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**SWEET LAKE GEOPRESSURED—GEOTHERMAL PROJECT,
MAGMA GULF—TECHNADRIL/DOE AMOCO FEE**

Volume II: Surface Installations Reservoir Testing

Annual Report for the Period February 28, 1981—February 10, 1982

Work Performed Under Contract No. AC08-80NV10081

**Magma Gulf-Technadril
Houston, Texas**

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

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

VOLUME II
SURFACE INSTALLATIONS
RESERVOIR TESTING

ANNUAL REPORT
for the period
28 February 1981 - 10 February 1982

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Editor

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MASTER

Prepared for the
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Division of Energy Technology
Under Contract DE-AC08-80NV10081

PREFACE

This report on the testing of Sand 5 (15,385 - 15,415 feet in depth) of the geopressured-geothermal test well, Magma Gulf-Technadril/DOE Amoco Fee No. 1, Cameron Parish, Louisiana, (Sweet Lake), presents the results obtained from the testing phase which began June 1981 and concluded February 1982.

This is the second in a series of comprehensive reports on this project prepared for DOE under contract DE-AC08-80NV10081. The first report on the drilling and completion of the production and disposal wells summarized the activity under the contract from its inception December 1, 1979 through rig release February 27, 1981. That report is for the first year of the project. The present report effectively serves as the annual report for the second year of the project, February 28, 1981 to February 10, 1982.

The comprehensive Testing Plan, which was formally submitted to DOE in June 1981, provided the basis for the results presented in this report. It was prepared in the March-June 1981 interval, during which the surface facilities were also installed and operators trained, preparatory to the initiation of testing in June 1981.

Many of the auxiliary research activities of the project were funded under Gas Research Institute Contract No. 5014-321-0290. Results of that contract are presented in the separate report prepared by Magma-Gulf-Technadril and issued by Gas Research Institute as GRI-79/0125 "Geopressured Well Project, Sweet Lake, Cameron Parish, Louisiana", Final Report (February 1980-September 1982). Summaries of the research results in that report are included in the present report, pp. 30 - 38.

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1.0 Summary

The Magma Gulf-Technadril/Department of Energy Amoco Fee # 1 (production) and salt water disposal wells were drilled in the period from August, 1980 to February 1981. Surface facilities were designed and constructed during March-June 1981. Flow testing began in June 1981 and continued until February, 1982.

The Miogypsinoides interval contains seven discrete sands in the test well. These sands have been numbered 1-7, beginning at the top of the sequence. Data from wireline logs and core samples suggested that the first zone to be perforated should be Sand 5. Because of its high porosity and permeability, Sand 5 was thought to contain almost 50% of the total hydraulic capacity of the well.

Flow testing of Sand 5 was performed in three stages, each of which is fully described in this report. Phase I was designed as an initial clean-up flow and a reservoir confirmation test. Phase II consisted of the reservoir limit determination test and lasted 17 days. Boundaries were confirmed which suggest that the Sweet Lake reservoir is fairly narrow, with boundaries on three sides, but is open in one direction with no closure for at least 4-1/4 miles. These boundaries approximate the shape of the graben in which the test well was drilled, but may or may not be directly related to the major faults forming the graben. Phase III testing was planned to be a long-term test at commercial design rates. Although Sand 5 alone would not support such rates, long-term production was demonstrated.

Additional research not supported by DOE funding was also performed during the period covered by this report. This research, consisting of mud logging, micropaleontology, organic geochemistry, core analysis, and rock mechanics, is summarized in this report, and presented by GRI-79/0125.

2.0 Introduction and Background

The Sweet Lake production well (Magma Gulf-Technadril/Department of Energy Amoco Fee #1) is an experimental geopressured-geothermal well in south-western Louisiana. The well, drilled and operated by the Magma Gulf-Technadril joint venture, is located in Section 13, T12S-R8W, Cameron Parish, approximately 15 miles south of Lake Charles. The target sand was the Miogypsinoides sands at a depth of the upper Frio. Total depth of the test well is 15,740 feet.

The test and disposal wells were drilled during the period of August, 1980 - February, 1981. The test well was perforated in June 1981. The report Sweet Lake Geopressured-geothermal Project; Magma Gulf-Tecnadril/DOE Amoco Fee, Volume I: Drilling and Completion, Test Well and Disposal Well covers project activities from the inception of the project up to and including release of the drilling rig. This volume is a report on surface facilities installation and testing activities and covers the period from February 28, 1981 to February 10, 1982, and effectively serves as the annual report of the second year of the project.

The main objective of the Sweet Lake project has been to determine, and demonstrate through long-term flow testing, the technologic and economic feasibility of recovery of dissolved natural gas and the potential for utilization of the thermal and hydraulic energy associated with geopressured-geothermal fluids, and high volume brine disposal in shallower strata. The primary emphasis of the testing has been directed to the separation and recovery of natural gas (primarily methane) from the brine, and to brine disposal.

Tests were outlined in the Geopressured-geothermal Testing Plan, MG-T/DOE Amoco Fee #1 well, Sweet Lake Prospect, Cameron Parish, Louisiana, June 1981. The testing phases were planned as follows:

Testing Phase	Title	Duration
Phase I	Initial Flow Test-Reservoir Confirmation	1-2 days
Phase II	Reservoir Limit Determination Test	10-20 days
Phase III	Long-Term Flow Test	150+ days

In addition to the achievement of the primary goals, the testing was designed to accumulate data to: 1) characterize and define the nature, size, and thus potential of the reservoir; 2) characterize analytically the brine and natural gas produced; 3) confirm the adequacy of the geopressured-geothermal test well and surface facilities design; and 4) define the extent of scaling/corrosion problems associated with long-term high-volume production and disposal of geopressured-geothermal brine, and minimize and control such scaling/corrosion.

A complete discussion of the achievement of the primary and secondary goals forms the bulk of this report. However, a brief discussion first of project history and geologic setting provides the necessary background to place the results of the Testing Phase in the proper framework.

2.1 Project History

In 1975, the U.S. Energy Research and Development Administration (now superseded by the U.S. Department of Energy) initiated a research, development, and demonstration program to stimulate commercial development of the geopressured-geothermal resources underlying the Gulf Coast region of the United States. Several investigators had recognized the energy potential and suggested that federally funded studies be conducted to assess the energy resource.

Earlier, the Sweet Lake geopressured-geothermal prospect was identified and leased by Gulf Geothermal Corporation in 1974. Its successor, Magma Gulf Corporation, submitted the Sweet Lake prospect for drilling and testing as well as one in Texas in response to a 1976 Request for Proposals from ERDA. The proposal for the Sweet Lake project 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. The primary objective of the investigation was to select the optimum site for extensive studies, including exploration, drilling, production testing, reservoir analysis, and environmental impact evaluation.

The selected site required additional leases which were obtained early in 1979 by Magma Gulf. A comprehensive proposal was submitted to DOE in June 1979 outlining a two-year project. Subsequently, a joint venture was formed, Magma Gulf-Technadril, Inc. (MG-T) to perform this work. In order to conduct these studies, DOE executed a contract (No. DE-AC08-80NV10081) with MG-T, to conduct the drilling, completion, and testing of one geopressured-geothermal test well and one disposal well. Gas Research Institute (GRI) also executed a contract with MG-T to provide funds for important corollary aspects of the program during the drilling and testing phases.

2.2 Geologic Setting

The Sweet Lake geopressured-geothermal prospect is a basin located on the north flank of an east-west salt ridge containing the Hackberry, Big Lake, and Sweet Lake structures. The south side of the basin is bounded by a fault downthrown to the north (Figure 2-1). This converges eastward with a major east-west fault downthrown to the south to form the eastern termination of the basin. The prospect is thus located in a graben bounded by two major growth faults. 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 of this area is formed by late Pleistocene deltaic deposits. Alternating massive sands and clays extend to an average depth of 9,000 feet and overlie the thick shales of the Anahuac formation. The Anahuac is underlain by the Frio Formation, the upper member of which is called the Camerina Zone. Several sands occur within this zone, the thickest being the basal Miogypsinoides. This target sand, the Miogypsinoides, was deposited on the outer shelf in upper Oligocene or lower Miocene time.

The Miogypsinoides sand is present over the entire area shown in Figure 2-1, but it is structurally lower in the graben. The key control wells are located in Section 7, T12S,R7W and Section 13, T12S, R8W, which is the structurally higher portion of the graben. The sand dips strongly northwestward from this area so that it occurs below 18,000 feet in the northwestern portion of the mapped area. The drill site was chosen so that the Miogypsinoides sand would be penetrated at a depth of 15,000 feet. This depth was chosen as a compromise between the desire to drill as deeply as possible to maximize the available heat and pressure, and the need to minimize the cost and risk involved in drilling deep wells.

A complete discussion of various geologic aspects of this project was presented in Sweet Lake Geopressured-geothermal Project: Magma Gulf-Technadril/DOE Amoco Fee, Volume I: Drilling and Completion, Test Well and Disposal Well. Section 4.2.4 Sand Character of Volume I is particularly pertinent to sections which follow in this volume. This described the porosities and permeabilities which were measured in core samples and calculated from log data. The calculated porosities and permeabilities are summarized in Figure 2-2. Of the seven sands within the Miogypsinoides sand interval, Sand 5 (as numbered from the top), at a depth of 15,385-15,415 feet, was estimated to have an hydraulic capacity of 10,800 millidarcy-feet. This represents 48.89% of the total capacity of seven sands.

Sand 3 and Sand 4, the two sands above Sand 5, were also considered promising, with 17.11% and 15.85% of the total capacity, respectively. Based on these analyses, Sand 5 was selected as the target sand for the testing proposed in the Testing Plan prepared for and approved by DOE.

3.0 Drilling Summary

3.1 MG-T/DOE AMOCO FEE No. 1 Test Well

The subject test well was spudded on August 22, 1980 and drilling operations were completed on February 26, 1981 with the setting of the 5-1/2 inch production tubing. This well, which is depicted in Figure 3-1, 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 surface and cemented in the 9-5/8 inch casing to 5,600 feet.

The production tubing consists 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 is inside the PBR. The 5-1/2 inch tubing is 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.

3.2 MG-T/DOE AMOCO Fee Salt Water Disposal Well

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 3-2, was drilled to a total depth of 7,440 feet with a 12-1/4 inch bit.

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 feet and cemented back to 1,970 feet. The Plugged Total Depth (PBD) inside the 9-5/8 inch casing is 7,350 feet.

This well was completed with a Baker Model F packer set at 6,254 feet. It should be noted that the first packer failed to set and was pushed to PBD. The production tubing in this well is 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.

4.0 Description of Surface Facilities

A plot plan of 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 at Pleasant Bayou. Pleasant Bayou facilities were more experimental in orientation, whereas Sweet Lake surface facilities were oriented to flow rate of 40,000 barrels per day, semi-commercial operation, 300°F, and with connections for power generation and gas sales.

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 is through a redundant series of 5-1/8-inch 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.

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, and thence 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 well head was ordered from FMC. However, FMC could not complete manufacture and the upper portion of the wellhead was manufactured by Gray under another 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 varies 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 reduces pressure to less than 5000 psi, which is the design rating of the Halliburton turbine meter. The second stage of chokes drops pressure to that desired in the separator, 300-1000 psig.

4.2.1 Gray Choke Valves

The Gray choke system and wellhead were acquired as surplus from DOE when FMC became unavailable 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 each valve; thus, the brine flow normally was directed through only one of the parallel choke valve legs and the other was a spare. This arrangement precluded the necessity of shutting in the test well to repair or replace one of these choke valves. A cut-away diagram of the Gray choke valves is shown in Figure 4-7.

It should be noted that the 4-1/16-inch 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 indentified 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 used 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. A cut-away diagram of the Willis choke valves is shown in Figure 4-8.

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) 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 pressure was observed and valves were needed at Gladys McCall. It was replaced by a straight piece of heavy wall pipe, and later a Gray ESD valve was added.

4.3 Brine/Gas Separator System

As the pressure was decreased across the choke valves from the well-head 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 in the process. Photographs of the separator system are shown in Figure 4-9.

The brine/gas separator vessel (V-301), construction details of which are given in Figure 4-10, 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 is 1,440 psig at 105°F, which is reduced to 1,290 psig at 350°F. These pressures were selected to permit injection of gas into commercial pipeline systems and to dispose of effluent brine into the disposal well without the necessity of installing pumping facilities.

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 the initial testing phases all gas produced was sent to the flare since the necessary gas cooling and drying facilities have not been provided as yet, and the connections to a commercial gas transmission pipeline system have not been 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 separations could be made in the vessel with only minor external additions, should minor quantities of oil be produced.

Sand drains were included in the separator, but since no sand was produced, they have not been used.

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, shown on Figure 4-11, consists 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 indicates the need for replacement. Principal species filtered have been iron and scale.

4.5 Salt Water Disposal Wellhead

A schematic diagram of the salt water disposal wellhead and casing spools is given in Figure 4-12, and a photograph of the installed wellhead is shown in Figure 4-13. The wellhead was furnished by FMC Corporation.

4.6 Production Gas System

As was discussed previously, the gas and water vapor from the separator was sent via split-range pressure control on the separator firstly to the gas pipeline system, and alternately as required to the field flare. Until the gas pipeline is installed, both lines are connected together to go to the flare.

4.6.1 Field Flare System

As may be seen 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 tankage 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 firework rocket.

4.6.2 Gas Pipeline System (Future)

It will be necessary to install additional surface facilities before the gas production can be sold to a gas transmission company. These facilities will include 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 contractor for water removal, a 40-gph triethylene glycol regenerator, and piping from the site to the chosen gas pipeline. It may also be necessary to install a gas/diethanolamine contactor, and a 10-gpm diethanolamine regenerator for reduction of the carbon dioxide concentration in the gas stream.

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. Surface blowdown was 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 are three tanks with a 100-barrel capacity and one tank with a 300-barrel capacity. The use of small tanks has naturally increased the cost of Sweet Lake drilling and operating.

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 could be pumped to the disposal well through the use of a 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.

4.8 Pressure Relief Systems

There were basically two types of pressure relief systems in the surface facilities design: firstly, there were conventional pressure relief or pop valve systems which relieve at preset pressure settings, and secondly, various pressure sensors which relieve the abnormal pressure situation by actuating the Emergency Shutdown (ESD) system that, in turn, closed gate valves upstream of the Gray choke valves and/or on the test wellhead, and thus 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 Setting	- 100 psig
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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 of the expected relatively high temperature (320-330°F), a modified GRC-512 pressure element was used in the test well although the actual temperatures would have permitted the use of a Hewlett-Packard gauge. A Hewlett-Packard Quartz Gauge was used in the salt water disposal well. These measurements are required for good reservoir definition.

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 0-10,000 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 will be 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 measurement 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. Orifice meter calibration was also a difficulty magnified by two-phase, multi-component flows.

4.9.3 Panel-Mounted Indicator/Controllers and Strip-Chart Recorders

The instrumentation that is to be 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 Dis- posal 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 Pres- sure	0- 1,500 psig
FR-102	Total Separator Gas Pro- duction	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 by-passing 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 is struck by a particle of sand in the brine stream, an acoustically-sensitive crystal in the probe converts the acoustical "pinging" of the impinging sand into an electronic signal, which is processed by the electronic circuitry and then the signal output is displayed on a strip-chart recorder.

The sand detectors have five sensitivity ranges, which are calibrated individually. Sand concentrations as low as 30 ppm can 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 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 overall ESD system layout is shown in Figure 4-14. In Figure 4-15, a photograph of the ESD control panel is shown. The Sweet Lake ESD control panel, located in the control room trailer, actuated a master valve on the wellhead, and the two gate valves upstream of the Gray choke valves on the choke skid (rather than on the flow wings as shown in Figure 4-15). Additionally, the Sweet Lake ESD system did not have a hydraulically-operated valve on the tubing/casing annulus. A control schematic of the ESD system is shown in Figure 4-16.

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 has opened, the closing of the valve returned hydraulic fluid to the reservoir on the skid.

A liquid nitrogen tank provided additional backup to the air system, in the unlikely event that the instrument air system should be depleted.

The sensors which actuated the ESD system on the Sweet Lake surface facilities are given 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 is 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 about 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 have been severe problems due to the supplier's

corporate problems. It has been supplemented with Dreger tubes for H_2S and CO_2 , used both by operators and by consultants such as SCAN. Dreger results have been 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 these 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 will 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 has confirmed that no significant scale has 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 was 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 via stored compressed air. For long term operation, an automatic start system should be provided.

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 as may be seen in Figure 4-17. Schematic diagrams of the system are presented in Figure 4-18. 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 have required excessive maintenance, perhaps precipitated by the frequent starts required by leaked-off air pressure.

4.13 Water System

Water at the site is 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, and thus water flowed 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 will 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 4.10 Instrumentation were contained in this trailer. A separate conventional trailer served as the site office.

4.16 Site Laboratory

A small skid-mounted and portable laboratory had been constructed from a transport container and 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.

It was intended that simple analytical tests on brine samples (e.g., pH, alkalinity, chloride, suspended solids, total dissolved

solids, etc.) 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 has been designed into the surface facilities. The following modes of flow testing operations may be conducted.

Test Well Direct to Surface Tankage

Test 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.

5.0 Well Completion and Perforation

5.1 Test Well

The original plan for completion of this 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 has been discussed in the geology section of Volume I, Drilling and Completion, both log and core analysis indicated a higher porosity and permeability in one of the sands (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 15,387-15,414 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 insure reliable reservoir performance testing.

Information concerning this 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 is included as Appendix I.

A temperature log was run from 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.

5.2 Disposal Well

Wireline log data and sidewall core analysis indicated that the

salt water disposal well contained numerous sand intervals between 2,500-7,500 feet 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 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 feet, 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 is included as Appendix II. Approximately 200 feet of sand were perforated in June, 1981 with a Schlumberger gun at 4 shots per foot.

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.

6.0 Flow Testing

The Testing Phase of the Sweet Lake Project was designed in three phases, the Initial Flow Test, the Reservoir Limit Test, and the Long-term Test at Design Commercial Rates. Two of these three phases have been completed. Long term (6 month) testing has also been demonstrated, although at less than commercial rates. The following sections summarize the operations during each of the testing phases. A daily, chronological description of site activities is attached as Appendix III.

6.1 Initial Flow Test

The Initial Flow Test was planned for a period of approximately 2 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. The acid treatment described in Section 5.2 eliminated these restrictions, and there was no further pressure build-up on the disposal well during subsequent testing.

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 on the test well. This information was used by Engineering Consultant J. Donald Clark and Intercomp Resource Development and Engineering and in reservoir engineering calculations. These calculations indicate 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, at 452 feet and at 1,753 from the well bore. While these may be the major sealing faults which form the graben, it is unlikely, at least in the case of the 452-foot barrier. These barriers may also be sand pinchouts, thinning, minor faulting, or simply a decrease in permeability away from the well bore.

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 estimates were proved to be

greatly in error due to metering problems and a high gas content (25-28 SCF/B) was subsequently measured.

Brine and gas samples were taken for analysis during this test. The results of these analyses are discussed in section 7.0.

Before the 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 initial test, and no elevation changes were detected. The temperature of these systems reached 215°F.

6.2 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 test 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 increase had become minimal at this time, 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.

6.3 Reservoir Limit Test

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

The Reservoir Limit Test began at 6:15 p.m. 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 were produced. The flow rate varied from a high of 16,000 B/D at 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. This was equivalent to a surface pressure of approximately 700 psi. The surface facilities do not function with greatest efficiency at wellhead pressures of less than 700 psi, so this was adopted as the lowest desirable pressure, and the flow rate was reduced to maintain this pressure.

RDI personnel and equipment were on site continuously throughout this test, as was Reservoir Engineering Consultant J. Donald Clark. Bottom-hole pressures were measured using a Hewlett-Packard quartz gauge. Data collected by RDI were used by Clark to calculate effective permeability, skin effect, completion efficiency, and distance to barriers. The results of these calculations, and comparison with interpretations by other engineers, are fully discussed in section 6.5.

6.4 Long-Term Test

The purpose of the originally planned long-term testing was to demonstrate that brine can be produced at relatively high rates (around 40,000 B/D) from a geopressured-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 the one sand that had been perforated could not sustain a 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 this time, and thus the decision was made to continue testing at variable rates from the one interval. Documentation of the daily flow rates and surface pressures is presented chronologically in Appendix III.

The long-term testing at Sweet Lake 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 was shut in only for routine maintenance until February 10, when the disposal well suddenly sanded up and would not accept brine. It is thought that this sanding up was due to backflow resulting from periods of shutting in the test well. A low range positive displacement gas meter was installed at the flare because of early measurement problems with orifices. Orifice meter calibration was also a difficulty magnified by two-phase multi-component flows.

For the most of this time, funds were very restricted, necessitating operation at only 5000 B/D to "preserve the well".

During this period of more than seven months, most of the purposes of the designed Long-Term Test were met. 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 and flared. The recovery of dissolved gas was more than adequately demonstrated. Perforation and testing of additional sands would reconfirm the technological viability of energy recovery from this resource, albeit at higher sustained rates.

6.5 Comparison of Reservoir Engineering Interpretations

The reservoir engineering consultant present on the site during testing, J. Donald Clark, made the first interpretation of the reservoir pressure data accumulated by Reservoir Data, Inc. As with the Initial Flow Test, permeability barriers were noted fairly close to the wellbore, at 318 feet, 645 feet, and 1,289 feet. These barriers do not correspond exactly to those determined during the Initial Flow Test, but do agree within the limits of accuracy of the calculations. The permeability barrier at 1,289 feet may be one of the major sealing faults, but it is unlikely that the closer barriers are the major sealing faults. These closer barriers are probably due to some other geologic cause such as minor faulting or thinning of the sand.

At the end of testing, the reservoir had been explored to a radial distance of 22,467 feet, or some 4-1/4 miles. The flow angle at this distance was estimated to be approximately 25°, and approximately 300,000,000 barrels of aquifer were explored. No barrier had been detected that would enclose the reservoir. Thus, while the distance explored through reservoir pressure data is some 4-1/4 miles, the reservoir is open for an unknown distance. The long-term testing of more than seven months indicated that this may indeed be an extensive reservoir.

Intercomp Resource Development and Engineering, Inc. worked with Clark in interpreting the reservoir engineering data. Intercomp personnel used tapes generated by Schlumberger from well logging to calculate petrophysical properties such as porosity, permeability, and salinity. These parameters were then used in computer history matching of the drawdown and build-up tests. By changing the angle of flow to 26°, a good match was made of simulated data and actual data. This angle agrees quite well with the estimate of flow angle made by Clark through on-site calculations.

Interpretations of the reservoir pressure drawdown data have been made by other interested parties, among them Systems, Science,

and Software (S-Cubed). Their report disagrees strongly with the interpretations made by Clark and by Intercomp. This analysis states that the near wellbore permeability is approximately 162 md, while the far-field permeability is only about 12 md. The change occurs around 200-250 feet from the wellbore. According to the S-Cubed analysis, no reservoir boundaries can be inferred from this data. The skin factor, as determined by both analyses, is slightly negative, indicating a stimulated well. S-Cubed reports that this may represent the presence of a very highly permeable zone in the immediate vicinity of the wellbore.

Both analyses have points to recommend them. Clark and Intercomp utilized the geologic interpretation made through well log correlation and seismic interpretation in formulating a model for reservoir engineering. Systems, Science, and Software in effect ignored the existing geologic interpretation, and devised a model based solely on reservoir engineering. However, in order to obtain a good computer history match, Intercomp moved the major faults to within 250 feet of the well. This does not agree with the interpretation made by the Magma Gulf geologist. The S-Cubed analysis states that the reservoir changes at approximately 200-250 feet from the well. Geologically, this is entirely feasible, as permeability changes, pinchouts, sand thinning, or minor faults are all viable possibilities. The S-Cubed analysis, however, further states that no reservoir boundaries can be inferred from the testing to date. This does not mesh with the known geology, because in the length of time the well was tested, the effects of the major sealing faults should have been observed. It is possible, however, that these effects were obscured by changes in flow rate or other variables.

It is the conclusion of the geologist that the reservoir does change close to the wellbore by some geologic feature other than major faulting, but that boundaries to the reservoir do exist, at least on two sides, and have been observed. It is obvious that much depends on the particular program and assumptions that are used in computer simulation.

7.0 Chemical Analytical Testing

Sampling and analytical testing of brine and gas samples were performed using a sampling frequency and 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 specific analyses, sampling procedures, and sampling frequencies were selected to provide adequate and pertinent information in four primary areas of interest and concern. These four areas were:

- solubility of methane in brine
- optimization of process facility operations (gas recovery)
- scaling and corrosion
- environmental considerations

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, will be discussed in Section 8.0, Inhibitor System.

7.1 Brine Analysis

The sampling and chemical analysis of both brine and gas from the Sweet Lake well was performed by McNeese State University. Results have been reported completely in the Proceedings of the Fifth Geopressured-Geothermal Energy Conference, 1981.

Samples were collected on June 20 and June 21, 1981 (during the Initial Flow Test) and on July 2, 1981 (during the Reservoir Limit Test). The results of these analyses are presented in Table I. 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 predicted value, primarily because of the higher concentration of dissolved solids. These sample analyses were confirmed by independent measurements made by Matson and Tomson, operators, and IGT personnel. It should be noted that analyses made by separate contractors were very consistent, and that the analyses were also consistent through time.

7.2 Gas Analysis

Gas samples were analyzed on June 21, July 13, and August 7, 1981. The results of these analyses are presented in Table II. The gas, as expected, predominantly methane, with minor amounts of other hydrocarbons and 8-10% carbon dioxide. This analysis is quite similar to analyses of gas obtained from other geopressured-geothermal wells.

7.3 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.

Samples were sent to Weatherly Laboratories for recombination studies. The results indicate that the brine should contain 34 SCF/B at saturation, which would mean that the Sweet Lake brine is 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 is 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.

The orifice measurement errors at Sweet Lake centered around precise orientation, flow direction, dimensioning, and two-phase flow peculiarities.

8.0 Inhibitor System

The scaling/corrosion inhibitor injection system consists of two 60-gallon inhibitor storage tanks with gauge glasses, three 30 gph Milton Roy positive-displacement injection pumps with pulsation dampers and a maximum discharge pressure of 7,500 psig, and associated pressure relief valves, gauges, and piping. Control of the system is manual based on observation of coupons.

The system was designed such 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 as a function of the micrometer setting. Scaling has never been a problem at Sweet Lake. At times it has been necessary to add an anti-freeze chemical to the inhibitor to preclude its freezing at low flow rates and low ambient temperature.

Inhibitors from pump discharges are injected through separate piping into the 8-inch brine line between the Gray choke valves and the turbine flow meter. It was desired to inhibit at the highest possible pressure point in the system to prevent corrosion and scale. The focus of effort was control of scale, not corrosion. Dealing with the scale has effectively taken care of corrosion, although mechanical erosion has been a problem.

8.1 Inhibitor Pilot Plant

Scaling/corrosion processes were anticipated to cause substantial problems in long-term, continuous geopressured-geothermal well operations. Therefore, understanding and inhibition of these processes is considered to be of major importance. Through consultation with Mason Tomson of Rice University and Jack Matson of the University of Houston, an inhibitor pilot plant was designed and constructed explicitly to study these scaling/corrosion processes and their mitigation through the use of appropriate inhibitors in actual flowing brine conditions without jeopardizing full-scale facilities.

The inhibitor pilot plant was effectively a miniature version of the full-scale surface facilities for geopressured-geothermal well testing, in which the effects of various inhibitors could be evaluated. A brine slipstream of 2-15 gpm (69-518 B/D) was pressured through the pilot plant from the brine line upstream of the separator in the main surface facilities and then discharged back into the brine line to the disposal well.

Studies and evaluations of various inhibitors and combinations of inhibitors were scheduled for the pilot plant. These studies were to

have demonstrated the optimum concentration and type(s) of inhibitor to control scaling/corrosion in the main surface facilities. Unfortunately, due to technical and mechanical difficulties the pilot plant was never used to perform these studies. Instead, the optimum inhibitor concentration was determined through experimentation with the main facilities, with no resultant damage. The pilot plant could be used for fine tuning, but this has not been necessary.

8.2 Inhibitor Concentration

Discussions with personnel from Rice University, The University of Houston, and McNeese State University (all working under separate contracts) led to the conclusion that use of a commercial inhibitor would prevent interpretation of the chemical reactions occurring in the surface facilities. This would result because the compositions of commercial inhibitors are proprietary. It was therefore decided that use of a generic chemical would prove to be not only cheaper, but also necessary to the understanding of the chemistry involved.

AMP-20 is such a generic chemical. 10 ppm was deemed to be a reasonable starting concentration; too low a dosage and scaling would not be inhibited but too high a dosage would actually cause precipitation of the inhibitors. This concentration was gradually lowered through experimentation, until a minimum of 1 ppm was reached. Lower concentrations allowed scale to form. The cost of this concentration of inhibitor, even at high flow rate, was on the order of pennies per day.

9.0 Related Work

Although the major cost of the Sweet Lake project was funded by the Department of Energy, some related research was funded by the Gas Research Institute. Information obtained from these research projects was used during the drilling of the well and during the testing phase, to refine geologic interpretations and reservoir models. Projects funded by GRI included mud logging, micropaleontology, organic geochemistry, core analysis, and rock mechanics.

Mud logging and micropaleontology were most useful during the drilling phase of the Sweet Lake project. Core analysis was important in geologic interpretation and designating perforation intervals. Organic geochemistry provided information on the hydrocarbon potential and maturation of the area. The rock mechanics studies obtained numerical data useful in reservoir engineering calculations.

This section will briefly describe each of these research projects and the implications for the Sweet Lake Project. These summaries are excerpts from "Geopressured Well Project: Sweet Lake, Cameron Parish, Louisiana", the Final Report from Magma Gulf Technadrill to the Gas Research Institute. Complete reports on each of the research projects can also be found in the Geopressured Well Project, Sweet Lake, Cameron Parish, Louisiana, Final Report (GRI-79/0125).

9.1 Mud Logging

Mud logging provides much useful information to both the geologist and the driller as the well is being drilled. This information is particularly useful in wildcat locations, in areas where abnormal pressure is encountered, or in situations where careful, daily evaluation of the lithology is important.

Integrated Drilling and Logging, Inc. (IDL) performed the mud logging of the Sweet Lake test well. They came onto the site when the well had reached a depth of 6,000 feet. The mud loggers monitored various parameters from 6,000 feet to total depth of the original hole (13,550 feet), and from the top of the sidetrack (10,600 feet) to the total depth of the sidetrack hole (15,750 feet). These parameters included:

- 1) Drilling rate. The penetration rate was measured through mechanical means and was converted to an estimate of porosity. This estimate later proved to be quite close to the porosity measured from diamond and sidewall core samples.

- 2) Pore pressure. Since at least 5,000 feet of hole was to be drilled in geopressured strata, knowledge of pore pressure was important so that the mud weight could be adjusted correctly to prevent under or overbalancing.

3) Lithology. The well cuttings were examined at thirty foot intervals and a lithologic description made.

4) Mud temperature. The mud temperature was monitored both going into the hole and coming out. This provided some indication of the heat downhole.

5) Gas. The gas content of the drilling fluid was closely monitored in case any shows should occur. It should be noted that gas shows recorded by IDL indicate free gas, not the dissolved methane present in geopressured-geothermal brine. Two shows were noted, at 10,785 feet and 12,885 feet, both rated as fair. These were well above the target sand.

6) Other. Information such as mud weight, weight on bit, and rpm were also noted and recorded. Trips and connections were marked on the log.

The mud log had particular significance to the daily correlation of the test well with the three key control wells. The lithologic description, along with the resultant lithologic log, was compared and correlated to the control well wireline logs. This continuous correlation allowed the geologist to identify the particular strata of the section that the well was drilling through at any given time, which has several implications to the geologic interpretation of the area.

As the test well was located in a graben in which there was fairly sparse well control, the exact location of the major bounding faults was not precisely known. Thus, the possibility existed that one of the faults could have crossed the wellbore above the Miogypsinoides sand. If this had been the case, the wellbore would not have penetrated the Miogypsinoides sand. The discrepancy in the stratigraphic section between the test well mud log and the control well wireline logs that would have indicated this fault would have been noted quickly through the continuous correlation, and appropriate action could have been taken immediately. Fortunately, no such fault crosses the wellbore.

The structure map and contours in Figure 2 had been derived for the interior of the graben primarily from seismic interpretation. Thus, although the Miogypsinoides sand was expected at 15,000 feet, the actual depth could have been several hundred feet higher or lower. The correlation of the mud log with the control well logs enabled the geologist to note any thickening or thinning of the stratigraphic section and to update the predicted depth of the Miogypsinoides sand accordingly. Some thickening of the section was noted, but the Miogypsinoides sand was encountered quite close to the original expected depth.

In addition to the duties described above, the mud loggers were also responsible for taking samples of well cuttings for micropaleon-

tological and organic geochemical analyses. Additional sets of well cuttings were also taken for future research. These samples have now been donated to the Louisiana Geological Survey, the University of Texas Bureau of Economic Geology, and McNeese State University.

9.2 Micropaleontology

Micropaleontological analysis identified microfossils present in well cuttings. This acted as another important correlation tool. Samples of well cuttings were taken every thirty feet and shipped periodically to Paleo-Data, Inc. From 4,000 feet to 6,000 feet these samples were collected by rig personnel, and from 6,000 feet to total depth by the mud loggers. At Paleo-Data, the cuttings were washed and examined microscopically for micro-fossils. The fossils were identified and the cuttings described lithologically. Paleo-Data reported important correlation fossils to Magma Gulf-Technadril as soon as they were identified. Paleo-Data had also identified fossils in the two control wells closest to the test well, the Union of California Pan Am Fee #1 and #2. The microfossil picks from the test well could thus be compared to two control wells. This information helped indentify placement in the stratigraphic section. The picks that were important in correlation are as follows:

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

Micropaleontological analysis was important to the geologist and the driller for many of the same reasons as mud logging. If a major fault crossed the wellbore, it would be immediately noted by a change in the microfossils present in the cuttings. Again, because the placement of the major growth faults was not precisely known, it was possible that the test well would cross one of them. If it had, the micropaleontology would have documented not only the placement of the fault, but also its throw, and appropriate action could have been taken immediately. The microfossil picks also served as an additional point of reference in determining if the stratigraphic section had thickened or thinned. This information, in conjunction with analysis of the mud log, was useful in updating the predicted depth of the Miogypsinoides sand.

Picking the precise top of the Miogypsinoides sand was important not only for correlation purposes, but also because of the planned coring program. Several researchers were interested in obtaining core from the sand as close to the transition zone between shale and sand as

possible. Thus it was important to stop drilling at the top of the sand. Mud logging or driller's logs could not be used to pick this point, as they require drilling through the formation to get data. As noted from the control wells, however, the *Miogypsinoides* microfossil first appears in the shale 30 to 100 feet above the sand. Since this was the only way to spot the top of the sand, it was imperative to identify the fossil as soon as it appeared in the cuttings. Accordingly, John Dunlap, Jr. came to the site in late December, 1980, and picked the *Miogypsinoides* microfossil at approximately 4:30 p.m. on Christmas Day, 1980.

9.3 Organic Geochemistry

Organic geochemical analysis was undertaken by Hartax, Int. to investigate four major areas. 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 reservoir oil or gas encountered during the drilling of this well as a means of determining whether or not such shows represent indigenous hydrocarbon 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 reservoir 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 hydrocarbons analysis, C₁₅+ liquid chromatographic separation, total organic carbon analysis, visual kerogen assessment, and vitrinite reflectance analysis.

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 9-1.

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 3,300 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 Myogysinoïdes sand. This was therefore the zone of primary interest to Magma Gulf Technadril.

The Zone E sediments grade from a slightly calcareous shale through siltstone to a coarse quartzose sand. The analyses suggest that this sand contains migrated out-of-place hydrocarbons. The sediments do not contain any indigenously generated hydrocarbons. Discussions with George Hart of Hartax and Geoffrey Bayliss of GeoChem indicate that there are no sediments studied in the Gulf Coast area that have buried deeply enough to be thermally mature, and thus to have produced indigenous hydrocarbons. This implies that the results from the Sweet Lake well (i.e. sediments not thermally mature) could have been predicted. The lack of thermally mature sediments then raises the question of what source could have produced the gas that is contained in the Sweet Lake reservoir. This may be an area where the theory of abiogenic methane outgassing through lower crustal rocks should be investigated.

9.4 Core Analysis

There are many tools that can be used in geologic interpretation of wells, such as mud logs, wireline logs, and micropaleontology, but for many tests there is no substitute for an actual sample of the rock involved. Particularly because the Sweet lake well was the first geopressured-geothermal well to be drilled in Louisiana, there were many scientists who wished to obtain core samples for their research projects. After discussion between scientists and drillers, it was decided to make four coring runs, each 40 feet in length, with the first core taken at the top of the Miogysinoïdes sequence. Four two-inch diameter diamond cores were taken, but none recovered the entire 40 feet. Recovered intervals are as follows:

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

These intervals are shown on the log in Figure 9-2.

Core Laboratories, Inc. had the contract for core analysis. This

included bench condition analysis for porosity and permeability, grainsize analysis, and gamma ray logging. Core Laboratories personnel were onsite to receive the core as it came out of the hole. It was bagged in plastic and brought to Houston, where a sample from each core was taken for porosity and permeability analysis. The remainder of the core was preserved in sealable plastic, pending distribution to reseachers.

In addition to the diamond cores, 44 sidewall cores were taken in the test well. These were taken over most of the stratigraphic section, from 6,490 feet to 15,075 feet. As these samples were above the Miogypsinoides sand, they did not bear directly on reservoir performance. The information was, however, useful in evaluating variations between hydro pressured and geopressed formations, and in comparing core analysis to wireline log analyses.

Conventional core analysis of the diamond cores showed that the Miogypsinoides sands had porosities of 14-24%, and air permeabilities of 4-3,670 md. (It should be noted that the low permeabilities were taken from shaly samples and may not be representative of the producible sands.) The high air of permeability is equivalent to a water permability of approximately 400 md. This is still a very high value, and is consistent with the high porosity. Grain size analysis by conventional sieve analysis showed that the cores are primarily fine-grained, with some very fine-grained and silt-size material. X-ray diffraction analysis of diamond core material by Accumin Analysis determined that the Miogypsinoides sand consists of 75% quartz, 19% feldspar, 4% illite, 2% illite/smectite (a mixed-layer clay), and a trace of kaolinite. Scanning electron microscope photographs show that the cementing material is quartz overgrowth, and that the clays are present as fine hairs lining the pores. Core Laboratories analyzed 3 sidewall core samples from the test well (7,020 feet, 7,050 feet, and 7,090 feet) by X-ray diffraction and concluded that these sands consisted primarily of quartz (89-97%), with some feldspar and a trace of calcite.

Twenty-nine sidewall cores were collected from the disposal well, from 6,580-6,720 feet. These cores were taken to confirm adequate porosity and permeability for disposal of the geopressure brine. Porosity ranged from 25 to 30%, and air permeability from 200 to 2000 md, with an average of 1 darcy. These results indicated that these shallow sands would be capable of accepting large quantities of brine.

The tests performed by Core Laboratories were important not only to confirm the potential for high-volume brine production and disposal, but were also instrumental in the selection of a perforation interval. The extremely high porosity and permeability of the 15,385-15,414 foot interval, in conjunction with its discrete log character, led to the decision that this would be the optimum sand for the initial test. The high permeability would allow reservoir limits and characteristics to be determined in a minimal time. From examination of the log, it

appeared that this sand was not in communication with any other sand in the sequence, eliminating complications in interpreting the reservoir engineering data. The porosity measurements made by Core Laboratories were used in the reservoir engineering calculations. The calculated water permeability was 344 md, quite close to the expected value.

The core that was not used in the above analyses was distributed to the following, according to their requests:

K.E. Gray, University of Texas
D.G. Bebout and R. Ferrell, Louisiana Geological Survey
J. Schatz, Terra Tek
T. Kraemer, U.S. Geological Survey
W. Rose, Institute of Gas Technology
G. Hart, Hartax, Int.
G. Pittman, Amoco Production

9.5 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 would thus yield information on long-term reservoir behavior, and also provide numerical values of certain parameters which can 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. 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 their work.

9.5.1 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 the 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.

9.5.2 Creep Measurements

The compaction measurements discussed in the previous section describe 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 dependent non-elastic 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 these 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.

Alternatively, 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. In general, creep curves generated by this model also show a good fit to measure data. Neither the delayed elastic nor the strain hardening model can be described as the preferred model at this time.

9.6 Core and Sample Distribution

All diamond core material was distributed to the researchers named in Section 9.4. Sidewall core material was returned to MG-T after Core Labs completed analysis and is presently stored in MG-T offices.

Two additional sets of well cuttings were collected at the time that the sets for micropaleontology and organic geochemistry were collected. One set was donated to Louisiana State University Department of Geology and the other to the Bureau of Economic Geology, University of Texas at Austin. In addition, selected well cuttings were donated to McNeese State University.

10.0 Conclusions

The MG-T/DOE Amoco Fee #1 well, completed in February 1981, penetrated the Miogypsinoides sand of the Upper Frio formation. The use of mud logging and micropaleontology provided continual correlation with control well logs, and enabled site personnel to pick the top of the Miogypsinoides sand at 15,065 feet. The measured core porosity (14-24%) was very close to the predicted value. The air permeability value of Sand 5 (3.5 darcys) was much higher than expected, and was one of the primary reasons for selecting Sand 5 as the first perforation zone.

Organic geochemical analysis of the well cuttings showed that the sediments of the Miogypsinoides sequence had not been buried deep enough to produce indigenous hydrocarbons. Any gas or oil present in these rocks thus presumably migrated there. Discussions with the subcontractor responsible for the organic geochemistry after the research was completed revealed that no Gulf Coast sediments studied to date have reached thermal maturity; that is, no Gulf Coast sediments appear to have been buried deep enough to produce indigenous hydrocarbons. Therefore, the results of the organic geochemical analysis of the Sweet Lake well could probably have been predicted. As the results would be nearly the same for any geopressured-geothermal well drilled in the Gulf Coast, the use of organic geochemistry on any future wells is not recommended. However, as a source for the hydrocarbons must exist, the theory of abiogenic methane outgassing from the crust should be investigated in this area.

Rock mechanics testing, both elastic (non-time dependent) and creep (time dependent), of each of the four cores indicates that rock compaction will probably contribute little to reservoir pressure maintenance. Both porosity and permeability are reduced under reservoir conditions. Data accumulated from this testing has been used to develop a mathematical model to explain creep behavior, and has been used by reservoir engineers to refine the models used to describe reservoir size and behavior.

The dissolved gas content of the brine is 25-28 standard cubic feet per barrel. Initial metering problems were resolved through the use of proper orifice plates and the installation of a positive displacement meter. This brine may be slightly undersaturated with respect to methane, as recombination studies show that this brine should contain 34 SCF/B at saturation.

The use of a generic chemical (AMP-20) to inhibit scale was very successful. Scale has not been a problem at Sweet Lake. Efforts were concentrated on preventing scale, with the assumption that if scale was inhibited, corrosion would also be inhibited. This assumption appears to have been correct, as corrosion has not been a problem Sweet Lake.

The drilling and testing of the Sweet Lake well has demonstrated that the geopressured resource is recoverable with present technology. Testing of one sand has shown that heat and dissolved gas are present in sufficient quantities to be usable. However, this one sand alone cannot support production at commercial rates (40,000 barrels per day). Future long-term testing of

additional sands in the Miogypsinoides sequence, both above and below Sand 5, would determine if the reservoir is sufficiently large to produce commercial quantities of geopressured-geothermal brine. It was nominally expected that a well producing 40,000 barrels per day could be economically viable. However, experience at Sweet Lake and costs of the facility indicate that this is still not so. Operational costs can be recovered through sales of gas and electric energy, but recovery of capital cost does not appear to be feasible.

FIGURE 2.2

MEASURED AND CALCULATED POROSITIES AND PERMEABILITIES

Sand Depth	Net Sand	Porosity, %				Permeability, md				Hydraulic Capacity, md-ft	Percent Hydraulic Capacity
		Core	Saraband	Neutron-Density Crossplot	Intercomp	Core, Air	Saraband, Air	Intercomp, Air	Estimated, Water		
15080-15144	41'	16.6	12.3	15.7	16.34	30	175	275	20	820	3.71
15170-15240	42'	16.3	12.1	14.6	13.86	122	143	48	20	840	3.80
15250-15285	27'	--	15.4	20.0	20.42	--	700	1011	140	3,780	17.11
15305-15355	25'	--	15.3	18.8	18.12	--	750	690	140	3,500	15.85
15385-15415	27'	24.3	19.0	23.2	20.84	3670	2960	2703	400	10,800	48.89
15460-15505	41'	--	12.2	15.0	15.69	--	130	90	20	820	3.71
15520-15600	51'	--	12.9	17.3	16.30	--	280	143	30	1,530	6.93
TOTAL	254'									22,090	100.00
	****									*****	*****

MGT-DOE AMOCO FEE #1

Baker Model "L" Sliding
Sleeve w/ Model "F"
seating Nipple
@ 14476'± to 14480'±
(4.31" X 4.22')

BOT Seal
Assembly (4.125" I.D. X 25.66')
@ 14520'± to 14546'±

Perforations:

15,387' to 15,414' EL

0 - 13339.94' 5 1/2" 23# C-95 Exline (334 jts) ** See Attached Tubing Setting
13339.94 - Seal Assembly 5 1/2" 25.54# S0095 FL4S (27 jts)

	<u>Collapse</u> (psi)	<u>Burst</u> (psi)	<u>Tension</u> (lbs)	<u>I.D.</u> (inches)	<u>Drift</u> (inches)	<u>Capacity</u> (Bbls/ft)
5 1/2" 23# C-95 Exline	12,920	12,540	606,000	4.545*	4.42*	0.0211
5 1/2" 25.54# S0095 FL4S	15,020	14,390	513,000	4.423*	4.298*	0.02
7 5/8" 39# C-95 Exline	9,980	10,900	941,000	6.625	6.50	0.0426
5 1/2" X 7 5/8" Annulus	(Cross-section area = 6.21 in ² or Equivalent to a 3.17 in. diameter)					0.0133

* All 5 1/2" Tubing is plastic coated and therefore the I.D. and Drift listed are reduced by an 1/8 (.125) inch.

Also, the smallest restriction in the 5 1/2" tubing string is the seal assembly (4.125" (4 1/8") X 25.66'). The 5 1/2" seal assembly is rated for 11,138 psi (collapse) and 14,474 psi (burst).

FIGURE 3-1

MGT - DOE AMOCO FEE NO.2
SALT WATER DISPOSAL WELL

FIGURE 3-2

FIGURE 4-1
SWEET LAKE SITE PLOT PLAN

MGT/DOE AMOCO FEE NO.1
TEST WELL

FIGURE 4-4
TEST WELLHEAD AND CASING SPOOLS

TEST WELLHEAD

CASING SPOOLS

FIGURE 4-5

FIGURE 4-6
GRAY CHOKE VALVE MANIFOLD
50

PBS (Pressure Balanced Stem) Choke

The PBS choke is a new Gray design for low torque operation at flow rates in the 5,000 to 10,000 psi range where large bore (2" to 6") service is needed.

As with all Gray chokes, the PBS choke can be supplied with either an adjustable or a positive bonnet.

Standard trims are used for various applications, but special trims can be developed to meet customer specifications. A variety of hardened steel and carbide tips and beans is also available.

Design Features

Pressure Balanced Stem

To balance the forces exerted on the metering tip, the PBS choke equalizes the effective piston areas in opposing directions in the upstream and downstream pressure cavities. This system produces very low torque characteristics over a broad flow band.

Metal-to-Metal Seal

A tapered metal-to-metal seal with hydraulic packing backup between the body and bonnet is provided by the lower housing. All PBS chokes are supplied with a GRAYLCC clamp to energize this seal. The backseat also forms a metal-to-metal seal.

Low Torque Design

The PBS choke operates with low torque. Its unique design minimizes the tip load on the stem; exposes the stem packing to only the lower downstream pressure, not the higher upstream pressure; and provides modified Acme threads on the stem and floating drive bushing.

Interchangeable Metering Tips

The three metering tip designs—sliding sieve (for gas and light liquids), full bore (for oil and heavy crude), and a special cleanup tip—are the key to the versatility of the PBS choke. All three are mechanically retained, field replaceable, and completely interchangeable. They are available in a wide variety of materials, including hardened carbon steel, stainless steel and tungsten carbide.

To inhibit vortexing and subsequent erosion of downstream piping, as well as to protect the metering tip, an optional blast sieve redirects the flowstream before it encounters the metering tip.

FIGURE 4-7
CUT-AWAY DIAGRAM OF GRAY CHOKES
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Square Body Construction

Smallest of the angle body line, the M1 valves are easily recognized by their bonnetless, square body construction. The sides of the valve body are flat and allow end connection hubs to be bolted directly to them. Thus, flanges are removable. This unique feature makes the M1 valves especially suited for compact installations such as manifolds or headers. Servicing is a simple matter of disconnecting the outlet flange and swiveling the valve to gain access to the trim.

Round Body Construction

Valves in sizes 2" through 6" are of round body construction, and are generally used for high pressure applications. Valves are available for working pressure up to 20,000 PSI.

All weldable bar stock materials can be used for body and end connection fabrication.

1. Stationary BACK DISC holes are aligned with inlet flow helping to produce the near linear flow characteristic standard to all Willis Multiple Orifice Valves.
2. Rotating FRONT DISC floats freely producing a tighter seal as pressure increases.
3. Unique TURNING FORK engages outer rim of disc assembly reducing flow interference to a minimum.
4. Groove contained THRUST BEARING provides support at full working pressure without bearing distortion.
5. Standard O-RINGS and BACK-UP RINGS are used eliminating the need for special gaskets or packing and its periodical adjustments.
6. Calibrated INDICATOR HEAD adjusts from closed to full open in 90° rotation. MOV's easily adapt to Willis Stepping Actuators or Diaphragm Actuators.

FIGURE 4-8
CUT-AWAY DIAGRAM OF WILLIS CHOKE VALVES

FIGURE 4-9
BRINE/GAS SEPARATOR SYSTEM

FIGURE 4-11
BRINE FILTER SYSTEM

FIGURE 4-12
SALT WATER DISPOSAL WELLHEAD AND CASING SPOOLS

FIGURE 5-13
SALT WATER DISPOSAL WELLHEAD

FIGURE 4-14
ESD SYSTEM LAYOUT
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FIGURE 4-15
ESD CONTROL PANEL

FIGURE 4-16
CONTROL SCHEMATIC - ESD SYSTEM
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FIGURE 4-17
INSTRUMENT AIR SYSTEM

FIGURE 9-1 Summary figure of organic geochemistry analyses

FIGURE9-2Dual induction log of the Miogypsinoides sequence in the MG-T/DOE Amoco Fee #1. Black intervals are cored intervals.

TABLE I
BRINE ANALYSIS

<u>COMPONENT</u>	<u>RICE</u> <u>6/19/81</u>	<u>MCNEESE</u> <u>6/20/81</u>	<u>MCNEESE</u> <u>6/21/81</u>	<u>MCNEESE</u> <u>7/2/81</u>
PH	6.08	5.6	6.0	5.66
ALKALINITY (PPM AS HCO ₃)	390	317	256	261
DISSOLVED SOLIDS	165,000	156,900	164,900	166,500
CONDUCTIVITY (U MHOS/CM)	225,780	162,000	177,000	165,000
TOTAL HARDNESS (MG/L)	35,039			
SODIUM		42,000	45,000	46,000
POTASSIUM		1,690	1,720	1,740
CALCIUM	12,530	11,200	11,900	11,000
MAGNESIUM	720	630	680	
IRON	190	52	58	59
STROTIUM		840	970	850
CHLORIDE		92,340	100,000	99,350
SULFATE	50			
PHOSPHATE	< 10			
SULFIDE	< 0.5	1.2	0.1	
SILICA, DISSOLVED	118	113	120	112
H ₂ S (PPM IN GAS)		0.6	20	.4

TABLE II
GAS ANALYSIS

<u>COMPONENT</u>	<u>WEATHERLY 6/22/81 MOL %</u>	<u>WEATHERLY 7/13/81 MOL %</u>	<u>CHROMASPEC 8/7/81 MOL %</u>
CARBON DIOXIDE	5.90	5.50	10.59
NITROGEN	0.15	0.55	0.24
METHANE	91.86	92.18	87.28
ETHANE	1.72	1.51	1.63
PROPANE	0.28	0.20	0.23
ISO-BUTANE	0.02	0.01	0.01
N-BUTANE	0.03	0.02	0.01
ISO-PENTANE	0.00	0.00	0.00
N-PENTANE	0.01	0.01	0.00
HEXANES	0.00	0.00	0.00
HEPTANES PLUS	<u>0.03</u>	<u>0.02</u>	<u>0.00</u>
TOTAL	100.00	100.00	99.99

APPENDIX I

MAGIA-GULF COMPANY
PROPOSED PRODUCTION INTERVAL
MG-T/DOE AMOCO FEE #1
SWEETLAKE FIELD
CAMERON PARISH, LOUISIANA

KEDA PROJECT NO. 80-0079
FEBRUARY, 1981

PREPARED BY
KEN E. DAVIS ASSOCIATES

1.0 INTRODUCTION

1.1 BACKGROUND

Following the study performed by Ken E. Davis Associates (KEDA) on Magma-Gulf's MG-T/DOE Amoco Fee SWD in Sweetlake Field, Cameron Parish, Louisiana, KEDA was requested to recommend a completion interval for the geopressed production well, MG-T/DOE Amoco Fee #1. KEDA was initially contacted by Ms. Karen Hoffman of Magma-Gulf Company by telephone. Additionally, such information as logs and core data was forwarded to KEDA's Mr. Fleniken along with follow-up conversations between Ms. Hoffman and Mr. Fleniken. A verbal recommendation was telephoned to Ms. Hoffman and Mr. Bob Rogers on January 23, 1981. This report covers the review of all the information as provided to KEDA and is the basis for the recommendations made herein. Erroneous data could negate or alter calculations and/or recommendations.

1.2 SCOPE OF WORK

A complete review was made of the logs and core data which were furnished to KEDA. The logs were analyzed to determine the productivity of the target sands below 15,000'± with primary emphasis placed on the sands at 15,385 - 15,415' and 15460 - 15505'. These objective sands were evaluated for their ability to produce 40,000 barrels per day of geopressed brine water. The evaluation was performed on a high speed digital computer and consisted of calculating the hydraulic capacity in millidarcy - feet and predicting the surface pressure performance

(frictional losses included) with respect to time. In conjunction with this, the pressure effects across the perforations were also considered. The results of the analysis provides the foundation for the recommendations which follow.

2.0 DISCUSSION

2.1 BRIEF COMPLETION REVIEW

The MG-T/DOE Amoco Fee #1 is located 1650' north and 2310' east of the southwest corner of Section 13, Township 12S, Range 8W, in Sweetlake Field, Cameron Parish, Louisiana (see Figure No. 1). The well was drilled to a total depth of 15,740'_± as a geopressured test well for production testing of geopressured brine waters below 15,000 feet.

The well was cased with 7" OD casing as an intermediate string. A 6 1/2" hole was drilled out from under the 7" OD casing and through the objective zones to a depth of approximately 15,740 feet. Subsequently, a 5 1/2" OD liner was cemented through the objective zones. It is KEDA's understanding that production will be through the 5 1/2" OD casing to the surface.

The geopressured sands of major concern are those sands below 15,000' with the zones at 15,385 - 15,415' and 15,460 - 15,505' being given priority consideration. The purpose of this study is to select sufficient footage having adequate permeability and perforation density to yield approximately 40,000 barrels of brine per day.

2.2 GEOLOGY

Geologically, the production sand lies within a graben and is bounded by two faults. This is shown in Figure No. 1, which is a structure map of the production sand, (Miogyp Sand).

Conventional cores were obtained from the well at the following depths:

- a) Core No. 1 (15,144 - 15,184')
- b) Core No. 2 (15,185 - 15,201')
- c) Core No. 3 (15,389 - 15,411')
- d) Core No. 4 (15,600 - 15,634')

The results of the analysis of the cores are provided in Attachment A. As indicated by the analysis description, the Tertiary Age Sands of the U.S. Gulf Coast typically show fine to very fine grain with small quantities of silt. The permeability values appear to be somewhat low for Core No. 1 and Core No. 4. Core No. 2, having a horizontal permeability of 122+ millidarcys, is the most representative analysis. This measurement is typical of that found in other penetrations in the Frio Sands between 12,000' and 20,000'. KEDA has reservations as to the accuracy of the 3 to 4' darcy determination for Core No. 3 (15,403 - 15,403.5') and feels such values are perhaps the result of a faulty test. Therefore, for purpose of evaluating the zones of interest in the sections to follow, an average effective permeability of 120 millidarcys has been used.

Analysis of both the compensated neutron-formation density log and the computer process log indicate comparable values for porosity which appear to be in the proper order of magnitude.

2.3 RESERVOIR PARAMETERS

The expected production performance evaluation is based on calculations made with the aid of a high speed digital computer

and the production zone data listed below. The basic mathematical theory of fluid flow through porous media was applied and calculations were performed to determine the surface pressure effects for various hydraulic capacities. Computer runs were made at capacities of 8,000, 10,000 and 12,000 millidarcy - feet for rates of 30,000 and 40,000 BWPd. The results of these computations are graphically illustrated in Figure No. 2. From this data sufficient net reservoir thickness was selected to provide adequate surface pressure for geopressure brine surface treatment. It was assumed that the required flowing surface pressure would be 1000 psi or greater.

2.3.1 PRODUCTION ZONE DATA

Average depth, feet	15,400
---------------------	--------

Top sand section, feet	15,385 - 15,416
------------------------	-----------------

Lower sand section, feet	15,461 - 15,505
--------------------------	-----------------

(based on ISF/Sonic dated 1-17-81)

Anticipated reservoir pressure, psi	12,000
-------------------------------------	--------

Viscosity of produced brine, cps	0.280
----------------------------------	-------

Average porosity, percent	20
---------------------------	----

(based on core data and computer processed
log dated 1-17-81)

Average effective permeability, millidarcys	120
---	-----

(based on core data)

Effective brine compressibility, psi^{-1}	0.6×10^{-5}
--	----------------------

Bottomhole pressure gradient, psi/ft	.0785
--------------------------------------	-------

Wellbore radius, inches	2.3
Fluid density, lb/gal	8.56
Tubing inside diameter, inches	4.6

2.3.2 INITIAL RESERVOIR PRESSURE

The initial reservoir pressure of the target producing zones at 15,385' and 15,416' is expected to be approximately 12,000 psi. A pressure recording obtained by wireline tester (called repeat formation tester, RFT) on the sand at 15,070 - 15,150' indicated a bottomhole formation pressure of 11,900 psi. The anticipated initial bottomhole pressure was estimated by extrapolation to a depth of 15,400 feet so the two zones of interest could be evaluated as a unit sand member.

2.4 PERFORATION PRESSURE EFFECTS

When considering the most efficient design for high rate production, perforation density, diameter and penetration depth become the most critical factors. These factors should be analyzed collectively with the required hydraulic capacity to provide maximum diameter penetration and adequate density to afford minimal pressure drops. Since extensive studies have not been completed, investigating the basic sanding mechanisms for geopressured hot water wells, all of the above factors, should be considered in attempting to control sand influx. Limited tests in other geothermal wells have proven that sand influx is rate sensitive, i.e.,

there is a critical velocity at which the sand begins to flow through the perforations. By designing for minimal pressure drops across the perforation, there is a better chance that destruction to the formation stress state will not occur and cause a consequent large influx of sand. The 5" liner limits the perforation diameter to approximately 0.38 inches. Therefore, the abovementioned conditions can best be accomplished using a casing gun having an equivalent perforation diameter and a penetration range of 10 - 15" based on API test methods (see API RP43).

The pressure drop across the perforations can be mathematically determined using the following equation.

$$P_f = \frac{PQ^2}{8090 A_p^2}$$

Where: P_f = pressure drop across perforation is psi

P = density of injected fluid in #/gal

Q = production rate in GPM

A_p = effective cross sectional area of
perforations in in²

If this equation is applied for the following conditions,

- a) perforation density - 4 shots per foot
- b) perforation diameter - 0.38 inches
- c) production rate - 40,000 BWPD
- d) perforation interval - 75 feet

the pressure drop is negligible (3.5 psi) when also assuming that only 40% of the perforations are open.

An additional factor which would also affect the pressure drop across the perforations is skin damage due to perforation plugging or particulate invasion into the near wellbore area. These phenomena could be evaluated during the initial testing of the well. In the event it is determined that more perforations are required, the target zone could be re-perforated under dynamic conditions. Many of the perforating service companies offer a high pressure lubricator, which is easily rigged and capable of handling pressures in excess of 15,000 psi. With sufficient weight (sinker bars) added to the perforating gun, perforating under flowing pressure conditions can be accomplished.

3.0 CONCLUSIONS

- a) The target sands at 15,385' - 15,416' and 15,461' - 15,505', assuming a minimum average effective permeability of 120 millidarcys, indicate the capability of producing at rates of 40,000 BWPd with surface pressures greater than 1000 psi for a projected production period of 12 months (see Figure No. 2).
- b) The target sands provide approximately 75 feet of net reservoir thickness to yield a hydraulic capacity approaching 10,000 millidarcy - feet.
- c) KEDA has reservations regarding the accuracy of the core analysis and has based the ability of the well to produce on a minimum hydraulic capacity of 10,000 millidarcy - feet.
- d) Theoretical calculations indicate that negligible pressure drop occurs across the sands of interest (75') at a perforation density of four (4) shots per foot.
- e) In the event initial testing indicates a necessity to open additional sand intervals to the wellbore or increase the perforation density this can be accomplished under flowing conditions.
- f) Sand production is evident in high volume production wells and should be expected.

4.0 RECOMMENDATIONS

- a) Displace the mud system with 10#/gal filtered brine water (< 5 micron). This will provide a pressure differential to clean the perforations of debris and assist in formation clean up.
- b) Perforate the intervals 15,385 - 15,416' and 15,461 - 15,505' at four (4) shots per foot using a Schlumberger 2 7/8" Hollow Carrier Gun (or equivalent). These measurements were taken from the Dual Induction - SFL - Sonic log dated 1-17-81. Borea sandstone test shots with this gun show an average penetration depth of 13.67 inches and a hole diameter of .38 inches.

FIGURES

FIGURE NO. 1

SURFACE FLOWING PRESSURE - PSI

FIGURE NO. 2

PRESSURE BEHAVIOR
PREDICTION

CORE ANALYSIS

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
 DALLAS, TEXAS

GALMA GULF - TECHNIDRILL
 O.U.E.-AMCO FEE NO.1
 WILDCAT
 CAMERON PARISH, LOUISIANA

DATE : 7-JAN-81
 FORMATION : FRIO
 DRLG. FLUID:
 LOCATION :

FILE NO : 2202-12676
 LABORATORY: HOUSTON, TX
 ANALYSTS : MASON
 ELEVATION :

CONVENTIONAL CORE ANALYSIS

SNP NO	DEPTH	PERM MD (KA) HORZ	VERT	POR %	OILZ PORE	WTRZ PORE	PROD PROD	GASZ BULK	GRAIN DEN(M)	DESCRIPTION
CORE NO.1 15144.0 - 15184.0 CUT 40 FT REC 35 FT										
1	15144.0-44.4	27.	34.	16.6	0.0	48.5		8.6	2.66	SD F-HG SSLTY N FLU NO ANALYSIS BY REQUEST SD F-HG SSLTY N FLU NO ANALYSIS BY REQUEST SHALE LOST CORE
	15144.4-52.0									
2	15152.0-52.4	32.	2.65	14.3	0.0	39.3		8.7	2.67	
	15152.4-63.0									
	15163.0-79.0									
	15179.0-84.0									
CORE NO.2 15185.0 - 15201.0 CUT 16 FT REC 12.5 F										
	15185.0-91.0									NO ANALYSIS BY REQUEST SD N-CG SSLTY N FLU NO ANALYSIS BY REQUEST LOST CORE
3	15191.0-91.4	122.	93.	16.3	0.0	71.2		4.7	2.64	
	15191.4-97.5									
	15197.5-01.0									
CORE NO.3 15309.0 - 15411.0 CUT 22 FT REC 16.5 F										
	15309.0-03.0									NO ANALYSIS BY REQUEST SD N-CG SSLTY N FLU NO ANALYSIS BY REQUEST LOST CORE
4	15403.0-03.5	3670.	3526.	24.3	0.0	81.2		4.6	2.65	
	15403.5-05.0									
	15405.0-11.0									
CORE NO.4 15600.0 - 15634.0 CUT 34 FT REC 32 FT										
	15600.0-04.1									NO ANALYSIS BY REQUEST SD F-VFG SLTY N FLU
5	15604.1-04.5	4.29	5.23	18.8	0.0	49.3		9.5	2.66	

APPENDIX II

MAGMA/GULF COMPANY
PROPOSED INJECTION INTERVAL
MG-T/DOE AMOCO FEE SWD
SWEETLAKE FIELD
CAMERON PARISH, LOUISIANA

KEDA PROJECT NO. 80-0079
NOVEMBER 28, 1980

PREPARED BY
KEN E. DAVIS ASSOCIATES

1.0 INTRODUCTION

1.1 BACKGROUND

As a result of several telephone conversations between Mr. Ken Davis of Ken E. Davis Associates (KEDA) and Mr. Bob Rogers of Magma/Gulf Company, KEDA was contracted to provide recommendations for the selection of a completion interval in the Amoco Fee SWD in Sweetlake Field, Cameron Parish, Louisiana. Information such as logs, core analyses and a drilling completion program, was provided to KEDA by Ms. Karen Hoffman of Magma/Gulf along with information obtained during telephone conversations between KEDA's Mr. John Fleniken and Ms. Karen Hoffman. This report is a review of the aforementioned information based on technical merit and is the basis for the recommended completion interval. The historical review section is a brief outline of KEDA's understanding of the past operations. Erroneous data in this section could negate associated calculations and recommendations.

1.2 SCOPE OF WORK

Initially, a review of all the data provided for this study was made. Considering the present condition and existing completion of the well the objective sands were analyzed for their ability to dispose of brine waters at rates of 40,000 barrels per day (BPD) and 60,000 barrels per day. The analyses consist of calculating the required reservoir thickness for disposing of 40 - 60,000 BPD determining the frictional loss in the 7" O.D. injection tubing and analyzing the pressure effects at the

perforations. From these analyses an acceptable surface operating injection pressure was determined such that the local fracture gradient is not exceeded.

2.0 DISCUSSION

2.1 HISTORICAL REVIEW

The MG-T/DOE Amoco Fee SWD is located in Section 13, north 1730 feet from the south line and east 2815 feet from the west line in Township 12S and Range 8W in Sweetlake Field, Cameron Parish, Louisiana (See Figure No. 1). The well was drilled to an approximate depth of 7440_± feet for the purpose of disposing of geopressed produced brine waters.

The injection well was surface cased to 1350_± feet with 13 3/8" O.D. casing and protection cased to approximately 7440_± feet with 9 5/8" O.D. casing.

A 7" O.D. injection string was run on a 7" x 9 5/8" injection packer and set at 6200_± feet (See Figure No. 2). The potential disposal sands are those located below 6200_± feet with the primary target sands being those at 7150 - 7350_± feet. The objective of this study is to select adequate footage with sufficient perforations per foot to effectively handle 40 - 60,000 BPD.

2.2 GENERAL COMMENTS

Screen liner, gravel pack type completions along with the careful attention and proper selection of drilling and completion fluids has proven to be the most efficient design for high rate disposal of brine waters. The screen liner, gravel pack type completion affords: 1) greater cross sectional area to the wellbore and is therefore capable of accepting fluid at

high rates and extremely low pressure drops across the screen liner, 2) improved permeability in the near wellbore area, 3) the advantage of the ability to sustain abuse by particulate plugging for longer periods of time and 4) greater ease of development or cleaning without the concern of degradation of cementation resulting in sand influx.

The primary complication experienced in gravel pack completions is solids regeneration beyond the gravel media in the formation itself. However, high rate backflowing techniques have proved to be successful in restoring injection efficiency.

Since the study well is a cased hole and will be a perforated completion, this study consists of recognizing the potential for sand influx, selection of perforation size and depth of penetrations and net usable reservoir opened, by perforating, to provide minimal pressure drops in the near wellbore area. Consideration is also given to the fact that the probability of obtaining open perforations for every shot is nil. A safe assumption is that approximately 40% of the total perforations will be open for transmitting fluid to the receiving formation.

2.3 GEOLOGIC SETTING

The Amoco Fee SWD target sands lie some 8 - 10,000 feet above the production sand, miogyp sand. As shown in Figure No. 1, which is the structure map for the miogyp sand, the production lies within a graben and is bounded by two faults. The faults top out

at 9 - 10,000 feet. Therefore, the disposal sands should not be affected by the faulting and, consequently, it would be expected that the sands should test as an unbounded reservoir having infinite areal extent.

Typical to Gulf Coast sands, as indicated by the core analysis, the target sands are fine to very fine grain, loosely cemented and calcareous. It is expected that these sands probably contain very small quantities of montmorillonite, kaolinite and illite.

2.4 RESERVOIR REQUIREMENTS

The following evaluation is the expected injection zone performance based on calculations made with the aid of Craft and Hawkins "Applied Petroleum Reservoir Engineering" (1959) and the injection zone data listed below. This evaluation aids in determining the required reservoir thickness needed to provide adequate hydraulic capacity to handle 40 - 60,000 barrels of brine per day. The calculations were made using the sand at 7146⁺ feet to 7345⁺ feet and 7398⁺ feet to 7440⁺ feet for an effective net usable sand thickness of 215 feet and a constant injection rate of 60,000 barrels per day.

2.4.1 INJECTION ZONE DATA

Top of injection zone, ft.	7152
(based on ISF - Sonic Log)	
Bottom of injection zone, ft.	7345
(based on ISF - Sonic Log)	

Bottomhole pressure gradient, psi/ft.	.465 (est.)
Fracture gradient, 0. 65 psi/ft.	4680 at 7100'
Injection tubing size, inches O.D.	7
Viscosity of injection fluid, cp	1
Anticipated reservoir pressure, psi	3348 at 7200'
Average porosity, percent	30
(based on Computer Processed Log & core data)	
Average permeability, millidarcys	1500
(based on core data)	
Injection Zone Compressibility, psi ⁻¹	6.5×10^{-6}
Net sand thickness, ft.	215

2.4.2 BOTTOMHOLE PRESSURE EFFECTS

Using the basic theory of fluid flow in porous media and the data in Section 2.4 above, the expected bottomhole pressure buildup can be determined (the diffusivity equation modified for steady state radial flow). The basic fluid flow equation assumes horizontal flow, negligible gravity effects, homogeneous and isotropic porous medium, single fluid of small and constant compressibility and applicability of Darcy's Law, and that viscosity of the injected fluid, compressibility of the system, permeability and porosity are independent of pressure. Additionally, the reservoir boundary condition must be of infinite areal extent.

Since minor wellbore damage may be experienced due to mud filtrate at start-up or later in the life of the well due to particulate plugging, a damage factor called "skin effect" has been included in the computation. This effect occurs in an infinitesimally thin zone around the wellbore contributing to additional pressure drop.

Increase in Bottomhole Pressure with Time

<u>Time</u>		<u>Bottomhole Pressure</u>
<u>(years)</u>	<u>Skin</u>	<u>Increase, psi</u>
	(40,000 BPD)	
1/2	0	202
1	0	210
5	0	223
1/2	2	238
1	2	245
5	2	259
1/2	5	291
1	5	297
5	5	311
	(60,000 BPD)	
1/2	0	304
1	0	313
5	0	334
1/2	2	356

Increase in Bottomhole Pressure with Time

(60,000 BPD CONTINUED)

<u>Time</u>		<u>Bottomhole Pressure</u>
<u>(years)</u>	<u>Skin</u>	<u>Increase, psi</u>
1	2	365
5	2	387
1/2	5	435
1	5	444
5	5	465

2.5 INJECTION TUBING FRICTIONAL LOSSES

The frictional losses in the tubing are the major controlling factor in surface operating injection pressure for high rate disposal. The 7" O.D., 23#/ft. casing which is set to approximately 6,200+ feet has a frictional loss of approximately 200+ psi at 40,000 BPD injection and 415+ psi at 60,000 BPD injection.

These values were determined using a frictional coefficient for new, clean pipe.

2.5.1 PERFORATION PRESSURE EFFECTS

In analyzing the pressure effects due to perforations and selecting the type perforating technique the first thing to consider is the cross sectional flow area. When designing a completion for high rate injection, the flow rate per unit area should be reduced by:

- a) Providing clean large perforations through the target injection zone.

- b) increasing perforation density.
- c) improving the opening length of perforation section.
- d) penetration depth into the reservoir.

This can best be accomplished with a large diameter (0.75 inch diameter) casing gun having good penetration ranging from 12" to 16" based on test data from Section 2, API RP43, Third Edition, October 1974. Additionally, since it is seldom that more than 40% of the perforations are open, a large section should be perforated to compensate for the loss of this flow area.

The larger perforations afford lower flow velocity which in turn reduces the pressure drop across the perforation opening and prolongs degradation of the cementing matrix. The large perforations are also more conducive to the installation of a through casing gravel pack in the event sand control becomes necessary.

Mathematically, the pressure drop across 215 feet of .75" diameter perforations assuming 40% of the perforations open, can be determined using the following equation.

$$P_f = \frac{PQ^2}{8090 A_p^2}$$

Where: P_f = pressure drop across perforation in psi

P = density of injected fluid in #/gal

Q = injection rate in GPM

A_p = cross sectional area of perforations in sq in.

Applying this equation, it is apparent that the pressure drop is negligible and only becomes effective at 20 or less perforation openings.

2.6 EXPECTED SURFACE INJECTION PRESSURE

Assuming the wellbore has damage and the pressure at the wellbore after 5 years of injection at 60,000 BPD to be the worst case, the following observations can be made:

- a) With an average velocity of 17.65 ft/sec the friction loss in the 6200+ feet of injection tubing is approximately 415 psi.
- b) Assuming that the produced geopressured water has a density approximately 9#/gal (after separation of the gas and temperature reduce) and the formation water has an equivalent density, the hydrostatic pressure effect is balanced.
- c) The theoretical maximum change in bottomhole pressure caused by continuous operation of the well is 465 psi.
- d) Therefore, the theoretical wellhead injection pressure is
 $415 \text{ psi} + 465 \text{ psi} = 880 \text{ psi}.$

These calculations are theoretical and will be greatly effected by the condition of the injection pipe and the average effective permeability which can be determined only by proper well testing. For example, if the average permeability is reduced by 30%, the surface injection pressure will approach 1200 psi which is very near the fracture pressure.

3.0 CONCLUSIONS

- a) Analyses of the primary zone of interest from 7146+ feet to 7440+ feet indicates the ability to receive brine water at rates of 40 - 60,000 BPD.
- b) The product of permeability and net reservoir thickness which is called the hydraulic capacity is the controlling factor in the ability of the well to take fluid.
- c) Large diameter perforations offer improved cross sectional area, lower velocity and reduces the turbulence factor across the perforations to enhance formation stability and limit sand influx.
- d) The large diameter perforations are more suitable to a through casing screen gravel pack should sand control be required.
- e) Additional footage can be perforated to improve flow efficiency in the event injection testing indicates the well falls below the theoretical performance.

4.0 RECOMMENDATIONS

- a) Perforate using clean, non-damaging solids free fluid with differential pressure into the wellbore. A pressure differential into the wellbore of 200 - 500 psi is normally sufficient to clean the debris from the perforations.
- b) Perforate the intervals 7146 - 7274, 7282 - 7345, and 7398 - 7430 at four shots per foot using the Schlumberger 5" Hyper Pack Carrier Casing Gun (or equivalent) all measurements taken from the ISF/Sonic Log. Test shots into Borea sandstone with this casing gun yield an average hole diameter of .78" with approximately 19" penetration.
- c) Perform short term injection test at some selected rate less than the proposed 40 - 60,000 BPD to determine the virgin reservoir properties prior to attempting high rate testing. This data collected from the short term testing can be used to more closely predict the well performance at high rates.

FIGURES

SWEET LAKE PROSPECT

DISPOSAL WELL DIAGRAM

TD ±⁹⁹ 7,440'

FIGURE NO. 2

CORE LABORATORIES, INC.

PRELIMINARY CORE ANALYSIS

COMPANY Magma Gulf - Tooling drill DATE 9-24-50 FILE NO. 2102-8E
Amoco Fed. Sl. ID FIELD w/c Sweetlake COUNTY Cameron STATE LA
 CORE Schlumberger DRILLING FLUID _____

DEPTH FEET	PERMEABILITY MILLIDARCS	POROSITY %	OIL % PORE	TOTAL WATER % PORE	PROBABLE PRODUCTION	OIL % VOL.	GAS % VOL.	↓	CRIT. WTR. P. COMBUSTION UNITS			
									FORMATION DESCRIPTION	W	BOOR	FLI CI
6580	1050.	20. ²	0. ⁰	90. ²	WTR	0. ⁰	2. ⁹	34	sd vfa sstly	0	no	no
6640	450.	27. ⁵	0. ⁰	84. ⁹	WTR	0. ⁰	4. ²	39	sd vfa sstly lmv	0	no	no
6660	400.	25. ⁴	0. ⁰	86. ⁹	WTR	0. ⁰	4. ⁹	35	sd vfa vstly scale	0	no	no
6670	250.	23. ³	0. ⁰	83. ³	WTR	0. ⁰	3. ⁹	40	sd vfa shu lam sstly lam	0	no	no
6680									not analyzed			
6690	460.	24. ⁵	0. ⁰	85. ⁷	WTR	0. ⁰	3. ⁵	36	sd vfa vstly scale	0	no	no
6700	450.	25. ²	0. ⁰	82. ⁵	WTR	0. ⁰	4. ⁴	36	sd vfa sstly lam calc	0	no	no
6810	2110.	30. ⁴	0. ⁰	93. ²	WTR	0. ⁰	2. ¹	35	sd vfa sstly	0	no	no
6820	480.	25. ³	0. ⁰	91. ³	WTR	0. ⁰	4. ⁷	36	sd vfa sstly lam sstly calc	0	no	no
6830	1950.	29. ⁹	0. ⁰	55. ⁰	WTR	0. ⁰	3. ²	33	sd vfa sstly scale	0	no	no
6850	1900.	29. ⁸	0. ⁰	92. ⁴	WTR	0. ⁰	2. ²	33	sd vfa sstly scale	0	no	no
6930	400.	26. ²	0. ⁰	84. ⁸	WTR	0. ⁰	4. ⁰	39	sd vfa sstly lam sstly	0	no	no
6950	250.	25. ²	0. ⁰	85. ⁷	WTR	0. ⁰	3. ⁶	42	sd vfa shu lam sstly	0	no	no
6970	700.	27. ⁶	0. ⁰	85. ¹	WTR	0. ⁰	4. ¹	35	sd vfa sstly	0	no	no
7010									not analyzed			
7030	650.	26. ⁹	0. ⁰	87. ³	WTR	0. ⁰	3. ³	35	sd vfa sstly	0	no	no
7050									not analyzed			
7090	640.	26. ⁹	0. ⁰	91. ⁵	WTR	0. ⁰	2. ³	36	sd vfa sstly	0	no	no
7110	1890.	29. ⁴	0. ⁰	84. ¹	WTR	0. ⁰	1. ⁷	33	sd vfa sstly	0	no	no
7140	600.	24. ⁹	0. ⁰	84. ²	WTR	0. ⁰	3. ⁹	34	sd vfa vstly scale	0	no	no
7170	540.	23. ⁵	0. ⁰	90. ⁴	WTR	0. ⁰	2. ³	36	sd vfa vstly scale	0	no	no
7190									not analyzed			
7200	650.	26. ⁸	0. ⁰	83. ²	WTR	0. ⁰	1. ⁵	35	sd vfa sstly scale	0	no	no
7210	1150.	30. ²	0. ⁰	90. ⁷	WTR	0. ⁰	2. ⁷	35	sd vfa shu	0	no	no
7230	6. ⁵	21. ²	0. ⁰	93. ⁴	(1.)	2. ⁰	1. ⁴	78	sd vfa shu sstly	0	no	no

PRELIMINARY CCRE ANALYSIS

CONFIDENTIAL

[illegible]

Excerpt from Magma Gulf-Technadril
Drilling and Testing Plan

B. Disposal Well

1. Drilling Procedure (See Figure 13)
 - a. Prepare location for rig.
 - b. Move in rig and rig up.
 - c. Drive 20-inch x 1/2-inch wall pipe per page 4-40.
 - d. Cut off drive pipe below rotary. Install flow line and fill-up line on 20-inch pipe.

- e. Pick up 17 1/2-inch bit and bottom-hole assembly (BHA) and drill to 1,350 feet. Run deviation survey at less than 200-foot intervals. Allowable deviation is one-half degree per 100 feet with a maximum deviation of 2 degrees.
- f. Condition hole for logging SLM out of hole. Run open-hole logs 0-1,350 feet per page 4-44.
- g. Make cleanup trip. Circulate and condition hole to run casing. Check rig-hole alignment prior to running casing.
- h. Run and cement 13 3/8-inch casing per pages 4-40 and 4-42. Center 13 3/8-inch casing in rotary and hold while cement sets. Should cement not circulate, top out with recommended cement.
- i. Cut off 13 3/8-inch casing and 20-inch conductor. Install 13 3/8-inch slip-on type 3,000 WP wellhead with base plate (see Figure 14). Level base plate on 20-inch drive pipe and weld head onto 13 3/8-inch surface casing.
- j. Nipple up 12-inch, 3,000 psi blowout preventers (BOPs). See Figure 15.
- k. Test BOP assembly, including valves on choke and kill line plus circulating system to standpipe to 2,000 psi. Test casing to 2,000 psi. (Notify Louisiana Conservation representative for witness of casing test.)
- l. Pick up 12 1/4-inch bit and BHA and GIE. Drill out float collar, cement, and float shoe plus 10 feet of formation. Circulate for 30 minutes to check for mud loss. Should the formation take fluid, add sufficient gel to mud system to sustain full returns and drill ahead.
- m. Drill sufficient depth to bury BHA, then pull out of hole. Pick up 12 7/32-inch O.D. welded blade stabilizers at 60, 90, and 150 feet above bit. Pick up monel drill collar on last bit run prior to reaching total depth (approximately 7,440 feet).
- n. Drill 12 1/4-inch hole to depth equivalent to $\pm$ 7,440 feet in UOC Pan Am Fee No. 1. SLM out of hole on next to last bit run.
- o. Condition hole to log. POH running multishot directional survey.
- p. Run open-hole logs per page 4-44.
- q. Lay down monel drill collar. GIE with stabilized BHA. Condition hole to run 9 5/8-inch casing.
- r. Run 9 5/8-inch casing per page 4-40 and cement per page 4-43. Should cement not circulate, top out with recommended cement.

- s. Install 13 5/8-inch, 3,000 WP x 11-inch, 5,000 WP casing head spool ("B" section, Figure 14).
- t. Nipple up blowout preventers and test to 3,000 psi as outlined in Step k.
- u. Pick up bit and scraper and BHA without stabilizers and clean out inside of casing to float collar. Displace mud with 9.5 ppg brine. POB. Lay down DP and DC.
- v. Run logs inside 9 5/8-inch casing per page 4-44.
- w. Rig up and run 7-inch casing to approximately 6,400 feet with injection packer. Space out with 60,000 pounds of weight-set injection packer applied just as casing hanger "shoulders-up" in "B" section head. See page 4-41.
- x. Nipple up tree and test seals as recommended by manufacturer.
- y. Release rig.
- z. Rig up nitrogen truck and coil tubing unit. Displace water from well down to above 2,000 feet.
- aa. Rig up wire line lubricator and perforate proposed injection interval with a casing gun.
- bb. If well will flow, clean out perforations by a limited flow test being careful to limit sand production.
- cc. Treat perforations and injection zone with HCl and HF1 to clean perforations and well bore damaged zone.
- dd. If well will not flow, rig up nitrogen truck and coil tubing unit. Clean out perforations by a limited "backflow" test. NOTE: Injection efficiency contingent upon "backflow" rates and quantities.
- ee. Perform injection test.
- ff. SI for future operations.

2. Surface Equipment and Services

- a. Wellhead (See Figure 14)

The Christmas tree assembly will be rated at 5,000 psi WP.

- b. Blowout Prevention Equipment (See Figure 15)

The blowout preventer will be 3,000 psi WP, ram-type, hydraulic-controlled equipment. An annular-type preventer will be above the ram preventer which will be 3,000 psi WP also.

c. Drill Rig

The rig will be capable of drilling to 8,000 feet with 4 1/2-inch drill pipe and capable of running 9 5/8-inch casing to 7,440 feet. The mast should be capable of 750,000 pounds API static hook load and the substructure must have 750,000-pound capacity.

d. Drilling Recording Instruments

Drilling recording instruments consisting of a pit level device and three-pen recorder for measuring rate of penetration, pump pressure, and hook load.

3. Downhole Equipment and Services

a. Casing Program

(1) Conductor Casing

20-inch O.D., 1/2-inch wall, 104-pound, A-234 Grade B welded. Drive to ± 100 feet with D-30 hammer. Required bearing load is $\pm 540,000$ pounds including safety factor.

(2) Surface Casing

<u>Depth</u>	<u>Size</u>	<u>Wt.</u>	<u>Grade</u>	<u>Conn.</u>	<u>Colps Rate/SF</u>	<u>Burst Rate/SF</u>	<u>Tension Rate 1,000/SF</u>
0-1350	13 3/8"	72	N-80 and K-55	Butt.	2670/4+	5380/6+	1661/20+

(a) Run float shoe and float collar two joints apart. Thread lok shoe, top of first joint, and collar.

(b) Run two bow spring centralizers on bottom two joints.

(c) Land casing in tension.

(d) Set base plate flush and level on 20-inch pipe.

(3) Production String Casing

<u>Depth</u>	<u>Size</u>	<u>Wt.</u>	<u>Grade</u>	<u>Conn.</u>	<u>Colps Rate/SF</u>	<u>Burst Rate/SF</u>	<u>Tension Rate 1,000/SF</u>
0-1700	9 5/8"	47	C-75	Butt.	4630/11.8	6440/5.3	1018/3.1
1700-7440	9 5/8"	43.5	N-80	Butt.	3810/2.4	6330/6.3	1005/5.7

(a) Run float shoe and float collar two joints apart. Thread lok shoe, top of first joint, and collar.

- (b) Run two flow diverter type centralizers on each of first two joints. Run one flow diverter type centralizer every second joint for the next 10 joints.
- (c) Reciprocate pipe $\pm$ 15 feet while cementing. Hold 2,500 psi on plug, after plug bumps, for $\pm$ 4 hours or until the tail cement attains 250 psi compressive strength.
- (d) Land casing in tension.

(4) Injection String

<u>Depth</u>	<u>Size</u>	<u>Wt.</u>	<u>Grade</u>	<u>Conn.</u>	<u>Colps Rate/SF</u>	<u>Burst Rate/SF</u>	<u>Tension Rate 1,000/SF</u>
0-6,400	7"	23#	K-55	LTC w/ ABC Mod. coupling	3270/1.1	4360/1.2	366/2.5

- (a) Make up one joint of 7-inch casing below injection packer and 7-inch casing above.
- (b) Run in hole to approximately 6,400 feet and set injection packer.
- (c) Space out so that 60,000 pounds of casing weight is set down on packer at the same time the hanger "shoulders up" in tree. Back out landing joint.
- (d) Nipple down BOPs.

b. Drilling Fluid Program

<u>Depth</u>	<u>Type Mud</u>	<u>Weight</u>	<u>Visc.</u>	<u>Percent Solids</u>	<u>Water Loss</u>	<u>PV/YP</u>
0-1350	Gel-water	9.0-9.2	40-50	6-7	30	8/12
1350-5000	Gel-water Lignite	9.0-9.2	35-40	3-5	20	7/12
5000-6400	Gel-water Lignite	9.0-9.2	35-38	3-5	15	5/10
6400-7400	Gel-water Lignite	9.0-9.2	40-45	3-5	2-4	14/7

- (1) Have water loss below 4 cc at $\pm$ 6,400.

- (2) After reaching total depth, wash mud tanks that will be used to circulate 9.5 ppg brine water.
- (3) It is estimated to require $\pm$ 1,000 barrels to complete job.
- (4) Do not mix mud with brine.

c. Deviation Program

Single Shot

0-1,350 feet

Run Totco at least every 200 feet. Maximum allowable deviation is 2 degrees.

1,350-6,400 feet

Run Totco at least every 500 feet. Maximum allowable deviation is 5 degrees.

6,400-7,400 feet

Run Totco every 200 feet. Maximum allowable deviation is 5 degrees.

Multishot Directional

Run multishot from total depth to surface.

d. Cementing Program

(1) Surface Casing

Type Cement

Lead Slurry—Lightweight cement plus 35 percent silica flour and 3 percent salt mixed at 13.4 ppg yields 2.12 cubic feet per sack.

Tail Slurry—Class "E" plus 40 percent silica flour mixed at 15.8 ppg yields 1.55 cubic feet per sack.

Quantity

Lead Slurry—Using 100 percent excess should require 567 sacks for 850 feet of fill-up.

Tail Slurry—Using 100 percent excess should require 450 sacks for 500 feet of fill-up.

Top Out—Should cement not circulate, Class "E" plus 40 percent silica flour and 2 percent calcium chloride mixed at 15.8 ppg yields 1.55 cubic feet per sack.

(2) Production String

Type Cement

Lead Slurry--Lightweight cement plus 35 percent silica flour and 3 percent salt mixed at 13.4 ppg yields 2.12 cubic feet per sack.

Tail Slurry--Class "H" plus 40 percent silica flour mixed at 15.8 ppg yields 1.55 cubic feet per sack.

Quantity

Lead Slurry--Using 50 percent excess, 6,400 feet of fill-up should require 1,450 sacks.

Tail Slurry--Using 50 percent excess, 1,000 feet of fill-up should require 300 sacks.

Top Out--Should cement not circulate, Class "H" plus 40 percent silica flour and 2 percent calcium chloride.

e. Hydraulics Program

Assumptions

- (1) 500-foot, 7 3/4-inch O.D. x 12 13/16-inch I.D. drill collars.
- (2) 4 1/2-inch DP.
- (3) GD PZ9 Triplex pump (85% eff.).
- (4) 6 1/2-inch liners.
- (5) 100 SPM

<u>Depth</u>	<u>Hole Size</u>	<u>Mud Wt.</u>	<u>AVDP Ft./Min.</u>	<u>GPM</u>	<u>Jets</u>	<u>J. Vel</u>	<u>Press Drop</u>		<u>Pump Press</u>
							<u>Jets</u>	<u>System</u>	
1850'	17 1/2"	9.0-9.2	60	331	9-9-10	525	2484	148	2632
					9-10-10	490	2159	148	2307
					10-10-10	459	1894	148	2042
					10-10-11	429	1655	148	1803
					10-11-11	403	1458	148	1506
4000'	12 1/4"	9.0-9.2	60	331	9-9-10	525	2484	276	2760*
					9-10-10	490	2159	276	2435
					10-10-10	459	1894	276	2170
					10-10-11	429	1655	276	1931
					10-11-11	403	1458	276	1734

*Exceeds working press of pump which is 2,650 pounds with 6 1/2-inch liners.

Liner Size	Mud Wt.	AVDP Ft./Min.	GPM	Jets	J. Vel	Press Drop		Pump Press
						Jets	System	
12 1/4"	9.0-9.2	60	331	9-9-10	525	2484	432	2916*
				9-10-10	490	2159	432	2591
				10-10-10	459	1894	432	2326
				10-10-11	429	1655	432	2087
				10-11-11	403	1458	432	1890

*Exceeds working press of pump which is 2,650 pounds with 6 1/2-inch liners.

f. Logging Program

Open Hole

Run 1--Induction	0-1350'
Run 2--Caliper	0-1350'
Run 3--Dual Induction	1350-7440'
Run 4--FDC-CNL-GR	1350-7440'
Run 5--Sonic with Caliper	1350-7440'
Run 6--Sidewall Cores	Various

Cased Hole--9 5/8-Inch Casing

Run 1--GR-N	0-7360'
Run 2--CBL-VDL	0-7360'
Run 3--Casing Caliper	0-7360'

g. Completion

- (1) Run and set 7-inch, 8 rd x 9 5/8-inch, 40-pound injection packer with 6-foot polish receptacle and locator sub with 7-inch O.D., 8 rd box top connection O-ring. Packoff overshot to seal over 5 1/2-inch polish back off sub. Overshot has 8-inch O.D. guide ring for 9 5/8-inch casing. Polish I.D. of packer is 7 3/8 inches x 12 feet.
- (2) Run hole with 9 5/8-inch retrievable squeeze tool on drill pipe with 900 feet of tail pipe below packer.
- (3) Displace liner with ± 900 gallons of HCL acid.
- (4) Squeeze acid into formation.
- (5) Overdisplace acid with 50 barrels of clean solids-free 9.5 brine.
- (6) Lay down squeeze tool and tail pipe.
- (7) Complete well.

Appendix III Daily Flow-Test Reports

- 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 well-site 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 with 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 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 9:00 a.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 disposal well, and at 11:30 a.m. the disposal wellhead pressure increased suddenly to 815 psig. Brine production was immediately switched back to blow down tanks. The RDI pressure tool was removed from the disposal well and Halliburton began injectivity tests at 9:30 p.m.

- 6/21/81 Halliburton began acid treatment of the disposal well at 6:57 a.m. and completed treatment at 9:30 a.m. Brine production was switched to the disposal well at 2:00 p.m., at a rate of 3780 B/D. Injection of AMP-20 inhibitor began at 2:40 p.m.
- 6/22/81 Extremely low gas production rates had apparently been observed, and a new orifice plate for the separator gas line was made in order to confirm this rate. Weatherly Laboratory personnel came on site at 5:00 p.m. to take samples for PVT analysis. The test well was shut in at 8:04 p.m., completing the Initial Flow Test, and beginning the reservoir build-up test. Total brine production from this test was approximately 11,000 bbl. The bottom-hole pressure was drawn down to 11,740 psia, and a first approximation of the permeability to water was 261 md.
- 6/23/81 - Well shut in for reservoir build-up test
6/29/81
- 6/30/81 The Reservoir Limit Test began at 6:15 p.m. at a brine production rate of 16,000 B/D. Surface pressure was 4660 psia and bottom-hole pressure was 11,974 psia.
- 7/1/81 After 12 hours of testing, the bottom-hole pressure had decreased to 9646 psia and the surface pressure to 2362 psia. The flow rate continued at 16,000 B/D. Minor adjustments were made throughout the day to keep the flow rate at approximately 15,000 B/D.
- 7/2/81 Flow was maintained at 15,000 B/D, with the bottom-hole pressure decreasing to 8441 psia and the surface pressure to 1318 psia by midnight. The flow rate dropped to 12,500 B/D at 11:00 p.m.
- 7/3/81 The flow rate increased to 14,000 B/D by 3:00 a.m. and to 15,000 B/D by 5:00 a.m. The decrease in surface pressure during this time may have been due to mud plugging the Willis chokes. Flow rate was maintained at 15,000 B/D for the remainder of the day. Bottom-hole pressure was 8164 psia and surface pressure 1052 psia at 11:00 p.m. Inhibitor pumping rate was decreased.
- 7/4/81 The flow rate varied between 14,000 - 15,250 B/D. Bottom-hole pressure was 8090 psia and surface pressure 1001 psia at 11:00 p.m.

7/5/81 In order to maintain surface pressures, the flow rate was allowed 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 shut in for short time at 11:09 a.m. Bottom-hole pressure was 8033 psia and surface pressure was 958 psai 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 at 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 psia and surface pressure 756 psia at 11:00 p.m.

7/12/81 Flow maintained at 11,500 B/D. Bottom hole pressure was 7858 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 11:00 p.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 3426 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 psia 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 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 2188 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 5000 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 psia 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 psia 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 3:00 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 to 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.

9/23/82 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.

9/28/81 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 2310 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 2015 psia at 11:00 p.m.
10/7/81	Flow rate 4900 - 5200 B/D. Surface pressure 2042 psia at 11:00 p.m.
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 - 10/23/81	Well shut in for repairs.
10/24/81	Well opened up at 3:00 p.m. at rate of 5000 B/D. Surface pressure 3310 psia 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 psia 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.
11/21/81	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 4800-5400 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 2353 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 psia at 11:00 p.m.

12/22/81 Flow rate 2500 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 3246 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.
1/6/82	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 psia at 11:00 p.m.
1/8/82	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 psia 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 by 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.