740
11-17-80
JMB

MASTER

NO STOCK

DOE/ET/28460-3(Vol. 1)

INVESTIGATION AND EVALUATION OF GEOPRESSURED-GEOTHERMAL WELLS

Final Report, Beulah Simon No. 2 Well,
Vermilion Parish, Louisiana

Volume I: Completion and Testing

By
R. J. Dobson
J. H. Hartsock
R. L. McCoy
J. A. Rodgers

July 1980
Date Published

Work Performed Under Contract No. AC08-77ET28460

Gruy Federal, Inc.
Houston, Texas

DIST-700
NTIS 25

U. S. DEPARTMENT OF ENERGY
Geothermal Energy

R163

DISCLAIMER

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

DISCLAIMER

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

DISCLAIMER

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

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

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

Price: Paper Copy \$8.00
Microfiche \$3.50

INVESTIGATION AND EVALUATION OF
GEOPRESSURED-GEOTHERMAL WELLS

FINAL REPORT
BEULAH SIMON NO. 2 WELL
VERMILION PARISH, LOUISIANA

Volume I: Completion and Testing

R. J. Dobson
J. H. Hartsock
R. L. McCoy
J. A. Rodgers

Gruy Federal, Inc.
2500 Tanglewilde, Suite 150
Houston, Texas 77063

Date Published--July 1980

Prepared for the
U.S. Department of Energy
Division of Geothermal Energy
Under Contract No. DE-AC08-77ET28460

Delta Drilling Company and Howard Water Well Service Company rigs at the Beulah Simon No. 2 test site, Vermilion Parish, Louisiana.

PREFACE

This report is issued in two volumes. Volume I is a description of the acquisition, completion, and testing of a second geopressured-geothermal test well under the "Well of Opportunity" program, together with a discussion and interpretation of the physical and chemical data obtained from the test. Volume II is a compilation of the test data and computer printouts of the various reservoir calculations.

CONTENTS

	<u>Page</u>
1.0 Executive Summary	1
2.0 Introduction and Background	3
2.1 General	3
2.2 Location	4
2.3 Operation and Land/Mineral Owner Agreements.	4
2.4 Drilling Contractor Agreement	6
3.0 Objectives	7
4.0 Geology	8
4.1 Regional Setting	8
4.1.1 Sedimentation	8
4.1.2 Structure	8
4.1.3 Reservoir Characteristics	9
4.1.4 Oil and Gas Traps	9
4.2 Local Geology	9
5.0 Petrophysics	16
5.1 Open-Hole Log Analysis - Test Well	16
5.1.1 Porosity	16
5.1.2 Net Thickness	18
5.1.3 Reservoir Permeability	18
5.1.4 Salinity	19
5.1.4.1 Rwa Method	19
5.1.4.2 SP-Derived Rw	21
5.2 Open-Hole Log Analysis - Disposal Well	22
5.3 Cased-Hole Log Analysis	23
6.0 Drillsite and Support Facilities	24
6.1 Site Layout	24
6.2 Living Quarters	24
6.3 Water Supply	24
6.4 Utilities	24

	<u>Page</u>
7.0 Test Well	26
7.1 Initial and Anticipated Well Completion Status	26
7.2 Liner and Tubing Installation	26
7.3 Wellhead Design	26
7.4 Logging Program	26
7.4.1 Open-Hole Logs	26
7.4.2 Cased-Hole Logs	26
7.5 Drilling Operations	26
7.5.1 Blowout Preventers	26
7.5.2 Drilling Fluids	31
7.5.3 Drilling Rig	31
7.6 Completion Operations	31
7.6.1 Open-Hole Operations	31
7.6.2 Casing Liner	31
7.6.3 Cementation of Liner	34
7.6.4 Cleanout of Cement from Liner	35
7.6.5 Running Casing Tieback.	35
7.6.6 Production Tubing	35
7.6.7 Christmas Tree	35
7.6.8 Perforating	37
8.0 Saltwater Disposal Well	38
8.1 General	38
8.2 Design Requirements	38
8.3 Rig Selection	38
8.4 Disposal Well Operations	38
8.4.1 Conductor Casing	38
8.4.2 Surface Casing	40
8.4.3 Completion Casing	40
8.4.4 Completion Operations	40
8.4.5 Petrophysical Data	40
8.4.5.1 Perforations and Injectivity Tests	42
8.4.5.2 Injection Well Stimulation	42
9.0 Test Objectives	44
9.1 Surface Testing Facilities	44
9.1.1 Design	44
9.1.2 Piping	44
9.1.3 Separator	44

	<u>Page</u>
9.1.4 Metering	46
9.1.5 Air Cooler	46
9.1.6 Filters	46
9.1.7 Safety Sensors	46
9.1.8 Scale Inhibitor	46
9.2 Data Collection	47
9.3 Meter Prover	47
9.4 Performance of Surface Equipment	47
10.0 Testing Operations	48
10.1 Cleanup	48
10.2 Recovery of Hewlett-Packard Gauge.	48
10.3 First Flow Test	50
10.4 Remedial Work on Disposal Well	50
10.5 Second Flow Test	50
10.6 Pressure Buildup	51
10.6.1 Calculation of Fluid Density	51
10.7 Bottomhole Sampling	53
11.0 Test Analysis	54
11.1 Analysis of Drawdown	54
11.1.1 Flowing Tubing Pressures	54
11.1.2 Casing Pressures	54
11.1.3 Bottomhole Pressures (Estimated)	54
11.2 Buildup Analysis	56
11.2.1 Bottomhole Pressures	56
11.2.2 Tubing Pressures	56
11.2.3 Casing Pressures	61
11.3 Analytical Model	61
11.4 Chemical Analysis of Water	61
11.5 Chemical Analysis of Gas	67
11.6 Analysis of Scale and Scale Coupons	67
11.7 PVT Analysis of Recombined Sample.	74
12.0 Abandonment Procedure.	78
12.1 Killing the Well	78
12.2 Site Restoration	80
13.0 Conclusions	83
14.0 References	85
Appendix A	86

FIGURES

<u>Figure</u>	<u>Page</u>
1 Location Map	5
2 Cross Section A-A'	10
3 Cross Section B-B'	11
4 Cross Section C-C'	12
5 Structure map, top of Camerina sand	14
6 ISF log, Beulah Simon No. 2	15
7 Permeability versus Swirr	20
8 Schematic location plat of Beulah Simon No. 2	25
9 Schematic of downhole conditions, Beulah Simon No. 2	27
10 Total friction loss versus rate of production, 3-1/2 inch production tubing	28
11 Wellhead schematic, Beulah Simon No. 2 test well	29
12 Condition at takeover, Beulah Simon No. 2	33
13 Beulah Simon No. 1 saltwater disposal well schematic	39
14 ISF electric log, Beulah Simon No. 1 saltwater disposal well . .	41
15 Injectivity test, Beulah Simon No. 1	43
16 Surface test facilities, Beulah Simon No. 2	45
17 Water production rate and flowing tubing pressure versus time, Beulah Simon No. 2	52
18 Casing pressure versus time (drawdown).	55
19 Bottomhole pressure (calculated from casing pressure) versus time (drawdown).	57
20 Pressure correction (casing) versus time (buildup)	58
21 Pressure correction (tubing) versus time (buildup)	59
22 Pressure buildup plot (bottomhole pressure)	60
23 Pressure buildup plot (tubing pressure)	62

FIGURES (continued)

<u>Figure</u>	<u>Page</u>
24 Pressure buildup plot (casing pressure)	63
25 Standard deviation of measured and computed pressures for analytical model	64
26 Relative volume and density versus pressure: BHT = 286°F . .	76
27 Gas solubility and formation volume factor versus pressure: BHT = 266°F.	77
28 Abandonment condition, Beulah Simon No. 2	79
29 Beulah Simon No. 1 saltwater injection well, status after plugging and abandonment	81
30 Time summary: completion, testing, and abandonment, for Beulah Simon No. 2	82

PLATE

1 Christmas tree and work platform, Beulah Simon No. 2	36
--	----

TABLES

<u>Table</u>	<u>Page</u>
1 Tubular and cementing design specifications, Beulah Simon No. 2	30
2 Equipment furnished by drilling contractor, Delta Drilling Co. Rig No. 47	32
3 Summary of test analysis	65
4 Chemical analysis of produced water, Beulah Simon No. 2	66
5 Flowing sample from bottom hole at end of test, Beulah Simon No. 2 test well	68
6 Sample with sludge (oil phase), Beulah Simon No. 2 test well	69
7 Chemical analysis of gas	70
8 Gas composition of vapor flashed from separator liquid, Beulah Simon No. 2	71
9 Analysis of scale coupons	72
10 Scale analysis	73
11 Inhibitor concentration at data header	75

1.0 EXECUTIVE SUMMARY

Gruy Federal, Inc., under a contract with the U. S. Department of Energy (DOE), Division of Geothermal Energy, conducted geopressured-geothermal (Geo²) test operations at the Beulah Simon No. 2 well site during the period from September through December 1979.

This location is in Vermilion Parish, Louisiana, approximately 5 miles northeast of the town of Kaplan. The well was originally drilled to 15,265 feet by a group for which Southport Exploration, Inc. was the operator. Before total depth was reached, Gruy arranged with the operator and the lessor to provide for Geo² testing in the event of a dry hole. However, the drilling rig had a prior commitment and was not available for a completion attempt at the time drilling operations were terminated, and several months elapsed between the completion of drilling operations and the commencement of Gruy's test operations.

The Beulah Simon No. 2 well provided the second geopressured-geothermal test to be completed under the DOE-Gruy "Well of Opportunity" program. The completion in a geopressured aquifer of Oligocene age at approximately 14,700 feet and the testing of hot salt water from this zone were accomplished without significant difficulty. Some problems were encountered with the wireline and wireline high-pressure lubricator associated with the running of bottomhole instruments.

The objectives of the project were all accomplished, and good test data were obtained on the flow rates of gas and water. The gas content was 24 standard cubic feet per stock tank barrel of water. This is only slightly higher than the quantity measured in the Fairfax Foster Sutter No. 2 test well, even though the total dissolved solids were less than half as concentrated as in the Sutter well. The important test and analysis results are summarized on page 2.

During the initial use of the injection well while cleaning the test well, sand flowed into the well bore. After cleaning approximately 0.5 cubic yards of sand out of the 5-1/2" casing there was never any indication of sand fill during the production test.

The disposal well accepted the full wellhead stream at temperatures as high as 255°F (124°C). Over the 10-day flow period the hot brine did not appear to adversely affect the clay minerals in the disposal aquifer. Previously, while testing the Fairfax Foster Sutter No. 2, only a one-day hot water injection test had been attempted. Since it appears that shallow Pliocene sands of south Louisiana are suitable for the disposal of large amounts of hot water, no cooling system was included in the design of the third well of opportunity, Gruy-DOE-Tenneco Fee "N" No. 1.

Another important conclusion from this operation is that presently available wirelines and pressure lubricators are not adaptable for use with uninhibited well fluids under flowing conditions. In addition, this test demonstrated that injection of scale inhibitor down the annulus eliminated scale buildup within the flow string and surface facilities.

SUMMARY OF TEST RESULTS
BEULAH SIMON NO. 2 TEST WELL

Total depth:	15,265 ft (surface elevation 24 ft)
Formation:	Camerina (Upper Oligocene)
Perforated interval:	14,674-14,770 ft
Original reservoir pressure:	13,015 psi at 14,722 ft
Original reservoir temperature	266°F (130°C)
Completion and testing:	
Duration:	62 days, Oct. 28 to Dec. 29, 1979
Tests:	10-day drawdown, Nov. 28 to Dec. 8; 20-day buildup, Dec. 8 to Dec. 29
Production Rate:	11,011 BWPd initial 10,833 BWPd final
Gas/water ratio:	19.6-20.8 scf/STB (separator pressure of 500 psi) 24.0 scf/bbl at standard conditions
Sand production:	None
Scale formation:	None
Analysis of water:	
Total dissolved solids	103,925 ppm
Chlorides	50,300 ppm
pH	6.61
Density	1.066 gm/cc
Analysis of gas:	
Methane	88.868 mol percent
Carbon dioxide	7.726 mol percent
Aquifer geometry:	Two parallel faults
porosity	18.7 percent
Permeability	12 md
Disposal interval:	2,464 to 2,524 feet
Injection pressure:	70-90 psi
Injection temperature:	251-255°F

2.0 INTRODUCTION AND BACKGROUND

2.1 General

As part of a program to investigate unconventional sources of energy in the United States, the DOE has undertaken a broad-scale investigation of the energy which might be available from deep, high-pressured aquifers found in porous sediments of Tertiary age along a broad coastal belt of Louisiana and Texas. This potential resource consists of natural gas, principally methane, dissolved in the reservoir brines, plus the thermal energy available from the natural temperature of these brines and possibly some hydraulic energy available from the flow streams of producing wells.

A number of investigators have attempted to assess the magnitude of this potential energy resource.^{1-5*} Estimates have varied from 600 to 1,730 quads (1 quad = 10^{15} Btu) under various development and production scenarios, without consideration of economic viability or production experience. Such estimates are highly speculative, because no commercial or even experimental utilization of this energy source has ever been attempted.

Since there are no known completions by industry in geopressed aquifers in the United States, hands-on data on geopressed-geothermal reservoirs are available from only two sources:

- Test wells especially drilled for long-term, high-volume tests;
- Conversion and completion of wells drilled by industry which have resulted in "dry holes," i.e., devoid of conventional commercial hydrocarbons.

Beginning in FY 1978, Gruy Federal, Inc., under a contract with the DOE,** undertook a program to provide for the "identification, qualification, acquisition, planning and conducting of geothermal-geopressed formation tests in oil or gas prospective wells, about to be drilled, being drilled, or being abandoned. . . ."6 The program is known as the "Well of Opportunity" (WOO) program because the concept was to take over dry holes drilled by industry as they became available and to conduct short-term tests on the methane content of the brines and the flowing characteristics of the well aquifer systems. Important monetary savings, at least 50 percent of the cost of drilling a new test well, can be realized by taking over a well already drilled by others.

*References are listed in Section 14.

**Original contract No. EG-77-C-08-1528 between U. S. Energy Research and Development Administration (ERDA) and H. J. Gruy and Associates, Inc. dated September 14, 1977.

The Beulah Simon No. 2 was the second well of opportunity successfully completed in a geopressured aquifer and subsequently tested. This operation was first recommended to DOE in April 1979. In July 1979 a revised submittal incorporated experience gained from the Fairfax Foster Sutter No. 2 test.⁷ Site preparation was begun on August 15 following verbal approval by DOE; written approval was received on August 21 and the Delta Drilling Company Rig No. 47 arrived at the location on September 15.

2.2 Location

The Beulah Simon location is in Section 26, T. 11 S., R. 2 E., Vermilion Parish, Louisiana, about 5 miles northeast of the town of Kaplan and 30 miles southeast of Lafayette (Fig. 1). Access to the well site is via parish and oilfield roads, including 2,200 feet of board and shell road installed by Southport Exploration, Inc. The terrain is flat and low-lying, subject to flooding, and the site, at an elevation of approximately 20 feet above sea level, was protected by a ring levee.

Adjacent oil and gas fields include Abbeville to the southeast, LeRoy to the east, LeLeux to the north, Perry Point to the northwest, and Kaplan to the southwest. The nearest hydrocarbon production was from Southport Beulah Simon No. 1 about a mile to the west, which produced gas for a short time from a different reservoir and fault block.

2.3 Operation and Land/Mineral Owner Agreements

Southport Exploration, Inc. was among the first independent operators to cooperate in the well-of-opportunity program. Several earlier Southport interest wells were offered and monitored, but these became unavailable for various mechanical reasons.

Southport et al. agreed to make the well available if it proved nonproductive of hydrocarbons at total depth, but could not agree to share the drilling rig under contract to them because of pressing drilling obligations elsewhere. However, Southport left the salvageable casing in the hole, so that the well was in a condition to reenter. Southport and partners agreed to a nominal cash payment for use of the casing and wellbore, which was paid when operations commenced. Gruy agreed to assume responsibility for the plugging and cleanup operations required by the Southport lease and state regulations and to attempt to salvage some 3,500 feet of 9-5/8 inch casing.

The landowners were equally cooperative and agreed to a comparatively modest payment for the right to conduct the geopressured-geothermal test until January 31, 1980. Excellent relations were maintained with these land and mineral owners throughout the project.

A separate landowners' agreement was required because Southport's lease expired a short time after its operations were concluded. Additionally, conventional oil and gas leases do not provide for and probably do not cover geothermal activity in the state of Louisiana. Geothermal rights have been separated from oil and gas rights as to state lands, and it is the legally-untested presumption that such separation will apply to oil and gas leases on private lands.

ROAD CLASSIFICATION

Heavy-duty	Light-duty
Medium-duty	Unimproved dirt
U S Route	State Route

GRUY FEDERAL, INC.
HOUSTON, TEXAS

LOCATION MAP
COSSINADE FIELD AREA
VERMILION PARISH, LOUISIANA

CROWLEY, LA.
N3000-W9215/15

1955

LAFAYETTE, LA.
N3000-W9200/15

1955

TRUE NORTH
MAGNETIC NORTH

APPROXIMATE MEAN
DECLINATION, 1955

0 3000 6000 9000

SCALE IN FEET

FIGURE 1

2.4 Drilling Contractor Agreement

Requests for day-rate bids were sent to six drilling contractors who had rigs working in the general area of the Beulah Simon No. 2. After consideration of the hourly rate, rig capabilities, rig availability, and personnel, Delta Rig No. 47 was selected for the completion operations. Howard Water Well Service was selected to drill the disposal well on a turnkey basis with Gruy furnishing the tubulars, mud, and cement.

3.0 OBJECTIVES

The well of opportunity program was designed to obtain short-term test data from several geopressured-geothermal aquifers in different geologic environments along the Gulf Coast region of Texas and Louisiana. The task required not only expertise in drilling, completing, and testing the wells and interpreting physical data from these aquifers, but also a knowledge of the regional geology, effective communication and close coordination with oil and gas operators, and a scouting system capable of finding the deep wells and following their progress during drilling.

As stated in the Request for Proposal dated April 1, 1977, the objectives of the geopressured well tests are to obtain data related to:

- The aquifer fluid properties, including in-situ temperature, chemical composition, hydrocarbon content, and pressure.
- The characteristics of geopressured geothermal reservoirs, including permeability, porosity, and extent and distribution of sands and shales.
- The behavior of fluids and the reservoir under conditions of fluid production at moderate and high flow rates, including pressure-time behavior at different flow rates, fluid characteristics under varying production conditions, and other information related to the reservoir production drive mechanisms and physical and chemical changes that may occur with various production conditions.
- The evaluation of completion techniques and production strategies for geopressured-geothermal wells.

Without exception the test on the Beulah Simon No. 2 well was successful in accomplishing all the goals established for this program.

4.0 GEOLOGY

4.1 Regional Setting

This general area occupies a portion of the Gulf Coast Geosyncline, a large arcuate depositional geosyncline extending from Florida westward to Mexico.

4.1.1 Sedimentation

Sediments of Recent to Cretaceous age have been encountered as well as diapiric salt of Jurassic age. The Tertiary, from which most of the oil and gas is derived, consists almost exclusively of a regressive sequence of sands and shales. Each cycle of sediments is represented by, from north to south, (1) a largely sand facies deposited in a continental to lagoonal environment; (2) a sand-shale facies deposited in a marine inner to middle neritic environment; and (3) a shale facies deposited in an outer neritic to bathyl environment. As the Tertiary strata are primarily regressive with the shoreline migrating southward, the sequence of beds encountered by a well is first, a continental sand facies, then a marine inner to middle neritic sand and shale facies, and finally an outer neritic to bathyl shale facies.⁸

Oil and gas are found most often in sand reservoirs deposited in an inner to middle neritic environment, ranging in age from Eocene to Oligocene.

4.1.2 Structure

This area is a south-dipping monocline with regional dips of about 150 feet per mile at 10,000 to 12,000 feet. Interruptions of this dip are caused either through vertical uplift by flowage of salt or shale, by gravity slumping along normal faults, by differential compaction between sand and shale bodies, or by a combination of all three.

Salt domes are formed by the movement of salt from its "mother" layer, the Louann Salt, which underlies the area at an estimated depth of at least 40,000 feet. The overlying sediments are uplifted, faulted, and pierced as a result of the salt's intrusion. Salt has penetrated to or near the surface on some domes, whereas on other structures its deeper presence is inferred by the oblate shape on the anticline and by a strong gravity minimum near the crest of the structure. Shale also acts diapirically, and many salt domes are complicated by shale flowage. Faulting associated with salt domes is generally complex. On piercement domes in which the salt has intruded most of the sediments, radial faulting predominates. On deep-seated domes, graben faulting is a common feature.

Faults also originate in response to sedimentary loading. Such faults are generally regionally developed and are characterized by an expanded sedimentary section in the downthrown block. They are commonly referred to as "growth" faults or "contemporary" faults. They are also characterized by "roll-over," which is bedding-plane dip into the fault plane (the opposite of textbook "drag"). Anticlines formed by such growth faults are elongate in a direction parallel to the strike of the fault.⁹

All faults in the area are normal faults. Fault-plane dip ranges from 30° to 70°, steep at shallow depths and flattening with increasing depth. Most faults encountered at producing depths have dips of 45° to 55°. Displacement on many growth faults exceeds 3,000 feet.

4.1.3 Reservoir Characteristics

Porosities and permeabilities in the hydro pressured sediments generally are excellent, and recovery factors for both oil and gas are high. These properties tend to diminish in the geopressed regions. In the normally pressured reservoirs oil recoveries typically range from 400 to 1,000 barrels per acre-foot and gas recoveries from 1.5 to 2 million cubic feet per acre-foot. Most reservoirs have active water drives, but depletion reservoirs not not unusual.

Reservoir pressure gradients range from a normal hydrostatic value of 0.465 psi per foot in the sand and sand-shale facies to a maximum of nearly 1 psi per foot in the geopressed environment. Sediments whose pressure gradient exceeds 0.465 psi per foot are overpressured. They are composed of shales and occasional sands which at the time of burial lacked adequate continuous permeability to allow connate water to escape during compaction. The shales are less dense, and have a higher bulk water content. They exhibit a reduced resistivity on electric logs, and generally can be drilled faster than normally pressured sediments.

4.1.4 Oil and Gas Traps

Virtually all oil and gas production in the area is associated with structure. Sand pinchouts are common, and where they are associated with fault-generated structures or salt uplifts they influence the accumulation of oil and gas; production from stratigraphic traps other than on closed structures is rare.

Hydrocarbon production from fault traps generally occurs on the downthrown side of the fault. However, where regional faults cross large uplifts, accumulation in the upthrown closure is common.

4.2 Local Geology

The Beulah Simon No. 2 test site has been identified as in the Cossinade field area.

Regionally, the Beulah Simon No. 2 is in a synclinal area between the Abbeville field to the southeast, the Leroy field to the east, the Perry Point and Leleux fields to the north, the Gueydon field to the west, and the Kaplan field to the southwest¹⁰ (see cross sections, Figs. 2, 3, and 4).

The target geopressed-geothermal aquifer consists of a thick development of Camerina "A" sand of upper Frio age, which is the first significant sand development below a thick Discorbis-Marginulina age shale section.¹¹

NORTH

A

THE CALIFORNIA CO.
E.L. SIMON NO. 1
SEC. 14, 11S, 2E

OWEN ETAL
F.T. HUNTER NO. 1
SEC. 14, 11S, 2E

ATLANTIC RICHFIELD CO.
G.B. LANDRY NO. 1
SEC. 23, 11S, 2E

TOP CAMERINA

SOUTH

A'

GRUY/DOE
B. SIMON NO. 2
SEC. 26, 11S, 2E

FIGURE 2

COSSINADE FIELD AREA

VERMILION PARISH, LOUISIANA

CROSS SECTION A-A'

* PROD. FELL FROM 6000
MCF/DAY TO ZERO FEB-80.
NEW OFFSET WELL
BEING DRILLED 5-80

INDEX MAP

UNION OIL CO OF CAL.
C BELL #1
SEC 28, 11S, 2E

WEST

B

WESTERN NATURAL GAS
S. SONNIER #1
SEC 23, 11S, 2E

SUN OIL CO.
SIMON #1
SEC 19, 11S, 3E

EAST

B'

H. HUNT TRUST
N. PREJEAN #1
SEC 28, 11S, 3E

TOP CAMERINA

TOP CAMERINA

TOP CAMERINA

FAULT "A"

INDEX MAP

0 2000 4000
SCALE

FIGURE 3

COSSINADE FIELD AREA

VERMILION PARISH, LOUISIANA

CROSS SECTION B-B'

COSSINADE FIELD AREA
VERMILION PARISH, LOUISIANA
CROSS SECTION C-C'

FIGURE 4

INDEX MAP

0 2000' 4000'
SCALE

EAST

C'

ARKIA EXP.CO.
D. DUTTON #1
SEC 32, 11S, 3E

The Camerina section has been identified as having been deposited in an inner neritic environment during a regressive stage.

The Camerina "A" accounts for significant gas condensate production in a large number of structures up regional dip (north). The closest hydrocarbon production in this section is on the north flank of the Abbeville field some 6 miles southeast, and in the adjacent Cossinade field. Both accumulations are minor. However, in the Lake Arthur field (approximately 20 miles west-northwest) in Jefferson Davis Parish, the Camerina section has produced more than 700 billion cubic feet.

Figure 5 is a structural interpretation at the top of the Camerina "A" sand. This interpretation is based on limited deep-well control and a seismic interpretation made available by the original operator. The limited deep-well control is in agreement with the seismic data.

The test well is bounded on the north, south, and west by major down-to-the-coast (growth-type) faults. Undoubtedly, additional faulting is present which is not apparent from the limited subsurface control. As discussed in Section 11.3, the interpretation of the transient pressure data indicates the presence of two parallel barriers, probably faulting, at distances of 556 and 794 feet from the well.

The net sand thickness for the Camerina "A" section in the Beulah Simon No. 2 is 266 feet (see log, Fig. 6). This is the best sand development in the area, comparing with 100 to 130 net feet for other wells in the vicinity. Interpretation of geophysical data indicates the possibility of a fault some 2,000 feet to the north. This thickening of section, however, indicates that this well is probably in the growth zone on the downthrown block and that the fault is somewhat closer than the seismic interpretation indicates. Electric logs are not available for all of the adjacent wells, some of which did not penetrate the Camerina "A" sand.

Fig. 6.-- ISF log, Beulah Simon No. 2.

5.0 PETROPHYSICS

5.1 Open-Hole Log Analysis - Test Well

Analyses of the available log data were conducted in an effort to determine:

1. effective reservoir porosity
2. net effective reservoir thickness
3. a reasonable estimate of the reservoir permeability
4. salinity of the reservoir fluid.

The final logging run was made prior to re-entry, and the decision was made to proceed with setting the liner rather than attempt to secure additional logging data; the latter would have endangered the operation by requiring the exposure of two radioactive sources to adverse borehole conditions.

The available log data consisted of a Schlumberger ISF-Sonic log which contained the following:

1. spontaneous potential
2. gamma ray
3. induction - SFL (shallow focused log)
4. compensated borehole sonic log.

The Beulah Simon No. 1, about a mile away, was logged with a gamma-gamma density device; therefore the logs of both the Simon No. 1 and Simon No. 2 were used in the analyses.

A discussion of the methodology used to determine the desired reservoir parameters follows.

5.1.1 Porosity

Limited petrophysical data were available from the subject well for analyzing the aquifer properties. Normally the sonic log does not provide the accuracy for porosity measurements that might be obtained from density-type measurements, because the shale content and compaction corrections are much more significant in the sonic response. In the Simon No. 1 the apparent formation water resistivity was determined using induction resistivity (R_{ILD}) and density porosity (ϕ_d). This apparent water resistivity was then used with the logs of the No. 2 well to obtain porosity corrected to density response. This was done by the Rwa method utilizing resistivity response, which assumes that the salinity of the formation waters does not change appreciably between the two wells, and by computation of the "C" factor, which is simply an empirical factor to correct the sonic response to match that of a density device.

The equation used to relate formation density to density porosity is¹²

$$\phi_d = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} - V_{sh} \left(\frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_f} \right) \quad (1)$$

where ρ_{ma} = matrix density (gm/cc),
 ρ_b = bulk density (gm/cc),
 ρ_f = fluid density (gm/cc),
 ρ_{sh} = shale density (gm/cc),
and V_{sh} = shale volume (decimal fraction).

Shale content was obtained from the familiar Hilchie equation for Tertiary systems:

$$V_{sh} = 0.083(2.0^{3.71I_{gr}} - 1.0), \quad (2)$$

where
$$I_{gr} = \frac{GR_{log} - GR_{cs}}{GR_{sh} - GR_{cs}}$$

GR_{log} = gamma reading of formation of interest,
 GR_{cs} = gamma reading of "clean" shale-free sand (API units),

and GR_{sh} = gamma reading of "shale" section (API units).

The apparent water resistivity is then simply

$$R_{wa} = \frac{R_t \phi_d^m}{a}$$

where ϕ_d = density porosity (decimal),
 m = cementation factor (usually assumed to be 2.15 in sandstone for the Humble relationship),
and a = tortuosity factor (usually assumed to be 0.62 for sandstones).

After obtaining R_{wa} for a zone in the Simon No. 1 well, an "equivalent" ϕ_d was then calculated for the No. 2 well:

$$\phi_d = (R_{wa}(a)/R_t)^{1/m}$$

The sonic porosity (ϕ_s) was then computed from the following routine:

$$\phi_s = \frac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} - V_{sh} \left\{ \frac{\Delta t_{sh} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \right\}, \quad (3)$$

where ϕ_s = sonic porosity (decimal),
 Δt = log Δt (μ sec/ft.),
 Δt_{ma} = matrix travel time (55 μ sec/ft),
 Δt_f = fluid travel time (190 μ sec/ft),
and V_{sh} = shale content, previously defined.

Finally,

$$\phi_s(\text{corrected}) = \phi_s(\text{uncorr.}) \times C, \quad (4)$$

where $C = \phi_d / \phi_s(\text{uncorr.})$

$$\text{and } \phi(\text{effective}) = \frac{\phi_{Rwa} + \phi_s(\text{corrected})}{2}.$$

The Beulah Simon No. 2 has 80 feet of sand in the upper zone with an average porosity of 14.5 percent, and 186 net feet of sand in the lower zone with an average porosity of 18.7 percent. The bottom 48 feet of the lower sand has an average porosity of 22.4 percent. The total sand interval (266 net feet) has an average porosity of 17.4 percent.

5.1.2 Net Thickness

The gross thickness of the sand tested is 208 feet; i.e., from 14,566 feet to 14,774 feet. Although there do not appear to be any significant shale members which would impede the vertical migration of fluids, several zones with somewhat larger percentages of shale do exist. By correcting the gross sand thickness for the shale volumes, a net sand thickness of 186 feet was derived. The perforated interval, 14,674 to 14,770 feet, was chosen near the bottom of the interval because the log response indicated higher porosities and lower shale content.

5.1.3 Reservoir Permeability

A log-calculated permeability value was required early in the well program in order to estimate the well's deliverability and to design appropriate wellhead, testing, and disposal facilities.

Both Schlumberger and Dresser Atlas present empirical equations for estimating formation permeability, but unfortunately they are based upon core analysis data in which two immiscible fluids are present in the pores. Their application, therefore, requires a prior knowledge of the irreducible water saturation. The equations are quite similar, differing primarily in constants and units. Estimates made using both equations were nearly identical.

The equations are:

A. Schlumberger:

$$k = \left(\frac{100\phi_E^{2.25}}{S_{w_{irr}}} \right)^2 \quad (5a)$$

where k = permeability (md),
 ϕ_E = effective porosity (decimal),
and $S_{w_{irr}}$ = irreducible water saturation (decimal);

B. Dresser Atlas:

$$k = \frac{0.136\phi_E^{4.4}}{S_{w_{irr}}^2} \quad (5b)$$

where k = permeability (md),
 ϕ_E = effective porosity (percent),
and $S_{w_{irr}}$ = irreducible water saturation (percent).

Assuming that $S_{w_{irr}}$ is 100 percent (which is known to be too high), the permeabilities calculated for the mean effective porosity (18.7 percent) from Eqs. 5a and 5b are 5.3 md and 5.4 md, respectively. Figure 7 graphically shows the relationship between permeability and $S_{w_{irr}}$ for the mean reservoir porosity. Since cores were not available for capillary pressure analyses, accurate determination of the irreducible water saturation was impossible. The test program was designed on the basis of an anticipated permeability between 5 and 21 md (corresponding to an $S_{w_{irr}}$ range of 100 to 50 percent). Analysis of reservoir data indicates an effective permeability of approximately 12 md, which corresponds to an $S_{w_{irr}}$ value of 66 percent.

5.1.4 Salinity

In order to estimate gas solubility and potential scaling and corrosion problems, a knowledge of the formation water salinity was required. This was calculated by two methods.

5.1.4.1 R_{wa} Method

The salinity (expressed in equivalent parts per million of NaCl) was determined as a function of temperature and apparent water resistivity by the following procedure.

Fig. 7.-- Permeability versus Sw_{IRR} for porosity of 18.7%.

$$\text{NaCl (ppm)} = \left(\frac{3647.5}{R_w(75^\circ) - 0.0123} \right)^{1/0.995}, \quad (6)$$

where $R_w(75^\circ)$ = resistivity of the water at 75°F (ohm-m²/m)

and

$$R_w(75^\circ) = R_{w(\text{res})} \left[\frac{T_{(\text{res})} + 7.0^\circ\text{F}}{82.0^\circ\text{F}} \right], \quad (7)$$

where $R_{w(\text{res})}$ = apparent resistivity of the reservoir water (ohm-m²/m)

and $T_{(\text{res})}$ = reservoir temperature (°F).

The apparent resistivity of the formation water, $R_{w(\text{res})}$, was obtained from a derivation of the familiar Humble formation factor equation,

$$R_{w(\text{res})} = \frac{R_T \phi_E^{2.15}}{0.62}, \quad (8)$$

where R_T = resistivity of the undisturbed formation (ohm-m²/m)

and ϕ_E = effective porosity (decimal).

To arrive at Eq. 8, 100 percent water saturation was assumed, making the value of the saturation exponent insignificant.

The mean $R_{w(\text{res})}$ calculated was 0.022 ohm-m²/m as determined by the analyses of the test zone. Wireline data indicated a reservoir temperature of approximately 270°F. Using these parameters, the total salinity was calculated to be equivalent to 98,678 ppm (mg/l) NaCl, which is in good agreement with the chemical analysis.

5.1.4.2 SP-Derived R_w

Solving for formation fluid resistivity from the SP (spontaneous potential) and then solving for equivalent NaCl salinity yielded results much different from those obtained by the R_{wa} method. The biased mean value of the SP-calculated R_w 's was 0.027 ohm-m²/m (76,681 ppm NaCl). The equations used to determine the resistivity of the formation fluids are:

$$R_w = \frac{R_{we} + 0.131[10^{1/(\log(T_f/19.9) - 2.0)}]}{-0.5R_{we} + 10^{[0.0426/\log(T_f/50.8)]}} \quad (9)$$

and

$$R_{we} = R_{mf} \left(10^{[SSP/(60 + 0.133T_f)]} \right) \quad (10)$$

where R_{mf} = resistivity of mud filtrate at formation temperature (ohm-m²/m)

and SSP = static spontaneous potential (millivolts).

The discrepancy between the log-calculated salinity obtained by two independent methods and the chemical analysis of the produced water is interesting, in that the R_{wa} salinity appears to be reasonable while the SP salinity is too low. This may be due to erroneous measurement of filtrate resistivity, erroneous temperatures, or erroneous SP scaling.

5.2 Open-Hole Log Analysis - Disposal Well.

The available log data were analyzed to identify the zones of highest injectivity potential. Log data consisted of an induction-sonic log with an SP recording. The minimum acceptable disposal depth (2,000 ft) had been specified earlier by the Louisiana Department of Conservation. Based on a correlation with offset wells, the decision was made to drill the disposal well to 2,500± ft, then log and assess the injectivity potential at that depth. The well penetrated three qualifying sand members ranging in thickness from 40 to 100 ft. The observed porosities ranged from 35 to 44 percent, the mean being 41 percent through the perforated interval (2,464 to 2,524 ft).

The equation used to transform sonic interval transit time to porosity is:

$$\phi_s = \frac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \left(\frac{100}{\Delta t_{sh}} \right) - V_{sh} \left(\frac{\Delta t_{sh} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \right) \quad (11)$$

where ϕ_s = sonic porosity,
 Δt = log Δt (μ sec/ft),
 Δt_{ma} = matrix travel time (58.8 μ sec/ft),
 Δt_f = fluid travel time (190 μ sec/ft),
 Δt_{sh} = shale travel time (140 μ sec/ft),
and V_{sh} = shale content (estimated to be 0.15).

5.3 Cased-Hole Log Analysis

Cased-hole logs consisted of a gamma ray/neutron/collar log, a cement bond log, and a casing inspection log (test well only).

These logs were run to determine the integrity of the cement-pipe and cement-formation interfaces, to establish an open-hole/casing-collar correlation, and to verify that the casing wall thickness was satisfactory. An explanation of the various qualitative interpretation techniques used to analyze these logs is beyond the scope of this report.

6.0 DRILLSITE AND SUPPORT FACILITIES

6.1 Site Layout

The drillsite layout shown in Fig. 8 accommodated conventional drilling equipment used for the completion of the test well and the drilling of the disposal well. The living quarters and office facilities were located on the turnaround area at the site.

Waste oil and grease spillage was trapped and drained into a ditch around the rig for recovery and disposal to prevent contamination of the area. This is a standard practice, required by state and Federal environmental agencies.

6.2 Living Quarters

A three-bedroom air-conditioned house trailer provided quarters for drilling consultants and Gruy and DOE representatives. Motel accommodations were available in nearby Kaplan.

6.3 Water Supply

Potable water was hauled to the site and stored in a sanitary tank. Water used as engine coolant and for preparing drilling mud and cement was supplied by a water well completed by Southport at the location.

6.4 Utilities

Two telephone lines were installed in the living quarters. A portable telecopier was used to transmit the morning reports to the Houston office.

During completion operations, the rig had 110-volt electrical power adequate to meet anticipated requirements. During the test period, rental generators were used to provide electrical power.

Fig. 8 -- Schematic location plat of Beulah Simon No. 2.

7.0 TEST WELL

7.1 Initial and Anticipated Well Completion Status

Figure 9 shows the status of the hole at the time of takeover, the status during testing, and the status of the well after final plugging and abandonment.

7.2 Liner and Tubing Installation

Table 1 summarizes the design for the tubular goods installed in the well by Southport before operations were transferred to Gruy. The table also shows the liner, tieback casing, and tubing design, as well as cementing specifications for the equipment installed by Gruy during completion operations. The operational procedures for setting the liner and the tubing are covered in Section 7.6. Figure 10 shows the calculated pressure loss due to friction while producing 10,000 B/D of brine through the 3-1/2 inch tubing.

7.3 Wellhead Design

Figure 11 is a sketch of the wellhead and christmas tree acquired for this well. The tree has a rated working pressure of 10,000 psi and a rated test pressure of 15,000 psi. All gate valves in the vertical run of the tree are fabricated from T-24 steel, and packing and seals are adequate for 300°F service. The tree consists of two 3-1/16 inch diameter master gate valves and a 3-1/16 inch swab valve. Between the top master valve and the swab valve was a split flow body that reduced the bending moment on the tree while the well was flowing at a high rate. Each wing of the split flow body included a hand-operated gate valve, an automatic safety valve, and a choke assembly. One of the choke assemblies was an adjustable choke; the other was a positive choke.

7.4 Logging Program

7.4.1 Open-Hole Logs

The suite of logs obtained by Southport in the open-hole section of this well included an ISF-Sonic log that was adequate for evaluation purposes, and hence no additional logs were taken in the open hole.

7.4.2 Cased Hole Logs

After the 5-1/2 inch liner was run and cemented, gamma-ray/neutron, cement bond, and collar locator logs were run to establish a reference for perforating and to meet state regulatory requirements (a gamma-ray/neutron log must be run through all potential geopressured sands).

7.5 Drilling Operations

7.5.1 Blowout Preventers

The blowout preventers (BOP's) and choke manifold furnished with the rig

Fig. 9 -- Schematic of downhole conditions, Beulah Simon No. 2.

Fig. 10 -- Total friction loss versus rate of production, 14,550 feet, $3\frac{1}{2}$ -inch production tubing, water viscosity = 0.22 cp.

Fig. 11 -- Wellhead schematic, Beulah Simon No. 2 test well.

TABLE 1
TUBULAR AND CEMENTING DESIGN SPECIFICATIONS
BEULAH SIMON NO. 2

CASING	Size, in.	Depth, ft		Weight, lb/ft	Minimum Drift, in.	Casing Description		Casing Design Factors		
		From	To			Grade	Thread	Collapse (dry)	Tension	Burst (dry gas)
Surface	13-3/8	0	2,400	54.5	12.459	J-55	ST&C	Installed by Southport		
		2,400	3,500	61.0	12.359	K-55	ST&C			
Intermediate	9-5/8	0	2,300	43.5	8.599	N-80	Buttress	"	"	"
		2,300	2,800	43.5	8.599	N-80	LT&C	"	"	"
		2,800	5,300	47.0	8.525	N-80	LT&C	"	"	"
		5,300	10,800	47.0	8.525	S-95	LT&C	"	"	"
		10,800	12,100	47.0	8.525	N-80	LT&C	"	"	"
Liner No. 1	7-5/8	11,900	13,800	39.0	6.50	N-80	FJ	"	"	"
Liner No. 2	5-1/2	11,555	15,233	23.0	4.545	P-110	SFJ-P	1.04	6.89	6.31
Tieback	7	0	10,700	38.0	5.795	P-110	SFJ-P	1.10	3.22	1.1
	7	10,700	11,555	32.0	5.969	P-110	FL4S	1.05	3.04	1.1
Tubing	3-1/2	0	11,065	12.95	2.625	P-110	PH-6	•	1.71	•
		11,065	14,465	12.95	2.625	C-75	Special clearance coupling	*	7.25	•

CENTRALIZERS:

Casing	Size, in.	Centralizers	Remarks
Surface	13-3/8	Yes	Surface, intermediate, and both liners were run by Southport
Intermediate	9-5/8	Yes	
Liner No. 1	7-5/8	Yes	
Liner No. 2	5-1/2	Yes	
Tieback	7	Yes	Tied back with BOT collar
Tubing	3-1/2	Yes	Centralizers, one on each of bottom three joints

CEMENT:

Casing	Size, in.	No. Sacks	Type	Water per sack, gals	Slurry wt, lb/gal	Slurry vol, cu ft/ sack
Liner	5-1/2	660	**	5.56	18.0	1.39

PRESSURE TESTS:

Casing	Minimum Pressure Test Required by State of Louisiana, Department of Conservation
Surface	Installed and tested by original operator
Intermediate	Installed and tested by original operator
Liner, 7-5/8"	Installed and tested by original operator
Liner, 5-1/2"	2,500 psi or 0.2 psi/ft, whichever is greater
Tieback	2,500 psi or 0.2 psi/ft, whichever is greater

*No differential.

**Cement class H plus 35% coarse silica flour plus 3% KCl plus 42 lb Hi-Dense No. 3 per sack plus 0.6% Halad 22A plus 0.75% CFR-2 plus 1/4 lb D-AIR 1 per sack plus retarder.
Laboratory analysis of cement and water to determine setting time was obtained prior to cementing operations.

were rated to a working pressure of 5,000 psi, hence they were replaced with 10,000-psi rental units.

7.5.2 Drilling fluids

The well was drilled using a 17.8-lb/gal lignosulfonate mud, and fluid of the same type and density was used for the completion operations.

7.5.3 Drilling Rig

Table 2 summarizes the equipment furnished by the contractor.

7.6 Completion Operations

7.6.1 Open-Hole Operations

When the Beulah Simon No. 2 well was turned over to Gruy Federal, the 13-3/8 inch casing and the 9-5/8 casing had been cut 3 ft below ground level and cement plugs had been placed in the well as shown in Fig. 12.

Before Delta Drilling Rig No. 47 moved to the site on September 15, 1979, the 13-3/8 inch conductor casing had been extended to the surface and a 13-3/8 inch 5,000-psi casing housing welded to it.

After the drilling rig was on location and rigged up, the 9-5/8 inch casing was backed out at 101 ft and pulled. Three new joints (124.25 ft) of 9-5/8 inch, 47.0 lb/ft, N-80 casing were run and screwed into the top of the 9-5/8 inch casing at 101 ft. A pull of 200,000 pounds was applied and the slips were set in the 13-3/8 inch casing housing. A retrievable bridge plug was set at 120 ft and the 9-5/8 inch casing above that depth was tested to 2,100 psi.

A 13-5/8 inch 5,000-psi × 11-inch 10,000-psi WKM type "S" casing head, BOP stack, and choke manifold were installed and tested to their working pressures.

When all of the surface BOP equipment had been tested, an 8-1/2 inch bit was used to clean out to the top of the 7-5/8 inch liner at 11,882 ft, using a 17.8-lb/gal lignosulfonate drilling fluid.

A 6-1/2 inch drill bit was used to clean out the 7-5/8 inch liner and the open hole to 15,232 ft and to drill new hole to 15,233 ft. A short trip was made to check open hole conditions from 13,931 to 15,233 ft. There was some drag while making the short trip, but not enough to require further hole conditioning. The 6-1/2 inch bit was pulled and the casing crew rigged up and ran the 5-1/2 inch liner.

7.6.2 Casing Liner

Ninety joints (3,678 ft) of 5-1/2 inch, 23.00 lb/ft, P110 FJ casing were picked up and run on 4-1/2 inch drill pipe to 15,233 ft. The top of the 5-1/2 × 7-inch tieback sleeve was at 11,536 ft. Eight centralizers were spaced between 15,213 and 14,140 ft.

TABLE 2
EQUIPMENT FURNISHED BY DRILLING CONTRACTOR
DELTA DRILLING CO. RIG NO. 47

<u>Drawworks</u>	National 130 Grooved for 1-3/8" drill line Parkersburg 60" Hydromatic brake
<u>Derrick</u>	Lee C. Moore mast 142 feet high Static hook load rating: 8 lines 656,000 10 lines 683,000 12 lines 703,000
<u>Substructure</u>	Lee C. Moore 20 feet high 750,000 lb. casing capacity simultaneous with 500,000 lb.
<u>Power Source</u>	3 Superior PTDS-8 (diesel) 2,250 horsepower
<u>Pumps</u>	1 National model 10P130, 6¼" x 10", 1,300 hp 1 Emsco model D-1000, 7½" x 18", 1,000 hp, compound driven 2 Mud mixing centrifugal pumps
<u>Drill String</u>	10,000' 4½" OD, 16.6 lb/ft, Gr. E, 4½" XH by 6¼" OD tool joints 7,300' 4½" OD, 16.6 lb/ft, Gr. X-95, 4½" XH by 6¼" OD tool joints Other grades of pipe available.
<u>Preventers</u>	1 Hydril model GK, 10", 5,000 psi 2 Cameron model QRC, 10", 5,000 psi 1 Payne accumulator, 80-gallon capacity, with 6 stations
<u>Other Equipment</u>	Crown block: Lee C. Moore, 7 sheaves, 450-ton capacity Traveling block: Ideco, 6 sheaves, 450-ton capacity Hook: Byron Jackson model 4300 Light plants: two 3306 TA Caterpillar, 150 kw., 220/240 volts AC Swivel: National N-815 Mud tanks: three 6' x 8' x 41' with two mud mixers--10 hp Lights: Rig-A-Lite vapor-proof fluorescent Desander: Swaco, size no. 6 Rotary table: Emsco T2750 Bunkhouse: 10' x 41', wheeled trailer, air-conditioned Shale shaker: Brandt, dual Desilter: 14-4" cones Crown-O-Matic

Fig. 12 -- Condition at takeover, Beulah Simon No. 2.

7.6.3 Cementation of Liner

The hole was circulated clean through the liner and a spearhead of 20 barrels of SAM-5 (18.0 lb/gal), followed by 400 sacks Class H cement with 40 percent silica flour weighing 18.4 lb/gal, was pumped. As the cement cleared the 5-1/2 inch liner float shoe, 80% returns were lost while pumping the next 45 barrels. The wiper plug bumped bottom and was pressured to 1,000 psi. When there was no flow back, indicating that the float equipment held, the liner was released and the drill string was pulled out of the hole. The annulus was filled from the trip tank each 5 stands while pulling out.

An 8-3/4 inch drill bit was picked up on the bottomhole assembly, and while running in the hole with the bit at 3,522 ft the well began flowing through the casing annulus. By the time the inside blowout preventer was installed in the drill pipe, the kelly picked up, and the Hydril closed, the pit volume had increased by 95 barrels.

A pump truck was connected to the kill line on the casing housing and the drill pipe and 18.0-lb/gal mud was pumped down the drill pipe to reduce the shut-in drillpipe pressure in order to snub into the hole. The shut-in pressure was reduced from 1,500 to 670 psi after 307 barrels of mud had been pumped. At this reduced pressure it was possible to strip the drill pipe through the bag blowout preventers and lower the bit from 3,522 to 11,536 ft.

While 18.0-lb/gal mud was circulated through a choke and backpressure was held on the annulus, the drilling fluid weight stabilized at 17.8 lb/gal. When the pumps were shut down, pressure was 300 psi on the casing and 450 psi on the drill pipe. With the well shut in, 75 barrels of 18.0-lb/gal drilling fluid was pumped into the drill pipe, which reduced the casing pressure to 300 psi. The drilling fluid was then weighted to 18.3 lb/gal and pumped into the drill pipe, further reducing the casing pressure to 200 psi. The mud weight then was increased to 18.3 lb/gal while circulating, and when returns of 18.3 lb/gal reached the surface, both the tubing and casing pressures were zero. However, to ensure safe operating conditions while repairing the cementation of the 5-1/2 inch liner, the drilling fluid weight was increased to 18.5 lb/gal.

With the well dead, the 8-3/4 inch drill bit was pulled and a 7-5/8 inch squeeze tool was run to 11,042 ft, set, and used to squeeze 62 barrels of Class "H" cement mixture below the squeeze tool with maximum and final surface pressure of 1,300 psi. After waiting on cement for 12 hours, the cement squeeze was pressure-tested to 2,000 psi. When no bleedoff was observed the squeeze tool was opened, reverse circulated to condition the drilling fluid, and pulled out of the hole.

An 8-3/4 inch bit was run and tagged the cement in the 7-5/8 inch casing at 11,502 ft. Solid cement was drilled from 11,502 to 11,555 ft (corrected top of 5-1/2 inch casing liner). After the hole had been conditioned, the 8-3/4 inch bit was pulled and a squeeze packer was run to test the seal

between the 5-1/2 inch and 7-5/8 inch. A pressure of 2,000 psi was applied for 30 minutes, after which there was no bleedoff. The pump truck then displaced 7,500 ft of 18.5-lb/gal drilling fluid from the drill pipe with 8.4-lb/gal water. With the squeeze tool set, the drill pipe pressure was slowly reduced to zero and the well observed for 30 minutes. With a 3,900-psi differential to the well bore no flow was observed, so the fresh water was reversed out.

7.6.4 Clean Out of Cement from Liner

A 4-1/2 inch mill was used to clean the cement out of the top of the 5-1/2 inch liner (11,562 to 11,566 ft) and run to 15,208 ft. The hole was conditioned before running CBL/CNL/GR from 15,218 to 11,550 ft. The cement bond log indicated good bonding above and below the test objective and the sand was adequately isolated.

7.6.5 Running Casing Tieback

The tieback sleeve (polished bore receptacle, PBR) was cleaned out to 11,556 ft, the hole conditioned, and the 4-1/2 inch drill pipe laid down. Casing tools were rigged up and 280 joints of 7-inch casing (11,555 ft) with a tieback on bottom were run to 11,556 ft and stabbed into the PBR of the 5-1/2 x 9-5/8 inch liner hanger. A pressure of 3,500 psi was applied to the seals. The tieback was then screwed into the PBR and a pull of 75,000 lb exerted. The 7-inch casing slips were set and the 11-inch 10,000-psi BOP's nipped up.

A trip was made to run a 4-1/2 inch mill to 15,208 ft and a 7-inch casing scraper was run to 11,500 ft. The drilling fluid was circulated and conditioned and the drill pipe was pulled and laid down.

7.6.6 Production Tubing

The 3-1/2 inch tubing was picked up and run to a total depth of 14,930 ft. The 18.5-lb/gal drilling mud was displaced with 10.0-lb/gal salt water and the well was observed for one hour for possible flow. The 3-1/2 inch tubing was picked up so that the 3-1/2 inch guide shoe would be at 14,191.44 ft. A 3-1/2 inch Otis "R" nipple was placed at 2,751 ft. The bottom master valve of the Christmas tree was installed and tested to 10,000 psi.

A backpressure valve was placed in the Canfield bushing of the wellhead and another in the "R" nipple at 2,751 ft. Tubing pressure was bled off and the drilling rig was released at 5 p.m. on October 17.

7.6.7 Christmas Tree

The christmas tree, chokes, and flow loops were installed and pressure-tested to 10,000 psi. Plate 1 is a photograph of the tree, the kill line, the chemical injection line, and the production work platform used during testing operations.

7.6.8 Perforating

Upon completion of the perforation of the disposal well, a high-pressure lubricator was rigged up on the test well and tested to 10,000 psi. The geopressured-geothermal zone (14,647 to 14,770 ft) was then perforated using a 2-7/8 inch hyper-dome gun with zero phasing and 4 shots per foot. After the first run of the perforating gun, perforating from 14,770 to 14,750 ft, the pressure on the tubing was 6,500 psig; this pressure did not increase while the remaining runs were made.

8.0 SALTWATER DISPOSAL WELL

8.1 General

The saltwater disposal well, located 160 ft from the test well, was drilled while the test well was being completed.

8.2 Design Requirements

1. This disposal well was designed to provide an injection capacity up to 10,000 B/D at an injection pressure not to exceed 300 psi and an injection temperature up to 280°F (138°C).
2. The Louisiana Department of Conservation specified that the minimum acceptable saltwater disposal aquifer depth in this area was 2,000 ft.
3. The Louisiana State Department of Conservation regulations specify that each disposal well must protect fresh water or shallow brackish water sands by:
 - a. Setting and cementing two complete strings of casing through all fresh or brackish water sands by circulating cement to the surface on each string if no tubing is used, or
 - b. Cementing one string of casing through the fresh water sands to the surface and isolating the tubing by a production packer inside the second string of casing.

A review of the electric log on the test well indicated that three possible disposal aquifers should be penetrated between 2,180 and 2,650 ft. Figure 13 shows the well schematic that meets (a) above.

8.3 Rig Selection

Because of the shallow gravel beds known to be in the general vicinity of this site, the risks in drilling a disposal well were compounded; hence, modified turnkey drilling bids were solicited. Gruy agreed to furnish tubular goods, cement and services, and the required electric logs; the drilling contractor agreed to drill the well to total depth and set the various strings of casing for a fixed fee, while the completion work would be performed on a day-rate basis. Howard Water Well Service of Jennings, Louisiana, was the successful bidder.

8.4 Disposal Well Operations

8.4.1 Conductor Casing

A diesel hammer was used to drive the 13-3/8 inch, 53.5 lb/ft, K-55 plain-end beveled casing to 105 ft below ground level on August 31, 1979.

Fig. 13.-- Beulah Simon No. 1 saltwater disposal well schematic.

8.4.2 Surface Casing

A water well rig started moving to the location on September 13 and began drilling out from below the 13-3/8 inch casing on September 14. A 12-1/4 inch hole was drilled from 105 to 1,226 ft and 32 joints of 9-5/8 inch OD, 36.0 lb/ft, J-55, 8RD THD, LT&C casing (1,183.31 ft) were run to 1,226 ft. One centralizer was used on each of the bottom 12 joints.

8.4.3 Completion Casing

The 9-5/8 inch casing was cemented with 210 sacks HOWCO Lite Weight cement plus 40% silica flour followed by 200 sacks class H cement plus 40% silica flour plus 2% CaCl₂. The cement was displaced with 9.2-lb/gal mud until cement was returned to the surface.

After rigging up on the 9-5/8 inch casing, an 8-3/4 inch hole was drilled to 2,702 ft and Schlumberger ran ISF-Sonic and logs from 2,708 to 1,228 ft.

The hole was conditioned before running 65 joints of 5-1/2 inch, 15.50 lb/ft, K-55, ST&C casing to 2,698 ft. Twenty-one centralizers were spaced between 1,166 and 2,678 ft.

The 5-1/2 inch casing was cemented with 1,000 sacks of HOWCO Lite Weight cement plus 40% silica flour plus 2.7 lb NaCl per sack of cement, followed by 420 sacks class H cement plus 40% silica flour plus 2% CaCl₂. The cement was spearheaded with 1,000 gallons of mud flush. The 5-1/2 inch casing was displaced with 9.2-lb/gal mud and the plug bumped bottom at 7 p.m. on September 20.

8.4.4 Completion Operations

The 5-1/2 inch casing was cleaned out to 2,653 ft, the drilling fluid was displaced with produced salt water, and the drill pipe was pulled out of the hole and laid down.

A cement bond-variable density-gamma ray log was run from 2,652 to 641 ft. The log indicated satisfactory bonding over the injection zones.

After the wellhead was installed on the 5-1/2 inch casing, the water well rig was released at 10 a.m. on October 2 and moved off location.

8.4.5 Petrophysical Data

Analysis of the ISF Sonic log (Fig. 14) obtained on this well showed the following sands had been penetrated:

<u>Sand</u>	<u>Top, ft</u>	<u>Bottom, ft</u>	<u>Net Thickness, ft</u>	<u>Calculated Weighted Average Porosity, %</u>
1	2350	2400	40	35
2	2449	2568	109	38
3	2599	2647	42	38

Fig. 14.-- ISF electric log, Beulah Simon No. 1 saltwater disposal well.

8.4.5.1 Perforations and Injectivity Tests

The No. 2 sand was selected as the initial disposal sand. The interval from 2,464 to 2,524 ft was perforated with four shots per foot, using a 4-inch OD casing gun. For convenience, the perforating was accomplished using three 20-foot perforating guns with three separate trips in the hole.

The potential injection sands consist of fine to medium silica grains that vary from unconsolidated to poorly consolidated with argillaceous materials. They are highly susceptible to flowing or sloughing into the wellbore when the well is produced. In order to use such aquifers for disposal the static fluid head should be equal to or greater than the aquifer pressure. Under dynamic conditions a positive pressure differential should always exist from the wellbore to the aquifer. For this reason, taking a water sample for compatibility analysis of the injection aquifer and the produced brine involves the risk of sanding up the well.

In order to evaluate injection test data while protecting the disposal well from backflowing, 500 psi backpressure was held on the formation while perforating the first 20-foot section. While the perforating equipment was out of the hole to change guns, injectivity tests using salt water from adjacent producing operations were conducted on the disposal sand. The results of these tests are shown in Fig. 15.

8.4.5.2 Injection Well Stimulation

Based upon the results of the injectivity test shown in Fig. 15, the perforations from 2,524 to 2,464 ft were treated, in sequence, with: 1,000 gal 7-1/2 percent HCl; 2,000 gal HF; 500 gal 7-1/2 percent HCl with diverter; 500 gal 7-1/2 percent HCl; 4,000 gal HF; and 500 gal 7-1/2 percent HCl, and finally displaced with 60 barrels of salt water. An injection test after acidizing showed that the rate had to be increased in excess of 8 bbl/min to build up surface pressure. All acid was then displaced with lease salt water. Figure 15 also shows that the acidizing was successful; the disposal well was capable of taking all anticipated production from the test well, provided that the maximum production did not exceed 11,000 B/D and the maximum injection pressure did not exceed 90 psig. The surface air coolers were bypassed and 255°F (124°C) well fluid was injected at a rate of 11,000 B/D with a maximum surface injection pressure of 200 psig. When the test well was shut in, the injection pressure dropped to zero or to a slight vacuum almost instantaneously.

Fig. 15.-- Injectivity test, Beulah Simon No. 1.

9.0 TEST OBJECTIVES

The test on the Beulah Simon No. 2 well was designed to obtain the maximum amount of information about the aquifer rock and fluid properties within the time and funds allotted. These properties are:

- Well deliverability
- Formation flow capacity
- Wellbore damage
- Aquifer geometry
- Distance to existing boundaries
- Gas solubility
- Chemical composition of the water and gas
- Physical properties of the water and gas.

In addition, the performance of downhole and surface equipment exposed to large quantities of high-pressure, high-temperature brines has not been well established. For example, the maximum temperature to which the Hewlett-Packard quartz crystal gauge is calibrated is 302°F (150°C), which is near the expected bottomhole temperature. Similarly the injectivity performance of shallow Miocene sands subjected to this temperature and injection rate had not been determined. All of these factors were considered when designing the test procedures.

9.1 Surface Testing Facilities

9.1.1 Design

A schematic diagram of the surface testing equipment is shown in Fig. 16. These facilities were designed to accommodate hot brines at rates up to 10,000 B/D and temperatures as high as 350°F (177°C). The surface equipment was constructed for operating pressures up to 500 psi, since the bulk of the pressure drop occurs at the chokes in the wellhead.

9.1.2 Piping

All mainline surface piping was 3-inch API (FL), Schedule 80, butt-welded line pipe rated to 1,850 psi at temperatures up to 250°F (121°C). The valves in the system were trimmed with T-24 steel with high-temperature packing.

9.1.3 Separator

The test separator was a conventional three-phase, 42-inch × 10-ft horizontal separator in which the standard 2-inch dump valves were replaced with 3-inch valves. The working pressure rating of the vessel was 1,440 psi; however, operating pressure never exceeded 400 psi. In order to withstand the high temperatures, the liquid-level float was fabricated from Teflon™. The fluid retention time was approximately 30 seconds at the maximum design throughput of 10,000 B/D.

Fig. 16.-- Surface test facilities, Beulah Simon No. 2.

9.1.4 Metering

The liquid drain from the separator was split into two streams, each containing a 10,000-B/D HOWCO turbine meter with digital readout. Two 100-bbl calibration tanks were provided for periodic calibration of each meter. The gas production from the separator was measured using a 3-inch flange-type orifice meter with a 1/2-inch orifice plate and a Barton recorder.

9.1.5 Air Cooler

The compatibility of the disposal aquifers with these hot brines was unknown. For this reason a fan-type air-cooled heat exchanger rated at 23,400,000 Btu/hr was installed in the system. The cooler was capable of reducing the water temperature from 350°F (177°C) to 190°F (86°C) at a throughput rate of 10,000 B/D per day when the ambient temperature was 100°F (38°C). The cooler contained two 120-inch diameter fans, each driven by a 30-hp electric motor. The overall dimensions of the horizontal skidmounted cooler were 32 feet long, 11 feet wide, and 8-2/3 feet high. However, this unit was not used during the test because the injectivity was not affected by the hot brine.

9.1.6 Filters

Before the produced water was injected into the disposal well, it was filtered through a multi-tower Halliburton high pressure filter. The replaceable cartridges retain particles 50 microns or larger in size and withstand temperatures up to 300°F (149°C). During the flow test it was necessary to change cartridges every two or three days.

9.1.7 Safety Sensors

One low-pressure and three high-pressure sensors were installed in the surface flow lines to activate the safety valves on the wellhead in case pressure problems developed in the system. One high-pressure sensor was placed between the data header and the separator to detect any pressure rise resulting from sand erosion of the chokes; the second was installed ahead of the cooler to shut the well in if scale buildup occurred in the cooler; and the last was placed ahead of the injection well to terminate production if the injection pressure rose above 400 psi. The low-pressure sensor was installed between the separator and the cooler to stop flow in case a serious leak in the surface facilities occurred.

9.1.8 Scale Inhibitor

Before the test well was placed on production a blend of a phosphonate and a polymer was mixed with 3 parts of fresh water and displaced down the 3-1/2 inch tubing and up the 7 × 3-1/2 inch annulus. Fifty gallons were left inside the 3-1/2 inch tubing so that any produced fluid would be inhibited before reaching the surface. A variable-speed duplex pump was connected to the tubing head (Fig. 11) so that fresh water from a 100-bbl supply tank could be pumped into the annulus to displace the inhibitor into the production stream as the well flowed.

Addition of the scale inhibitor did not affect the chemical analysis brine.

9.2 Data Collection

A data header was assembled ahead of the separator to monitor and record data at a central site. This manifold contained a sonic sand detector, a continuous-recording thermometer, a scale coupon holder, and valve assemblies to collect full well stream samples. Pressure and temperature recorders were installed on both sides of the cooler to monitor inlet and outlet temperatures and to detect any increase in the pressure differential due to scale buildup in the cooler.

A dual-pen pressure recorder was attached to the 3-1/2 inch tubing annulus and the 9-5/8 × 7-inch casing annulus to detect any fluid communication which might occur outside the 7-inch casing.

A dual-pen recorder was attached to the disposal well tubing head to record its injection pressure and temperature.

At the wellhead a 10,000-psi deadweight pressure gauge was installed in the data collection area to measure the surface flowing and shut-in tubing pressures periodically.

9.3 Meter Prover

To ensure accurate measurements of the produced liquids, a calibration tank was used to calibrate each of the turbine meters. A known volume of water was pumped through each meter to obtain a factor for correcting the daily production. The absolute error in the metered volume varied from 0.8 to 1.8 percent; the meter accuracy improved toward the end of the flow period.

9.4 Performance of Surface Equipment

Because of the initially higher injection pressures, the valves downstream from the separator were replaced with 1,440-psi rated working pressure valves. The surface equipment performed without a malfunction. The scale inhibitor was completely effective; upon dismantling the equipment after completing the test, no scale was visible.

10.0 TESTING OPERATIONS

10.1 Cleanup

A wireline truck with single-conductor cable was moved in and a mast truck was rigged up along with a high-pressure lubricator.

On Oct. 29 a collar locator and temperature log were run in the hole, but the temperature log failed to operate. The quartz crystal pressure gauge and tubingend locator were then run; the static bottomhole pressure at 14,722 ft was 13,015 psi (middle of perforations). The pressure gauge was then relocated at the bottom of the tubing at 14,235 ft.

The well was then opened gradually to a 16/64-inch setting on the adjustable choke to clean up with 6,500 psig tubing pressure. The tubing pressure decreased to 6,365 psig in 10 minutes. The adjustable choke was slowly increased to 32/64 inch and the well was allowed to clean up to the pit for 1-1/2 hours. The well stabilized on the 32/64-inch choke with 2,917 psig on the tubing and 5,700 psig on the casing at a surface flowing temperature of 220°F. An attempt was made to transfer the flow stream through the testing equipment, but failed when the separator dump valves failed to operate. The dump valves were cleaned and another attempt was made to flow to the disposal well. The pressure at the disposal well increased to 150 psig when hot water (220°F) contacted the perforations. This increase can be attributed to the loss in hydrostatic pressure due to the lower density of the hot brine. The test well was shut in approximately 25 minutes later and a surface tubing pressure of 6,387 psig was recorded.

At 11:40 p.m. on Oct. 29 the signal from the Hewlett-Packard gauge was lost and an attempt was made to pull the gauge out of the well. It is assumed that during cleanup there was enough variation in the tension on the Hewlett-Packard gauge line to cause the shear pin in the tubing locator to shear prematurely, allowing the gauge to travel up the hole and sever the single-conductor cable.

10.2 Recovery of Hewlett-Packard Gauge

Tools and line were reciprocated repeatedly before coming free. The tools were then pulled to 5,700 ft, where they lodged again. Tools were again reciprocated with as much as 2,500 lb line pull without success. Grease was injected below the rams without success. A super choke was then installed on the 7-inch casing annulus in preparation to kill the well. A pump truck was connected to the tubing and a 10-bbl spacer plug plus 95 bbl of 18.6-lb/gal mud was pumped into the tubing while an equal amount of fluid was bled simultaneously from the casing through the super choke. Tubing pressure was zero following this displacement.

The high-pressure lubricator was removed and a considerable amount of single-conductor cable was found balled up within it. A wireline clamp was installed above the wireline BOP's, the damaged wireline was removed, and

the lubricator was rethreaded. The single-conductor line was then spliced and the lubricator reinstalled. When the wireline was extracted from the tubing, the end of the line was found to be raveled and broken, and 4,400 feet of single-conductor cable were left in the hole along with the Hewlett-Packard gauge and miscellaneous weight bars.

The single-conductor wireline truck was then rigged down and a slick-line truck was rigged up along with lubricator, rope spear, and oil and Spang jars. The top of the wireline fish was tagged at 10,325 ft and pulled free with 1,200 lb pull over line weight. On pulling out of the hole, 50 feet of 3/16-inch wireline was recovered. The same tools were run in the hole and set down on the fish at 10,300 ft. It was pulled free with 350 lb over line weight and pulled up hole to 5,000 ft, where it was stopped to check for fish on line. A portion of the fishing tools were missing when tools cleared the BOP's. The fishing tools had parted between the oil jars. A 5/8-inch grapple with skirt was run in the hole to 950 ft (top of fish). The first trip was unsuccessful but the fishing tools were rerun in the hole to 950 ft, where they engaged the fish and pushed it down to 2,550 ft. Upon pulling out of the hole with the wire line, the lost tools and a 3-ft ball of the 3/16-inch wireline were recovered. A wireline spear was run in the hole to 10,300 ft, engaged the fish, and pulled out of hole with 700 lb drag, recovering approximately 1,500 ft of 3/16-inch wireline. The spear was rerun and engaged the fish at 11,600 ft. After pulling and jarring for 6 hours with 2,000 lb pull, the 3/16-inch wireline sheared. On pulling out of the hole approximately 5 feet of 3/16-inch wire line was recovered.

The wireline jars were replaced and the fish was engaged at 11,625 ft. When 2,000 lb of pull was applied, the top section of the mast truck gave way, falling and causing the Otis wireline to break and fall in the hole. There was no damage to the high-pressure lubricator. The damaged mast truck was removed and a replacement was moved in and rigged up.

Additional fishing tools were rigged up and run in the hole to 193 ft. The fish was engaged and pulled up the hole to 159 ft, at which point it could not be raised further. Because of mechanical problems and numerous wireline trips with loss of tools it was decided to kill the well to recover all of the fish inside the 3-1/2 inch tubing. The wireline truck was rigged down, a pump truck was brought in, and the well was killed by circulating 18.3-lb/gal mud. The pump truck and testing facilities were rigged down and a backpressure valve was set in the Canfield bushing. The well platform and the top section of the christmas tree were rigged down.

A workover rig had meanwhile been located and was moved in and rigged up. The existing tree was moved and BOP's, manifold, and accumulators were installed and tested. The tubing was pulled and the wireline tools recovered. The 3-1/2 inch tubing was rerun to 14,838 ft, pulled up to 14,223 ft, and hung off. The backpressure valve was installed and the BOP's nipped down. The lower section of the tree was installed and tested. The rig was rigged down, the upper section of tree installed and tested, and the tree platform and kill lines were installed.

A pump truck was moved in and connected to the 7-inch casing annulus, and 470 bbl of 10.0-lb/gal salt water were pumped into the casing, taking equal

returns through the adjustable choke of the tree. The shut-in tubing pressure at the completion of displacement was 6,180 psig and the 7-inch casing pressure was 6,200 psig. The well was then shut in and the pump truck was rigged down and moved out.

Testing facilities were moved in and rigged up. An adjustable choke was installed on the 7-inch casing annulus. All safety equipment was reinstalled and tested and a by-pass line for the water filters was fabricated.

10.3 First Flow Test

The Hewlett-Packard gauge with a thermometer was run to 14,722 ft to record bottomhole temperature. The device was retrieved, the thermometer removed, and the pressure gauge rerun and hung at 14,350 ft. The bottomhole temperature at 14,722 ft was found to be 266°F. The well was opened on a 1/4 inch choke and flowed to the pit to clean up at an estimated rate of 3,200 B/D. The production rate was increased to 8,563 B/D and the injection pressure at the disposal well increased to 218 psi. Because of this increased pressure on the disposal well, production was diverted to the pit and the production rate increased to 10,963 B/D and then closed in for bottomhole pressure buildup on Nov. 18.

While the bottomhole pressure buildup on the test well was being recorded, the disposal well was given a second acid treatment.

The signal from the Hewlett-Packard gauge was lost because of a short in the rope socket just above the gauge. This was repaired and the initial production test was started. While the flow rate was being increased, the wireline went slack because it had lodged in the lubricator. After it was worked free, a damaged section was found at a depth corresponding to the bottom of the flow tubes of the lubricator. After freeing the tools that became stuck across the master valves because of the wireline problem, the Hewlett-Packard gauge was pulled out of the hole.

10.4 Remedial Work on Disposal Well

During the initial flow test the injection pressure on the disposal well continued to increase. A wireline unit was used to run a blind box into the 5-1/2 inch tubing and the top of a sand fill was located at 2,452 ft. Since this was above the top perforations, a coiled tubing rig was moved in to clean out the sand fill. When the sand was removed from the tubing the injectivity pressure was found to be 120 psi at a rate of 11,520 B/D.

10.5 Second Flow Test

This flow test was started at 9 p.m. on November 28, 1979, using an 18/64-inch positive choke while the well flowed through the separator to the pit. Over a one-hour interval the adjustable choke was opened gradually to 22/64 inches; the separator pressure was stabilized at 500 psig; and the fluid was flowed to the disposal well. The choke settings remained fixed throughout the 10-day flow test and the well was shut in at 9 p.m. on

December 8, 1979. Figure 17 shows the water flow rate and the surface tubing pressure as functions of time.

The flow rates shown in Fig. 17 have been corrected for thermal expansion, i.e., they are volumetric flow rates at 60°F. Throughout the test the well experienced only a 5 percent decline in production rate even though the flowing tubing pressure dropped from a high of 5,205 psi to 3,221 psi.

10.6 Pressure Buildup

The Hewlett-Packard quartz crystal gauge was run to a depth of 14,722 ft less than two hours after the well was shut in. Bottomhole pressures were recorded for 106 hours, at which time the signal was lost. The gauge was retrieved, the rope socket was rewired, and the gauge was rerun to 14,722 ft. After 49 hours of operation, the signal was again lost. An attempt was made to retrieve the gauge, but when it reached 475 ft the wireline stuck. It was later established that sticking occurred in the flow tubes of the lubricator. The gauge was left hanging at this depth and the casing and tubing pressures were recorded at the surface by deadweight tester. The shut-in period was terminated at 8 a.m. on December 28, 1979.

10.6.1 Calculation of Fluid Density.

Because of previous failure to receive signals from the Hewlett-Packard gauge at the surface, bottomhole pressures were not recorded during the drawdown period. During the last 12 days of the buildup, the pressure gauge failed and bottomhole data were not recorded. It was necessary, therefore, to correct the measured surface casing and tubing pressures to bottomhole conditions by accounting for the changes in fluid density as a function of the mean fluid temperature.

It was assumed that the brine density could be approximated by the relationship

$$\bar{\rho} = \rho_i e^{-\alpha(T - T_i)},$$

where ρ = fluid density at temperature T_0 ,
 T_i = reference temperature,
 T = mean temperature of fluid column,
and α = a constant.

Using bottomhole and surface temperature data the values of ρ_i and α were determined for the casing annulus fluid, with the results shown in Appendix A. Attempts to compute bottomhole pressures using surface flowing tubing pressures and calculated frictional losses and head proved fruitless because of the temperature dependence of the water density and viscosity.

At the end of the test period at 9 p.m. on December 28, the shut-in tubing pressure was 5,544 psi and the shut-in casing pressure was 6,021 psi.

Upon completion of the pressure buildup test, the wireline BOP's were closed and the lubricator was removed from the wellhead. It was found that scale deposited on the wireline had caused it to become wedged in the flow tubes. After removing the scale buildup from the wireline, the lubricator

Fig. 17.-- Water production rate and flowing tubing pressure versus time, Beulah Simon NO. 2.

was installed, the BOP's opened, and the gauges pulled out of the hole at 8 a.m. on Dec. 29.

10.7 Bottomhole Sampling

At 7:45 a.m. on Dec. 30 the well was opened and flowed to the pit for an hour before running a 2-inch OD bottomhole sampler in the hole. Upon reaching total depth it was found that the sampler had fired prematurely; hence the recovered sample was obtained from an unknown depth.

A second run of the sampler was attempted on Dec. 31, but the wireline stuck in the flow tubes of the lubricator when 1,800 ft of line was in the hole. Rather than risk any additional expenditure, the sampler was pulled without taking a fluid sample. The wireline operator, thinking that the sampler had cleared the master valves, closed the top master valve and cut the wireline; hence the sampler was lost in the hole. The well was then shut in to await the arrival of a workover rig to start abandonment operations.

11.0 TEST ANALYSIS

The test of the Beulah Simon No. 2 well comprised a 10-day flow followed by a 20-day buildup. Drawdown and buildup data were analyzed independently to estimate flow capacity and the distance to and configuration of any linear barriers. At least one barrier was clearly identified by the test data. The analytical model used to define the reservoir geometry indicated that the test well is located between two parallel faults.

11.1 Analysis of Drawdown

The flow rate history during the 10-day flow period is depicted in Fig. 17. The average flow rate was 11,000 B/D, and the total change in flow rate during the test period was only 5 percent. This small variation does not warrant the use of the superposition principle and a constant-rate solution is adequate.

Bottomhole pressures were not recorded during the drawdown period, and therefore only surface tubing and casing pressures were available for analysis. Hence bottomhole flowing pressures were estimated from the surface casing pressures, using a technique described below (Sec. 11.1.3).

11.1.1 Flowing Tubing Pressures

Attempts to compute bottomhole pressures using surface flowing tubing pressures and calculated frictional losses and fluid head proved fruitless because of the temperature dependence of the water density and viscosity.

11.1.2 Casing Pressures

Casing pressures recorded at the surface are also affected by temperature changes. These pressures were analyzed with full awareness that variations in fluid density, caused by temperature changes and by the displacement of scale inhibitor by fresh water, resulted in changes in fluid head throughout the test.

Figure 18 shows a plot of casing pressures during production versus the logarithm of time.

From the slope of the first straight-line portion the computed flow capacity is 1,914 md-ft. The distance to the first linear barrier is estimated at 470 ft. It should be noted that aquifer properties computed using casing pressures without correcting for thermal effects are subject to error. As the weight of the fluid column decreases, the slope of the casing pressure line becomes too small, leading to an overestimate of the formation flow capacity. The error in the overestimate is a complex function of the flow rate, the overall heat transfer coefficient, the formation temperature, and the depth.

11.1.3 Bottomhole Pressures (Estimated)

Flowing bottomhole pressures were estimated using surface casing pressures and flowing temperature measurements. The fluid density was assumed to vary exponentially with the average temperature of the fluid column. Density changes, mostly occurring early in the drawdown, accounted for 30

Fig. 18.-- Casing pressure versus time (drawdown).

percent of the total drawdown. Figure 19 is a semi-log plot of estimated bottomhole pressures against time. Flow capacity and distance to the nearest linear barrier computed from this plot are 2,590 md-ft and 476 ft, respectively.

11.2 Buildup Analysis

Following the 10-day drawdown, the well was shut in for 20 days to monitor a buildup. Since the well had not reached a pseudo steady state pressure distribution by the end of the flow period, the Horner method was used for the analysis of the buildup pressures. This is the preferred method provided pseudo-steady state does not exist before the time the well is shut in. Since the rate did not vary significantly before buildup testing, variable flow-rate analyses were not attempted.

11.2.1 Bottomhole Pressures

A Hewlett-Packard gauge was lowered into the well to record bottomhole pressures. When the well was shut in, about 3 hours were required for the gauge to reach bottom and allow the temperature of the quartz crystals to stabilize before the first accurate pressure could be recorded. After 180 hours the signal was lost and no further pressures could be recorded. Pressures beyond 180 hours were extrapolated using surface pressures along with Figs. 20 and 21. Figure 20 is a plot of ΔP (bottomhole pressure - casing pressure - 15) versus shut-in time, and Fig. 21 is a similar plot for tubing pressures. These plots establish a trend of the difference between surface and bottomhole pressures. The extrapolated bottomhole pressures were obtained by adding surface pressures to the difference of pressures from the graph for a given shut-in time.

Figure 22 is a Horner plot for the entire buildup. Although the extrapolated pressures may not be entirely accurate, fortunately all these pressures fall on the second straight line and do not affect the computation of flow capacity. The second straight line extrapolates to a pressure (p^*) of 12,920 psia. An error in the extrapolated pressure has negligible effect on the time at which the two lines intersect; therefore the distance to the linear barrier calculated using the Davis and Hawkins method¹⁵ and the Horner method¹⁴, both of which use the time of intersection of two lines, will be reasonably accurate. The method of images, on the other hand, calculates the distance to the linear barrier using the deviation of pressure buildup curve from the first straight line, and will not be affected by the use of extrapolated pressures.

The flow capacity was calculated to be 2,297 md-ft, and the average distance to the nearest linear barrier calculated by three different methods is 642 ft.

11.2.2 Tubing Pressures

Tubing pressures at the surface during the buildup were also analyzed, even though it was known that thermal effects cause changes in the density of

Fig. 19.-- Bottomhole pressure (calculated from casing pressure) versus time (drawdown).

Fig. 20.-- Pressure correction (casing) versus time (buildup).

Fig. 21.-- Pressure correction (tubing) versus time (buildup).

Fig. 22.-- Pressure buildup plot (bottomhole pressure).

the fluid column and hence affect the surface pressures.

Figure 23 is a Horner plot using the tubing pressures recorded during buildup. The flow capacity computed from this plot was 3,446 md-ft and the average distance to the nearest linear barrier was 759 ft.

11.2.3 Casing Pressures

Casing pressures during buildup are affected by temperature differences much like tubing pressures. The flow capacity and the average distance to the nearest fault, computed using surface-measured casing pressures, were 3,156 md-ft and 771 ft, respectively (Fig. 24).

11.3 Analytical Model

Two interpretations of the data are possible. The first interpretation, using a technique developed by Prasad¹⁶, assumes that the well lies within a wedge formed by the intersection of two faults at an angle of approximately 120°. The second interpretation, from a technique presented by Tiab and Kumar¹⁷, assumes that the well is situated between two parallel faults.

An analytical model was used to compute pressures in a well completed in a wedge-shaped reservoir (two intersecting faults) and in a well in a parallel-fault system. Using a minimum standard deviation criterion to measure the uniqueness of fit, the best fit occurred with parallel faults at 556 and 794 ft from the well (Fig. 25).

The permeability was computed to be 11.6 md. A computer printout of the results from the analytical model is presented in Appendix B. Table 3 is a summary of the results of analyses of the data from the drawdown and buildup tests and the analytical model.

11.4 Chemical Analysis of Water

Table 4 summarizes the chemical analyses of the water reported by Southern Petroleum Laboratories and the Institute of Gas Technology. The analyses by Southern Petroleum Laboratories represent the average concentrations from 10 daily samples taken from the data header upstream of the separator. A complete chemical analysis was made on site immediately after taking each sample. The analyses by IGT represent average concentrations from six samples, three of which were taken from various points in the surface installation during the last two days of the flow test, one was taken with the bottomhole sampler, and the other two were taken at the surface as the well was being flowed before the bottomhole sampler was run.

The discrepancy between the total dissolved solids determined by the two laboratories can be attributed to differences in sample handling. Southern Petroleum Laboratories conducted their analyses on site in a fully equipped mobile laboratory. As soon as a sample was taken it was filtered at essentially the flowing temperature, the filtrate was evaporated, and the residue was weighed. IGT, on the other hand, sent samples to Chicago, where they were analyzed after they had cooled.

Fig. 23.-- Pressure buildup plot (tubing pressure).

Fig. 24.-- Pressure buildup plot (casing pressure).

Fig. 25.-- Standard deviation of measured and computed pressures for analytical model.

TABLE 3
SUMMARY OF TEST ANALYSIS

	DRAWDOWN		BUILDUP			
	Casing Pressure (Surface)	BHP Estimated Using Casing Pressure	Casing Pressure (Surface)	Tubing Pressure (Surface)	Bottomhole Pressure	Analytical Model
Slope of first straight line (M_1), psi/cycle	356	290	238	218	327	330
Slope of second straight line (M_2), psi/cycle	765	830	802	880	930	not defined
Flow capacity (kh), md-ft	1914	2590	3156	3446	2296	2160
Permeability (k), md	10.29	13.92	16.97	18.53	12.35	11.62
Slope ratio, M_1/M_2	2.15	2.86	3.37	4.04	2.84	--
Elapsed time at the intersection of the two lines (T_x or ΔT_x), hours	66	50	92	104	104	--
Distance to first linear barrier (L_1), ft	470	476	913* 669 [†] 730 [§]	891* 735 [†] 650 [§]	727* 600 [†] 598 [§]	556
Distance to second linear barrier (L_2), ft	--	--	--	--	--	731

Data for analysis: $h = 186$ ft
 $\phi = 0.19$
 $\mu = 0.4$ cp
 $c = 6 \times 10^{-6}$

*Standing equation
[†]Horner method
[§]Image method

TABLE 4
CHEMICAL ANALYSIS OF PRODUCED WATER
BEULAH SIMON NO. 2

<u>Constituent</u>	<u>Southern Petroleum Labs</u> (10 Samples)		<u>National Gas Institute</u> (6 Samples)	
	<u>Milligrams Per Liter</u>	<u>Standard Deviation</u>	<u>Milligrams Per Liter</u>	<u>Standard Deviation</u>
Total Dissolved Solids	103,925	8016	91,533	1524
Total Solids	104,947	7815	102,250	25,924
Calcium (CaCO ₃)	7,869	548	6,955	736
Magnesium (MgCO ₃)	910	39	887	18
Bicarbonate (HCO ₃)	606	93	868	118
Carbonate	1	0	0	--
Chloride (Cl)	50,300	909	54,050	1372
Total Iron (Fe)	33	9.4	N.D.	--
Dissolved Silicate (SiO ₂)	92	9.5	69	35.6
Copper (Cu)	0.152	0.019	N.D.	--
Zinc (Zn)	0.136	0.163	N.D.	--
Boron (B)	89.6	2.757	67.8	9.4
Arsenic (As)	0.002	0.000	< 0.01	--
Chromium (Cr)	0.086	0.014	N.D.	--
Mercury (Hg)	0.005	0.000	N.D.	--
Lead (Pb)	7.73	10.646	N.D.	--
Cadmium (Cd)	0.269	0.077	N.D.	--
Sodium (Na)	32,190	1521	28,150	2620
Potassium (K)	454	68	470	15
Ammonia (NH ₃)	29.8	2.94	N.D.	--
Barium (Ba)	30.4	1.96	N.D.	--
Sulfate (SO ₄)	444	15	381	64
Density (gm/ml)	1.066	0.0023	--	--
pH	6.61	0.088	7.03	0.46
SUS Viscosity	28.55	0.314	--	--

Table 4 shows a consistent total solids concentration; hence the difference in the total dissolved solids can be attributed to the higher concentration of suspended solids in the cooler samples.

During the wireline operations, the operators noticed a marked reduction on the surface weight indicator when the tool approached the perforated interval. Conversely, a drag resistance was evident each time the tools were pulled through this interval. While the well was flowing before the bottomhole sampler was run, a surface sample representative of the fluid adjacent to the perforations was taken. A chemical analysis was performed on this sample in Houston after the sample had cooled (Table 5). Comparing the analysis of this sample with those from the flowing test shows several significant differences. Although the dissolved solids are less, the total suspended solids are much higher. Similarly the total iron content and the dissolved silicate concentration are higher. No explanation for these differences is offered at this time, since this phenomenon has not been encountered before.

The sludge removed from this sample was analyzed, with the results shown in Table 6.

11.5 Chemical Analysis of Gas

Table 7 is a comparison of the gas analyses performed on site by Southern Petroleum Laboratories and in Chicago by the Institute of Gas Technology. Except for some minor differences in the mol percentages of methane and carbon dioxide, the agreement is good.

Southern Petroleum Laboratories took a water sample from the separator on November 30, 1979, at a pressure of 500 psig and a temperature of 230°F (110°C). This water sample was then flashed to 15.025 psia and the evolved gas was analyzed. Table 8 is a summary of this analysis, which shows that the mole percentage of carbon dioxide in the gas stream is higher at lower separation pressures. If multistage separation is planned for production from these aquifers, the lower Btu content of the gas leaving the second stage separator must be anticipated.

11.6 Analysis of Scale and Scale Coupons

Scale coupons were installed in the data header and at the disposal well to measure the effectiveness of the scale inhibitor. Table 9 lists the weight change experienced by each coupon. Only one coupon was placed at the disposal well and it indicates a weight loss of 0.9 percent during the 10-day test. The last coupon in the data header lost almost as much weight in three days as the one at the disposal well lost during the entire test.

The first two coupons in the data header were not weighed when they were pulled but were given to Champion Chemicals to analyze the small amount of scale which had accumulated on them. Table 10 shows the composition of the solid scale from these two coupons. In both coupons there is a relatively

TABLE 5
 FLOWING SAMPLE FROM BOTTOM HOLE AT END OF TEST
BEULAH SIMON NO. 2 TEST WELL

<u>Constituent</u>	<u>ppm</u>	<u>Constituent</u>	<u>ppm</u>
Total dissolved solids	94,900	Sodium	38,000
Total suspended solids	40,600	Potassium	7.5
Calcium	3,610	Copper	3.27
Magnesium	24	Zinc	23.2
Carbonate	< 1	Boron	26
Bicarbonate	3,480	Arsenic	< 0.02
Chloride	68,000	Chromium	0.1
Iron	4,190	Mercury	< 0.005
Sulfate	497	Lead	0.95
Dissolved silicate	2,200	Cadmium	0.30
Density		1.060	
Conductivity		14.29	
pH		6.65	

TABLE 6

SAMPLE WITH SLUDGE (OIL PHASE)Beulah Simon No. 2 Test Well

<u>CONSTITUENT</u>	<u>WEIGHT %</u>
Hydrocarbon	53.35
Barium	18.19
Chromium	0.0009
Magnesium	0.4665
Lead	0.0047
Silica	0.3732
Iron	0.933
Manganese	0.0467
Aluminum	0.4665
Calcium	2.799
Copper	0.0093
Sodium	2.333
Zinc	0.933
Titanium	0.0019
Strontium	0.2799

TABLE 7

CHEMICAL ANALYSIS OF GAS (MOLE PERCENT)

	SPL (10 Samples)		IGT (6 Samples)	
	<u>AVE.</u>	<u>STD. DEV.</u>	<u>AVE.</u>	<u>STD. DEV.</u>
Nitrogen (N_2)	0.271	0.015	0.066	0.038
Carbon Dioxide (CO_2)	7.726	0.745	5.062	0.141
Methane (CH_4)	88.868	0.682	91.079	0.107
Ethane (C_2H_6)	2.202	0.052	2.291	0.037
Propane (C_3H_8)	0.601	0.006	0.722	0.025
ISO Butane ($i-C_4H_{10}$)	0.178	0.004	0.162	0.012
Normal Butane ($n-C_4H_{10}$)	0.070	0	0.091	0.011
Others (Hydrogen, C_5+ , Benzene, Toluene)	0.084	.008	0.527	0.054

BTU Content (Calculated)

Wet 970

Dry 987

TABLE 8
COMPOSITION OF VAPOR FLASHED FROM SEPARATOR LIQUID
BEULAH SIMON NO. 2 TEST WELL

<u>Constituent</u>	<u>Mol Percent</u>
Nitrogen	0.35
Carbon dioxide	18.42
Methane	79.17
Ethane	1.55
Propane	0.34
Isobutane	0.09
n-Butane	0.05
Isopentane	0.02
n-Pentane	<u>0.01</u>
	100.00

Specific gravity at 60°F (air = 1) 0.7481

Calculated Btu/cu ft at 15.025 psia and 60°F:

Dry basis 862

Wet basis 847

TABLE 9
ANALYSIS OF SCALE COUPONS

DATA HEADER

<u>Weight In</u>	<u>Date In</u>	<u>Weight Out</u>	<u>Date Out</u>
8.8682	11/28	*	11/29
9.5000	11/29	*	12/3
8.9147	12/3	8.9147	12/5
8.8249	12/5	8.7543	12/8

DISPOSAL WELL

8.8512	11/28	8.7740	12/8
--------	-------	--------	------

*Coupons given to Champion Chemical for scale analysis.

TABLE 10
SCALE ANALYSIS
(Weight Percent)

Hydrocarbons	7.2	22.1
Carbonate	17.8	23.3
Iron compounds	64.5	38.0
Acid-insoluble	<u>10.5</u>	<u>16.6</u>
	100.0	100.0

high percentage of iron compound in the scale, which suggests that corrosion may be occurring in the tubing and surface facilities. Since the scale inhibitor is a chelating agent, it is possible that it is responsible for the corrosion.

Each day that the well was flowing, a fluid sample was analyzed by Champion Chemical to measure the concentration of scale inhibitor in the flowing well stream. Table 11 shows the inhibitor concentrations from these tests. Although the original plan required an inhibitor concentration of not less than 50 ppm, this condition was only satisfied in one day's sample. Even so, scale buildup in the wellbore and surface installation was never observed.

11.7 PVT Analysis of the Recombined Sample

At the beginning, middle, and end of the flow period, separator gas and liquid samples were taken for recombination studies. The first sample was destroyed during recombination when the windowed cell ruptured. Each of the remaining two samples was recombined in a windowed cell, using the gas-to-water ratio measured at the separator at the time of sampling. The temperature was increased to 266°F (130°C) and the pressure was gradually increased until the last bubble was seen to dissolve. This occurred at 12,500 psia for the sample taken on November 30, and at 12,650 psia for the sample taken on December 8. Because the bubble-point pressure of each mixture is close to the initial reservoir pressure (13,015 psia), it is reasonable to conclude that the water is saturated with gas at reservoir conditions.

The pressure-volume relationships measured in tests were:

1. Formation volume factor
2. Gas Solubility
3. Relative volume
4. Liquid density.

These are plotted in Figs. 26 and 27 as a function of pressure at the aquifer temperature. Data for the two samples show very good agreement except for the formation volume factor. Since the formation volume factor depends upon the liquid volume at standard conditions, it is possible that a small error in measurement of this quantity was magnified in the liquid volumes at higher pressure.

TABLE 11

INHIBITOR CONCENTRATION AT DATA HEADER

<u>Date</u>	<u>Time</u>	<u>Concentration T-96, ppm</u>
11/29/79	8 a.m.	32
11/29/79	3 p.m.	43
11/30/79	6 p.m.	51
12/ 1/79	7:30 a.m.	8
12/ 1/79	4 p.m.	Broken in shipment
12/ 2/79	8:30 a.m.	8
12/ 2/79	4 p.m.	37
12/ 3/79	9 a.m.	26
12/ 3/79	4 p.m.	24
12/ 4/79	10:30 a.m.	7
12/ 4/79	3 p.m.	29
12/ 5/79	4 p.m.	26
12/ 6/79	9 a.m.	15

Figure 26. - Relative volume and density versus pressure.
(BHT = 266°)

Figure 27. - Gas solubility and formation volume factor versus Pressure.
(BHT = 266°)

12.0 ABANDONMENT PROCEDURE

Under the terms of the agreements with Southport Exploration et al. and the surface and mineral owners, Gruy was obliged to restore the land to its original condition. Since the well site is located within a rice field, it was necessary to remove all drilling mud and cuttings and regrade the site for rice cultivation. The landowners proved to be most difficult to satisfy in this regard.

12.1 Killing the Well

A workover unit was moved in on January 3, 1980. The well was killed by filling the $7 \times 3\text{-}1/2$ inch annulus and the 3-1/2-inch tubing with 18-lb/gal mud. The wellhead was removed, tubing was lowered to 14,767 ft, and a cement plug was placed from this depth to 14,581 ft, following which all of the 3-1/2-inch tubing was recovered.

The 7-inch casing was cut at 11,462 ft and also 3 ft below the Braden head. Casing jacks exerting an initial pull of 346,500 lb were used to recover the 7-inch casing down to the initial cut. The 3-1/2 inch tubing was rerun to 11,517 ft and a 50-sack cement plug was displaced through the tubing. It was necessary to repeat this operation because the mud column was unbalanced and the location of the cement could not be verified.

A second plug of 100 sacks was placed from 11,517 to 11,142 ft to cover the top of the 7-inch casing remaining in the well. The 17-lb/gal mud was displaced with 10.8-lb/gal mud and returned for credit.

Several unsuccessful attempts were made to recover a portion of the 9-5/8 inch casing within the 13-3/8 inch surface string. Cuts were made at 3,525, 2,541, and 1,493 ft, but a pull of 400,000 lb with the casing jacks did nothing more than stretch the casing a few inches. It was then concluded, and later confirmed by word of mouth, that the annulus between the 13-3/8 and the 9-5/8 inch casing had been cemented from the surface during original cementing operations. This had not been entered on the previous operator's drilling report.

Finally a dynamite charge was used to rupture the 9-5/8 inch casing below the bottom of the 13-3/8 inch casing, for the purpose of disposing of all waste mud, well cuttings, and rain water from the reserve pits. Several days were spent in churning this material into a suspension and pumping it into the well. This method of disposing of waste mud and cuttings was considerably cheaper than hauling the material to an approved disposal site, and was the method recommended by the Louisiana Department of Conservation.

Two cement plugs were placed in the 9-5/8 inch casing. The bottom plug, consisting of 100 sacks Class H cement was placed with its top at 3,400 ft; the second plug of 50 sacks of Class H cement was spotted with its top at the cutoff point of the 20-inch, 5 ft below ground level. The condition of the test well after abandonment is shown in Fig. 28.

Fig. 28.-- Abandonment condition, Beulah Simon No. 2.

To abandon the disposal well, 50 sacks of Class H cement were mixed and pumped into the 5-1/2 inch casing, followed by 40 barrels of 10.2-lb/gal drilling fluid, followed by 25 sacks of Class H cement. This allowed for the lower cement plug top to be at 2,324 ft and the top plug at the surface. After allowing time for the cement to set, the 9-5/8 inch and the 5-1/2 inch casing were cut 4 ft below ground level. A 1/2-inch steel plate was welded to the 9-5/8 inch casing and the cellar was filled. The status of the well after plugging and abandonment is shown in Fig. 29.

The fresh-water well used during drilling and testing was pulled and plugged by the contractor who drilled it for the initial drilling operation.

12.2 Site Restoration

All the board road and the turnaround lumber was removed from the location, the site was completely leveled, and all trash was removed. Restoration work was hampered by heavy rain. The landowners and the tenant farmer found the restoration to be satisfactory as of March 18, 1980, and a settlement for the extension of the lease has been paid.

Figure 30 is a bar graph showing the time required for the major phases of this operation.

Fig. 29.-- Beulah Simon No. 1 saltwater injection well, status after plugging and abandonment.

Fig. 30.-- Time summary: completion, testing, and abandonment, for Beulah Simon No. 2.

13.0 CONCLUSIONS

The following conclusions are based upon the results of the geopressured-geothermal test on the Beulah Simon No. 2.

1. The desired rate of production, averaging 11,000 barrels per day, equivalent to the capacity of the surface equipment, was maintained throughout the scheduled 10-day flow test.
2. The produced brine is saturated with natural gas (hydrocarbons and carbon dioxide) at reservoir conditions, containing 24 standard cubic feet of gas per stock tank barrel of water.
3. At 14,722 ft, corresponding to the midpoint of the perforations, the bottomhole temperature was 266°F (130°C); the static aquifer pressure was 13,015 psia.
4. The on-site analysis showed the produced brine to contain an average of 103,900 ppm of total dissolved solids. This compares favorably with 99,000 ppm equivalent NaCl concentration calculated from electric logs.
5. The calculated average porosity in the test interval is 18.7 percent. This determination was made from an analysis of the sonic log of the test well, augmented by a formation density log from an adjacent well.
6. The effective permeability of the aquifer in the area influenced by the test is calculated from pressure transient data to be 11.6 md.
7. The most credible interpretation of the pressure transient data indicates that the Beulah Simon No. 2 well penetrates the Camerina A sand between two parallel faults which are 556 ft and 731 ft from the well. This geometry is substantiated by subsurface geology and seismic interpretation.
8. During the 10-day flow period the full well stream was injected into the disposal well at temperatures up to 259°F (126°C). There was no indication of injectivity reduction caused by the contact of this hot water with the clay minerals within the sand body. This indicates that a cooling system probably will not be required in similar tests.
9. The downhole injection of scale inhibitor prevented scale deposition in the tubing, wellhead, and surface facilities, which was experienced on the first geopressured-geothermal well test in the program (Fairfax Foster Sutter No. 2).
10. The Hewlett-Packard quartz crystal pressure gauge performed satisfactorily at reservoir conditions. The surface signal from the HP gauge was lost on several occasions by the failure of the O-rings in the single-conductor cable rope socket, thus causing a short. Several types of O-ring seals were tried, but none was capable of withstanding

the bottomhole conditions for more than a few days.

11. The diameter of the cable increased under operating conditions to the extent that it could not be retrieved through the flow tubes. Laboratory analyses showed that the cable had been impregnated with a hydrocarbon material which caused the line to expand. It is presumed that the grease used to seal the flow tubes of the wireline lubricator decomposed at bottomhole conditions. A different type of high-temperature lubricant should be sought for future tests.
12. For safety purposes a minimum of two wireline blowout preventers should be installed between the lubricator and the swab valves. These should be closed when the wireline is static in the hole to prevent line movement directly below the flow tubes.
13. For high rates of production, provisions must be made to protect the pressure gauge and wireline from movement. Gruy Federal has designed a system which employs two parallel tubing strings, each seated in a separate polished bore receptacle, for separation while maintaining communication. Flow will be maintained through the larger (e.g., 5-inch) tubing string. The smaller string (e.g. 2-3/8 inches) will permit continuous recording of flowing or static bottomhole pressure in a medium of inhibited water which is continuously injected by means of a surface pump. Thus the Hewlett-Packard gauge will be shielded from vibrations, flow thrust, and formation water, while at the same time the entire system is inhibited against scale and corrosion. This system is adaptable to high-volume geopressured-geothermal test wells. Equipment for such a system is not immediately available; however, the design and fabrication are feasible.
14. The flowing time was too short to determine the volume of water contained in the aquifer.
15. Conventional two-phase horizontal separators, properly modified for flow rates and temperature, satisfactorily handle the effluent.
16. The data collection program established prior to the test was successful in collecting and integrating the data required to evaluate this test.
17. No sand production was detected after the initial cleanup period.

14.0 REFERENCES

1. National Energy Plan II, Second National Energy Plan (1979), p. I-16.
2. Ibid., p. VI-16.
3. Ibid., p. VI-18.
4. Wallace, R. H., Jr., Kraemer, T. F., Taylor, R. E., and Wesselman, J. B.: U.S. Geological Survey Circular 790 (1978), p. 144.
5. Papadapulos, S. S., Wallace, R. H., Jr., Wesselman, J. B., and Taylor, R. E.: "1975 Assessment of Onshore Geopressed-Geothermal Resources in the Northern Gulf of Mexico," Assessment of Geothermal Resources of the United States, 1975, U.S. Geological Survey Circular 726, D. E. White and D. L. Williams, ed., pp. 125-146.
6. Stearns, R. T., "Request for Proposals (RFP) EY-77-R-08-0008 to Investigate and Evaluate Geothermal-Geopressed Wells," U.S. Energy Research and Development Administration, April 1977.
7. Gruy Federal, Inc.: "Detailed Completion Prognosis for Geopressed-Geothermal Well-of-Opportunity Prospect No. 6, Beulah Simon No. 2 Well," July 31, 1979.
8. Dobie, C. Walter, ed., Typical Oil and Gas Fields of Southwestern Louisiana, vol. II, published by the Lafayette (La.) Geological Society, 1970.
9. Sheller, James W., ed.: Typical Oil and Gas Fields of Southern Louisiana, vol. I, published by the Lafayette, (La.) Geological Society, 1964.
10. Landes, Kenneth: Petroleum Geology of the United States; Wiley Interscience Press, 1970.
11. Gulf Coast Paleo Stratigraphy; compiled by the Houston Chapter of the American Association of Petroleum Geologists.
12. Dresser Atlas Log Interpretation Charts, 1979 edition.
13. Winsauer, W. O., Sherin, H. M., Jr., Masson, P. H., and Williams, M.: "Resistivity of Brine Saturated Sands in Relation to Pore Geometry," Bull., AAPG, 36 (1952), no. 2.
14. Horner, D. R.: "Pressure Buildup in Wells," Proc., Third World Petroleum Congress, sec. III (1951).
15. Davis, E. Grady, Jr., and Hawkins, M. F., Jr.: "Linear Fluid-Barrier Detection by Well Pressure Measurements," J. Pet. Tech., October 1963.
16. Prasad, R. K.: "Pressure Transient Analysis in the Presence of Two Intersecting Boundaries," J. Pet. Tech., January 1975, pp. 89-96.
17. Tiab, D., and Kumar, A.: "Detection and Location of Two Parallel Sealing Faults Around a Well," paper SPE 6056 presented at the SPE-AIME 51st Annual Fall Technical Conference and Exhibition, New Orleans, October 1976.

APPENDIX A

Flowing bottomhole pressures were estimated using surface casing pressures and flowing temperature measurements. An exponential temperature function (Eq. 1) was assumed appropriate to determine the average water density given the average column temperature. (This solution was assumed valid for $107 \leq T \leq 256^\circ\text{F}.$)

$$\bar{\rho} = \rho_i e^{-\alpha\theta} \quad (1)$$

where $\bar{\rho}$ = Average column density (lb/ft³)

ρ_i = Initial column density (lb/ft³)

α = Exponential constant ($^\circ\text{F}^{-1}$)

θ = Excess average temperature ($T - T_i$)

T_i = basis average temperature ($^\circ\text{F}$)

The following sets of well data were used to determine ρ_i and α . The bottomhole temperature was assumed constant (270°F).

Early Drawdown

BHP = 13015 psia (@ 14772 ft)

Casing = 5669 psia

Head = 7346 psia

ρ_i = 71.85 lb/ft³

T_i = $(107 + 270)/2 = 188.5^\circ\text{F}$

θ_i = 0°

Early Shut-in

BHP = 12017 psia (@ 14772 ft)

Casing = 4976 psia

Head = 7041 psi

ρ_i = 68.87 lb/ft³

T_f = $(256 + 270)/2 = 263.0^\circ\text{F}$

θ_i = 74.5°

Therefore,

$$\alpha = 5.6859 \times 10^{-4} / ^\circ\text{F}$$

and

$$\rho = 71.85 \exp(5.6859 \times 10^{-4} \theta)$$

The bottomhole pressure can be estimated using Eq. 2.

$$\text{BHP (psia)} = \text{CASING (psig)} + \text{HEAD} + 15. \quad (2)$$

$$\text{where HEAD} = 7345.7 \exp((-2.843 \times 10^{-4}) [T_s - 107])$$

T_s = Surface flowing temperature ($^\circ\text{F}$)