ft}) / (27 \text{ ft}) = 307.5 \text{ mds}$$

II. $B_g = (P_b)(T_f)(Z)(1000) / (5.61)(520)(P_R) =$

$$B_g = () () () (.34279 / ()) = \text{Res. bbl/MCF}$$

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP_{skin}

$$s = 1.151 \left[\left(\frac{P_i - P_{1hr}}{m} \right) - \log \left(\frac{k}{\phi \mu C_T r_w^2} \right) + 3.23 \right]$$

$$s = 1.151 \left[\left(\frac{(12053) - (11896)}{22} \right) - \log \left(\frac{(307.5)}{(.23)(.379)(3.23)(.0525)} \right) + 3.23 \right] = +.056$$

$$\Delta P_{\text{skin}} = (0.87)(s)(m) = \text{psi}$$

$$\Delta P_{\text{skin}} = (0.87)(.056)(22) = 1.06 \text{ psi}$$

IV. Diffusivity, η

$$\eta = .006328 (k) / (\phi \mu C_T) =$$

$$\eta = .006328 (307.5) / (.23)(.379)(3.23) \times 10^{-6} = 6,911.018 \text{ ft}^2/\text{day}$$

FIGURE No. 4A
RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST (CONT'D)

19

Test Date: June 19-22, 1981 ; Type Test: No. 1 Drawdown Lease and Well No. MG-T/DOE AMOCO Fee No. 1
Calculation of Productivity Index (I/D-psi) and Completion Efficiency, CE

$$J \text{ (actual)} = \frac{Q_w}{P_i - P_f} = \frac{(2820)}{(12,053 - 11,896)} = \underline{17,962} \text{ Bbls./D-psi}$$

$$J \text{ (ideal)} = \frac{Q_w}{(P_i - P_f) - \Delta P_{\text{skin}}} = \frac{(2820)}{(12,053 - 11,896) - (1.06)} = \underline{18,084} \text{ Bbls./D-psi}$$

$$CE = \frac{J \text{ (actual)}}{J \text{ (ideal)}} = \frac{(17,962)}{(18,084)} = \underline{.9932} \text{ OR } \underline{99.32} \%$$

Distance to Barriers or Discontinuities, d

$$d = 2\sqrt{h\tau}$$

$$d = 2\sqrt{(6911018)} \times \sqrt{\tau} = (.5258) \sqrt{\tau}$$

time τ days	$\sqrt{\tau}$	d, ft.	M (psi/cycle)	Flow Angle	Jones Y Function	Bbls. of Aquifer Explored or tested
.0022	2820	247	22	360°	1.4671066	233,309
.0035	2820	311	22	360°	.92218128	371,174
.0070	2820	440	44	180°		371,174
.105	3000	1703	165	48°		1,579,464
.105		1703	135	Change Choke Size		
.23	4680	2522	229			
2.70	3720	8640	600		.0247147	13,849,640
3.031	2820	9154	Negative			

$(311)^2 \pi / (43560) = 6.98$ acres to first permeability barrier.
 $(7758)(.23)/(1.0509) = 1698$ Bbls./Ac.Ft.
 $(6.98 \text{ acres})(27 \text{ ft.})(1698 \text{ Bbls./Ac.Ft.}) = 320,005$ Bbls.

Weatherly PVT data corrected to 22.2 ft³/standard bbl. (dry gas)

B.P.P. = 6340 psia
 $R_w = 1.0693$ @ 6340 psia
 $R_w = 1.0509$ @ 12,062 psia
 $\mu_w = 0.379$ cps. @ 12,062 psia

FIGURE No. 6
RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST
FOR
GEOTHERMAL-GEOPRESSURED WELL

21

No. 1
MG-T/DOE

Test date: June 22-23, 1981 Type Test: Buildup Lease and Well No. AMOCO Fee No. 1
Producing Formation: Miocypsinoides No. 5 Sand Field: Sweet Lake Area
Hole size: _____ Casing Size: _____ Tubing Size: 4 1/2" State: Louisiana (Cameron PH)
Cumulative Production: 10,574 Gas Gravity: 632 Z: _____
Constant Rate Production: 2820 (bbls/day) Water Salinity: 165,000 PPM Total Solids
Total Production Life: 3,031 days Porosity, ϕ : .23 Gas-Water Ratio: 22.2 ft³/bbl
Reservoir Temperature: 299 °F Net Pay: 27 ft. Perforations: 15,387-15,414 ft
 μ_g _____ cps μ_w .379 cps B_v 1.0509 R.B./B. B_g _____ R.B./MCF
 C_T 3.23 $\times 10^{-6}$ C_g _____ $\times 10^{-6}$ C_v 2.78 $\times 10^{-6}$ C_r 1.5 $\times 10^{-6}$
 m 17.6 psi/cycle P at 1 hour: 11,277 S_g _____ S_w 1.00 P_i 12,053 psia
 P_f 11,141.43 psia

I. Calculation of kh (md-ft) and k (md):

$$kh = 162.6 (Q)(B)(\mu)/(md)$$

$$kh = 162.6 (2820) (1.0509) (.379) / (17.6) = \underline{10,376.7} \text{ md-ft}$$

$$k = (10,376.7) \text{ md-ft} / (27) \text{ ft} = \underline{384.3} \text{ mds}$$

II. $B_g = (P_b)(T_f)(Z)(1000)/(5.61)(520)(P_R) =$

$$B_g = () () () (.34279/()) = \underline{\hspace{2cm}} \text{ Res. bbl/MCF}$$

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP_{skin}

$$s = 1.151 \left[\left(\frac{P_{hr} - P_f}{m} \right) - \log \left(\frac{k}{\phi \mu C_T r_w^2} \right) + 3.23 \right]$$

$$s = 1.151 \left[\left(\frac{(11,277) - (11,141)}{17.6} \right) - \log \left(\frac{(384.3) 10^6}{(.23)(.379)(3.23)(.0525)} \right) + 3.23 \right] = \underline{+.62}$$

$$\Delta P_{\text{skin}} = (0.87)(s)(m) = \text{psi}$$

$$\Delta P_{\text{skin}} = (0.87)(.62)(17.6) = \underline{9.6} \text{ psi}$$

IV. Diffusivity, η

$$\eta = .006328 (k) / \phi \mu C_T =$$

$$\eta = .006328 (3843) / (.23)(.379)(3.23) 10^{-6} = \underline{8,655,846} \text{ ft}^2/\text{day}$$

Note: Pressure at the sand face was building up at a flow rate of 2820 BWPD when well was shut in. Therefore, low buildup pressure slope.

FIGURE No. 6A
RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST (CONT'D)

22

Test Date: June 22-23, 1981 : Type Test: No. 1 Buildup Lease and Well No. MG-T/DOE AMOCO Fee No. 1

Calculation of Productivity Index (B/D-psi) and Completion Efficiency, CE

$$J \text{ (actual)} = \frac{Q_w}{P_i - P_f} = \frac{(\quad)}{(\quad)} = \quad \text{Bbls./D-psi}$$

$$J \text{ (ideal)} = \frac{Q_w}{(P_i - P_f) - \Delta P_{\text{skin}}} = \frac{(\quad)}{(\quad) - (\quad)} = \quad \text{Bbls./D-psi}$$

$$CE = \frac{J \text{ (actual)}}{J \text{ (ideal)}} = \frac{(\quad)}{(\quad)} \text{ OR } \frac{(\quad)}{(\quad)}$$

Distance to Barriers or Discontinuities, d

$$d = 2\sqrt{h^2 c}$$

$$d = 2 \sqrt{(8,655,846)} \times \sqrt{c} = (5,884) \sqrt{c}$$

time t days	$\sqrt{t}$	d, ft.	$\frac{u}{(psi/cycle)}$	Flow Angle	Jones Y Function	Bbls. of Aquifer Explored or tested
<u>.0007</u>	<u>.0265</u>	<u>156</u>	<u>17.6</u>	<u>360°</u>	<u> </u>	<u> </u>
<u>.002</u>	<u>.0447</u>	<u>263</u>	<u>17.6</u>	<u>360°</u>	<u> </u>	<u> </u>
<u>.002</u>	<u>.0447</u>	<u>263</u>	<u>35.2</u>	<u>180°</u>	<u> </u>	<u> </u>
<u>.006</u>	<u>.0775</u>	<u>456</u>	<u>35.2</u>	<u>180°</u>	<u> </u>	<u> </u>
<u>.20</u>	<u>.4472</u>	<u>2634</u>	<u>370.0</u>	<u>17°</u>	<u> </u>	<u> </u>
<u> </u>	<u> </u>	<u> </u>	<u> </u>	<u> </u>	<u> </u>	<u> </u>

FIGURE NO. 8

RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST
FOR
GEOTHERMAL-GEOPRESSURED WELL

24

Test date: June 30-July 17, 1981 Type Test: Drawdown No. 2 Lease and Well No. MG-T/DOE AMOCO Fee No. 1
Producing Formation: _____ Field: Sweet Lake Area
Hole size: _____ Casing Size: _____ Tubing Size: 5 1/2" State: Louisiana (Cameron Ph)
Cumulative Production: 10,574 Bbls Gas Gravity: 632 Z: _____
Constant Rate Production: 17,500 (bbls/day) Water Salinity: 165,000 PPM Total Solids
Total Production Life: 3,031 days Perosity, ϕ : .23 Gas-Water Ratio: 22.2 ft³/bbl
Reservoir Temperature: 299 °F Net Pay: 27 ft. Perforations: 15,387-15,414 ft
 μ_g _____ cps μ_w .379 cps B_v 1.0509 R.B./N. B_g _____ R.B./MCF
 C_T 3.23 $\times 10^{-6}$ C_g _____ $\times 10^{-6}$ C_w 2.78 $\times 10^{-6}$ C_r 1.5 $\times 10^{-6}$
 α 126.5 psi/cycle P at 1 hour: NA S_g _____ S_w 1.00 P_i 12,053 psia @ 15,337 Ft.
 P_f _____ psia

I. Calculation of kh (md-ft) and k (md):

$$kh = 162.6 (Q)(B)(\mu)/(md)$$

$$kh = 162.6 (17,500) (1.0509) (.379) / (126.5) = 89.59.2 \text{ md-ft}$$

$$k = (895.2) \text{ md-ft} / (27) \text{ ft} = 331.8 \text{ mds}$$

II. $B_g = (P_b)(T_f)(Z)(1000)/(5.61)(520)(P_R) =$

$$B_g = () () () (.34279/()) = \text{Res. bbl/ MCF}$$

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP_{skin}

$$s = 1.151 \left[\left(\frac{P_i - P_{1hr}}{m} \right) - \log \left(\frac{K}{\phi \mu C_T r_w^2} \right) + 3.23 \right]$$

$$s = 1.151 \left[\left(\frac{() - (NA)}{()} \right) - \log \left(\frac{()}{() () ()} \right) \right]$$

$$\Delta P_{\text{skin}} = (0.87)(s)(m) = \text{psi}$$

$$\Delta P_{\text{skin}} = (0.87)() () = \text{psi}$$

IV. Diffusivity, η

$$\eta = .006328 (k) / \phi \mu C_T =$$

$$\eta = .006328 (331.8) / (.23) (.379) (3.23) 10^{-6} = 7.457.157$$

FIGURE No. 8A
RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR BREAKDOWN TEST (CONT'D)

25

Test Date: June 30-July 17, 1981 Type Test: No. 2 Drawdown Lease and Well No. AMOCO Fee No. 1
MG-T DOE
Calculation of Productivity Index (3/D-psi) and Completion Efficiency, CE

$$J \text{ (actual)} = \frac{Q_w}{P_i - P_f} = \frac{(\quad)}{(\quad)} = \quad \text{Bbls./D-psi}$$

$$J \text{ (ideal)} = \frac{Q_w}{(P_i - P_f) - \Delta P_{\text{skin}}} = \frac{(\quad)}{(\quad) - (\quad)} = \quad \text{Bbls./D-psi}$$

$$CE = \frac{J \text{ (actual)}}{J \text{ (ideal)}} = \frac{(\quad)}{(\quad)} \text{ OR } \frac{(\quad)}{(\quad)}$$

Distance to Barriers or Discontinuities, d

$$d = 2\sqrt{\eta c}$$

$$d = 2\sqrt{(7,457,157)} \times \sqrt{c} = (5462) \sqrt{c}$$

time ² days	$\sqrt{c}$	d, ft.	m (psi/cycle)	Flow Angle	Jones Y Function	Bbls. of Aquifer Explored or tested
?	17,500	--	126.5 g	360°	-	-
.0034	17,500	318	253	180°	1.759196	194,571
.014	17,500	646	441	103°	.744703	459,632
.056	17,500	1,293	1150	39.6°	.499772	684,892
.18	16,200	2,317	1480	30.8°	.209983	1,630,080
.90	15,250	5,182	1805	25.2°	.0544096	6,290,978
1.20	15,000	5,983	1670	?	.0383844	8,917,417
1.55	14,900	6,800	2045	?	.0366342	9,343,459
3.00	15,000	9,460	1805		.0165949	20,626,158
7.61	14,150	15,068	492		1.89032 x 10 ⁻³	184,075,225
8.61	12,000	16,027	492		1.97011 x 10 ⁻³	173,741,007
9.61	7,950	16,932	492		2.06643 x 10 ⁻³	128,471,991
15.66	10,708	21,615	492		1.21388 x 10 ⁻³	281,979,839
17.00	10,600	22,520	492		1.12959 x 10 ⁻³	303,020,998

FIGURE NO. 9
EXPLORATION DRAWDOWN
Water Explored Vs. Time
&

FIGURE NO. 10
Reservoir Water Explored
Vs.
Time in Days
Mlogyp Sand No. 6
MG-T/DOE AMOCO Fee No. 1
Sweet Lake Field Area, Cameron Parish, LA
June 30 through July 17, 1981

TABLE No. 1

29

Mlogypsinoïdes No. 5 Sand
 MG-T/DOE, AMOCO Fee No. 1 Well
 Sweet Lake Area, Cameron Parish, Louisiana

Reservoir Fluid Summary

Reservoir Temperature, ° F	299
Saturation Pressure at 299 ° F, Psia	2006
Compressibility of Reservoir (Brine) Water at 299 ° F	
Vol. per Vol. per Psia x 10 ⁶	
From 2006 Psia to 8000 Psia	2.84
From 8000 Psia to 12062 Psia	2.78
Saturated (Brine) Water at 2006 Psia, 299 ° F	
Density, Grms. per Ml.	1.0022
Lbs. per Bbl.	351.24
Specific Volume, Cu. Ft. per Lb.	0.015983
Viscosity, Centipoise	0.365
Formation Volume Factor, Bbls. per Bbl.	
"Standard Bbls. at 60 ° F and 15.025 Psia"	1.0761
Solution Gas-Water Ratio, Cu. Ft. per Bbl.	
"Standard Bbls. at 60 ° F and 15.025 Psia"	9.4 dry
	9.6 wet
Reservoir (Brine) Water at 12,062 Psia, 299 ° F (extrapolated)	
Density, Grms. Per Ml.	1.0312
Lbs. per Bbl.	361.4
Specific Volume, Cu. Ft. per Lb.	0.01663
Viscosity, Centipoise	0.394
Formation Volume Factor, Bbl. per Bbl.	
"Standard Bbls. at 60 ° F and 15.025 Psia"	1.0459

Note: Properties of Reservoir water are extrapolated values.

Lab. No. N-1313

TABLE No. 2

Milogypsinoides No. 5 Sand
 MG-T/DOE, AMOCO Fee No. 1 Well
 Sweet Lake Area, Cameron Parish, Louisiana

COMPOSITE LABORATORY DATA AT 299 °F

Recombination (5): 8.10 SCF Sep. Gas @ 15.052 & 60 °F/Bbl. Sep. Water @ Sep. Cond. (Pro)

Pressure PSIA	Pressure Volume Relations			Water Viscosity CPS.	Differential Liberation		
	Relative Volume V/Vsat. Btw	Specific Volume cu. ft. per Pound	Liquid Volume Percent		Formation	Solution	
					Volume Factor Bw	Gas-Water Ratio	
						Per Barrell of Brine @ 60 °F	
						15.025 Psia	
					Dry	Wet	
12062 Res.	0.9719**	0.015534	100.00	0.395**	1.0459	***	***
10000	0.9775	0.015623	100.00	0.386	1.0519		
8000	0.9830	0.015711	100.00	0.378	1.0578		
6000	0.9884	0.015798	100.00	0.372	1.0636		
4000	0.9944	0.015893	100.00	0.368	1.0701		
3000	0.9970	0.015935	100.00	0.366	1.0729		
2006 BPP	1.0000	0.015983	100.00	0.365	1.0761	9.4	9.6
1500	1.0039		99.77	0.369			
1000	1.0167		98.65	0.386			
500				0.41			
422	1.0708		93.83				

NOMENCLATURE:

V/Vsat. is the volume of fluids (water and gas) at the indicated temperature and pressure relative to the volume of saturated water at bubble-point pressure and indicated temperature.

Bw is the volume of water at reservoir temperature and indicated pressure relative to the volume of standard volume of water at 60 °F and 15.025 Psia.

Gas-Water Ratio is cubic feet of gas at 15.025 psia at 60 °F, per barrel of (brine) water at 60 °F and 15.025 psia.

Note: ** Extrapolated
 *** Based on separator water shrinkage.

Lab. No. N-1313

Table No. 3
Exploration Drawdown Calculations
Miogyp Sand No. 5, Second Flow Test
MG-T/DOE AMOCO Fee No. 1 Well

Date Time	Cum. Days	B.H.P. psia	Qw BWPD	$\frac{dp}{dt}$ Qw Bw = y	W=Bw/BwCwY Water Explored 10 ⁶ BhLs
7-2-81					
10:00 AM	1.66	8558.32	-	-	-
11:00 AM	1.70	8535.89	15,505	.03319549	10.398
12:00 AM	1.74	8515.12	15,432	.03088413	11.176
13:00 PM	1.78	8497.77	15,179	.0262287	13.160
14:00 PM	1.82	8479.40	15,106	.0279049	12.369
15:00 PM	1.86	8442.79	15,360	.0546927	6.311
16:00 PM	1.91	8422.14	15,396	.0307775	11.215
17:00 PM	1.95	840.64	15,179	.0264555	13.047
18:00 PM	1.99	8388.49	15,179	.0244146	14.138
20:00 PM	(Adj. Choke)	8368.38	14,780	-	-
21:00 PM	2.114	8370.74	14,816	.0242229	14.250
22:00 PM	2.156	8353.41	14,853	.0267735	12.892
7-3-81					
1:00 AM	2.28	8426.69	13,838	.0422188	8.176
	(Adj. Choke)		-	-	-
5:00 AM	2.45	8349.57	15,432	-	-
6:00 AM	2.49	8327.65	15,432	.0325941	10.590
7:00 AM	2.53	8310.76	15,396	.025173	13.71
8:00 AM	2.57	8285.40	15,505	.0375317	9.197
9:00 AM	2.61	8269.19	15,541	.0239345	14.421
10:00 AM	2.66	8255.04	15,613	.0207965	16.597
11:00 AM	2.70	8246.37	15,469	-	-
12:00 AM	2.74	8251.74	15,396	- Adjusting	-
7-3-81					
17:00 PM	2.948	8220.77	15,360	Adjusting	-
18:00 PM	2.99	8203.24	15,360	.0261885	13.180
19:00 PM	3.031	8193.85	15,396	.013995	24.663
20:00 PM	3.037	8185.15	15,287	.0130592	26.431
21:00 PM	3.114	8177.36	15,251	.0117208	29.448
22:00 PM	3.156	8170.24	15,179	.0107636	32.068
23:00 PM	3.198	8164.72	15,142	.0083682	41.262
24:00 PM	3.239	8158.12	15,106	.0100257	34.428
7-4-81					
1:00 AM	3.28	8151.70	15,106	.009752	35.393
2:00 AM	3.32	8144.89	15,179	.0102949	33.528
3:00 AM	3.36	8139.50	15,106	.00818767	42.157
4:00 AM	3.41	8134.56	15,179	.00745818	46.280
5:00 AM	3.45	8129.74	15,287	.00723512	47.707
6:00 AM	3.49	8124.43	14,998	.00812423	42.486
7:00 AM	3.53	8119.48	15,215	.0074654	46.235
8:00 AM	3.57	8115.40	14,925	.0062728	55.025
9:00 AM		Choke adj.	-	-	-
11:00 AM		8130.43	14,672	-	-
12:00 AM	3.74	8126.17	14,708	.006646255	51.934
13:00 PM	3.78	8023.63	14,635	.00398256	86.667
21:00 PM		8093.70	Choke adj.	-	-
22:00 PM	4.15	8092.10	14,581	.003080738	112.04
24:00 PM	4.24	8088.47	14,581	.00285634	120.842

Date Time	Cum. Days	S.R.P. psia	Qw BWPd	$\frac{dp}{dt}$ Qw Bw = Y	W-Sw/BwCwY Water Explored 10 ⁶ BhLs
7-5-81					
2:00 AM	4.32	8084.61	14,583	.00303732	113.642
4:00 AM	4.41	8080.02	14,491	.00362192	95.300
6:00 AM	4.49	8076.27	14,509	.00296541	116.398
8:00 AM	4.57	8072.13	14,599	.00325363	106.089
10:00 AM	4.66	8067.15	14,455	.00395278	87.323
12:00 AM	4.74	8862.80	14,563	.00342712	100.716
14:00 PM	4.82	8057.06	14,400	.00457341	75.473
16:00 PM	4.91	8053.15	14,255	.00322751	106.945
18:00 PM	4.99	8049.84	14,490	.00262090	131.698
20:00 PM	5.07	8046.01	14,400	.00297093	101.233
22:00 PM	5.16	8042.98	14,418	.0024079	124.901
24:00 PM	5.24	8038.50	14,327	.0034928	86.106
7-6-81					
2:00 AM	5.32	8034.46	14,346	.0031457	95.608
4:00 AM	5.41	8030.45	14,273	.00313823	95.836
6:00 AM	5.49	8026.89	14,020	.002836437	106.033
8:00 AM	5.57	8023.60	14,201	.00258790	116.216
10:00 AM		Choke plugged			
7-7-81	-	Well shut in for 35 minutes	-	-	-
9:00 AM	6.61	8005.70	13,621	.00320644	93.797
11:00 AM	6.69	8001.75	13,367	.003300797	91.116
13:00 PM	6.78	7997.36	13,336	.00367839	81.763
15:00 PM	6.86	7994.41	13,187	.002498895	120.355
17:00 PM	6.95	7990.73	13,313	.00308765	97.406
7-7-81					
19:00 PM	7.03	7987.35	13,078	.00289039	104.054
21:00 PM	7.11	7984.97	13,169	.00202635	148.422
23:00 PM	7.19	7981.45	13,223	.0029736	101.141
7-8-81					
1:00 AM	7.28	7978.09	13,078	.0028699	104.796
3:00 AM	7.36	7976.03	13,005	.00176936	169.981
5:00 AM	7.45	7971.93	12,969	.00353129	85.169
7:00 AM	7.53	7970.18	12,951	.0015094	199.254
9:00 AM	7.61	7967.54	12,879	.00228978	131.347
11:00 AM	7.69	7965.73	12,896	.0016112996	213.575
13:00 PM	7.78	7963.00	12,915	.00242682	141.804
15:00 PM	7.86	7959.53	12,897	.003088946	111.408
17:00 PM	7.95	7957.35	12,879	.001943318	177.085
19:00 PM	8.03	7955.58	12,842	.00158232	217.487
21:00 PM	8.11	7953.73	12,860	.001651519	208.374
23:00 PM	8.24	7950.41	12,897	.0029554	116.441
7-9-81					
1:00 AM	8.28	7947.50	12,842	.0026014356	132.286
3:00 AM	8.36	7945.79	12,860	.00152654	225.432
5:00 AM	8.44	7943.44	12,806	.00210672	163.350
7:00 AM	8.53	7941.14	12,770	.00206771	166.432
9:00 AM	8.61	7939.50	12,843	.001466044	234.736
11:00 AM	8.70	7936.97	12,876	.0022554	152.581
13:00 PM	8.78	7935.13	12,752	.001656568	207.739

Date Time	Cum. Days	B.H.P. psia	Qw BWPD	$\frac{dp}{dt}$ Qw Bw = Y	W=S _w /B _w C _w Y Water Explored 10 ⁶ BhLs
7-9-81					
15:00 PM	8.86	7933.24	12,752	.001704926	201.846
17:00 PM	8.95	7931.27	12,752	.001773608	194.030
19:00 PM	9.03	7929.28	12,824	.001781486	193.172
21:00 PM	9.11	7927.49	12,643	.001625383	211.724
23:00 PM	9.20	7925.47	12,679	.00182613	188.419
7-10-81					
1:00 AM	9.28	7924.62	12,752	.000765262	449.400
3:00 AM	9.36	7921.53	12,661	.003010391	114.314
5:00 AM	9.45	7920.45	12,734	.000973708	353.426
7:00 AM	9.53	7918.82	12,679	.001475895	233.169
9:00 AM	9.62	7917.12	12,679	.001539277	223.569
11:00 AM	9.70	7915.10	12,698	.001826358	188.426
13:00 PM	9.78	7913.26	12,553	.00168283	204.497
15:00 PM	9.87	7911.76	12,716	.001354287	254.107
17:00 PM	9.95	7910.43	12,661	.001205970	285.358
18:00 PM	Choke Adjustment				
7-11-81					
2:00 AM	10.32	7873.62	12,680	.002363149	145.625
4:00 AM	10.41	7870.59	12,715	.002735766	125.790
6:00 AM	10.49	7867.99	12,752	.0023408028	147.015
8:00 AM	10.57	7866.51	12,734	.00133434	257.905
10:00 AM	10.66	7867.49	-	-	-
12:00 AM	10.74	7864.32	-	-	-
14:00 PM	10.82	7862.23	12,700	.00128274	264.802
16:00 PM	10.91	7861.05	12,426	.001090193	315.663
18:00 PM	10.99	7859.64	12,715	.001273079	270.316
20:00 PM	11.07	7854.59	12,715	.0044364	75.474
22:00 PM	11.16	7852.06	12,860	.00258563	152.368
24:00 PM	11.24	7849.56	12,896	.0022552	154.628
7-12-81					
2:00 AM	11.32	7847.59	12,752	.001773539	194.038
8:00 AM	11.41	7849.19	12,752	.00393189	87.523
10:00 AM	11.66	7839.98	12,679	.0009869479	348.684
12:00 AM	11.74	7838.75	12,679	.00111371	308.997
Production Problems					
7-13-81					
2:00 AM	12.32	7857.53	11,075	.0007976209	431.148
4:00 AM	12.41	7857.04	11,075	.000507577	677.519
6:00 AM	12.49	7856.16	11,075	.0009115668	377.255
8:00 AM	12.57	7855.30	11,147	.000885095	388.538
10:00 AM	12.66	7854.15	11,183	.001179748	291.497
12:00 AM	12.74	7852.98	11,147	.001204141	285.592
14:00 PM	12.82	7852.41	11,111	.0005885336	584.322
16:00 PM	12.99	7849.64	10,931	.001818636	183.055
7-14-81					
8:00 AM	13.57	7841.69	11,002	.0009697524	354.620
10:00 AM	13.66	7840.86	11,002	.000865478	397.345
12:00 AM	13.74	7839.47	10,821	.00145245	236.767

Date Time	Cum. Days	S.R.P. psia	Qw BWPD	$\frac{dp}{dt}$ Qw Bw = Y	W-Sw/BwCwY Water Explored 10 ⁶ BhLs
7-14-81					
16:00 PM	13.91	7838.50	10,894	.00104255	329.857
18:00 PM	13.99	7837.24	10,819	.0013360816	257.389
22:00 PM	14.16	7835.18	10,930	.00108409	318.095
24:00 PM	14.24	7834.24	10,749	.001003154	342.812
7-15-81					
2:00 AM	14.32	7833.06	10,749	.001259399	273.061
		Changing Rates			
14:00 PM	14.82	7818.64	10,678	.00122528	280.664
7-16-81					
2:00 AM	15.32	7815.45	10,709	.00146765	234.316
6:00 AM	15.49	7814.37	10,709	.00098557	348.927
8:00 AM	15.57	7813.09	10,709	.00137123	250.792
10:00 AM	15.66	7811.94	10,708	.00123208	279.116
12:00 AM	15.74	7811.02	10,613	.000994487	345.799
16:00 PM	15.91	7809.28	10,788	.000926558	371.151
22:00 PM	16.16	7805.35	10,725	.00167412	205.417
24:00 PM	16.24	7804.46	10,804	.009450504	363.889
7-17-81					
2:00 AM	16.32	7803.52	10,741	.001003998	342.523
		Rate changes, pressure went up.			

FIGURE No. 4

Pressure and Temperature Gradients
 MG-T/DOE Amoco Fee No.1 Well
 Sweetlake Prospect, Cameron Ph., Louisiana

Conducted Reservoir Data Inc. on June 17, 1981.

Gauge: EPG 512, SN47553, GRC

Date: June 17, 1981

Time	Depth, ft.	Pressure, psia	Temp., °F
13:49:20	0' (Lubrication)	3999.51	95
14:16:00	3000'	5684.51	108
14:27:00	4000'	6216.63	120
14:37:00	5000'	6784.08	132
14:47:00	6000'	7291.14	147
14:57:00	7000'	7847.43	161
15:06:00	8000'	8365.74	176
15:17:00	9000'	8893.68	190
15:27:00	10,000'	9587.15	214
15:38:00	11,000'	9916.95	231
15:48:00	12,000'	10,450.92	250
15:57:00	13,000'	11,011.20	267
16:07:00	14,000'	11,626.79	284
16:15:00	15,000'	12,209.62	296
16:21:50	15,400'	12,420.65	299
16:25:00	"	12,415.83	299
16:30:00	"	12,409.17	299
16:35:00	"	12,403.75	299
16:40:00	"	12,398.65	299
16:50:00	"	12,389.28	299
17:00:00	"	12,380.71	299
17:30:00	"	12,357.58	299
18:00:00	"	12,336.32	299
19:00:00	"	12,262.49	299
20:00:00	"	12,228.74	299
21:00:00	"	12,198.53	298
22:00:00	"	12,172.38	299
23:00:00	"	12,149.47	299
Date: June 18, 1981			
00:00:00	"	12,129.48	299
01:00:00	"	12,111.66	299
01:12:00	"	12,108.30	299

FIGURE NO. 13
RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST
FOR

37

GEOHERMAL-GEOPRESSURED WELL

Cleaning MG-T/DOE.

Test date: Nov. 12-13, 1983 Type Test: Drawdown Lease and Well No. Amoco Fee No. 1

Producing Formation: Miocypinoides No. 3 Sand Upper Frio Field: Sweet Lake Area

Hole size: _____ Casing Size: 54 Tubing Size: 54 State: (Cameron Parish) Louisiana

Cumulative Production: 0 Gas Gravity: 0.9432 Z: _____

Constant Rate Production: 2800 (bbls/day) Water Salinity: 168,500 PPM Total Solids

Total Production Life: Initial days Porosity, 0.20 Gas-Water Ratio: 24.5 ft³/bbl

Reservoir Temperature: 300 °F Net Pay: 24 ft. Perforations: 15,260-280; 15,245-255

μ_g _____ cps μ_w 0.342 cps B_w 1.0491 R.B./B. B_g _____ R.B./MCF

C_T 2.95 $\times 10^{-6}$ C_g _____ $\times 10^{-6}$ C_w 2.57 $\times 10^{-6}$ C_r 0.375 $\times 10^{-6} = (1.5)(.20)/(.80)$

m 162e psi/cycle P at 1 hour: 11,460e S_g _____ B_w 100% $P_{11,886.67}$ psia $\$15,246$

$P_{11,869.83}$ psia $\$15,200$

I. Calculation of kh (md-ft) and k (md):

$$kh = 162.6 (Q)(B)(\mu)/(\Delta m)$$

$$kh = 162.6 (2800) (1.0491) (.342) / (162) = 1,008.3 \text{ md-ft}$$

$$k = (1008.3) \text{ md-ft} / (24) \text{ ft} = 42 \text{ mds}$$

II. $B_g = (P_b)(T_f)(Z)(1000)/(5.61)(520)(P_r) =$

$$B_g = () () () (.34279 / ()) = \text{Res. bbl/MCF}$$

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP_{skin}

$$s = 1.151 \left[\left(\frac{P_i - P_{1hr}}{m} \right) - \log \left(\frac{K}{\phi \mu C_T r_w^2} \right) + 3.23 \right]$$

$$s = 1.151 \left[\left(\frac{(11,869.83 - 11,460)}{162} \right) - \log \left(\frac{(42)}{(.20)(.342)(29.5)(.0525)} \right) + 3.23 \right] = -3.27$$

$$\Delta P_{\text{skin}} = (0.87)(s)(m) = \text{psi}$$

$$\Delta P_{\text{skin}} = (0.87)(-3.27)(162) = -460 \text{ psi}$$

IV. Diffusivity, η

$$\eta = .006328 (k) / \phi \mu C_T =$$

$$\eta = .006328 (42) / (.20)(.342)(2.95) \times 10^{-6} = 1,317,157 \text{ ft}^2/\text{day}$$

FIGURE NO. 13A
RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST (CONT'D)

38

Test Date: Nov. 12-13, 1983 Type Test: Cleaning Drawdown Lease and Well No. Amoco Fee No. 1

Calculation of Productivity Index (B/D-psi) and Completion Efficiency, CE

$$J(\text{actual}) = \frac{Q_w}{P_i - P_f} = \frac{(2800)}{(11870 - 11460)} = \underline{6.8293} \text{ Bbls./D-psi}$$

$$J(\text{ideal}) = \frac{Q_w}{(P_i - P_f) - \Delta P_{\text{skin}}} = \frac{(2800)}{(11870 - 11460) - (-460)} = \underline{3.2184} \text{ Bbls./D-p.}$$

$$CE = \frac{J(\text{actual})}{J(\text{ideal})} = \frac{(6.8293)}{(3.2184)} = \underline{2.122} \text{ OR } \underline{212.2\%}$$

IMPOSSIBLE

Distance to Barriers or Discontinuities, d

$$d = 2\sqrt{\eta c}$$

$$d = 2\sqrt{(1,317,157)} \times \sqrt{c} = (2295) \sqrt{c}$$

time t days	$\sqrt{t}$	d, ft.	m (psi/cycle)	Flow Angle	Jones Y Function	Bbls. of Aquifer Explored or tested
.0007	2800	60.7	1627	360°?	34.254231	10,828
.03	2800	397.5	1627	360°?	.7992654	464,044
.09	2800	688.5	6207	95°	1.019639	363,750
.32	3500e	1298	6207	94°	.2294188	1,616,669
.56	4000	1717	12707	60°	.2349692	1,578,480
1.00	4000	2295	12707	60°	.13158276	2,818,714

(7758)(.20)/(1.0491) = 1,479 Bbls./Ac. Ft.
(397.5)²TI/(43,560) = 11.4 Acres
(11.4 Ac.)(24 Ft.)(1,479 B/AcFt) = 404,654 Bbls.
(2295)²TI/(43,560) = 379.9 Acres
(379.9 Ac.)(24 Ft.)(1479) = 13,484,930 Bbls.
(2,818,714 Bbls)(1479)(379.9) = 5.02 Feet Net.

FIGURE NO. 14

39

RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST

FOR

GEOTHERMAL-GEOPRESSURED WELL

MG-T/DOE

Test date: November 13, 1983 Type Test: Buildup Lease and Well No. Amoco Fee No. 1
Producing Formation: Miogypsinoidea No. 3 Sand (Upper Frio) Field: Sweet Lake Area
Hole size: Casing Size: 54" Tubing Size: 54" State: Louisiana (Cameron Ph.)
Cumulative Production: 3850 Bbls. Gas Gravity: 1.9432 Z:
Constant Rate Production: 3850 (bbls/day) Water Salinity: 165,000 PPM Total Solids
Total Production Life: 1 days Porosity, ϕ : .20e Gas-Water Ratio: 24.5 ft³/bbl
Reservoir Temperature: 300 °F Net Pay: 24 ft. Perforations: 15,245-15,280 ft
 μ_g cps μ_w .342 cps Bw 1.0491 R.B./B. Bg R.B./MCF
 C_T 2.95 $\times 10^{-6}$ C_g $\times 10^{-6}$ C_w 2.57 $\times 10^{-6}$ C_r 0.375 $\times 10^{-6}$
 m 1707 psi/cycle P at 1 hour: 10,705 S_g S_w 100% P_i 11,873.54 psia
 P_f 10,133.00 psia

I. Calculation of kh (md-ft) and k (md):

$$kh = 162.6 (Q)(B)(\mu)/(\Delta m)$$

$$kh = 162.6 (3850) (1.0491) (.342) / (170) = 1321.2 \text{ md-ft}$$

$$k = (1321.2 \text{ md-ft}) / (24 \text{ ft}) = 55 \text{ mds}$$

II. $B_g = (P_b)(T_f)(Z)(1000)/(5.61)(520)(P_g) =$

$$B_g = () () () (.34279/()) = \text{Res. bbl/MCF}$$

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP_{skin}

$$s = 1.151 \left[\left(\frac{P_{iw} - P_f}{m} \right) - \log \left(\frac{K}{\phi \mu C_T r_w^2} \right) + 3.23 \right]$$

$$s = 1.151 \left[\left(\frac{(10,705) - (10,133)}{170} \right) - \log \left(\frac{(55) 10^6}{(.20) (.342) (2.95) (.0525)} \right) + 3.23 \right] = -3.59$$

$$\Delta P_{\text{skin}} = (0.87)(s)(m) = \text{psi}$$

$$\Delta P_{\text{skin}} = (0.87)(-3.59) () = -531 \text{ psi}$$

IV. Diffusivity, η

$$\eta = .006328 (k) / \phi \mu C_T =$$

$$\eta = .006328 (55) / (.20) (.342) (2.95) 10^{-6} = 1,724,849 \text{ ft}^2/\text{day}$$

FIGURE NO. 15
7.2 DAY EXPLORATION DRAWDOWN TEST
 November 22-29, 1983
 Mlogyp No. 3 Sand
 MG-T/DOE AMOCO Fee No. 1 Well
 Sweet Lake Field Area, Cameron Parish, LA

FIGURE NO. 16

RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST

41

FOR

GEOTHERMAL-GEOPRESSURED WELL

Exploration

MG-T/DOE

Test date: Nov. 22 to 29, 1983 Type Test: Drawdown Lease and Well No. Amoco Fee No. 1
Producing Formation: Micogypsinoidea No. 3 Bone (Upper Frio) Field: Sweet Lake Area
Hole size: Casing Size: 5 1/2" Tubing Size: 5 1/2" State: Louisiana (Cameron Ph.)
Cumulative Production: ±3850 Gas Gravity: ±.9432 Z:
Constant Rate Production: 2300 (bbls/day) Water Salinity: ±168,500 PPM Total Solids
Total Production Life: 1 days Porosity, ϕ : ±.20 Gas-Water Ratio: 24.5 ft³/bbl
Reservoir Temperature: 300 °F Net Pay: ±24 ft. Perforations: 15,245-15,280 ft
 μ_g cps μ_w 0.342 cps B_w 1.0491 R.B./B. B_g R.B./MCF
 C_T 2.95 $\times 10^{-6}$ C_g $\times 10^{-6}$ C_w 2.57 $\times 10^{-6}$ C_r 0.375 $\times 10^{-6}$
 m 165 psi/cycle P at 1 hour: 11,430 S_g S_w 100% P_i 11,795.24 psia @ 15,200 ft.
8:47AM; 11-22-83
 P_f 7,977.12 psia @ 15,200 ft.
8:20AM; 12-7-83

I. Calculation of kh (md-ft) and k (md);

$$kh = 162.6 (Q)(B)(\mu)/(m)$$

$$kh = 162.6 (2300) (1.0491) (.342) / (165) = 813.2 \text{ md-ft}$$

$$k = (813.2) \text{ md-ft} / (24) \text{ ft} = 34 \text{ mds}$$

II. $B_g = (P_b)(T_f)(Z)(1000)/(5.61)(520)(P_R) =$

$$B_g = () () () (.34279)/() = \text{Res. bbl/MCF}$$

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP_{skin}

$$s = 1.151 \left[\left(\frac{P_i - P_{wf}}{m} \right) - \log \left(\frac{K}{\phi \mu C_T r_w^2} \right) + 3.23 \right]$$

$$s = 1.151 \left[\left(\frac{(11,795) - (11,430)}{(165)} \right) - \log \left(\frac{(34) 10^6}{(.20) (.342) (2.95) (.0525)} \right) + 3.23 \right] = -4.68$$

$$\Delta P_{\text{skin}} = (0.87)(s)(m) = \text{psi}$$

$$\Delta P_{\text{skin}} = (0.87)(-4.68) (165) = -602 \text{ psi}$$

IV. Diffusivity, η

$$\eta = .006328 (k) / \phi \mu C_T =$$

$$\eta = .006328 (34) / (.20) (.342) (2.95) 10^{-6} = 1,066,270 \text{ ft}^2/\text{day}$$

FIGURE NO. 16A
RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST (CONT'D)

42

Test Date: Nov. 22-Dec. 7, 1983 Type Test: Exploration Drawdown Lease and Well No. MG-T/DOE Amoco Fee No.1

Calculation of Productivity Index (B/D-psi) and Completion Efficiency, CE

$$J \text{ (actual)} = \frac{Q_w}{P_i - P_f} = \frac{(2300)}{(11795 - 11430)} = \underline{6.3014} \text{ Bbls./D-psi}$$

$$J \text{ (ideal)} = \frac{Q_w}{(P_i - P_f) - \Delta P_{\text{skin}}} = \frac{(2300)}{(11795 - 11430) - (-602)} = \underline{2.3785} \text{ Bbls./D-psi}$$

$$CE = \frac{J \text{ (actual)}}{J \text{ (ideal)}} = \frac{(6.3014)}{(2.3785)} = \underline{2.649} \text{ OR } \underline{264.9} \%$$

Distance to Barriers or Discontinuities, d $d = 2\sqrt{\eta c}$

$$d = 2\sqrt{(1,066,270)} \times \sqrt{c} = (2065) \sqrt{c}$$

time t , days	$\sqrt{t}$	d, ft.	η (psi/cycle)	Flow Angle	Jones Y Function	Bbls. of Aquifer Explored or tested
.01042	2720	211	±165	?	2.499141	.148
.0118	2452	224	±165	?	2.32053	.159
.0132	2067.7	237	±165	?	2.432386	.152
.0146	2165.5	250	±165	?	2.042939	.182
.0160	2544.8	261	±165	?	1.808673	.206
.01875	2242.0	283	±165	?	1.052636	.392
.0229	2315.4	312	±165	?	1.393793	.267
.0299	2393.8	357	±165	?	1.186521	.314
.509	2112.7	1,473	512.16(dp/dt)	?	.2310739	1.605
1.009	2401	2074	347.52(dp/dt)	?	.1379655	2.688
1.509	2175	2537	246.24(dp/dt)	?	.0925169	4.009
2.05	2228	2957	173.52(dp/dt)	?	.07443090	4.983
3.05	2209.7	3606	129.36(dp/dt)	?	.05594186	6.630
4.134	2202.2	4199	118.00(dp/dt)	?	.05120301	7.244
5.13	2300	4677	80.76(dp/dt)	?	.0335536	11.054
6.13	2160	5113	77.16(dp/dt)	?	.0341357	10.865
6.63	2130	5317	73.14(dp/dt)	?	.03281297	11.303

FIGURE NO. 19
FLOWING PRESSURE & TEMPERATURE
VS.
DEPTH
Mlogypsinoides No. 3 Sand
MG-T/DOE AMOCO Fee No. 1 Well
Panel Instruments
December 7, 1983

Table No. 5
Exploration Drawdown Calculations
Miogypsainoides No. 3 Sand (15,245 ft.-15,280 ft.)
November 22 thru December 7, 1983
MG-T/DOE Amoco Fee No. 1 Well
Sweet Lake Area, Cameron Ph., Louisiana

Date Time	Cum. Days	B.H.P. psia	Qw BWPD	$\frac{dp}{dt}$ Qw BwC = Y	W=Sw/BwCwY Water Explored 10 ⁶ Bbls
11-22-83					
8:47 AM	0	11,795.24	0	-	-
9:00 AM	.00902	11,533.13	-	-	-
9:02 AM	.010417	11,523.25	2,720	2.492893	0.148
9:04 AM	.0118	11,514.98	2,452	2.314732	0.160
9:06 AM	.0132	11,507.67	2,068	2.426305	0.153
9:08 AM	.0146	11,501.24	2,166	2.037362	0.182
9:10 AM	.0160	11,494.57	2,545	1.803187	0.206
9:12 AM	.0174	11,486.96	2,286	2.290399	0.162
9:14 AM	.0188	11,483.54	2,242	1.049526	0.353
9:20 AM	.0229	11,469.51	2,315	1.389914	0.267
9:25 AM	.0264	11,459.18	2,269	1.252935	0.296
9:30 AM	.0299	11,448.89	2,394	1.182916	0.314
9:35 AM	.0333	11,439.87	2,438	1.018206	0.364
9:40 AM	.0368	11,422.21	2,312	2.102159	0.176
9:50 AM	.0437	11,414.35	2,308	0.468619	0.791
10:00 AM	.0506	11,399.97	2,394	0.826547	0.449
10:10 AM	.0576	11,386.02	2,316	.828836	0.447
10:20 AM	.0646	11,369.21	2,328	.993613	0.373
10:30 AM	.0715	11,361.58	2,375	.442073	0.839
11:00 AM	.0924	11,329.48	2,329	.632189	0.587
11:30 AM	.113	11,299.75	2,300	.592896	0.626
12:00 PM	.134	11,274.68	2,350	.489326	0.758
12:30 PM	.155	11,250.91	2,325	.468940	0.791
13:00 PM	.176	11,228.57	2,326	.440540	0.842
13:30 PM	.197	11,208.01	2,271	.415257	0.893
14:00 PM	.217	11,189.54	2,312	.366430	1.012
14:30 PM	.238	11,169.69	2,327	.391269	0.948
15:00 PM	.259	11,152.12	2,278	.353777	1.048
15:30 PM	.280	11,135.47	2,225	.343238	1.081
16:00 PM	.301	11,119.65	2,275	.318960	1.163
16:30 PM	.322	11,104.24	2,275	.310694	1.194
17:00 PM	.342	11,089.97	2,272	.288089	1.287
Bw = 1.0491, Cw = 2.57x10 ⁻⁶ , C = .9975					
17:30 PM	.363	11,076.08	2,155	.295642	1.254
18:00 PM	.384	11,062.57	2,168	.285830	1.298
18:30 PM	.405	11,050.15	2,156	.264231	1.404
19:00 PM	.426	11,037.52	2,172	.266720	1.391
19:30 PM	.447	11,025.72	2,121	.255184	1.453
20:00 PM	.467	11,014.03	2,170	.247096	1.501

Table No. 5 (cont'd.)

Date Time	Cum. Days	B.H.P. psia	Qv BWPD	$\frac{dp}{dt}$ Qv BwC = Y	W=Sv/BwCvY Water Explored 10 ⁶ Bbls
11-22-83					
20:30 PM	.488	11,002.63	2,167	.241300	1.537
21:00 PM	.509	10,991.96	2,113	.231620	1.601
22:00 PM	.551	10,970.78	2,136	.226273	1.639
23:00 PM	.592	10,951.96	2,460	.175455	2.114
24:00 PM	.634	10,933.44	2,480	.171266	2.166
11-23-83					
1:00 AM	.676	10,915.69	2,490	.163486	2.269
2:00 AM	.717	10,898.78	2,494	.155499	2.385
3:00 AM	.759	10,882.77	2,480	.148054	2.505
4:00 AM	.801	10,868.31	2,460	.134808	2.751
5:00 AM	.842	10,853.81	2,450	.135732	2.733
6:00 AM	.884	10,838.89	2,448	.1397780	2.653
7:00 AM	.925	10,826.95	2,400	.114097	3.251
8:00 AM	.967	10,816.30	2,410	.101348	3.660
9:00 AM	1.009	10,801.82	2,401	.138311	2.682
10:00 AM	1.051	1,0789.95	2,294	.1186694	3.125
11:00 AM	1.092	10,778.04	2,319	.1177857	3.149
13:00 PM	1.176	10,755.64	2,316	.1129002	3.285
15:00 PM	1.259	10,740.31	2,351	.0747723	4.960
17:00 PM	1.342	10,719.79	2,359	.1020805	3.633
19:00 PM	1.426	10,701.74	2,375	.0871495	4.256
21:00 PM	1.509	10,681.83	2,375	.0961300	3.858
23:00 PM	1.592	10,664.48	2,409	.0825875	4.491
11-24-83					
1:00 AM	1.676	10,647.64	2,371	.0814445	4.554
3:00 AM	1.759	10,631.40	2,383	.0781472	4.746
5:00 AM	1.842	10,616.11	2,373	.0738858	5.020
7:00 AM	1.925	10,601.02	2,340	.0739477	5.016
9:00 AM	2.009	10,586.29	2,386	.0707919	5.239
11:00 AM	2.092	10,572.45	2,363	.0671620	5.522
13:00 AM	2.176	10,558.73	2,353	.0668627	5.547
15:00 AM	2.259	10,544.62	2,294	.0705318	5.259
17:00 AM	2.342	10,532.08	2,354	.0610861	6.072
19:00 AM	2.426	10,519.69	2,349	.0604839	6.132
21:00 AM	2.509	10,507.20	2,341	.0611804	6.602
23:00 AM	2.592	10,495.42	2,342	.0576533	6.433
24:00 AM	2.634	10,489.34	2,186	.0637874	5.815
11-25-83					
2:00 PM	2.72	10,477.54	2,195	.0616592	6.015
4:00 PM	2.80	10,466.87	2,273	.0538195	6.891
6:00 PM	2.88	10,455.59	2,084	.0620554	5.976
8:00 PM	2.97	10,445.19	2,230	.0534882	6.934
10:00 PM	3.05	10,434.41	2,210	.0559419	6.630
12:00 PM	3.13	10,423.79	2,293	.0531118	6.983
14:00 PM	3.22	10,413.24	2,126	.0569144	6.517

Table No. 3 (cont'd.)

Date Time	Cum. Days	B.H.P. psia	Qw BWPD	$\frac{dp}{dt}$ Qw BwC = Y	W-Sw/BwCwY Water Explored 10 ⁶ Bbls
11-25-83					
16:00 PM	3.30	10,402.84	2,229	.0534978	6.933
20:00 PM	3.47	10,383.14	2,216	.0509727	7.276
24:00 PM	3.64	10,365.80	2,125	.0467988	7.926
11-26-83					
4:00 AM	3.80	10,547.43	2,222	.0474094	7.823
8:00 AM	3.97	10,329.63	2,134	.0478241	7.755
9:00 AM	4.05	10,318.57	Pressure element moved		
12:00 AM	4.13	10,303.82	2,202	.0512030	7.244
14:00 AM	4.22	10,295.10	2,200	.0454512	8.160
16:00 AM	4.30	10,287.11	2,200	.0421675	8.796
20:00 AM	4.47	10,270.88	2,200	.0430796	8.610
24:00 AM	4.64	10,254.16	2,200	.0427929	8.667
11-27-83					
4:00 PM	4.80	10,238.40	2,200	.0410729	9.030
8:00 PM	4.97	10,221.87	2,250	.0421223	8.805
12:00 PM	5.13	10,208.47	2,300	.0335536	11.054
16:00 PM	5.30	10,193.55	2,275	.0374546	9.904
19:50 PM	5.47	10,181.06	2,273	.0328751	11.282
24:00 PM	5.63	10,166.79	2,270	.0337949	10.975
11-28-83					
4:00 AM	5.80	10,153.13	2,268	.0345326	10.740
8:00 AM	5.97	10,140.04	2,264	.0331457	11.190
12:00 AM	6.13	10,127.18	2,160	.0341357	10.865
16:00 AM	6.30	10,155.27	2,146	.0318202	11.656
20:00 AM	6.47	10,102.99	2,131	.0330444	11.224
24:00 AM	6.63	10,090.80	2,130	.0328130	11.303
11-29-83					
1:00 PM	6.68	10,087.89	2,000	.0333691	11.115
4:00 PM	6.80	10,079.20	2,000	.0332162	11.166
5:50 PM	6.88	10,073.80	1,990	.0339454	10.926
		Flow meter out of service			
13:13 PM	7.19	10,048.05	1,990e	.0399229	9.290
14:00 PM	7.22	9,022.05	?	Rate increased above 5000	
16:00 PM	7.30	8,674.27	?	BWPD for special gas-water	
18:00 PM	7.38	8,998.93	5,881	ratio and gas composition	
20:00 PM	7.47	8,931.11	5,704	studies. Pressures and	
24:00 PM	7.63	8,834.92	5,518	rates not stabilized for	
				valid calculations.	
11-30-83					
4:00 AM	7.80	8,751.98	5,414	.0585566	
8:00 AM	7.97	8,681.65	5,394	.0498340	Not valid
12:00 AM	8.13	8,524.27	5,786	.1039684	
24:00 AM	8.63	8,026.18	6,612		
12-1-83					
12:00 PM	9.13	7,756.20	6,423		
24:00 PM	9.63	7,639.79	5,986		

Table No. 5 (cont'd.)

Date Time	Cum. Days	B.H.P. psia	Qw BWPD	$\frac{dp}{dt} = \gamma$ Qw BwC	W=Sw/BwCwY Water Explored 10 ⁶ Bbls
12-3-83					
12:00 PM	11.13	7,573.03	4,954		
24:00 PM	11.63	7,563.02	4,780		
12-4-83					
12:00 PM	12.13	7,563.27	4,512		
24:00 PM	12.63	7,566.87	4,370		
12-5-83					
12:00 PM	13.13	7,613.98	4,181		
24:00 PM	13.63	7,895.86	2,970		
12-6-83					
12:00 PM	14.13	7,953.87	3,160		
24:00 PM	14.63	7,971.69	3,182		
12-7-83					
8:20:00 PM	14.98	7,977.12	3,170		

Sand face flowing
pressures now
rising

Pressure still rising

TABLE NO. 6

Miogypsinoides No. 3 Sand
 MG-T/DOE, Amoco Fee No. 1 Well
 Sweet Lake Area, Cameron Parish, Louisiana

Reservoir Fluid Summary

Reservoir Temperature, °F	293
Saturation Pressure at 293 °F, Psia	8800
Compressibility of Reservoir (Brine) Water at 293 °F	
Vol. per Vol. per Psia X 10 ⁶	
From 8800 Psia to 10000 Psia	2.61
From 10000 Psia to 11000 Psia	2.59
From 11000 Psia to 11887 Psia	2.57
Saturated (Brine) Water at 8800 Psia, 293 °F	
Density, Grms. per Ml.	1.0512
Lbs. per Bbl.	368.4
Specific Volume, Cu. Ft. per Lb.	0.015238
Viscosity, Centipoise	0.323
Formation Volume Factor, Bbls. per Bbl.	
"Standard Bbls. at 60 °F and 15.025 Psia"	1.0576
Solution Gas-Water Ratio, Cu. Ft. per Bbl.	
"Standard Bbls. at 60 °F and 15.025 Psia"	25.39 Wet
	24.50 Dry
Reservoir (Brine) Water at 11887 Psia, 293 °F	
Density, Grms. per Ml.	1.0597
Lbs. per Bbl.	371.4
Specific Volume, Cu. Ft. per Lb.	0.015116
Viscosity, Centipoise	0.342
Formation Volume Factor, Bbl. per Bbl.	
"Standard Bbls. at 60 °F and 15.025 Psia"	1.0491

LAB NO. N2171-10510

TABLE NO. 7

51

Miogyssinoides No. 3 Sand
 MG-T/DOE Amoco Fee No. 1 Well
 Sweet Lake Area, Cameron Parish, Louisiana

COMPOSITE LABORATORY DATA AT 293 °F

RECOMBINATION (5) 19.98 SCF SEP. GAS @ 15.025 Psia & 60°F/BBL. SEP. WATER @ SEP. COND.
 (Produced Gas-Water Ratio)

Pressure PSIA	Pressure Volume Relations			Water Viscosity Centipoise	Differential Liberation		
	Relative Volume V/Vsat. Btw	Specific Volume cu. ft. per Lb.	Liquid Volume Percent		Form. Volume Factor B _w	Solution	
						Gas-Water Ratio Per Barrel of Brine @ 60°F 15.025 Psia	
11887 RES.	0.9920	0.015116		0.342	1.0491	24.50	25.39
11000	0.9943	0.015151		0.336	1.0516	24.50	25.39
10000	0.9969	0.015191		0.330	1.0543	24.50	25.39
9000	0.9995	0.015230			1.0571	24.50	25.39
8800 BPP	1.0000	0.015238	100.00	0.323	1.0576	24.50	25.39
8700	1.0003	0.015243	Bubble				
8500	1.0009	0.015252	Bubble				
8000	1.0023	0.015273	Bubble	0.320			
7000	1.0053	0.015319	99.98	0.315	1.0622	22.32	23.19
6000	1.0083	0.015364	99.95	0.312			
5000	1.0118	0.015418	99.89	0.310			
4000	1.0153	0.015471	99.81	0.315	1.0690	17.00	17.77
3000	1.0219	0.015572	99.44	0.32			
2000	1.0353	0.015776	98.42	0.33	1.0728	11.49	12.09
1000	1.0779	0.016425	94.78	0.34			
500	1.1800	0.017981	86.70				
253	1.4050	0.021409	72.85				
15*					1.0000	00.00	00.00

Nomenclature:

V/Vsat. is the volume of fluids (water and gas) at the indicated temperature and pressure relative to the volume of saturated water at bubble-point pressure and indicated temperature.

B_w is the volume of water at reservoir temperature and indicated pressure relative to the volume of standard volume of water at 60 °F and 15.025 Psia.

Gas-Water Ratio is cubic feet of gas at 15.025 psia at 60 °F per barrel of (brine) water at 60 °F and 15.052.

Note: * Indicated value measured at 60 °F.

LAB. NO. N2171-10510

Table No. 8
 Flowing Pressure & Temperature Gradients
 Miogypsinoides No. 3 Sand
 MG-T/DOE Amoco Fee No. 1 Well
 Sweet Lake Area, Cameron Parish, Louisiana
 Panex Instruments, December 7, 1983

Time	Depth Feet	Pressure psia	Temperature °F	Flowing Gradients	
				psi/ft.	°F/ft.
08:20:00	15,200	7977.12	301.5		
08:49:40	14,000	7438.83	300.3	.4486	.0010
09:14:50	13,000	6982.97	298.1	.4559	.0022
09:37:20	12,000	6522.83	295.1	.4601	.0030
10:01:20	11,000	6063.68	290.8	.4592	.0043
10:23:20	10,000	5606.73	286.0	.4570	.0048
10:49:10	9,000	5151.12	279.4	.4556	.0066
11:13:20	8,000	4694.15	272.6	.4570	.0068
11:40:10	7,000	4238.74	265.3	.4554	.0073
12:02:50	6,000	3782.95	257.9	.4558	.0074
12:21:40	5,000	3327.76	250.1	.4558	.0078
12:41:30	4,000	2871.75	241.8	.4554	.0083
13:01:00	3,000	2414.97	233.1	.4568	.0087
13:25:10	2,000	1958.22	224.7	.4568	.0084
13:47:30	1,000	1505.14	216.9	.4531	.0078
14:08:20	0	1056.44	209.1	.4487	.0078

REFERENCES

1. Hurst, Wm.; 1934 "Unsteady Flow in Oil Reservoirs," Physics, (March, 1934) Vol. 5
2. Hurst, Wm.; Moore, T. V.; and Schilthuis, R. J. 1933. "The Determination of Permeability from Field Data," Proceedings, API Bull. 211 4.
3. Hurst, Wm., 1953 "Establishment of the Skin Effect and Its Impediment to Fluid Flow into a Well Bore," Petroleum Engineer, (October, 1953) 25, B-6.
4. Jones, P. J., 1956. "Gulf Coast Wildcat Verifies Reservoir Limit Test," Oil and Gas Journal, (June, 1956) pp. 54, 184.
5. Jones, P. J., 1957. "Drawdown Exploration, Reservoir Limit, Well and Formation Evaluation," Paper 824-G, Permian Basin Oil Recovery Conference, Midland, Texas.
6. Jones, P. J., 1961 "Reservoir Limit Test on Gas Wells," SPE- 24, Gas Technology Symposium, Tyler, Texas.
7. Matthews, C. S., 1960 "Analysis of Pressure Buildup and Flow Test Data," Formation Evaluation Symposium, Houston, Texas.
8. Matthews, C. S., and Russell, D. G. 1967. "Pressure Buildup and Flow Tests in Wells," Monograph Vol. 1, SPE, AIME.
9. Schilthuis, R. J., 1936. "Active Oil and Reservoir Energy," Transactions, SPE, AIME, Vol 118, 33-52.
10. Clark, J. D., and Clark, N. J., "Reservoir Parameters Are Paramount," Petroleum Engineer, (July, 1966) pp. 61-69.
11. Van Everdingen, A. F., and Hurst, Wm., 1949 "The Application of the La Place Transformation to Flow Problems in Reservoirs," Transactions, SPE, AIME, Vol. 186.

APPENDIX D

**IGT TEST ACTIVITIES ON THE
MG-T/DOE AMOCO FEE NO. 1
WELL DURING AUGUST 1981**

**C. G. Hayden
P. L. Randolph
T. L. Osif**

**Prepared by
Institute of Gas Technology
IIT Center, 3424 S. State Street
Chicago, Illinois 60616**

October 1981

IGT TEST ACTIVITIES ON THE MG-T/DOE
AMOCO FEE NO. 1 WELL DURING AUGUST, 1981

by

C. G. Hayden, P. L. Randolph, T. L. Osif

INSTITUTE OF GAS TECHNOLOGY

Introduction

The first month of production testing of the MG-T/DOE Amoco Fee No. 1 well by the operator suggested gas content of brine of less than half of expected values. However, at the same time, it was recognized that problems existed in flow metering and that some sample analyses provided results inconsistent with understanding from prior tests of other wells. Some of these issues are discussed in the Background section of this report.

During August 1981, IGT personnel collected and analyzed samples of gas and brine from the separator during testing of the MG-T/DOE Amoco Fee No. 1 well. Various portions of this work and the related reviews of data developed by participants in the well test were performed in accordance with the statements of work for a) IGT's DOE-sponsored project "Computer Simulation of Geopressured Aquifers," b) IGT's GRI-sponsored project "Gas From Formation Waters," and c) a purchase order to IGT from Magma Gulf-Technadril. In the interest of completeness, and with concurrence of the sponsors, work performed under these projects is consolidated into this single report.

IGT focus was on three questions:

- What is the quantity and quality of gas leaving the separator dissolved in the disposal brine?
- Is the reservoir saturated with gas?
- In what ways does the chemistry of the produced brine affect gas behavior and partitioning between phases?

Achieving meaningful conclusions on these subjects has required substantial departures from the sampling schedule and sample handling procedures prescribed in the procedures manual for geopressured fluids developed for DOE (Ref. 1). For this reason, the procedures used and results of analyses performed are described here in considerable detail. Discussions addressing the above three questions are then presented. Conclusions and recommendations are summarized in the last sections of this report.

Handwritten notes:
10-15-81
349
10-15-81

Background

Preliminary data obtained by MG-T and its contractors indicated that the gas and brine effluents were considerably different than had previously been seen by IGT on the Wells of Opportunity (WOO) program. The chemistry of the brine was different from the low-salinity brines observed on wells IGT had tested, but was consistent with the high volume producing design wells. The quantity of gas produced, as well as the gas lost in disposal brine, was inconsistent with previously expected values based on solubility data. These observations will be discussed in more detail in the following sections.

Brine chemistry data supplied to IGT by Dr. B. E. Hankins of McNeese State University on August 5, 1981 indicated a high salinity, high calcium content for the produced fluids (Ref. 1). Analysis results transmitted verbally were as follows:

pH		5.66
Alkalinity		261 mg HCO_3^-/l
Total Dissolved Solids		166,500 mg/l
Na	46,000 mg/l	K 1740 mg/l
Cl	99,350 mg/l	NH_3 88 mg/l
Ca	11,000 mg/l	B 62 mg/l
Mg	670 mg/l	Fe 59 mg/l
Sr	850 mg/l	SiO_2 112 mg/l

Gas measurements and analyses had previously been done by MG-T and Weatherly Laboratories, Inc., personnel. Flare line gas metering problems were identified, and much progress had been made by early August in resolving discrepancies. Early reported gas-to-brine ratios ranged from 8 to 12 SCF/STB. John Neal of Weatherly Laboratories, Inc. (Ref. 2) performed a recombination using 8.1 SCF/STB as the produced gas-to-water ratio (GWR) and found the corresponding bubble point of the reservoir would be approximately 2006 psia. If gas and brine metering were correct, it would appear that the reservoir was undersaturated. John Neal's recombination studies also indicated that ~34.3 SCF/STB would be required for saturation at reservoir pressure and temperature. Accumulation of gas in the high-pressure corrosion coupon bypass line provided evidence that two phases existed at the wellhead when wellhead pressure was greater than 2000 psi. This suggested that more than 8.1 SCF/STB were actually being produced.

The analysis of the flare line gas used in the recombination is given below:

Mole % (dry)		Mole % (dry)	
Carbon Dioxide	7.00	n-Butane	0.03
Nitrogen	0.29	iso-Pentane	0.00
Methane	90.65	n-Pentane	0.01
Ethane	1.66	Hexanes	0.00
Propane	0.27	Heptanes +	0.07
iso-Butane	0.02		

Other flare line gas analyses exist, and are comparable with the above.

Weatherly Laboratories also measured the quantity and composition of gas still remaining in the disposal brine. The value measured in the recombination study was 0.9 SCF/STB (dry). The composition of this gas as given in Weatherly's report is as follows (Ref. 2):

Mole % (dry)		Mole % (dry)	
Carbon Dioxide	12.3	n-Butane	0.0
Nitrogen	—	iso-Pentane	0.0
Methane	85.8	n-Pentane	0.0
Ethane	1.6	Hexanes	0.0
Propane	0.3	Heptanes +	0.0
iso-Butane	0.0		

IGT experience with this type of analysis indicated that the CO₂ content was surprisingly low and may be caused by the high calcium content of the brine. Several measurements were made by Weatherly Laboratories of the amount of gas remaining in the brine after the separator. Most of these gave values similar to those obtained at WOO wells having comparable separator temperature and pressure. However, a measurement on July 28, 1981, gave a solution GWR of 8.3 SCF/STB (Ref. 3). This value is completely inconsistent with proper separator operation. It is not clear whether the anomalous result was due to separator malfunction or to a problem with sample collection. The bubble point exhibited by the sample was 870 psia, or ~630 psi above the sample collection pressure.

IGT Sampling Procedures for Gas and Brine

IGT has developed sampling and analysis procedures on Wells of Opportunity tests to accurately measure the total gas production from a

geopressured geothermal well. These procedures were modified to compensate for the lack of an onsite gas chromatograph and an acid liberation-nitrogen purge carbonate train. Emphasis was placed on collecting both brine and gas samples and performing a hydrogen sulfide analysis in 15 minutes. Brine and gas samples are collected in as short a time as possible to minimize the chance that any change in conditions (flowing or compositional) will occur during the sampling procedure. Hydrogen sulfide instability necessitates rapid analysis for accurate results.

- Flare line gas samples were caught in preheated Teflon-lined stainless steel sample cylinders. The cylinders were preheated to above 100°C to minimize water condensation within the sample vessel. The closed valve ends were fitted with Swagelok caps to prevent leaks, and the sample was shipped to IGT for analysis.
- The gas samples were heated at IGT to a temperature greater than 100°C and analyzed using a mass spectrometer.
- Draeger hydrogen sulfide analyses of the flare line gas samples were performed using procedures outlined in Gas Processors Association's Tentative Method of Test for Hydrogen Sulfide in Natural Gas Using Length of Stain Tubes. The same procedure is used for flare line Draeger CO₂ determinations, although CO₂ is also quantified in the mass spectrometer analysis.
- At least two brine samples were caught each time in Teflon-lined stainless steel pressure vessels at separator pressure and temperature. The closed valve ends were sealed with Swagelok caps and quickly cooled by immersion into a cold water bath. One of the samples from each set was shipped to IGT for analysis, and the other was partially analyzed in the field and then discarded.
- The brine analysis consisted of several steps. The first was to reduce pressure on the cooled brine to 1 atmosphere by using a large syringe. The syringe was connected to the cylinder valve and the valve opened. The exsolved gas pushed the plunger in the syringe. After the cylinder was struck several times to enhance gas dissolution, the gas volume was read directly off the syringe. The brine was emptied into a graduated cylinder and its volume noted. At this point the field samples were discarded.

Several more analytical steps were performed on samples shipped to IGT as follows:

- The gas was analyzed using a mass spectrometer.
- The brine was divided into two portions and measured. The first portion was immediately treated with sodium hydroxide to stabilize the CO₂ in solution (going to a pH of ~10). The second portion of the sample was untreated.

- A representative sample of the alkaline brine was treated with acid and purged with nitrogen, quantitatively trapping and measuring the exsolved CO₂. This procedure measures "total CO₂," which includes dissolved CO₂, bicarbonate, and carbonate species.
- A portion of the untreated brine was titrated with sulfuric acid to determine alkalinity. The remaining untreated brine was then acidified and analyzed for calcium content.

Results of IGT Analyses

IGT performed several types of analyses to help define gas production for this well. Table 1 contains results of flare line gas analyses. (All reported pressures have been corrected for instrument drift by subtracting 70 psi from all originally read values as instructed by Larry Durrett. All pressure, temperature, and flowrate data were provided by MG-T.) Gas analyses were performed at IGT with a DuPont Model 21-104 mass spectrometer. It is important to note that the cylinders were heated prior to analysis to avoid liquid water, which would dissolve CO₂ and cause erroneous measurements.

When the flow rate was increased from about 1400 BPD to over 15,000 BPD the temperature of the produced brine rose from ~160° to 275°F. At 275°F flowing brine temperature, the gas stream contained so much water vapor that condensation may still have occurred in the preheated gas cylinders. Some CO₂ probably remained in solution in this liquid phase in the cylinders when gas was withdrawn for laboratory analysis.

The high water content at 275°F was also a problem when using Draeger tubes in the field. Table 2 is a summary of the Draeger tube analyses performed. Note that no analyses were performed after the large flow rate increase on August 11. It was felt that the water interference at that point made the results unreliable.

The hydrogen sulfide concentration on August 10, 1981 was measured after a shut-in period. It is believed the low value is due to the reaction of hydrogen sulfide with tubulars during this shut-in.

Table 3 presents the amount of gas liberated from cooled disposal brine upon reducing pressure to 1 atmosphere. It is important to note that all of the liberations performed at IGT on stored samples yielded lower GWR's than did similar flashes performed in the field.

Table 1. MASS SPECTROMETRIC ANALYSES OF
FLARE LINE GAS, MOLE PERCENT

Date	8-7-81	8-7-81	8-10-81	8-11-81	8-11-81	8-12-81	8-12-81	8-12-81
Time	1045	1830	1220	1840	1937	1130	1420	1605
Brine Rate (BPD)	~1400	~1400	~1400	>15,000	>15,000	>15,000	>15,000	>15,000
Separator Pressure (psia)	236	239	256	480	445	464	348	579
Brine Temperature (°F)	160	160	165	244	275	275	275	275
Methane	89.28	88.77	90.04	90.14	89.45	89.15	88.87	89.78
Ethane	1.74	1.73	1.68	1.83	1.72	1.50	1.40	1.48
Propane	.39	.35	.33	.38	.35	.23	.23	.23
n-Butane	.05	.06	.04	.06	.05	.03	.03	.03
i-Butane	.02	.04	.02	.02	.00	.00	.00	.01
Pentanes	.01	.01	.01	.02	.02	.00	.01	.00
Hexanes	.00	.00	.00	.00	.00	.00	.00	.00
Benzene	.10	.13	.03	.05	.05	.04	.06	.03
Tolulene	.07	.09	.01	.03	.03	.02	.03	.01
Xylene	.00	.01	.00	.00	.00	.00	.00	.00
Hydrogen	.01	.00	.04	.02	.04	.00	.00	.01
Nitrogen	.20	.22	.37	.15	.23	.24	.21	.24
Carbon Dioxide	8.13	8.59	7.43	7.30	8.06	8.79	9.16	8.18

Table 2. DRAEGER GAS ANALYSIS OF FLARE LINE GAS

<u>Date</u>	<u>Time</u>	(psig) <u>Pressure</u>	(°F) <u>Temperature</u>	(ppm) <u>H₂S</u>	(vol. %) <u>CO₂</u>
8-7	1030	291	160	22	9
8-7	1800	294	160	22	8
8-8	0800	303	167	25	8.5
8-10	1205	311	165	13*	7.8

* The H₂S probably reacted with tubulars during the preceding shut-in period.

Table 3. GAS LIBERATED FROM BRINE AFTER THE SEPARATOR
BY PRESSURE REDUCTION TO 1 ATMOSPHERE

<u>Date</u>	<u>Time</u>	<u>Pressure, psia</u>	<u>Temperature, °F</u>	<u>Gas-Brine Ratio</u>	
				<u>Field*</u>	<u>IGT Chicago**</u> SCF/STB
8-7	1030	236	160	1.56	1.39
8-7	1800	239	160	1.62	1.12
8-8	0800	248	167	1.71	
8-10	1205	256	165	1.67	1.53
8-11	1840	480	244	2.91	2.10
8-12	1130	464	275	2.99	
8-12	1130	464	275	3.05	
8-12	1420	348	275	2.36	1.96
8-12	1605	569	275	3.76	3.15

* Pressure reduction done in the field less than one hour after sample collection.

** Pressure reduction and analyses done at IGT-Chicago several days after sample collection.

Table 4 contains results of the analyses performed on the six brine samples analyzed at IGT. Included is the liberated gas analysis, pH, solution CO₂, alkalinity, acidity, and the calcium concentration. The gas analyses were performed on gas at ambient temperature using a mass spectrometer. Solution CO₂ values contain the total amount of CO₂ in all forms including dissolved CO₂ and various carbonate species remaining in solution at 1 atmosphere. The acidity is a very rough measurement made by counting the number of drops (in units of 10) of aqueous sodium hydroxide needed to make a portion of the brine alkaline (pH ~10). Calcium concentrations were measured using standard atomic absorption techniques used by IGT's analytical laboratory for brine analyses.

Upon trying unsuccessfully to perforate a deeper zone, it was found that the well bore had filled with several hundred feet of solids below the producing interval. IGT performed a preliminary analysis of solids recovered with a wireline bailer. The analysis first entailed manual separation of tubing liner material (plastic) from the rest of the solids. It was found that 7.7% by weight of the small sample provided to IGT was liner material. The remaining solids were then washed with 1N HCl, to dissolve salts and carbonates. Weight loss due to removal of these components was 7.0% of the sand or 6.5% of the original solids.

Discussion

The three objectives this study set out to answer are as follows:

- To determine the quantity and composition of the gas leaving the separator dissolved in the disposal brine
- To determine whether the reservoir is saturated with gas
- To determine how the chemistry of the produced brine affects gas behavior and partitioning between phases.

The discussion of our results and conclusions is presented by treating each of these topics in a separate section.

I. Quantity and Composition of Gas Remaining in Disposal Brine

The data collected in the field are presented graphically in Exhibit 1. The dashed line is a least-squares linear fit to the data. The correlation is excellent ($r^2 = 0.988$) with a y intercept of 0.12 SCF/STB. An intercept of 0.0 is expected if the data are collected at a constant temperature. Gas

Table 4. ANALYSIS OF BRINE AND GAS FLASHED FROM THE BRINE SAMPLES FROM THE
MG-T/DOE AMOCO FEE WELL NO. 1, SWEET LAKE PROSPECT, CAMERON PARISH, LA.

Component	Units	8-7-81 1030 hrs	8-7-81 1845 hrs	8-10-81 1215 hrs	8-11-81 1836 hrs	8-12-81 1420 hrs	8-12-81 1605 hrs
Gas Analysis							
Methane	mole %	74.09	79.10	74.81	78.91	80.28	77.17
Ethane	mole %	1.17	1.20	1.15	1.18	1.03	1.00
Propane	mole %	0.13	0.15	0.14	0.15	0.10	0.11
n-Butane	mole %	0.004	0.003	0.003	0.004	0.003	0.003
iso-Butane	mole %	0.002	0.001	0.001	0.003	0.001	0.001
Benzene	mole %	0.02	0.03	0.03	0.03	0.02	0.04
Toluene	mole %	0.005	0.004	0.004	0.006	0.006	0.008
Carbon Dioxide	mole %	24.58	19.51	23.86	19.72	18.56	21.67
Caloric Content	Btu/SCF	763	815	771	812	822	791
Specific Gravity	--	0.801	0.752	0.794	0.754	0.742	0.772
Liquid Analysis							
Alkalinity	mg HCO_3^-/L	320	430	290	286	150	141
Total CO_2	SCF/STB	1.52	1.71	1.67	1.70	1.13	1.40
Solution CO_2	mg NaOH/L	24,000	9,000	9,000	22,000	25,000	25,000
Calcium	mg Ca^+/L	12,200	11,600	11,800	11,500	11,500	11,600
pH	--	6.1	6.2	6.0	6.0	5.5	5.4

Exhibit 1. COMPARISON OF FIELD MEASUREMENTS WITH VALUES CALCULATED WITH THE S^3 ALGORITHM

solubility is temperature dependent, and this effect is greater for carbon dioxide than for methane. The separator pressure has a water vapor pressure component which is temperature dependent. Brine temperature was not constant during data collection, which may account for the small positive intercept.

The solid line in Exhibit 1 is from an algorithm developed by Systems Science and Software (S³) (Ref. 4) to fit Culberson and McKetta's data for methane solubility in water (Ref. 5). This algorithm has been found by IGT to closely fit the total gas liberated by pressure reduction to 1 atmosphere from disposal brine in WOO wells. Note that the S³ prediction is above the values measured for the MG-T well. This difference may be in part due to vapor pressure of water in the separator being higher than on WOO tests because the brine temperature is higher (275°F). The low total gas values are not due to an insufficiency of methane, but do reflect smaller amounts of carbon dioxide.

The amount of methane contained in the MG-T disposal brine is compared with the amount contained in the HO&M Prairie Canal Co., Inc., Well No. 1 (Ref. 6) in Exhibit 2. The x-axis is expressed as partial pressure of methane to eliminate contributions of other gases. These data can be compared because the effect of temperature on methane solubility in this range, under these conditions, is small compared to the pressure effect. The amount of methane in the disposal brine is greater, at a given partial pressure, for the MG-T well than for the Prairie Canal well. However, the amount of total gas in the disposal brine is less for the MG-T well than for the Prairie Canal well. This difference in total gas is largely carbon dioxide, which is the only component present in quantities large enough to account for this difference. One would predict that the methane solubility in the MG-T disposal brine would be less than in the Prairie Canal brine based on the higher salinity of the MG-T well. Because this was not observed, another mechanism may exist for reducing methane solubility in the Prairie Canal well vs. the MG-T well.

Blount (Ref. 7) has demonstrated that carbon dioxide decreases methane solubility in water when the carbon dioxide content of the dissolved gas exceeds 15%. The MG-T gas liberated from the disposal brine contained ~20% carbon dioxide, while the Prairie Canal well disposal brine liberated gas containing ~30% carbon dioxide. With the inhibiting effect on methane solubility dependent on the percentage of the gas which is carbon dioxide, it is not unreasonable to expect the MG-T disposal brine to contain more methane

Exhibit 2. PARTIAL PRESSURE METHANE IN THE SEPARATOR (psia)
COMPARISON OF AMOUNTS OF METHANE REMAINING IN DISPOSAL
BRINE BETWEEN THE MG-T/DOE AMOCO FEE NO. 1 and the
HO&M PRAIRIE CANAL CO., INC. WELL # 1

than the Prairie Canal well, as observed. We conclude from the above discussion that the MG-T disposal brine contained less total gas than did Prairie Canal, but contained more methane at a given partial pressure than Prairie Canal.

Another possibility is that the previously mentioned 70 psi correction to separator pressure was not the appropriate correction for the actual time of sample collection. It is conceivable that future analyses, accompanied by accurate pressure data, will reveal that total gas in solution in separator brine, rather than the methane component, will be consistent with results from WOO tests. This consistency was observed for samples from the Pleasant Bayou No. 2 well collected in October, 1980 (Ref. 8).

Exhibit 3 is a plot comparing gas liberations done in the field to those performed later at IGT. The line in Exhibit 3 is a least-squares linear fit to the field data presented in Exhibit 1. The liberations performed at IGT all had a lower GWR than those done in the field. This indicates a loss through leaks or reactions with the sample vessel. The sample vessel is Teflon-lined stainless steel, which is fairly inert to most gases and to CO₂-carbonate systems, although a small amount of hydrogen gas was detected in some samples. In addition, an acid wash was performed on one empty cylinder to look for deposited carbonates, but none were found (less than 0.1 SCF CO₂/STB equivalent in carbonate). Leaks apparently are the primary cause of this occurrence. The leaks were trivial on WOO tests where the analysis was completed within 30 minutes after sampling. On wells where the IGT field lab is not available and the analyses are necessarily postponed, this becomes a problem. Most of the cylinders were equipped with new valves. The problem was still significant, and a different type valve may be required on future tests.

The conclusions pertinent to well operation are not substantially affected by these problems. At 1000 psi separator operating pressure, 6.3 ± 0.5 SCF/STB of gas will be lost in the disposal brine. This gas will have a heating value of about 5000 to 6000 Btu/STB. Secondary recovery of this gas is dependent upon disposal pressure requirements and the accompanying economic factors.

9590

Exhibit 3. COMPARISON OF FIELD ANALYSES TO ANALYSES OF
SAMPLES AT IGT

II. Gas Content of Reservoir Brine

Determining whether or not the reservoir brine is saturated with gas is a major objective of DOE well tests. Unfortunately, the conventional method used to determine saturation by comparing produced gas-to-brine ratios against recombination data has had many problems. Gas-to-brine production ratios had not been measured with the accuracy required for meaningful comparisons to recombination data. On this well, for instance, John Neal of Weatherly Laboratories (Ref. 2) stated that the reservoir fluid exhibited a bubble point of 2006 psia and 299°F when recombining the "produced GWR" of 8.1 SCF/STB, and that the brine was undersaturated at reservoir conditions. It has since been found that the produced GWR is substantially above the 8.1 SCF/STB, which was considered accurate when Weatherly took their samples. IGT has recognized that this problem exists on many well tests and is using an independent test to deduce reservoir saturation conditions through other surface manifestations. This has resulted in the "bubble test," the theory and practice of which will be discussed below.

The theory is based on the premise that gas in contact with an aqueous phase will have a different composition than the dissolved gas with which it is in equilibrium. This is expected because the various gaseous components have different fugacities and subsequently different solubilities in the aqueous phase. For the natural gas-CO₂ system common in geopressured aquifers, the free gas phase has a lower CO₂ content and higher ethane, propane, and butane contents relative to methane than does the dissolved gas. The magnitude of variations in concentrations is illustrated by the Weatherly Laboratories analyses of gases from four steps in differential liberation shown in Table 5. The data shown are from the Riddle-Saldana Well No. 2 (Ref. 11) samples that had been recombined to actual reservoir pressure and temperature.

The compositional differences are related to reservoir behavior through the following model: Assume that a reservoir contains no free gas phase at reservoir pressure and temperature. As brine is produced, the pressure around the well bore drops. If the pressure falls below the bubble point, gas is differentially liberated from the brine and is trapped in the pore space. Gas accumulates in the pore space until critical saturation is reached. At this point a quasi-steady state is reached in which a small amount of free gas may

Table 5. COMPOSITIONS DURING DIFFERENTIAL LIBERATION OF GAS
FROM BRINE, RIDDLE-SALDANA WELL NO. 2

Pressure Step, psia	6632-4000	4000-2500	2500-1000	1000-15
Total Gas, SCF/STB	6.8	7.7	10.8	17.0
Gas Composition, mol %				
CO ₂	1.80	3.05	8.76	18.64
Methane	92.24	92.74	88.46	79.18
Ethane	4.43	3.44	2.44	1.85
Propane	0.96	0.54	0.26	0.10
n-Butane	0.19	0.07	0.02	0.01
i-Butane	0.18	0.07	0.02	0.03
n-Pentane	0.08	0.02	0.01	<0.01
i-Pentane	0.05	0.01	0.01	<0.01
Hexanes	0.03	0.01	<0.01	<0.01
Heptanes+	0.04	0.05	0.02	0.19

flow into the well bore but it is being replenished by additional solution gas being differentially liberated from the brine. It is important to note that this free gas which is trapped in the reservoir contains more ethane, propane, and butanes relative to methane that does the solution gas which is being produced. The free gas phase accumulating around the well bore thus has a characteristically different composition than does the solution gas.

If the flow rate is increased, there is a sudden, large pressure drop around the well bore, and the steady state condition no longer exists. Free gas immediately around the well bore expands, coalesces, and flows into the well bore. As this free gas reaches the surface, it raises the GWR and the concentrations of ethane, propane, and butanes in the produced gas. This is the characteristic "bubble." If the reservoir were undersaturated such that the bottomhole pressure was above the bubble point, then the free gas phase would not have formed and the bubble phenomenon would not be seen.

This bubble of free gas is a temporary occurrence. Once a quasi-steady state is reached at the new bottomhole pressure, more gas will be differentially liberated from the brine and trapped further out in the reservoir. The net effect is a decrease in the GWR and in the concentrations of ethane, propane, and butanes relative to methane in the produced, predominantly solution gas. The GWR and the ethane, propane, and butane concentrations should fall below those of the previous lower flow rate. Our test is to monitor changes in the GWR's and ethane/methane, propane/methane, and butanes/methane ratios during various flow conditions.

Table 6 presents hydrocarbon ratios calculated from the flare line gas analyses presented in Table 1. Examination of these hydrocarbon ratios in relation to producing conditions and the "bubble" model produces the following observations:

- Although variations exist because of shut-in periods, the analyses of the three samples collected on August 10 provide ratios for a brine production rate of about 1400 BPD.
- The samples taken on August 11 were collected after producing 1.5 and 5.5 well volumes of fluid following increase of brine rate to more than 15,000 BPD. The higher ethane/methane and propane/methane ratios for the sample collected at 1840 hours are characteristic of the "bubble" due to production of free gas that had accumulated near the well bore during prior production at about 1400 BPD.

Table 6. HYDROCARBON RATIOS

<u>Date</u>	<u>Time</u>	<u>Ethane</u> <u>Methane</u> $\times 10^2$	<u>Propane</u> <u>Methane</u> $\times 10^3$	<u>Butanes</u> <u>Methane</u> $\times 10^3$
8-7-81	1045	1.95	4.4	0.8
8-7-81	1830	1.95	3.9	1.1
8-10-81	1220	1.87	3.7	0.7
8-11-81	1840	2.03	4.2	0.9
8-11-81	1937	1.92	3.9	0.6
8-12-81	1130	1.68	2.6	0.3
8-12-81	1420	1.58	2.6	0.3
8-12-81	1605	1.65	2.6	0.4

- The lower values of ratios for samples collected on August 12 are as expected due to gas liberation in the reservoir at the continuing high (>15,000 BPD) production rate.

These observations support the hypothesis that the reservoir brine is near saturation with gas. The evidence is not conclusive of saturation because of the following:

- Accurate GWR data are not available to support the hydrocarbon ratio changes.
- Whether or not a reservoir is saturated is best determined at the beginning of the well test. Previous flow tests only cloud the issue. Our results only indicate that the near well-bore bottomhole pressure during the low flow rate was below the reservoir bubble point. If the reservoir was slightly undersaturated, say by only 1000 psi, the evidence given in this test would be unchanged.
- Lack of the onsite laboratory caused difficulties in sampling and analysis. The lack of an onsite gas chromatograph is a serious handicap. The changes in composition that IGT looks for are small, and storage and transfer of the samples to IGT before analysis can only be detrimental to accuracy.

A copy of the report on recombination of samples collected on June 22, 1981, has been provided to IGT. Although validity of results is somewhat in question due to the reported low gas content of separator brine (0.9 SCF/STB vs. an expected 3.4 SCF/STB), errors due to this difference should be only about 10 percent at the extrapolated solubility of 34.3 SCF of separator gas at 15.025 psia and 60°F per bbl separator brine at 520 psig and 242°F.

Exhibit 4 provides a graphical comparison of actual recombination data points with values calculated using the algorithms of Haas (Ref. 9) and Blount (1981 version) (Ref. 7). The calculations are shown for salinities of both 166,500 mg/l and 116,900 mg/l. The higher value is the number for total dissolved solids (TDS) provided by Dr. Hankins of McNeese State University (Ref. 1) during a telephone conversation on August 5, 1981. The lower value is calculated sodium chloride content of brine based upon the Na⁺ concentration of 46,000 mg/l provided by Dr. Hankins during the same conversation.

Plots of this type for recombination of samples collected while producing the saturation GWR from low salinity Wells of Opportunity have consistently shown agreement within ± 3.0 SCF/STB for Weatherly Laboratory data points and values calculated using the two algorithms. This background makes it

MG-T/DOE AMOCO FEE NO. 1 WELL

Exhibit 4. COMPARISON OF RECOMBINATION DATA WITH CALCULATED GAS SOLUBILITY

hazardous to ignore the approximate agreement between recombinations and values calculated using 116,900 mg/l. It will be interesting to see what future, definitive work reveals for solubility under reservoir conditions in relation to the range of 31 to 34 SCF/STB representative of methane solubility in the NaCl content of produced brine and the lower (22 to 27 SCF/STB) range calculated using the TDS value 166,500 mg/l in the two algorithms.

III. Brine Chemistry Relevant to CO₂

Results of the minimal number of brine analyses performed by IGT were previously presented in Table 4. These results differ from our prior experience on Wells of Opportunity in that substantial differences in alkalinity, pH, and "acidity" (amount of NaOH required to produce a pH of 10) were observed from sample to sample. Comparison of IGT's data with analyses by Rice University, plus the complexity of inhibitor control on this well (Ref. 10), has led to the hypothesis that the observed variations in brine chemistry were largely due to undocumented variations in inhibitor concentration. The discussion below adds credibility to this hypothesis.

The analyses performed were alkalinity, "acidity," acid-liberated CO₂, pH, and calcium concentrations for each sample. The interactions between these and many other chemical species form a complex system. Calcium and carbonate combine to form scale and precipitate which subsequently affect all of the abovementioned parameters. Likewise, the inhibitors used (acetic acid and AMP-20, a phosphonate type inhibitor) change the pH, form complex calcium ions, and change bicarbonate to dissolved CO₂. The acidity, as described herein, is affected by the calcium concentrations through the formation of Ca(OH)₂, which then influences all the other parameters listed. A detailed investigation into the chemistry change is beyond the scope of this work, but one observation will be made.

The alkalinity and the pH are both strongly tied to the amount of inhibitor, primarily acetic acid, injected into the brine. The amount of acetic acid nominally added is comparable to the alkalinity of reservoir brine on a molar basis. The acetic acid probably almost completely dissociates into the hydronium (H⁺) ion and the acetate ion, because the acetate is complexed with the Ca⁺⁺ ions. The H⁺ ions react with bicarbonate to form water and dissolved CO₂ as follows:

The close relation between pH and alkalinity is plotted in Exhibit 5. Note that a log scale is used on the x-axis, and pH, which may be defined as the negative log of the hydronium ion concentration, is on a linear scale. The concentration of inhibitor appears to be a primary cause of change of both the pH and the alkalinity.

It is possible that precipitation of $CaCO_3$ is another reason for the decrease in alkalinity from 300 to 150 mg HCO_3^-/ℓ when flow rate was increased from about 1400 to over 15,000 BPD. If the concentration of inhibitor in supply tanks was not simultaneously increased, the higher brine rate may have diluted the inhibitor to below the threshold for effectiveness (Ref. 10).

Assuming precipitation of $CaCO_3$ from the brine is described by the reaction

a decrease of 150 mg HCO_3^-/ℓ in alkalinity would produce 124 mg/ ℓ of $CaCO_3$ and 54 mg/ ℓ of CO_2 . In more familiar units, these values correspond to 43 pounds of calcite per 1000 bbl of brine and 0.16 SCF CO_2 /bbl of brine. Such production of calcite and CO_2 would probably not have been detected.

Conclusions

The major conclusions from IGT's work reported herein are —

- Reservoir brine is probably at or near saturation with natural gas.
- At the times of sample collection by IGT, partitioning of gaseous species between the gas and brine outputs of the separator was reasonably consistent with that from separators used on Wells of Opportunity tested by Eaton Operating Company and the separators used for the 1980 testing of the Pleasant Bayou Well No. 2.
- Total CO_2 content of produced brine, including bicarbonate ions and carbonate precipitates, is lower than experienced on Wells of Opportunity, as would be expected due to the high Ca^{++} content of produced brine.
- Partitioning of CO_2 between the gas output of the separator, CO_2 in solution in brine to the disposal well, bicarbonate ions in brine to the disposal well and $CaCO_3$ precipitates is dependent upon details of inhibitor injection in relation to separator pressure and temperature.
- Solids retrieved from below perforations in the production well contained about 7 percent by weight plastic lining from the production casing and about 6.5 percent by weight carbonates and other salts soluble in 1N HCl.

Exhibit 5. RELATIONSHIP BETWEEN ALKALINITY
AND THE BRINE pH

The major significance of the IGT work reported herein is the suggestion that reservoir brine may well be at or near saturation with natural gas. At the same time, this result is not definitive due to lack of precision, time dependent metering of gas and brine flow rates required to establish correlation of changes in total produced gas/brine ratio with the observed changes in chemical composition of produced gas.

The above conclusion regarding partitioning of gaseous species between separator outputs was qualified as "reasonably consistent" with prior experience. This qualification is due to a) lack of an onsite gas chromatograph and hardware for prompt acid liberation of CO₂ from separator brine samples, b) the discrepancy between quantities of gas liberated from brine samples in the field vs. samples analyzed later in IGT's Chicago laboratory, and c) the change of 70 psi in separator pressure provided to IGT on the basis of calibration of the pressure gauge several days after collection of IGT's last sample.

Comparison of recombination data by Weatherly Laboratories with expectations from laboratory studies of methane solubility in brine, in the context of prior similar comparisons for Wells of Opportunity, provided a surprising result: Namely, the recombination data points agreed with solubility calculated on the basis of only the NaCl content of produced brine. Differences at actual data points were a maximum of about 3 SCF/STB and consistent with differences observed on Wells of Opportunity. In contrast, expected gas solubility assuming total dissolved solids are equivalent to that weight of NaCl is less than the recombination measurement at 10,270 psia by 7 to 11 SCF/STB.

During mid August, operator installation of a positive displacement meter and changes in the orifice meter run resulted in about doubling reported gas production rates. However, it is IGT's judgment that accuracy of gas and brine rate measurements is not yet adequate to warrant a conclusion regarding actual produced gas/brine ratio in comparison with the values of 23 to 27 SCF/STB calculated on the basis of 166,500 mg/l of dissolved solids and the range of 31 to 35 SCF/STB calculated from the 117,000 mg/l NaCl content and extrapolated from recombination studies.

Recommendations

The MG-T/DOE Amoco Fee No. 1 Well has demonstrated over 250,000 bbl of brine production without buildup of injection pressure on the disposal well. This is in sharp contrast to prior well tests performed as a part of DOE's Geopressured-Geothermal Program and is very encouraging in the context of low operating cost for energy production.

The major uncertainty in cost of energy production from this well is the ratio of produced gas to produced brine. It is therefore recommended that effort be concentrated upon modifications of surface hardware, metering and procedures for fluid analyses, plus data interpretation to determine this ratio.

The most significant recommended hardware and metering changes are —

- Addition of an air cooler and small separator between the present separator and the orifice meter to remove water vapor
- Use of an orifice meter run that meets ANSI standards for natural gas metering and permits change of orifice size without disruption of flow
- Addition of a brine metering skid after the main separator which permits turbine calibration and change of turbine size without disruption of flow
- Adding 100 percent redundant instrumentation capable of 1-day turnaround in calculating gas/brine ratio in terms of SCF/STB with 1/2 hour or less time resolution.

After the recommended hardware and metering changes have been implemented, it is recommended that field operating procedures be tailored to providing definitive conclusions regarding gas/brine ratio and whether reservoir brine is saturated with natural gas. Specific recommended procedural steps are —

- Produce the well at a constant rate of 2000 to 2500 BPD until flow metering and fluid sample analyses reveal that a steady state condition has been achieved. Fluid sampling and analysis would consist of simultaneously collecting separator output gas and brine samples in pressure cylinders and then promptly analyzing these on location to determine
 - composition of flare line gas
 - quantities of liquids from the small separator in relation to gas or brine production
 - quantity and composition of gas liberated by pressure reduction to 1 atmosphere after cooling liquid samples to ambient temperature

- quantity of CO₂ liberated by acid plus alkalinity of brine after gas liberation to 1 atmosphere pressure.

Inhibitor concentration in surface brine must also be constant and known.

- Perform stepwise variations in separator pressure between lowest practicable value and 1000 psi. Analyze suites of samples at each pressure and combine with flow meter data to calculate total produced hydrocarbons and CO₂. Do not proceed until total gas/brine ratio for each gaseous species is found to be independent of separator pressure.
- Collect separator gas and brine samples for recombination studies and comprehensive chemical analysis.
- With production rate still constant, change to an orifice plate and a turbine as appropriate to accurate flow metering at a brine rate of 15,000 to 20,000 BPD.
- Increase brine rate to 15,000 to 20,000 BPD during a 30-second time interval. Collect suites of samples at roughly 1.5, 3, 5, and 10 times the time required for fluid transit from perforations to the wellhead. Exact times of sampling should be adjusted to provide samples at maxima and minima in orifice differential pressure. Analysis of these samples will reveal whether free gas production contributes to any observed fluctuations in gas/brine ratio. Inhibitor injection rate must be simultaneously increased to maintain constant concentrations.
- Maintain constant producing conditions until rate metering and sample analyses again clearly reveal steady-state operation.
- If steady-state values of gas/brine ratio or composition of total produced gas differ from those at the lower rate, repeat the variation of separator pressure to verify material balance and repeat sampling for recombination studies and comprehensive chemical analyses.
- Reduce brine rate back to 2000 to 2500 BPD with all procedures similar to those before, during, and after the previous rate increase.
- If analysis of data from the above steps does not reveal consistency between field data and laboratory recombination studies, iterate the above steps with changes in details until such consistency is achieved.

If the bubble point of reservoir brine exceeds the lowest bottomhole pressure previously experienced during testing of this well, the above steps in production rate will be accompanied by interpretable changes in both gas/brine ratio and chemical composition of produced gas. On the other hand, if no changes in gas/brine ratio or gas composition are observed, it will be clear that the initial bubble point in the reservoir was lower than the bottomhole pressure experienced at the rate of 15,000 to 20,000 BPD. If this latter situation is experienced, the additional step of production at maximum possible rate may warrant similar detailed analysis.

Completion of the actions recommended above should provide a basis of understanding warranting a major reduction in operating costs. Rate metering would be automated with sufficient redundancy to catch discrepancies. Daily calculation of gas/brine ratio would continue until larger time intervals were clearly warranted. Fluid sampling interval would be increased until sampling was only in response to observed changes in gas/brine ratio or other producing characteristics (e.g., scaling, injection pressure increase, anomalous rates, or anomalous pressures).

The understanding of producing characteristics from the above recommended steps, in conjunction with results of reservoir engineering analysis, would provide firm technical basis for engineering evaluation, cost estimates, and decisions regarding gas cleanup and sale.

ACKNOWLEDGMENTS

The authors are grateful for the cooperation and information provided by the organizations performing this well test, which include Magma Gulf-Technadril, Weatherly Laboratories, McNeese State University, and Rice Engineering Design and Development Institute of Rice University. Of particular importance was the cooperation and assistance given in the field by Larry Durrett and Jonne Berning, which helped make this study possible and meaningful. Portions of this work were performed under Department of Energy Contract No. DE-AC08-78ET27098 titled "Computer Simulation of Production From Geopressured-Geothermal Aquifers," Gas Research Institute Contract No. 5011-321-0140 titled "Gas Saturation in Formation Waters," and Magma Gulf-Technadril P. O. No. 1577.

93(3000)/65036MG-T

REFERENCES

1. Hankins, B. E., McNeese State University, Lake Charles, Louisiana, Private Communication, 1981.
2. Neal, J., "Reservoir Fluid Analysis for Magma Gulf-Technadril Amoco Fee Well No. 1," Weatherly Laboratories, Inc., Lafayette, Louisiana, 1981.
3. Weatherly Laboratories, Inc., Data files on location, 1981.
4. Garg, S. K. et al., "Geopressured Geothermal Reservoir and Well Bore Simulation," Final Report (Year 2) SSS-R-78-3639. Systems Science and Software, La Jolla, Calif., 1981.
5. Culberson, O. L. and McKetta, J. J., "Phase Equilibria in Hydrocarbon Water Systems, III, Solubility of Methane in Water at Pressures in Excess of 10,000 psia," Trans. AIME 192 (1951), 223-26.
6. Eaton Operating Co., "Testing Geopressured-Geothermal Reservoirs in Existing Wells, Final Report, HO&M Prairie Canal Co. Well No. 1," Department of Energy Contract No. DE-AC08-80ET27081 (to be published).
7. Idaho State University, "Solubility of Methane in Waters From Pleasant Bayou Well No. 2," Report for Institute of Gas Technology under P.O. No. S542544, Idaho State University, Pocatello, 1981.
8. Randolph, P. L., and Rockar, E. M., "Do We Know Whether the Pleasant Bayou #2 is Saturated With Methane?" IGT Technical Report, Institute of Gas Technology, Chicago, Illinois, 1981.
9. Haas, J. L., Open File Report No. 78-1004. U.S. Department of the Interior, Geological Survey, Reston, Va., n.d.
10. Oddo, J. E. and Thomson, M. B., "Scale and Corrosion Report for the Magma Gulf-Technadril Amoco Fee #1 Design Well," Rice Engineering Design and Development Institute, Rice University, 1981.
11. Eaton Operating Company, "Testing Geopressured-Geothermal Reservoirs in Existing Wells, Final Report, Riddle-Saldana Well No. 2," Vol. II, Well Test Data, Department of Energy Contract No. DE-AC08-80ET27081 (to be published).

APPENDIX E

Well Test Analysis

WELL TEST ANALYSIS
MG-T/DOE AMOCO FEE NO. 1
SWEET LAKE PROJECT
SAND ZONE #3

January, 1984

Prepared for
MAGMA GULF - TECHNADRIL

Dowdle Fairchild & Ancell, Inc.

MG-T/DOE AMOCO #1 TEST ANALYSIS

Magma Gulf-Technadril contacted Dowdle Fairchild & Ancell to investigate the sand zone #3 test in the captioned well. The charge was to develop a description of the reservoir using reservoir simulation techniques. The work was to be done utilizing the background that Mr. Ancell had acquired during the analysis of the sand zone #5 test in 1981.

The data provided was adequate to describe the basic rock and fluid properties. A complete list of the documents utilized is shown in References.

The test period has been comprised of (1) a one day flow test, (2) a nine day shut in period, (3) a seven day constant rate flow test, (4) an eight day variable rate flow test monitored with bottom hole pressure gauge and (5) a 30 plus day flow period with only surface pressures recorded. Currently the well is flowing at about 2500 bpd with a surface pressure of 300 psia. This is the delivery capability of this zone.

The best data for describing the reservoir is the seven day constant rate flow test. Most of the effort was expended to work with that portion of the test. Once the simulation of the seven day test was complete, the eight day test and the one day test were simulated as a check of the description. The first one day flow test was not used primarily because the flow rates were not measured through the separator. Figure 1 is a cartesian plot of the fifteen days of flow time. Figure 2 is a semi-log plot of the first seven days.

RESERVOIR DESCRIPTION

The simulator used is a single phase, two dimensional flow model. The simulator uses radial coordinates. Included in the formulation is a potential development that linearizes the pressure dependent properties of compressibility and viscosity.

Table 1 shows the basic parameters used for the study. The only ones that require any discussion are the water formation volume factor, B_w , and rock compressibility, C_r . The B_w used is presented in the Weatherly "Reservoir Fluid Analysis" Report for the separator gas-water ratio of 19.98 SCF/STB. The rock compressibility was derived from the bulk compressibility values measured by the University of Texas¹, Appendix E.

The reservoir geometry used as a starting point is that described in the paper by Gould, Clark, and Keener.² This is a wedge shaped reservoir bounded on two sides by linear barriers with a flow angle of 60 degrees at the well. In the sand 5 test, the flow angle was found to be restricted out into the graben but this test did not reach far enough to determine whether or not the restriction is necessary for sand zone 3.

These linear boundaries conform to the angle formed by the graben faults identified by the geology and are shown on Figure 3. However, the determined distances to the faults are much closer to the well than indicated by the geology.

The early time rates (first 6 to 10 minutes) are not recorded due to gas in the tubing. The necessary rates were "backed out" during the simulation process. It was found that rates of 3600 bpd for about one minute and 1000 bpd for five minutes give reasonable pressure calculations for this very early time.

When history matching the seven day test, the parameters used were the reservoir permeability, the distance to the faults, and the angle of the faults. The final description and history match run are shown on Table 1 and Figure 4. The prediction of the eight day variable rate flow test is shown on Figure 5. A word is in order about this run. Days eight and nine were simulated by specifying constant rates of 5500 bpd and 6200 bpd and calculating the pressure at the end of the day. Days ten through fifteen were simulated by specifying the indicated bottom hole pressure and calculating the rate for the day. These rates are shown as the stair steps of Figure 5.

Figure 6 shows the estimated early one day test and subsequent buildup. This simulation uses only a first estimate for brine flow rates. The conclusion is that the rates could be adjusted within the tolerance to give an excellent match. Further refinement of the rates was not warranted.

The only disturbing part of this description is that a negative skin is necessary to describe the flow. The simulator uses an expanded well bore to simulate a negative skin. We had to use a well bore radius of eight feet to match the test. This is indicative of some anomaly within a few feet of the well. It is possible that this may be related to the two zones perforated which we have not seen before. There may be other explanations for this problem. Regardless, this has hardly any effect on the long term flow characteristics of the well.

In analyzing the data it may be of interest to see the sensitivity of the various parameters. Table 2 shows the values used in the various runs, and the plotted results are shown on Figure 7. Notice how the distance to the faults affects the curvature of the drawdown. The spread of the flow angle also has an important effect on the shape of the curve.

ALTERNATE DESCRIPTION

The description above assumes that the rock properties are continuous over the reservoir. An alternate idea is that there are no faults, but the rock changes in characteristics. An alternate description assumes a high permeability area in the vicinity of the well bore with reductions away from the well. Figure 8 is the calculated seven day test for this description. This assumes that there is a step function in permeability at a distance of 175 ft from the well. The permeability in the near-well area is 42 md and in the outer area it is 7 md.

Obviously, this description fits the data for this test as well as the description using linear barriers. This same idea was proposed by the University of Texas for the sand 5 test. An alternate description for the sand 5 test would have a high permeability zone of about 300 md surrounded by a ring of about 20 md.

DISCUSSION

One is now faced with choosing the proper description from the two postulated. If the linear barrier or fault description is chosen, then there must be unmapped faults in the vicinity of the well. Also, the faults must be about the same distance from the well. The fact that the subject well drilled into the graben in the center without cutting either fault above or below the sand section seems unlikely. On the other hand it seems just as unlikely that the well would hit in the center of a high permeability spot in both the number 3 and number 5 sands, and further that the high permeability zones are nearly exactly the same size.

If we take the two tests together, we find some differences that can help some. First, the recent sand 3 test investigated about 20 million barrels of water. If this is contained in a circular reservoir, it will have a radius of about 2800 ft. This size will easily fit within the graben as it is mapped in Figure 3. However, sand 5 shows two things that make this not possible for it to be contained in the graben. There were definite and repeatable barriers shown in the early time of the flow tests. Also, that test investigated about 300 million barrels of water. If this is contained within a circular reservoir, it would have a radius in excess of 9000 ft. This will not fit within the graben.

This raises the question of why there were no slope reflections in the sand 3 test. This is probably due to the early time rate variation and the fact that the faults are so close and about equal distance from the well.

Again, the negative skin is a detriment to the description because it is thought to be physically impossible to explain the data that way. However, this is common to both descriptions and cannot be used to distinguish between the two.

CONCLUSIONS

From this we can conclude that it is more likely that the heterogeneities seen are some minor faults not seen on seismic and difficult to see in any wellbore.

There is reason to believe that the same description that fits the sand 5 behavior also fits the sand 3 behavior. The description developed for the sand 3 is a lay down copy for the description for the sand 5 tests.

The permeability of sand zone 3 is about 42 md which is nearly an order of magnitude less than sand 5. The result is that the total deliverability from sand 3 has been reached during the test and is something less than 2500 bpd.

REFERENCES

1. Hoffman, K. S., "Final Report-Geopressured Well Project, Sweet Lake, Cameron Parish, LA," GRI, Jan., 1983.
2. Gould, T. L., Keener, C. B., Clark, J. D., "Reservoir Engineering and Computer Model Analysis of Flow Tests, Sweet Lake Geothermal-Geopressured Prospect, 1981.
3. Durrett, L. R., "Daily Report," Period Nov. 14, 1983 through Dec. 7, 1983.
4. Weatherly, "Reservoir Fluid Analysis," Sand Zone No. 3.
5. MG-T/DOE, "Geopressured-Geothermal Testing Plan," June 1981.
6. Andrade, M., "Analysis of Sweet Lake Geopressure-Geothermal Aquifer," Dept. of Petroleum Engineering, University of Texas.

TABLE 1
RESERVOIR PARAMETERS

Rock Properties

Net Thickness	20 ft
Porosity	20%
Permeability	42 md
Rock Compressibility	3×10^{-6}

Fluid Properties

<u>Pressure, psia</u>	<u>Bw, resbbl/STB</u>	<u>Viscosity, Cp</u>
9000	1.0560	.323
10000	1.0532	.330
11000	1.0505	.336
11887	1.0480	.342

Reservoir Boundaries

TABLE 2
MAGMA GULF-TECHNADRIL
AMOCO FEE NO. 1
SWEET LAKE PROSPECT

SIMULATIONS RUNS

<u>Run</u>	<u>Dist. to Faults, ft</u>	<u>Flow Angle</u>	<u>Re ft</u>	<u>Rate Criteria</u>
1	400	50	10k	2nd Drawdown Test Rates (First Seven Days)
2	250	30	10k	2nd Drawdown Test Rates (First Seven Days)
3	225	40	10k	2nd Drawdown Test Rates (First Seven Days)
4	225	60	27k	2nd Drawdown Test Rates (First Seven Days)

0000 47

0000 47

FIGURE 3 Structure map of Sweet Lake area. Contoured on the top of the Miogypsinoides sand.

APPENDIX F
DISTRIBUTION OF CORES
Core Number 1

15144'	- 15144'4"	Core Lab
15144'4"	- 15144'6"	Rice
15144'6"	- 15145'	UT
15146'	- 15147'	LGS
15147'	- 15147'4"	Terra Tek
15147'4"	- 15147'5"	LGS
15147'5"	- 15147'11"	LBL
15147'11"	- 15148'	LGS
15148'	- 15148'6"	UT
15148'6"	- 15149'6"	Hart/LGS
15150'6"	- 15151'	LGS
15151'6"	- 15151'7"	Amoco
15151'7"	- 15152'	LGS
15152'	- 15152'5"	Core Lab
15152'5"	- 15152'6"	LGS
15152'6"	- 15153'	UT
15153'	- 15153'2"	LGS
15153'2"	- 15153'6"	USGS
15153'6"	- 15154'1"	LGS
15154'1"	- 15154'5"	Terra Tek
15154'5"	- 15154'6"	LGS
15154'6"	- 15155'	UT
15155'	- 15155'6"	LGS
15156'	- 15156'6"	LGS
15157'	- 15157'1"	LGS
15157'1"	- 15157'7"	UT
15157'7"	- 15157'8"	LGS
15157'8"	- 15158'	USGS
15158'	- 15158'2"	LGS
15158'8"	- 15159'	LGS
15159'6"	- 15160'	LGS
15160'	- 15160'5"	Hart
15160'5"	- 15160'6"	LGS
15160'6"	- 15161'	UT
15161'	- 15161'4"	LGS
15161'4"	- 15161'5"	Hart
15161'5"	- 15162'	LGS
15162'6"	- 15162'8"	LGS
15162'8"	- 15163'	USGS
15163'	- 15163'3"	LGS
15163'6"	- 15164'4"	LGS
15164'4"	- 15164'8"	UT
15164'8"	- 15165'	LGS
15165'	- 15165'6"	LBL
15165'6"	- 15166'	LGS
15166'	- 15167'	Hart/LGS
15167'	- 15167'6"	UT
15167'6"	- 15168'6"	LGS
15168'11"	- 15169'1"	LGS
15169'1"	- 15169'4"	USGS
15169'4"	- 15169'9"	UT

15169'9"	- 15171'4"	LGS
15171'4"	- 15171'9"	UT
15171'9"	- 15172'3"	LGS
15172'9"	- 15173'3"	LGS
15173'9"	- 15174'1"	LGS
15174'1"	- 15174'4"	USGS
15174'4"	- 15174'6"	LGS
15174'10"	- 15175'8"	LGS
15175'8"	- 15176'	UT
15176'	- 15176'4"	LGS
15176'8"	- 15177	LGS
15177'	- 15177'1"	Amoco
15177'1"	- 15177'9"	LGS
15178'7"	- 15178'11"	Terra Tek

Core Number 2

15185'	- 15185'5"	LGS
15185'9"	- 15185'11"	LGS
15185'11"	- 15186'5"	UT
15186'5"	- 15186'9"	Terra Tek
15186'9"	- 15188'5"	LGS
15188'5"	- 15188'9"	Terra Tek
15188'9"	- 15189'	LGS
15189'	- 15189'6"	UT
15189'	- 15189'11"	LGS
15189'11"	- 15190'	Amoco
15190'	- 15190'1"	LGS
15190'7"	- 15190'10"	LGS
15190'10"	- 15191'2"	Core Lab
15191'2"	- 15191'3"	LGS
15191'3"	- 15191'9"	LBL
15191'9"	- 15192'	LGS
15192'	- 15192'6"	UT
15192'6"	- 15193'	LGS
15193'6"	- 15194'	LGS
15194'6"	- 15195'	LGS
15195'	- 15195'6"	UT
15195'6"	- 15196'	LGS
15196'	- 15196'3"	USGS
15196'3"	- 15197'	LGS
15197'	- 15197'1"	Hart
15197'1"	- 15197'6"	LGS

Core Number 3

15189'	- 15389'2"	LGS
15389'2"	- 15389'8"	UT
15389'8"	- 15390'	Terra Tek
15390'6"	- 15391'	LGS
15391'6"	- 15391'7"	LGS
15391'7"	- 15391'10"	IGT
15391'10"	- 15392'	LGS
15392'6"	- 15392'8"	LGS
15392'8"	- 15392'11"	IGT
15392'11"	- 15393'3"	LGS
15393'3"	- 15393'9"	UT
15393'9"	- 15394'2"	LGS
15394'8"	- 15395'	LGS
15395'6"	- 15395'9"	LGS
15393'9"	- 15396'	IGT
15396'	- 15396'2"	LGS
15396'2"	- 15396'3"	Amoco
15396'3"	- 15396'7"	LGS
15396'7"	- 15396'10"	IGT
15396'10"	- 15397'	LGS
15397'	- 15397'6"	UT
15397'6"	- 15398'	LBL
15398'	- 15398'6"	LGS
15398'6"	- 15398'10"	Terra Tek
15398'10"	- 15399'	LGS
15399'	- 15399'6"	UT
15399'6"	- 15399'7"	Amoco
15399'7"	- 15400'1"	LGS
15400'7"	- 15401'	LGS
15401'6"	- 15402'1"	LGS
15402'1"	- 15402'2"	Hart
15402'2"	- 15402'8"	UT
15402'8"	- 15402'10"	LGS
15402'10"	- 15403'	USGS
15403'	- 15403'5"	UT
15403'5"	- 15403'6"	LGS
15403'6"	- 15404'	UT
15404'	- 15404'2"	LGS
15404'8"	- 15405'	LGS
15405'	- 15405'6"	UT

Core Number 4

15600'	- 15600'6"	UT
15600'6"	- 15600'8"	Hart/LGS
15600'8"	- 15601'	LGS
15601'6"	- 15601'8"	LGS
15601'8"	- 15601'10"	USGS
15601'10"	- 15602'	LGS
15602'6"	- 15603'6"	LGS
15603'10"	- 15604'	LGS
15604'	- 15604'6"	Core Lab
15604'6"	- 15606'	LGS
15605'	- 15605'4"	USGS
15605'4"	- 15606'6"	LGS
15605'6"	- 15606'	UT
15606'	- 15606'2"	LGS
15606'2"	- 15606'6"	Terra Tek
15606'6"	- 15608'6"	LGS
15608'6"	- 15608'8"	Amoco
15608'8"	- 15609'	Terra Tek
15609'	- 15610'	LGS
15610'	- 15610'6"	UT
15610'6"	- 15611'	LGS
15611'6"	- 15612'6"	LGS
15613'	- 15613'6"	LGS
15613'6"	- 15614'	UT
15614'	- 15615'8"	LGS
15615'8"	- 15616'	Terra Tek
15616'	- 15616'3"	LGS
15616'3"	- 15616'8"	UT
15616'8"	- 15616'10"	LGS
15616'10"	- 15617'4"	Hart
15617'9"	- 15618'6"	LGS
15619'	- 15619'5"	LGS
15619'10"	- 15620'1"	LGS
15620'1"	- 15620'7"	UT
15620'7"	- 15620'9"	LGS
15620'9"	- 15620'11"	USGS
15620'11"	- 15621'	LGS
15621'6"	- 15622'	LGS
15622'6"	- 15623'	LGS
15623'6"	- 15623'10"	LGS
15623'10"	- 15624'4"	UT
15624'4"	- 15625'	LGS
15625'	- 15626'	LBL/LGS
15626'	- 15626'8"	LGS
15626'8"	- 15626'10"	USGS
15626'10"	- 15627'3"	LGS
15627'3"	- 15627'8"	Terra Tek
15627'8"	- 15628'6"	LGS
15628'6"	- 15628'8"	Amoco
15628'8"	- 15629'5"	LGS

15629'5" - 15629'11"	UT
15629'11" - 15630'	LGS
15630' - 15630'4"	USGS
15630'4" - 15630'11"	LGS
15630'11" - 15631'4"	UT
15631'4" - 15632'	LGS

APPENDIX G
GAS WATER RATIO
MEASUREMENTS

MG-T/DOE AMOCO FEE NO.1 WELL
SWEET LAKE PROSPECT
GAS/WATER RATIO MEASUREMENTS
SEPTEMBER, 1981

SUMMARY

Gas production from brine from the subject geopressured-geothermal test well results in produced wet gas/water ratios of 21-24 SCF/B, with an additional 2-3 SCF/B lost with the brine to the disposal well at separator operating pressures of 300-500 psig.

Thus, the brine from this test well appears to be unsaturated with respect to gas content (i.e., 23-27 SCF/B as opposed to 34 SCF/B determined at saturation under reservoir conditions). However, the degree of unsaturation is not nearly as great as has been reported earlier (13-15 SCF/B). The data reported earlier were erroneously low due to measurement problems, which have now been resolved.

Wet gas/water ratios of 13-15 SCF/B have been reported during earlier testing (June-July, 1981) of the subject geopressured-geothermal well; in fact, a value of 8.5-9 SCF/B was reported during the Initial Flow Test in mid-June. These earlier gas/water ratios have now been determined to be erroneously low through a systematic study of both gas and brine measurements.

GAS MEASUREMENTS

Early gas production measurements were made only with concentric orifice plates and strain-gauge differential pressure instrumentation. The gas production rates thus determined were not initially considered suspect because consistent (albeit low) measurements were obtained using several orifice plates of different bores as well as different differential pressure instruments calibrated at several different ranges.

GAS/WATER RATIO MEASUREMENTS

Page 2

However, a Rockwell positive displacement meter was installed for gas rate measurements on July 29, and measurements thus obtained were about 113% higher than those obtained with the orifice plates. The positive displacement meter was then removed and proven and found to be accurate to within about 1%. The gas measurements with the orifice plates were thus determined to be erroneously low.

Inspection and systematic study of all components of the orifice plates-differential pressure instrumentation systems demonstrated that the measurement errors were attributable to the following:

Calculation Errors	- 12%
Improperly Designed and Constructed Orifice Plates (Plates not beveled to create proper sharp knife-edge)	- 27%
Steam Condensation Upstream of Orifice Plates	- 61%

BRINE MEASUREMENTS

Brine flow rate measurements were made with a Halliburton turbine meter which was piped upstream of the separator to obtain immediate flow response from the wellhead, and to avoid the time lag downstream of the separator. Unfortunately, full stream flow (i.e., free gas and dissolved gas in addition to brine) is measured upstream of the separator, and not brine only.

The indicated full stream flow rate was determined to be about 26-44% higher than the brine flow rate from the separator (refer to Table 1). This erroneously high indicated flow rate when used in gas/water ratio calculations will result in ratios of 5-6 SCF/B lower than actual ratios.

GAS/WATER RATIO MEASUREMENTS

Page 3

Calibration test run data for the Halliburton turbine meters utilized for brine flow rate measurements are given in Table 1. It can be seen from these data that the turbine meters when measuring brine only are accurate to within less than 1%.

GAS/WATER RATIO

Comparative wet gas/water ratios determined recently using both orifice plates/differential pressure instrumentation and positive displacement meters for gas rate measurements, and turbine meters for brine measurements are given in Table 2. It should be noted that the ratios given in Table 2 are production wet gas/water ratios, and further that gas lost in the brine to the disposal well (about 2 SCF/B at 300 psig separator pressure - refer to Figure 1) must be added to arrive at total gas/water ratio.

Weatherly Laboratories have determined that the dry gas/water ratio in the brine from the Sweet Lake Test Well should be about 34 SCF/B at saturation under reservoir conditions as may be seen in Figure 2. It thus appears that the Sweet Lake brine is still unsaturated with respect to natural gas content; however, the degree of unsaturation is not nearly as great as believed initially.

TABLE 1

MG-T/DOE AMOCO FEE NO.1 WELL
SWEET LAKE PROSPECT

CALIBRATION OF HALLIBURTON LIQUID TURBINE METERS

SEPTEMBER, 1981

DATE	08/28/81	08/28/81	08/31/81	09/02/81	09/04/81
NOMINAL TEST RUN RATE, B/D	2,000	2,000	5,000	5,000	5,000
TEST RUN NO.	1	2	1	2	3
CALIBRATION TANK VOLUME, BBLs	158.4	152.0	152.0	152.0	152.0
TIME REQUIRED TO FILL TANK, MIN.	118.22	111.42	43.30	45.32	42.75
BRINE PRODUCTION RATE, B/D MEASURED	1,930	1,964	5,055	4,830	5,120
BRINE PRODUCTION RATE, B/D DETERMINED FROM TURBINE METER	1,925	1,964	5,055	4,861	5,086
% ERROR	- 0.26	0.0	0.0	+ 0.64	- 0.64
FULL STREAM PRODUCTION RATE, B/D* DETERMINED FROM TURBINE METER	2,777	2,766	6,385	6,672	6,535
% ERROR	+ 43.9	+ 40.8	+ 26.3	+ 38.1	+ 27.6

* NOTE: Full Stream Rate can only be utilized as an indication of relative brine rate since the Turbine Wheel is turned by both free gas and dissolved gas in addition to brine.

TABLE 2

MG-T/DOE AMOCO FEE NO.1 WELL
 SWEET LAKE PROSPECT
COMPARATIVE GAS/WATER RATIO MEASUREMENTS
 SEPTEMBER, 1981

DATE	GAS PRODUCTION, SCF/D		BRINE PRODUCTION, STB/D	GAS/WATER RATIO	
	POSITIVE DISPLACEMENT OR TURBINE METER	ORIFICE DP CELL		POSITIVE DISPLACEMENT OR TURBINE METER	ORIFICE DP CELL
NOMINAL 2,000 B/D TEST RUN					
Aug.28	42,393	40,600	1,907	22.2	21.3
Aug.29	42,238	39,574	1,867	22.6	21.2
Aug.30	44,735	41,205	1,892	23.6	21.8
NOMINAL 5,000 B/D TEST RUN					
Sept.2		104,239	4,899		21.3
Sept.4		108,763	4,561		23.8
Sept.5		113,918	4,991		22.8
Sept.6		111,305	4,858		22.9

FIGURE 2

Company Magma Gulf - Technadril Well Amoco Fee Well No. 1
 Reservoir _____ Field Sweet Lake Prospect

FIGURE 1: Effect of GWR on Bubble Point Pressure @ 299°F.

Bbl. Sep. water @ 535 psia & 242°F
 Lab. No. N-1313

APPENDIX H
SEPARATOR WATER FLASH

WEATHERLY LABORATORIES, INC.

J. E. WEATHERLY, JR.
CHAIRMAN

223 GEORGETTE LAFAYETTE, LA 70506
PHONE (318) 232-4877

JOHN D. NEAL
PRESIDENT
BRYAN SONNIER
VICE PRESIDENT

NOVEMBER 29, 1983

MAGMA GULF-TECHNADRIL
ROUTE 1, BOX 185A
BELL CITY, LA 70630

ATTENTION: MR. LARRY DURRETT

RE: AMOCO FEE WELL NO. 1
SWEET LAKE PROSPECT FIELD
SAND ZONE NO. 3
CAMERON PARISH, LOUISIANA

SEPARATOR WATER FLASH TO 0 PSIG & 68°F

(SAMPLED: 11-23-83, 1700 HRS @ 500 PSIG & 164°F)

SOLUTION GAS-WATER RATIO, DRY = 2.64

SCF GAS @ 15.025 PSIA & 60°F

BBL. WATER @ 0 PSIG & 60°F

SHRINKAGE = 0.9694

VOL. S.T. WATER @ 60°F

VOL. SEP. H₂O @ 500 PSIG & 164°F

STOCK TANK WATER DENSITY = 1.1123

Gm/Ml @ 60°F

GAS GRAVITY, DRY = 0.9625

(SEE ANALYSIS ON PAGE-3)

RESPECTFULLY SUBMITTED,

Karen Lestelle

KAREN LESTELLE

959/3

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 SAMPLED: 11-23-83 @ 1700 HRS.
 500 PSIG & 128 DEGREES F

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	5.76	
NITROGEN	0.22	
METHANE	91.77	
ETHANE	1.81	0.492
PROPANE	0.31	0.086
ISO-BUTANE	0.02	0.007
N-BUTANE	0.05	0.015
ISO-PENTANE	0.00	0.002
N-PENTANE	0.00	0.002
HEXANES	0.00	0.000
HEPTANES PLUS	0.06	0.031
TOTALS	100.00	0.635

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6263 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 996.3 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 978.8 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9979

ON-SITE DRAGER MEASUREMENTS ON 11-23-83 AT 1518 HOURS:

CARBON DIOXIDE = 5.85 MOL %
 HYDROGEN SULFIDE = 6.2 PPM

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 SAMPLED: 11-23-83 @ 1700 HRS.
 500 PSIG & 128 DEGREES F

HYDROCARBON ANALYSIS OF FLASHED GAS FROM SEPARATOR WATER

FLASHED FROM 500 PSIG TO 0 PSIG

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	41.50	
NITROGEN	0.00*	0.00*
METHANE	57.46	0.000
ETHANE	0.95	0.260
PROPANE	0.09	0.025
ISO-BUTANE	0.00	0.000
N-BUTANE	0.00	0.000
ISO-PENTANE	0.00	0.000
N-PENTANE	0.00	0.000
HEXANES	0.00	0.000
HEPTANES PLUS	0.00	0.001
TOTALS	100.00	0.286

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.9625 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 614.4 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 603.7 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9972

NOTE: * CALCULATED NITROGEN FREE.

MAGMA GULF -TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 SAMPLED: 11-24-83 @ 1500 HOURS
 495 PSIG & 137 DEGREES F
 BY: TECHNADRIL PERSONNEL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	5.90	
NITROGEN	0.21	
METHANE	91.62	
ETHANE	1.79	0.488
PROPANE	0.30	0.083
ISO-BUTANE	0.02	0.007
N-BUTANE	0.04	0.013
ISO-PENTANE	0.00	0.002
N-PENTANE	0.00	0.002
HEXANES	0.00	0.000
HEPTANES PLUS	0.12	0.059
TOTALS	100.00	0.654

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6292 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 997.3 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 979.9 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

WEATHERLY LABORATORIES, INC.

J. E. WEATHERLY, JR.
CHAIRMAN

223 GEORGETTE LAFAYETTE, LA 70506
PHONE (318) 232-4877

JOHN D. NEAL
PRESIDENT
BRYAN SONNIER
VICE PRESIDENT

JANUARY 4, 1984

MAGMA GULF-TECHNADRIL
3 NORTH POINT DRIVE
SUITE 200
HOUSTON, TX 77060

ATTENTION: MR. LARRY DURRETT

RE: AMOCO FEE WELL NO. 1
SWEET LAKE PROSPECT FIELD
SAND ZONE NO. 3
CAMERON PARISH, LOUISIANA
SAMPLED BY: WEATHERLY LAB

SEPARATOR WATER FLASH TO 0 PSIG & 71°F

(SAMPLED: 12-29-83, 0330 HRS @ 250 PSIG & 197°F)

SOLUTION GAS-WATER RATIO, DRY = 1.38

SCF GAS @ 15.025 PSIA & 60°F

BBL. WATER @ 0 PSIG & 60°F

SHRINKAGE = 0.9714

VOL. S.T. WATER @ 60°F

VOL. SEP. H2O @ 250 PSIG & 197°F

STOCK TANK WATER DENSITY = 1.0975

Gm/Ml @ 60°F

GAS GRAVITY, DRY = 0.9786

(SEE ANALYSIS ON PAGE 3)

RESPECTFULLY SUBMITTED,

D. G. Plaisance
D. G. PLAISANCE
PETROLEUM ENGINEER

CC: MAGMA GULF-TECHNADRIL
ROUTE 1, BOX 185A
BELL CITY, LA 70630
ATTEN: JONNE BERNING

LAB. NO. N2174-10551

PAGE 1 OF 7

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 SAMPLED: 12-29-83 @ 0330 HOURS
 250 PSIG & 140 DEGREES F
 BY: WEATHERLY LAB

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	9.17	
NITROGEN	0.20	
METHANE	88.72	
ETHANE	1.47	0.402
PROPANE	0.19	0.053
ISO-BUTANE	0.01	0.004
N-BUTANE	0.02	0.005
ISO-PENTANE	0.00	0.001
N-PENTANE	0.00	0.000
HEXANES	0.07	0.028
HEPTANES PLUS	0.15	0.076
TOTALS	100.00	0.569

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6604 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 963.0 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 946.2 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

ON-SITE DRAGER MEASUREMENTS:

CARBON DIOXIDE = 11.5 MOL %
 HYDROGEN SULFIDE = 40 PPM

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 SAMPLED: 12-29-83 @ 0330 HOURS
 250 PSIG & 197 DEGREES
 BY: WEATHERLY LAB

HYDROCARBON ANALYSIS OF FLASHED GAS FROM SEPARATOR WATER

FLASHED FROM 250 PSIG TO 0 PSIG

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	43.29	
NITROGEN	0.00*	0.00*
METHANE	55.88	0.000
ETHANE	0.77	0.209
PROPANE	0.06	0.016
ISO-BUTANE	0.00	0.001
N-BUTANE	0.00	0.001
ISO-PENTANE	0.00	0.000
N-PENTANE	0.00	0.000
HEXANES	0.00	0.000
HEPTANES PLUS	0.00	0.001
TOTALS	100.00	0.228

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.9786 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 594.1 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 583.7 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9972

NOTE: * CALCULATED NITROGEN FREE.

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 DRAW DOWN PHASE DAY 32
 SAMPLED: 12-23-83 @ 1500 HOURS
 300 PSIG & 154 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	8.57	
NITROGEN	0.20	
METHANE	89.39	
ETHANE	1.51	0.412
PROPANE	0.20	0.055
ISO-BUTANE	0.01	0.004
N-BUTANE	0.02	0.006
ISO-PENTANE	0.00	0.001
N-PENTANE	0.00	0.000
HEXANES	0.00	0.001
HEPTANES PLUS	0.10	0.054
TOTALS	100.00	0.533

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6518 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 965.0 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 948.1 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 DRAW DOWN PHASE DAY 34
 SAMPLED: 12-26-83 @ 1500 HOURS
 300 PSIG & 145 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	8.54	
NITROGEN	0.20	
METHANE	89.43	
ETHANE	1.50	0.409
PROPANE	0.20	0.055
ISO-BUTANE	0.01	0.004
N-BUTANE	0.02	0.006
ISO-PENTANE	0.00	0.001
N-PENTANE	0.00	0.000
HEXANES	0.00	0.000
HEPTANES PLUS	0.10	0.049
TOTALS	100.00	0.524

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6511 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 964.5 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 947.6 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 DRAW DOWN PHASE DAY 36
 (SURFACE 512 PSIA)
 SAMPLED: 12-28-83 @ 1145 HOURS
 300 PSIG & 153 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	8.56	
NITROGEN	0.20	
METHANE	89.37	
ETHANE	1.50	0.409
PROPANE	0.19	0.054
ISO-BUTANE	0.01	0.004
N-BUTANE	0.02	0.005
ISO-PENTANE	0.00	0.001
N-PENTANE	0.00	0.000
HEXANES	0.00	0.000
HEPTANES PLUS	0.15	0.071
TOTALS	100.00	0.544

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6526 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 966.4 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 949.5 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 DRAW DOWN PHASE DAY 36
 SAMPLED: 12-28-83 @ 1500 HOURS
 250 PSIG & 138 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	9.13	
NITROGEN	0.20	
METHANE	88.90	
ETHANE	1.48	0.405
PROPANE	0.19	0.053
ISO-BUTANE	0.01	0.004
N-BUTANE	0.02	0.005
ISO-PENTANE	0.00	0.001
N-PENTANE	0.00	0.000
HEXANES	0.00	0.000
HEPTANES PLUS	0.07	0.037
TOTALS	100.00	0.505

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6559 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 956.9 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 940.2 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

Appendix I

RESERVOIR FLUID ANALYSIS

FOR

MAGMA GULF-TECHNADRIL

MG-T/DOE AMOCO FEE NO. 1 WELL
SAND ZONE NO. 3
SWEET LAKE FIELD
CAMERON PARISH, LOUISIANA

WEATHERLY LABORATORIES, INC.

J. E. WEATHERLY, JR.
CHAIRMAN

223 GEORGETTE LAFAYETTE, LA 70506
PHONE (318) 232-4877

JOHN D. NEAL
PRESIDENT
BRYAN SONNIER
VICE PRESIDENT

DECEMBER 30, 1983

MAGMA GULF-TECHNADRIL
3 NORTHPOINT DRIVE
SUITE 200
HOUSTON, TEXAS 77060

ATTENTION: MR. LARRY DURRETT

RE: RESERVOIR FLUID STUDY
MG-T/DOE AMOCO FEE NO. 1 WELL
SAND ZONE NO. 3
SWEET LAKE FIELD
CAMERON PARISH, LOUISIANA

GENTLEMEN:

ATTACHED ARE THE RESULTS OF THE ANALYSES OF THE CHEMICAL AND PHYSICAL CHARACTERISTICS OF A RECOMBINED RESERVOIR FLUID SAMPLE FROM THE SUBJECT WELL. SURFACE SEPARATOR SAMPLES WERE COLLECTED FROM THIS WELL BY A REPRESENTATIVE OF WEATHERLY LABORATORIES, INC. ON NOVEMBER 25, 1983. THE GAS-WATER RATIO (GWR) MEASURED ON THIS 72 HOUR TEST, 19.98 CUBIC FEET OF SEPARATOR GAS PER BARREL OF SEPARATOR LIQUID, WAS USED AS THE BASIS FOR ONE RECOMBINATION. THE RESULTANT RESERVOIR FLUID EXHIBITED A BUBBLE POINT OF 8,000 PSIA AT THE RESERVOIR TEMPERATURE 293 DEGREES FAHRENHEIT.

OTHER RECOMBINATIONS WERE DONE TO DETERMINE A BUBBLE POINT -VS- GWR RELATIONSHIP. A DIFFERENTIAL LIBERATION AND VISCOSITY MEASUREMENTS WERE PERFORMED USING RESERVOIR FLUID RECOMBINED TO THE PRODUCED GWR AT THE TIME OF SAMPLING.

WE WISH TO THANK YOU FOR THIS OPPORTUNITY OF SERVING YOU. SHOULD THERE BE ANY QUESTIONS CONCERNING THIS REPORT, PLEASE CONTACT US.

YOURS VERY TRULY

JOHN NEAL

CC: MR. JONNE BERNING
MAGMA GULF-TECHNADRIL
ROUTE 1, BOX 185A
BELL CITY, LA 70630

LAB. NO. N2171-10510

MAGMA GULF-TECHNADRIL
MG-T/DOE AMOCO FEE NO. 1 WELL
SAND ZONE NO. 3
SWEET LAKE FIELD

GEOPRESSURE/GEOTHERMAL PROJECT SAMPLING AND LABORATORY PROCEDURE

- 1) WATER VAPOR CONTENT OF SEPARATOR GAS WAS DETERMINED BY FLOWING GAS FROM A METERING VALVE ON THE SEPARATOR GAS METER RUN THROUGH A WEIGHING TUBE (INDICATOR DRIERITE (CaSO_4) WEIGHED TO 0.1 MILLIGRAM) TO A RUSKA GASOMETER. SEPARATOR GAS SAMPLES WERE TAKEN FROM THE SAME PLACE INTO 1 GALLON STAINLESS STEEL (S.S.) CYLINDERS AFTER THOROUGH PURGING. SEPARATOR LIQUID SAMPLE CYLINDERS (1000 ML. S.S.) WERE FIRST CHARGED WITH SEPARATOR GAS TO FULL SEPARATOR PRESSURE. THE LIQUID CYLINDERS WERE THEN CONNECTED TO THE SEPARATOR WATER SAMPLING POINT BY A S.S. TUBE LONG ENOUGH TO LOOP THROUGH A COOLING BATH. THE WATER TRANSFER LINE WAS THEN SLOWLY AND THOROUGHLY PURGED AT THE CYLINDER. SEPARATOR WATER WAS LET INTO THE CYLINDER BY SLOWLY BLEEDING GAS FROM THE TOP VALVE. AT NO TIME WAS THE WATER CAUGHT IN THE CYLINDER ALLOWED TO DROP BELOW SEPARATOR PRESSURE.
- 2) FLASH LIBERATION OF GAS FROM SEPARATOR WATER WAS ACCOMPLISHED BY USING A WEIGHED SEPARATOR FLASK. THIS SEPARATOR FLASK WAS CONNECTED TO THE OUTLET OF A SEPARATOR WATER CYLINDER BY A SHORT CAPILLARY LINE. GAS FROM THE SEPARATOR FLASK PASSED THROUGH A WEIGHED DRYING TUBE THROUGH A GLASS CYLINDER (~ 300 ML.) TO A RUSKA GASOMETER. A VACUUM VALVE AND A MERCURY MANOMETER WAS CONNECTED TO THE GAS MANIFOLD BETWEEN THE DRYING TUBE AND THE GASOMETER. BEFORE COMMENCING THE FLASH, THE ENTIRE FLASH GAS MANIFOLD WAS EVACUATED AND THEN FILLED WITH HELIUM TO ATMOSPHERIC PRESSURE. A KNOWN VOLUME OF SEPARATOR WATER WAS PUSHED OUT OF THE SAMPLE CYLINDER AT A PRESSURE SLIGHTLY ABOVE FIELD SEPARATOR PRESSURE BY USE OF A CALIBRATED MERCURY PUMP. THE VOLUME OF STOCK TANK WATER PRODUCED WAS DETERMINED BY ITS WEIGHT AND DENSITY. THE VOLUME OF DRY GAS EVOLVED WAS DETERMINED WITH THE GASOMETER. THIS GAS VOLUME WAS SUBJECT TO + 2 % ERROR DUE TO THE VERY SMALL AMOUNTS MEASURED. THE GAS WAS CHARGED TO A CHROMATOGRAPH FOR ANALYSIS FROM THE GLASS CYLINDER.
- 3) PHYSICAL RECOMBINATION OF SEPARATOR EFFLUENTS:
SEPARATOR GAS WAS CHARGED INTO A TEMPERATURE CONTROLLED CELL. THE VOLUME OF THIS WINDOWED CELL IS KNOWN FOR ANY PRESSURE AND TEMPERATURE. THE PRESSURE OF THE GAS IN THE CELL WAS MEASURED WITH A MERCURY MANOMETER AND A BAROMETER. THIS CALCULATED GAS VOLUME WAS SUBJECT TO A + 1 % ERROR DUE TO THE SMALL AMOUNT CHARGED TO THE CELL. A VOLUME OF SEPARATOR WATER WAS CHARGED INTO THE WINDOWED CELL BY USE OF A CALIBRATED MERCURY PUMP. THE WATER WAS METERED AND MEASURED AT A PRESSURE SLIGHTLY ABOVE FIELD SEPARATOR PRESSURE. FOUR RECOMBINATIONS WERE DONE IN ORDER TO PRODUCE A SATURATION PRESSURE-VS-GAS WATER RATIO CURVE. RESERVOIR FLUID RESULTING FROM RECOMBINATION OF THE PRODUCED GWR (FIFTH RECOMBINATION) WAS USED TO PERFORM A DIFFERENTIAL LIBERATION AND VISCOSITY MEASUREMENT.

MAGMA GULF-TECHNADRIL
MG-T/DOE AMOCO FEE NO. 1 WELL
SAND ZONE NO. 3
SWEET LAKE FIELD

- 4) PRESSURE-VOLUME RELATIONS OF RECOMBINED RESERVOIR FLUID AT RESERVOIR TEMPERATURE:
EACH DATUM OF PRESSURE-VOLUME RELATIONS WAS CORRECTED FOR MERCURY PUMP CALIBRATION, MANIFOLD EXPANSION, CELL EXPANSION, MERCURY COMPRESSIBILITY AND MERCURY THERMAL EXPANSION. LIQUID VOLUME PERCENT WAS DETERMINED BY CALIBRATED CATHETOMETER AND BY DATA INTERPRETATION.
- 5) DIFFERENTIAL LIBERATION OF RESERVOIR FLUID AT RESERVOIR TEMPERATURE:
GAS FROM EACH PRESSURE DECREMENT OF THE DIFFERENTIAL LIBERATION WAS ANALYZED IN THE SAME MANNER AS DESCRIBED IN 2), (FLASH LIBERATION). DIFFERENTIAL LIQUID CHANGES WERE NOTED.
- 6) VISCOSITY OF RESERVOIR FLUID WAS MEASURED BY MR. J. R. COMEAU OF WEATHERLY LABORATORIES. A DESCRIPTION OF MR. COMEAU'S EXPERIMENTAL PROCEDURES IS GIVEN BELOW:
GEOTHERMAL WATER VISCOSITIES WERE MEASURED USING A RUSKA ROLLING BALL VISCOMETER WITH AN ELECTRONIC DETECTION SYSTEM TO PREVENT ELECTROLYSIS. THE DETECTION SYSTEM CONSISTS OF A SENSITIVE AUDIO AMPLIFIER WITH POSITIVE FEEDBACK ADJUSTED JUST BELOW OSCILLATION. THE BALL IS HELD BY AN ELECTROMAGNET. WHEN CURRENT TO THE MAGNET IS TURNED OFF, A PULSE IS PRODUCED WHICH STARTS A DIGITAL TIMER. WHEN THE BALL STRIKES THE CONTACT AT THE OTHER END OF THE VISCOMETER THE ELECTRICAL DISTURBANCE PRODUCED IS GENERALLY AMPLIFIED AND TURNS THE TIMER OFF. TIMES WERE MEASURED TO 1/100TH OF A SECOND AND AVERAGED. THE VISCOMETER WAS CALIBRATED AT EACH OF TWO ANGLES USING DISTILLED WATER AT SEVERAL TEMPERATURES. t p VERSUS u WERE PLOTTED TO OBTAIN CALIBRATION.

t = ROLL TIME, (SECONDS)

p = DENSITY DIFFERENCE BETWEEN BALL AND RESERVOIR FLUID, (gm./ml.)

u = VISCOSITY, (CENTIPOISE)

THE VISCOMETER WAS CHARGED WITH RESERVOIR FLUID AND RUN AT 293°F AT 1000 LB. INTERVALS. THE VISCOSITIES HAD A PROBABLE ERROR OF ± 0.01 CENTIPOISE.

NOTE: ALL DATA FOR PRESSURES GREATER THAN 11,000 PSI WERE OBTAINED BY EXTRAPOLATION.

FIELD DATA FOR WEATHERLY LABORATORY INVESTIGATION

WELL RECORD

COMPANY
WELL
FIELD
PARISH AND STATE

MAGMA GULF-TECHNADRIL
MG-T/DOE AMOCO FEE NO. 1
SWEET LAKE
CAMERON, LOUISIANA

FIELD CHARACTERISTICS

FORMATION NAME
SAND NAME AND DESIGNATION
DATE COMPLETED
ORIGINAL RESERVOIR PRESSURE

ZONE 3

WELL CHARACTERISTICS

ORIGINAL PRODUCED GAS-LIQUID RATIO

PERFORATIONS	15,245-15,285	FT.
ELEVATIONS		
TOTAL DEPTH		
LAST RESERVOIR PRESSURE	11,887	PSIA
RESERVOIR TEMPERATURE	293	DEGREES F

SAMPLING CONDITIONS

DATE SAMPLED	(72 HOUR TEST)	11-25-83	1700 HOURS
TUBING PRESSURE, FLOWING		3460	PSIG
PRIMARY SEPARATOR TEMPERATURE	168°F (SEP.)	132	DEGREES F, (METER RUN)
PRIMARY SEPARATOR PRESSURE		500	PSIG
PRIMARY SEPARATOR GAS RATE	(WET GAS)	41,959	SCF/DAY
SEPARATOR LIQUID RATE		2,100	BBL./DAY
GAS-LIQUID RATIO (SEPARATOR)		19.98	SCF/BBL. SEP. WATER
SHRINKAGE FACTOR (VOL.S.T.WATER @ 60°F/VOL.SEP.WATER)		0.9674	
GAS-LIQUID RATIO (STOCK TANK)		20.65	SCF/BBL. S.T. WATER
PRESSURE BASE		15.025	PSIA @ 60 DEGREES F

NOTE: FOR DRY GAS, 19.94 SCF/BBL. SEP. WATER @ SEP. CONDITIONS.
20.61 SCF/BBL. S.T. WATER @ 60°F.

MAGMA GULF-TECHNADRIL
 MG-T/DOE AMOCO FEE NO. 1 WELL
 SAND ZONE NO. 3
 SWEET LAKE FIELD

CALCULATION OF GAS RATE, 11-25-83 TEST
 (Factors from GPSA Engineering Data Book)

$\sqrt{H_w P_f}$ =	115.7152	H_w =	26 "H ₂ O ,	P_f =	515 psia
F_b =	12.7121	D =	2.626 " ,	d =	0.250 "
F_{pb} =	0.9804		15.025 psia		
F_r =	1.0008	b =	0.0979		
Y_2 =	1.0003	H_w/P_f =	0.050 ,	d/D =	0.095
F_g =	1.2591	Gravity =	0.6308 ,	F_g =	$\sqrt{1 / 0.6308}$
F_{tf} =	0.9372	Temp. =	132 degrees F ,	F_{tf} =	$\sqrt{520 / 592}$
F_{pv} =	1.0262	$p_{Tr'}$ =	1.678 ,	$p_{Pr'}$ =	0.762
		Z =	0.9496 ,	F_{pv} =	$\sqrt{1 / Z}$
		EPSILON =	8		

$$Q = \sqrt{H_w P_f} \times F_b \times F_{pb} \times F_r \times Y_2 \times F_g \times F_{tf} \times F_{pv} \times 24$$

$$Q = 41.959 \text{ MCF/day @ 15.025 PSIA @ 60 Degrees F}$$

MAGA GULF-TECHNADRIL
 MG-T/DOE AMOCO FEE NO. 1 WELL
 SAND ZONE NO. 3
 SWEET LAKE FIELD

RESERVOIR FLUID SUMMARY

Reservoir Temperature, Degrees F	293
Saturation Pressure at 293 Degrees, Psia	8800
Compressibility of Reservoir Oil at 293 Degrees F	
Vol. per Vol. per Psi x 10 ⁶	
From 8800 Psia to 10000 Psia	2.61
From 10000 Psia to 11000 Psia	2.59
From 11000 Psia to 11887 Psia	2.57
	<u>DIFF. LIB.</u>
Saturated Oil at 8800 Psia, 293 Degrees F	
Density, Gms. per Ml.	1.0512
Lbs. per Bbl.	368.4
Specific Volume, Cu.Ft. per Lb.	0.015238
Viscosity, Centipoise	0.323
Formation Volume Factor, Bbls. per Bbl.	
"Equivalent Stock Tank Oil" at 60 Degrees F	1.0565 * , 1.0576
Solution Gas-Oil Ratio, Cu.Ft. per Bbl.	23.31 * , 25.39 WET
"Equivalent Stock Tank Oil" at 60 Degrees F	23.22 * , 24.50 DRY
Reservoir Oil at 11887 Psia 293 Degrees F	
Density, Gms. per Ml.	1.0597
Lbs. per Bbl.	371.4
Specific Volume, Cu.Ft. per Lb.	0.015116
Viscosity, Centipoise	0.342
Formation Volume Factor, Bbl. per Bbl.	
"Equivalent Stock Tank Oil" at 60 Degrees F	1.0480 * , 1.0491

NOTE: REFERENCES TO 'OIL' ABOVE SHOULD READ 'WATER'.

* BASED ON SEPARATOR WATER FLASH.

MAGMA GULF-TECHNADRIL
MG-T/DOE AMOCO FEE NO. 1 WELL
SAND ZONE NO. 3
SWEET LAKE FIELD

COMPOSITE LABORATORY DATA @ 293 DEGREES F

RECOMBINATION (1) 18.00 SCF SEP. GAS @ 15.025 PSIA & 60°F/BBL. SEP. WATER @ SEP. CONDITIONS.

PRESSURE VOLUME RELATIONS							
PRESSURE	RELATIVE VOLUME	SPECIFIC VOLUME	LIQUID VOLUME	FORMATION VOLUME FACTOR	RELATIVE OIL VOLUME	OIL DENSITY	SOLUTION GAS-OIL RATIO
PSIA	V/Vsat Bt	Cu. Ft./Lb.	PERCENT	Bo **		GM/CC	PER BARREL STOCK TANK OIL AT 60°F DRY ** WET **
11887 RES.	0.9894	0.015117		1.0476			21.17 21.27
11000	0.9916	0.015151		1.0499			21.17 21.27
10000	0.9942	0.015190		1.0527			21.17 21.27
9000	0.9967	0.015229		1.0553			21.17 21.27
8000	0.9994	0.015270		1.0582			21.17 21.27
7760 B.P.	1.0000	0.015279	100.00	1.0588			21.17 21.27

7700	1.0003	0.015284	BUBBLE
7500	1.0008	0.015291	BUBBLE
7000	1.0023	0.015314	99.99
6000	1.0053	0.015360	99.97
5000	1.0085	0.015409	99.92
4000	1.0122	0.015465	99.84
3000	1.0183	0.015559	99.51
2000	1.0303	0.015742	98.61
1000	1.0699	0.016347	95.22
501	1.1671	0.017832	87.52
251	1.3755	0.021016	74.22
128	1.8880	0.028847	54.09

NOMENCLATURE:

V/Vsat. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

Bo IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 15.025 PSIA AND 60

DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: ** BASED ON SEPARATOR WATER FLASH.
REF. TO 'OIL' ABOVE SHOULD READ 'WATER'.

LAB. NO. N2171-10510

PAGE 7 OF 25

MAGMA GULF-TECHNADRIL
MG-T/DOE AMOCO FEE NO. 1 WELL
SAND ZONE NO. 3
SWEET LAKE FIELD

COMPOSITE LABORATORY DATA @ 293 DEGREES F

RECOMBINATION (2) 15.00 SCF SEP. GAS @ 15.025 PSIA & 60°F/BBL. SEP. WATER @ SEP. CONDITIONS.

PRESSURE VOLUME RELATIONS							
PRESSURE	RELATIVE VOLUME	SPECIFIC VOLUME	LIQUID VOLUME PERCENT	FORMATION VOLUME FACTOR	RELATIVE OIL VOLUME	OIL DENSITY	SOLUTION GAS-OIL RATIO
PSIA	V/V _{sat} Bt	Cu.Ft./Lb.		B _o **		GM/CC	PER BARREL STOCK TANK OIL AT 60°F DRY ** WET **
11887 RES.	0.9854	0.015115		1.0465			18.08 18.17
11000	0.9876	0.015149		1.0498			18.08 18.17
10000	0.9902	0.015189		1.0516			18.08 18.17
9000	0.9927	0.015227		1.0542			18.08 18.17
8000	0.9953	0.015267		1.0570			18.08 18.17
7000	0.9980	0.015308		1.0599			18.08 18.17
6240 B.P.	1.0000	0.015339	100.00	1.0620			18.08 18.17
6200	1.0001	0.015341	BUBBLE				
6000	1.0008	0.015351	99.99				
5500	1.0022	0.015373	99.98				
5000	1.0038	0.015397	99.96				
4000	1.0073	0.015451	99.89				
3000	1.0128	0.015535	99.62				
2000	1.0235	0.015699	98.85				
1000	1.0574	0.016219	95.94				
500	1.1369	0.017439	89.35				
250	1.3100	0.020094	77.60				
50	6.2437	0.095772	16.29				

NOMENCLATURE:

V/V_{sat}. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

B_o IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 15.025 PSIA AND 60 DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: ** BASED ON SEPARATOR WATER FLASH.
REF. TO 'OIL' ABOVE SHOULD READ 'WATER'.

MAGMA GULF-TECHNADRIL
MG-T/DOE AMOCO FEE NO. 1 WELL
SAND ZONE NO. 3
SWEET LAKE FIELD

COMPOSITE LABORATORY DATA @ 293 DEGREES F

RECOMBINATION (3) 12.00 SCF SEP. GAS @ 15.025 PSIA & 60°F/BBL. SEP. WATER @ SEP. CONDITIONS.

	PRESSURE VOLUME RELATIONS								
PRESSURE	RELATIVE	SPECIFIC	LIQUID	FORMATION	RELATIVE	OIL	SOLUTION	GAS-OIL RATIO	
	VOLUME	VOLUME		VOLUME					
PSIA	V/Vsat	Cu.Ft./Lb.	VOLUME	FACTOR	OIL	DENSITY	PER BARREL	STOCK TANK OIL	
	Bt		PERCENT	Bo		GM/CC	AT 60°F		
				**	VOLUME		DRY **	WET **	
11887 RES.	0.9819	0.015108		1.0455			14.98	15.06	
11000	0.9841	0.015142		1.0479			14.98	15.06	
10000	0.9866	0.015181		1.0505			14.98	15.06	
9000	0.9891	0.015219		1.0532			14.98	15.06	
8000	0.9917	0.015259		1.0560			14.98	15.06	
7000	0.9942	0.015298		1.0586			14.98	15.06	
6000	0.9969	0.015339		1.0615			14.98	15.06	
5000	0.9996	0.015381		1.0644			14.98	15.06	
4850 B.P.	1.0000	0.015387	100.00	1.0648			14.98	15.06	
4900	1.0002	0.015390	BUBBLE						
4500	1.0011	0.015404	99.99						
3990	1.0028	0.015430	99.96						
3002	1.0076	0.015504	99.76						
2004	1.0166	0.015642	99.14						
1000	1.0440	0.016064	96.81						
500	1.1049	0.017001	91.59						
224	1.2967	0.019952	78.12						
133	1.6369	0.025187	63.23						

NOMENCLATURE:

V/V_{sat}. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

B_o IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 15.025 PSIA AND 60

DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: ** BASED ON SEPARATOR WATER FLASH.
REF. TO 'OIL' ABOVE SHOULD READ 'WATER'.

MAGMA GULF-TECHNADRIL
 MG-T/DOE AMOCO FEE NO. 1 WELL
 SAND ZONE NO. 3
 SWEET LAKE FIELD

COMPOSITE LABORATORY DATA @ 293 DEGREES F

RECOMBINATION (4) 9.00 SCF SEP. GAS @ 15.025 PSIA & 60°F/BBL. SEP. WATER @ SEP. CONDITIONS.

PRESSURE VOLUME RELATIONS								
PRESSURE	RELATIVE	SPECIFIC	LIQUID	FORMATION	RELATIVE	OIL	SOLUTION	
	VOLUME	VOLUME		VOLUME		DENSITY	GAS-OIL RATIO	
PSIA	V/Vsat	Cu.Ft./Lb.	VOLUME	FACTOR	OIL	GM/CC	PER BARREL	
	Bt		PERCENT	Bo	VOLUME		STOCK TANK OIL	
				**			AT 60°F	
							DRY **	WET **
11887 RES.	0.9784	0.015098		1.0442			11.89	11.96
11000	0.9806	0.015132		1.0466			11.89	11.96
10000	0.9831	0.015170		1.0493			11.89	11.96
9000	0.9857	0.015210		1.0520			11.89	11.96
8000	0.9882	0.015249		1.0547			11.89	11.96
7000	0.9908	0.015289		1.0575			11.89	11.96
6000	0.9934	0.015329		1.0603			11.89	11.96
5000	0.9960	0.015369		1.0630			11.89	11.96
4000	0.9987	0.015411		1.0659			11.89	11.96
3520 B.P.	1.0000	0.015431	100.00	1.0673			11.89	11.96
3500	1.0001	0.015433	BUBBLE					
3000	1.0019	0.015460	99.96					
2500	1.0045	0.015500	98.83					
2000	1.0088	0.015567	99.54					
1500	1.0159	0.015676	98.98					
1000	1.0303	0.015899	97.73					
502	1.0782	1.016638	93.19					
231	1.2207	0.018837	82.65					

NOMENCLATURE:

V/Vsat. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

Bo IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 15.025 PSIA AND 60 DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: ** BASED ON SEPARATOR WATER FLASH.
 REF. TO 'OIL' ABOVE SHOULD READ 'WATER'.

MAGMA GULF-TECHNADRIL
MG-T/DOE AMOCO FEE NO. 1 WELL
SAND ZONE NO. 3
SWEET LAKE FIELD

COMPOSITE LABORATORY DATA @ 293 DEGREES F

RECOMBINATION (5) 19.98 SCF SEP. GAS @ 15.025 PSIA & 60°F/BBL. SEP. WATER @ SEP. COND.- PRODUCED GWR

PRESSURE VOLUME RELATIONS			DIFFERENTIAL LIBERATION					
PRESSURE	RELATIVE VOLUME	SPECIFIC VOLUME	LIQUID VOLUME	FORMATION VOLUME FACTOR	FORMATION VOLUME FACTOR	OIL VISCOSITY	SOLUTION GAS-OIL RATIO	
PSIA	V/V _{sat} Bt	Cu.Ft./Lb.	PERCENT	B _o **	B _o	CENTIPOISE	PER BARREL STOCK TANK OIL AT 60°F	
							DRY	WET
11887 RES.	0.9920	0.015116		1.0480	1.0491	0.342	24.50	25.39
11000	0.9943	0.015151		1.0505	1.0516	0.336	24.50	25.39
10000	0.9969	0.015191		1.0532	1.0543	0.330	24.50	25.39
9000	0.9995	0.015230		1.0560	1.0571		24.50	25.39
8800 B.P.	1.0000	0.015238	100.00	1.0565	1.0576	0.323	24.50	25.39
8700	1.0003	0.015243	BUBBLE					
8500	1.0009	0.015252	BUBBLE					
8000	1.0023	0.015273	BUBBLE					
7000	1.0053	0.015319	99.98		1.0622	0.315	22.32	23.19
6000	1.0083	0.015364	99.95			0.312		
5000	1.0118	0.015418	99.89			0.310		
4000	1.0153	0.015471	99.81		1.0690	0.315	17.00	17.77
3000	1.0219	0.015572	99.44			0.32		
2000	1.0353	0.015776	98.42		1.0728	0.33	11.49	12.09
1000	1.0779	0.016425	94.78			0.34		
500	1.1800	0.017981	86.70					
253	1.4050	0.021409	72.85					
15								
15*					1.0000		0.00	0.00

NOMENCLATURE:

V/V_{sat}. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

B_o IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 15.025 PSIA AND 60 DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: • INDICATES VALUE MEASURED @ 60°F

** BASED ON SEPARATOR WATER FLASH

ALSO BASED ON SEP. WATER FLASH:

SOLUTION GAS IN RES. FLD. IS

23.22 SCF DRY GAS/BBL. S.T. WATER @ 60°F

23.31 SCF WET GAS/BBL. S.T. WATER @ 60°F

REF. TO "OIL" ABOVE SHOULD READ "WATER"

LAB. NO. N2171-10510

PAGE 11 OF 25

MAGMA GULF-TECHNADRIL
MG-T/DOE AMOCO FEE NO. 1 WELL
SAND ZONE NO. 3
SWEET LAKE FIELD

OBSERVED SATURATION PRESSURES FROM
STEPWISE RECOMBINATION @ 293 F

GAS-LIQUID RATIO (SCF. 1ST STG. GAS) <u>(BBL. 1ST STG. LIQ.)</u>	SATURATION PRESSURE (PSIA)
19.98 (PRODUCED)	8800 BUBBLE POINT
18.00	7760 BUBBLE POINT
15.00	6240 BUBBLE POINT
12.00	4850 BUBBLE POINT
9.00	3520 BUBBLE POINT

MAGMA GULF-TECHNADRIL
MG-T/DOE AMOCO FEE NO. 1 WELL
SAND ZONE NO. 3
SWEET LAKE FIELD

SEPARATOR WATER FLASH TO 0 PSIG & 67°F

SOLUTION GAS-WATER RATIO, DRY = 2.60

, WET = 2.66

SCF GAS @ 15.025 PSIA & 60°F

BBL. WATER @ 0 PSIG & 60 °F

SHRINKAGE

= 0.9674

VOL. S.T. WATER @ 60°F

VOL. SEP. H2O @ 500 PSIG & 168°F

STOCK TANK WATER DENSITY

= 1.1132

Gm/Ml. @ 60°F

GAS GRAVITY

, DRY = 0.9432

(SEE ANALYSIS ON PAGE 15)

, WET = 0.9339

PRODUCED NOVEMBER 25, 1983:

GWR = 20.61 + 2.60 = 23.21

SCF TOTAL DRY GAS @ 15.025 PSIA & 60°F

BBL. STOCK TANK WATER @ 60°F

GWR = 20.65 + 2.66 = 23.31

SCF TOTAL WET GAS @ 15.025 PSIA & 60°F

BBL. STOCK TANK WATER @ 60°F

MAGMA GULF-TECHNADRIL
 MG-T/DOE AMOCO FEE NO. 1 WELL
 SAND ZONE NO. 3
 SWEET LAKE FIELD

SEPARATOR GAS SAMPLED:
 NOVEMBER 25, 1983
 500 PSIG & 132°F

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	
	<hr/>	
WATER		0.18 ± .02
CARBON DIOXIDE	5.95	5.94
NITROGEN	0.22	0.22
METHANE	91.55	91.38
ETHANE	1.77	1.77
PROPANE	0.29	0.29
ISO-BUTANE	0.02	0.02
N-BUTANE	0.05	0.05
ISO-PENTANE	0.00	0.00
N-PENTANE	0.00	0.00
HEXANES	0.00	0.00
HEPTANES PLUS	0.15	0.15
	<hr/>	<hr/>
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.6308	0.6308

NOTE: WATER VAPOR MEASURED ON SITE, AVERAGE 4 RUNS.

H2S ON SITE = 4 PPM
 CO2 ON SITE = 6 MOLE %

MAGA GULF-TECHNADRIL
 MG-T/DOE AMOCO FEE NO. 1 WELL
 SAND ZONE NO. 3
 SWEET LAKE FIELD

SOLUTION GAS FROM
 SEPARATOR WATER FLASH
 @ 0 PSIG & 67°F
 (CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	

WATER		2.22
CARBON DIOXIDE	39.25	38.38
NITROGEN	-----	-----
METHANE	59.63	58.30
ETHANE	0.95	0.93
PROPANE	0.08	0.08
ISO-BUTANE	0.00	0.00
N-BUTANE	0.00	0.00
ISO-PENTANE	0.00	0.00
N-PENTANE	0.00	0.00
HEXANES	0.00	0.00
HEPTANES PLUS	0.09	0.09
	-----	-----
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.9432	0.9339

MAGMA GULF-TECHNADRIL
 MG-T/DOE AMOCO FEE NO. 1 WELL
 SAND ZONE NO. 3
 SWEET LAKE FIELD

SOLUTION GAS FROM
 7000 PSIA SAMPLE -
 DIFFERENTIAL LIBERATION
 (CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	

WATER		1
CARBON DIOXIDE	4.40	4.36
NITROGEN	----	----
METHANE	91.68	90.76
ETHANE	2.74	2.71
PROPANE	0.74	0.73
ISO-BUTANE	0.03	0.03
N-BUTANE	0.10	0.10
ISO-PENTANE	0.00	0.00
N-PENTANE	0.00	0.00
HEXANES	0.00	0.00
HEPTANES PLUS	0.31	0.31
	-----	-----
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.6292	0.6291

GAS DEVIATION FACTOR (Z) = 1.161 @ 7000 PSIA & 293°F

BBLS. GAS IN RES./MMSCF (Bg) = 643 @ 7000 PSIA & 293°F

MAGMA GULF-TECHNADRIL
 MG-T/DOE AMOCO FEE NO. 1 WELL
 SAND ZONE NO. 3
 SWEET LAKE FIELD

SOLUTION GAS FROM
 4000 PSIA SAMPLE -
 DIFFERENTIAL LIBERATION
 (CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	
	<hr/>	
WATER		2
CARBON DIOXIDE	2.27	2.22
NITROGEN	----	----
METHANE	94.73	92.84
ETHANE	2.30	2.25
PROPANE	0.44	0.43
ISO-BUTANE	0.01	0.01
N-BUTANE	0.04	0.04
ISO-PENTANE	0.00	0.00
N-PENTANE	0.00	0.00
HEXANES	0.00	0.00
HEPTANES PLUS	0.21	0.21
	<hr/>	<hr/>
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.5990	0.5995

GAS DEVIATION FACTOR (Z) = 1.000 @ 4000 PSIA & 293°F

BBLs. GAS IN RES./MMSCF (Bg) = 969 @ 4000 PSIA & 293°F

MAGMA GULF-TECHNADRIL
 MG-T/DOE AMOCO FEE NO. 1 WELL
 SAND ZONE NO. 3
 SWEET LAKE FIELD

SOLUTION GAS FROM
 2000 PSIA SAMPLE -
 DIFFERENTIAL LIBERATION
 (CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	
	<hr/>	
WATER		3
CARBON DIOXIDE	3.13	3.04
NITROGEN	----	----
METHANE	94.69	91.84
ETHANE	1.76	1.71
PROPANE	0.25	0.24
ISO-BUTANE	0.01	0.01
N-BUTANE	0.02	0.02
ISO-PENTANE	0.00	0.00
N-PENTANE	0.00	0.00
HEXANES	0.00	0.00
HEPTANES PLUS	0.14	0.14
	<hr/>	
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.6002	0.6009

GAS DEVIATION FACTOR (Z) = 0.948 @ 2000 PSIA & 293°F

BBLS. GAS IN RES./MMSCF (Bg) = 1837 @ 2000 PSIA & 293°F

MAGMA GULF-TECHNADRIL
 MG-T/DOE AMOCO FEE NO. 1 WELL
 SAND ZONE NO. 3
 SWEET LAKE FIELD

SOLUTION GAS FROM
 15 PSIA SAMPLE -
 DIFFERENTIAL LIBERATION
 (CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	

WATER		5
CARBON DIOXIDE	18.01	17.11
NITROGEN	----	----
METHANE	80.75	76.70
ETHANE	1.05	1.00
PROPANE	0.06	0.06
ISO-BUTANE	0.02	0.02
N-BUTANE	0.04	0.04
ISO-PENTANE	0.00	0.00
N-PENTANE	0.00	0.00
HEXANES	0.00	0.00
HEPTANES PLUS	0.07	0.07
	-----	-----
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.7367	0.7310

GAS DEVIATION FACTOR (Z) = 1.000 @ 15 PSIA & 293°F

BBLS. GAS IN RES./MMSCF (Bg) = 257,920 @ 15.025 PSIA & 293°F

Company Magma Gulf-Technadril
Reservoir Sand Zone No. 3

Well MG-T/DOE Amoco Fee No. 1
Field Sweet Lake

FIG. 1: Effect of Gas-Water Ratio on Bubble Point Pressure @ 293°F

Lab. No. N2171-10510

Page 20 of 25

Company Magma Gulf-Technadril
Reservoir Sand Zone No. 3

Well MG-T/DOE Amoco Fee No. 1
Field Sweet Lake

FIGURE 2: Liq. Vol. % vs Pressure-Res. Water @ 293°F GWR = 19.98

Lab. No. N2171-10510

Page 21 of 25

Company Magma Gulf-Technadril
 Reservoir Sand Zone No. 3

Well MG-T/DOE Amoco Fee No. 1
 Field Sweet Lake

FIGURE 3: Diff. Liberation of Reservoir Water @ 293°F GWR = 19.98

Lab. No. N2171-10510

Page 22 of 25

Company Magma Gulf-Technadrill Well MG-T/DOE Amoco Fee No. 1
 Reservoir Sand Zone No. 3 Field Sweet Lake

FIG. 4: FVF & Solution GWR of Saturated Water (Based on sep. water flash) @ 293°F

Lab. No. N2171-10510

Page 23 of 25

Company Magma Gulf-Technadril
Reservoir Sand Zone No. 3

Well MG-T/DOE Amoco Fee No. 1
Field Sweet Lake

FIGURE 5: Specific Volume of Saturated (Bubble Point) Water @ 293°F

Lab. No. N2171-10510

Page 24 of 25

Company Magma Gulf-Technadril Well MG-T/DOE Amoco Fee No. 1
Reservoir Sand Zone No. 3 Field Sweet Lake

FIGURE 6: Viscosity of Reservoir Water @ 293°F GWR = 19.98

Lab. No. N2171-10510

Page 25 of 25

Appendix J

Gas Analysis as a Function of Separator Pressure

WEATHERLY LABORATORIES, INC.

J. E. WEATHERLY, JR.
CHAIRMAN

223 GEORGETTE LAFAYETTE, LA 70506
PHONE (318) 232-4877

JOHN D. NEAL
PRESIDENT
BRYAN SONNIER
VICE PRESIDENT

DECEMBER 8, 1983

MAGMA GULF-TECHNADRIL
3 NORTHPOINT DRIVE
SUITE 200
HOUSTON, TX 77060

ATTENTION: MR. LARRY DURRETT

RE: AMOCO FEE WELL NO. 1
SWEET LAKE PROSPECT FIELD
SAND ZONE NO. 3
CAMERON PARISH, LOUISIANA

RESERVOIR PRESSURE (PSIA)	10.720	10.550	10.400	10.118	9.030	8.780	8.554
DATE	11-23-83	11-24-83	11-25-83	11-28-83	11-29-83	11-30-83	11-30-83
TIME	1700 HRS.	1500 HRS.	1700 HRS.	1500 HRS.	1400 HRS.	1515 HRS.	1100 HRS.
PRESSURE	500 PSIG	495 PSIG	500 PSIG	490 PSIG	495 PSIG	550 PSIG	460 PSIG
TEMPERATURE	128°F	128°F	132°F	132°F	157°F	190°F	190°F
CARBON DIOXIDE	5.76	5.90	5.95	6.18	7.51	6.88	7.19
NITROGEN	0.22	0.21	0.22	0.20	0.19	0.23	0.22
METHANE	91.77	91.62	91.55	91.24	89.92	90.59	90.53
ETHANE	1.81	1.79	1.77	1.75	1.77	1.76	1.63
PROPANE	0.31	0.30	0.29	0.28	0.29	0.29	0.21
ISO-BUTANE	0.02	0.02	0.02	0.01	0.02	0.02	0.00
NORMAL-BUTANE	0.05	0.04	0.05	0.03	0.03	0.03	0.02
ISO-PENTANE	0.00	0.00	0.00	0.00	0.01	0.00	0.00
NORMAL PENTANE	0.00	0.00	0.00	0.01	0.01	0.01	0.00
HEXANES	0.00	0.00	0.00	0.03	0.03	0.04	0.02
HEPTANES PLUS	0.06	0.12	0.15	0.27	0.22	0.15	0.18
SPECIFIC GRAVITY	0.6263	0.6292	0.6308	0.6375	0.6491	0.6407	0.6419

RESERVOIR PRESSURE (PSIA)	8.310	8.024	7.824	7.625	7.614	7.603
DATE	11-30-83	12-01-83	12-01-83	12-02-83	12-05-83	12-02-83
TIME	1500 HRS.	0015 HRS.	0900 HRS.	0930 HRS.	1115 HRS.	1845 HRS.
PRESSURE	530 PSIG	500 PSIG	500 PSIG	500 PSIG	500 PSIG	500 PSIG
TEMPERATURE	197°F	187°F	190°F	186°F	178°F	185°F
CARBON DIOXIDE	7.05	7.23	7.36	7.02	7.29	7.56
NITROGEN	0.22	0.26	0.21	0.20	0.28	0.20
METHANE	90.68	90.51	90.49	90.79	90.53	90.05
ETHANE	1.62	1.61	1.56	1.54	1.50	1.64
PROPANE	0.23	0.21	0.20	0.19	0.20	0.20
ISO-BUTANE	0.01	0.01	0.00	0.01	0.01	0.01
NORMAL-BUTANE	0.02	0.01	0.02	0.01	0.02	0.03
ISO-PENTANE	0.00	0.00	0.00	0.00	0.00	0.01
NORMAL PENTANE	0.01	0.00	0.01	0.02	0.00	0.02
HEXANES	0.00	0.01	0.00	0.01	0.01	0.04
HEPTANES PLUS	0.16	0.15	0.15	0.21	0.16	0.24
SPECIFIC GRAVITY	0.6399	0.6414	0.6419	0.6411	0.6415	0.6486

RESPECTFULLY SUBMITTED,

Karen Lestelle
KAREN LESTELLE

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 10,720 PSIA
 SAMPLED: 11-23-83 @ 1700 HRS.
 500 PSIG & 128 DEGREES F
 BY: WEATHERLY LABORATORIES

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	5.76	
NITROGEN	0.22	
METHANE	91.77	
ETHANE	1.81	0.492
PROPANE	0.31	0.086
ISO-BUTANE	0.02	0.007
N-BUTANE	0.05	0.015
ISO-PENTANE	0.00	0.002
N-PENTANE	0.00	0.002
HEXANES	0.00	0.000
HEPTANES PLUS	0.06	0.031
TOTALS	100.00	0.635

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6263 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 996.3 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 978.8 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9979

ON-SITE DRAGER MEASUREMENTS ON 11-23-83 AT 1518 HOURS:

CARBON DIOXIDE = 5.85 MOL %
 HYDROGEN SULFIDE = 6.2 PPM

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 10,550 PSIA
 SAMPLED: 11-24-83 @ 1500 HOURS
 495 PSIG & 137 DEGREES F
 BY: TECHNADRIL PERSONNEL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	5.90	
NITROGEN	0.21	
METHANE	91.62	
ETHANE	1.79	0.488
PROPANE	0.30	0.083
ISO-BUTANE	0.02	0.007
N-BUTANE	0.04	0.013
ISO-PENTANE	0.00	0.002
N-PENTANE	0.00	0.002
HEXANES	0.00	0.000
HEPTANES PLUS	0.12	0.059
TOTALS	100.00	0.654

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6292 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 997.3 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 979.9 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 10,400 PSIA
 SAMPLED: 11-25-83 @ 1500 HOURS
 500 PSIG & 132 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	5.95	
NITROGEN	0.22	
METHANE	91.55	
ETHANE	1.77	0.484
PROPANE	0.29	0.082
ISO-BUTANE	0.02	0.007
N-BUTANE	0.05	0.015
ISO-PENTANE	0.00	0.002
N-PENTANE	0.00	0.002
HEXANES	0.00	0.000
HEPTANES PLUS	0.15	0.076
TOTALS	100.00	0.668

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6308 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 998.6 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 981.1 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

ON-SITE DRAGER MEASUREMENTS:

CARBON DIOXIDE = 6 MOL. %
 HYDROGEN SULFIDE = 4 PPM

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 10,118 PSIA
 SAMPLED: 11-28-83 @ 1500 HOURS
 490 PSIG & 132 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSES OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	6.18	
NITROGEN	0.20	
METHANE	91.24	
ETHANE	1.75	0.478
PROPANE	0.28	0.079
ISO-BUTANE	0.01	0.005
N-BUTANE	0.03	0.010
ISO-PENTANE	0.00	0.000
N-PENTANE	0.01	0.002
HEXANES	0.03	0.013
HEPTANES PLUS	0.27	0.142
	100.00	0.729

CALC. GAS SPECIFIC GRAVITY (AIR = 1.00) 0.6375 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 1003.6 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 986.0 WATER SAT
 SEP. GAS COMPRESS. (@ 1 ATM. & 60 F) = 0.9978

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 9,030 PSIA
 SAMPLED: 11-29-83 @ 1400 HOURS
 495 PSIG & 157 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	7.51	
NITROGEN	0.19	
METHANE	89.92	
ETHANE	1.77	0.484
PROPANE	0.29	0.080
ISO-BUTANE	0.02	0.006
N-BUTANE	0.03	0.009
ISO-PENTANE	0.01	0.004
N-PENTANE	0.01	0.002
HEXANES	0.03	0.014
HEPTANES PLUS	0.22	0.118
TOTALS	100.00	0.717

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6491 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 988.0 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 970.7 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 8,780 PSIA
 SAMPLED: 11-29-83 @ 1515 HOURS
 550 PSIG & 190 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	6.88	
NITROGEN	0.23	
METHANE	90.59	
ETHANE	1.76	0.480
PROPANE	0.29	0.082
ISO-BUTANE	0.02	0.007
N-BUTANE	0.03	0.009
ISO-PENTANE	0.00	0.000
N-PENTANE	0.01	0.005
HEXANES	0.04	0.016
HEPTANES PLUS	0.15	0.076
TOTALS	100.00	0.675

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6407 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 990.2 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 972.9 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 8,554 PSIA
 SAMPLED: 11-30-83 @ 1100 HOURS
 460 PSIG & 190 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	7.19	
NITROGEN	0.22	
METHANE	90.53	
ETHANE	1.63	0.444
PROPANE	0.21	0.059
ISO-BUTANE	0.00	0.000
N-BUTANE	0.02	0.005
ISO-PENTANE	0.00	0.000
N-PENTANE	0.00	0.000
HEXANES	0.02	0.010
HEPTANES PLUS	0.18	0.092
TOTALS	100.00	0.610

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6419 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 984.4 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 967.1 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 8,310 PSIA
 SAMPLED: 11-30-83 @ 1500 HOURS
 530 PSIG & 197 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	7.05	
NITROGEN	0.22	
METHANE	90.68	
ETHANE	1.62	0.443
PROPANE	0.23	0.064
ISO-BUTANE	0.01	0.003
N-BUTANE	0.02	0.006
ISO-PENTANE	0.00	0.000
N-PENTANE	0.01	0.004
HEXANES	0.00	0.000
HEPTANES PLUS	0.16	0.081
TOTALS	100.00	0.601

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6399 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 984.8 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 967.5 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 8,024 PSIA
 SAMPLED: 12-01-83 @ 0015 HOURS
 500 PSIG & 187 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	7.23	
NITROGEN	0.26	
METHANE	90.51	
ETHANE	1.61	0.438
PROPANE	0.21	0.058
ISO-BUTANE	0.01	0.004
N-BUTANE	0.01	0.004
ISO-PENTANE	0.00	0.000
N-PENTANE	0.00	0.000
HEXANES	0.01	0.005
HEPTANES PLUS	0.15	0.076
TOTALS	100.00	0.585

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6414 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 981.6 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 964.4 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 7,824 PSIA
 SAMPLED: 12-01-83 @ 0915 HOURS
 500 PSIG & 190 DEGREES F
 BY: WEATHERLY LABORATORIES

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	7.36	
NITROGEN	0.21	
METHANE	90.49	
ETHANE	1.56	0.425
PROPANE	0.20	0.056
ISO-BUTANE	0.00	0.000
N-BUTANE	0.02	0.005
ISO-PENTANE	0.00	0.000
N-PENTANE	0.01	0.002
HEXANES	0.00	0.002
HEPTANES PLUS	0.15	0.078
TOTALS	100.00	0.568

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6419 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 980.1 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 963.0 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

ON-SITE DRAGER MEASUREMENTS:

CARBON DIOXIDE = 6 MOL. %
 HYDROGEN SULFIDE = 13 PPM

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 7,625 PSIA
 SAMPLED: 12-02-83 @ 0915 HOURS
 500 PSIG & 186 DEGREES F
 BY: WEATHERLY LABORATORIES

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	7.02	
NITROGEN	0.20	
METHANE	90.79	
ETHANE	1.54	0.421
PROPANE	0.19	0.054
ISO-BUTANE	0.01	0.003
N-BUTANE	0.01	0.003
ISO-PENTANE	0.00	0.000
N-PENTANE	0.02	0.006
HEXANES	0.01	0.005
HEPTANES PLUS	0.21	0.110
TOTALS	100.00	0.602

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6411 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 987.4 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 970.2 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

ON-SITE DRAGER MEASUREMENTS:

CARBON DIOXIDE = 5 MOL. %
 HYDROGEN SULFIDE = 14 PPM

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 7,614 PSIA
 SAMPLED: 12-05-83 @ 1115 HOURS
 500 PSIG & 178 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	7.29	
NITROGEN	0.28	
METHANE	90.53	
ETHANE	1.50	0.410
PROPANE	0.20	0.056
ISO-BUTANE	0.01	0.003
N-BUTANE	0.02	0.007
ISO-PENTANE	0.00	0.001
N-PENTANE	0.00	0.000
HEXANES	0.01	0.003
HEPTANES PLUS	0.16	0.079
TOTALS	100.00	0.559

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6415 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 980.0 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 962.8 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 7,603 PSIA
 SAMPLED: 12-02-83 @ 1845 HOURS
 500 PSIG & 185 DEGREES F
 BY: TECHNADRIL

HYDROCARBON ANALYSIS OF SEPARATOR GAS

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	7.56	
NITROGEN	0.20	
METHANE	90.05	
ETHANE	1.64	0.447
PROPANE	0.20	0.055
ISO-BUTANE	0.01	0.002
N-BUTANE	0.03	0.011
ISO-PENTANE	0.01	0.005
N-PENTANE	0.02	0.006
HEXANES	0.04	0.019
HEPTANES PLUS	0.24	0.119
TOTALS	100.00	0.664

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.6486 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 985.7 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 968.4 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9978

MAGMA GULF-TECHNADRIL
AMOCO FEE WELL NO. 1
SWEET LAKE PROSPECT FIELD
SAND ZONE NO. 3
CAMERON PARISH, LOUISIANA
RESERVOIR PRESSURE: 10,720 PSIA

SEPARATOR WATER FLASH TO 0 PSIG & 68°F

(SAMPLED: 11-23-83, 1700 HRS @ 500 PSIG & 164°F)

SOLUTION GAS-WATER RATIO, DRY = 2.64

SCF GAS @ 15.025 PSIA & 60°F

BBL. WATER @ 0 PSIG & 60°F

SHRINKAGE = 0.9694

VOL. S.T. WATER @ 60°F

VOL. SEP. H2O @ 500 PSIG & 164°F

STOCK TANK WATER DENSITY = 1.1123

Gm/Ml @ 60°F

GAS GRAVITY, DRY = 0.9625

(SEE ANALYSIS ON PAGE 16)

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 10,720 PSIA
 SAMPLED: 11-23-83 @ 1700 HRS.
 500 PSIG & 164 DEGREES F

HYDROCARBON ANALYSIS OF FLASHED GAS FROM SEPARATOR WATER

FLASHED FROM 500 PSIG TO 0 PSIG

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	41.50	
NITROGEN	0.00*	
METHANE	57.46	
ETHANE	0.95	0.260
PROPANE	0.09	0.025
ISO-BUTANE	0.00	0.000
N-BUTANE	0.00	0.000
ISO-PENTANE	0.00	0.000
N-PENTANE	0.00	0.000
HEXANES	0.00	0.000
HEPTANES PLUS	0.00	0.001
TOTALS	100.00	0.286

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.9625 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 614.4 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 603.7 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9972

NOTE: * CALCULATED NITROGEN FREE.

MAGMA GULF-TECHNADRIL
AMOCO FEE WELL NO. 1
SWEET LAKE PROSPECT FIELD
SAND ZONE NO. 3
CAMERON PARISH, LOUISIANA
RESERVOIR PRESSURE: 10,400 PSIA

SEPARATOR WATER FLASH TO 0 PSIG & 68°F

(SAMPLED: 11-25-83, 1700 HRS @ 500 PSIG & 168°F)

SOLUTION GAS-WATER RATIO, DRY = 2.60

SCF GAS @ 15.025 PSIA & 60°F

BBL. WATER @ 0 PSIG & 60 °F

SHRINKAGE = 0.9674

VOL. S.T. WATER @ 60°F

VOL. SEP. H2O @ 500 PSIG & 168°F

STOCK TANK WATER DENSITY = 1.1132

Gm/Ml @ 60°F

GAS GRAVITY , DRY = 0.9432

(SEE ANALYSIS ON PAGE 18)

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 10,400 PSIA
 SAMPLED: 11-25-83 @ 1700 HOURS
 500 PSIG & 168 DEGREES F

HYDROCARBON ANALYSIS OF FLASHED GAS FROM SEPARATOR WATER
 FLASHED FROM 500 PSIG TO 0 PSIG

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	39.25	
NITROGEN	0.00*	
METHANE	59.63	
ETHANE	0.95	0.259
PROPANE	0.03	0.024
ISO-BUTANE	0.00	0.000
N-BUTANE	0.00	0.000
ISO-PENTANE	0.00	0.000
N-PENTANE	0.00	0.000
HEXANES	0.00	0.000
HEPTANES PLUS	0.09	0.043
TOTALS	100.00	0.326

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.9432 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 614.8 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 630.6 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9972

NOTE: * CALCULATED NITROGEN FREE.

MAGMA GULF-TECHNADRIL
AMOCO FEE WELL NO. 1
SWEET LAKE PROSPECT FIELD
SAND ZONE NO. 3
CAMERON PARISH, LOUISIANA
RESERVOIR PRESSURE: 7,824 PSIA

SEPARATOR WATER FLASH TO 0 PSIG & 71°F

(SAMPLED: 12-01-83, 0900 HRS @ 500 PSIG & 230°F)

SOLUTION GAS-WATER RATIO, DRY = 2.70

SCF GAS @ 15.025 PSIA & 60°F

BBL. WATER @ 0 PSIG & 60°F

SHRINKAGE = 0.9585

VOL. S.T. WATER @ 60°F

VOL. SEP. H2O @ 500 PSIG & 230°F

STOCK TANK WATER DENSITY = 1.1085

Gm/Ml @ 60°F

GAS GRAVITY, DRY = 0.9403

(SEE ANALYSIS ON PAGE 20)

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 7,824 PSIA
 SAMPLED: 12-01-83 @ 0900 HRS.
 500 PSIG & 230 DEGREES F

HYDROCARBON ANALYSIS OF FLASHED GAS FROM SEPARATOR WATER

FLASHED FROM 500 PSIG TO 0 PSIG

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	38.97	
NITROGEN	0.00*	
METHANE	60.00	
ETHANE	0.88	0.240
PROPANE	0.06	0.018
ISO-BUTANE	0.00	0.000
N-BUTANE	0.00	0.000
ISO-PENTANE	0.00	0.000
N-PENTANE	0.00	0.000
HEXANES	0.00	0.000
HEPTANES PLUS	0.09	0.047
TOTALS	100.00	0.305

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 0.9403 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 644.4 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 633.1 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9973

NOTE: * CALCULATED NITROGEN FREE.

MAGMA GULF-TECHNADRIL
AMOCO FEE WELL NO. 1
SWEET LAKE PROSPECT FIELD
SAND ZONE NO. 3
CAMERON PARISH, LOUISIANA
RESERVOIR PRESSURE: 7,625 PSIA

SEPARATOR WATER FLASH TO 0 PSIG & 67°F

(SAMPLED: 12-02-83, 0915 HRS @ 500 PSIG & 225°F)

SOLUTION GAS-WATER RATIO, DRY = 2.60

SCF GAS @ 15.025 PSIA & 60°F

BBL. WATER @ 0 PSIG & 60 °F

SHRINKAGE = 0.9608

VOL. S.T. WATER @ 60°F

VOL. SEP. H2O @ 500 PSIG & 225°F

STOCK TANK WATER DENSITY = 1.1089

Gm/Ml @ 60°F

GAS GRAVITY , DRY = 1.0051

(SEE ANALYSIS ON PAGE 22)

MAGMA GULF-TECHNADRIL
 AMOCO FEE WELL NO. 1
 SWEET LAKE PROSPECT FIELD
 SAND ZONE NO. 3
 CAMERON PARISH, LOUISIANA
 RESERVOIR PRESSURE: 7,625 PSIA
 SAMPLED: 12-02-83 @ 0915 HRS.
 500 PSIG & 225 DEGREES F

HYDROCARBON ANALYSIS OF FLASHED GAS FROM SEPARATOR WATER

FLASHED FROM 500 PSIG TO 0 PSIG

COMPONENT	SEPARATOR GAS	
	MOL %	GPM @ 15.025 PSIA
CARBON DIOXIDE	45.36	
NITROGEN	0.00*	
METHANE	53.58	
ETHANE	0.82	0.224
PROPANE	0.06	0.017
ISO-BUTANE	0.00	0.000
N-BUTANE	0.00	0.000
ISO-PENTANE	0.00	0.000
N-PENTANE	0.00	0.000
HEXANES	0.01	0.005
HEPTANES PLUS	0.17	0.088
TOTALS	100.00	0.334

CALC. GAS SPECIFIC GRAVITY (AIR=1.00) = 1.0051 SEPARATOR GAS

SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) DRY = 582.5 REAL
 SEP. GAS HEAT OF COMB. (BTU/CU. FT. @ 15.025 PSIA & 60 F) WET = 572.3 WATER SAT.
 SEP. GAS COMPRESSIBILITY (@ 1 ATM & 60 F) Z = 0.9971

NOTE: * CALCULATED NITROGEN FREE.

APPENDIX - K

A BASE LINE FOR DETERMINING
LOCAL, SMALL-SCALE
VERTICAL MOVEMENTS
IN LOUISIANA

by

Drukell B. Trahan

Louisiana Geological Survey
Louisiana State University
Baton Rouge, Louisiana

ABSTRACT

Subsidence in Louisiana is a result of many factors ranging from local, man-induced to regional, large-scale processes. The measurement of local, man-induced subsidence is especially critical in areas with high rates of land loss. In order to measure local vertical movement, absolute historical geodetic movements have been estimated by adjusting all movements along the first-order vertical control network from northeast to southwest Louisiana as related to the Monroe Uplift. The adjustment will serve as a base line by which local subsidence or uplift can be measured.

A generalized trend of increasing subsidence to the south in Louisiana is probably a reflection of increasing sediment thickness and weight toward the axis of the Gulf Coast Basin. Anomalous values as low as -17.6 mm/yr occur superjacent to the positions of Pleistocene and Holocene fluvial elements. Positive movement, up to $+4.1$ mm/yr, has been found associated with the Iberian structural axis in south-central Louisiana.

Land subsidence due to natural causes may far outweigh subsidence resulting from fluid withdrawal or depressurization of geopressured aquifers. The effects of regional and local natural processes should not be underestimated in any systematic approach to measuring subsidence.

INTRODUCTION

The U.S. Department of Energy is presently testing geopressured-geothermal energy reserves in southwestern Louisiana. The reserves are in areas where sandstones are enclosed between the shales of downthrown fault blocks in major depocenters. Within these sandstone reservoirs, fluid pressure and temperature are high, a result of the encapsulation of pore waters under a heavy overburden. During the development of these reservoirs, the hydraulic energy--up to 13,000 psia--is released. The resulting reduction in pressure may cause dewatering and compaction of the surrounding shales and subsidence at the land surface (Gustavson and Kreitler, 1976, p. 20).

Depressurization of deep geopressured aquifers is one of a host of factors which could cause subsidence of the land surface. Ground-water withdrawal and marsh reclamation by drainage are other potential causes. The effect of these local activities on the land surface may be determined by comparing historical subsidence rates. In addition, natural causes of subsidence must be ascertained and an attempt made to determine absolute movement.

Subsidence is widespread in South Louisiana. Besides the effect of deep crustal movement and surface compaction due to dewatering of marshy soils, the shales of the Gulf Coast Basin are highly susceptible to compaction resulting from dewatering and compression. Subsidence is a critical concern in coastal areas already at or below sea level, where current rates of land loss are estimated to be $129 \text{ km}^2/\text{yr}$. Problems caused by subsidence are high rates of land loss, increased urban flooding, building foundation failures, and ecosystem imbalances.

Preliminary base-line subsidence monitoring in the areas of geopressured-geothermal energy development involved adjustment of local lines of historical first-order leveling (Trahan, 1982). In each case, the data were referenced to a benchmark common to all epochs of leveling by numerically maintaining the common benchmark at a fixed elevation. The depicted relative movements are true, but misleading. The reference benchmarks, assumed to be steady for the purpose of determining relative motion, are probably subsiding, therefore introducing an error factor in the data presented by Trahan (1982). Most of the South Louisiana coastal plain is subsiding at some rate. Rates ranging from -0.5 to -4.3 cm/yr were suggested by Swanson and Thurlow (1973, p. 2760). Holdahl and Morrison (1974, p. 381) calculated a range from -0.03 to greater than -0.05 cm/yr for the coastal plain in South Louisiana. In both studies, the data were adjusted regionally, with assumptions based on sea level rise, and thus do not provide the scale necessary to monitor local subsidence.

Man-induced effects such as depressurization of deep geopressured aquifers will result in local subsidence over relatively small areas. The purpose of this study was to establish a local base line from which these movements may be quantified.

METHODOLOGY

The method described here involves the tie-in and adjustment of leveling lines in a region of unknown actual movement to those in a region where uplift has been quantified. Schumm, Watson, and Burnett (1982) used geomorphic evidence to quantify movement of the Monroe Uplift in northeast Louisiana. Changes in stream channel characteristics and differences

between actual and theoretical valley gradients indicate that the area has been uplifting at an increasing rate, from +0.4 to +1.4 mm/yr, for the last 3500 years. Other investigators have also found evidence for continued activity of the Monroe Uplift. The most recent movements are believed to have occurred at least during the Miocene (Fisk, 1939; Spooner, 1935). The uplift was a compensatory effect resulting from the deposition of thick deltaic masses in the Gulf Coast Basin to the south (Spooner, 1935, p. 130). It is unlikely that this isostatic relationship ceased to exist into the Quaternary period. The effects of continental glaciation and the continued, although cyclic, deltaic progradation in the Gulf Coast could only have served to continue uplift to the north.

A description of this relationship can be provided through an analysis of rates of vertical motion from north to south through Louisiana. Current mapping involves the first-order leveling network from northeastern Louisiana to southwestern Louisiana (Fig. 1), which has been adjusted to movement associated with the Monroe Uplift. Where possible, loop closure adjustments (LCA) were made for all epochs of leveling along the network. Where closure errors existed, the loops were closed mathematically by averaging the elevations at the junction point and distributing the resulting difference around the loop. Loop spurs were adjusted by correcting benchmark heights along the spur for the elevation difference at the spur-loop junction. Interpolations were made, when necessary, at junctions of lines where years of leveling did not coincide; the relative rate of movement for the common benchmark served as the adjustment. Relative movements were plotted and adjusted to account for uplift ranging from +0.4 to +1.4 mm/yr at Winnsboro, Louisiana, which is located on the southern flank of the Monroe Uplift. The resulting profiles show changes in

Fig. 1. The Louisiana first-order leveling network showing positions of major junctions and the boundary of the Monroe Uplift.

TRANSO T. P. 1

elevation between epochs and show the adjusted topographic expression of the land surface (Figs. 2-7). Geomorphic and structural elements were included in the profiles for reference and correlation.

PROFILES

Winnsboro to Alexandria, Louisiana

This survey line extends from Winnsboro through Jonesville to the south and then continues in a southwesterly direction to Alexandria, Louisiana (Fig. 2). The benchmark at Winnsboro is the reference point for all movements depicted in this study. In the adjusted profile for the period 1934 to 1966, uplift increases to a point above the position of the Foulos salt dome. To the south, uplift decreases where the survey line crosses the Tensas River-Little River-Catahoula Lake drainage system. West of this feature is a section of uplift which corresponds to the structural position of the La Salle Arch. Still farther to the west towards Alexandria, subsidence tends to dominate the profile and is greatest at a position within the Red River valley.

Monroe to Iowa, Louisiana

This survey line parallels the Ouachita River valley from Monroe to a point approximately 42 km south of Monroe (Fig. 3). The survey line then turns to the southwest away from the valley. The movement profile effectively parallels the topographic profile for some distance, depicting greater subsidence across the Little and Red River valleys and less subsidence in the uplands between the valleys. From the south valley wall of the Red River to Iowa, subsidence increases, corresponding presumably to

Fig. 2. Total absolute change in elevation based on movement of the Monroe Uplift, Winnsboro to Alexandria, Louisiana, 1934 to 1966. Geomorphic and structural features (Anderson, 1978; Schumm, Watson, and Burnett, 1982; Stanfield, 1976) indicated for reference and correlation.

Fig. 3. Total absolute change in elevation based on movement of the Monroe Uplift, Monroe to Iowa, Louisiana, 1934 to 1966. Geomorphic and structural features (Anderson, 1979; Stanfield, 1976) indicated for reference and correlation.

thickening Gulf Coast Basin sediments. A spike in the movement profile 4 km north of Iowa may be associated with the structure of the Woodlawn salt dome.

Orange, Texas, to Baldwin, Louisiana

Subsidence is depicted along the major portion of this profile from Orange, Texas, to Lafayette, Louisiana, for the period 1965 to 1982 (Fig. 4). The greatest subsidence is in the shape of a trough along a segment of the line between the Mermentau and Vermilion rivers, which are west of and in Lafayette, respectively. The line turns at Lafayette to the southeast and follows the Iberian structural axis (Barton, 1933) parallel to the Five Islands salt dome trend. Uplift is dominant along this segment of the line.

Sulphur to Holly Beach, Louisiana

Major subsidence, which is evident between Sulphur and Holly Beach, is greatest 4 km south of Sulphur (Fig. 5). This survey line crosses the contact between the Pleistocene Prairie terrace and the Holocene coastal marshland at a point where subsidence is decreasing. This point occurs approximately 5 km south of the subsidence maximum. Subsidence is minimal from the Hackberry salt dome to a point 11 km north of Holly Beach, where the profile again deflects downward. Subsidence is indicated for the segment of the profile 12 km north of Holly Beach.

Iowa to Creole, Louisiana

The survey line from Iowa to Creole (Fig. 6) is about 32 km to the east of and parallel to the preceding transect (Fig. 5). The profiles are

Fig. 4. Total absolute change in elevation based on movement of the Monroe Uplift, Orange, Texas, to Baldwin, Louisiana, 1965 to 1982. Geomorphic and structural features (Anderson, 1979; Stanfield, 1976) indicated for reference and correlation.

Fig. 5. Total absolute change in elevation based on movement of the Monroe Uplift, Sulphur to Holly Beach, Louisiana, 1965 to 1982. Geomorphic and structural features (Anderson, 1979; Stanfield, 1976) indicated for reference and correlation.

Fig. 6. Total absolute change in elevation based on movement of the Monroe Uplift, Iowa to Creole, Louisiana, 1965 to 1982. Geomorphic and structural features (Anderson, 1979; Stanfield, 1976) indicated for reference and correlation.

similar. Maximum and minimum rates of subsidence are at approximately the same geomorphic positions; correlations between movement extremes, however, are greater. The position of the Sweet Lake salt dome and the Prairie terrace-coastal marshland boundary both coincide with the point where the rate of subsidence is lowest.

Holly Beach, Louisiana, to Rockefeller Refuge

In general, subsidence decreases along this line from Holly Beach on the west eastward to Rockefeller Refuge (Fig. 7). Anomalous subsidence rates occur in areas adjacent to the Calcasieu and Mermentau River valleys, with the greatest amount of subsidence depicted in the Mermentau River valley.

DISCUSSION

This report presents what is believed to be a best estimate for absolute geodetic movements in Louisiana. Holdahl and Morrison (1974, p. 378) based their regional analysis on a sea level rise of 1 mm/yr. With the adjustment of all movements to the quantified movement of the Monroe Uplift, assumptions based on recent sea level rise have presumably been circumvented. The profiles illustrate a general trend of increasing negative movement from northeast to southwest Louisiana. Except for the area southeast of Lafayette, these movements range from +2.3 mm/yr south of Winnsboro to -17.6 mm/yr south of Iowa. These extremes, however, are not normal; rather, they occur as anomalous values related to the positions of structural and geomorphic elements. If the average rate of uplift and subsidence along each line is used, the range can be generalized from +1.2 mm/yr adjacent to the Monroe Uplift to -6.7 mm/yr in the coastal area

Fig. 7. Total absolute change in elevation based on movement of the Monroe Uplift, Holly Beach to Rockefeller Refuge, Louisiana, 1965 to 1982. Geomorphic features indicated for reference and correlation.

of southwestern Louisiana. Uplift associated with the Iberian structural axis is as great as +4.1 mm/yr and averages +2.8 mm/yr.

The depicted movements correlate with recent geomorphic elements. The thickest recent sediments, such as those found in recent alluvial valleys (Figs. 3 and 7), are susceptible to dewatering and compaction. Movements related to deeper structural elements are, for the most part, overshadowed by movements related to recent geomorphic features. In addition, the movement profiles may serve as a useful tool for mapping buried valleys and depocenters. For example, the anomalous subsidence trough depicted in Figure 4 correlates well with an area of Pleistocene Red River alluviation (Varvaro, 1957, p. 23, pl. 2). Where strong correlations exist between the movement profiles and major structural elements, recent activity of these structural elements may be substantiated (e.g., the Iberian structural axis southeast of Lafayette, Fig. 4). Some profiles exhibit negative correlations which may be a product of structural movement (Figs. 5-6). Greater subsidence would be expected south of the Prairie terrace-coastal marshland boundary. The absence of pronounced subsidence here may be a result of continuing water saturation of sediments, since this land surface is at or below sea level in most places. Sediment dewatering may have been curtailed, or subsidence to the north may be an anomalous response to compaction of a buried Pleistocene Red River fluvial system. On the other hand, natural subsidence may have been counteracted by movement associated with the Hackberry-Sweet Lake salt ridge.

The National Geodetic Survey, in its leveling work, applies several corrections to elevations observed in the field (Balazs and Young, 1982). Random errors caused by instrument variations or human inconsistencies have presumably been reduced by loop closure adjustments. Other corrections are

based on natural orthometric and gravimetric variations. These are theoretically constant for each benchmark independent of time. When the change in elevation for a benchmark is documented, these variations are presumably eliminated (Balazs, 1983, personal commun.).

Other assumptions must be made when adjusting lines of leveling to determine movement. The reliance in this study on positive and measurable movement of the Monroe Uplift has already been discussed. Furthermore, it has been assumed, in connecting lines and making adjustments, that relative movements during the last half-century have been incremental.

SUMMARY

The coastal area of Louisiana is rapidly submerging. Before the man-induced effects of geopressured-geothermal development or any one of a number of causes can be ascertained, ideally a base line of absolute historical and natural effects must be determined. Indications in this study are that natural effects in Louisiana are not to be underestimated and may far outweigh any man-induced effects.

The increase in negative movement rates to the south is believed to be related to the thickening of sediments in the Gulf Coast Basin. The relationship may be a reflection of greater dewatering in the thicker sediments or isostatic adjustments resulting from loads and stresses placed on the basement by the weight of the sediment pile. Anomalies in the general trend are correlated with more recent geomorphic and structural elements. Pleistocene and Holocene fluvial deposits and salt domes contribute substantially to crustal motion in Louisiana.

This estimate of absolute geodetic movements in Louisiana is consistent with the range of movement suggested by Holdahl and Morrison (1974). Higher

subsidence values are a result of local anomalies which were not detected in their regional evaluation.

Future work should include an expansion of this base line into other parts of the state and a tie-in to tide stations for further comparison. Consolidation of the vertical control network in selected areas with high rates of land loss will also aid in the understanding of local subsidence.

ACKNOWLEDGMENTS

This work was sponsored in its entirety by the U.S. Department of Energy under contract number DE-AC08-81NV10174. I wish to express formal gratitude to the National Geodetic Survey in Rockville, Maryland, for its valuable assistance in acquiring survey data and continued support. Additional thanks go to the cartographic and editorial staffs of the Louisiana Geological Survey and to all the other professionals who have offered their input during various phases of the study. Special gratitude is owed to Anna Babin and Steve Bennett for helping to assimilate the vast amounts of geodetic data into a workable format.

REFERENCES

- Anderson, E. G., 1979, Basic Mesozoic study in Louisiana, the northern coastal region and the Gulf Basin province: La. Geol. Survey, Baton Rouge, La., Folio Series No. 3, vol. 1, 58 p.
- Balazs, E. I., 1983, Personal commun.: National Geodetic Survey, Rockville, Md.
- Balazs, E. I., and G. M. Young, 1982, Corrections applied by the National Geodetic Survey to precise leveling observations: U.S. Dept. Commerce,

- Nat. Oceanic and Atmospheric Admin., NOAA Tech. Memorandum NOS NGS 34, 12 p.
- Barton, D. C., 1933, The Iberian structural axis: Jour. Geology, vol. 41, no. 3, p. 225-242.
- Fisk, H. N., 1939, Jackson Eocene from borings at Greenville, Mississippi: Bull., Am. Assoc. Petr. Geol., vol. 23, no. 9, p. 1393-1403.
- Gustavson, T. C., and C. W. Kreidler, 1976, Geothermal resources of the Texas Gulf Coast: Environmental concerns arising from the production and disposal of geothermal waters: Univ. Texas, Austin, Bur. Econ. Geology, Austin, Tex., Geol. Circ. 76-7, 35 p.
- Holdahl, S. R., and N. L. Morrison, 1974, Regional investigations of vertical crustal movements in the U.S., using precise relevelings and mareograph data, in R. Green, ed., Recent crustal movements and associated seismic and volcanic activity: Tectonophysics, vol. 23, p. 373-390.
- Schumm, S. A., C. C. Watson, and A. W. Burnett, 1982, Investigation of neotectonic activity within the Lower Mississippi Valley Division: U.S. Corps of Engineers, Contract no. DACW38-80-C-0096, 158 p.
- Stanfield, C. P., 1976, A list of Louisiana oil and gas fields and salt domes including the offshore areas showing code numbers and abbreviations: La. Geol. Survey, Baton Rouge, La., Resources Inf. Series no. 1, 137 p.
- Spooner, W. C., 1935, Oil and gas geology of the Gulf Coastal Plain of Arkansas: Ark. Geol. Survey, Little Rock, Ark., Bull. no. 2, p. 125-139.

Swanson, R. L., and C. I. Thurlow, 1973, Recent subsidence rates along the Texas and Louisiana coasts as determined from tide measurements: Jour. Geophysical Research, vol. 78, no. 15, p. 2665-2671.

Trahan, D. B., 1982, Monitoring local subsidence in areas of potential geopressured fluid withdrawal, southwestern Louisiana: Trans., Gulf Coast Assoc. Geol. Socs., vol. 32, p. 231-236.

Varvaro, G. G., 1957, Geology of Evangeline and St. Landry parishes: Dept. Conservation, La. Geol. Survey, Baton Rouge, La., Geol. Bull. no. 31, p. 23, pl. 2.

Appendix L

Plug and Abandon Permits

MAGMA GULF—TECHNADRIL

430 Highway 6 South—Suite 208

Houston, Texas 77079

Telephone: (713) 870-1480

June 27, 1984

HO-TM-84-019

bcc: Jonne Berning
John Cogar
Clay Durham
Tom Goebel
Carl Guillot
Frank O'Brien
Sweetlake Files

Mr. W. C. Wilhite
Director-Lake Charles District
Office of Conservation
Louisiana Department of Natural Resources
P.O. Box 1767
Lake Charles, LA 70601

SUBJECT: REQUESTED PERMIT FOR PLUGGING AND ABANDONMENT
- MG-T/DOE AMOCO FEE NO. 1 WELL (SERIAL NO. 167759)
- SWEETLAKE PROJECT

Dear Mr. Wilhite:

Our Sweetlake geopressured-geothermal resource evaluation program has been completed, and our client, the U.S. Department of Energy, has instructed us to plug and abandon the brine test well and its associated salt water disposal well.

We are, therefore, requesting a permit from your office to plug and abandon the brine test well according to the attached plans, procedures, and drawings. We will be pleased to provide any additional information that you may require.

We are planning tentatively to commence with these P & A operations on July 9, 1984, and, therefore, will appreciate your prompt attention to our permit request. We would also appreciate receiving the appropriate forms (if any) for filing with your office when plugging and abandonment of the subject test well has been completed.

Thank you for your cooperation in this matter.

Sincerely,

Larry R. Durrett

Larry R. Durrett
Manager-Production Testing

LRD/lrs

Attachments

cc: Mr. James H. Welsh
Director-Injection And Mining
Office of Conservation
Baton Rouge, LA

Mr. Bob Clarke
Nevada Operations Office
U.S. Department of Energy

MG-T/DOE AMOCO FEE NO. 1 WELL
SWEETLAKE PROJECT
PROPOSED PLUG AND ABANDONMENT PROCEDURE
JUNE 1984

Prelude: An Otis pump-through bridge plug was set at 14,500 feet in the seal assembly extension of the subject geopressured-geothermal well on April 10, 1984. Pressure was then bled off the 5-1/2-inch tubing string and the wellhead. The test well is shown in its present configuration in the attached Figure 1.

The desired plug and abandonment configuration is shown in Figure 2.

- 1) Rig up a cement pump truck to the 5-1/2-inch tubing string. Mix up 57 cubic feet of Class H cement with 35% silica flour and retarder and "bullhead" same into the tubing followed by precisely 297 barrels of 17 ppg mud. This will result in a 500-foot cement plug from 14,780-15,280 feet, and cover the Sand Zone No. 3 perforations.
- 2) Allow the cement to set for at least one week.
- 3) Remove the wellhead (except the bottom master valve), flow wings and associated piping to the Willis choke valves.
- 4) Move in a rig, rig up, and nipple up a 5,000 psig BOP stack.
- 5) Attempt to pull the entire 14,495-foot 5-1/2-inch tubing string from the seal assembly and recover same. If the tubing string is stuck, pick up a mechanical cutter and a work string, cut the tubing at about 14,475 feet (or at the free point), and then recover the tubing.
- 6) Spot a 200-foot Class H cement (with 35% silica flour and retarder) plug at 14,400-14,600 feet (or at the depth of the mechanical cut) - 100-feet inside and 100-feet outside of the 5-1/2-inch tubing. This plug will require 48 cubic feet of cement.

- 7) Cut the 7-5/8-inch casing at about 5,400 feet (or higher free point) and recover same.
- 8) Spot a 200-foot cement plug at 5,300-5,500 feet (or at the depth of the mechanical cut) - 100 feet inside and 100-feet outside the 7-5/8-inch casing. This plug will require about 82 cubic feet of cement.
- 9) Cut the 9-5/8-inch casing at about 3,950 feet (or higher free point) and recover same.
- 10) Spot a 200-foot cement plug at 3,850-4,050 feet (or at the depth of the mechanical cut) - 100-feet inside and 100-feet outside the 9-5/8-inch casing. This plug will require about 166 cubic feet of cement.
- 11) Spot a 100-foot cement plug in the 13-3/8-inch casing at a depth of 10-110 feet. This plug will require about 83 cubic feet of cement.
- 12) Torch cut the 13-3/8-inch, 20-inch, and 30-inch casings three feet below grade and remove casing hangers; weld a 1/2-inch steel plate with a 1/2-inch needle valve on top to the 30-inch casing.
- 13) Load out all recovered tubulars and equipment.
- 14) Back fill the cellar.
- 15) Rig down the rig and move off the site.

Note - The associated salt water disposal well (MG-T/DOE Amoco Fee SWDW No. 1) will be plugged in a similar manner, the surface facilities dismantled and moved out, and the well sites will be restored to their original condition.

LRD/lrs

FIGURE 1
MG-T/DOE AMOCO FEE NO. 1 WELL
SWEETLAKE FIELD WILDCAT - CAMERON PARISH, LOUISIANA
COMPLETION OCTOBER 30, 1983
REVISION 1, 6/20/84

FIGURE 2
MG-T/DOE AMOCO FEE NO. 1 TEST WELL
SWEETLAKE PROJECT
PROPOSED PLUG AND ABANDONMENT CONFIGURATION
JUNE 1984

Work Permit
STATE OF LOUISIANA DEPARTMENT OF CONSERVATION

Well Name & No. MG-T/DOE Amoco Fee No. 1 Sec. 13 T 12S R 8W
Field Sweetlake Wildcat Parish Cameron
Permit Serial No. 167759 Work Permit No. 590-84
Description of Work Plug and abandon according to the enclosed
plans, procedures, and drawings

Sand & Reservoir To Be Tested Not Applicable TD 15,740 ft.

Operator Magma Gulf-Technadril
Address 3 Northpoint Drive - Suite 200
City, State & Zip Houston, TX 77060

Permit Requested By Larry R. Durrett Date 6/27/84
Larry R. Durrett
Permit Authorized By W. E. White District L.C. Date 6-28-84

See Instructions On Reverse Side

Form DM-4R Rev.

MAGMA GULF—TECHNADRIL

430 Highway 6 South—Suite 208

Houston, Texas 77079

Telephone: (713) 870-1480

June 27, 1984

HO-TM-84-018

bcc: Jonne Berning
John Cogar
Clay Durham
Tom Goebel
Carl Guillot
Frank O'Brien
Sweetlake Files

Mr. James H. Welsh
Director of Injection And Mining
Office of Conservation
Louisiana Department of Natural Resources
P.O. Box 44725
Baton Rouge, LA 70804-4275

SUBJECT: REQUESTED PERMIT FOR PLUGGING AND ABANDONMENT
- MG-T/DOE AMOCO SWDW NO. 1 (SERIAL NO. 970720)
- ALSO KNOWN AS MG-T/DOE AMOCO FEE NO. 2 WELL

Dear Mr. Welsh:

Our Sweetlake geopressured-geothermal resource evaluation program has been completed, and our client, the U.S. Department of Energy, has instructed us to plug and abandon the brine test well and its associated salt water disposal well.

We are, therefore, requesting a permit from your office to plug and abandon the subject salt water disposal well according to the attached plans, procedures, and drawings. We will be pleased to provide any additional information that you may require.

We are planning tentatively to commence with these P & A operations on July 9, 1984, and, therefore, will appreciate your prompt attention to our permit request. We would also appreciate receiving the appropriate forms (if any) for filing with your office when plugging and abandonment of the subject disposal well has been completed.

Thank you for your cooperation in this matter.

Sincerely,

Larry R. Durrett

Larry R. Durrett
Manager-Production Testing

LRD/lrs

Attachments

cc: Mr. Bill Wilhite
Director-Lake Charles District
Office of Conservation

Mr. Bob Clarke
Nevada Operations Office
U.S. Department of Energy

MG-T/DOE AMOCO FEE SWDW NO.1
SALT WATER DISPOSAL WELL
SWEETLAKE PROJECT
PROPOSED PLUG AND ABANDONMENT CONFIGURATION
JUNE 1984

The subject salt water disposal well is shown in its present configuration in Figure 1. The desired and intended plug and abandonment configuration is shown in Figure 2.

- 1) Rig up a pump truck to the 7-inch casing (used as a completion tubing string). Mix up 250 cubic feet of Class H cement with retarder and "bullhead" same into the well followed by precisely 230 barrels of 9 ppg drilling mud. This will result in a 600-foot cement plug from 3,825-4,425 feet, and will cover the perforations. Allow the plug to set for at least one week.
- 2) Remove the wellhead (except the bottom master valve) and associated piping.
- 3) Move in a rig and rig up.
- 4) Attempt to pull the 2,000+ feet of 7-inch casing out of the Baker packer and recover same. If the 7-inch casing is stuck, pick up a mechanical cutter on a work string, and cut the casing at about 1,950 feet (or at the free point) and then recover the casing.
- 5) Spot at 200-foot cement plug at 1,900-2,100 feet (or other depth of the mechanical cut) - 100-feet inside and 100-feet outside the 7-inch casing. This plug will require about 82 cubic feet of cement.
- 6) Cut the 9-5/8-inch casing at about 1,275 feet (or higher free point) and recover same.
- 7) Spot a 200-foot cement plug at 1,175-1,375 feet (or other depth of the mechanical cut) - 100-feet inside and 100-feet outside the 9-5/8-inch casing.
- 8) Spot a 100-foot cement plug in the 13-3/8-inch casing at a depth of 10-110 feet. This plug will require about 83 cubic feet of cement.

- 9) Torch cut the 13-3/8-inch and 20-inch casings three feet below grade and remove casing hangers; weld a 1/2-inch steel plate with a 1/2-inch needle valve on top to the 20-inch casing.
- 10) Load out all recovered tubulars and equipment.
- 11) Back fill the cellar.
- 12) Rig down the rig and move off the site.

Note - The associated geopressured-geothermal test well (MG-T/DOE Amoco Fee No. 1 Well) will be plugged in a similar manner, the surface facilities dismantled and moved out, and the well sites will be restored to their original condition.

LRD/lrs

FIGURE 1

MG-T/DOE AMOCO FEE SWDW NO. 1
SALT WATER DISPOSAL WELL

RECOMPLETION - APRIL 6, 1982

FIGURE 2
 MG-T/DOE AMOCO FEE SWDW NO. 1
 SALT WATER DISPOSAL WELL
 PROPOSED PLUG AND ABANDONMENT CONFIGURATION
 JUNE 1984

Work Permit
STATE OF LOUISIANA DEPARTMENT OF CONSERVATION

Well Name & No. MG-T/DOE Amoco Fee SWDW No. 1 Sec. 13 T 12S R 8W
Field Sweetlake Wildcat Parish Cameron
Permit Serial No. 970720 Work Permit No. _____

Description of Work Plug and abandon according to the enclosed
plans, procedures, and drawings

Sand & Reservoir To Be Tested Not Applicable TD 7,436 ft.
PBTD 4,516 ft.

Operator Magma Gulf-Technadril
Address 3 Northpoint Drive - Suite 200
City, State & Zip Houston, TX 77060

Permit Requested By Larry R. Durrett Date 6/27/84
Larry R. Durrett

Permit Authorized By _____ District _____ Date _____

See Instructions On Reverse Side

Form DM-4R Rev.

EDWIN W. EDWARDS
GOVERNOR
WILLIAM C. HULS
SECRETARY

DEPARTMENT OF NATURAL RESOURCES
OFFICE OF CONSERVATION

HERBERT W. THOMPSON
ASSISTANT SECRETARY
and
COMMISSIONER

July 5, 1984

Magma Gulf-Technadrill
3 Northpoint Dr. - Suite 200
Houston, TX 77060

Attn: Mr. Larry R. Durrett

Re: MG-T/DOE Amoco Fee SWDW No. 1
Serial No. 970720
North Sweetlake Field
Cameron Parish

Gentlemen:

Approval is hereby given to perform the work in the above referenced well as proposed in Work Permit No. UIC-84-514.

In accordance with the requirements of Statewide Order No. 29-B, three (3) updated copies of the Well History and Work Resume Report (Form WH-1), Plug and Abandon Report (Form P&A), and the cementing report must be sent to the Injection and Mining Division at the above address within twenty (20) days of the plugging.

Yours very truly,

HERBERT W. THOMPSON
Commissioner of Conservation

James H. Welsh
James H. Welsh
Director of Injection and Mining

LCB:ts

Enclosure

cc: Lake Charles District

Work Permit

STATE OF LOUISIANA DEPARTMENT OF CONSERVATION

Well Name & No. MG-T/DOE Amoco Fee SWD No. 1 Sec. 13 T 12S R 8W
 Field Sweetlake North Parish Cameron
 Permit Serial No. 970720 Work Permit No. UIC-84-514

Description of Work Plug and abandon according to the enclosed
plans, procedures, and drawings
JUN 23 7:11:42

Sand & Reservoir To Be Tested Not Applicable TD 7,436 ft.
CONTROL PBTD 4,516 ft.

Operator Magma Gulf-Technadril
 Address 3 Northpoint Drive - Suite 200
 City, State & Zip Houston, TX 77060

Permit Requested By Larry R. Durrett Date 6/27/84
Larry R. Durrett

Permit Authorized By James H. Webb District _____ Date 7/5/84

See Instructions On Reverse Side

Form DM-4R Rev.

MAGMA GULF—TECHNADRIL

430 Highway 6 South—Suite 208

Houston, Texas 77079

Telephone: (713) 870-1480

March 19, 1985

Mr. Frank Perkins
Director-Lake Charles District
Office of Conservation
Louisiana Department of Natural Resources
P.O. Box 1767
Lake Charles, LA 70601

SUBJECT: - PLUG AND ABANDON REPORT
- MG-T/DOE AMOCO FEE NO. 1 WELL (SERIAL NO. 167759)
- SWEETLAKE PROJECT

Dear Mr. Perkins:

This is further to our letter of June 27, 1984 wherein we requested, and later obtained, a permit (No. 590-84) to plug and abandon the subject DOE geopressured-geothermal brine research test well. Plug and abandonment procedures began on August 13, 1984 using W.L. Estis Rig No. 20, and were completed on September 14, 1984.

You may recall that it was necessary to depart from the approved P & A plan because of difficulties that were encountered; however, our modified plan was discussed with you and we received your verbal approval of same at the time. As requested by your office, your representative, Mr. Joe Durham, was contacted before the top two cement plugs were spotted in the well. The subject well is shown in Figure 1 as it existed in August 1984, and in Figure 2 in its final Plug and Abandonment configuration.

We tested only two of the geopressured-geothermal brine reservoirs in the well (Sand Zone No. 5, 15,387'-15,414' and Sand Zone No. 3, 15,245'-15,255' and 15,260'-15,280') because of DOE funding limitations. A total of 1.06 million barrels of brine containing about 25 SCF/STB of solution natural gas were produced from the Sand Zone No. 5 reservoir in 1981-1982 at an average rate of about 6,800 B/D. Brine production from the Sand Zone No. 3 reservoir totalled only 349,000 barrels (1983-1984), contained about 24 SCF/STB of solution natural gas, and was produced at an average rate of about 2,700 B/D.

Mr. Frank Perkins

March 19, 1985
Page 2

The associated salt water disposal well (MG-T/DOE SWDW No. 1) was similarly plugged and abandoned, all surface facilities were removed, and the well sites were restored to their original condition to the complete satisfaction of both the fee land owner (Amoco Production Company) and the surface lessee (Mr. Charles Precht, Jr.). Site restoration activity was completed on or about October 8, 1984.

We will be pleased to supply any additional information that you may require; otherwise, this will represent our final report on the subject brine well.

Sincerely,

Larry R. Durrett

Larry R. Durrett
Manager-Production Testing

LRD/lrs

Attachments

cc: Mr. James Welsh - Office of Conservation (Baton Rouge)
Mr. Bill Hardeman - Amoco Production Company
Ms. Mary Brownlee - Amoco Production Company

Dr. Clay Durham - MG-T
Mr. Frank O'Brien
Mr. Carl Guillot
Mr. Jonne Berning
Sweetlake Permit File

STATE OF LOUISIANA
OFFICE OF CONSERVATION
PLUG AND ABANDON REPORT

WORK PERMIT NO. 590-84

WELL SERIAL NO. 167759

DATE WORK FINISHED (MM-DD-YY) 9-14-84

Lake Charles DISTRICT
(Three Copies to be Filed with the District Office)

NOTE: This Report Will Be Returned If Not Properly Completed And Signed.

Field Sweetlake Wildcat Parish Cameron Sec. 13 Twp. 12S Rge. 8W

Operator Magma Gulf-Technadril CODE Well Name MG-T/DOE Amoco Fee Well No. 1

Total Depth 15,740' Condition of Well Dead

CHECK APPROPRIATE BOX:

☐ 29 DRY HOLE

☒ 30 FORMERLY PRODUCTIVE WELL

	CASING SIZE	AMOUNT PULLED	CEMENT PLUGS			
			FROM	TO	SACKS	HOW PLACED
301	5-1/2"	13,878'	14,780'	15,280'	35	Pumped
302	7-5/8"	2,365'	13,800'	14,000'	50	Spotted via Tubing
303	9-5/8"	2,330'	2,165'	2,565'	195	Spotted via Tubing
304			10'	110'	68	Spotted via Tubing

Mud Record: Weight 17.0 ppg Viscosity 50 cs

Remarks: This well was a DOE geopressured-geothermal brine well drilled
and tested for research purposes.

This work was done according to the Rules and Regulations of the Office of Conservation.

WITNESS

Magma Gulf-Technadril
OPERATOR

(Signed)
REPRESENTATIVE
Larry R. Durrett

FIGURE 1
MG-T/DOE AMOCO FEE NO. 1 WELL
SWEETLAKE FIELD WILDCAT - CAMERON PARISH, LOUISIANA
COMPLETION OCTOBER 30, 1983
REVISION 1, 6/20/84

FIGURE 2
MGT/DOE AMOCO FEE NO. 1 TEST WELL
SWEETLAKE PROJECT
PLUG AND ABANDONMENT CONFIGURATION
SEPTEMBER, 1984

MAGMA GULF—TECHNADRIL

430 Highway 6 South—Suite 208

Houston, Texas 77079

Telephone: (713) 870-1480

March 20, 1985

Mr. James H. Welsh
Director of Injection And Mining
Office of Conservation
Louisiana Department of Natural Resources
P.O. Box 44725
Baton Rouge, LA 70804-4275

SUBJECT: - PLUG AND ABANDONMENT REPORTS
- MG-T/DOE AMOCO FEE SWDW NO. 1 (SERIAL NO. 970720)
- SWEETLAKE PROJECT

Dear Mr. Welsh:

This is further to our letter of June 27, 1984 wherein we requested, and received on July 7, a permit to plug and abandon the subject salt water disposal well. This well was associated with a DOE research geopressured-geothermal brine test well (MG-T/DOE Amoco Fee No. 1). Plug and abandonment procedures began on September 18, 1984 using W.L. Estis Rig No. 20, and were completed on September 23, 1984.

It was necessary to modify the P & A plan submitted to, and approved by, your Office because of collapsed and/or stuck casing that was encountered. We received verbal approval of our modified P & A plans from Mr. Fritz Spencer of your Office on September 18, 1984.

The subject salt water disposal well is shown as it was recompleted on April 6, 1982 in Figure 1, and in its final Plug and Abandonment configuration in Figure 2. Plug and Abandon and Well History and Work Resume Reports are also attached.

A total of 1.06 million barrels of 9.2 ppg brine from the associated test well were injected into the 7,000-7,320 foot interval in this well in 1981-82. After recompletion of the salt water well in 1982, some 349,000 barrels of brine were injected into the 3,976-4,425 foot interval in 1983-84. Thus, a total of about 1.4 million barrels of brine were injected into the disposal well.

Mr. James H. Welsh

March 20, 1985
Page 2

The associated geopressured-geothermal test well (MG-T/DOE Amoco Fee No. 1) was similarly plugged and abandoned, all surface facilities were removed, and the well sites were restored to original condition to the complete satisfaction of both the fee land owner (Amoco Production Company) and the surface lessee (Mr. Charles Precht, Jr.). Site restoration activity was completed on or about October 8, 1984.

We have also completed and attached the Annual Salt Water Disposal Report For 1984 for the subject well.

We will be pleased to supply any additional information that you may require; otherwise, this will represent our final report on the subject salt water disposal well.

Sincerely,

Larry R. Durrett
Manager-Production Testing

LRD/lrs

Attachments

cc: Mr. Frank Perkins - Office of Conservation (Lake Charles)
Mr. Bill Hardeman - Amoco Production Company
Ms. Mary Brownlee - Amoco Production Company

Dr. Clay Durham - MG-T
Mr. Frank O'Brien
Mr. Carl Guillot
Mr. Jonne Berning
Sweetlake Permit File

STATE OF LOUISIANA
OFFICE OF CONSERVATION
PLUG AND ABANDON REPORT

WORK PERMIT NO. UIC-84-514

WELL SERIAL NO. 970720

DATE WORK FINISHED (MM-DD-YY) 9/23/84

Injection and Mining Division

(Three Copies to be Filed with the District Office)

NOTE: This Report Will Be Returned If Not Properly Completed And Signed.

Field Sweetlake North Parish Cameron Sec. 13 Twp. 12S Rge. 8W

Operator Magma Gulf-Technadril CODE Well Name MG-T/DOE Amoco Fee SWD Well No. 1

Total Depth 7,436' Condition of Well Dead

CHECK APPROPRIATE BOX:

☐ 29 DRY HOLE

☒ 30 FORMERLY BRINE INJECTION

	CASING SIZE	AMOUNT PULLED	CEMENT PLUGS			
			FROM	TO	SACKS	HOW PLACED
301	7"	1,218'	10'	110'	58	Spotted via Tubing
302	9-5/8"	450'	350'	550'	108	Spotted via Tubing
303			1,120'	1,320'	58	Spotted via Tubing
304			3,825'	4,425'	324	Pumped

Mud Record: Weight 9.0 ppg Viscosity 45 cs

Remarks: This brine injection well was associated with a DOE research
geopressured-geothermal test well, MG-T/DOE Amoco Fee No. 1.

This work was done according to the Rules and Regulations of the Office of Conservation.

[Signature]
WITNESS

Magma Gulf-Technadril
OPERATOR

(Signed) *Larry R. Durrett*
REPRESENTATIVE
Larry R. Durrett

FIGURE 1

MG-T/DOE AMOCO FEE SWDW NO. 1
SALT WATER DISPOSAL WELL

RECOMPLETION - APRIL 6, 1982

FIGURE 2
 MG-T/DOE AMOCO FEE SWDW NO. 1
 SALT WATER DISPOSAL WELL
 SWEETLAKE PROJECT
 PLUG AND ABANDONMENT CONFIGURATION
 SEPTEMBER 1984

OFFICE OF CONSERVATION
WELL HISTORY AND WORK RESUME REPORT

FIELD

Sweetlake North (Wildcat)

SERIAL NO.

970720

INJECTION INTERVAL

3,976-4,425 Feet

RESERVOIR (COMPANY SAND IDENTIFICATION)

Miocene

Three typewritten copies of this report must be filed with the District Office of the Office of Conservation in which the well is located within twenty (20) days of the date of completion. NOTE: If not properly completed and signed this report will be returned.

Salt Water Disposal Well

LEASE AND WELL DATA

CHECK APPROPRIATE BOXES

☐ NEW WELL
☐ RECOMPLETION
☒ P & A

☐ 31 INACTIVE DRY HOLE PUT. UTIL.
☐ 32 INACTIVE DRY HOLE NO PUT. UTIL.
☐ 36 INACTIVE WAITING ON PIPELINE
☐ 37 INACTIVE WAITING ON MARKET

PRODUCT

☐ OIL
☐ GAS
☒ OTHER
Brine

IF RECOMPLETION

☐ SAME RESERVOIR
☒ DIFFERENT RESERVOIR

DATE COMP. RECOM.
OR P & A
M D Y

9/23/84

OPERATOR

Magma Gulf-Technadril

CODE

ADDRESS

3 Northpoint Drive, Suite 200
Houston, TX 77060

WELL NAME

MG-T/DOE Amoco Fee SWDW

WELL NO.

1

PARISH

Cameron

SEC. 13

TWP. 12S

RGE. 8W

DATE PERMIT ISSUED

7/5/84

DATE SPUNDED
M D Y

9/18/80

DATE READY TO PRODUCE*

4/6/82

TOTAL DEPTH

7,436 Feet

PSTD.

4,516 Feet

GROUND ELEVATION

+ 8.3 Feet

CASING HEAD FLANGE ELEVATION

DISTANCE FROM RMB TO CNF

DATE WELL TURNED INTO TANKS

N/A

SINGLE, DUAL OR TRIPLE COMPLETION?

NOTE: IF THIS IS A MULTIPLE COMPLETION,
FURNISH A SEPARATE REPORT FOR
EACH COMPLETION

WAS WELL DIRECTIONALLY
DRILLED?

No

WAS DIRECTIONAL SURVEY MADE?

WERE 3 COPIES FILED WITH THE
OFFICE OF CONSERVATION?

DATE FILED

TYPE OF ELECTRICAL OR OTHER LOSS RUN (CIRCLE LOSS FILED WITH OFFICE OF CONSERVATION)

DATE FILED

CASING, LINER AND TUBING RECORD

Casing Size	Hole Size	Casing Weight	Depth Set		Sacks Cement	Test Pressure	Hours Under Pressure	Date Tested (MM DD YY)	Name of Test Witness - State if Conservation Agent or Offset Operator
			From	To					
10 1/2									
10 1/2									
10 1/2									
10 1/2									
10 1/2									

TUBING SIZE:

DEPTH OF TUBING:

DEPTH OF PACKER(S):

INITIAL COMPLETION OR RE-COMPLETION DATA

INITIAL PRODUCTION	GAS VOLUME	GOR	CHOKE SIZE	PRODUCING METHOD
BOPD	SCF/DAY	CF/BSL	1/4"	
FLOWING TUBING PRESSURE	SHUT-IN TUBING PRESSURE	CASING PRESSURE	WATER PRODUCTION	BSSW
BPSI	BPSI	BPSI	BPD	%
GRAVITY	BHP (SHUT-IN)	COMPANY REPRESENTATIVE	DATE GAUGED	
"API 60" F	BPSI			

PLUG AND ABANDON (P & A) DATA

Casing Size	Amount Pulled	CEMENT PLUG				Date Work Performed	Name of Test Witness - State if Conservation Agent or Offset Operator
		From	To	Sacks	How Placed		
7"	1,128'	10'	110'	58	Tubing	9/22/84	
9-5/8"	450	350'	450'	108	Tubing	9/21/84	
		1,120'	1,320'	58	Tubing	9/20/84	
		3,825'	4,425'	324	Pumped	6/28/84	

CERTIFICATE: I, the undersigned, state: That I am employed by WK Technology, Inc. and that I am authorized to make this report, and that this report was prepared under my supervision and direction and that all facts stated herein are true, correct and complete to the best of my knowledge.

Signature:

Larry R. Dunette

Title: Manager-Testing

*Date well is equipped to produce, but due to no available market, no pipe line connection, etc., the well has been shut-in.

ANNUAL SALTWATER DISPOSAL WELL REPORT
FOR CALENDAR YEAR 1984

LOUISIANA OFFICE OF CONSERVATION
INJECTION AND MINING DIVISION

Trans: 2

COMPLETE THIS REPORT FOR EACH CLASS II SALTWATER DISPOSAL WELL YOU OPERATE, INCLUDING
ANNULAR DISPOSAL IN PRODUCING WELLS. (NOTE: SEE INSTRUCTIONS ON BACK)

1. Operator Name and Address Magma Gulf-Technadril 3 Northpoint Drive - Suite 200 Houston, TX 77060	Operator Code <div style="border: 1px solid black; height: 20px; width: 100%;"></div>						
2. Disposal Well Name and Number MG-T/DOE Amoco Fee SWDW No. 1	Serial No. <div style="border: 1px solid black; padding: 2px;">970720</div>						
3. Field Name Sweetlake North	Field Code <table border="1" style="width:100%; border-collapse: collapse;"> <tr> <td style="width:33%; text-align: center;">Sec</td> <td style="width:33%; text-align: center;">Twn</td> <td style="width:33%; text-align: center;">Rge</td> </tr> <tr> <td style="text-align: center;">13</td> <td style="text-align: center;">12S</td> <td style="text-align: center;">8W</td> </tr> </table>	Sec	Twn	Rge	13	12S	8W
Sec	Twn	Rge					
13	12S	8W					

4. Source and Volume of Injected Fluids:
 A. Produced Salt Water: MG-T/DOE Amoco Fee No. 1

Operator (01)	Name	Oper Code	Lease; Unit; Well Name (1) (2) (3)	LUW Type	LUW Code	Vol for YR (BBLs)
	Magma Gulf-Technadril		MG-T/DOE Amoco Fee	3	970720	215,015
			SWDW No. 1			
	NOTE- THIS WELL WAS PLUGGED AND ABANDONED					
	ON 9/23/84. THUS, THIS WILL BE THE					
	THE LAST REPORT ON THE WELL.					
(02)	B. Total "Other" Volume for Year (Identify Sources On Back)....					None
(03)	C. TOTAL VOLUME for YEAR (Source Total).....					215,015

Completed by Larry R. Durrett 713/ 999 -6464
 (type or print) (phone)

Larry R. Durrett 3/20/85
 (signature) (date)