DOE/ET/27081—1 VOL. I

UC-66

GEOPRESSURED - GEOTHERMAL PROGRAM

FINAL REPORT
P.R. GIROUARD WELL NO. 1
LAFAYETTE PARISH, LOUISIANA

VOLUME I
COMPLETION AND TESTING

TESTING GEOPRESSURED GEOTHERMAL RESERVOIRS IN EXISTING WELLS

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PREPARED FOR
U.S. DEPARTMENT OF ENERGY
NEVADA OPERATIONS OFFICE
UNDER CONTRACT NO. DE-AC08-80ET27081

MASTER

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JANUARY 1981

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1.0 EXECUTIVE SUMMARY

The P. R. Girouard No. 1 Well, located approximately 10 miles southeast of Lafayette, Louisiana, was the fourth successful test of a geopressured-geothermal aquifer under the Wells of Opportunity program. Eaton Operating Company, Inc. assumed control of the site on May 6, 1980, when the operator, Wainoco Oil and Gas Company, abandoned the well as a dry hole at a total depth of 15,700 feet.

The well was tested through 3-1/2 inch tubing set on a packer at 14,570 feet without major problems. The geological section tested was the Oligocene Marginulina Texana No. 1 sand of upper Frio age. The interval tested was from 14,744 to 14,819 feet. Produced water was piped down a disposal well perforated from 2,870 to 3,000 feet in a Miocene saltwater sand.

Four flow tests were conducted for sustained production rates of approximately 4,000 BWPD to approximately 15,000 BWPD. The highest achieved, during a fifth short test, was 18,460 BWPD. The test equipment was capable of handling higher rates.

The gas-to-water ratio was relatively uniform at approximately 40 SCF/bbl. Some 1 to 5 SCF of the 40 SCF/bbl were retained in the brine, depending on separator pressure; as separator pressure increased and residence time decreased more gas was retained in the disposal water. Laboratory recombination studies determined a saturation value of about 44.5 SCF/bbl, indicating that this reservoir brine was possibly undersaturated. The heating value of the gas is 970 BTU/SCF.

The initial reservoir drawdown test of one day duration resulted in sufficient transient pressure flow information to develop the needed reservoir data. The information obtained was supplemented and confirmed by a subsequent buildup test and a second drawdown test. These tests depicted a very restricted permeability closure around the well bore, which limited the drainage of the well. The productive sand interval pinched out very rapidly around the well. The reservoir drawdown configuration was very similar to one depicting a completion in the end of an elongated lenticular sand.

The reservoir tests show that is is doubtful that this well would sustain production rates over 10,000 BWPD for any lengthy period from the sand zone in which it was completed. This limited flow capacity is due to the well's poor location in the reservoir and is not a result of any production deficiencies of the Marginulina Texana sand.

The surface test equipment was not treated with chemical to restrict carbonate scaling, because scaling was relatively light (0.03 grams per square

inch per 1000 barrels of water) and was not visually observed until the end of the testing. Treatment would be required, however, if long-term production was desired.

Sand production was minimal. Actual measurements indicated production of a very fine formation sand ranging from 0.5 to 1.7 pounds per 1,000 barrels of water. Sand production appeared to be related to high flow rates which resulted in a local drawdown around the well bore.

A one-page summary of test data follows on page 3.

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
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Houston, Texas 77027
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SUMMARY OF TEST RESULTS

P. R. GIROUARD WELL NO. 1
CADE FIELD
LAFAYETTE PARISH, LOUISIANA

Total Depth of Well	15,700 Feet
Formation	Oligocene Marginulina Texana No. 1
Gross Perforations	14,744 - 14,819 Feet (8 HPF)
Original Reservoir Pressure	13,203 Psia
Original Reservoir Temperature	274°F
Original Shut-In Surface Pressure	6,695 Psia
Average Porosity	26% (Sonic Travel Time Log)

FLOW TESTS: (From 7-22-80 to 8-7-80)

Test No. 1	1.01 Day Reservoir Drawdown Test (Produced 4,117 Barrels of Water)
	2.18 Day Continuous Reservoir Build Up Test (BHP After 6.1 Days was 13,173 psia)
Test No. 2	1.36 Day Reservoir Drawdown Test (Produced 10,604 Barrels of Water)
Test No. 3	1.19 Day Flow Test (Produced 13,727 Barrels of Water)
Test No. 4	1.38 Day Flow Test (Produced 9,664 Barrels of Water)
Test No. 5	0.18 Day Flow Test For Sand Production (Produced 2,193 Barrels of Water)
Produced Dry Gas to Saltwater Ratio	40 SCF/BBL
Total Water Produced	41,930 Barrels

ANALYSIS OF WATER:

Total Dissolved Solids	23,500 ppm
Chlorides	13,300 ppm
Density	1.017 g/cm^3 at 24.0°C

ANALYSIS OF GAS:

Methane	91.3 Mole Percent
Carbon Dioxide	6.0 Mole Percent
Heavier Hydrocarbons	2.5 Mole Percent
Other	0.2 Mole Percent
Heating Value	970 BTU/SCF

Highest Flow Rate Achieved	18,460 BWPD
Highest Surface Temperature Observed	255°F
Sand Production	Minimal; 0.5 to 1.7 lbs. Per 1,000 BBLS.
Corrosion	None Observed
Scaling	Light; 0.03 Grams Per 1,000 BBLS Per SQ.IN.
Lowest Flowing Surface Pressure Observed	490 Psia
Lowest Flowing Bottom Hole Pressure Measured	11,242 Psia
Test Well Productivity Index	3.0 to 4.0 BPD/Psi
Maximum Explored Volume of Reservoir Water	Greater Than 5.2 Million Barrels
Maximum Distance Explored (BHP Instrument)	A Radius of 1,540 Feet
Reservoir	Very Restricted, Lenticular with a Permeability Range of 200 to 240 Mds. and a Flow Angle of Less Than 50°
Disposal Well Gross Perforations	2,870 to 3,000 Feet (4 HPF)
Disposal Well Pressure Range	71 to 385 Psig

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2.0 INTRODUCTION AND BACKGROUND

2.1 Events Leading to Project Initiation

This report covers the acquisition, completion, and testing of a geopressured-geothermal (GEO^2) well and reservoir by Eaton Operating Company, Inc. (Eaton) under contract with the United States Department of Energy, Division of Geothermal Energy (DOE-DGE). The work performed by Eaton is a continuation of the Wells of Opportunity (WOO) Program. The WOO Program was initiated in 1977 to take advantage of the low cost of oil and gas wells previously drilled by industry to obtain short-term test data on the energy producing potential of underground aquifers. Geopressured-geothermal resources could make an important contribution to our nation's energy supply if it should become commercially feasible to produce saltwater reservoirs and to extract the dissolved hydrocarbons, heat and kinetic energy in these formations.

The P. R. Girouard Well No. 1 acquired for this particular test was drilled by Wainoco Oil and Gas Company at a cost of approximately $2.6 million. Wainoco temporarily abandoned the well as a dry hole at a depth of 15,700 feet and offered the well to Eaton for GEO^2 testing. Contracts were finalized with Wainoco and the landowner on May 6, 1980, and actual field operations were initiated on May 15, 1980.

2.2 Location and Geography

The P. R. Girouard Well No. 1 location is located approximately 10 miles southeast of Lafayette, Louisiana and 1,452' west of U. S. Highway 90. Lafayette is a rapidly growing city and the center of Louisiana's oil and gas business. Highway 90 is a major interstate highway connecting Lafayette with other important towns and cities. The specific well location is in Section 10, Township 11S, Range 5E, Lafayette Parish, Louisiana. The terrain is flat and is about 29 feet above sea level. The land is normally used for soybean production.

Figure 2-1 indicates the location of the P. R. Girouard Well No. 1 in relation to other GEO^2 test wells. Figure 2-2 is a topographic map of the area.

2.3 Operator Contracts and Agreements

Wainoco Oil & Gas Company (Wainoco) was the operator and principal working interest owner of the test well. Drilling of the well was completed during April, 1980. Wainoco then elected to plug back and test one zone at approximately 12,300 feet. The test indicated no commercial hydrocarbon potential, and Wainoco agreed to temporarily plug the well, so that Eaton could move

in a small rig to complete the well for a GEO^2 test. Eaton's legal agreement with Wainoco can be found in Appendix "A".

In Louisiana, it is considered necessary to obtain permission of the land and mineral owners to conduct GEO^2 testing. Permission from Mr. Paul Ray Girouard was received through a signed letter agreement during May, 1980. A copy of Eaton's agreement with Mr. Girouard is located in Appendix "A".

2.4 Rig Contractor Agreements

Mathieu Drilling, Inc. was awarded the contract to complete the test well and drill a disposal well on the site. Mathieu's Rig No. 16 performed the work. The rig was moved on location on May 12, 1980. The rig description and drilling contract can be found in Appendix "B".

The rig contract for plug and abandonment operations was awarded to WellTech, Inc. Rig operations were completed on September 19, 1980. A description of WellTech's Rig No. 3 and the contract can be found in Appendix "B".

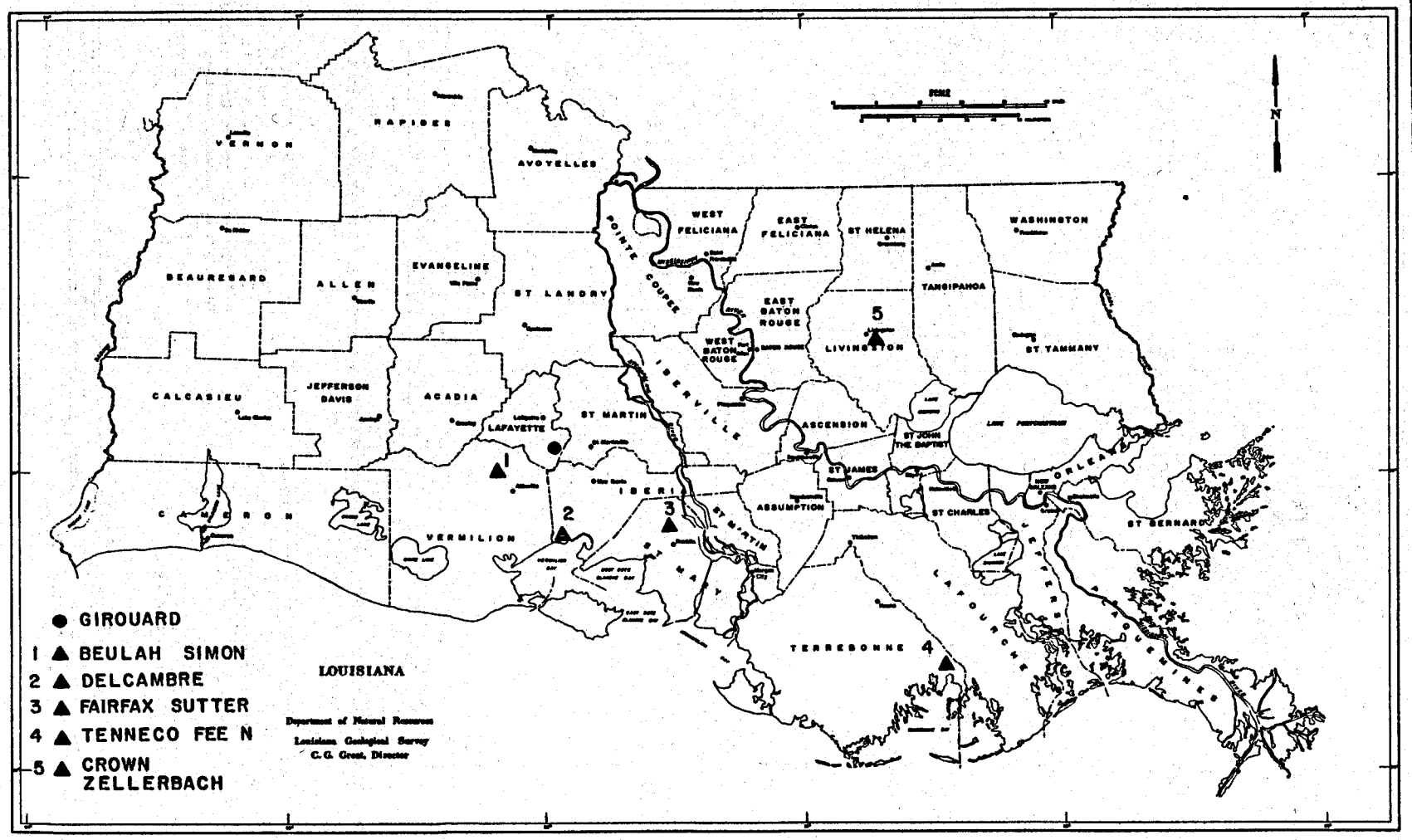

Figure 2-1. Geopressured-Geothermal Test Wells In Louisiana

DOE CONTRACT NO.
DE-AC08-80ET-27081

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Eaton Operating Co., Inc.
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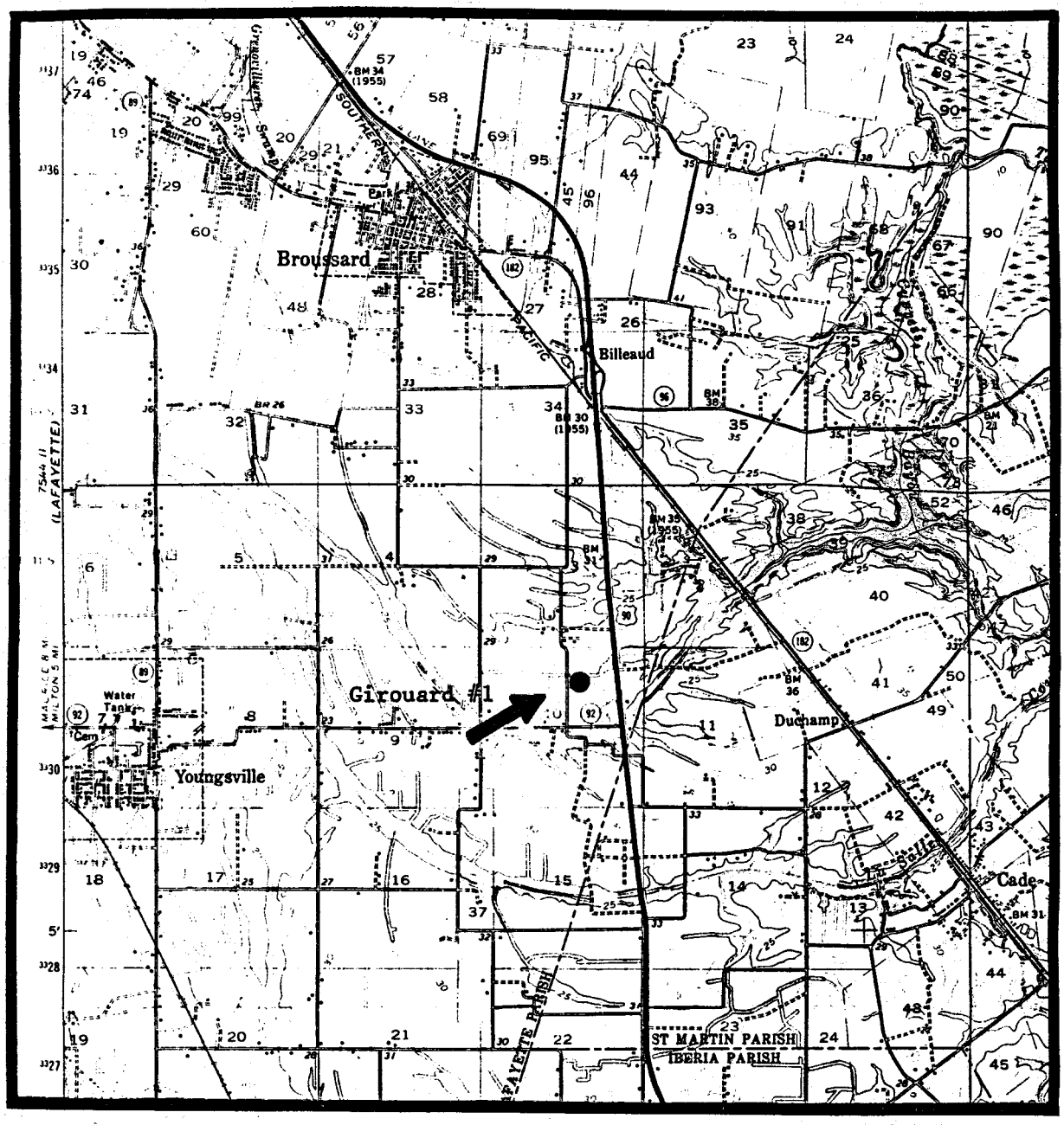

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ST. MARTINVILLE, LA.
N3000—W9145/15

1970

AMS 7644 III—SERIES V785

ROAD CLASSIFICATION

Primary highway, all weather, hard surface
Light-duty road, all weather, improved surface
Secondary highway, all weather, hard surface
Unimproved road, fair or dry weather
U. S. Route
State Route

SCALE 1:62500

1 ½ 0 1 2 3 4 MILES

3000 0 3000 6000 9000 12000 15000 18000 21000 FEET

1 .5 0 1 2 3 4 5 KILOMETRES

CONTOUR INTERVAL 5 FEET
NATIONAL GEODETIC VERTICAL DATUM OF 1929

TOPOGRAPHIC MAP
FIGURE 2-2

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
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Houston, Texas 77027
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DOE CONTRACT NO.
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3.0 OBJECTIVES

The "Wells 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 Louisiana and Texas.

The task requires capability to drill, complete, and test the wells and to interpret data, knowledge of the regional geology, communication and coordination with oil and gas operators, and a scouting system capable of locating potential GEO^2 test wells.

The objectives of the WOO test program in general, and of the P. R. Girouard Well No. 1 test in particular, are to obtain accurate, reliable, short-term information concerning the following:

A. The aquifer fluid properties, including in situ temperature, chemical composition, hydrocarbon content, and pressure.

B. The characteristics of geopressured-geothermal reservoirs, including permeability and porosity, extent and distribution of sands and shales, degree of compaction, and rock composition.

C. The behavior of fluid and reservoir under conditions of fluid production at moderate and high rates, including pressure time behavior at different flow rates, fluid characteristics under varying production conditions, and other information related to the reservoir production drive mechanisms and physical and chemical changes that may occur with various production conditions.

D. The evaluation of completion techniques and production strategies for geopressured-geothermal wells.

E. Analysis of the long-term environmental effects of an extensive commercial application of geopressured-geothermal energy, to the extent determinable during testing.

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4.0 GEOLOGY

4.1 Regional Setting

The Wainoco #1 P. R. Girouard Well was tested in the Marginulina Texana No. 1 Sand, (Marg. Tex. 1). The Marg. Tex. 1 occurs in the upper Frio formation of the Late Oligocene Epoch.

The Marg. Tex. 1 sand was deposited on a broad continental shelf created by epeirogenic movements in the upper Gulf Coast belt at the close of Eocene time. (Bornhauser, 1958) This extensive shelf was characteristic of parts of the region during much of the Cenozoic Era. (Meyerhoff et al, 1968) This area lies within the southern reaches of the Mississippi Embayment of the Gulf Coast geosyncline. Sediments deposited in this area consist almost entirely of medium-to-fine-grained quartz sand, illite and montmorillonite, and abundant organic debris. (Jones, 1969)

4.2 Local Geology

The test well is located in the Cade field. The field lies at the apex of a highly faulted low relief domal structure. The primary faulting consists of east-west trending, down-to-the-coast growth-types. The tested reservoir is situated in the southernmost block, approximately 1,200 feet from the northbounding fault. This fault has a displacement which varies from 100' in the east to 300' in the west (Figure 4-1).

The Marg. Tex. 1 sand, in the test well, appears to be an elongated lenticular lense of the barrier bar or strand plain type of depositional environment (Figure 4-2). Cross Section A-A' (Figure 4-3) shows the Marginulina Texana No. 1 sand to have a 105' gross thickness in the DOE - Eaton #1 Girouard well. The 13' gross sand thickness in the upthrown Superior #1 Broussard well illustrates a pinchout of sand towards the north.

The synclinal feature shown in cross-section B-B' (Figure 4-4) also reveals thinning of the tested sand to the east. To date, this well has uncovered the maximum Marginulina Texana No. 1 sand development in the immediate area.

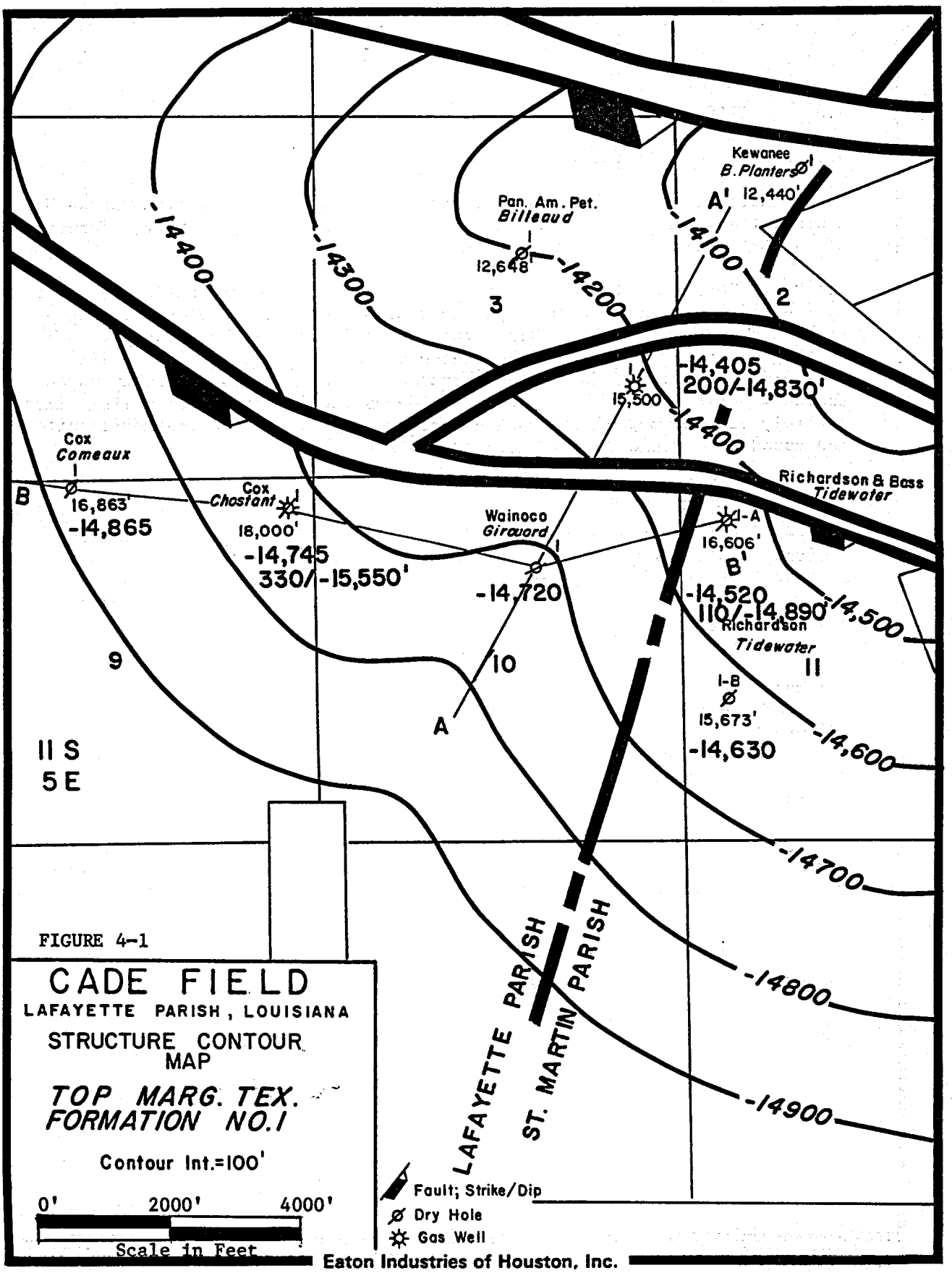

FIGURE 4-1

CADE FIELD
LAFAYETTE PARISH, LOUISIANA
STRUCTURE CONTOUR MAP
TOP MARG. TEX. FORMATION NO.1
Contour Int.=100'

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Eaton Operating Co., Inc.
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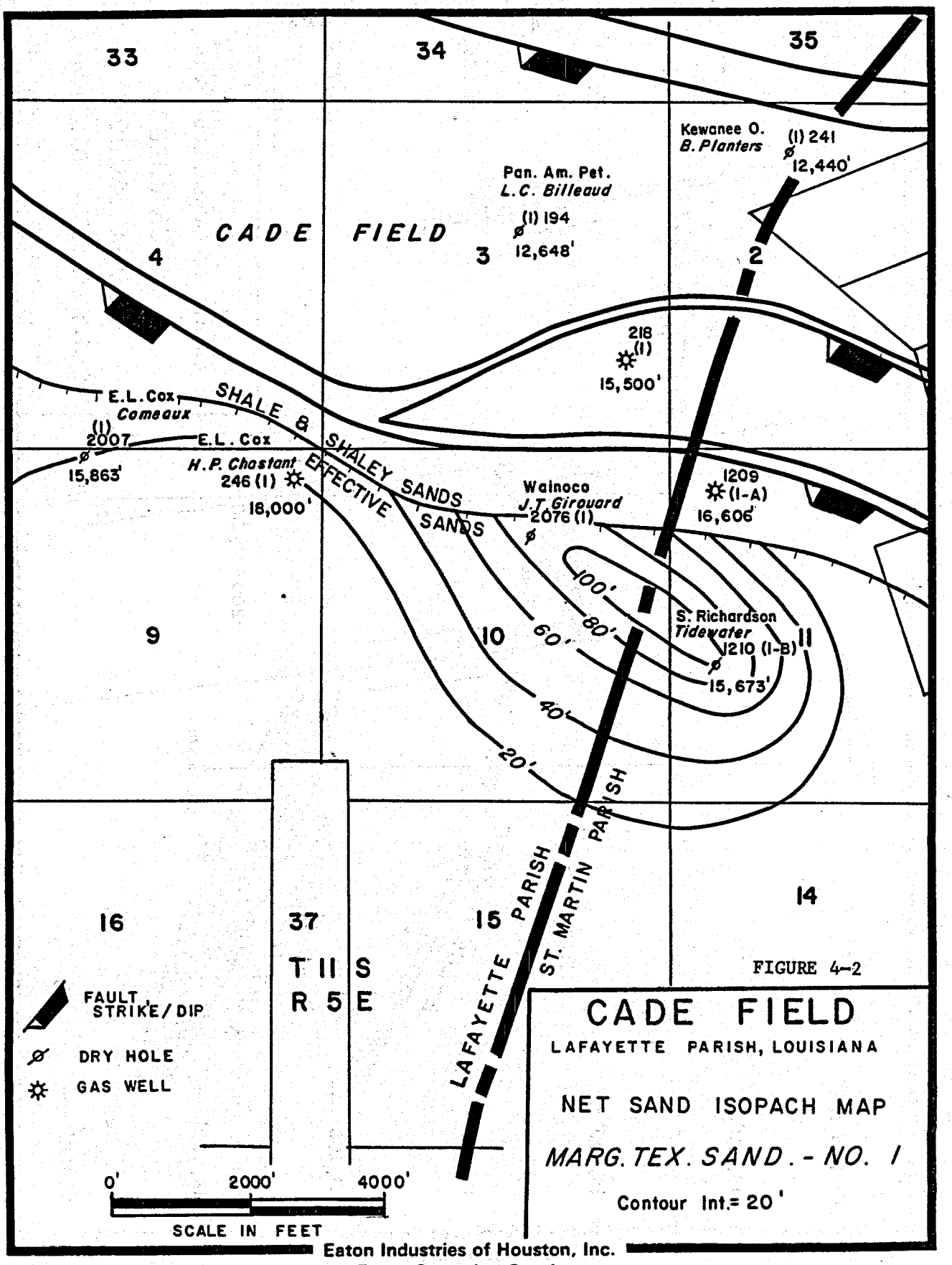

FIGURE 4-2

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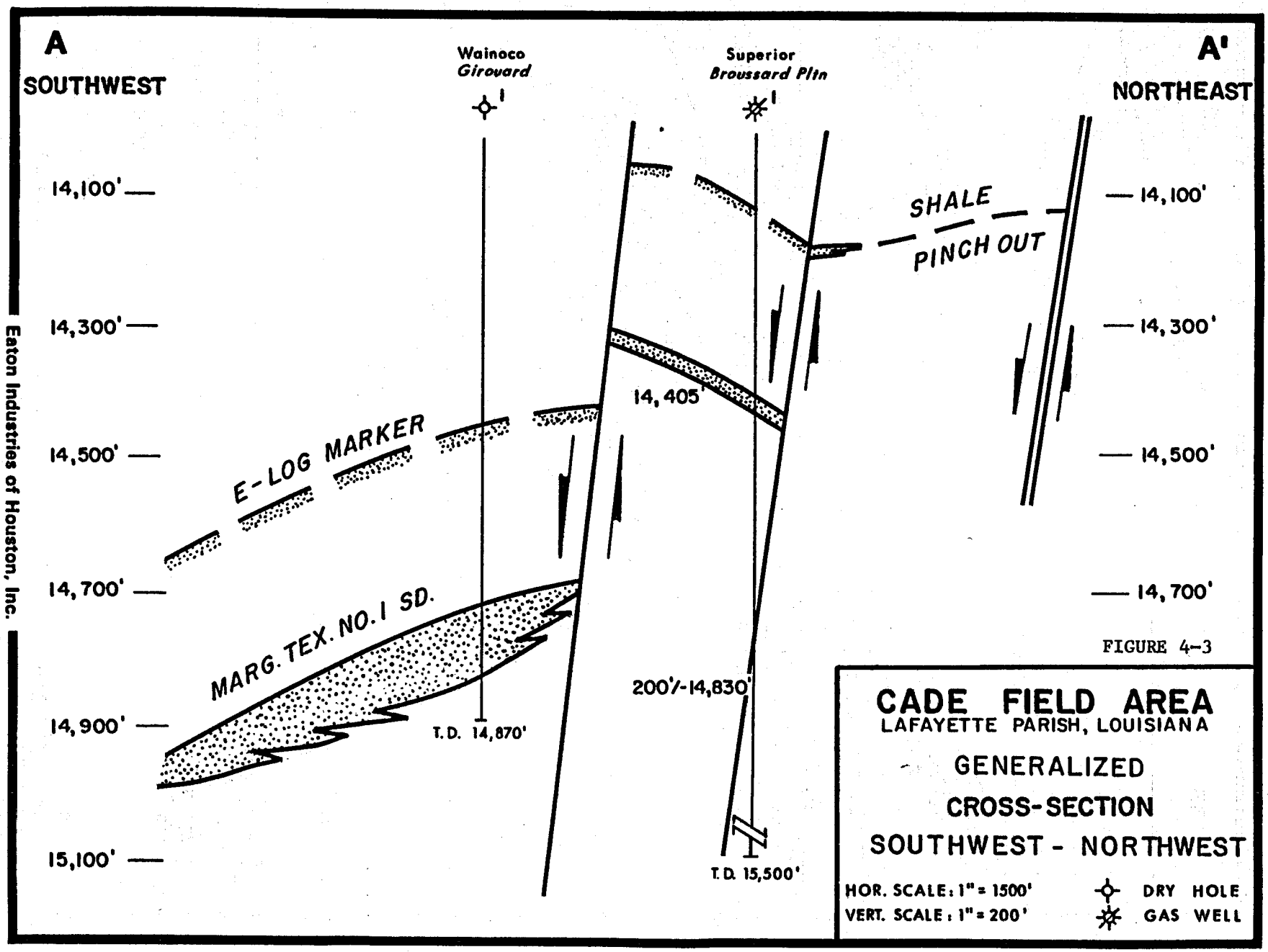

FIGURE 4-3

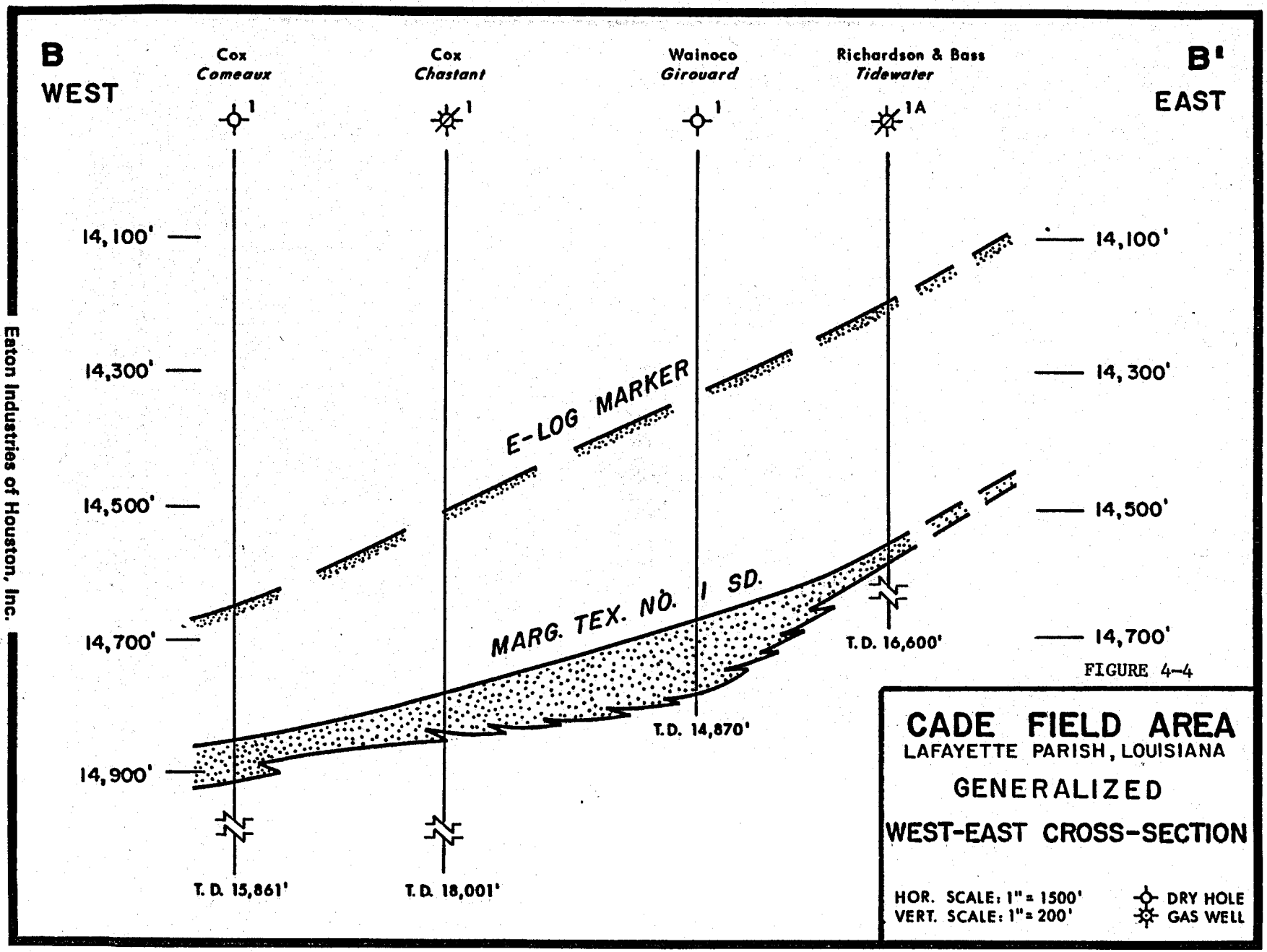

FIGURE 4-4

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5.0 PETROPHYSICS

5.1 Open-Hole Log Analysis-Test Well

During the drilling phase of the #1 P. R. Girouard Well, Wainoco Oil & Gas Corporation conducted several logging surveys for hydrocarbon evaluation. The logs were made available to Eaton for use in reservoir determination for the DOE Wells of Opportunity program. The following logs were used in evaluation of the target reservoir.

1. ISF Induction Log - 1"
2. Acoustic Velocity Log - 5"

The aforementioned logs contained data from which the following formation measurements could be determined.

1. Spontaneous Potential
2. Induction
3. Gamma Ray
4. Sonic Time Travel
5. Computed Apparent Water Resistivity

5.1.1 Porosity

The mean porosity of the net pay sand was 28%, with a range from 12% to 34%. These values were determined from the sonic log (Figure 5-1) and the Schlumberger "Porosity Evaluation from Sonic Log" graph (Figure 5-2). Sampling of the sonic time travel on a two-foot interval basis yielded the porosity value. An observed sand travel time of 93 microseconds/ft. and an assumed matrix velocity of 18,000 microseconds/ft. were used in the porosity determination.

5.1.2 Sand Thickness

The net sand thickness of the geopressure geothermal test zone was estimated to be 91'. This value was determined from the gross interval of 107' (Figure 5-3) based on the following calculations.

1. The 100% shale and "clean sand" baselines were established from the gamma ray track of the sonic log.

2. A midpoint line was established.

3. All sand thicknesses for which the gamma ray log values fell on the "clean sand" side of the midpoint line were assumed to be net pay, provided the calculated sonic porosity exceeded 10%.

5.1.3 Permeability

The permeability estimates of the geopressure geothermal test zone were not available prior to the flow test. Conventional or sidewall cores were not obtained from the test zone during drilling operations. Also, empirical equations presented in logging literature for permeability estimation of various wireline logging devices have irreducible water-saturation values as a part of the mathematical statements. These equations, designed for saturated hydrocarbon formations, may not be applicable in 100% water-saturated sand.

5.1.4 Salinity

The water salinity of the test sand is estimated to be 33,500 ppm. This mean of values was determined by the following methods.

1. SP Method

2. Modified Humble Equation

5.1.4.1 SP Method: The estimated salinity using the SP (spontaneous potential) method is 35,000 ppm. This value was determined by solving for formation fluid resistivity using the maximum SP value from the induction log and then plotting on the Schlumberger "Resistivity Salinity" graph (Figure 5-4). The equations used in determining formation fluid resistivity are as follows:

$$SSP = -(60 + .133T) \log R_{mf}/R_{we} \qquad (1)$$

solving for R_{we}:

$$R_{we} = R_{mf} \left(10^{SSP/(60 + 0.133T)}\right) \qquad (2)$$

where:

SSP = static spontaneous potential - millivolts

T = formation temperature - F^{o}

R_{mf} = resistivity of mud filtrate - ohms

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R_{we} = equivalent formation fluid resistivity - ohms.

and:

maximum SP (uncorrected)	= 32 mv.
corrected SSP	= 34 mv.
R_{mf}	= .45@73°F = .14@256°F
R_{we} (equation 2)	= 0.06 ohm - meters
Salinity	= 35,000 ppm

5.1.4.2 Modified Humble Method: An estimated salinity of 32,000 ppm was calculated using the Modified Humble Method and was determined primarily as a function of porosity and true formation resistivity. The mathematical equation is as follows:

$$F = R_o/R_w \quad (3)$$

$$F = .81/\phi^2 \quad (4)$$

therefore:

$$R_o/R_w = .81/\phi^2 \quad (5)$$

$$R_w = R_o\ \phi^2/.81 \quad (6)$$

where:

F = formation factor - dimensionless

R_o = 100% water saturated rock - ohm-m

R_t = true formation resistivity - ohm-m

R_w = formation water resistivity - ohm-m

ϕ = porosity - %

Assuming a 100% water-saturated formation where $R_t = R_o$, equation #6, and the following parameters: R_t = .75 ohm-m and a porosity of 26%, a formation water resistivity of .063 ohm-m is obtained. When the formation water resistivity is plotted on the Schlumberger Resistivity Salinity graph (Figure 5-4), a salinity determination of 32,000 ppm is obtained.

5.2 Open-Hole Log Analysis - Disposal Well

The Eaton #1 SWD Girouard was drilled for saltwater disposal purposes to a depth of 4,606'. Four potential disposal sands were encountered and are identified as follows:

Sand A 4,340'- 4,420'
Sand B 3,908'- 4,020'
Sand C 2,866'- 3,010'
Sand D 2,594'- 2,772'

Sand "A" sanded up during completion operations, and sand "C" proved to have the best alternate potential, so sand "C" was completed for saltwater disposal. It has a net thickness of 144', porosity of 37%, salinity of 37,000 ppm, and an estimated temperature and pressure of 105°F and 1,408 psi, respectively. (See Figures 5-5, 5-6, and 5-7).

5.3 Cased-Hole Log Analysis - Test Well

A Micro-Seismogram log was run on the test well after the zone of interest had been cased and cemented. This type of log is primarily for completion use, and has a two-fold purpose:

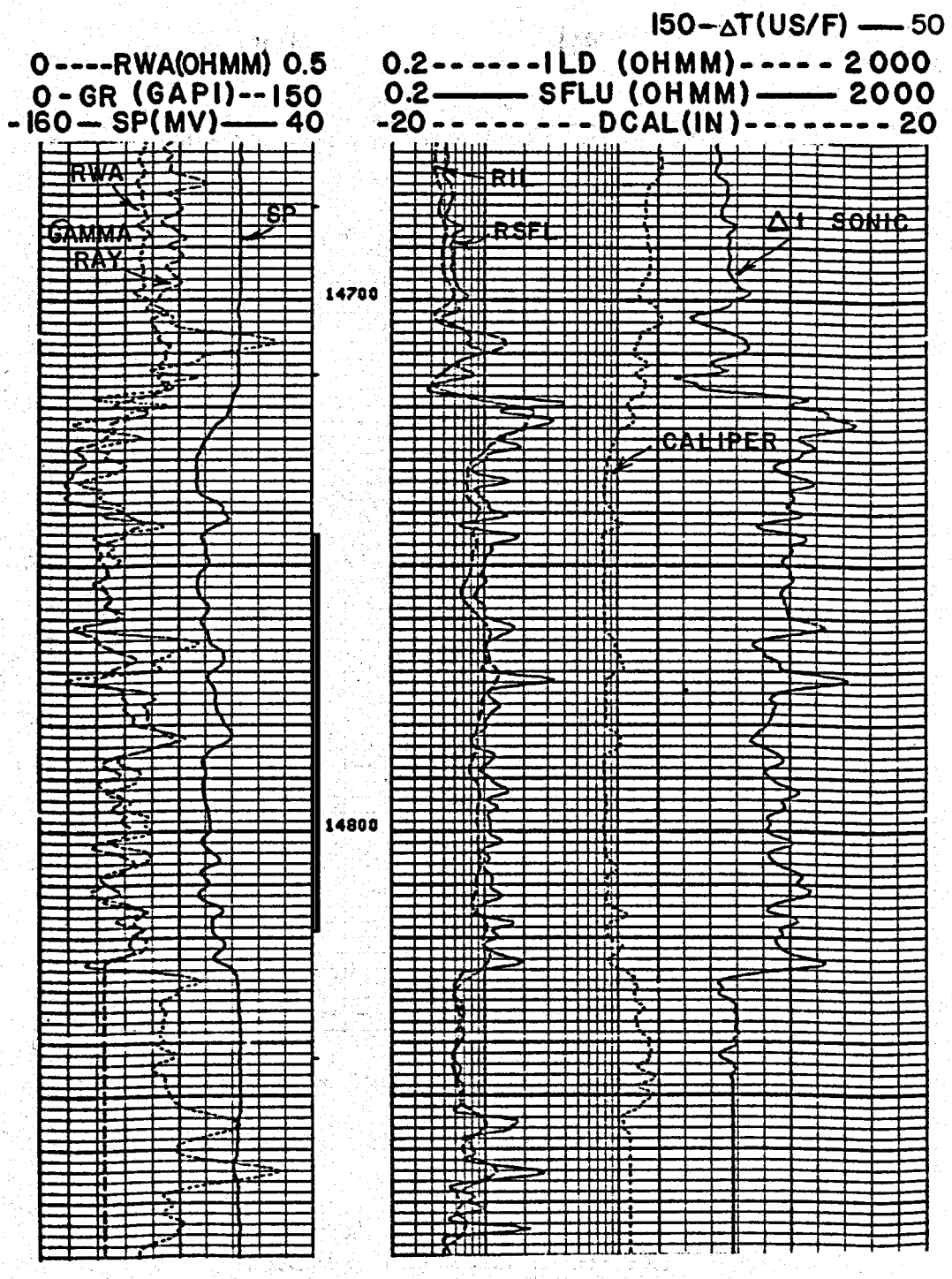
1. Establish an open-hole vs. casing-collar correlation.

2. Determine integrity of casing vs. cement and cement vs. formation bonding.

Analysis of the test well Micro-Seismogram log (Figure 5-8) showed that a 9' section of the upper portion of the test zone was not completely bonded, but that the interval from 14,744 - 14,819 had excellent bonding.

5.4 Cased-Hole Log Analysis - Disposal Well

A Micro-Seismogram log was also run on the disposal well for the same purposes as stated in Section 5.3 for the test well. Analysis of the disposal well log (Figure 5-5) indicated that although cement bonding of the disposal sands was not complete, there was excellent bonding between the disposal sands, thereby isolating these zones from one another and the overlying fresh water sands (Figure 5-9).



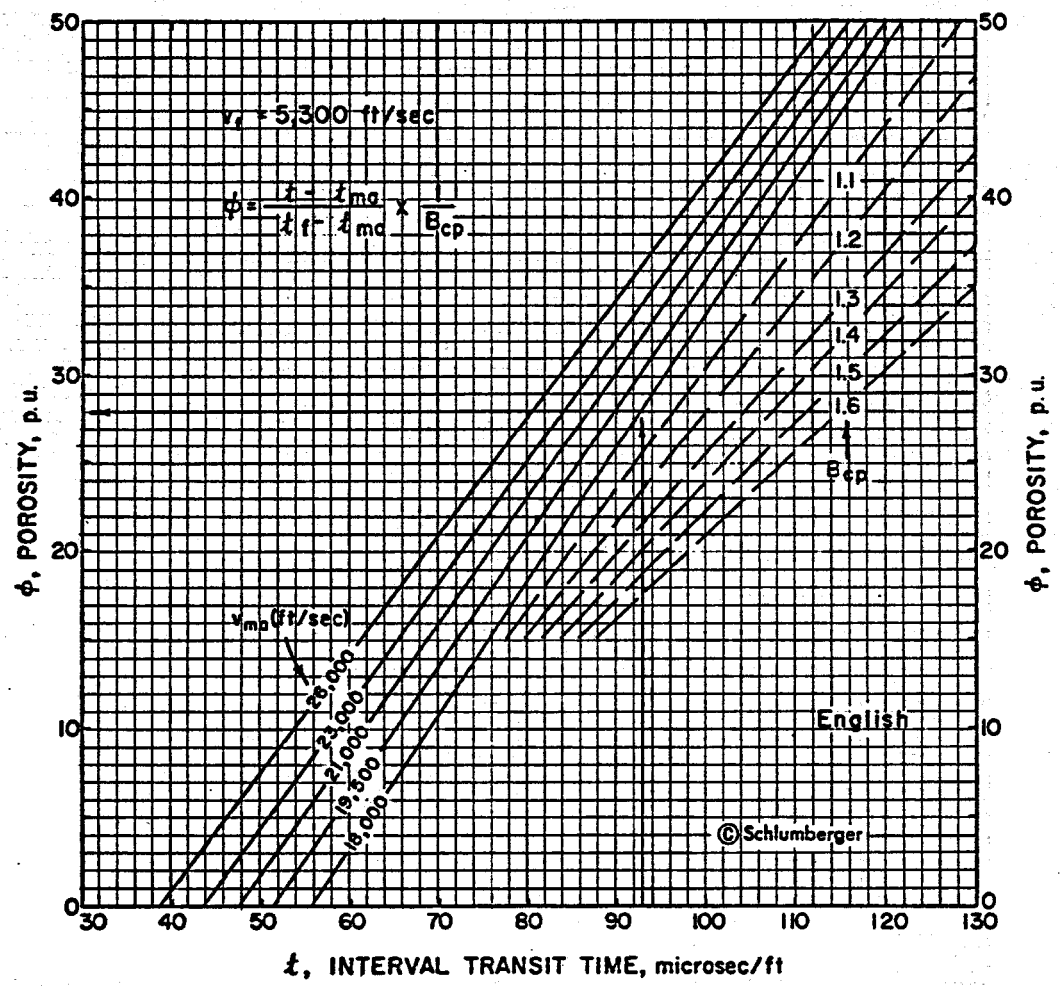
SONIC LOG - NO.1 MARG. TEX. SAND

WAINOCO, 1 - P.R. GIROUARD

FIGURE 5-1

Schlumberger

POROSITY EVALUATION FROM SONIC



	v_{ma} (ft/sec)	t_{ma} (microsec/ft)
Sandstones	18,000-19,500	55.5-51.3
Limestones	21,000-23,000	47.6-43.5
Dolomites	23,000-26,000	43.5-38.5

FIGURE 5-2

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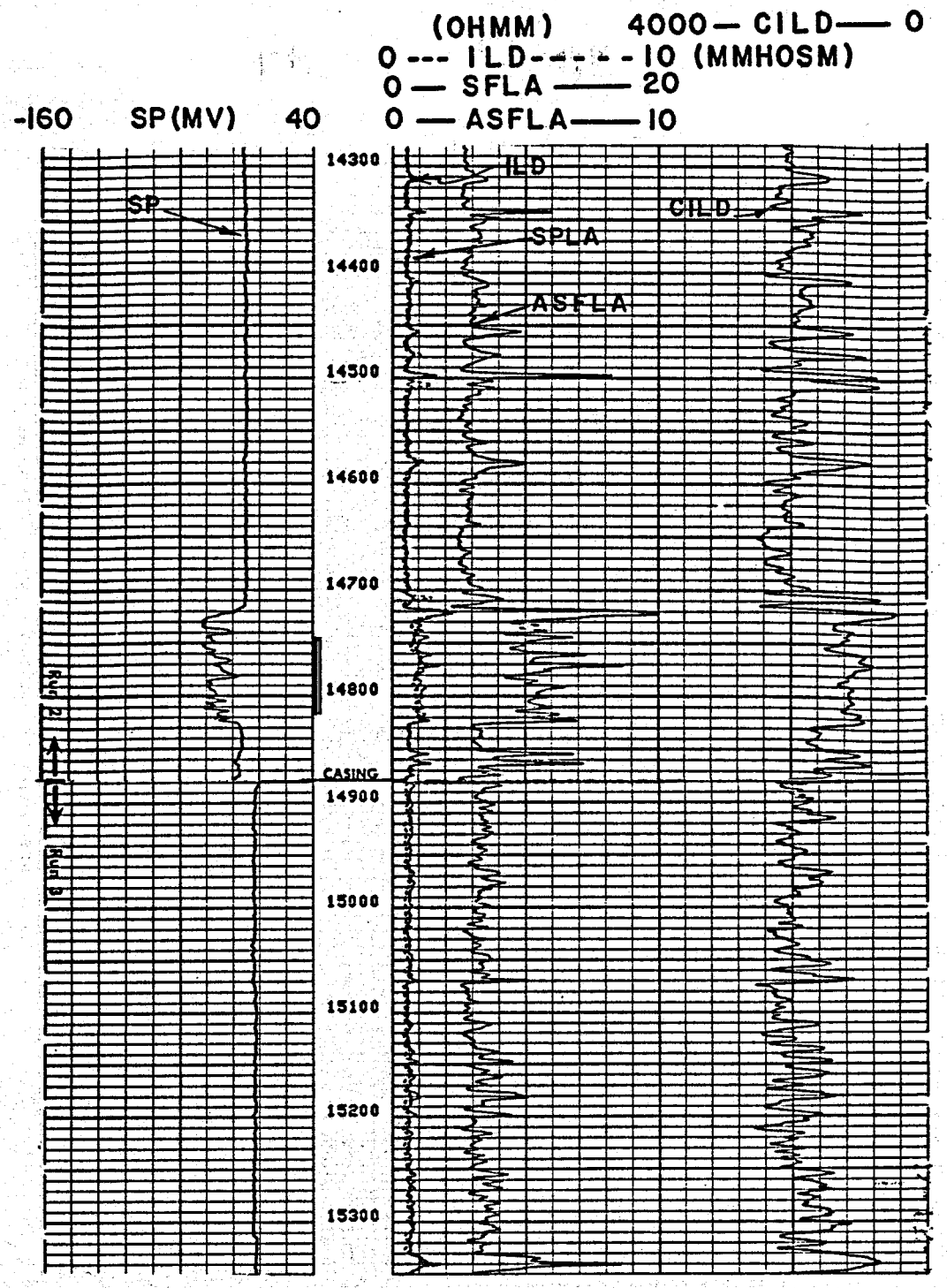

ISF LOGS- NO.1 MARG.TEX SAND

WAINOCO , 1- P.R. GIROUARD

FIGURE 5-3

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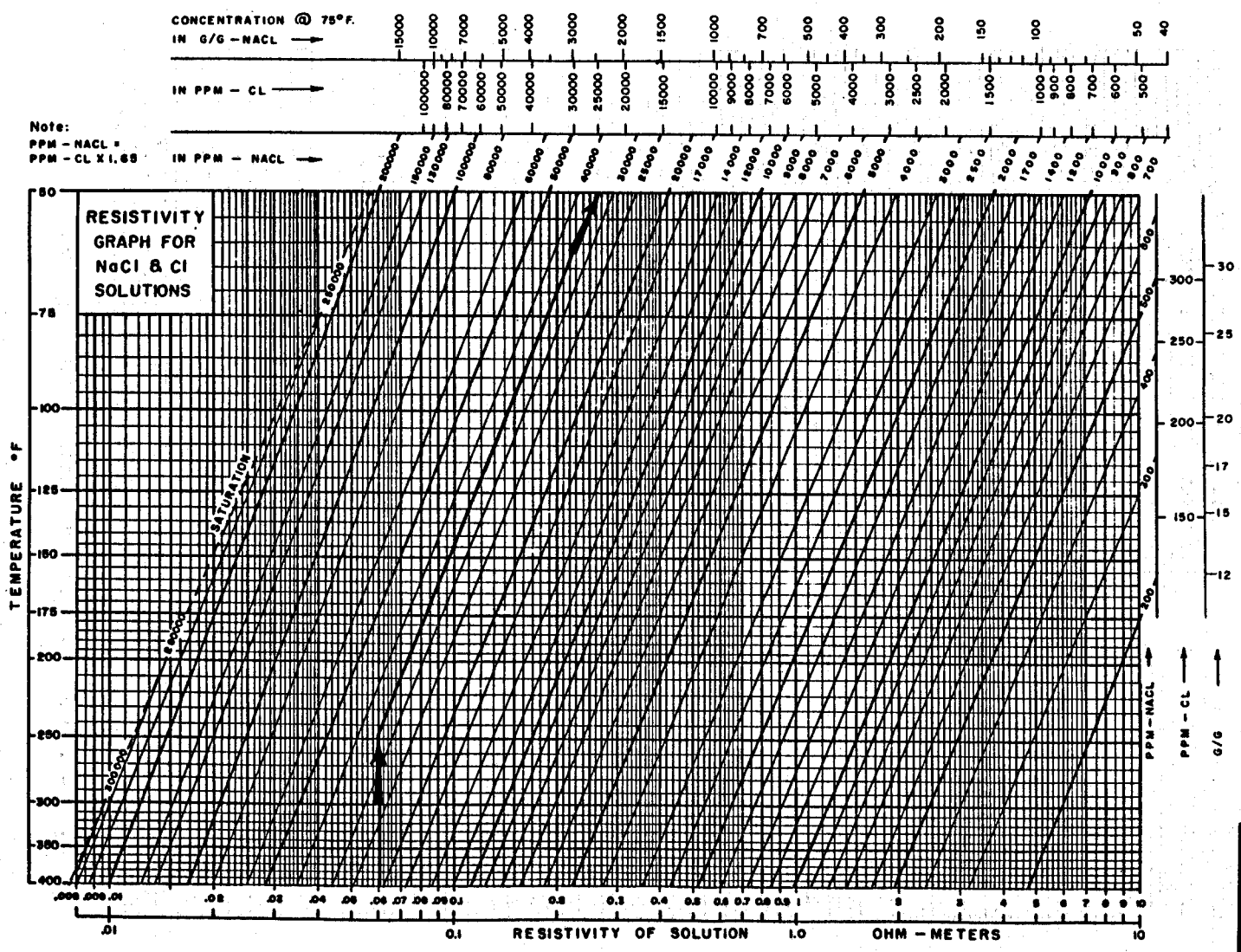
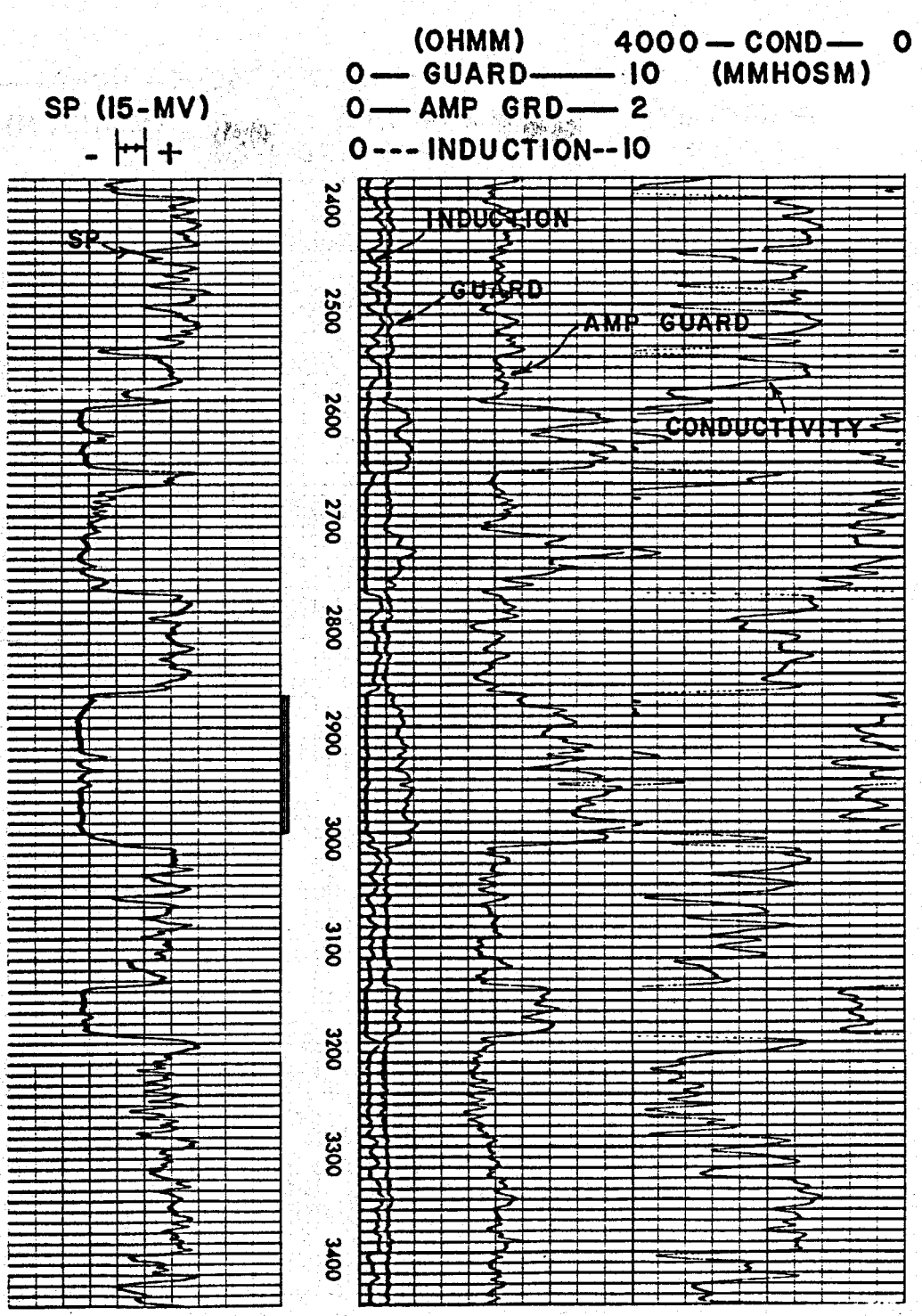


FIGURE 5-4 RESISTIVITY SALINITY GRAPH

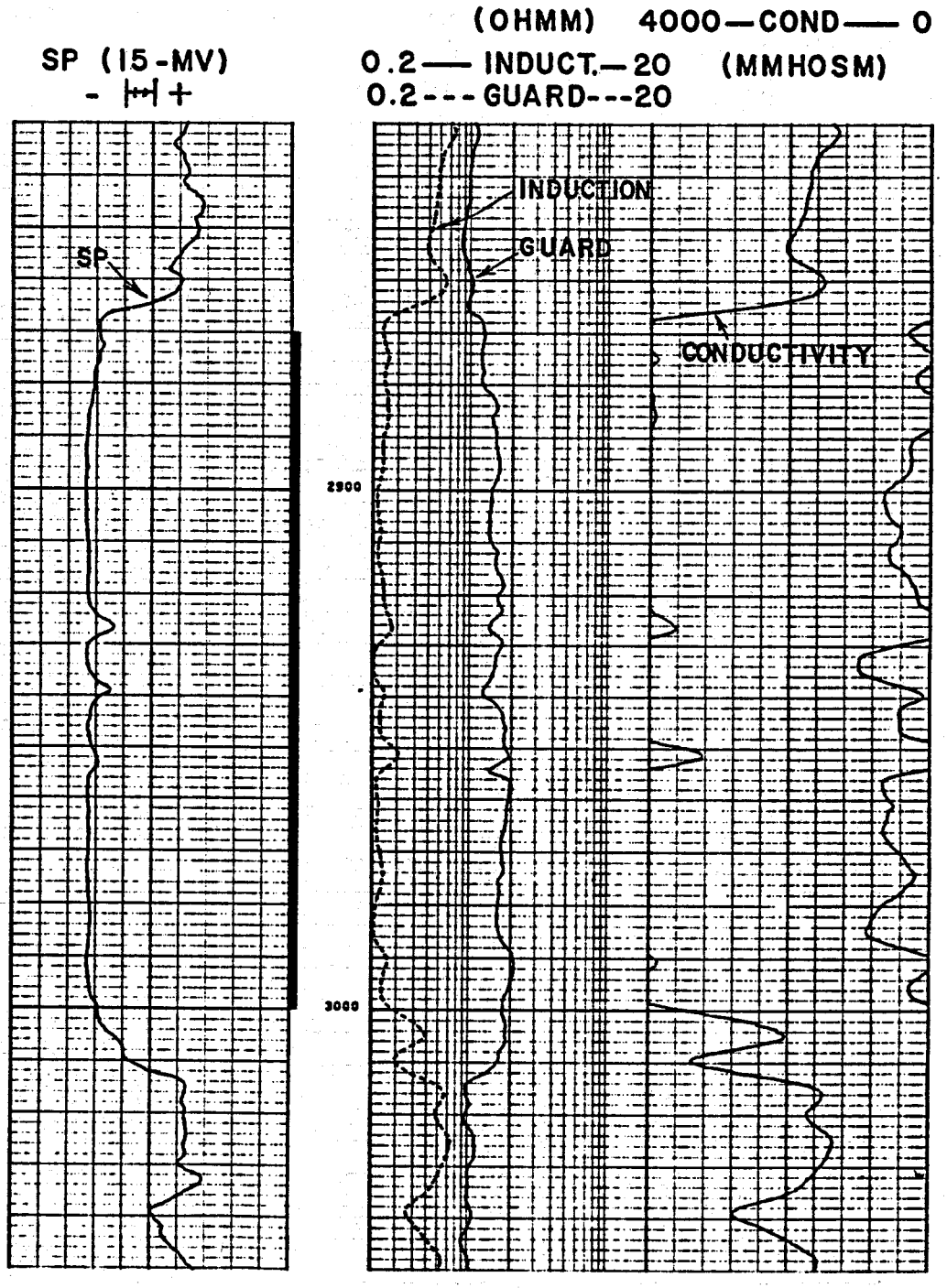
Schlumberger



ISF LOG - MIOCENE SAND

EATON - 1-D GIROUARD

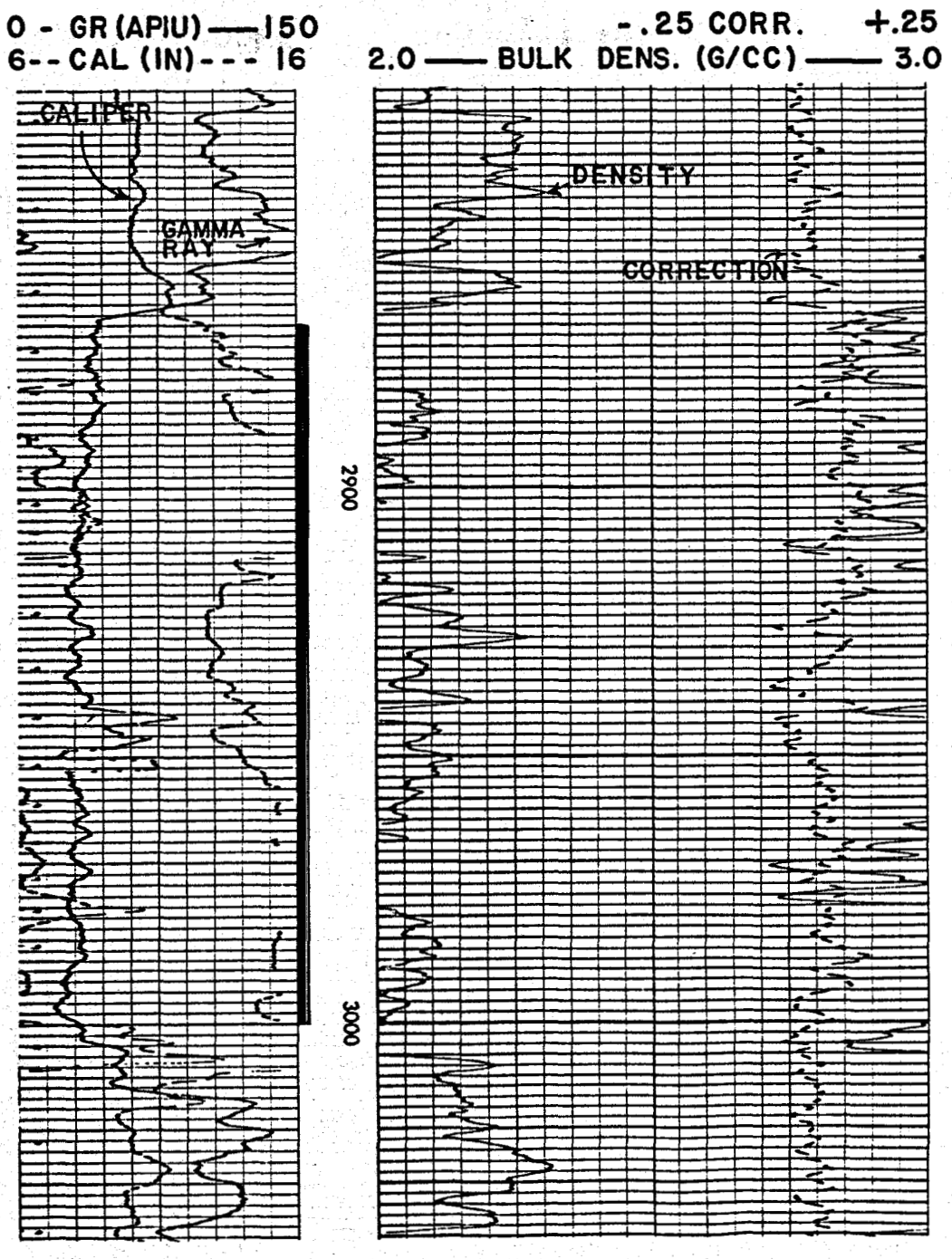
FIGURE 5-5



ISF LOG (5") - MIOCENE SAND

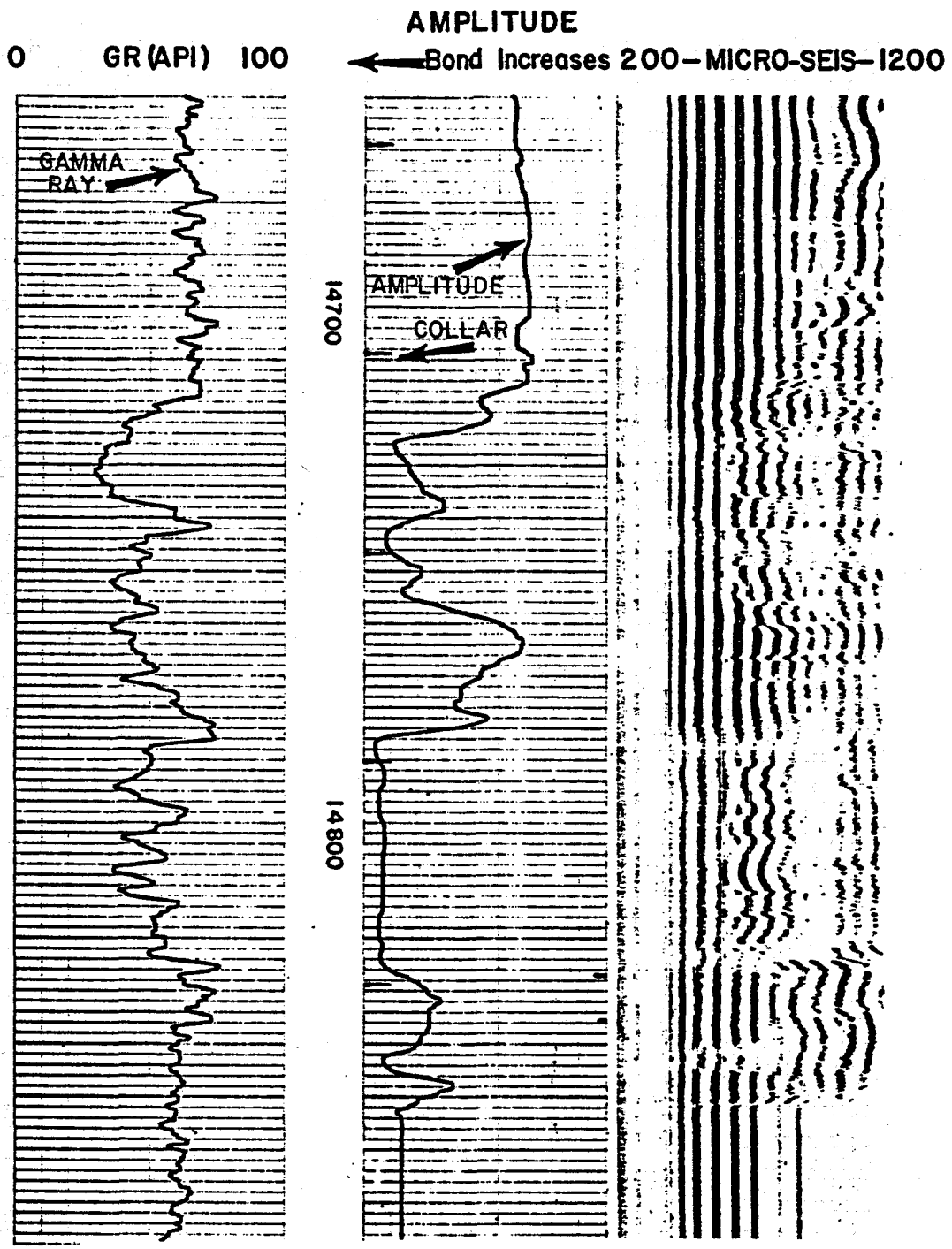
EATON , I-D GIROUARD

FIGURE 5-6



DENSITY LOG - MIOCENE SAND
EATON - I-D GIROUARD

FIGURE 5-7



MICRO-SEISMOGRAM LOG - TARGET ZONE

WAINOCO NO.1 GIROUARD

FIGURE 5-8

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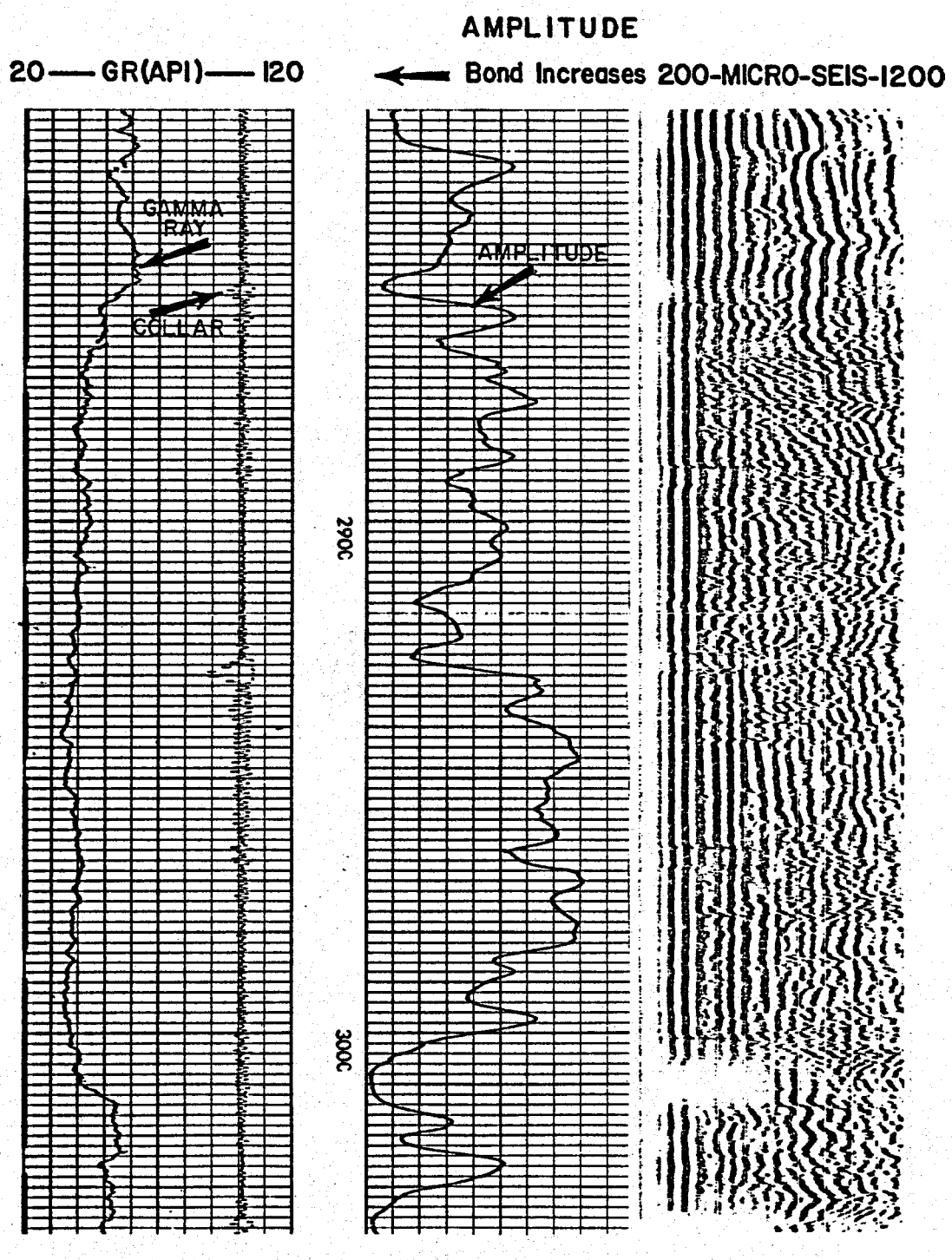

MICRO-SEISMOGRAM LOG - DISPOSAL ZONE

EATON NO. I-SWD GIROUARD

FIGURE 5-9

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6.0 RE-ENTRY AND COMPLETION OPERATIONS - TEST WELL

6.1 Drill Site and Support Facilities

6.1.1 Site Layout

The location layout shown in Figure 6-1 accommodated conventional drilling and workover equipment used for completion of the test well and the drilling of the disposal well. The site was covered with boards for the support of rig operations. Prior to moving in the well testing equipment, a portion of the location was covered with a layer of sand and gravel. This fill material provided a good level working area for the testing operation.

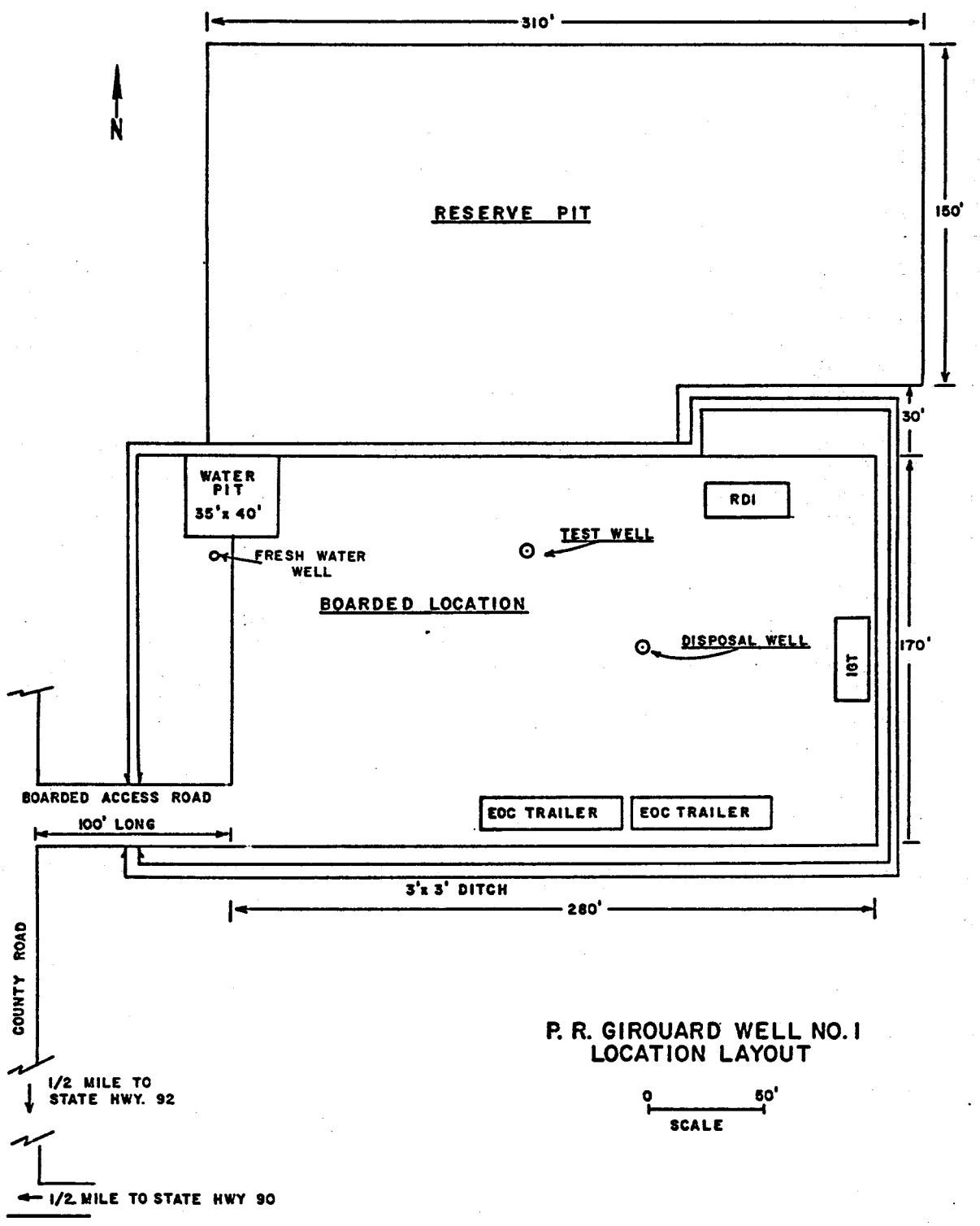
Rain water, waste oil, and grease spillage were trapped and drained into a ditch around the location for disposal. The ditch was pumped out into the reserve pit, and at the end of the testing operations the fluids in the reserve pit were pumped down the disposal well.

6.1.2 Living Facilities and Utilities

Air-conditioned living facilities were provided for six individuals. Weatherly Engineering, the rig contractor, and Reservoir Data, Inc. brought in living trailers for their personnel. Motel accommodations were available in Lafayette, Louisiana.

Water for drilling and other operations was obtained from a drilling fluids supply company. Drinking water was brought to the site by a local water delivery service.

Two telephones were installed in the Eaton house trailers. Rented generators were used to supply electrical power.



P. R. GIROUARD WELL NO. I
LOCATION LAYOUT

FIGURE 6-1

6.2 Test Well Design

6.2.1 Initial and Actual Well Completion Status

Figure 6-2 is a schematic drawing of the test well showing the conditions when Eaton took over operations from Wainoco. The lower portion of the well was abandoned by setting a cement retainer at 14,869 feet and squeezing 100 sacks of cement below the retainer. Wainoco perforated the interval from 12,324 to 12,348 feet and tested the well. These perforations were squeezed off leaving a cement plug in the 9-5/8" O.D. casing.

FIGURE 6-2

WAINOCO-P. R. GIROUARD WELL NO.1
CONDITION AT TIME OF EATON TAKEOVER

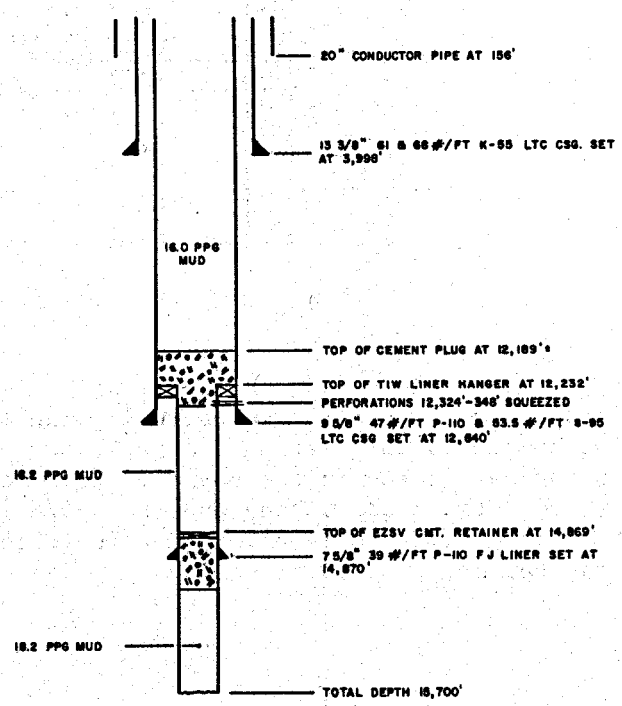


FIGURE 6-3

WAINOCO - P. R. GIROUARD WELL NO. I
CONDITION DURING TESTING

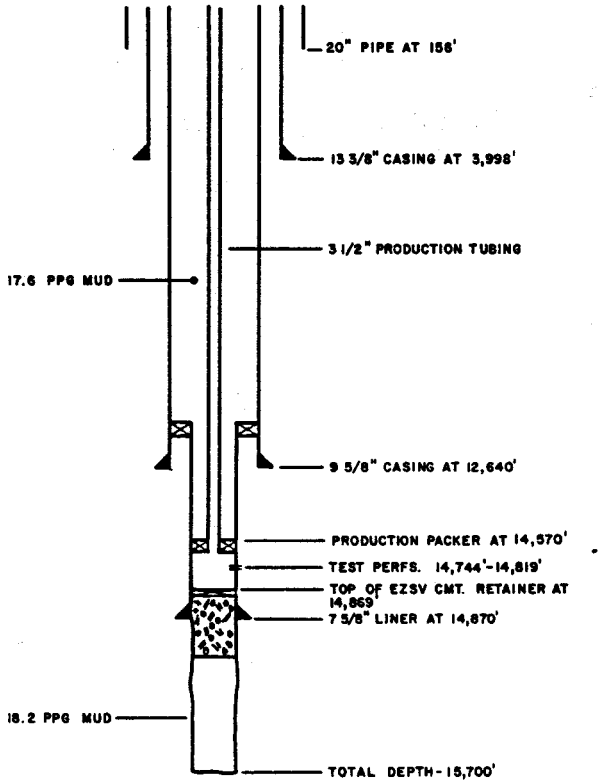


Figure 6-3 is a schematic diagram illustrating the tubular configuration of the well as completed for testing. A packer was set at 14,570 feet, and 3-1/2 inch tubing was landed in the packer. Drilling fluid was left in the annular space between the tubing and the 9-5/8 inch casing. The well was perforated from 14,744 to 14,819 feet using wireline perforating guns run through the tubing.

6.2.2 Tubular Goods Design

Engineering design and safety calculations were performed prior to completion of the well. Figure 6-4 shows the specifications for the tubular goods installed in the test well, as well as hole sizes and design safety factors.

FIGURE 6-4

WAINOCO P. R. GIROUARD WELL NO. 1

TUBULAR AND CEMENTING SUMMARY

Tubular	O.D. Size (in.)	Depth From (Ft.)	Depth To (Ft.)	Weight lbs./Ft.	Minimum Drift (in.)	Casing Description Grade	Casing Description Thread	Casing Design Factors Burst	Casing Design Factors Collapse	Casing Design Factors Tension
Conductor Pipe	20	0	156	NA	NA	NA	Welded	*	*	*
Surface Casing	13-3/8	0	2,225	61.0	12.35	K-55	LTC	*	*	*
		2,225	3,998	68.0	12.259	K-55	LTC	*	*	*
Intermediate Casing	9-5/8	0	5,471	47.0	8.525	P-110	LTC	1.24	4.83	*
		5,471	12,640	53.5	8.500	S-95	LTC	0.98	3.54	*
Drilling Liner	7-5/8	12,232	14,870	39.0	6.500	P-110	FJ	2.0	1.63	*
Tubing	3-1/2	0	14,600	12.95	2.625	P-105	FH-6	2.03	1.49	2.04

Casing	O.D. Size (in.)	Hole Size (in.)	Remarks
Surface	13-3/8	17-1/2	Cemented back to surface
Intermediate	9-5/8	12-1/4	Estimated cement top at 7,800'±
Liner	7-5/8	8-1/2	Squeezed top of liner twice

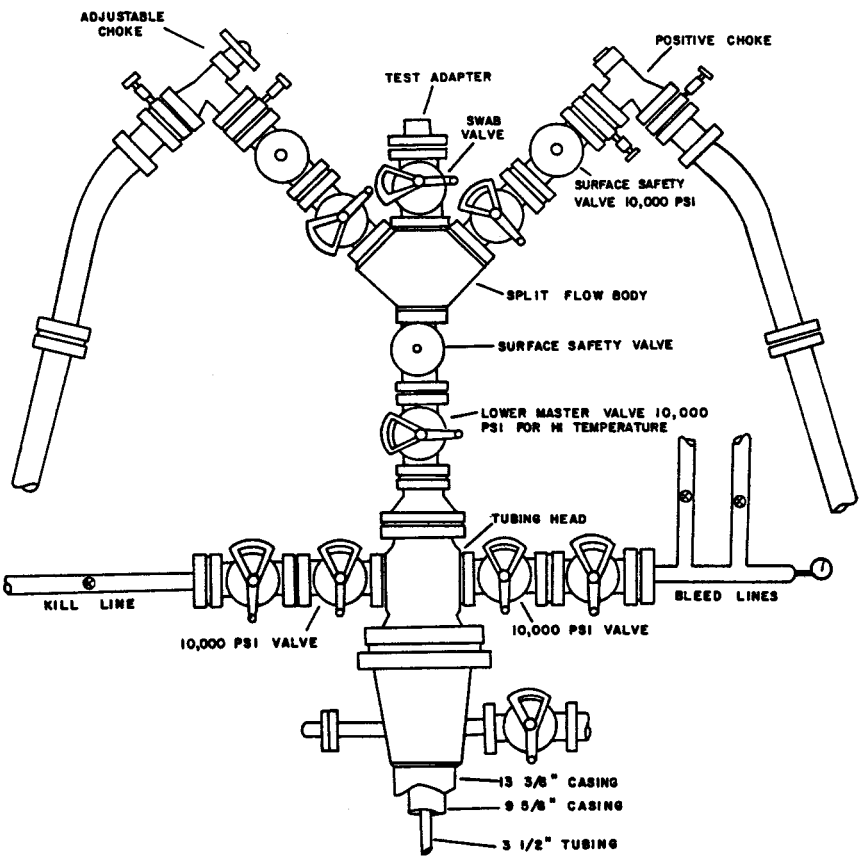
Note: All casing run, cemented, and tested by Wainoco.

* Tubulars in place and no longer exposed to well bore conditions.

6.2.3 Wellhead Design

Figure 6-5 is a schematic of the wellhead and christmas tree used for this well. The tree was designed using parts from prior GEO^2 christmas trees. All gate valves and flanges had a rated working pressure of 10,000 psi. The upper section consisted of three hand-operated gate valves and three pneumatic operated surface safety valves. A "swab" valve was installed on top for wireline accessibility. All valves in the upper section were 3-1/16 inch, inner diameter. Two flow loops were installed to balance bending moments near the top of the tree during maximum flow conditions. Fluid flow through the loops was controlled by an adjustable choke on one wing and a positive choke on the other.

FIGURE 6-5



WAINOCO - P. R. GIROUARD WELL NO. I
CHRISTMAS TREE SCHEMATIC

6.2.4 Logging Program

The suite of open-hole logs obtained by Eaton supplied adequate information for sand evaluation purposes. After the well was cleaned out, a gamma-ray, cement bond, and casing collar locator log was run to evaluate formation isolation and to serve as a reference for perforation operations.

6.3 Re-Entry Operations

The Mathieu Rig Number 16 was moved to the Wainoco P. R. Girouard Number 1 location on May 12, 1980, to commence completion operations on the test well. A blowout preventer stack approved by Eaton was installed and tested to 5000 psi. A work string consisting of 3-1/2" O.D. drill pipe, 4-3/4" O.D. drill collars, a casing scraper for 9-5/8" O.D. 47 pound per foot casing and an 8-3/4" O.D. bit was assembled and run in the well bore. While running in the hole, the well was circulated to condition mud at 2000 feet, 4082 feet, 6155 feet, 8262 feet, 10,018 feet and 12,124 feet. The bit hit solid fill at 12,217 feet, and the well was circulated with 17.8 pound per gallon water-based lignosulfonate mud. The casing was pressure-tested to 1500 psi after drilling down to the top of the liner at 12,232 feet.

After this pressure test, the drill string was pulled to pick up a 6-1/2" O.D. bit. The cement in the top of the 7-5/8" O.D. liner was drilled from 12,232 feet to 12,243 feet. The bit took additional torque to get through the squeezed perforations at 12,324 to 12,348 feet. At this point, the casing was pressure-tested to 1500 psi for 15 minutes to confirm that the perforations were still holding. The well was cleaned out to the top of the EZSV retainer at 14,869 feet, and the drill string was pulled.

6.4 Completion Operations

6.4.1 Cased Hole Logs

A gamma-ray, cement bond evaluation, and casing collar locator log was run on electric wireline to determine if a cement squeeze job was required. The log indicated that the upper portion of the test sand was not completely cemented. It was decided not to perforate the top part of the sand to avoid expensive squeeze operations.

6.4.2 Production Packer Setting

Welex ran a gauge ring and junk basket on wireline, but the gauge ring would not go past the top of the liner at 12,232 feet. Another wireline run was attempted, but the gauge ring still would not pass the liner top. A liner top dressing mill was run on 3-1/2" O.D. tubing to open the liner tie-back sleeve. However, the gauge ring still failed to pass through the top of the liner. An attempt with a smaller 6.44" O.D. gauge ring also failed. When a 6.299" O.D. gauge ring was run, it stuck in the liner top and a 2.3 foot segment broke off. A fishing spear was run on tubing, but did not

recover the broken segment. A tapered mill and jars were run on the tubing string and succeeded in pushing the gauge ring segment to bottom.

An Otis type "WD" permanent production packer was run on wireline and set at 14,570 feet. The blowout preventers were nippled down and the tubing head was installed.

6.4.3 Production Tubing

The 3-1/2" O.D. tubing and bottom hole tubing assembly were run in the well as shown in Figure 6-6. Each joint of tubing was tested to 8000 psi with tubing testing equipment.

Before inserting the tubing seal assembly into the packer, the tubing was partially displaced with saltwater to provide approximately 2000 psi differential pressure from the formation into the well bore. The tubing was seated in the packer. The blowout preventers were nippled down, and the tubing was hung in the tree. The christmas tree was pressure-tested to 8000 psi.

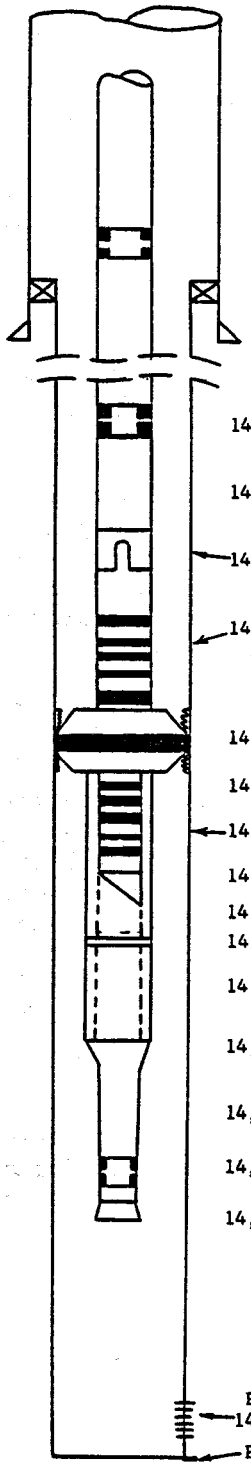
6.4.4. Completion Perforations

A 2" O.D. through-tubing perforating gun was used to perforate the interval 14,778 feet to 14,798 feet and 14,799 feet to 14,819 feet. The tubing pressure increased to 1500 psi. The well was opened to flow to clean the perforations and flowed 8 barrels of saltwater. The same interval was then perforated with another 4 shots per foot. When pulling out of the hole, the gun stuck at 14,593 feet. During an attempt to work the gun free, the rope socket parted at the top of the gun. A wireline unit was rigged up, and a no-go locator mandrel was run in the well with weight bars and a collar locator. The gun was jarred loose and fell to the bottom of the well.

The well was opened to flow on June 9, 1980, and produced an estimated 100 barrels of mud and 150 barrels of saltwater. The final fluid produced was all saltwater. A back-pressure valve was installed in the tree and the rig was released on June 9, 1980.

P. R. GIROUARD WELL NO. 1

WELL SETTING DURING TESTING



DEPTH TO TOP OF ITEM	LENGTH	ITEM DESCRIPTION	
0	26.00'	Rotary Kelly Bushing to tubing hanger	
26.00'	32.13'	Tubing	
58.13'	0.43'	Double Pin Sub	
58.56'	9.32'	Pup joints 7.60' and 1.72	
67.88'	226.75'	Tubing	
294.63'	0.79'	Otis Type "R" Nipple	O.D. 4.32 I.D. 2.562
295.42'	14,232.29'	Tubing	
14,527.71'	0.79'	Otis Type "R" Nipple	O.D. 4.32 I.D. 2.562
14,528.50'	32.59'	Tubing	
14,561.09'	1.21'	Straight slot locator sub	O.D. 4.48 I.D. 2.75
14,562.30'	16.09'	Seal Assembly	O.D. 4.00 I.D. 2.75
14,570.00'	3.42'	Otis Type "WD" Packer	O.D. 6.38" I.D. 4.00"
14,573.42'	0.50'	Crossover	O.D. 6.38" I.D. 4.20"
14,573.92'	7.42'	Seal Bore Extension	O.D. 5.02" I.D. 4.00"
14,578.39	0.98'	Mule Shoe Guide	O.D. 3.98" I.D. 2.75"
14,579.37	-	End of Tubing String	
14,581.34'	0.63'	Connector	O.D. 5.75" I.D. 4.20"
14,581.97	7.42	Seal Bore Extension	O.D. 5.02" I.D. 4.00"
14,589.39'	0.51'	Crossover	O.D. 5.75" I.D. 2.75"
14,589.90'	5.72'	Pup joint	
14,595.62'	0.95'	Otis Type "RN" Nipple	O.D. 4.26" I.D. 2.329"
14,596.57	0.78'	Wireline re-entry guide	O.D. 4.25" I.D. 2.55"

NOTE: Seals spaced 7.7' above packer
All depths measured from 27.8' above casing head flange.
All tubing and pup joints are 3½" O.D., 12.95 lb/ft. grade P-105 with Hydril PH-6 connections.

PERFORATIONS:
14,744' - 14,819'

PLUG BACK DEPTH 14,869'

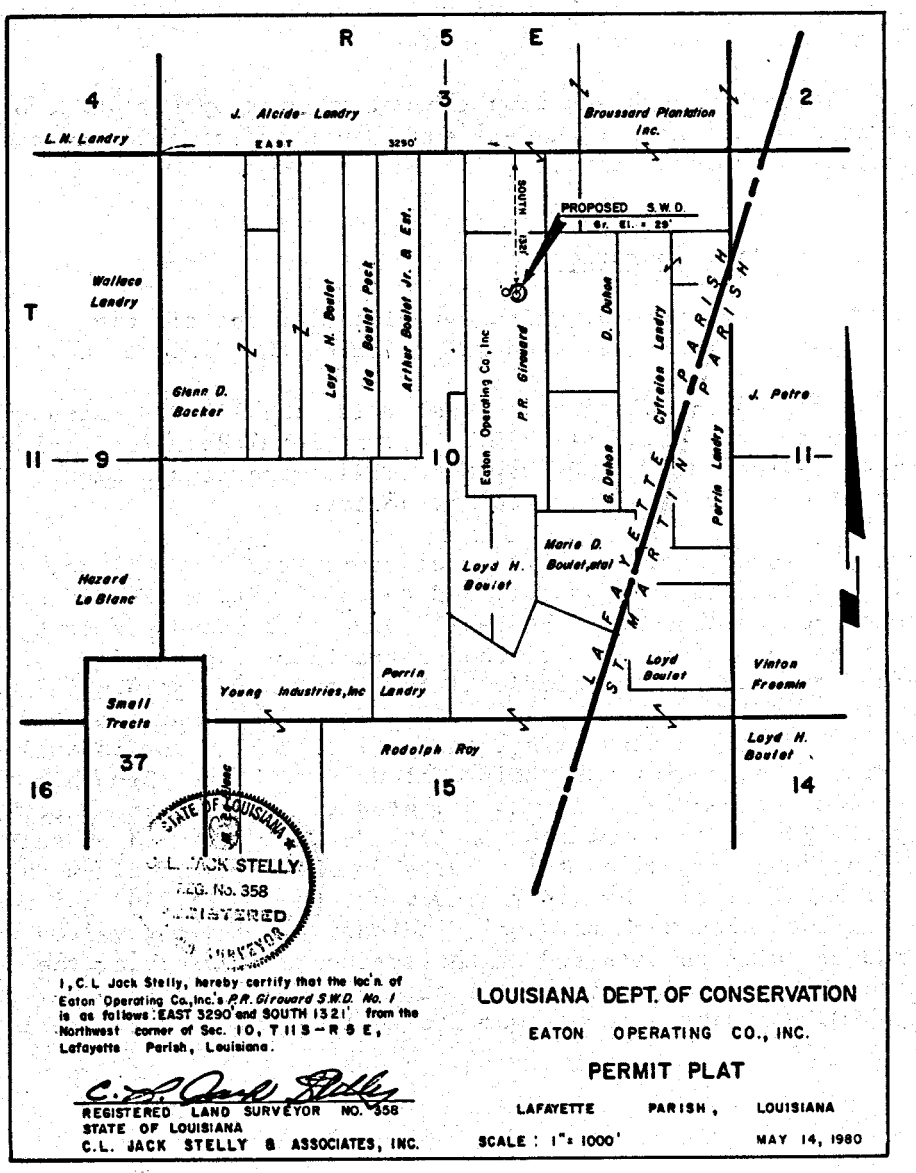
FIGURE 6-6

7.0 DRILLING AND COMPLETION OPERATIONS - DISPOSAL WELL

7.1 Location

The brine disposal well was located 110 feet southeast of the test well. Figure 7-1 is a surveyor's plat of the location.

FIGURE 7-1



7.2 Design Requirements

A brine disposal well was required for the test because of the large volumes of water produced. The primary design requirements for the well were the following:

- An injection capacity in excess of 15,000 barrels per day at an injection pressure not to exceed 500 psi.
- High temperature capability of up to 300°F.
- A minimum aquifer depth of 2500 feet, as specified by the Louisiana Department of Conservation for the area.
- Protection of fresh and brackish water sands by setting two complete strings of casing through all such sands and circulating cement to the surface on both strings.

7.3 Drilling Operations

The Mathieu Rig Number 16, which was also used for cleaning out and completing the test well, was selected for drilling the disposal well.

While the rig was completing the test well, the 14" O.D. structural casing was driven for the disposal well. International Hammers Service Company drove the casing, using a Delmag D-12 diesel-operated hammer. The final blow count was 130 blows per foot at 58 feet.

The rig was moved over the structural casing and the well was spudded on June 14, 1980. The well was drilled to 1544' with a 12-1/4" O.D. bit and 8.9 pound per gallon mud. The 9-5/8" O.D. 43.5 pound per foot, N-80 grade, LT&C casing was set at 1534'. One centralizer was installed six feet above the shoe, one each in the middle of the first three joints in the hole and one in the middle of the top joints. A down-jet float shoe was installed on the end of the casing string, and a float collar was installed two joints off bottom. The casing was reciprocated 1-1/2 hours through a ten foot stroke before cementing. It was cemented with a 12.8 pound per gallon lead slurry of 320 sacks of Halliburton Lite Wate cement with 3% salt, followed by a 15.6 pound per gallon tail slurry of 300 sacks of class "H" cement with 2% calcium chloride. The wiper plug was seated with 1400 psi pump pressure, which was then bled back to 0 psi, indicating the float valves were holding. Full mud circulation occurred at the surface while pumping the cement slurry. No cement returns were noted, however, so a top cement job was performed. A 1-1/4" O.D. tubing assembly was run to 120 feet between the 14" O.D. and

9-5/8" O.D. casing strings. The annulus was cemented with 50 sacks of class "H" cement with 2% calcium chloride. Another top job using the same volume was performed at 60 feet, because no cement returns were noted at the surface from the job at 120 feet.

The cement top was tagged at 10 feet in the annulus after allowing the slurry time to set. An 8½" hole was then drilled to 4,616 feet.

7.4 Selection of Disposal Zone

An induction electric log and a compensated density log were run in the hole from 4,513 to 1,518 feet. Analysis of the logs indicated that the following potential disposal sands had been penetrated:

Sand	Top	Bottom	Thickness	Average Porosity %
A	4,340'	4,420'	80'	39%
B	3,908'	4,020'	112'	43%
C	2,866'	3,010'	144'	37%
D	2,594'	2,772'	178'	37%

It was decided to complete the well in sand "A" and reserve the other sands for additional disposal capacity. Sand "C" was considered the best alternate disposal zone.

7.5 Completion Operations

A string of 5-1/2 inch. 15.5 pound per foot. grade K-55, ST&C casing was run in the hole to 4,607 feet. A down-jet float shoe was installed on the end of the casing string, and a float collar was placed two joints off bottom. Two centralizers were installed on each of the bottom two casing joints and one centralizer was installed on each of the next 74 joints. Halliburton cable type scratchers were placed at ten foot intervals from 4430 to 4330 feet and 4030 to 3920 feet. The casing assembly was reciprocated for one hour through a ten foot stroke before cementing. The casing string was cemented with a lead slurry of 1850 sacks of Halliburton Lite Wate cement followed by 500 sacks class "H" tail slurry. A total of 150 barrels of cement was circulated to the surface. The wiper plug was seated in the float collar with 2200 psi pump pressure.

A 6 inch by 10 inch tubing head was installed and tested to 2000 psi and after a 6 inch 5000 psi working pressure blowout preventer stack had been installed, a 4-3/4 inch O.D. bit was run to bottom on 2-7/8 inch O.D. drill pipe. The 9.0 pound per gallon mud in the well bore was displaced with 9.5 pound per gallon saltwater.

A gamma-ray, cement bond, and casing collar locator log was run from 4,513 to 2,513 feet. The log indicated good isolation of the disposal zones.

7.5.1 Attempt to Recover Fluid Sample

The 5-1/2 inch O.D. casing was perforated from 4,340 to 4,420 feet with four shots per foot.

An attempt was made to flow test the well to obtain an uncontaminated sample of saltwater from the disposal aquifer. A Halliburton RTTS packer was run on 2-7/8 inch O.D. drill pipe and set at 4,313 feet. The tubing volume was displaced with 14,636 cubic feet of nitrogen, and the packer circulating port was closed. The nitrogen pressure was bled off at the surface, but the well did not flow. By attempting reverse circulation up the drill pipe, it was determined that the drill pipe had plugged with formation sand. An attempt to wash out the well bore with nitrogen and foam resulted in further production of formation sand. At this point, it was decided to plug back to another saltwater sand. A Halliburton bridge plug was set on electric wireline at 4,220 feet, which was the top of the sand fill. The drill string was layed down, and the rig was released on July 3, 1980.

7.5.2 Perforation and Injectivity Tests

After the rig had been moved off location, the well was perforated from 2,870 to 3,000 feet with 3-1/8 inch casing guns, 4 holes per foot. Injectivity tests were performed during perforating gun runs.

Figure 7-2 is a graph illustrating injection rate versus number of perforations in the casing, at a constant injection pressure of 550 psi. Adding holes to the casing improved the injection rate, but the highest rate achieved was only 3,495 BWPD. An injectivity test was then performed at various injection pressures. The highest rate achieved was 6,545 BWPD at 800 psi. Figure 7-3 is a graph of injection rate versus injection pressure, before stimulation.

FIGURE 7-2

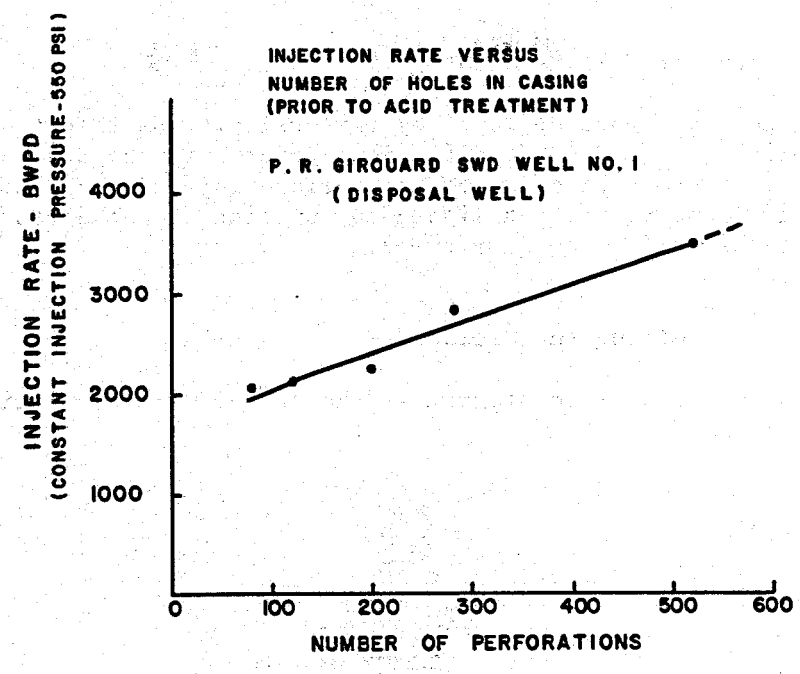
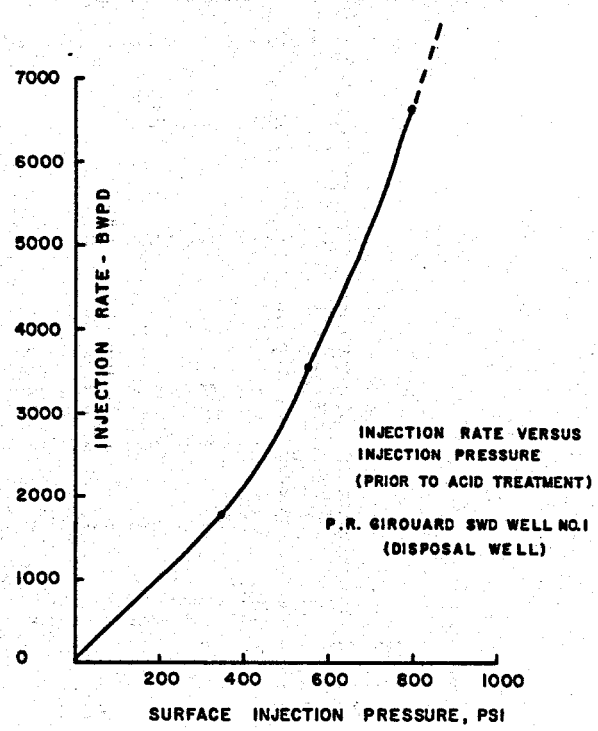


FIGURE 7-3



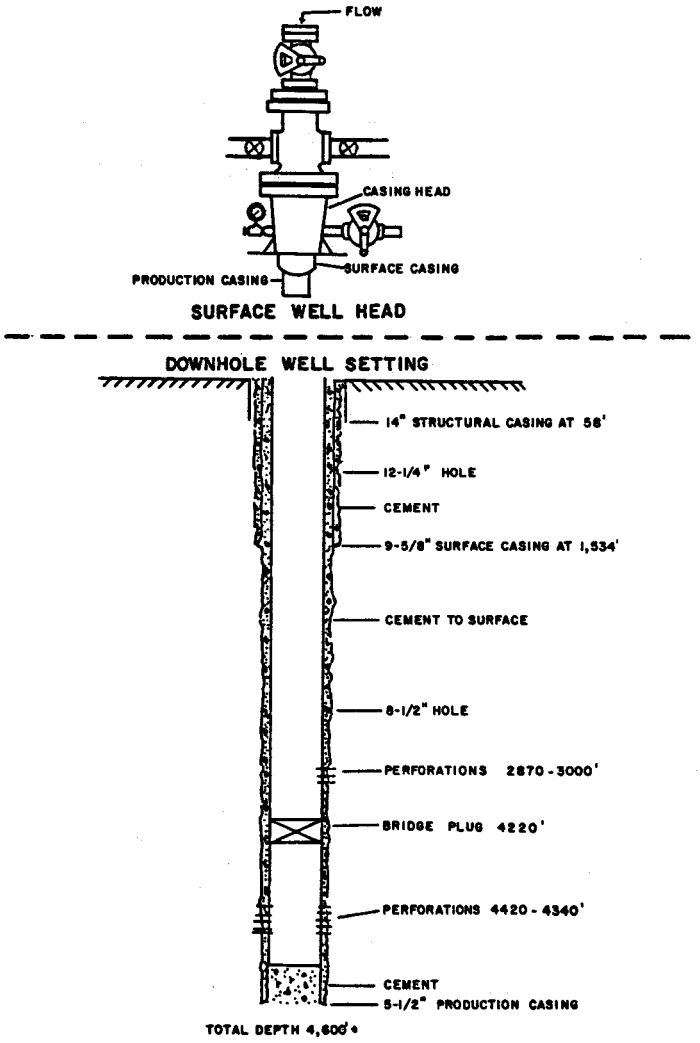
7.5.3 Disposal Well Stimulation

To stimulate acceptance of water by the well, it was then treated with 15,000 gallons of acid. After the acid treatment, the well accepted salt-water at 14,400 BWPD at only 200 psi surface injection pressure and was capable of accepting all anticipated production from the test well without the use of surface booster pumps.

7.5.4 Well Setting and Wellhead

Figure 7-4 is a schematic diagram of the actual well completion and the surface wellhead.

FIGURE 7-4



P.R. GIROUARD SWD WELL NO. I

8.0 TEST OBJECTIVES

The test equipment and procedures for the P. R. Girouard No. 1 were designed to obtain the maximum information within the time and funds allotted. Specific information desired was the following:

- Gas Content and Solubility
- Well Deliverability
- Formation Flow Capacity
- Aquifer Geometry
- Distance to Existing Boundaries
- Chemical Composition of Produced Fluids
- Physical Properties of Produced Fluids
- Performance of Downhole Equipment
- Performance of Surface Test Equipment
- Scaling and Corrosion Potential
- Formation Sand Production
- Disposal Well Injectivity

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9.0 SURFACE TESTING FACILITIES

9.1 Design Requirements

The test facilities were designed to produce and inject the well effluent continuously and to obtain data at points indicated on Figure 9-1. Design criteria were as follows:

- Wellhead Working Pressure — 10,000 psi
- Flow Line Shut In Pressure — 7,000 psi
- Temperature — 300°F
- Brine Flow Rate — 20,000 BPD
- Separator Operating Pressure — 1,200 psi
- Filter Operating Pressure — 600 psi

9.2 Main Process Equipment

Figure 9-1 is a diagram of the surface test equipment. The well stream entered the flow line at the point where the two flow loops connected. The flow rate, pressure, and temperature were measured ahead of the choke manifold. Well effluent samples were obtained from a sampling port ahead of the choke manifold. The sample port was positioned in the flow stream so that sampling could be performed at flowing wellhead pressure and before the scale inhibitor injection point. The main flow then passed through a choke manifold and through a data header. The data header incorporated a sonic sand detector and a scale-corrosion measuring coupon. The flow then entered a conventional horizontal well test separator. The gas was measured by an orifice meter and then flared. The separator brine passed through a flow meter manifold. Water samples were obtained at the flow meter manifold. The brine then passed through a 50 micron filter tower manifold before entering the disposal well. Pressure and temperature were measured at the disposal wellhead.

Reservoir Data Incorporated (RDI) provided a three-inch Camco turbine-type flow meter which was installed in the flow line close to the wellhead. This turbine meter was wired into the RDI digital recording instruments, so that fluid flow could be printed along with pressure and temperature data. The computer software for this meter failed to operate, however, and the fluid flow rate was not recorded during the test. Nevertheless, water flow was recorded by hand every 30 minutes at the water metering skid as the water passed through a Halliburton three-inch turbine meter.

SURFACE TEST SCHEMATIC

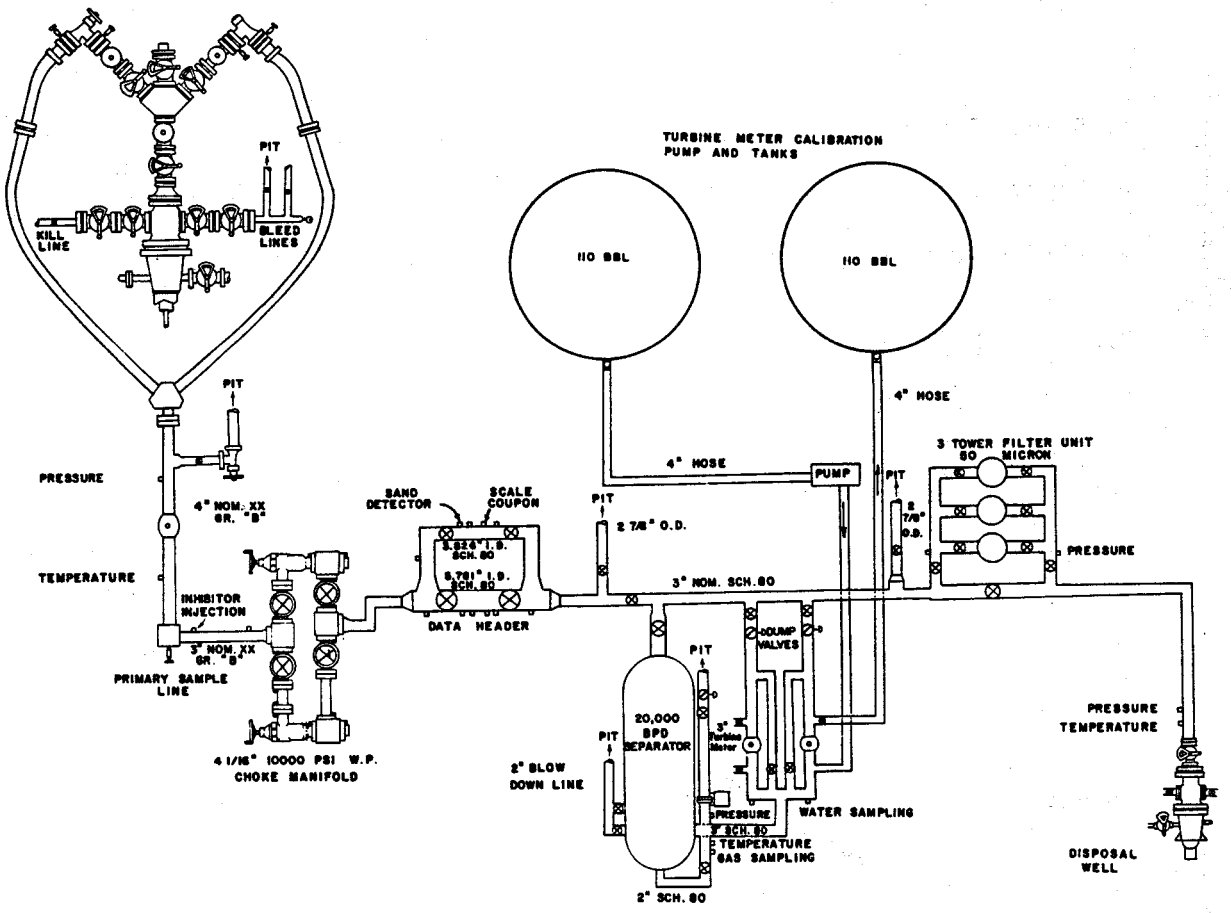

FIGURE 9-1

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Houston, Texas 77027
(713) 627-9764

9.3 Safety Considerations

The test well christmas tree was equipped with three fail-safe pneumatic safety gate valves. The valves were set to close if the flow line reached a low of 1000 psi, separator pressure reached a high of 1,200 psi, or the filter unit pressure reached a high of 600 psi. The pneumatic system could also be activated manually at a safe distance from the test well. The 9-5/8 inch casing pressure on the test well could be controlled in case of a tubing leak with two pressure-relief and choke lines to the pit and a kill line through which drilling mud could be pumped.

All test equipment was pressure-tested prior to flow. There were several relief and by-pass lines to the pit. The separator had a pressure-relief burst plate.

Caution signs were posted to warn visitors of the high pressure and high temperature pipes and vessels. Personnel were given safety instructions and were required to wear hard hats.

9.4 Data Gathering and Sampling Equipment

The following subcontractors participated in developing raw data relevant to deducing the quantity and properties of produced fluids:

- Institute of Gas Technology (IGT)
- Reservoir Data, Inc. (RDI)
- Weatherly Engineering.

Data recorded by each are described in the following sections.

9.4.1 Institute of Gas Technology Data Recording

IGT was responsible for the majority of data collection and interpretation concerning the quantity and properties of produced fluids. The channels of real time data recorded by IGT are the following:

- Wellhead Temperature

Wellhead temperature was sensed by a Foxborough temperature transmitter installed in the high pressure line between the wellhead choke and the large manifold. Concern for possible sand erosion of the thermal well for this sensor led to mounting it in a tee above the high pressure line. Although

this was successful, recorded temperatures were consistently low by 20° to 30°F. This is believed to have been caused by the development of a gas bubble in the tee and cooling of the tee by radiation and convection to the atmosphere.

- Wellhead Pressure

A Statham-type wellhead pressure transducer was initially installed in the high pressure line between the wellhead choke and the large choke manifold. Although data from this sensor was continuously recorded, true wellhead pressure was measured only after moving the transducer to the wellhead, after the second flow test.

- Separator Pressure

Separator pressure was continuously recorded by a 0 to 2,000 psi Statham-type transducer installed on the flanged tap for the orifice meter.

- Orifice Meter Differential Pressure

This pressure was continuously recorded, using a Statham-type differential pressure transducer with a range of 0 to 400 inches of water.

- Gas Temperature

Gas temperature from a sensor in a thermal well approximately 3 feet downstream from the orifice meter was successfully recorded at all times during gas production using a Honeywell temperature transmitter with a range of 0° to 400°F.

- Brine Production

Starting with the second drawdown test, electrical pulses corresponding to increments of 0.1 barrel of brine production were electronically counted and digitally recorded by tapping signals from the brine turbine downstream from the separator. However, erroneous incremental jumps in recorded brine production of 10 to 30 barrels were experienced a few times each day. These increments were superposed upon a drift of about 1% from brine production rate deduced from manual recording or turbine counter data. Lack of an oscilloscope in the field precluded effective trouble-shooting. An oscilloscope could not be obtained before testing was complete. (One will be on hand for subsequent tests.)

- Disposal Well Injection Pressure

Data was recorded from a 0 to 2,000 psi Statham-type transducer during all periods of brine injection into the disposal well.

- Disposal Well Temperature

Data from a Foxborough 0° to 400°F temperature transmitter was successfully recorded during the first drawdown test. This data channel was abandoned when one of IGT's three temperature transmitters was damaged during a calibration check between the first and second drawdown test.

During the first drawdown test (July 22-23, 1980) data recording by IGT was by strip chart recorders only. By the beginning of the second drawdown test (July 29, 1980), sufficient equipment had arrived, and the necessary software had been written, to accomplish digital recording of all data channels discussed above. Digitizing of the analog pressure and temperature data was accomplished by using a single analog digital converter plus electronic switching. Production data was recorded by electronic counting of pulses corresponding to increments of 0.1 barrel of brine production.

Control software provided for scanning all analog channels every 5 seconds. Values measured each 5 seconds were then averaged linearly over operator-selected time intervals for data recording. Time intervals for permanent records varies from 10 seconds at the beginning of each test up to as long as 15 minutes during long-term stable production. Cumulative counts from the brine turbine were recorded at the time of each permanent record. Permanent records were produced both by real-time printouts and by scoring digital data on magnetic tapes. A backup strip chart recording of all analog channels was continued throughout the test.

9.4.2 Wireline Company Recording (Reservoir Data, Inc.)

RDI was responsible for data recording for analysis of reservoir behavior. The data sensing and recording by RDI consisted of the following:

- Pre-production Temperature Gradient

Temperature was measured at depth increments of 1000 feet and at the 14,644 foot gauge datum 100 feet above the top of the perforations. The temperature sensor was a thermistor-type Gearhart-Owens 1-7/16 inch differential temperature tool. Temperature digitally displayed at the surface was logged by hand.

- Pre-production Pressure Gradient

Pressure from a Hewlett-Packard downhole pressure gauge was recorded digitally at depth increments of 1000 feet down to 13,000 feet and at the 14,644 foot gauge datum, 100 feet above the top of the perforations.

- Bottom Hole Pressure

During the first flow and buildup tests, pressure at the 14,644 gauge datum was sensed with a Hewlett-Packard pressure sensor.

- Wellhead (Tubing) Pressure

Wellhead pressure during all four instrumented flow and buildup tests was sensed using a Panex quartz crystal pressure sensor.

- Wellhead Brine Production Rate

The production rate upstream of the large choke manifold was measured while adjusting the choke by use of a Camco 3-inch turbine meter and portable display. Digital recording of turbine meter output was not accomplished during the test.

With the exception of temperature, all RDI data were recorded on a common digital system that provided both real time printout at selected time increments and magnetic tape recordings during those times when bottom hole pressures were being recorded. The time increments for surface pressure recording were those dictated by reservoir data interpretation. Recording time increments were generally 10 seconds at the beginning of drawdown or buildup tests and were increased by steps to a maximum of 5 minutes as each drawdown or buildup test continued. Data from the Panex wellhead pressure gauge were successfully recorded at all times when that gauge was in hydraulic communication with wellhead pressure.

Recording of data from the high-pressure turbine meter was not successful during the test of this well. It is doubtful whether this data would have contributed significantly to the interpretation, because the pressure was substantially below wellhead pressure due to the necessity for controlling production rate with the small wellhead choke rather than the large chokes on the choke manifold.

All RDI raw data are presented in Volume 2.

9.4.3 Surface Well Testing Company (Weatherly Engineering)

Weatherly Engineering provided continuous recording of the following four channels of data:

- Separator Pressure

Separator pressure at the flange tap for the orifice meter was recorded on a 24-hour circular chart with a pressure range of 0 to 1500 psi.

- Orifice Meter Differential Pressure

Orifice meter differential pressure was recorded by a second pen on the same 24-hour circular chart for a differential pressure range of 0 to 100 inches of water.

- Gas Temperature

Gas temperature downstream of the orifice meter was recorded by a third pen on the same circular chart with a temperature range of 0° to 400°F.

- Sand Detection

The strip chart recorder on an OIC Sand Systems, Inc. sonic sand detector provided a continuous record of sand detector output at all times during brine production.

Weatherly Engineering personnel also provided around-the-clock manual data logging of the following parameters on time increments of 1/2 hour, or of 1 hour during periods when incoming data was relatively constant:

- Separator pressure from the circular chart described above.

- Orifice differential pressure from the circular chart described above.

- Orifice differential pressure trends in gas production calculated manually by multiplying the square root of the product of separator pressure and differential pressure by an orifice factor characteristic of 0.6 gravity gas at standard temperature and pressure.

- Temperature from a thermometer installed between the large choke manifold and the separator.

- Cumulative brine production from the counter on the brine turbine operating at separator pressure.

- Calculated brine production rate and gas-to-brine ratio derived from the difference in cumulative brine production at successive data logging times and the gas production estimate described above.

- Differential pressure across the filters between the separator and the disposal well.

- Disposal well brine temperature as revealed by a thermometer installed in a thermal well on the disposal wellhead.

- Disposal well pressure as indicated on a dial gauge installed on the disposal wellhead.

The raw data logged manually by Weatherly Engineering is presented in Appendix "E". The calculated values for gas production, brine production, and gas/water ratio in Appendix "E" differ from those logged manually in the field. This difference is caused by including gas temperature and composition in orifice interpretation and correcting brine flow rate to reflect brine volume at a temperature of 60°F.

10.0 PRE-TEST OPERATIONS

10.1 Completion and Well Bore Cleaning

The well was completed in the Oligocene Marginulina Textularia No. 1 sand. The completion interval was first perforated on June 8, 1980, with the drilling mud displaced with 9.0 pound per gallon brine water. The first perforating was conducted with a 1,500 psi pressure differential between the formation and the well bore in 7-5/8 inch casing. A 40-foot through-tubing perforating gun was used to perforate from 14,778 feet to 14,798 feet and 14,799 feet to 14,819 feet with 4 shots per foot. When the first perforating gun fired, a 1500 psi increase on the surface was noticed almost instantaneously. Perforating thereafter was performed with a balanced pressure between the formation and the well bore.

After perforating the interval 14,778 feet to 14,798 feet with 4 shots per foot, the well was allowed to flow about 8 barrels of formation fluid prior to the remainder of perforating. The perforating gun was then run to increase the number of perforations in the above intervals to 8 per foot. Two additional guns were then run to perforate the interval between 14,744 feet and 14,778 feet with 8 shots per foot. The well produced a total of 150 barrels of formation water on June 9, 1980, in the process of cleaning out perforating debris and drilling mud.

Two additional production periods were recorded. On July 15th, about 375 barrels of reservoir fluid were produced to clean the well. On July 17th about 1,100 barrels of reservoir fluid were produced at a rate of about 6000 barrels per day. The latter 4.5-hour flow test was to test surface operational equipment.

10.2 Preliminary Well Bore Pressure and Temperature Recordings

The Hewlett-Packard quartz crystal surface recording pressure element and a Camco surface recording temperature gauge were used to measure static well bore temperatures and pressures. These instruments were run into the well bore and recorded pressure and temperature at 1,000-foot intervals.

Figures 10-1 and 10-2 are the measured well bore pressures and temperatures tabulated and graphically plotted as a function of well bore depth. This should represent the original formation pressure and temperature as well as furnishing data for calculation of original pressure and temperature gradients. The straight line extrapolation of these data points provides the gradient values to be used. The time required for stabilization of pressure and temperature readings varies with each instrument; therefore individual readings may be slightly in error.

The temperature plot for this well allows two straight lines in the extrapolation, indicating a change in temperature gradient at about 11,200 feet in depth. The temperature measured at 1000 feet is probably in error, since the temperature at this depth usually falls upon gradient line extrapolation. The extrapolation at zero depth is the normal mean ground temperature in the area.

The pressure plot should also depict a deviation in slope at the same depth as the temperature plot. This was not apparent from the data recorded. Temperature does effect liquid density in a normal "PVT" relationship, but in this case it was not recognized, and a temperature correction factor was not used to adjust the pressure readings.

The temperature gauge was removed from the well and only the pressure element was returned to the well bore for the production testing. Reservoir Data Incorporated also provided a three inch Camco turbine-type flow meter which was installed in the flow line close to the wellhead. This turbine meter was wired into the RDI digital recording instruments so that fluid flow could be printed along with pressure and temperature data. The computer software for this meter failed to operate, and the fluid flow rate was not recorded during the test. Water flow, however, was recorded by hand every 30 minutes at the water metering skid as the water passed through a Halliburton three-inch turbine meter.

FIGURE 10-1

P. R. Girouard Well No. 1

Static Pressure and Temperature Depth Measurement

Depth (feet)	Pressure (psia)	Temperature (°F)	Gradient (psi/ft)
0	6,685.64	85	0
1,000	7,141.82	91	.455
2,000	7,576.81	100	.435
3,000	8,022.63	111	.445
4,000	8,463.53	122	.440
5,000	8,909.12	137	.445
6,000	9,347.83	149	.438
7,000	9,789.92	161	.442
8,000	10,212.70	172	.422
9,000	10,675.94	183	.463
10,000	11,083.00	194	.407
11,000	11,506.66	209	.423
12,000	11,910.44	225	.403
13,000	12,347.45	241	.437
14,000	---	254	--
14,644	13,141.48	272	.482

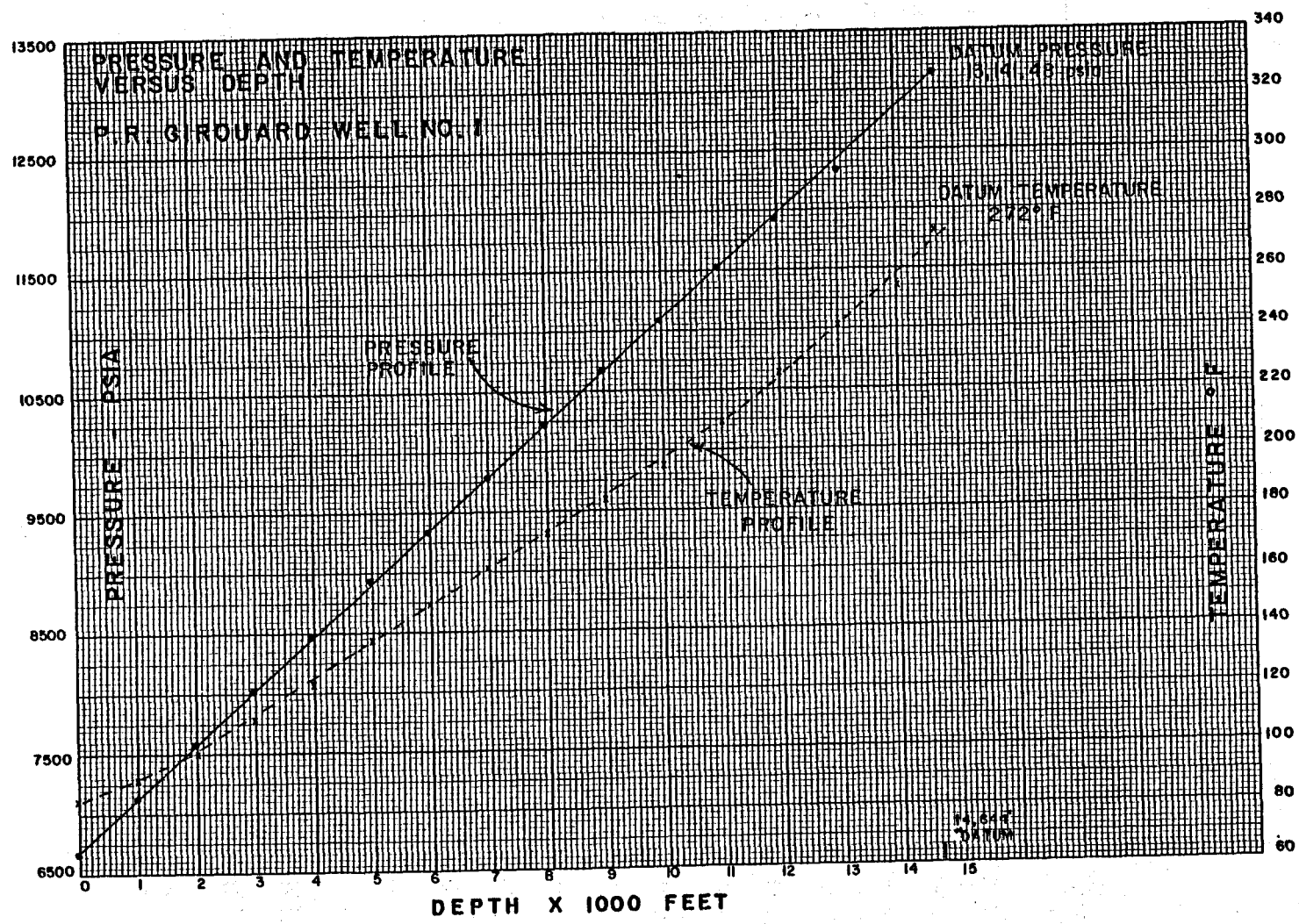

FIGURE 10-2

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Houston, Texas 77027
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DOE CONTRACT NO.
DE-AC08-80ET-27081

11.0 TEST PROCEDURE

The test procedure for the P. R. Girouard No. 1 Well included three preliminary flow periods to clean the hole and test the surface facilities. Following these preliminary flow periods, a sequence of flow and buildup tests was carried out to evaluate reservoir parameters, produced fluids, and flow characteristics.

11.1 First Flow Test

The initial reservoir pressure drawdown flow test lasted 1.01 days, during which 4,117 barrels of water were produced. The test provided early information to allow planning for the subsequent flow tests. During the flow period, the production increased from 3,688 to 4,344 BWPD at a constant choke setting.

11.2 Buildup Test

The first flow test was followed by a 2.18 day continuous reservoir buildup test. Two attempts were then made to obtain in situ samples of reservoir fluids. The bottom hole sampling operations are discussed in Section 12.6.4

11.3 Second Flow Test

The second reservoir pressure drawdown flow test lasted 1.36 days, during which 10,604 barrels of water were produced. The production rate averaged about 7,800 BWPD. The rate originally desired was 10,000 BWPD, but, because of a choke control problem and loss of wireline weight bars off the bottom hole pressure gauge, the rate actually obtained was lower. The loss of wireline weight caused concern that fluid passing the bottom hole instrument was pushing the tool up the hole. The test was terminated so that the Hewlett-Packard gauge could be removed from the well and higher flow rates could be achieved.

The second flow test generally supplemented the data obtained during the initial flow test. Formation sand production was observed during this test period.

11.4 Third Flow Test

The third flow test was performed to obtain flow characterisitcs and additional fluid properties. The bottom-hole pressure element was not in the well during this flow period. Pressures were recorded on the surface at the wellhead using the Panex gauge and were checked with a dead weight tester (DWT) for accuracy. The test was conducted over a period of 1.19 days, during which 13,727 barrels of water are produced. Flow rates in excess of 15,000 BWPD were reached, but fluctuations in separator dump valve operation prevented steady data readings. Sand production also occurred during this test. The flow period was discontinued so that the separator dump valve could be modified.

11.5 Fourth Flow Test

The well was flowed for 1.38 days after modification of the separator dump valve. A total of 9,664 barrels of water were produced during this test, which was conducted to gather reliable water and gas production data. Separator pressure was varied to investigate the effects of separator pressure upon the gas recovery. Formation sand production continued, and the test was discontinued because of concern about the sand production and filter plugging, and because sufficient production data had been obtained. Surface flowing pressures were recorded using the Panex pressure gauge and checked with the DWT.

11.6 Fifth Flow Test

The fifth flow test was conducted to physically measure formation sand production from the well and to compare the actual sand production to the sonic sand detector data. The test lasted 0.18 days, during which 2,193 barrels of water were produced. The highest flow rate achieved during this test was 18,460 BWPD. A total of 385 barrels of water were produced into two open steel tanks, and approximately 0.65 pounds of sand were recovered from the tanks. The sonic sand detector had registered production of 0.25 pounds of sand. Surface flowing pressures were recorded using the Panex pressure gauge and checked with the DWT. A detailed discussion of sand production can be found in Section 12.7.

12.0 TEST RESULTS AND ANALYSIS

12.1 Initial Drawdown Flow Test and Pressure Buildup Test

This test was originally designed as a well bore cleaning test and an early information test that would give sufficient data to allow a more thorough final testing procedure. The original plan was to open the well to a flowing rate of about 2400 BWPD by gradually opening the production choke over a two-minute period. The choke design made this plan difficult, and a flow rate of 3866.4 BWPD was obtained as a starting flow rate, after about nine minutes of trying to control the production rate with the choke. Once this rate had been established, it was decided to continue the 24-hour flow test. The pressure drawdown readings on the Hewlett-Packard printed tape were very smooth, indicating a reliable test in progress. It was obvious that any additional minor movement of the adjustable choke mechanism would cause major changes in producing rate.

The production rate established was not constant at the choke setting, but registered a uniform increase from 3866.4 BWPD to a final rate of 4344 BWPD at the end of the 24-hour flow period. There were no indications of any sand production during this flow period. The metered cumulative water produced during this test was 4,117 barrels at separator temperature and pressure. The gas in solution measured approximately 40 cubic feet of gas per barrel of water. The separator gas flared contained about 6.4% CO_2. The gas gravity was 0.63, and the heating value on an average daily basis was approximately 965 Btu per standard cubic foot.

A Hewlett-Packard surface-recording bottom hole pressure gauge was used for all bottom hole pressure measurements. A deadweight tester and a Panex recording pressure gauge were used for all wellhead pressure measurements. The bottom hole pressure element was set at 14,644 feet in the casing, 100 feet above the top of perforations. This placement was to eliminate possible "bird caging" of the wireline cable that might occur from fluid turbulence in the perforated interval.

The initial bottom hole pressure was 13,141.67 psia at gauge datum; this was corrected to 13,202.62 psia for a datum of 14,781.5 feet or midpoint of the perforated interval. The temperature measured at instrument datum was 272°F, which corrected to 274° at midpoint of the perforations. All measured pressures discussed in this report will be those measured at the instrument datum, since all interpretations for reservoir flow problems are determined from the rate of pressure change.

The rate of pressure drawdown at the sand face of the reservoir is depicted on Figure 12-1. This is represented on a semilog graphical plot of bottom

hole pressure drawdown versus the logarithm of time in days. Also plotted on this graph is the pressure buildup information that was obtained following the initial flow period of 1.0098 days. Figure 12-2 is the same pressure data that was recorded on tape and mechanically plotted by computer during this test period. Figure 12-3 is an enlargement of the graph to allow interpretation of pressure trends during the first 2½ hours of the flow period.

The plotting of pressure drawdown and the following pressure buildup on the same graph is for the purpose of qualifying the data obtained, since one should be the mirror image of the other if the test is properly conducted. Figure 12-4 is the semilog computer-plotted graph of the surface pressure during the flow test and the buildup test. The general shape of the plot is similar to bottom hole pressure, Figure 12-2, but the rate of change is very inconsistent. (Note: Figure 12-2 in hours, 12-4 in days.)

The time required to completely shut the well in was about 3 minutes. The pressure element continued measurement of the buildup pressure for 2.177 days and was removed to start bottom hole sampling. The bottom hole pressure at the time the element was removed was 13,015.43 psia or 126.24 psi below the original measured pressure. Details of this pressure data are contained in Appendix E, Volume II.

During the sampling period, the well was allowed to flow about 5 barrels of reservoir fluid just prior to obtaining the bottom hole sample. In general, the well can be considered to have been shut-in until the pressure element was run back to datum depth to start the second flow test. The final buildup pressure was measured after 6.0972 days of shut-in time and was recorded as 13,111.21 psia. This is 30.64 psi below the original pressure of 13,141.67 psia measured at instrument datum. The depth measurement was made on a new wireline and might not be at the exact depth at which recordings were made with the previous instrument.

Reservoir Data, Inc. had been unable to run the original cable back into the well for bottom hole sampling. Two new wireline units were sent to the location to ensure continuation into the second phase of testing. The original cable was later examined thoroughly and was found to be badly worn, with several strands broken and frayed. This had prevented the cable from going through the close-fitting lubricator tubes. During the interim, GO, Inc. furnished a mast truck and wireline unit for two runs of their bottom hole sampler.

The interpretation of this first flow test indicated the well was flowing from a very restricted flow area around the well bore. The reservoir

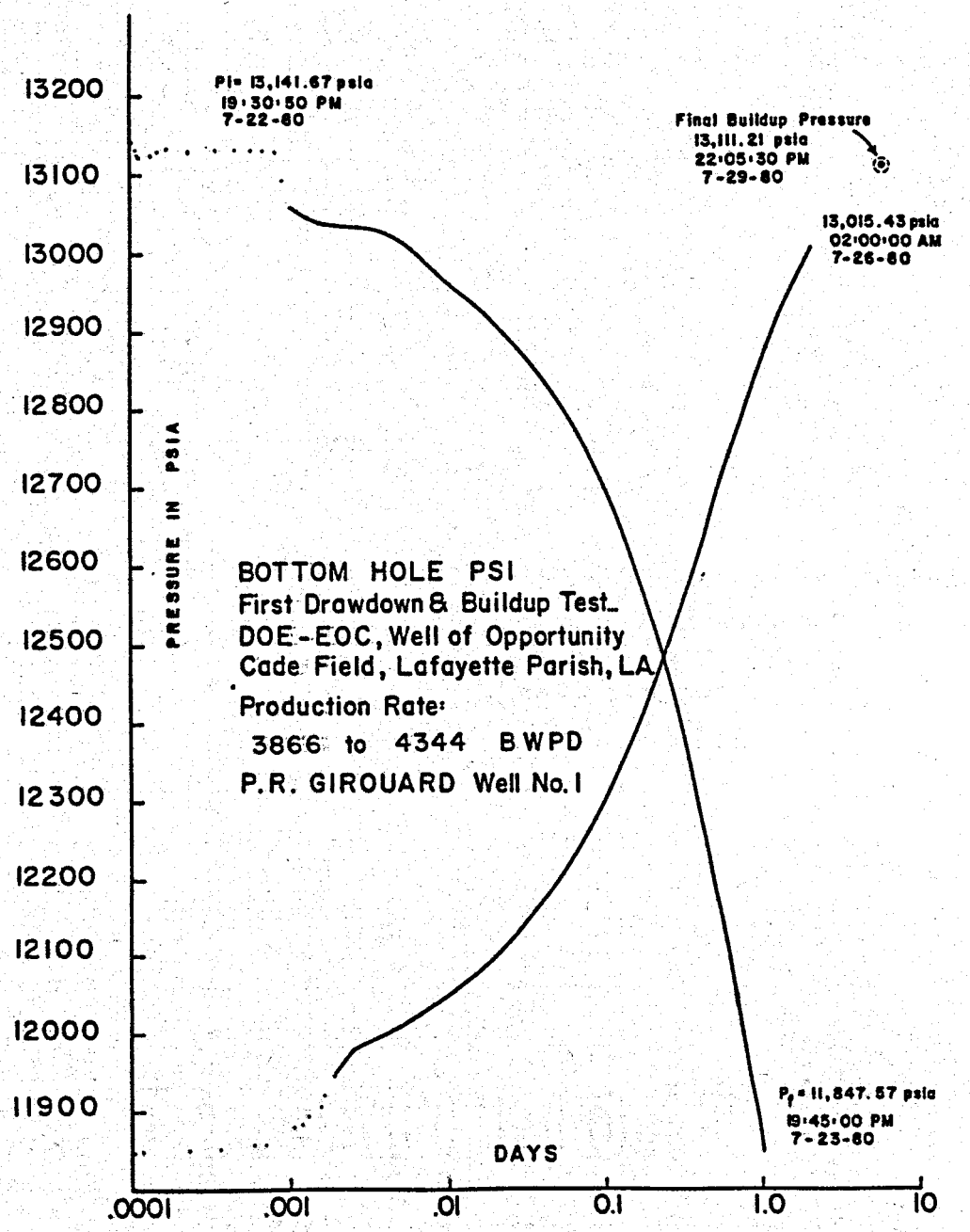
13200
13100
13000
12900
12800
12700
12600
12500
12400
12300
12200
12100
12000
11900
PRESSURE IN PSIA
Pi= 13,141.67 psia
19:30:50 PM
7-22-60
Final Buildup Pressure
13,111.21 psia
22:05:30 PM
7-29-80
13,015.43 psia
02:00:00 AM
7-26-60
BOTTOM HOLE PSI
First Drawdown & Buildup Test
DOE-EOC, Well of Opportunity
Cade Field, Lafayette Parish, LA
Production Rate:
3866 to 4344 BWPD
P.R. GIROUARD Well No. I
Pf = 11,847.57 psia
19:45:00 PM
7-23-60
DAYS
.0001
.001
.01
0.1
1.0
10

FIGURE 12-1

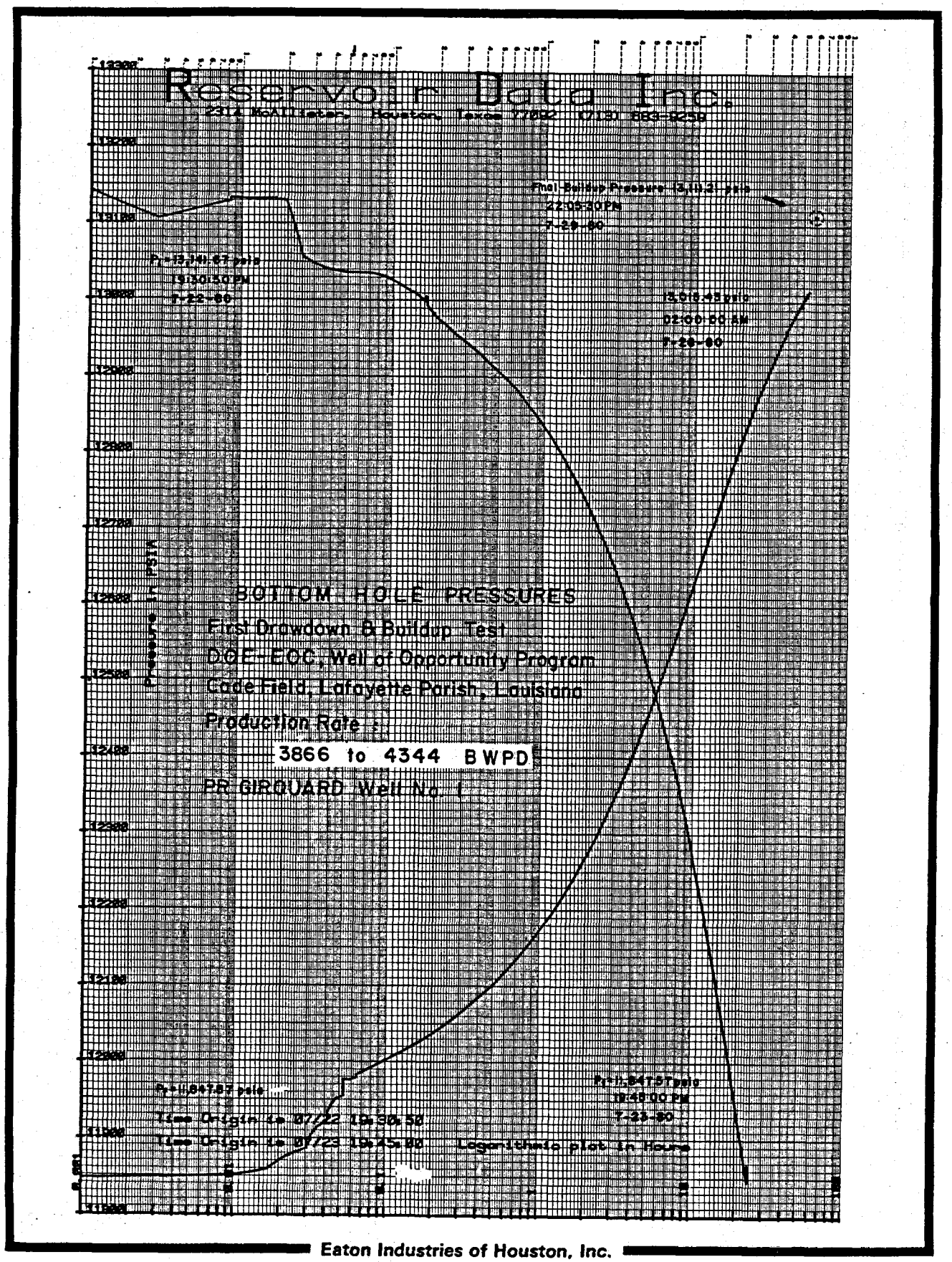

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FIGURE 12-2

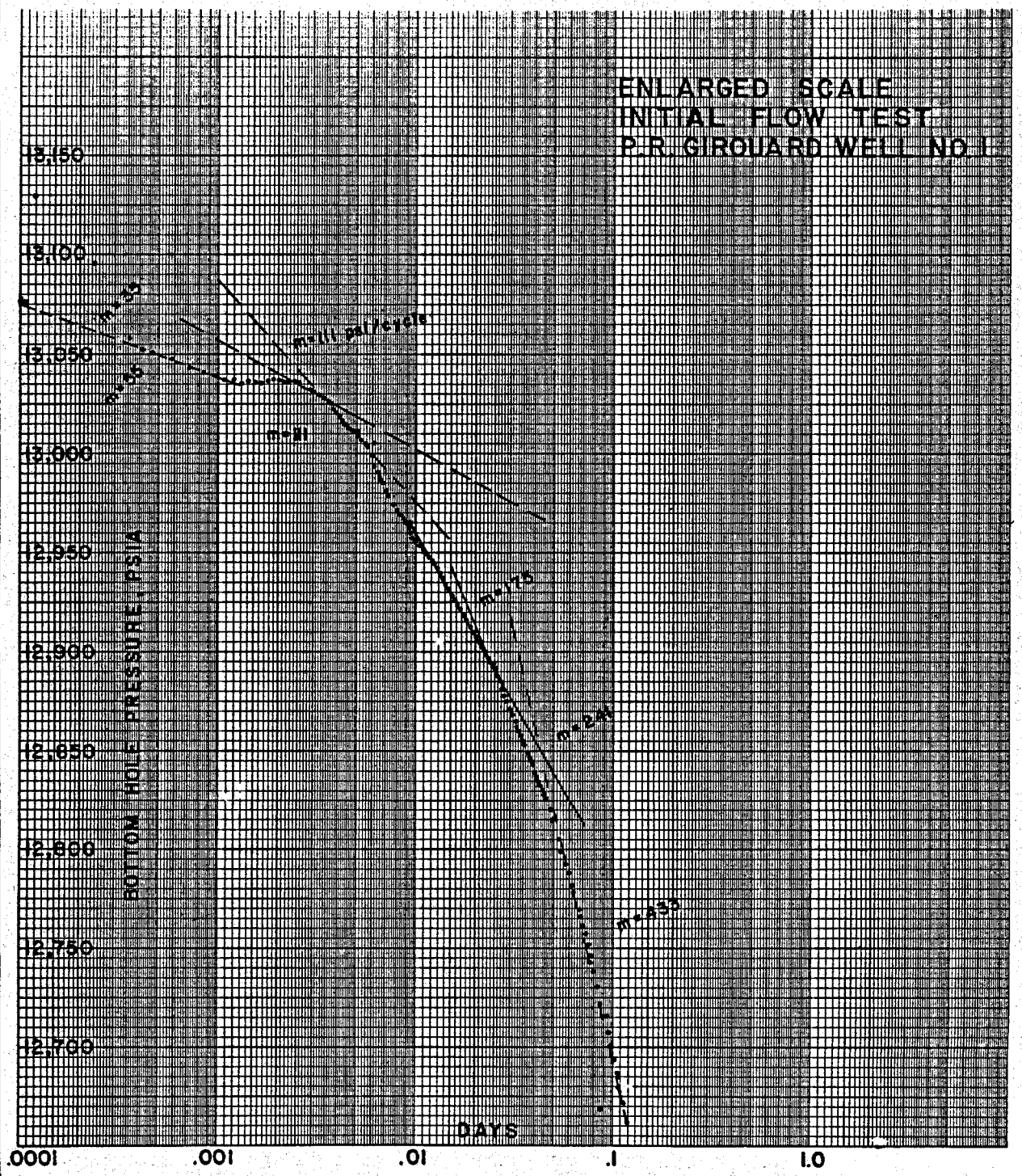

FIGURE 12-3

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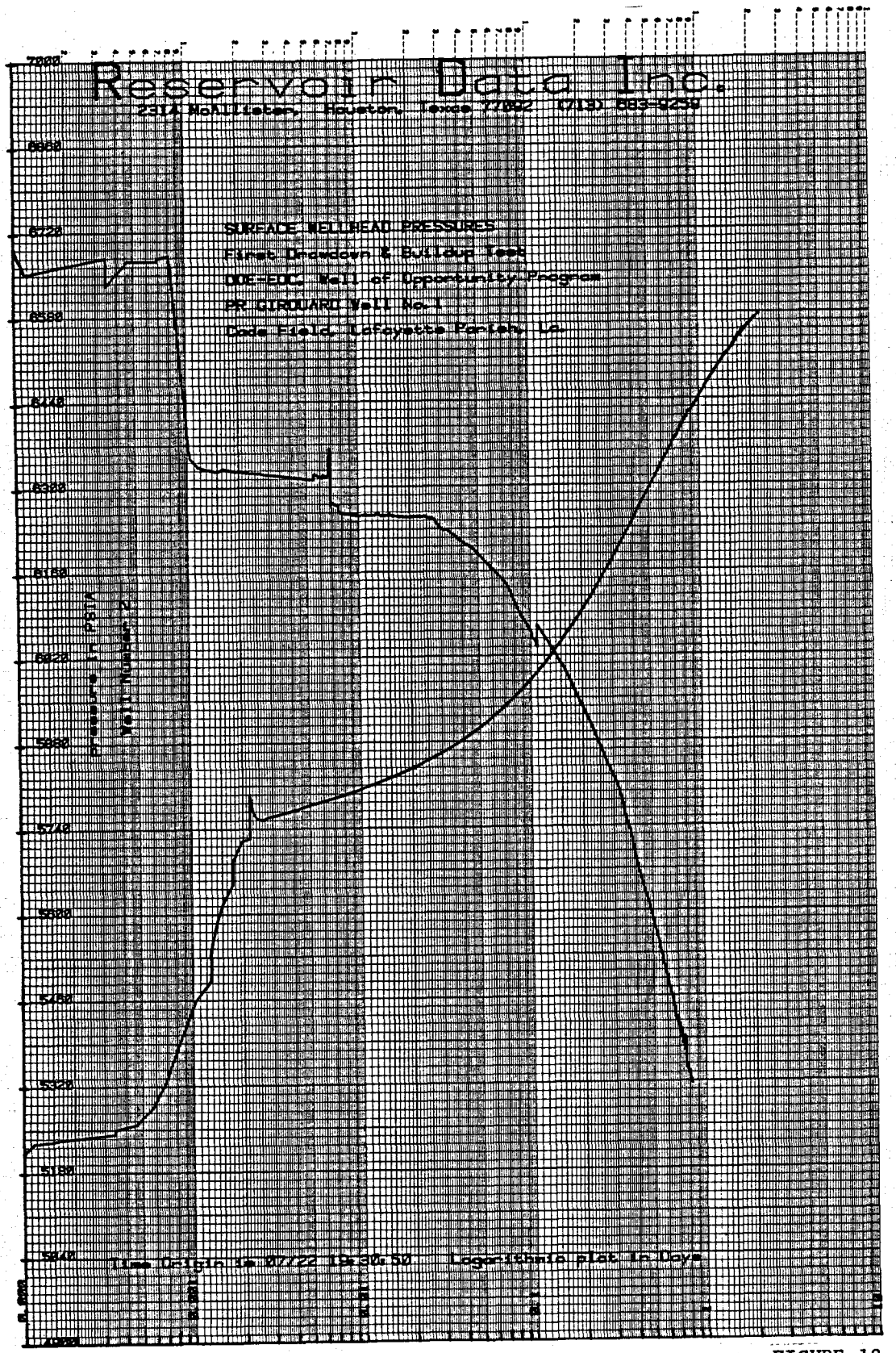
Reservoir Data Inc.
2317 McAllister, Houston, Texas 77002 (713) 883-9259
SURFACE WELLHEAD PRESSURES
First Drawdown & Buildup Test
DOE-EDC Well of Opportunity Program
PR GIROUARD Well No. 1
Dade Field, Lafayette Parish, La.
Pressure, PSIA
Well Number 2
Time Origin is 07/22 19:00:50
Logarithmic Plot, In Days

FIGURE 12-4

interpretation was that of a completion in one end of a lenticular type sand with permeability pinchout. This also meant the sand around the completion area was variable in net effective sand thickness. Therefore no radial flow slope was possible and a true Kh value could not be accurately determined.

Figures 12-5 and 12-6 are the calculation data sheets prepared for this interpretation. The data sheets assume that 91 net feet of pay (75 feet of perforations) contributed to this initial flow rate. The compressibility of water and the water formation volume factor was calculated from the Reservoir Fluid Analysis prepared by Weatherly Laboratories, Inc., dated August 20, 1980. The water formation volume factor calculated for 13,203 psia and 274°F reservoir conditions for an undersaturated brine was 1.0455 Bw and 3.202×10^{-6} for water compressibility. The first detectable slope occurred before a constant rate of flow had been established with the type of adjustable choke used. The value of 55 psi per cycle was used in this calculation for example purpose. Note a calculated value of 2470.4 md-ft and 27.1 mds. permeability. The resultant skin factor was -3.158, which is impossible considering the manner of completion for this well.

A drawdown slope between 20 and 25 psi per cycle is needed to gain a zero skin factor. These slopes would correspond to permeability between 200 and 240 mds. These values would allow a skin value of about -0.7 and +0.5. Experience has shown this is about the order of magnitude of permeability to allow such a high production rate with such low pressure loss during the first 4 minutes of flow. In other words, permeability of some 200 mds is the order of magnitude expected to meet conditions seen in this flow test. Permeability is one of the key functions used in determining distance to barriers; therefore these calculations are for use in approximation only. The slopes of drawdown read during the final flow period are realistic for the fluid expansion seen. Figure 12-7 is a plot of the calculation of the rate of aquifer drawdown, "Y", in psi per day per reservoir barrel of water. After flow time of 0.4 of a day, or 9.6 hours, these points are close to the 45 degree straight line plot developed by using a drawdown slope of 1100 psi per cycle. The calculations assume rates constant for every 30-minute period that production rates were reported. The corresponding water explored as a function of a flow time is correlated on the right side of the graph.

Pore volume calculations were attempted using reservoir geometry and acreage factors needed to meet the explored water depicted on Figure 12-7. A very restricted area of flow around the well was required to meet the geometry. In other words, a flow angle of less than 50 degrees and net pay much less than that previously estimated from the log of the well are required.

FIGURE 12-5

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST

FOR

GEOTHERMAL-GEOPRESSURED WELL

Test date: 7/22-23/80 Type Test: First Drawdown Lease and Well No. P. R. Girouard No. 1

Producing Formation: Oligocene-Marg.Tex.No. 1 Field: Cade (Lafayette Parish)

Hole size: 8-1/2" Casing Size: 7-5/8" Tubing Size: 3-1/2" State: Louisiana

Cumulative Production: 1625 Start / 5742 End Gas Gravity: 0.625 Z: 1.59

Constant Rate Production: 3806-4344 (bbls/day) Water Salinity: 22,500 PPM Total Solids

Total Production Life: 6.5 hrs.-1.27 days Porosity, ϕ: .26 Gas-Water Ratio: 37 ft^3/bbl

Reservoir Temperature: 274 °F Net Pay: 91e ft. Perforations: 14,744-14,819 ft

μg .039 cps μw .21e cps Bw 1.0455 R.B./B. Bg .4553 R.B./MCF

C_T 3.732 $X10^{-6}$ Cg ____ $X10^{-6}$ Cw 3.202 $X10^{-6}$ C_r .53 $X10^{-6}$

m 55 psi/cycle P at 1 hour: 12,969 Sg 0 Sw 1.00 Pi 13,203 psia

Pf ____ psia

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

kh = 162.6 (Q)(B)(μ)/(md)

kh = 162.2 (3806) (1.0455) (.21) / (55) = 2470.4 md-ft

k = (2470.4) md-ft / (91)ft = 27.1 mds

II. Bg = (Pb)(Tf)(Z)(1000)/(5.61)(520)(P_R) =

Bg = (15.025) (734) (1.59) .34279/(13,203) = .4553 Res. bbl/ MCF

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP skin

$$s = 1.151\left[\left(\frac{Pi - P_{1hr}}{m}\right) - \log\left(\frac{K}{\phi\mu C_t r_w^2}\right) + 3.23\right]$$

$$s = 1.151\left[\left(\frac{(13,142)-(12,969)}{(55)}\right) - \log\left(\frac{(27.1)\,10^6}{(.26)(.21)(3.732)(.101)}\right) + 3.23\right] = -3.158^*$$

ΔP skin = (0.87)(s)(m) = psi

ΔP skin = (0.87)(-3.158)(55) = -151 psi

* Negative skin shown 1st drawdown was not obtained, or less than 55.

IV. Diffusivity, η

η = .006328 (k) /$\phi\mu$ C_T =

η = .006328 (27.1) / (.26)(.21)(3.732)10^{-6} = 841,592 ft^2/day

η = .006328 (220) (.26)(.21)(3.732)10^{-6} = 6,832,110

$$Cw = \frac{Bsw-Bw}{Bsw(Pw-Psw)} = \frac{(1.0468-1.0456)}{1.0468(13,500-13,142)} = 3.202 \times 10^{-6} \text{ Bbl/Bbl. } \overline{\text{psi}} \text{ sat. water}$$

$$Bw @ 13,203 \text{ psia} = \frac{(3.202 \times 10^{-6})(1.0560)(13,203-10,090)}{1.0560-Bw} = 1.0455 @ 274^oF$$

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FIGURE 12-6

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST (CONT'D)

Test Date: 7/22-23/80 Type Test: First Drawdown Lease and Well No. P. R. Girouard No. 1

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

$$J\ (\text{actual}) = \frac{Qw}{P_i - P_f} = \frac{(\ 4117\ )1.0455}{(13{,}142 - 11{,}848)} = \underline{\ 3.326\ } \text{ bbls/D-psi}$$

$$J\ (\text{ideal}) = \frac{Qw}{(P_i - P_f) - \Delta P\ \text{skin}} = \frac{(\quad)}{(\quad - \quad)-(\quad)} = \underline{\qquad} \text{ bbls/D-psi}$$

$$CE = \frac{J\ (\text{actual})}{J\ (\text{ideal})} = \frac{(\quad)}{(\quad)} = \underline{\qquad} \quad \text{or} \quad \underline{\qquad}\ \%$$

Distance to Barriers or Discontinuities, d $\qquad d = 2\sqrt{t\eta}$

$d = 2\sqrt{(\ 841592\ )} \times \sqrt{t} = (\ 1834\ )\sqrt{t}$

time, days	t	d, ft.	(psi/cycle)	Flow Angle	Jones Y Function	Bbls of Aquifer Explored or Tested
.0023	.0480	88	55	360°	2.5723	0.116×10^6
.0035	.0592	109	111	360°	3.4115	0.088×10^6
.0060	.0774	142	175	228°	3.1374	0.095×10^6
.025	.1581	290	241	166°	1.0370	0.288×10^6
.051	.2258	414	433	92°	0.91328	0.327×10^6
.20	.4472	820	493	81°	0.26495	1.127×10^6
.30	.5477	1004	535	75°	0.19151	1.560×10^6
1.0098	1.0049	1843	1100	36°	0.11025	2.709×10^6

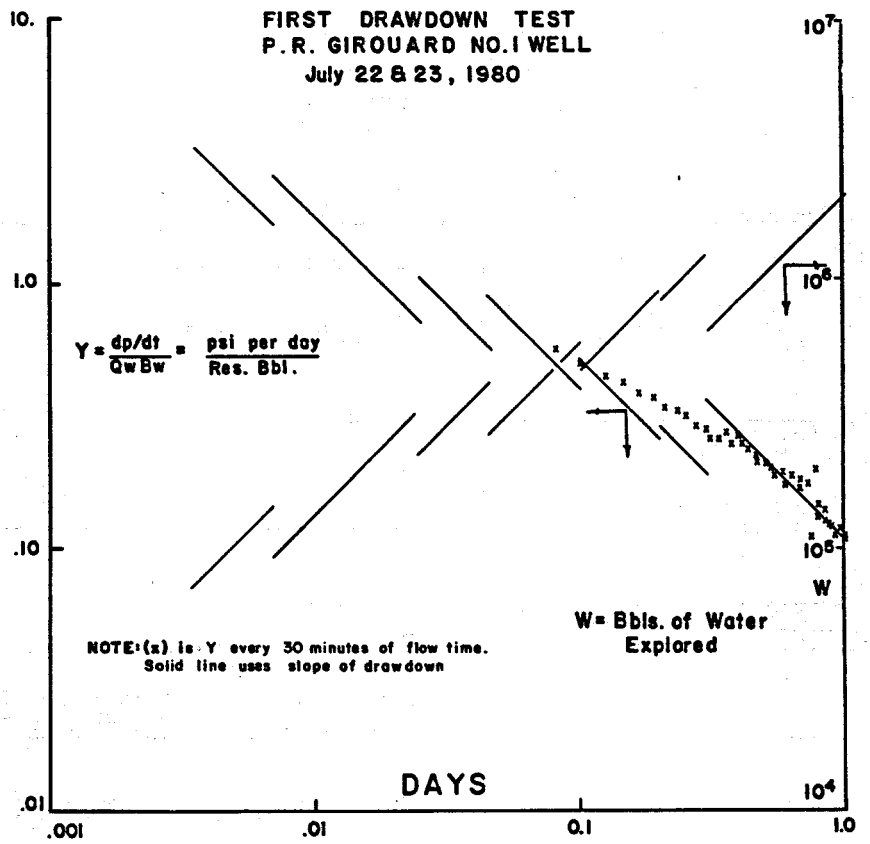
Opened well @ 19:30:50 PM on 7-22-80, closed well @ 19:45:00 PM on 7-23-80. Total flow time was 1454.67 minutes or 1.0098 days.

$Y = (1100)/(2.3)(4108.8)(1.0455)(1.0098) = .11025$ Res. Bbls. per day per psi.
$W = (1.0)/(1.0455)(3.202 \times 10^{-6})(.11025) = 2{,}709{,}344$ Bbls. of water explored.

Pore Volume Check

(7758 B/Ac.Ft.)(.26)/(1.0455) = 1929 Bbls. per acre - foot, water.
$(1843)^2\pi/(43{,}560) = 245$ acres; (245)(111/1100) = 24.7 acres
(24.7 Ac.)(1929 Bbls./Ac.Ft.)(91 Ft.) = 4,335,813 Bbls. (slightly high)
(24.7 Ac.)(1929 Bbls./Ac.Ft.)(56.8 Ft.) = 2,706,300 Bbls. (possible check)

FIGURE 12-7



The buildup test that followed the initial drawdown test developed the mirror-image configuration of the drawdown for the first 8 to 10 hours; then the slope curved to the right, as expected when the test is conducted following a drawdown test of one day. The plot does depict the same reservoir flow restriction around the well, as well as a relatively high value of permeability.

A sand interval having permeability barriers in the form of sands pinching out, possibly a sealing fault or two, and many other lithogical variations, presents problems for detailed interpretation. The general interpretation of close permeability barriers and extremely restricted flow areas is realistic. The capability of the well to produce at normally high rates for any extended period of time is highly unlikely.

To support the conclusion that barriers exist close to the well, Figure 12-8 details the pressures measured at 10-second intervals during the first 45 minutes of the buildup test. To completely shut the well in required about 3 minutes, or 0.00208 days on the log cycle graph. Note on

on Figure 12-8 that the first points fall on the solid straight line after this time. Note also that the measured pressure points fall on three distinct straight lines. Between .002 days and .0027 days (2.88 and 3.89 minutes) are four 10-second pressure points around the intersection of the dashed line and the first solid plotted straight line. The 3 slopes depicted on graph of 102, 147, and 212 psi per cycle respectively, when used in radial flow equations, would equate to negative skin effect. This would be true regardless of the amount of net effective sand applied to the flow equation. This indicates that there must be a permeability barrier prior to the 3.5 minute intersection depicted on this graph.

Therefore, theoretically, what condition could realistically be considered that would allow a zero skin effect? The thickness of effective pay must be reduced and permeability must be increased from that depicted on the drawdown calculations (Figures 12-1 and 12-2). The first perforations were made in an interval of 32 feet, with 1500 psig pressure differential between the formation and the well bore. The dashed line in Figure 12-8 crossing the first solid straight line at 0.0024 days, or about 3.5 minutes, is an estimated condition using 24 psi per cycle buildup slope, using 201.9 mds permeability, 32 feet of net effective sand, pressure at 1 hour on the slope of 12,010 psia, and a measured well flowing pressure of 11,848 psia.

These values were used mathematically as follows:

$$k = 162.6 \text{ QW Bw } \mu w/hm$$

$$201.9 = (162.6)(4344)(1.0455)(.21)/(32)(24)$$

$$\text{Skin} = 1.151\left[\frac{12{,}010-11{,}848}{24} - \log \frac{(201.9)(10^6)}{(.26)(.21)(3.732)(.1009)} + 3.23\right]$$

$$S = 1.151 \quad (6.750 - \log 9{,}819{,}986{,}143 + 3.23)$$

$$S = 1.151 \quad (6.750 - 9.992 + 3.23) = 1.151\ (-.012) = -.0138$$

(Details of the above calculations are included in Figures 12-9 and 12-10).

This is very close to zero skin effect and would meet the conditions depicted in the first drawdown and the mirror image buildup. The effective permeability of 201.9 mds would place the distance explored in .0243 days (3.5 minutes) at 247 feet from the well bore. The second intercept at .007 days would calculate a distance of 419 feet, and the third intercept at .0155 days (22.32 minutes) would be depicted at 623 feet from the well

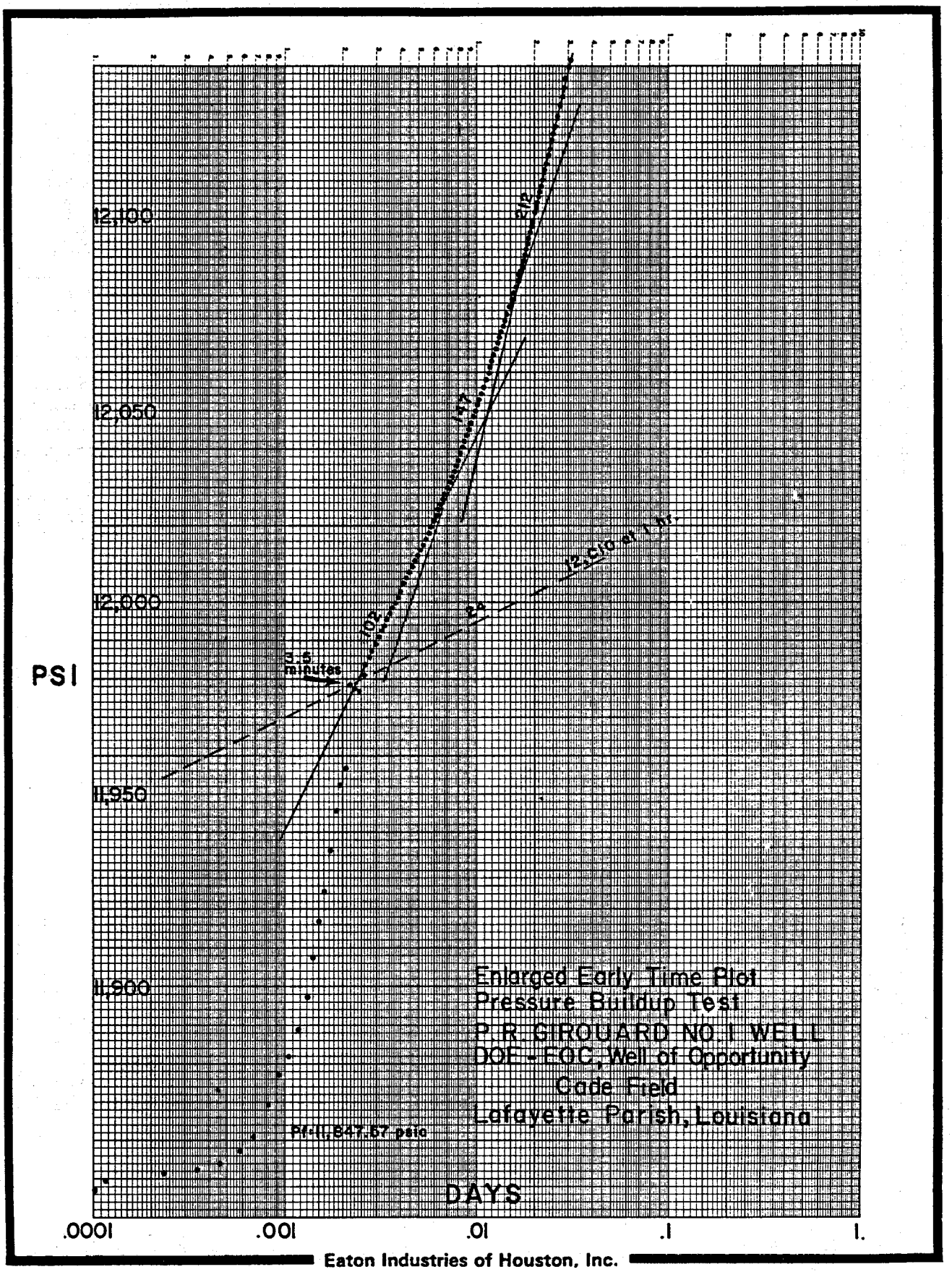


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FIGURE 12-8

FIGURE 12-9

RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST
FOR
GEOTHERMAL-GEOPRESSURED WELL

Test date: July 23, 1980 Type Test: Buildup Lease and Well No. P. R. Girouard No. 1
Producing Formation: Oligocene-Marg. Tex. No. 1 Field: Cade (Lafayette Parish)
Hole size: 8-1/2" Casing Size: 7-5/8" Tubing Size: 3-1/2" State: Louisiana
Cumulative Production: 5742 Bbls. Gas Gravity: 0.625 Z: 1.59
Constant Rate Production: 4344 (bbls/day) Water Salinity: 22,500 PPM Total Solids
Total Production Life: 1.27 days Porosity, ϕ: .26 Gas-Water Ratio: ±37 ft^3/bbl
Reservoir Temperature: 274 °F Net Pay: 32e ft. Perforations: 14,744-14,819 ft
μg .039 cps μw .21e cps Bw 1.0455 R.B./B. Bg .4553 R.B./MCF
C_T 3.732 $X10^{-6}$ Cg ____ $X10^{-6}$ Cw 3.202 $X10^{-6}$ C_r .53 $X10^{-6}$
m 24e psi/cycle P at 1 hour: 12,010e Sg ____ Sw 100% Pi 13,203 psia
p_f = 11,848 psia

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

kh = 162.6 (Q)(B)(μ)/(md)

kh = 162.2 (4344) (1.0455) (.21) / (24) = 6461.6 md-ft

k = (6461.6) md-ft / (32)ft = 201.9 mds

II. Bg = (Pb)(Tf)(Z)(1000)/(5.61)(520)(P_R) =

Bg = (15.025) (734) (1.59) .34279/(13,203) = .4553 Res. bbl/ MCF

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP skin

$$s = 1.151\left[\left(\frac{Pi - P_{1hr}}{m}\right) - \log\left(\frac{K}{\phi\mu C_t r_w^2}\right) + 3.23\right]$$

$$s = 1.151\left[\left(\frac{(12{,}010)-(11{,}848)}{(24)}\right) - \log\left(\frac{(201.9)\,10^6}{(.26)(.21)(3.732)(.1009)}\right) + 3.23\right] = -.0138$$

ΔP skin = (0.87)(s)(m) = psi

ΔP skin = (0.87)(-.0138)(24) = -.288 psi

IV. Diffusivity, η

η = .006328 (k) /$\phi\mu$ C_T =

η = .006328 (201.9) / (.26)(.21)(3.732)10^{-6} = 6,270,014 ft^2/day

S = 1.151(6.750 - log 9,819,986,143. + 3.23)
S = 1.151(6.750 - 9.992 + 3.23) = 1.151(-.012) = -.0138
Value close to zero skin.

$$\text{Slpe, } m = \frac{(162.6)(4344)(1.0455)(.21)}{(32)(201.9)} = 24 \text{ psi/cycle}$$

FIGURE 12-10

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST (CONT'D)

Test Date: July 23, 1980 Type Test: Buildup Lease and Well No. P. R. Girouard No. 1

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

$$J\ (\text{actual}) = \frac{Qw}{P_i - P_f} = \frac{(\quad)}{(\quad - \quad)} = \underline{\qquad\qquad} \text{ bbls/D-psi}$$

$$J\ (\text{ideal}) = \frac{Qw}{(P_i - P_f) - \Delta P\ \text{skin}} = \frac{(\quad)}{(\quad - \quad) - (\quad)} = \underline{\qquad\qquad} \text{ bbls/D-psi}$$

$$CE = \frac{J\ (\text{actual})}{J\ (\text{ideal})} = \frac{(\quad)}{(\quad)} = \underline{\qquad\qquad} \quad \text{or} \quad \underline{\qquad\qquad}\ \%$$

Distance to Barriers or Discontinuities, d $\qquad d = 2\sqrt{t\eta}$

$d = 2\sqrt{(\ 6270014\ )} \times \sqrt{t} = (\ 5008\ )\sqrt{t}$

time, days (3.5 min.)	t	d, ft.	(psi/cycle)	Flow Angle	Jones Y Function	Bbls of Aquifer Explored or Tested
.00243	.0493	247	24	360°	0.9455	0.316×10^6
.007	.0837	419	102	85°	1.3946	0.214×10^6
.0155	.1245	623	147	59°	0.90791	0.329×10^6
.021	.1449	762	212	41°	0.9664	0.309×10^6

Y = (24)/(2.3)(4344)(1.0455)(.00243) = .9455
W = (1.0)/(1.0455)(3.202×10^6)(.9455) = 316,000 Bbls.
$(762)^2\pi/(43{,}560)$ = 41.88 Ac.
(41.88 Ac.)(24/212) = 4.74 Ac. Effective Area
Y = (212)/(2.3)(4344)(1.0455)(.021) = .9664
W = (1.0)/(1.0455)(3.202×10^{-6})(.9664) = 309,000 Bbls. Explored
(309,000)/(1929 Bbls./Ac.Ft.)(4.74 Ac.) = 33.8 Ft. Net Sand Required.

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bore. Experience in interpreting reservoir limit tests in gas wells, having a much lower rate of fluid diffusivity or transmissability, concurs with the early conclusion arrived at from the original production drawdown plot. This example was used because the first pressure points, after the 3 minutes required to fully close in the well production, fell on a straight line extrapolation. The sensitivity built into the Hewlett-Packard pressure recording instrument allows this type of analysis.

The gross sand interval was estimated to have a total of 91 feet of permeable sand. The perforation interval covered only 75 feet of the total sand zone.

The data from the first drawdown test indicated the total net sand available was not contributing to the fluid flowing. The 32 net feet came from the first perforation of 32 feet made with 1500 psi differential pressure from formation to well bore. In the buildup test, using the data developed from the drawdown estimates, the net sand needed would be 33.8 feet. This is a proper order of magnitude to support the conclusions derived on the drawdown test.

In general, the conclusions that can be derived from the first production drawdown test, and confirmed by the subsequent buildup test, with the assumption of no skin effect, are the following:

1. Effective production capacity, or productivity, Kh, is approximately 6424 md.-ft.

2. Effective net sand is about 32 feet.

3. Effective permeability is about 202 mds.

4. Area explored in one day was about 25 acres.

5. Water explored in one day was 2.7 million barrels.

6. The well is completed in a lenticular-type sand with permeability pinchout. The well is flowing from a very restricted flow area in the updip structural portion of the reservoir.

7. The well is excellently located for a hydrocarbon producing well. The highly restricted flow area around the well would prevent the high rates of brine flow that would be required for geopressured-geothermal prospects.

12.2 Second Drawdown Flow Test

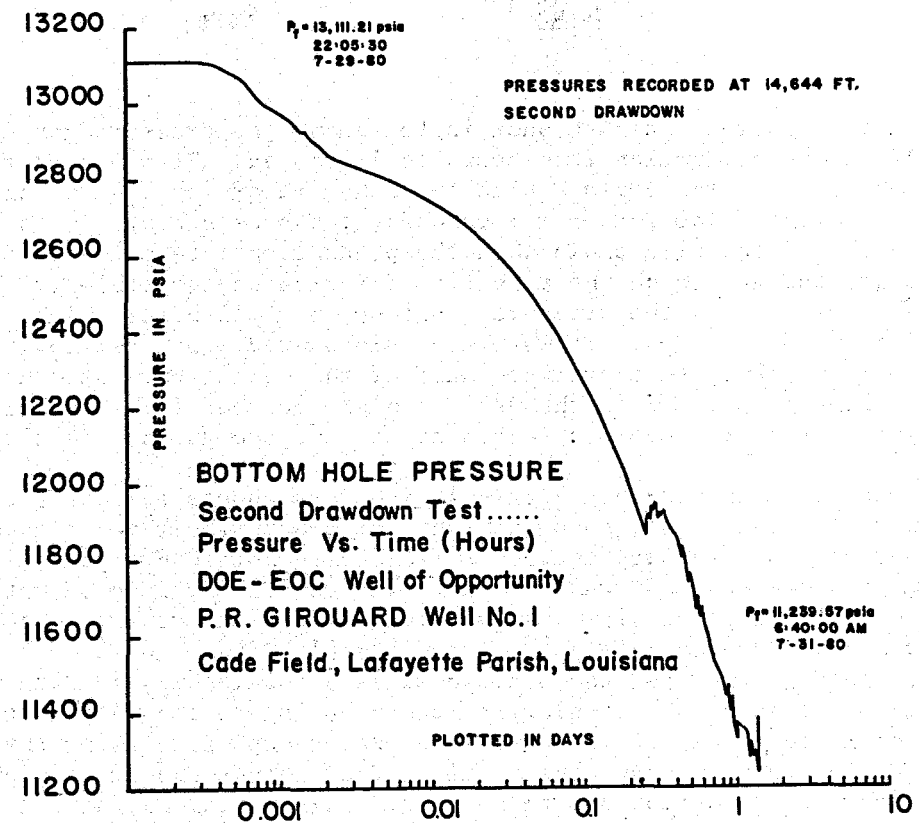
The second flow test was originally planned for a production rate of 5,000 BWPD. The data developed from the first 24-hour flow provided sufficient information to suggest modification of test procedures. The first test showed the reservoir sand pinching out close to the well bore and that the well could be opened much faster than originally planned. Controlling the choke to a prescribed rate was very difficult with the equipment on the well; therefore a revised plan was discussed and approved by all concerned.

The new plan was to attempt to open the choke within 20 to 30 seconds to permit a flow rate of around 10,000 BWPD, with a rate acceptable of 2,000 to 3,000 barrels per day above or below 10,000 BWPD. The plan was also to continue to draw the well bore pressure down without resorting to additional buildup tests. After 24 hours on flow, the rate was to be increased to the maximum safe limits of the production equipment, somewhere between 15,000 and 20,000 barrels per day.

The well and equipment were ready for the start of the test at 2205 hours on July 29, 1980. The surface pressure was 6666.12 psia, and the bottom hole pressure at 14,644 ft. was 13,111.21 psia. This was 28.53 psi below the initial surface pressure of 6694.65 psia and 30.46 psi below the initial bottom hole pressure of 13,141.67 psia, after six days of shut-in time.

The attempt to open the choke within 20 to 30 seconds was not successful. The rate of 6998.4 BWPD was established in about 3 minutes, and the choke was maintained in that position for the first 24 hours. The separator pressure was maintained at 250 psig, or the same as the previous test. The first part of this flow test saw a gradual increase in measured production rate to 7315.3 BWPD in 1.5 hours and then a gradual decrease to 6988.8 BWPD after the first 6 hours of the flow period. The flowing bottom hole pressure had dropped to 11,860.43 psia at 0415 on July 30th or 370 minutes into the second flow period. At this time, there was a sudden increase in bottom hole pressure to 11898.07 psia, and the grease seal in the lubricator broke loose temporarily. This pressure increase is depicted on Figure 12-11 at about 0.25 days on the time plot. This phenomenon continued for about 20 minutes and then continued to occur erratically on a mean decline slope at about 1270 psi per cycle. The previous decline slope was relatively smooth at 1010 psi per cycle. The sand detector indicated the passing of some debris for a short time after this phenomenon. This normally occurs when plugged perforations are opened and begin to flow for the first time.

FIGURE 12-11



Examination of production rates reported at 30 minute intervals did show a change following this probable opening of additional perforations. The production rate was declining from 7315.3 BWPD just prior to midnight to 6988.8 BWPD at 0400. At 0430, the rate averaged 7032 BWPD and then increased at a rate of about 155 barrels per hour for the next 3.5 hours. This is equivalent to 7531.2 BWPD. The drawdown slope increased from 1015 to 1270 psi per cycle. Therefore at least a portion of the increase in pressure decline rate could be from the production rate increase. The slope of 1270 psi per cycle should have been 1770 psi per cycle when compared to the slope from the initial flow test. The increase in net sand with the opening of additional perforations could have created sufficient decrease in flow slope to offset the additional major increase in slope expected from rate increase. The pressure data continued to fluctuate, and production of very fine sand was reflected on the sand detector throughout much of the remainder of this drawdown test. The pressure fluctuation is interpreted as being caused by cleaning of additional perforations with continuous pressure loss at the sand face.

The final production rate of the second test at 0645 hours on July 31, 1980 was measured by Weatherly Engineering as 8459.6 BWPD. The flowing pressure at datum depth was 11,241.52 psia, and the flowing tubing pressure was 3719.26 psia. The rate was cut back at this time to 1000 BWPD

for a few minutes and then shut in to remove the pressure gauge from the well, so the production rate could be increased. Pressure continued to be monitored on the surface with the Panex recording element and dead-weight tester. The reason for removing the pressure gauge was the loss of weight on the wire cable when the production rate exceeded 8500 BWPD. This was thought to be the result of friction on the cable from increased flow rates driving the pressure gauge up the well bore, which would invalidate its readings. It was later discovered, upon retrieving the pressure element, that over one half of the weight bars attached to the gauge had dropped off in the well. This accounted for the reduction in weight on the wire cable observed at the surface during the flow test.

Figures 12-12 and 12-13 are calculation data sheets for the second drawdown test. This test, being at a higher production rate, presented a higher rate of pressure decline. The same general interpretation drawn from the previous test was evident. The explored volume of water at the end of 1.357 days on flow was much larger than in the previous test. The increase was approximately 3 million barrels, for a total of 6.362 million. This would account for the additional sand volume exposed with the additional perforations opening and contributing to the flow test. In order to check the 6.362 million barrels of water explored, using the 1270 psi per cycle drawdown rate, the total 91 feet of net sand determined for the total sand section had to be used. This additional sand allowed a pore volume calculation of 4.599 million barrels of formation water, which is still less than the explored volume of aquifer. The addition of 28% more sand down dip of the well would suffice to equalize this difference. This would be a logical addition, since the sand section is depicted geologically to have considerable sand thickening down dip of the well location. In general, the second flow test supports the conclusion from the first flow test that only the lower portion of the zone, or the first perforated interval, was open to flow initially. The second test, at the higher rate, drew down the pressure sufficiently to open more of the sand interval to flow.

12.3 Third Flow Test

The third flow test began at 1115 hours on July 31, 1980, with the lubricator removed from the well and a Panex gauge attached to the flow line downstream from the adjustable choke on the christmas tree. The wellhead pressure, prior to opening the well at 1125, was 6255.58 psia. The choke was opened in steps over a two hour period until wellhead pressure was within 100 psi of the separator pressure. By 1330, a stable brine production rate of 15,566 BWPD was achieved at a separator pressure of 420 psi and a wellhead pressure of 490 psi.

FIGURE 12-12

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST

FOR

GEOTHERMAL-GEOPRESSURED WELL

Test date: 7/29,30,31/1980 Type Test: Second Drawdown Lease and Well No. P. R. Girouard No. 1

Producing Formation: Oligocene-Marg. Tex. No. 1 Field: Cade (Lafayette Parish)

Hole size: 8-1/2" Casing Size: 7-5/8" Tubing Size: 3-1/2" State: Louisiana

Cumulative Production: 30,073 Gas Gravity: 0.625 Z: 1.59

Constant Rate Production: 6998.4 (bbls/day) Water Salinity: 22,500 PPM Total Solids

Total Production Life: 2.8 days Porosity, ϕ: .26 Gas-Water Ratio: 37 ft^3/bbl

Reservoir Temperature: 274 °F Net Pay: 91 ft. Perforations: 14,744-14,819 ft

μg .039e cps μw .21 cps Bw 1.0455 R.B./B. Bg .4553 R.B./MCF

C_T 3.732 $X10^{-6}$ Cg ____ $X10^{-6}$ Cw 3.202 $X10^{-6}$ C_r .53 $X10^{-6}$

m 168 psi/cycle P at 1 hour: 12.755 Sg 0 Sw 1.00 Pi 13.203 psia

Pf 13,111.21 psia

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

kh = 162.6 (Q)(B)(μ)/(md)

kh = 162.2 (6998.4) (1.0455) (.21) / (168) = 1487.1 md-ft

k = (1487.1) md-ft / (91)ft = 16.3 mds

II. Bg = (Pb)(Tf)(Z)(1000)/(5.61)(520)(P_R) =

Bg = (15.025) (734) (1.59) .34279/(13,203) = .4553 Res. bbl/ MCF

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP skin

$$s = 1.151\left[\left(\frac{Pi - P_{1hr}}{m}\right) - \log\left(\frac{K}{\phi\mu C_t r_w^2}\right) + 3.23\right]$$

$$s = 1.151\left[\left(\frac{(13,111)-(12,755)}{(168)}\right) - \log\left(\frac{(16.3)10^6}{(.26)(.21)(3.732)(.101)}\right) + 3.23\right] = -4.09^*$$

ΔP skin = (0.87)(s)(m) = psi

ΔP skin = (0.87)(-4.09)(168) = -578* psi *Not valid data.

IV. Diffusivity, η

η = .006328 (k) /$\phi\mu$ C_T =

η = .006328 (16.3) / (.26)(.21)(3.732)10^{-6} = 506,197 ft^2/day

FIGURE 12-13

RESERVOIR LIMIT TEST

(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST (CONT'D)

Test Date: 7/29,30,31/80 Type Test: Second Drawdown Lease and Well No. P. R. Girouard No. 1

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

Qw = 7812.6 BWPD for 1.357 days flowing

$$J\ (\text{actual}) = \frac{Qw}{P_i - P_f} = \frac{(\ 7812.6\ )}{(13{,}111 - 11{,}240)} = \underline{\ 4.176\ } \text{ bbls/D-psi}$$

$$J\ (\text{ideal}) = \frac{Qw}{(P_i - P_f) - \Delta P\ \text{skin}} = \frac{(\qquad)}{(\qquad - \qquad) - (\qquad)} = \underline{\qquad\qquad} \text{ bbls/D-psi}$$

$$CE = \frac{J\ (\text{actual})}{J\ (\text{ideal})} = \frac{(\qquad)}{(\qquad)} = \underline{\qquad\qquad} \quad \text{or} \quad \underline{\qquad\qquad}\ \%$$

Distance to Barriers or Discontinuities, d $\qquad d = 2\sqrt{\eta t}$

$$d = 2\sqrt{(\ 506197\ )} \times \sqrt{t} = (\ 1423\ )\sqrt{t}$$

time, days	t	d, ft.	(psi/cycle)	Flow Angle	Jones Y Function	Bbls of Aquifer Explored or Tested
.0055	.07416	106	168	360°	1.815081	0.165×10^6
.0145	.12042	171	223	271.2°	0.913874	0.327×10^6
.030	.1732	246	358	168.9°	0.709106	0.421×10^6
.060	.2449	349	520	116.3°	0.5049496	0.592×10^6
.115	.3391	483	680	88.9°	0.3398667	0.879×10^6
.215	.4637	660	1015	59.6°	0.2766856	1.080×10^6
.32	.5657	805	1270	47.6°	0.21087407	1.417×10^6
1.357	1.1649	1658	1270	47.6°	0.046953	6.362×10^6

Opened well @ 22:05:30 PM on 7-29-80.
Closed well @ 6:40:00 AM on 7-31-80.
Total flow time was 1954.5 minutes or 1.357 days.
Total water production was 10,604 bbls. of water.
Rates increased from 6998.4 BWPD to 8459.6 BWPD.

(7758 Bbls/Ac.Ft.)(.26)/(1.0455) = 1929 Bbls/Ac.Ft.
$(1658)^2\pi/(43{,}560)$ = 198.3 Acres
(198.3)(168/1270) = 26.2 Acres Explored (Effective flow area)
(26.2 Ac.)(91 Ft.)(1929 Bbls./Ac.Ft) = 4,599,122 Bbls. of water.

Erratic fluctuation of pressure in the separator created gas-metering accuracy problems. After an additional twelve hours of attempting to achieve stable separator operation, the choke was adjusted by steps to reduce the brine flow rate from 15,134 BWPD at 2300 on July 31 to 9821 BWPD at 0200 on August 1, 1980. Before reducing the flow rate, the separator and wellhead pressures were both 600 psi. When the brine rate was reduced to 9821 BWPD with separator pressure at 600 psi, wellhead pressure increased to 3527 psi.

The third test was then continued 14 more hours until 1545 on August 1, 1980. During the 14 hours, no further changes were made in the choke setting or the separator pressure. The flow rate increased slightly to 10,065 BWPD, and the wellhead pressure increased to 3669 psi. The well produced 13,722.4 barrels of water during this flow period of about 28 hours and 35 minutes.

The sand detector output during the majority of the 15,000 BWPD flow was several times higher than in the second test. When the flow rate was reduced to 10,000 BWPD, the sand detector output returned to that of the second test. This sand production appears to reflect continued opening and cleaning of perforations. Although complete pressure buildup was not achieved at the start of flow, the production rate was higher than in previous flow tests, and the total sand production was almost as great as the sum of the two previous tests. The final flowing wellhead pressure was more than 300 psi higher than at the end of the second flow test, and it was still increasing.

The well remained shut-in until 1521 on August 2nd. Reservoir Data, Inc. brought out a new conductor cable and started to return the pressure gauge into the well bore at 0800 on August 2, 1980. The pressure unit reached datum at 1000 but failed to get a return signal from the bottom hole element to the surface readout. RDI pulled the pressure unit out of the well and found the gauge in order, but could not get contact through the conductor cable. When the cable was examined at the shop, it was found to have a broken conductor line about 600 feet from the end of cable. A decision was made to conduct the remaining flow test without a pressure unit in the well bore. Sufficient data was available from surface Panex pressures recorded to evaluate the reservoir configuration and the well productivity without the down hole pressure unit. The correlation of surface pressure to exact bottom-hole pressure is not accurate because of well bore temperature changes, friction losses, and fluid phase changes in the well bore. The sand production would also have created a hazard with the wireline in the tubing. It was decided to monitor only surface pressure, since sufficient data had been obtained from the first two flow tests to prepare a reservoir engineering analysis.

12.4 Fourth Flow Test

The fourth flow test started at 1521 on August 2nd with a surface pressure of 6430.05 psia at the wellhead. The well was opened to a production rate

of 6993.6 BWPD. This test was conducted to gather additional water and gas production data for evaluating gas/water production ratios. The production rate was maintained between 6400 and 7027 BWPD until about 2130 on August 3 (approximately 30 hours), when it was increased to 11,500 BWPD. The flowing tubing pressure was 4905.69 psia prior to this last rate increase. The high production rate was maintained for 3 hours with a flowing wellhead pressure of approximately 3153.68 psia. The well was shut in at 0030 hours on August 4th. The final shut-in surface pressure had increased to 6351.15 psia by 1130 on August 4, 1980, when the Panex pressure equipment was removed.

During the 30 hours of flow at slightly below 7000 BWD, separator pressure was varied and held at values of 540, 400, 700 and 450 psia successively. The purpose of these controlled changes in separator pressure was to investigate the effect on natural gas recovery from the produced reservoir brine.

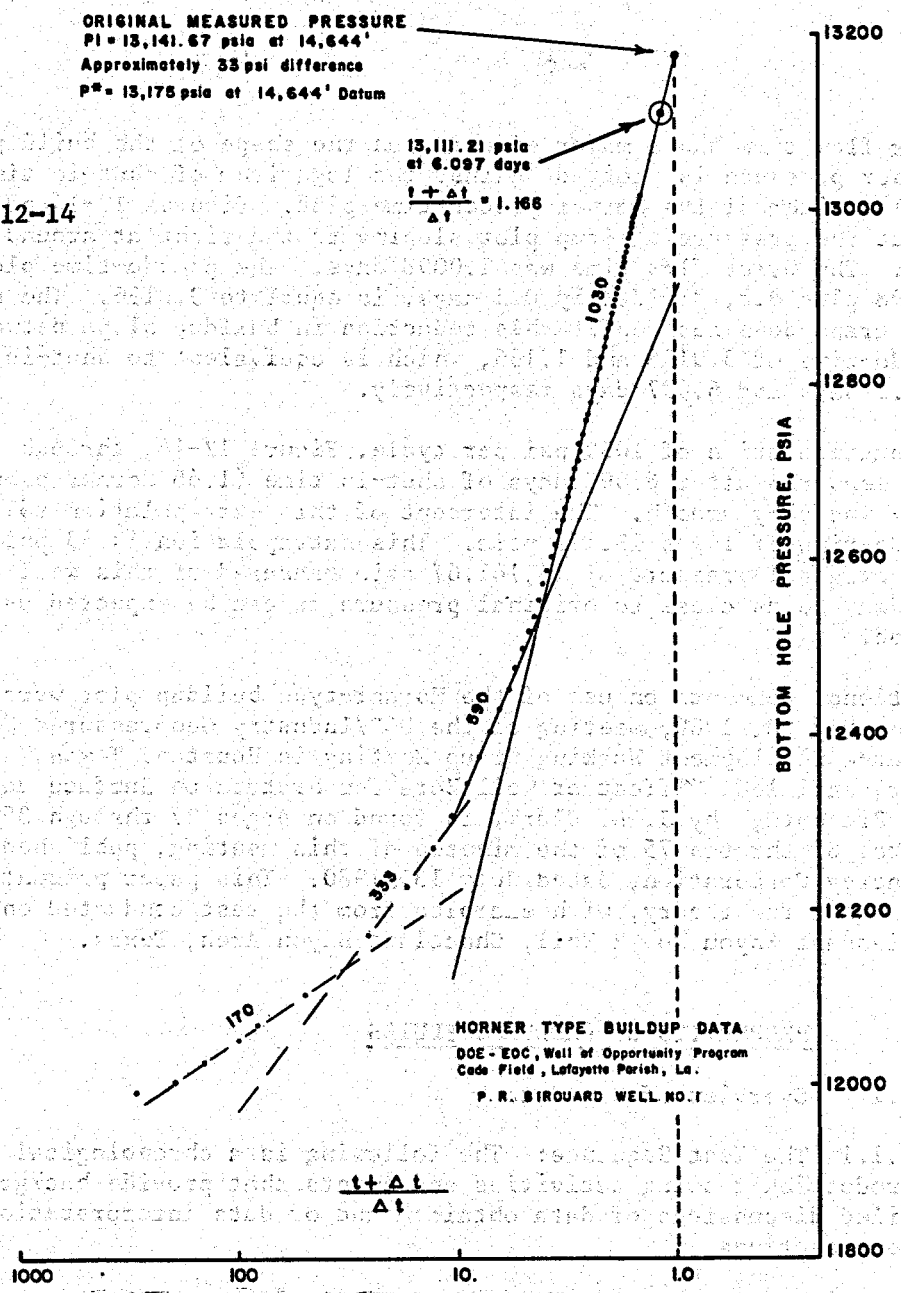
The production rate increase to about 11,500 BWPD was intended to continue the separator efficiency study with a reduced separator fluid retainer time and to determine whether a small dump valve seat, plus revised dump valve controller, could provide a stable high rate separator operation. Separator pressure tests were conducted at 460 psig and at 600 psig with a greater uniform pressure operation. The test operation had to be terminated because of increasing pressures in the flow through the sand filters. This test showed that increased separator pressures would be required to continue the 11,500 barrel per day flow rate.

Throughout the fourth flow test a minor amount of sand flow was detected, with an indicator marking just above the base line of the plot. Sand indicator readings did not increase significantly when the flow rate was increased from 7,000 to 11,500 barrels of formation brine per day. The rapid buildup in pressure across the filters probably was from washing of sand accumulated in the separator and/or surface flow line into the filters because of the turbulence created by the higher flow rate.

12.5 Horner-Type Buildup Analysis

Figure No. 12-14 is the Horner-type buildup plot using the pseudo-time of log $(t+\Delta t)/(\Delta t)$ versus pressure buildup. The flow time used in this pseudo-time calculation is 1.0098 days or 1454.112 minutes. The Hewlett-Packard pressure element was left in the well after the first flow test period for 2.1354 days or 3075 minutes. The pressure element was then removed to allow bottom hole sampling while the well was still shut in.

FIGURE 12-14



The pressure element was returned to well bore datum on July 29. The final buildup pressure measured 13,111.21 psia after 6.097 days of shut-in time. The final buildup slope using the pseudo-time plot was 1030 psi per cycle or somewhat less than the 1100 psi per cycle depicted on the final portion of the preceding drawdown plot. The extrapolated P* pressure was 13,175 psia, which is approximately 33 psi higher than the originally measured pressure of 13,142 psia at the same depth datum. The high value extrapolation would indicate another reason for using caution in reservoir interpretation by the type of pseudo-time graphical extrapolations.

Prior flow time has a major effect upon the shape of the buildup plot whether pressure is plotted against the logarithm of shut-in time or the logarithm of the Horner pseudo-time plot. Figures 12-1 and 12-2 depict the pressure buildup plot sloping to the right at around 0.5 days. The prior flow time was 1.0098 days. The pseudo-time plot of 1.0098 plus 0.5, divided by 0.5 days, is equal to 3.0196. The pseudo-time graph does not depict this reduction in buildup slope between the pseudo-time of 3.0196 and 1.166, which is equivalent to shut-in time of 0.5 days and 6.097 days respectively.

The extrapolation of 1030 psi per cycle, Figure 12-14, through the pressure measured after 6.097 days of shut-in time (1.66 Horner pseudo-time) was very smooth. The intercept of this extrapolation to the pseudo-time of 1 was 13,175 psia. This extrapolation is 33 psi higher than original pressure of 13,141.67 psia measured at this well depth. This may be as close to original pressure as can be expected using this method.

Additional comments on use of the Horner-type buildup plot were presented at the May 28, 1980, meeting of the DOE/Industry Geopressured-Geothermal Resource Development Working Group Meeting in Houston, Texas. This paper, entitled, "Effect of Well Bore Temperature on Surface and Bottom Hole Pressure," by J. D. Clark, is found on pages 27 through 35 and Figures 65 through 75 of the minutes of this meeting, published by C. K. GeoEnergy Corporation, dated July 18, 1980. This paper presents discussion of the theory, with examples from the test conducted on the DOE/GC Pleasant Bayou No. 2 Well, Chocolate Bayou Area, Texas.

12.6 PROPERTIES OF PRODUCED FLUIDS

12.6.1 Overview of Raw Data

12.6.1.1 The Test Sequence: The following is a chronological description of production testing activities and events that provide background for detailed discussions of data obtained and of data interpretation in subsequent sections.

- 7/21/80: RDI performed temperature and pressure gradient measurements in the production well bore.

- 7/22/80: 0730 hours (approx.) Started initial flow test after successfully recording bottomhole and wellhead pressure for 1-1/4 hours. An acceptable flow rate was achieved in a few minutes. No adjustments of chokes or separator operating conditions were made during this first 24-hour drawdown test. This constraint was observed to maximize quality of data for defining reservoir properties.

- 7/23/80: 0745 hours (approx.) Well was shut in for buildup data recording. Bottomhole and wellhead pressure were continuously recorded for the entire 24-hour period.

- 7/24/80 and 7/25/80: Both bottomhole and wellhead pressure were continuously recorded for this 48-hour period. Surface hardware was inspected for scale formation at points where the hardware had operated at wellhead pressure, at separator pressure before gas separation, and at disposal well pressure after gas separation. No indications of scale or produced solids were found. Because inhibitor had not been injected during the first 24-hour drawdown test, lack of scale after producing about 4000 barrels of reservoir brine led to the decision that inhibitor would not be needed in subsequent testing.

- 7/26/80 and 7/27/80: Recording of bottomhole and wellhead pressure was terminated at 1400 hours on 7/26/80 so that the bottomhole pressure gauge could be removed from the well to permit bottomhole sampling during daylight hours. Attempts to operate the Gearhart-Owen bottomhole sampler with the RDI wireline were unsuccessful because of problems with the lubricator and grease injection equipment.

- 7/28/80: After Gearhart-Owen wireline and lubricator equipment had been rigged up, two bottomhole sample runs were made. Samples were obtained on both runs. However both samples were obtained at unknown depths due to internal failure in the sampler and development of an electrical short before the electrical signal to activate the sampler was transmitted from the surface.

- 7/29/80: After RDI wireline and lubricator equipment had been rigged up, the bottomhole pressure gauge was run into the well, and successful recording of Hewlett-Packard bottomhole pressures plus Panex wellhead pressures began at 1600 hours. The second drawdown test started at about 2200 hours. Since deducing reservoir parameters was the primary objective of this second drawdown test, no adjustments to the choke or separator operating conditions were made after achieving an acceptable flow rate in a few minutes.

The second drawdown test continued for a full 24 hours on this date with no adjustments of the choke or separator operating conditions. At about 0420 hours both the bottomhole and wellhead pressures became erratic, with characteristics suggestive of the opening of additional perforations due to drawdown. However this onset of erratic pressure behavior was not accompanied by change in the low level of sand production that had been observed since the start of the second drawdown. Indeed the continuing low level of sand production to the surface stopped at about 1400 hours and then resumed at about 2000 hours.

- 7/31/80: 0645 hours (approx.) The second drawdown test was terminated for removal of the bottomhole pressure bomb to permit higher flow rate testing. The signal from the Hewlett-Packard bottomhole pressure gauge was lost when movement started. On removal of the instrument from the hole, the bottom three sinker bars were found to be missing.

- 7/31/80: 1115 to 2400 hours. After the bottomhole pressure gauge had been removed at 1115 hours, the choke was opened in steps and the flow carefully monitored for excessive sand production. Wellhead pressure had been reduced to about 500 psi by 1300 hours, with a flow rate in excess of 15,000 barrels/day. The production rate was limited by the required separator pressure plus friction drop in the production tubing for the remainder of this calendar day. Wellhead pressure and brine production rate remained fairly constant. However, large oscillations in separator operating conditions and disposal wellhead pressure severely compromised measurement of gas production. Sand detector output remained fairly constant at about five times the amplitude observed during the second drawdown test. By 2400 hours two of the 50-micron filters had caught sufficient sand to be operating near their rated differential pressure limit of 50 psi.

- 8/1/80: Between 0000 and 0200 hours, the adjustable wellhead choke opening was reduced in steps in search of a production rate that would permit both 1) stable separator operation and 2) reduced differential pressure buildup on filters due to sand production. Stable separator operation was achieved at a brine rate of about 9500 barrels/day. Sand production dropped to a level equivalent to that of the second drawdown test. However, filter differential pressure continued to increase, and the well was shut in at 1600 hours to change filters. Also, since flowing wellhead pressure was higher than that for a lower brine rate during the second drawdown test, additional bottomhole data collection was deemed desirable.

- 8/2/80: 1530 hours (approx.) After failure to obtain proper operation of the lubricator grease injection system and Hewlett-Packard bottomhole pressure gauge, production testing was resumed without bottomhole pressure data collection. Sand detector output at a flow rate of about 6700 barrels/day was slightly higher than observed during the second drawdown test at rates between 7000 and 8000 barrels/day.

- 8/3/80: Production continued for the entire 24 hours on this date. The separator was operated at three different pressures while maintaining a constant flow rate to provide additional data on the separator pressure-dependence of gas remaining in brine to the disposal well.

Between 1830 and 1930 hours separator output instrumentation was bypassed without changing the production rate to permit changing of the separator dump valve and control. After again achieving stable separator operation without changing the production rate, the choke was opened in steps between 2130 and 2230 hours to increase the production rate to about 11,000 barrels/day. This was done to determine whether stable separator operation could be achieved at a high rate with a smaller (2 in. versus 3 in.) dump valve and a less sensitive control sensor. Stable operation was achieved, but the reason is not clear because scale buildup was observed in the seat of the dump valve that had been removed. Variation of separator pressure at this increased flow rate was intended to provide additional data regarding the effect of separator residence time and pressure buildup on efficiency of gas recovery. However, rapid buildup of differential pressure on the filters resulted in termination of the test at 0030 hours on 8/4/80. Substantial amounts of sand found in the separator and surface plumbing on subsequent disassembly, plus minimal sand detector readings, suggest that the filter pressure buildup was caused by washing of sand from surface hardware onto the filters as a result of the increase in production rate to about 11,000 barrels/day.

12.6.1.2 Edited Raw Data: Raw data collected by IGT, RDI, and Weatherly Engineering has been combined into a single data set that provides a basis for interpretation by IGT. This combining process involved engineering judgements regarding which sensors provided information most likely to be a true representation of producing characteristics at each instant. IGT examined the totality of all data collected by the several subcontractors and edited the data to make the most realistic interpretation of actual well performance.

A small fraction (less than 5%) of raw data has been hand-edited to make it more representative of true well performance than as indicated by onsite recordings from sensors. Examples of instances where this has occurred are discussed below.

- Separator Upsets

A few separator upsets occurred, accompanied by brine flow through the orifice meter. If wellhead pressure was constant and if production-related data were the same before and after the upset, raw data were edited to the values that would have occurred in the absence of the upset.

- Separator Dump Valve and Control Sensor Replacement

When the separator dump valve and control sensor were replaced on the evening of 8/3/80, both brine and gas flow instrumentation were bypassed

by producing to the pit. However the wellhead pressure, which reflected a large friction drop, did not change during this hour. Therefore, raw data were hand-edited to reflect the values of gas and brine production that would have been recorded in the absence of bypassing instrumentation.

- Bottomhole Pressure Gauge Removal

All wellhead pressure sensors were disconnected at various times between 0700 and 1300 hours on 7/31/80 in the course of removing the bottomhole pressure gauge from the well and resuming production. Manual editing of data was performed to provide a semi-quantitative estimate of actual wellhead behavior during this time interval.

The combined and edited data set used to define fluid production and properties is included in its entirety as Appendix F. Plots of edited data are presented in Figures 12-15 through 12-20, (2-part figures). The data reflected in each column of Appendix F and in the figures are as follows:

- Wellhead Pressure (Figure 12-15)

Values recorded prior to 0945 hours on 7/31/80 are from the RDI surface Panex gauge. Between 0945 and 1300 hours on that date, values shown are a combination of values recorded by IGT, RDI, and Weatherly Engineering judged most representative of actual wellhead pressures. Most of the values shown after 1300 hours on 7/31/80 are values recorded by IGT. The exceptions are a small portion of the buildup on the afternoon of 8/1/80 and several hours during the morning of 8/3/80. Values during these intervals have been hand-edited to provide continuity over gaps in IGT recording using data from RDI or Weatherly Engineering with a small adjustment to reflect the smooth nature of actual wellhead pressure response.

- Separator Static Pressure and Disposal Wellhead Pressure (Figure 12-16)

Most of these data were recorded by IGT. The only notable exceptions occurred on 8/3/80, when the IGT disposal wellhead pressure sensor was inoperative from 0500 to 1400 hours, and Weatherly data were used to fill the data gap. Secondly, hand-editing was used to provide estimated values for both of these pressures during the flow to the pit to change the dump valve and its control between 1830 and 1930 hours.

- Orifice Differential Pressure (Figure 12-17)

All values shown were recorded by IGT. The only hand-editing was insertion of estimated values between 1830 and 1930 hours on 8/3/80, plus hand-editing of a few individual data points that were artificially high due to brine flow through the orifice meter during separator upsets.

- Gas Temperature (Figure 12-18)

All values shown were recorded by IGT. The only hand-editing was at the same intervals as those for orifice differential pressure.

- Brine Temperature (Figure 12-19)

The majority of values for brine temperature are the result of hand-editing of data. This editing consisted of IGT recordings of brine temperature or gas temperature to obtain tabulated values consistent with the average of thermometer readings logged by Weatherly.

- Brine Flow Rate (Figure 12-20)

Values shown are based upon Weatherly tabulations. The only adjustments are occasional additions to reflect estimated flow to the pit during times when the turbine meter was bypassed and the 1-hour interval between 1830 and 1930 hours on 8/3/80. These adjustments were small.

The small number of tabulated and plotted data points for the first drawdown test reflects the lack of an operable digital recording system during that test. A 1-hour time interval was selected to minimize the scatter in calculated gas/water ratios due to variation in actual time of manually recording cumulative brine production. The tabulated and plotted values for parameters relevant to calculating the gas/water ratio reflect manually derived time averages over the same hours as the brine readings.

12.6.2 Characteristics of Produced Gas

Analyses of samples from two sources provided definitive data on characteristics of produced gas. These sources are the following:

- On the flare line between the orifice meter and back-pressure controller.
- Gas flashed from brine samples collected at the inlet to the brine metering skid.

Details of collection and analyses for these samples are provided in Sections 12.6.2.1 and 12.6.2.2. Additional gas samples from upstream of the large choke manifold and from downhole sampling are discussed in Sections 12.6.3.3 and 12.6.4.

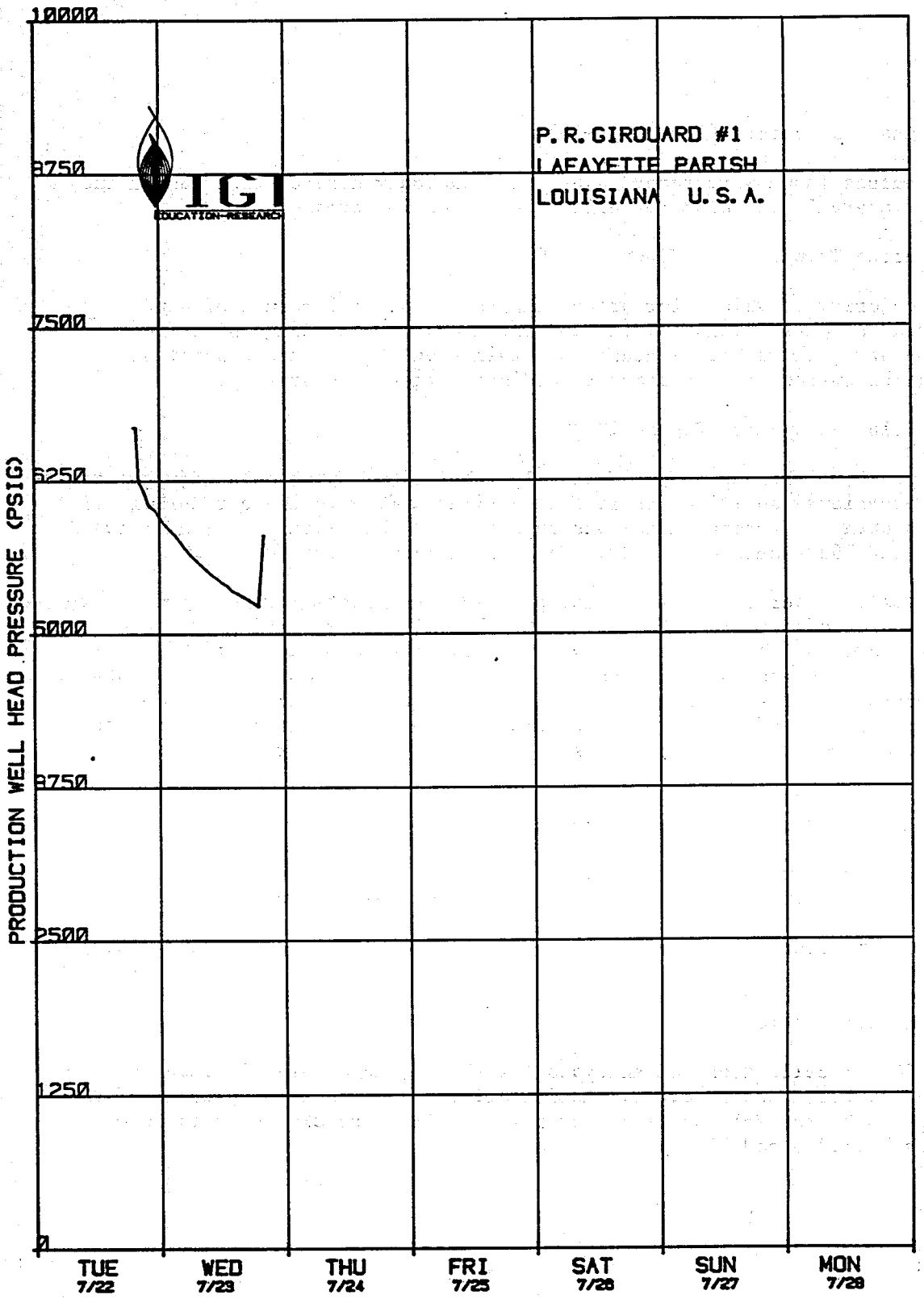


FIGURE 12-15, Part 1. Continuous Production Wellhead Pressure History

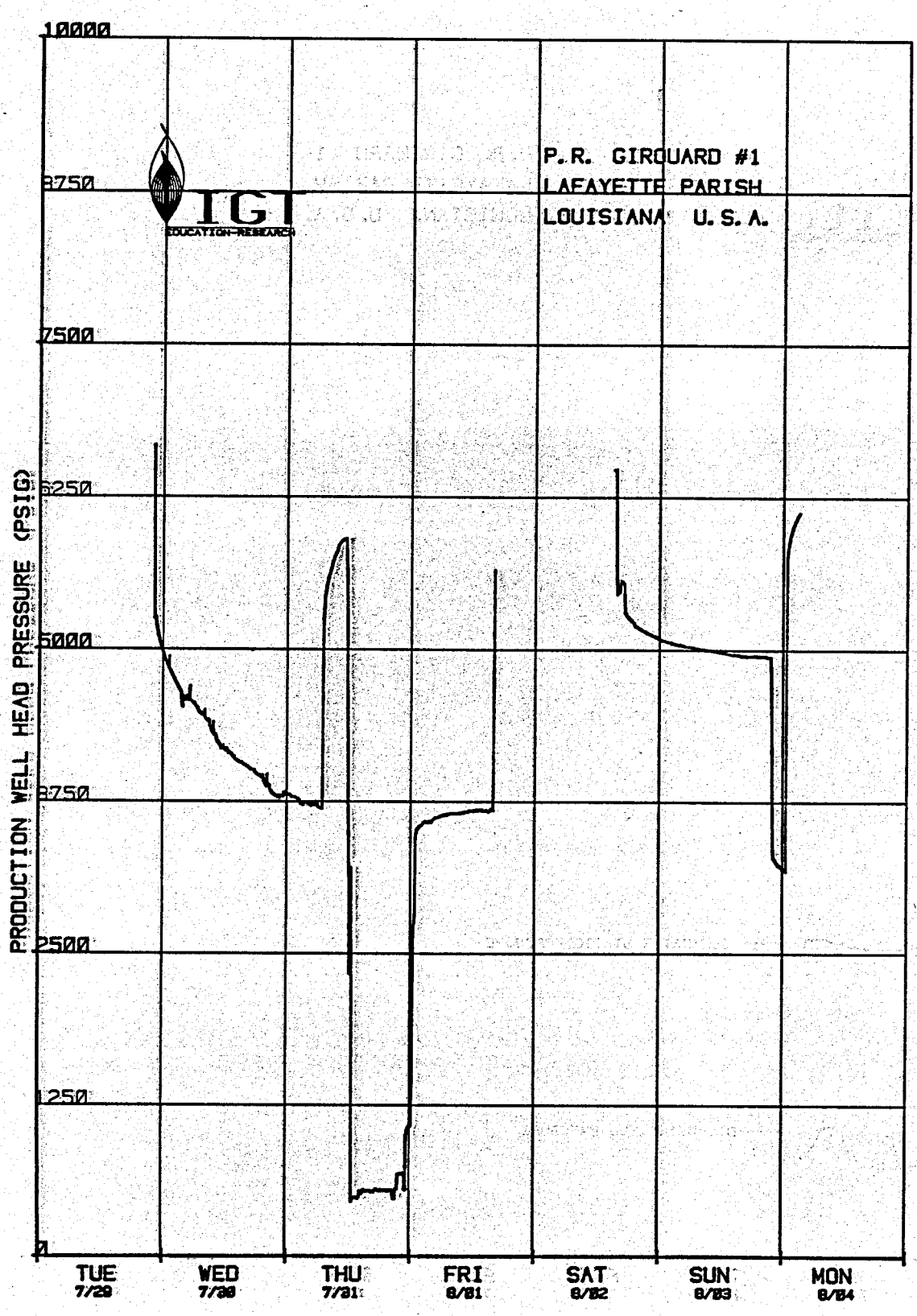


FIGURE 12-15, Part 2. Continuous Production Wellhead Pressure History

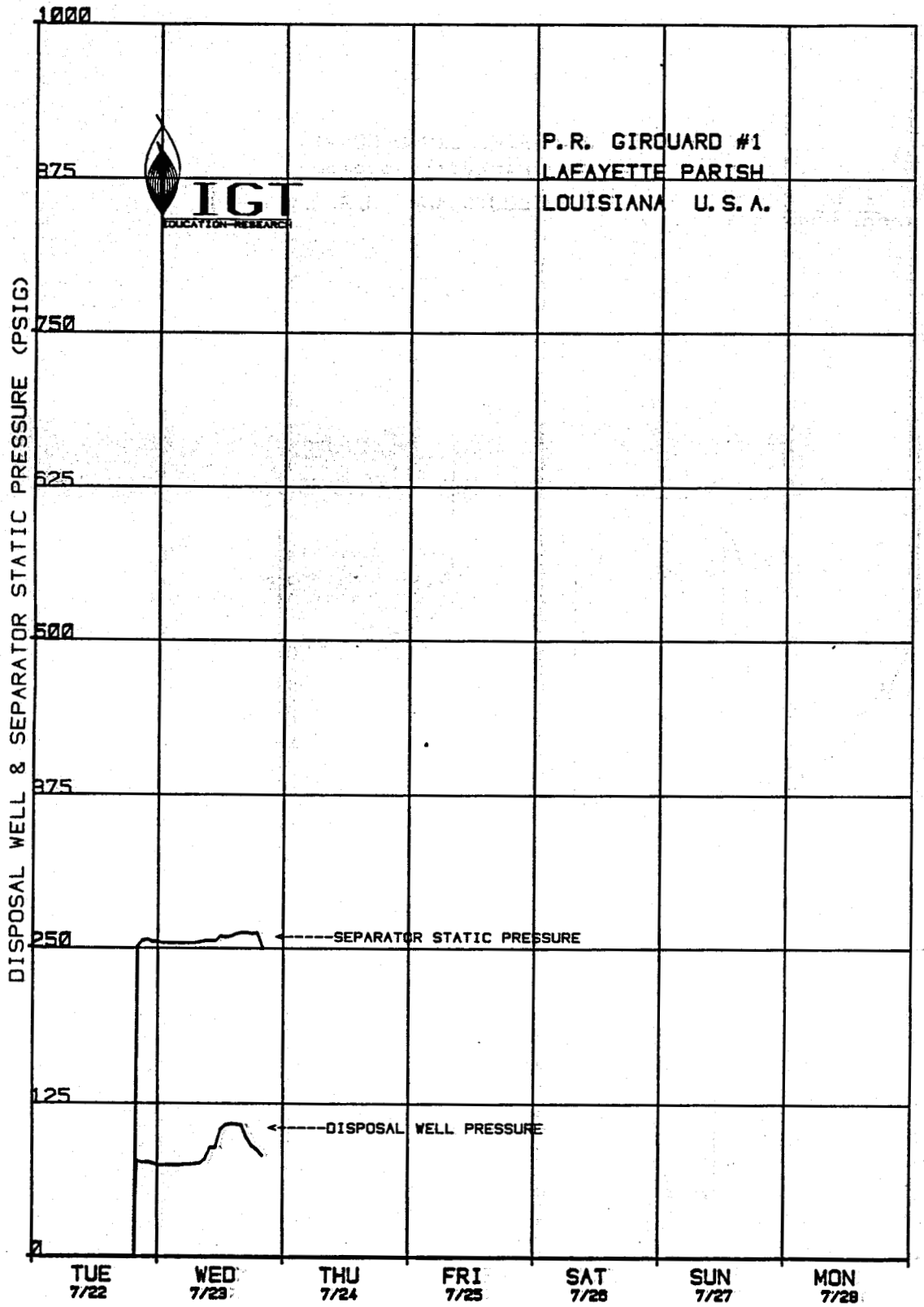


FIGURE 12-16, Part 1. Disposal Well and Separator Static Pressure History

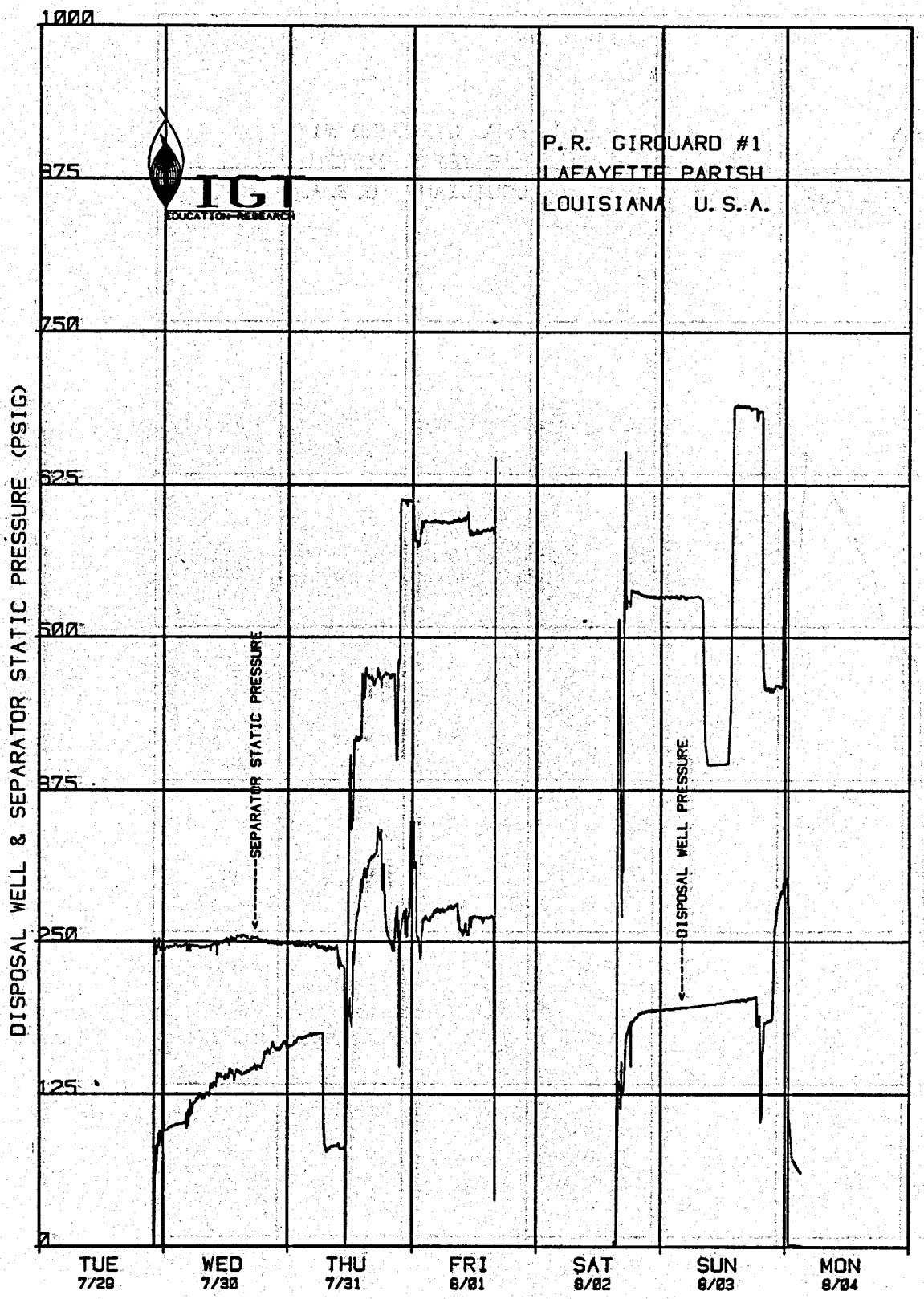


FIGURE 12-16, Part 2. Disposal Well and Separator Static Pressure History

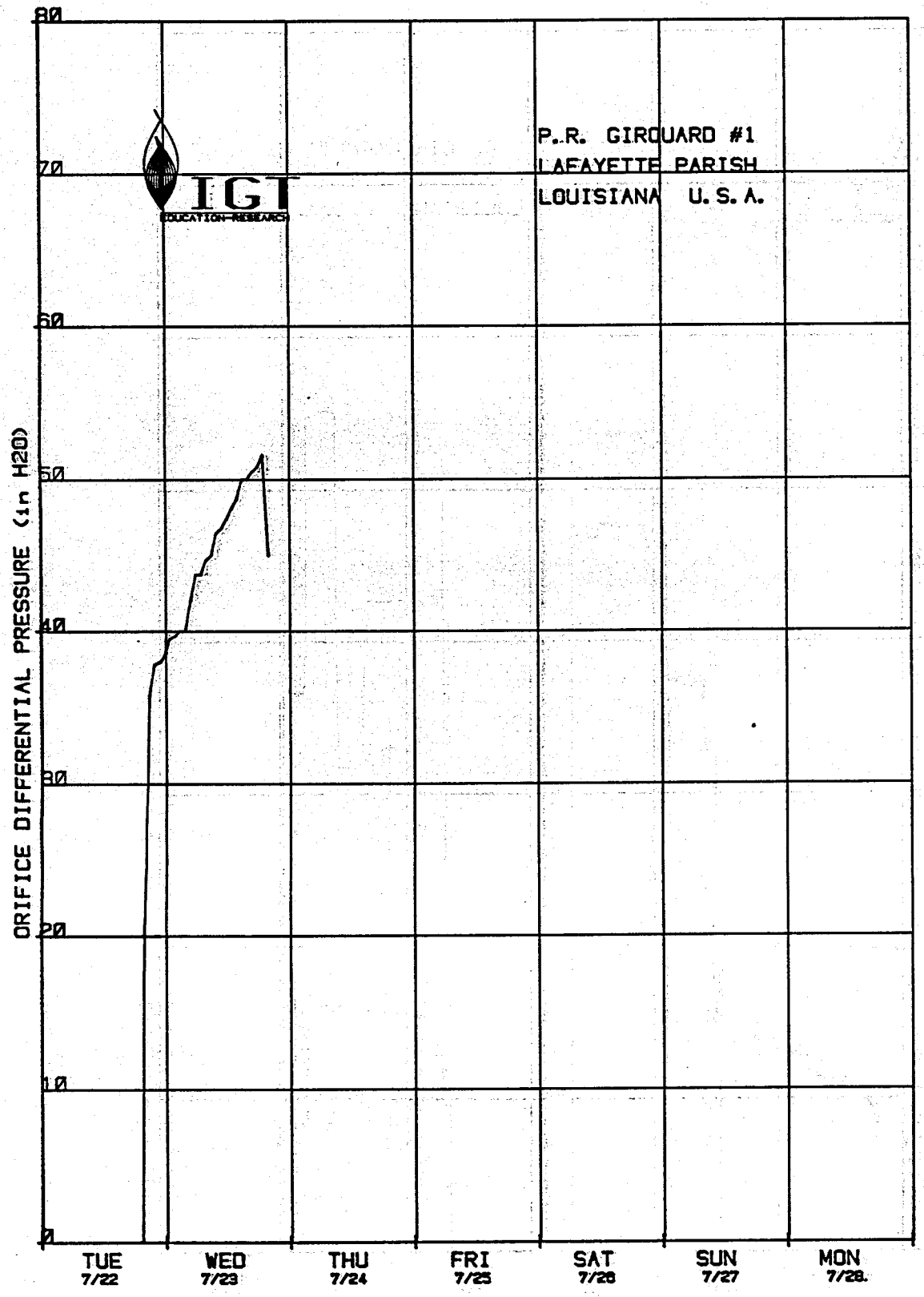


FIGURE 12-17, Part 1. Orifice Differential Pressure History

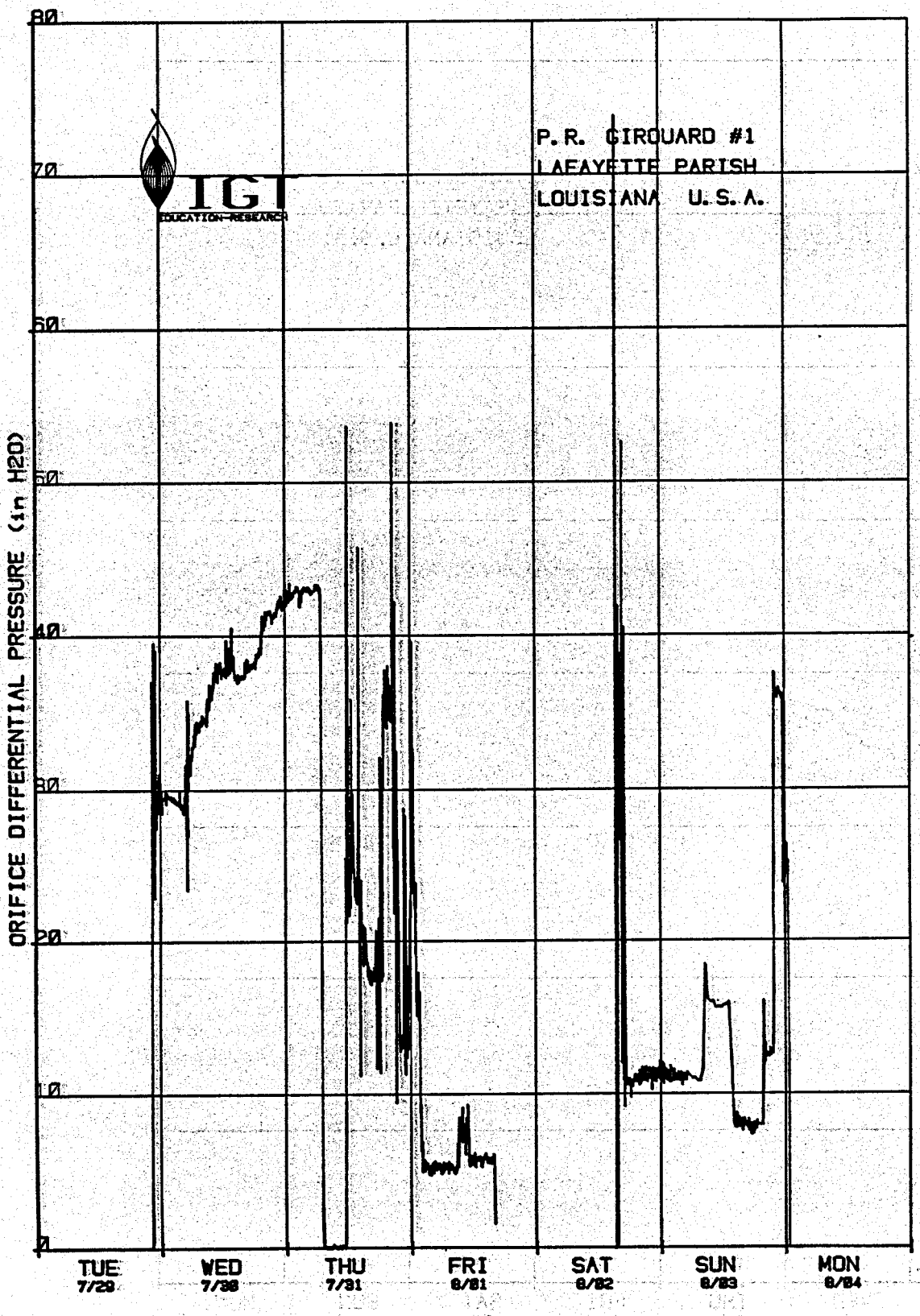


FIGURE 12-17, Part 2. Orifice Differential Pressure History

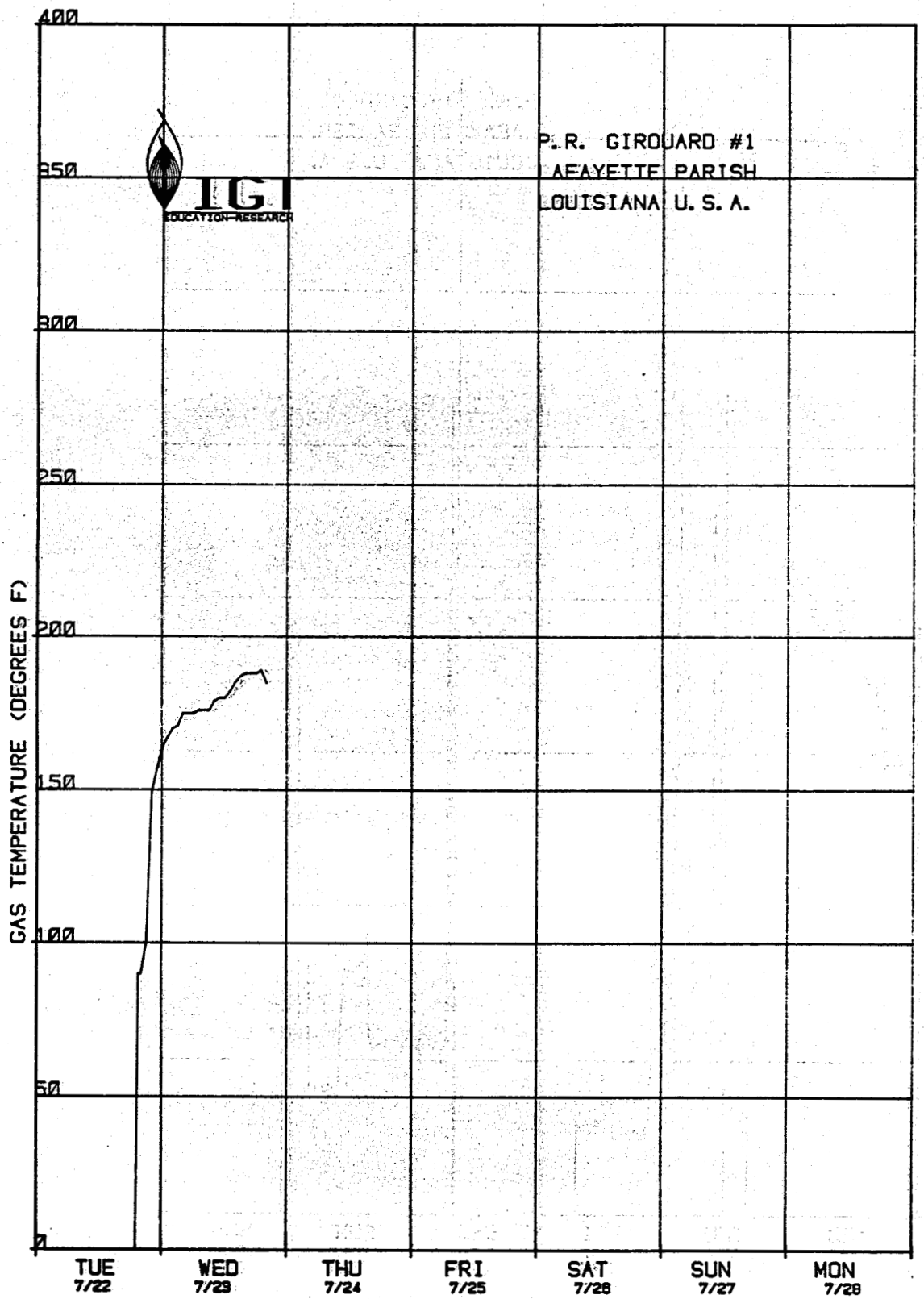


FIGURE 12-18, Part 1. Continuous Gas Temperature History

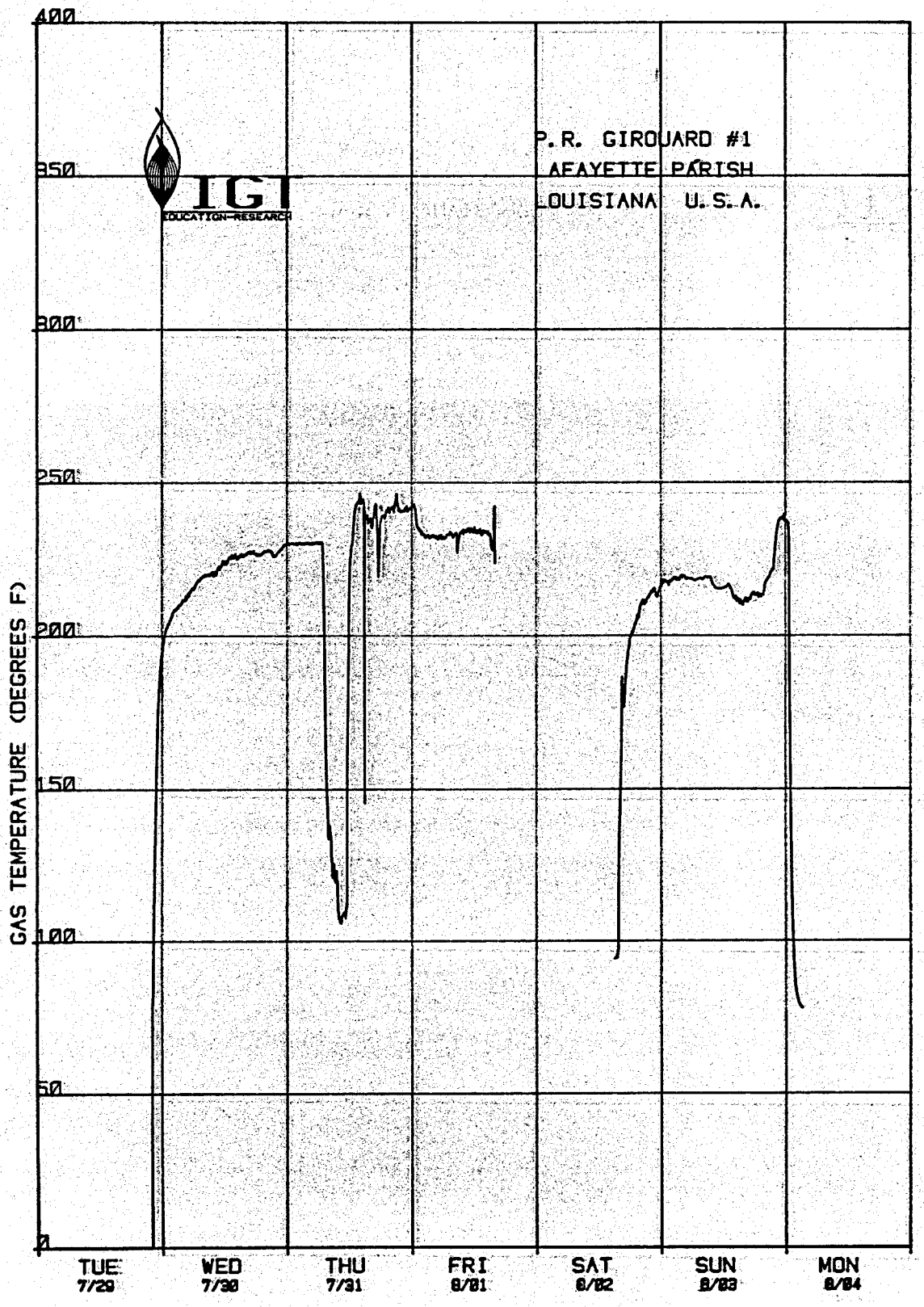


FIGURE 12-18, Part 2. Continuous Gas Temperature History

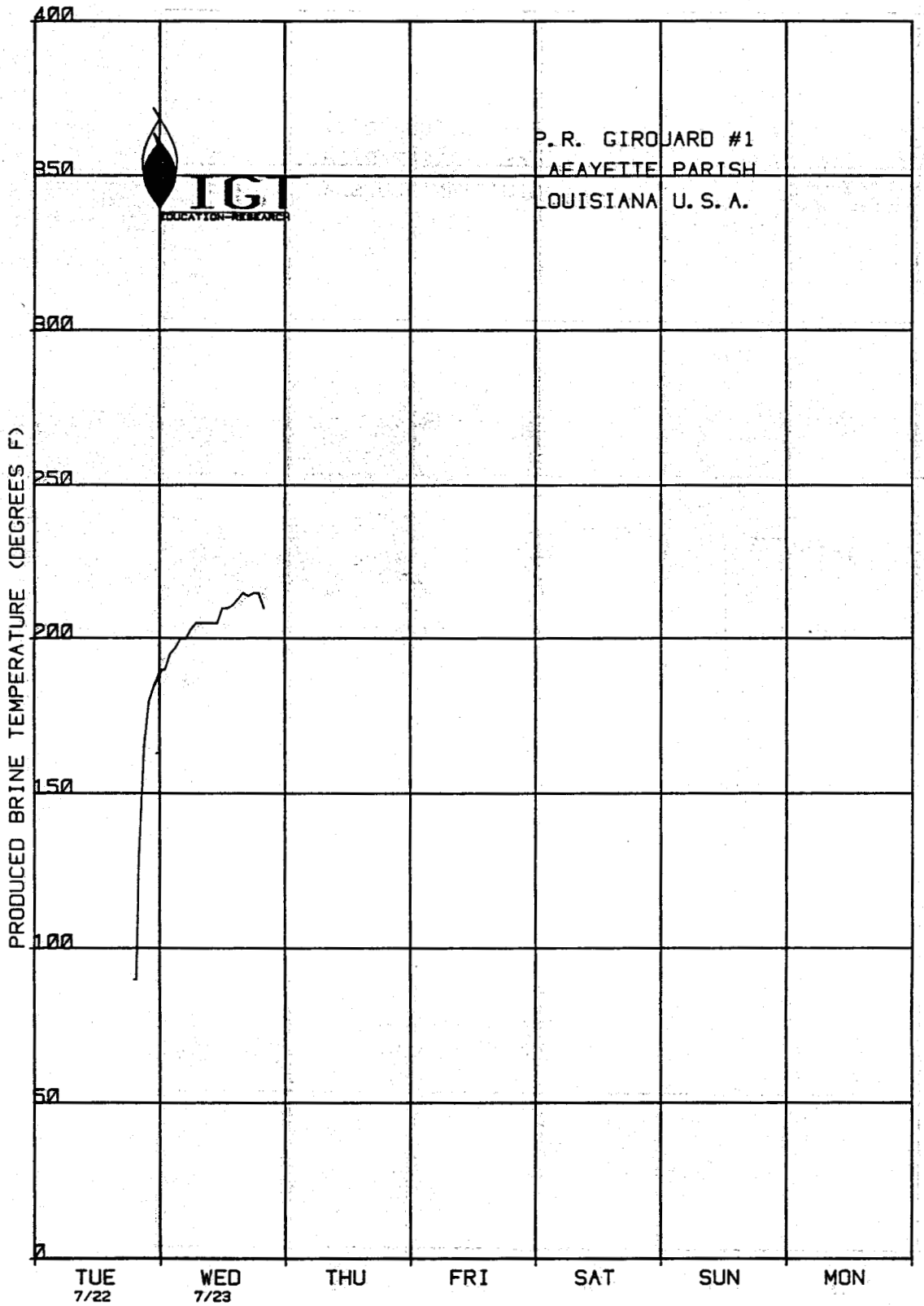


FIGURE 12-19, Part 1. Continuous Produced Brine Temperature History

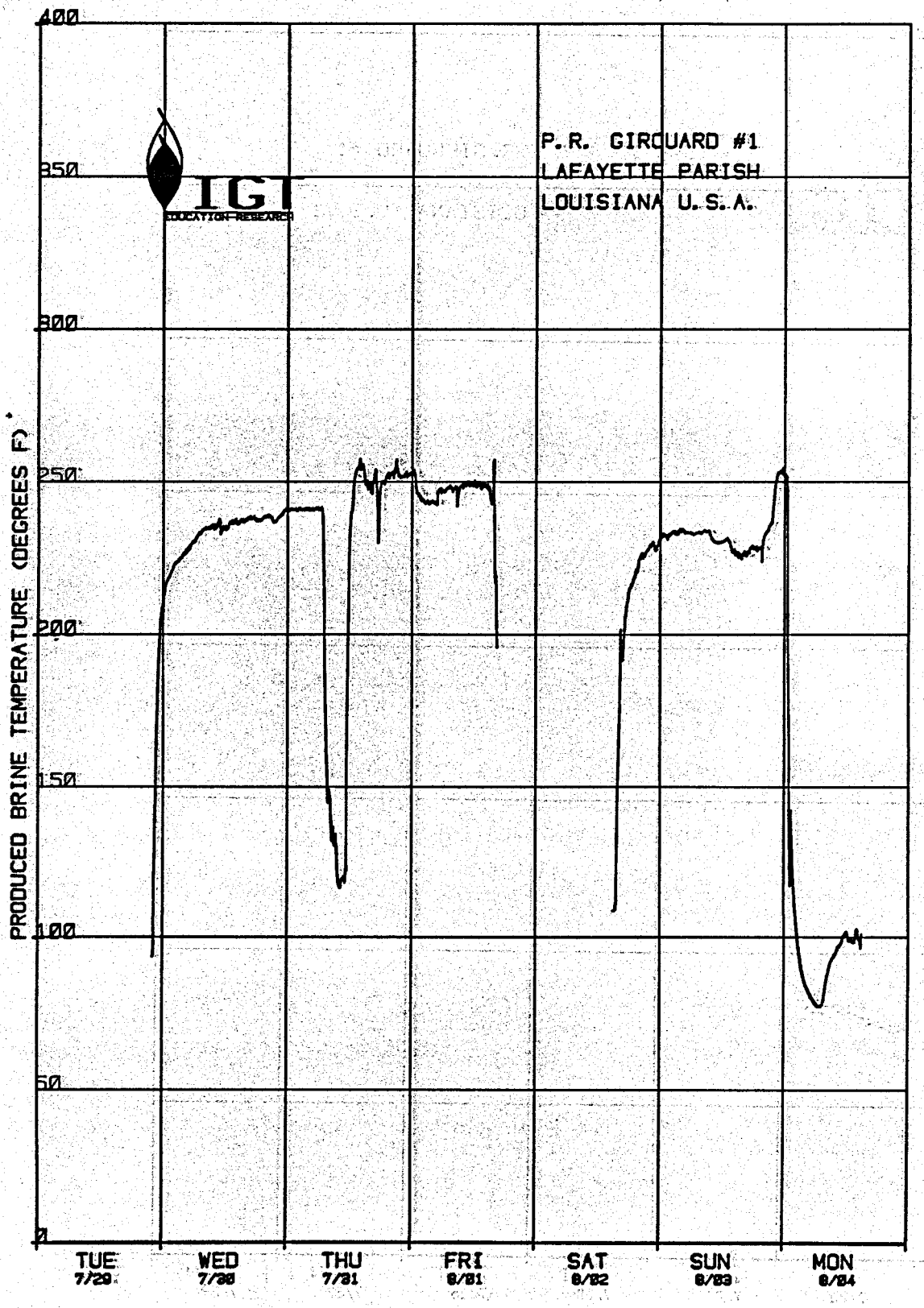


FIGURE 12-19, Part 2. Continuous Produced Brine Temperature History

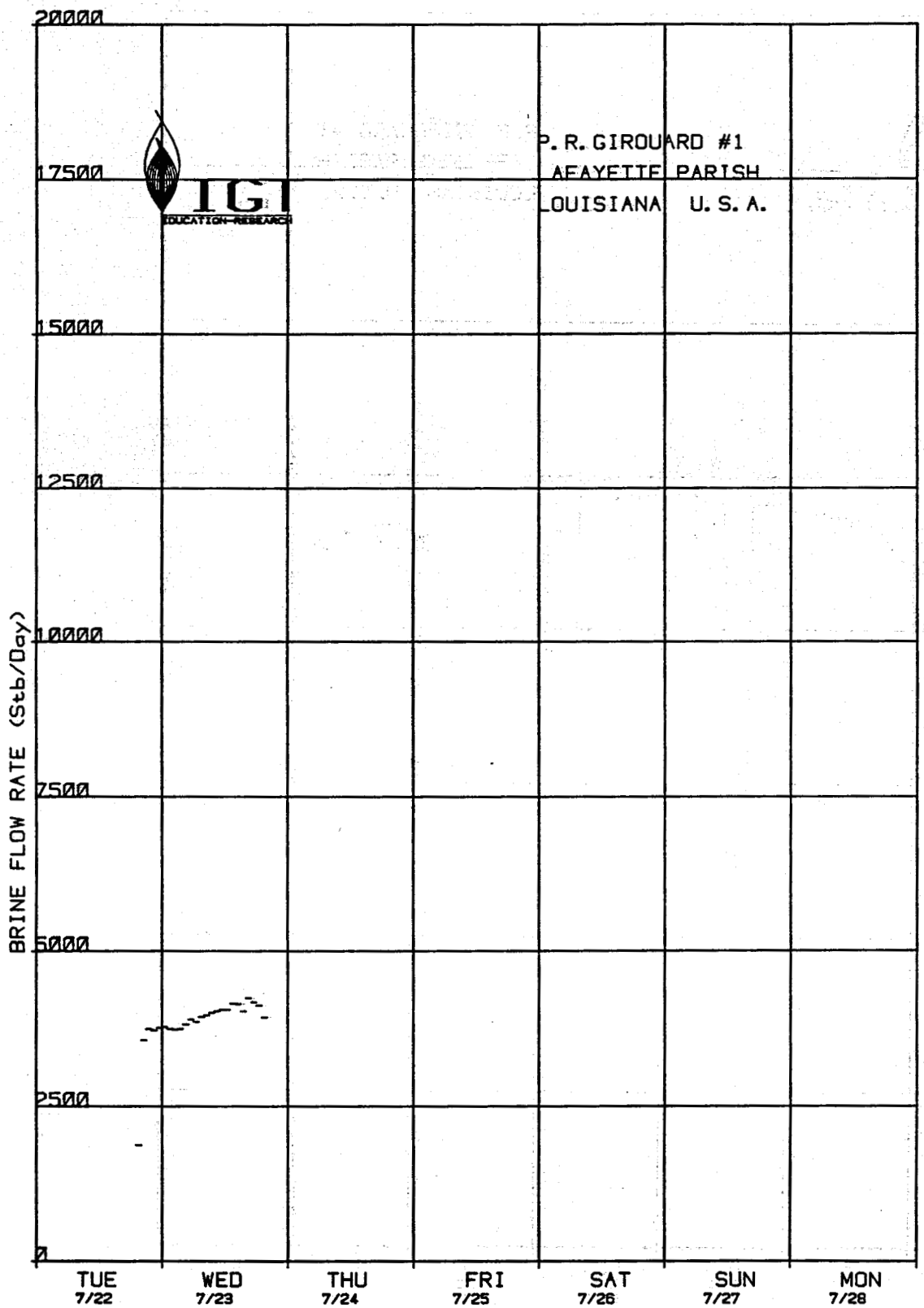


FIGURE 12-20, Part 1. Continuous Brine Flow Rate History

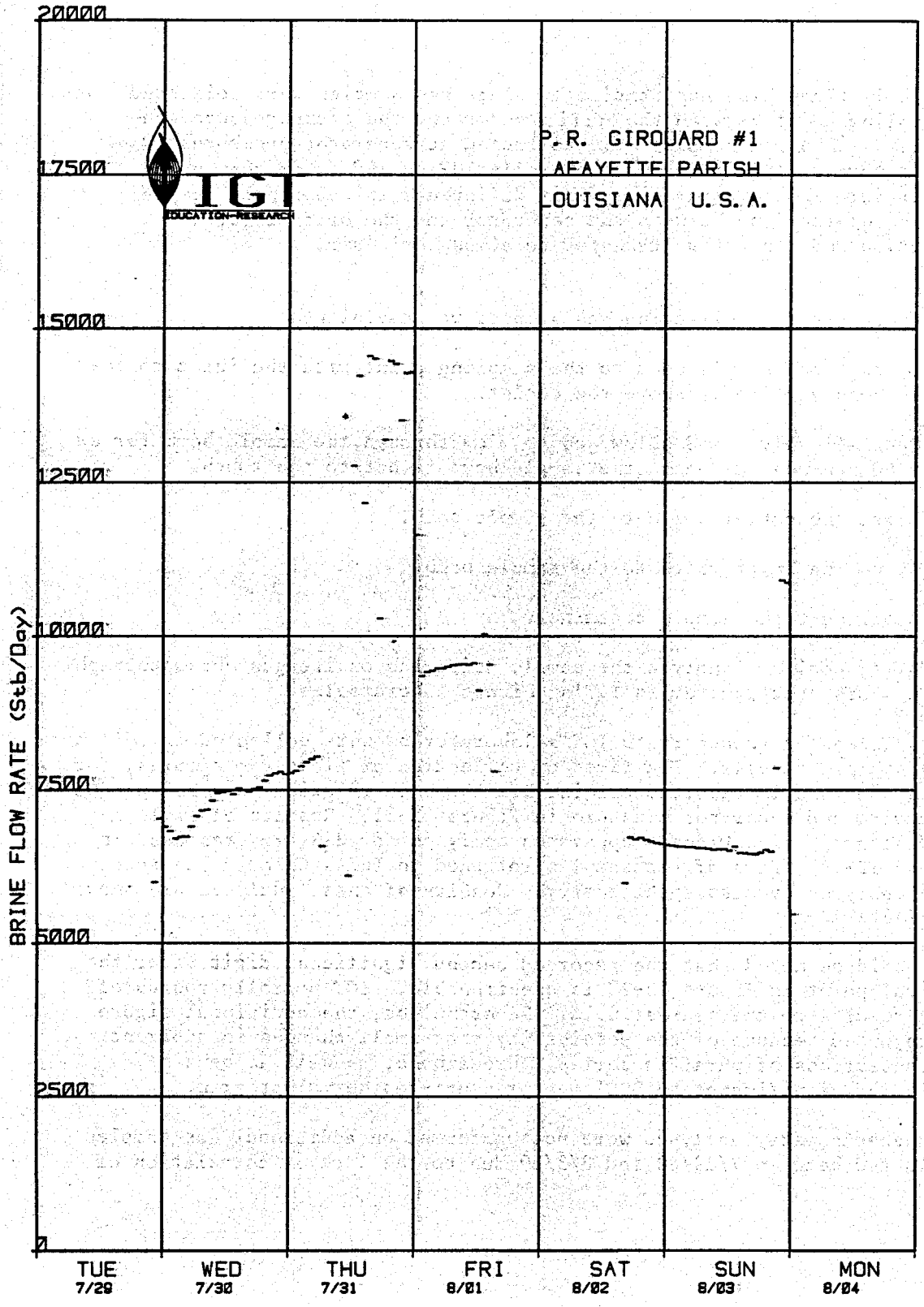


FIGURE 12-20, Part 2. Continuous Brine Flow Rate History

12.6.2.1 Flare Line Gas Sampling: Flare gas samples were collected from a sampling point between the orifice meter and the back-pressure controller. Thus all samples were collected at separator pressure. Gas temperature at this point was generally 10° to 15° lower than brine temperature in the separator. This difference is apparently due to cooling of the line between the separator and the orifice meter by radiation and conductive transfer to atmospheric air.

The procedure for collecting gas samples was as follows:

- Connect the sample bomb to the sampling point with the inlet to the sample bomb vertically above the outlet.
- Open all valves and allow gas to flow through the sample bomb for at least 60 seconds and until the sample bomb is hot to the touch.
- Close the outlet valve to the sample bomb.
- Close the inlet valve to the sample bomb.
- Disconnect the sample container.
- After cooling, analyze the sample using the onsite gas chromatograph or the mass spectrometer in IGT's Chicago laboratories.

All samples for transport to IGT's laboratories were collected in Teflon-lined sample vessels. The times of collection of flare gas samples, for which analysis is reported herein, are shown in relation to brine production rate and separator pressure in Figure 12-21. Results of field gas chromatograph plus Draeger apparatus analyses for H_2S are presented in Figure 12-22. Five of the samples returned to IGT's Chicago laboratory were analyzed by mass spectrometry. Results of these analyses are shown in Figure 12-23.

It should be noted that the recorded second significant digit after the decimal point in Figure 12-23 is questionable. IGT normally rounds off such results to the nearest 0.1%. Nevertheless, the additional figure is reported because of the possibility that small changes in apparent concentrations of paraffin series hydrocarbons, as well as benzine, may be of significance to DOE's geopressure-geothermal program.

Mass spectrometry analyses were not performed on additional gas samples collected between 7/29/80 and 8/3/80 due to the lack of correlation of

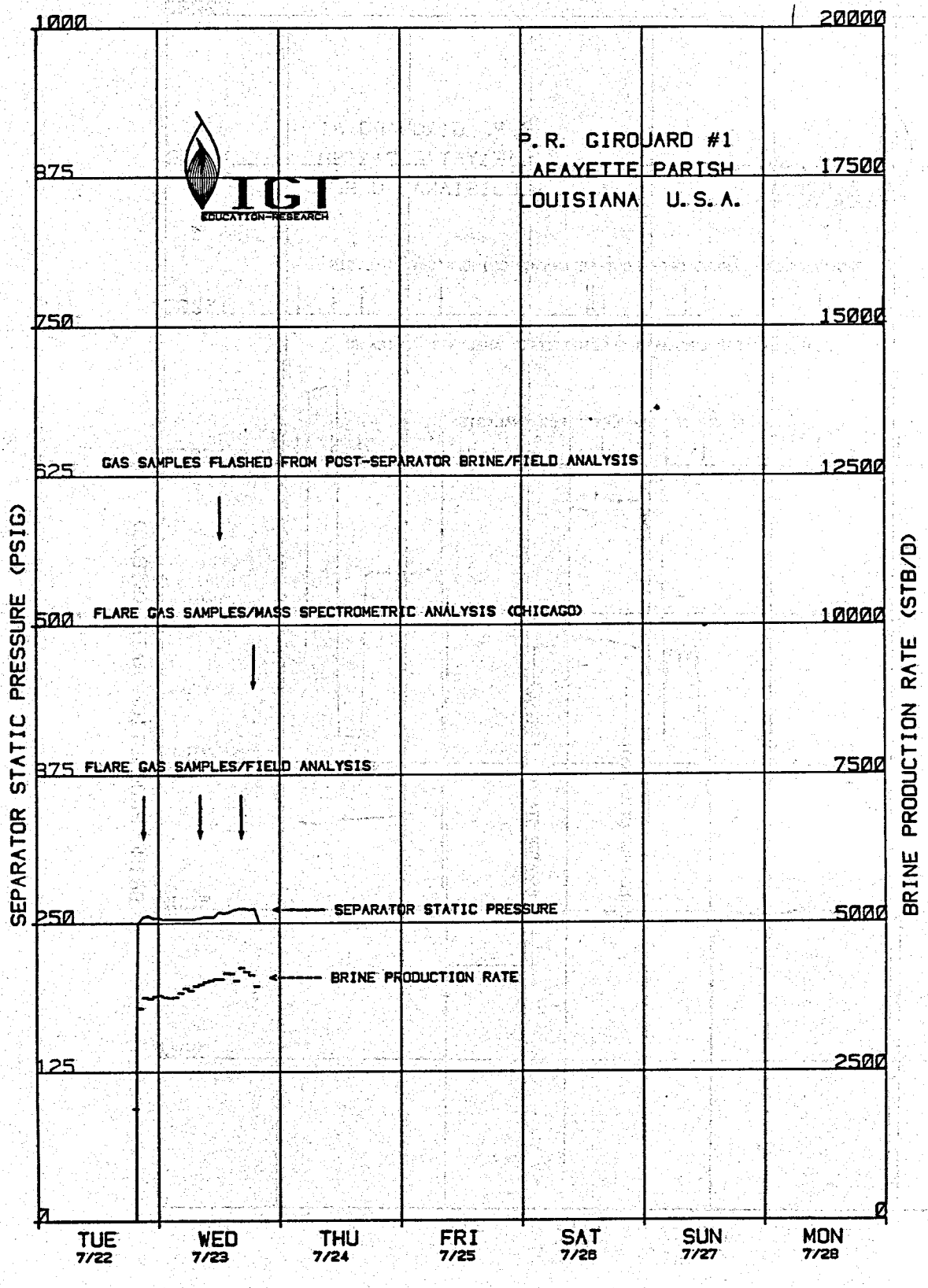


FIGURE 12-21, Part 1. Gas Sampling Times Related to Separator Static Pressure and Brine Production Rate

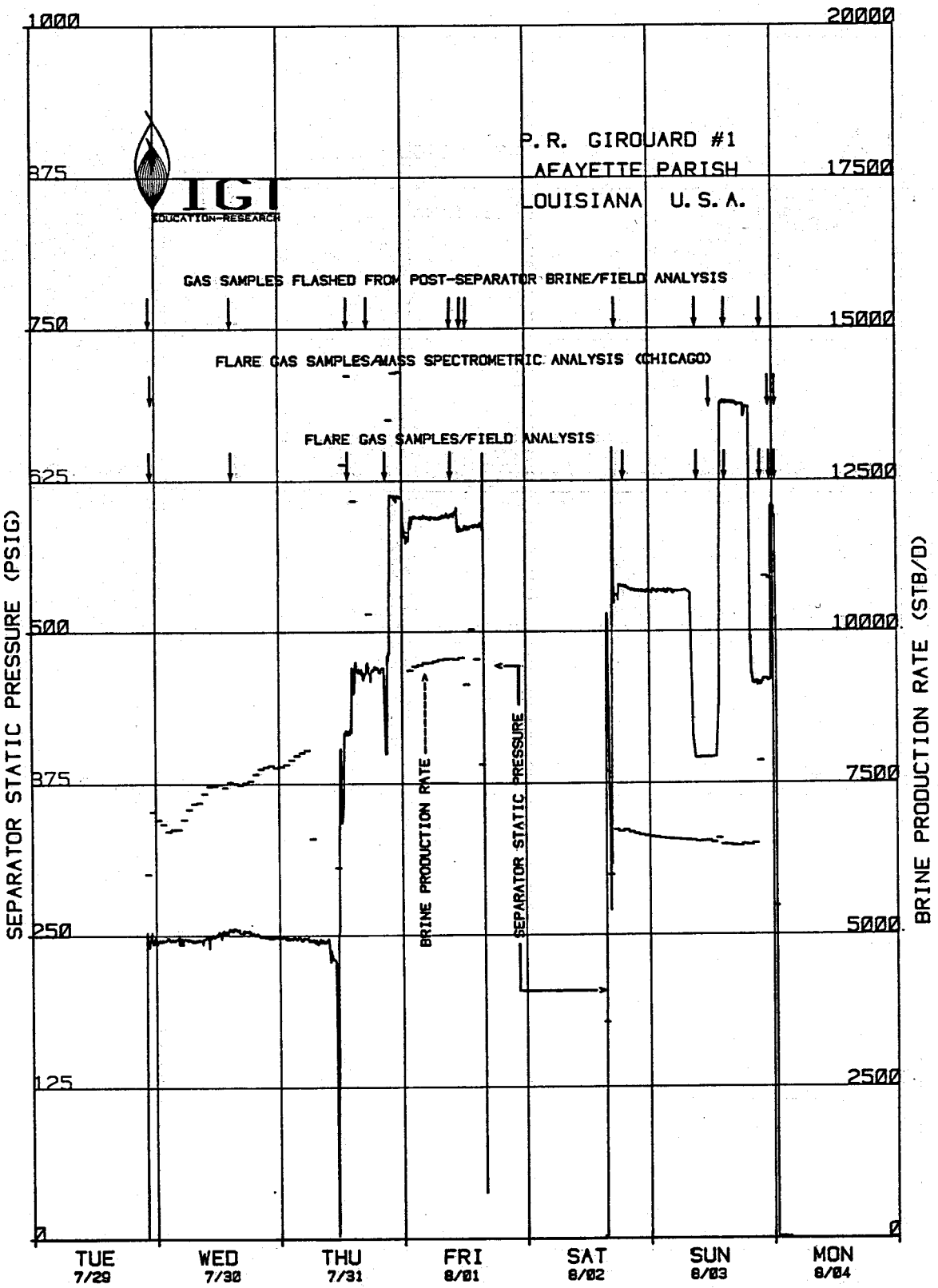


FIGURE 12-21, Part 2. Gas Sampling Times Related to Separator Static Pressure and Brine Production Rate

FIGURE 12-22 Concentrations of Gas Components of Flare Line (Field Analysis)

Sample Date and Time	Concentration, mole percent							
	Methane	Ethane	Propane	n-Butane	Isobutane	Pentanes	Carbon Dioxide	Nitrogen
22 July 80 2115	91.7	1.8	0.3	<0.1	0.1	<0.1	5.9	0.2
23 July 80 0835	91.2	1.8	0.3	<0.1	0.1	<0.1	6.4	0.2
23 July 80* 1610	91.3	1.8	0.3	<0.1	0.1	<0.1	6.4	0.1
29 July 80 2320	90.8	1.8	0.3	<0.1	0.1	<0.1	6.7	0.2
30 July 80 1500	91.1	1.8	0.3	<0.1	0.1	<0.1	6.6	0.2
31 July 80 1315	91.9	1.8	0.3	<0.1	0.1	<0.1	5.7	0.1
31 July 80 2100	91.4	1.8	0.3	<0.1	0.1	<0.1	6.3	0.3
1 Aug 80 0925	92.2	2.0	0.3	<0.1	0.1	<0.1	5.2	0.1
2 Aug 80 1850	92.3	1.9	0.3	<0.1	0.1	<0.1	5.1	0.2
3 Aug 80 0900	91.4	1.9	0.3	<0.1	0.1	<0.1	6.3	<0.1
3 Aug 80 ‡ 1425	93.2	1.4	0.3	<0.1	0.1	<0.1	4.8	0.1
3 Aug 80 2130	92.1	1.9	0.3	<0.1	0.1	<0.1	5.5	0.1
3 Aug 80 2320	91.3	1.9	0.3	<0.1	0.1	<0.1	6.2	0.2
4 Aug 80 0030	92.2	1.9	0.3	<0.1	0.1	<0.1	5.2	0.2

* Sample also analyzed for hydrogen sulfide with a Draeger apparatus: H_2S = 2.0 ppm.

\+ Sample also analyzed for hydrogen sulfide, ammonia and mercury with a Draeger apparatus: H_2S = 2.5 ppm; NH_3 < 1 ppm; Hg < 0.01 mg/m^3.

‡ Accuracy of this analysis is questionable due to electronic problems during on-line integration of the gas chromatograph output.

FIGURE 12-23 Concentrations of Components of Flare Line Gas by Mass Spectrometric Analysis

Sample Date	7-23-80	7-29-80	8-3-80	8-3-80	8-4-80
Time	7:00 PM	11:45 PM	11:35 AM	11:20 PM	12:20 AM
Date of Analyses	8-4-80	8-4-80	8-15-80	8-15-80	8-15-80
Methane	91.5 %	91.6 %	91.9 %	92.2 %	92.7 %
Ethane	1.8	1.8	1.93	1.87	1.91
Propane	0.29	0.30	0.34	0.33	0.34
n-Butane	0.08	0.06	0.04	0.05	0.05
i-Butane	0.12	0.10	0.09	0.10	0.10
Pentanes	0.00	0.00	0.02	0.01	0.01
Hexanes	0.00	0.00	0.00	0.00	0.00
Heptanes	0.00	0.00	0.00	0.00	0.00
Octanes	0.00	0.00	0.00	0.00	0.00
Argon	0.00	0.00	0.00	0.00	0.00
Oxygen	0.00	0.00	0.00	0.00	0.00
Benzene+	0.01	0.02	0.02	0.01	0.01
Nitrogen	0.20	0.12	0.21	0.22	0.17
Helium	0.01	0.01	0.01	0.01	0.01
CO_2	6.0	6.0	5.5	5.2	4.7

* The second significant digit after the decimal point is questionable. IGT normally reports such analyses rounded to the nearest 0.1%. However the additional digit is included here due to possible significance.

\+ May be residual solvent from cleaning of the Teflon line cylinders.

the observed small changes in chemical composition with either reservoir pressure, brine production rate, separator pressure, or length of time interval between sample collection and analysis.

12.6.2.2 Gas Flashed from Brine to the Disposal Well: Brine samples were collected at separator pressure from a sampling point on the brine metering skid. The sample collection and flashing procedure was as follows:

- Connect a 500 cc sample vessel to the sampling point with the outlet end of the vessel above the inlet end.

- Open valves flowing brine through the sample vessel for at least 60 seconds and until the vessel is hot to the touch.

- Close the sample vessel outlet valve.

- Close the sample vessel inlet valve.

- Disconnect the sample vessel from the sampling point and immerse it in water until it is cooled to field laboratory ambient temperature of about 25°C. Cooling by water immersion provided the advantage that any sample vessels exhibiting leakage by bubble formation could be rejected.

- After cooling, connect the sample vessel to a 500 cc syringe with less than 5 cc of air-filled dead volume in connecting tubing, fittings, and the syringe itself.

- Open the sample vessel to allow gas flashed from brine in the pressure vessels to move vertically into the large syringe.

- After quantitative determination of the amount of gas entering the syringe at atmospheric pressure, inject gas from the syringe into the gas chromatograph for analysis.

The gas/water ratio deduced from flashing and the results of the gas chromatograph analyses of flashed gas from post-separator brine are reported in Figure 12-24. Times of collection of each of these samples are indicated in relation to separator pressure brine production rate and separator pressure in Figure 12-21.

Comparison of the data presented in Figure 12-24 shows that the chemical composition of gas remaining in solution at separator pressure differs substantially from that of flare line gas. The most notable difference is that the mole percent of carbon dioxide in gas flashed from separator brine is nearly three times that observed in flare gas. In contrast,

FIGURE 12-24 Concentrations of Gas Components and Gas-Brine Ratios of Gas Flashed From Post Separator Brine (Field Analysis)

Sample Date and Time	Gas/Brine (ft^3/bbl)	Concentration, mole percent							
		Methane	Ethane	Propane (3)	n - Butane	Isobutane	Pentanes	Carbon Dioxide	Nitrogen (4)
23 July 80 (1) 1230	1.31	84.41	1.49	0.15	.01	.02	.02	13.42	0.46
29 July 80 2300	1.35	80.1	1.5	0.13	<0.1	<0.1	<0.1	17.4	0.9
30 July 80 (2) 1500	1.51	88.0	1.5	0.17	<0.1	<0.1	<0.1	9.8	0.6
31 July 80 1330	3.10	81.6	1.3	0.14	<0.1	<0.1	<0.1	16.0	0.8
31 July 80 1730	3.20	83.3	1.4	0.14	<0.1	<0.1	<0.1	14.6	0.6
1 Aug 80 0930	4.27	84.1	1.3	0.14	<0.1	<0.1	<0.1	14.3	<0.1
1 Aug 80 1111	4.27	83.9	1.4	0.18	<0.1	<0.1	<0.1	14.4	0.1
1 Aug 80 1220	3.73 (5)	83.3	1.5	0.14	<0.1	<0.1	<0.1	14.0	1.0
2 Aug 80 1730	4.16	80.6	1.4	0.15	<0.1	<0.1	<0.1	17.8	0.1
3 Aug 80 0900	2.91	82.4	1.4	0.16	<0.1	<0.1	<0.1	15.9	0.1
3 Aug 80 1425	4.79	81.7	1.4	0.1	<0.1	<0.1	<0.1	16.7	0.1
3 Aug 80 2125	3.20	81.5	1.2	0.16	<0.1	<0.1	<0.1	17.0	0.1

(1) The July 23, 1980 1230 hour analysis is for a duplicate sample flashed in IGT's Chicago Laboratory and analyzed with the mass spectrometer. This is due to problems with the field analysis of the first sample.

(2) No duplicate sample was available to double check this field analysis of a July 30, 1980 1500 hour sample.

(3) The second significant digit after the decimal point for propane is questionable. It is reported only to provide more realistic indications of differences than those provided by rounded numbers.

(4) N_2 concentrations are not significant due to air contamination of the sample and the normalization to an oxygen free basis.

(5) Leakage may have occurred during 24 hours between collection and flashing.

the ratios of ethane and propane to methane are significantly less in gas flashed from separator brine than in flare line gas.

Figure 12-25 shows the relationship between separator pressure and gas content of brine leaving the separator. Both total gas content and methane content are shown. Also shown is methane solubility in brine calculated from the algorithm for methane solubility in distilled water developed by Dr. S. K. Garg of Systems Science and Software (SSS).[2] Methane solubility at separator conditions was also calculated using the equation published for higher pressures by Dr. Blount.[1] Values are too high to be shown on the scale of Figure 12-25; they range from 8.09 SCF/STB at 250 psia to 13.45 SCF/STB at 700 psia. These values were calculated using a brine temperature of 240°F. This is within 10° of the actual brine temperature at sample collection time for all reported analyses, except for the samples collected at about 250 psi on 7/23/80 and 7/29/80, when temperature was substantially lower. Since the algorithm developed by SSS calculated gas contents close to the measured total dry gas content (including CO_2) observed from flashing brine samples collected at a temperature near 240°F, the algorithm has been adopted for estimating brine content of gas remaining in disposal well brine.

12.6.2.3 Gas Samples by Third Parties: Several parties other than IGT collected and analyzed gas samples. Representatives of the following organizations collected their own samples on location:

- Weatherly Laboratories
- McNeese State University - Lake Charles, La.
- U. S. Geological Survey - Menlo Park, Calif.
- U. S. Geological Survey - NSTL Station, Miss.

In addition, IGT provided samples for carbon isotope analysis to Dr. Dennis Coleman of the Illinois State Geological Survey. Other organizations to whom invitations were extended included the University of Texas at Austin, Lawrence Berkeley Laboratory, Louisiana State University and, through LSU, the Louisiana State Geological Survey.

A combined sample log showing times of sample collection, location and type of samples collected, tests performed on location, and tests intended to be performed off-location, is presented as Appendix L in Volume II. The following information has been reported to IGT by parties that have analyzed gas samples.

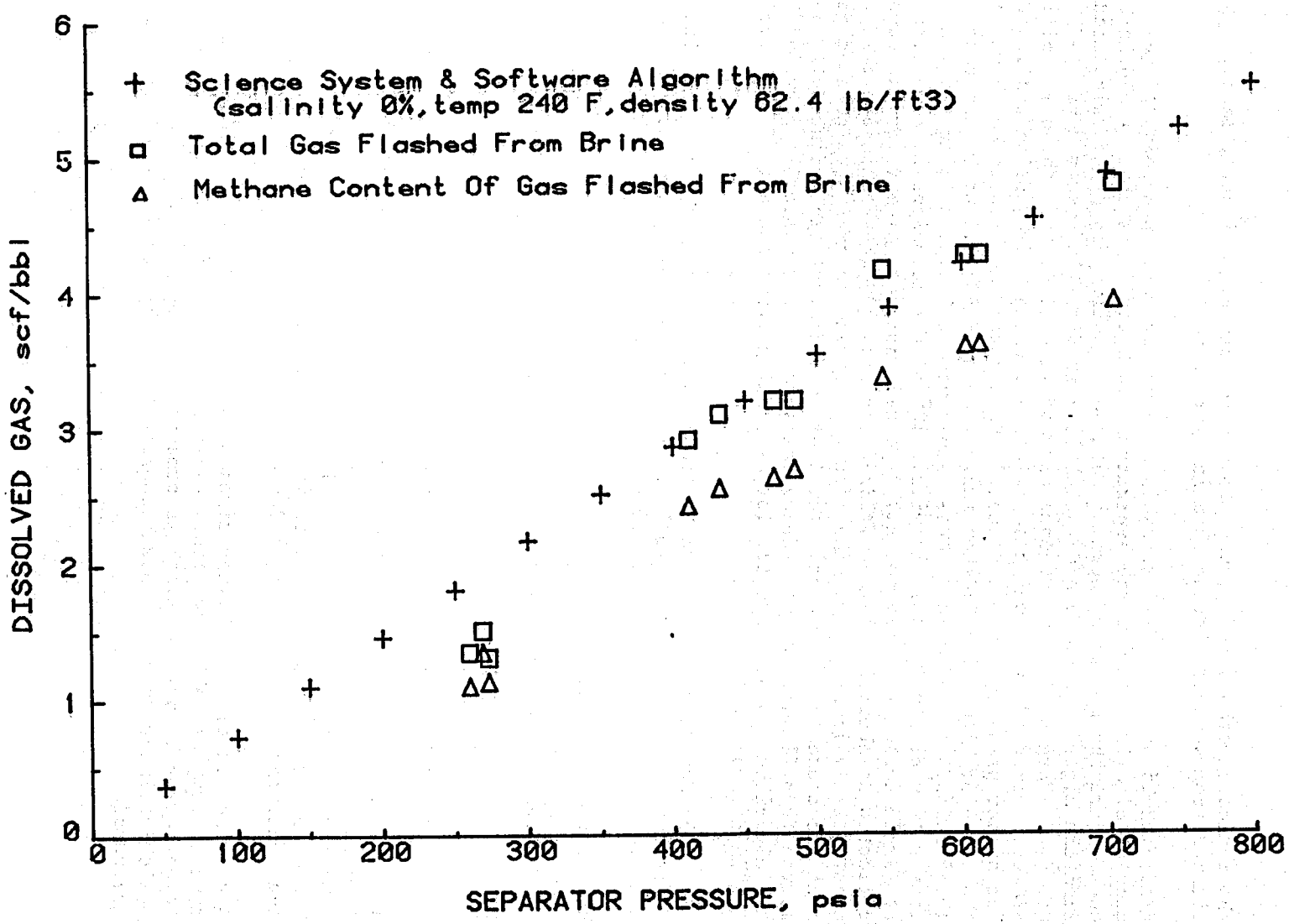


FIGURE 12-25. Separator Pressure Versus Gas Content: Post-Separator Brine

- Radioactivity Analyses: USGS Gulf Coast HydroScience Center (Thomas F. Kraemer and George Claypool)

Analytical results were provided to IGT in a letter dated October 16, 1980, from Mr. Thomas F. Kraemer. Gas analyses reported in the letter are presented in Figure 12-26.

Radioactivity analyses were performed by Mr. Kraemer. The reported gas analysis and carbon isotope data are from Mr. George Claypool, USGS, Denver, Colorado.

FIGURE 12-26
GAS COMPOSITION AND CARBON ISOTOPE DATA REPORTED
BY USGS GULF COAST HYDROSCIENCE CENTER
(Date: 8/1; Time: 1530 hours)

Component	Vol %
N	0.14
CH_4	92.11
CO_2	5.05
Ethane	2.17
Propane	0.37
Isobutane	0.13
N-butane	0.03
Isopentane	.001
n-Pentane	.001
$\delta^{13}C$(methane)	-42.5* (per milo)
C_1/C_1-C_5(%)	97.2

* This is a fairly typical value for gas wells in the area at about the same depth.

- Carbon Isotope Ratio Analysis: Illinois State Geological Survey (Dr. Dennis Coleman)

A portion of the gas sample collected by IGT at 1135 hours on August 3, 1980, was sent to Dr. Coleman for carbon isotope ratio analysis. His result for δC^{13} is -42.7, very close to the value reported by Dr. Claypool of USGS. The δC^{13} value is the difference between the C^{13}/C^{12} isotope ratios obtained for the samples and for an international standard. Dr. Coleman stated that thermogenic gas usually ranged from -40 to -55 δC^{13} values, with more mature gases having more positive values (closer to -40). The values for biogenic gases usually fall between -60 and -100. Both Dr. Coleman and Dr. Claypool stated that results from this relatively mature, thermogenic gas were typical of others for gas wells from similar conditions in the Gulf Coast area.

- Recombination and Differential Liberation Experiments: Weatherly Laboratories (Mr. John Neal)

Weatherly Laboratory, Inc. personnel collected several samples of separator gas and brine between 1100 and 1500 hours on August 1, 1980. The complete report from Weatherly Laboratories, Inc. is included as Appendix H in Volume II. Some of the salient features of reported data are summarized in the following paragraphs.

Samples were collected while the well was flowing at a rate of about 9500 barrels/day. Separator pressure at the time of sample collection was approximately 590 psig, and separator brine temperature was 240°F. Samples were collected only after separator operation had been stable for several minutes.

In contrast to IGT's brine sampling on the fluid metering skid, Weatherly brine samples were collected from a tap on the main separator vessel. The close agreement between the value of 4.3 SCF/bbl (of gas in separator brine) measured by Weatherly and the values of 4.27, 4.27, and 3.73 measured by IGT on the same date enhances confidence in the validity of both samples.

A gas/water ratio versus saturation pressure curve was developed by extrapolating results from recombination experiments at several gas/water ratios. Extrapolation to the original reservoir conditions of 13,142 psia at 274°F showed a solubility of 44.0 ft^3 of water-free separator gas (at 60°F and a pressure base of 15.025 psi) per barrel of brine (at 60°F and a pressure of 1 atmosphere). Changing to the pressure base of 14.73 psi used by IGT for reporting gas production resulted in a solution gas-brine ratio of 44.9 SCF/STB.

Differential liberation from a sample recombined to this solution gas/brine ratio at initial reservoir temperature and pressure was performed at pressure levels of 6000, 4500, 3000, 1500, and 15 psia. Chromatograph analyses of liberated gas were performed at each step in the sequence of pressure reductions. These analyses showed that the percent carbon dioxide increased dramatically from 1.56% on the first step (13,142 to 6,000 psi) to 9.57% on the final step (1500 to 15 psia). In contrast, the fraction of hydrocarbons heavier than methane decreased during the successive steps of gas liberation. For example, for the first step (13,142 to 6,000 psia), the ratio of liberated ethane to liberated methane was 0.0290. On the last step, from 1500 to 15 psia, the ratio of ethane to methane in liberated gas had dropped to 0.0147.

12.6.2.4 Selected Gas Composition for Production Computations: Chemical composition of the gas is a required input to determining gas production rate from orifice meter raw data (i.e., pressure, differential pressure, and temperature). While some variations in gas composition were observed, no correlation with variations in operating conditions was found. Therefore, the following composition was selected as representative of production and assumed constant in these computations.

Gas Component	Mole Percent
Nitrogen	0.11
Carbon Dioxide	5.88
Methane	91.72
Ethane	1.82
Propane	0.30
Isobutane	0.05
n-Butane	0.10
Pentanes	0.02
C6+	0.00

12.6.3 Produced Gas/Brine Ratio

Three subsections under this title provide 1) a detailed description of the field data interpretation used to deduce the ratio of produced gas to brine, 2) a comparison of the ratio with laboratory and published data on gas solubility, and 3) attempted validation of gas-to-water ratio from flashing of brine samples collected upstream of the separator.

12.6.3.1 Gas-to-Brine Ratio From Production Data: The following six-step procedure was followed in computing the produced gas/brine ratio:

- 1. Computing the gravity and heating value for the abovementioned average gas composition, using methodology prescribed in ANSI/ASTM D 3588-77. These values are:

  Dry gas heating value 975.8
  Dry gas gravity 0.6265.

- 2. Computing gas production to the flare line using methodology prescribed in A.G.A. Gas Committee Measurement Report No. 3. One departure was required, because gas temperature was higher than in the tables for determining supercompressibility ($F_{pv} = 1/\sqrt{z}$). The values of z used for interpretation were calculated for various separator pressures and temperatures, using a computer program developed by IGT for a different project. The values used are:

Test	Pressure, psig	Temperature, °F	Supercompressibility
1	250	180	1.0076
2	250	225	1.0080
3	460	238	1.0096
3	590-612	230-240	1.0127
4	533	217	1.0127
4	396	215	1.0096
4	689	212	1.0169
4	457	217	1.0112

- 3. Reducing calculated gas production by an amount corresponding to the ratio of partial pressure of water at orifice meter temperature to absolute separator pressure. The greatest reduction was 9% and occurred at the end of the second flow test when separator pressure was 260 psia and orifice meter temperature was 230°F.

- 4. Reducing brine production as measured by the turbine meter to account for the difference in brine volume between standard conditions (60°F, 1 atm) and actual brine temperature and pressure in the turbine meter. Thermal expansion of brine due to the high actual temperature is much greater than the compression of brine due to separator pressure. The largest correction, slightly over 5%, occurred during the evening of July 31 when brine temperature reached 257°F at a separator pressure of 415 psia.

- 5. Dividing the results of 3) by the results of 4) to deduce the flared gas/brine ratio.

- 6. Adding the gas/brine ratios for the disposal well brine stream and the flare line. The gas content of brine to the disposal well is

estimated using an algorithm developed by System Science and Software to fit the data of Culbertson and McKetta as previously discussed. The maximum addition for gas content of the disposal well brine stream was 4.86 SCF/bbl during the afternoon of August 3, when separator pressure was at the maximum value of slightly over 700 psia and brine temperature was 227°F.

This procedure was performed on a microcomputer using 1-hour averaging of edited raw data. A complete listing of input raw data is provided in Appendix F of Volume 2. One-hour averaging was selected because of variations in calculated brine rate due to the small variations in the time of hand logging of cumulative brine production from turbine meter readouts. (These readouts display cumulative production. Brine rate is determined by subtracting successive readings and dividing by the time interval.) The following procedure was followed to provide 1-hour averages from the edited raw data values.

- Linear averages over each hour were calculated for gas temperature (orifice meter) and brine temperature.

- Gas production rate was calculated at the time of each line of edited raw data. A linear average of these calculated values was then performed over each hour.

- Brine rate was calculated from hourly manual readings and then corrected to standard conditions using the linear averages of turbine meter temperature and pressure over that hour.

- Linear averages of brine temperature and separator pressure over each hour were used to calculate the ratio of gas-to-brine in brine to the disposal well.

Daily summaries of production are shown in Figure 12-27, Parts 1-5. These summaries include daily and cumulative production quantities for both natural gas and thermal energy in units of millions of Btu's, as well as hourly values of temperature, brine production, gas production, and produced gas/brine ratio. Natural gas energy is calculated by multiplying the volume of gas production by the heating value of the gas. Thermal energy production calculations are based on a specific heat of 1.0 Btu/lb for brine and a base temperature of 120°F. This base temperature is higher than the value of 60°F used in the United States Geological Survey estimates of the thermal energy resource base. A more comprehensive listing of key parameters in computations of hourly values of produced gas/water ratio and produced energy is provided in Appendix I of Volume II.

Note that Figure 12-27, Parts 1-5, reports estimated total gas production. This consists of measured gas from the flare line plus an estimate of gas remaining in solution in disposal well brine. Details are provided in Appendix I.

FIGURE 12-27, Part 1

IGT WELL TEST ANALYSIS
****

WAINOCO P.R.GIROUARD WELL NO.1

DATE: 7/22/80

GAS COMPOSITION:

NITROGEN	.0011
CARBON DIOXIDE	.0588
METHANE	.9172
ETHANE	.0182
PROPANE	.0030
ISOBUTANE	.0005
n-BUTANE	.0010
PENTANES	.0002
C6+	0.0000

CALCULATED GAS PROPERTIES:
DRY GAS HTG VAL... = 975.82
DRY GAS GRAVITY...= .6265

PRES BASE=14.73; TEMP BASE=60F
THERMAL ENERGY BASE TEMP =120F

PRODUCTION SUMMARY:

	GAS (MCF)	GAS (MMBTU)	THERMAL (MMBTU)
DAILY	27.5	26.8	13.0
CUM.	27.5	26.8	13.0

PRODUCTION DETAILS:

TIME	BRINE DEGF	BRINE STBPD	GAS MCF/D	GAS SCF/STB
0100	-	0.	0.0	0.00
0200	-	0.	0.0	0.00
0300	-	0.	0.0	0.00
0400	-	0.	0.0	0.00
0500	-	0.	0.0	0.00
0600	-	0.	0.0	0.00
0700	-	0.	0.0	0.00
0800	-	0.	0.0	0.00
0900	-	0.	0.0	0.00
1000	-	0.	0.0	0.00
1100	-	0.	0.0	0.00
1200	-	0.	0.0	0.00
1300	-	0.	0.0	0.00
1400	-	0.	0.0	0.00
1500	-	0.	0.0	0.00
1600	-	0.	0.0	0.00
1700	-	0.	0.0	0.00
1800	-	0.	0.0	0.00
1900	-	0.	0.0	0.00
2000	110	1885.	59.4	31.53
2100	165	3571.	153.2	42.90
2200	180	3750.	150.0	40.00
2300	185	3727.	148.3	39.79
2400	190	3767.	148.0	39.28

IGT WELL TEST ANALYSIS
****

WAINOCO P.R.GIROUARD WELL NO.1

DATE: 7/23/80

GAS COMPOSITION:

NITROGEN	.0011
CARBON DIOXIDE	.0588
METHANE	.9172
ETHANE	.0182
PROPANE	.0030
ISOBUTANE	.0005
n-BUTANE	.0010
PENTANES	.0002
C6+	0.0000

CALCULATED GAS PROPERTIES:
DRY GAS HTG VAL... = 975.82
DRY GAS GRAVITY...= .6265

PRES BASE=14.73; TEMP BASE=60F
THERMAL ENERGY BASE TEMP =120F

PRODUCTION SUMMARY:

	GAS (MCF)	GAS (MMBTU)	THERMAL (MMBTU)
DAILY	131.7	128.6	100.3
CUM.	159.2	155.3	113.3

PRODUCTION DETAILS:

TIME	BRINE DEGF	BRINE STBPD	GAS MCF/D	GAS SCF/STB
0100	190	3781.	149.0	39.40
0200	195	3749.	148.6	39.65
0300	197	3737.	148.9	39.85
0400	200	3752.	148.2	39.49
0500	200	3824.	151.8	39.69
0600	203	3903.	154.8	39.65
0700	205	3864.	154.5	39.98
0800	205	3940.	156.6	39.75
0900	205	3970.	157.5	39.67
1000	205	4012.	159.4	39.74
1100	205	4037.	159.7	39.56
1200	210	4058.	162.0	39.92
1300	210	4058.	162.4	40.01
1400	211	4158.	163.2	39.24
1500	213	4151.	165.4	39.85
1600	215	4030.	165.2	41.00
1700	214	4247.	166.5	39.20
1800	215	4178.	166.5	39.84
1900	215	4127.	167.7	40.63
2000	210	3935.	153.9	39.10
2100	-	0.	0.0	0.00
2200	-	0.	0.0	0.00
2300	-	0.	0.0	0.00
2400	-	0.	0.0	0.00

FIGURE 12-27, Part 2

IGT WELL TEST ANALYSIS
****

WAINOCO P.R.GIROUARD WELL NO.1

DATE: 7/29/80

GAS COMPOSITION:

NITROGEN	.0011
CARBON DIOXIDE	.0588
METHANE	.9172
ETHANE	.0182
PROPANE	.0030
ISOBUTANE	.0005
n-BUTANE	.0010
PENTANES	.0002
C6+	0.0000

CALCULATED GAS PROPERTIES:
DRY GAS HTG VAL... = 975.82
DRY GAS GRAVITY....= .6265

PRES BASE=14.73; TEMP BASE=60F
THERMAL ENERGY BASE TEMP =120F

PRODUCTION SUMMARY:

	GAS (MCF)	GAS (MMBTU)	THERMAL (MMBTU)
DAILY	21.5	21.0	10.0
CUM.	21.5	21.0	10.0

PRODUCTION DETAILS:

TIME	BRINE DEGF	BRINE STBPD	GAS MCF/D	GAS SCF/STB
0100	-	0.	0.0	0.00
0200	-	0.	0.0	0.00
0300	-	0.	0.0	0.00
0400	-	0.	0.0	0.00
0500	-	0.	0.0	0.00
0600	-	0.	0.0	0.00
0700	-	0.	0.0	0.00
0800	-	0.	0.0	0.00
0900	-	0.	0.0	0.00
1000	-	0.	0.0	0.00
1100	-	0.	0.0	0.00
1200	-	0.	0.0	0.00
1300	-	0.	0.0	0.00
1400	-	0.	0.0	0.00
1500	-	0.	0.0	0.00
1600	-	0.	0.0	0.00
1700	-	0.	0.0	0.00
1800	-	0.	0.0	0.00
1900	-	0.	0.0	0.00
2000	-	0.	0.0	0.00
2100	-	0.	0.0	0.00
2200	-	0.	0.0	0.00
2300	139	6016.	234.6	39.00
2400	201	7046.	280.7	39.84

IGT WELL TEST ANALYSIS
****

WAINOCO P.R.GIROUARD WELL NO.1

DATE: 7/30/80

GAS COMPOSITION:

NITROGEN	.0011
CARBON DIOXIDE	.0588
METHANE	.9172
ETHANE	.0182
PROPANE	.0030
ISOBUTANE	.0005
n-BUTANE	.0010
PENTANES	.0002
C6+	0.0000

CALCULATED GAS PROPERTIES:
DRY GAS HTG VAL... = 975.82
DRY GAS GRAVITY....= .6265

PRES BASE=14.73; TEMP BASE=60F
THERMAL ENERGY BASE TEMP =120F

PRODUCTION SUMMARY:

	GAS (MCF)	GAS (MMBTU)	THERMAL (MMBTU)
DAILY	293.7	286.6	292.6
CUM.	315.2	307.5	302.6

PRODUCTION DETAILS:

TIME	BRINE DEGF	BRINE STBPD	GAS MCF/D	GAS SCF/STB
0100	216	6913.	274.5	39.71
0200	220	6841.	273.0	39.91
0300	224	6720.	270.8	40.30
0400	226	6753.	268.8	39.80
0500	227	6755.	267.3	39.56
0600	230	6917.	277.3	40.10
0700	232	7086.	284.4	40.13
0800	234	7178.	285.9	39.84
0900	235	7194.	287.7	39.99
1000	235	7342.	294.0	40.04
1100	236	7463.	299.2	40.09
1200	235	7474.	300.3	40.18
1300	236	7497.	301.3	40.19
1400	237	7440.	303.9	40.84
1500	237	7535.	300.4	39.86
1600	237	7508.	300.2	39.98
1700	238	7483.	300.4	40.15
1800	238	7524.	301.7	40.10
1900	238	7556.	303.2	40.12
2000	239	7665.	307.7	40.14
2100	239	7751.	311.0	40.12
2200	237	7780.	311.3	40.01
2300	239	7806.	312.1	39.98
2400	241	7769.	312.3	40.20

FIGURE 12-27, Part 3

IGT WELL TEST ANALYSIS
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WAINOCO P.R.GIROUARD WELL NO.1

DATE: 7/31/80

GAS COMPOSITION:

NITROGEN	.0011
CARBON DIOXIDE	.0588
METHANE	.9172
ETHANE	.0182
PROPANE	.0030
ISOBUTANE	.0005
n-BUTANE	.0010
PENTANES	.0002
C6+	0.0000

CALCULATED GAS PROPERTIES:
DRY GAS HTG VAL... = 975.82
DRY GAS GRAVITY....= .6265

PRES BASE=14.73; TEMP BASE=60F
THERMAL ENERGY BASE TEMP =120F

PRODUCTION SUMMARY:

	GAS (MCF)	GAS (MMBTU)	THERMAL (MMBTU)
DAILY	409.2	399.4	409.4

PRODUCTION DETAILS:

TIME	BRINE DEGF	BRINE STBPD	GAS MCF/D	GAS SCF/STB
0100	241	7786.	312.8	40.17
0200	241	7823.	313.3	40.05
0300	241	7900.	313.7	39.71
0400	241	7967.	314.4	39.47
0500	241	8017.	313.9	39.16
0600	241	8055.	313.9	38.97
0700	238	6597.	261.7	39.67
0800	167	0.	0.0	0.00
0900	140	0.	0.0	0.00
1000	127	0.	0.0	0.00
1100	119	0.	0.0	0.00
1200	166	6121.	393.4	64.26
1300	243	12778.	575.7	45.06
1400	255	14236.	601.0	42.22
1500	246	12175.	561.0	46.08
1600	249	14559.	558.3	38.35
1700	250	14515.	540.6	37.25
1800	244	10293.	523.1	50.83
1900	250	13199.	655.8	49.68
2000	252	14479.	750.2	51.81
2100	254	14432.	693.5	48.05
2200	253	13507.	591.9	43.82
2300	252	14280.	606.5	42.48
2400	253	14294.	627.1	43.87

IGT WELL TEST ANALYSIS
****

WAINOCO P.R.GIROUARD WELL NO.1

DATE: 8/01/80

GAS COMPOSITION:

NITROGEN	.0011
CARBON DIOXIDE	.0588
METHANE	.9172
ETHANE	.0182
PROPANE	.0030
ISOBUTANE	.0005
n-BUTANE	.0010
PENTANES	.0002
C6+	0.0000

CALCULATED GAS PROPERTIES:
DRY GAS HTG VAL... = 975.82
DRY GAS GRAVITY....= .6265

PRES BASE=14.73; TEMP BASE=60F
THERMAL ENERGY BASE TEMP =120F

PRODUCTION SUMMARY:

	GAS (MCF)	GAS (MMBTU)	THERMAL (MMBTU)
DAILY	259.6	253.3	284.4

PRODUCTION DETAILS:

TIME	BRINE DEGF	BRINE STBPD	GAS MCF/D	GAS SCF/STB
0100	252	11654.	713.8	61.25
0200	245	9362.	506.1	54.06
0300	244	9429.	351.1	37.23
0400	243	9451.	343.2	36.32
0500	244	9487.	349.5	36.84
0600	247	9491.	347.5	36.61
0700	248	9516.	351.1	36.90
0800	248	9539.	347.9	36.47
0900	247	9551.	355.1	37.18
1000	249	9556.	422.8	44.25
1100	250	9547.	410.1	42.95
1200	250	9573.	359.2	37.53
1300	249	9128.	357.9	39.21
1400	249	10041.	360.9	35.94
1500	249	9548.	362.4	37.96
1600	246	7814.	291.2	37.26
1700	-	0.	0.0	0.00
1800	-	0.	0.0	0.00
1900	-	0.	0.0	0.00
2000	-	0.	0.0	0.00
2100	-	0.	0.0	0.00
2200	-	0.	0.0	0.00
2300	-	0.	0.0	0.00
2400	-	0.	0.0	0.00

FIGURE 12-27, Part 4

IGT WELL TEST ANALYSIS
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WAINOCO P.R.GIROUARD WELL NO.1

DATE: 8/02/80

GAS COMPOSITION:

NITROGEN	.0011
CARBON DIOXIDE	.0588
METHANE	.9172
ETHANE	.0182
PROPANE	.0030
ISOBUTANE	.0005
n-BUTANE	.0010
PENTANES	.0002
C6+	0.0000

CALCULATED GAS PROPERTIES:
DRY GAS HTG VAL... = 975.82
DRY GAS GRAVITY....= .6265

PRES BASE=14.73; TEMP BASE=60F
THERMAL ENERGY BASE TEMP =120F

PRODUCTION SUMMARY:

	GAS (MCF)	GAS (MMBTU)	THERMAL (MMBTU)
DAILY	100.7	98.2	76.3
CUM.	100.7	98.2	76.3

PRODUCTION DETAILS:

TIME	BRINE DEGF	BRINE STBPD	GAS MCF/D	GAS SCF/STB
0100	-	0.	0.0	0.00
0200	-	0.	0.0	0.00
0300	-	0.	0.0	0.00
0400	-	0.	0.0	0.00
0500	-	0.	0.0	0.00
0600	-	0.	0.0	0.00
0700	-	0.	0.0	0.00
0800	-	0.	0.0	0.00
0900	-	0.	0.0	0.00
1000	-	0.	0.0	0.00
1100	-	0.	0.0	0.00
1200	-	0.	0.0	0.00
1300	-	0.	0.0	0.00
1400	-	0.	0.0	0.00
1500	-	0.	0.0	0.00
1600	123	3566.	180.3	50.55
1700	188	5998.	371.1	61.87
1800	208	6739.	284.6	42.23
1900	217	6709.	262.9	39.18
2000	222	6732.	264.0	39.22
2100	226	6697.	264.3	39.46
2200	228	6670.	263.5	39.50
2300	230	6647.	261.8	39.38
2400	230	6634.	263.8	39.77

IGT WELL TEST ANALYSIS
****

WAINOCO P.R.GIROUARD WELL NO.1

DATE: 8/03/80

GAS COMPOSITION:

NITROGEN	.0011
CARBON DIOXIDE	.0588
METHANE	.9172
ETHANE	.0182
PROPANE	.0030
ISOBUTANE	.0005
n-BUTANE	.0010
PENTANES	.0002
C6+	0.0000

CALCULATED GAS PROPERTIES:
DRY GAS HTG VAL... = 975.82
DRY GAS GRAVITY....= .6265

PRES BASE=14.73; TEMP BASE=60F
THERMAL ENERGY BASE TEMP =120F

PRODUCTION SUMMARY:

	GAS (MCF)	GAS (MMBTU)	THERMAL (MMBTU)
DAILY	275.0	268.3	278.8
CUM.	375.6	366.6	355.1

PRODUCTION DETAILS:

TIME	BRINE DEGF	BRINE STBPD	GAS MCF/D	GAS SCF/STB
0100	233	6615.	263.1	39.78
0200	233	6604.	261.4	39.58
0300	234	6592.	260.7	39.55
0400	234	6585.	260.1	39.50
0500	234	6577.	259.9	39.52
0600	234	6574.	259.4	39.45
0700	233	6566.	258.8	39.42
0800	234	6560.	260.9	39.77
0900	234	6554.	261.2	39.86
1000	233	6538.	260.3	39.81
1100	231	6545.	258.5	39.49
1200	231	6550.	258.9	39.52
1300	232	6523.	260.3	39.90
1400	229	6591.	260.6	39.53
1500	227	6484.	264.0	40.71
1600	226	6482.	263.2	40.61
1700	227	6469.	261.6	40.44
1800	228	6465.	258.6	40.00
1900	228	6493.	260.4	40.10
2000	229	6482.	254.4	39.24
2100	234	6506.	252.1	38.75
2200	238	7869.	305.8	38.86
2300	251	10919.	419.2	38.39
2400	253	10878.	415.7	38.22

FIGURE 12-27, Part 5

IGT WELL TEST ANALYSIS
****

WAINOCO P.R.GIROUARD WELL NO.1

DATE: 8/04/80

GAS COMPOSITION:

NITROGEN	.0011
CARBON DIOXIDE	.0588
METHANE	.9172
ETHANE	.0182
PROPANE	.0030
ISOBUTANE	.0005
n-BUTANE	.0010
PENTANES	.0002
C6+	0.0000

CALCULATED GAS PROPERTIES:
DRY GAS HTG VAL... = 975.82
DRY GAS GRAVITY....= .6265

PRES BASE=14.73; TEMP BASE=60F
THERMAL ENERGY BASE TEMP =120F

PRODUCTION SUMMARY:

	GAS (MCF)	GAS (MMBTU)	THERMAL (MMBTU)
DAILY	8.4	8.2	7.9
CUM.	384.1	374.8	363.0

PRODUCTION DETAILS:

TIME	BRINE DEGF	BRINE STBPD	GAS MCF/D	GAS SCF/STB
0100	219	5472.	202.5	37.00
0200	127	0.	0.0	0.00
0300	101	0.	0.0	0.00
0400	-	0.	0.0	0.00
0500	-	0.	0.0	0.00
0600	-	0.	0.0	0.00
0700	-	0.	0.0	0.00
0800	-	0.	0.0	0.00
0900	-	0.	0.0	0.00
1000	-	0.	0.0	0.00
1100	-	0.	0.0	0.00
1200	-	0.	0.0	0.00
1300	-	0.	0.0	0.00
1400	-	0.	0.0	0.00
1500	-	0.	0.0	0.00
1600	-	0.	0.0	0.00
1700	-	0.	0.0	0.00
1800	-	0.	0.0	0.00
1900	-	0.	0.0	0.00
2000	-	0.	0.0	0.00
2100	-	0.	0.0	0.00
2200	-	0.	0.0	0.00
2300	-	0.	0.0	0.00
2400	-	0.	0.0	0.00

Variations in calculated gas/water ratio with time are shown graphically in Figure 12-28, Parts 1 and 2. Although this figure indicates some large variations in hourly values of gas/water ratio, it is most probable that the ratio of gas-to-brine in the reservoir is 40 SCF/STB. Reasons for this conclusion are discussed in the following chronological observations.

- Production Flow Tests 1 and 2 (afternoon 7/22/80 through 0700 hours 7/31/80: With the exception of start-up and shutdown periods, stable separator operations at a pressure of 250 psi and a differential pressure in excess of 25 inches of water were experienced on these tests. The first test provides the most reliable measurement of gas-to-brine ratio because pressure drawdown was minimal. Thus there is little, if any, distortion of the ratio by gas coming out of solution in the reservoir and being trapped.

- Third Production Flow Test (mid-day 7/31/80 through afternoon 8/1/80): The 7/31/80 portion of this flow test was at the maximum feasible brine production rate. The high calculated values of gas-to-brine ratio in this period are erroneous because of linear averaging of orifice differential pressure during large oscillations in separator operation. The character of these oscillations is shown in Figure 12-29. Averaging of instantaneous values of 5-second time intervals was provided by the data acquisition system. However, instantaneous gas production depends upon the square root of the instantaneous value of the product of separator static pressure and orifice differential pressure. For oscillations of this type, the average of instantaneous square root values would be substantially smaller than the square root of the average of instantaneous values. IGT's computer software for data acquisition is being revised for future tests, so that square roots will be taken at each 5-second reading.

After the flow rate had been reduced to achieve stable separator operation shortly after midnight on 7/31/80, the calculated gas-to-brine ratio averaged about 37 SCF/STB. Minimal significance is attached to this value because orifice differential pressure was only about 5 inches of water. For this very low differential pressure, a zero offset of 0.84 inches of water would change the calculated ratio to 40 SCF/STB. In contrast, for the differential pressure of 40 inches of water during the first flow test, a zero offset of 0.84 inches of water changed the calculated value of the ratio only from 40 to 39.6 A zero offset of less than 1 inch of water could well have resulted from either condensation in the small tubing to the differential pressure gauge or accumulation of water in the small tube during separator upsets characterized by brine production through the flare line.

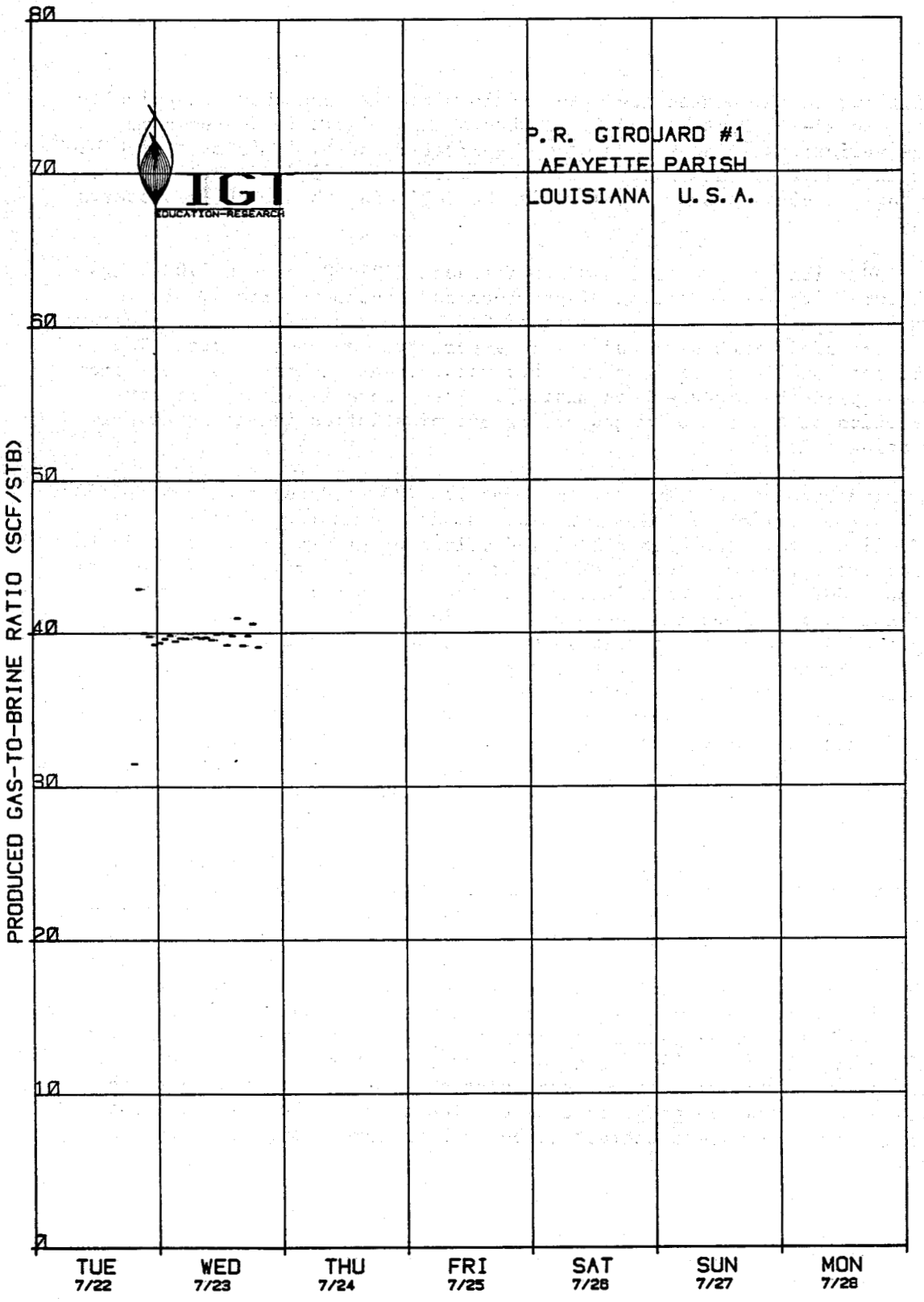

FIGURE 12-28, Part 1. Hourly Values of Gas-to-Brine Ratio

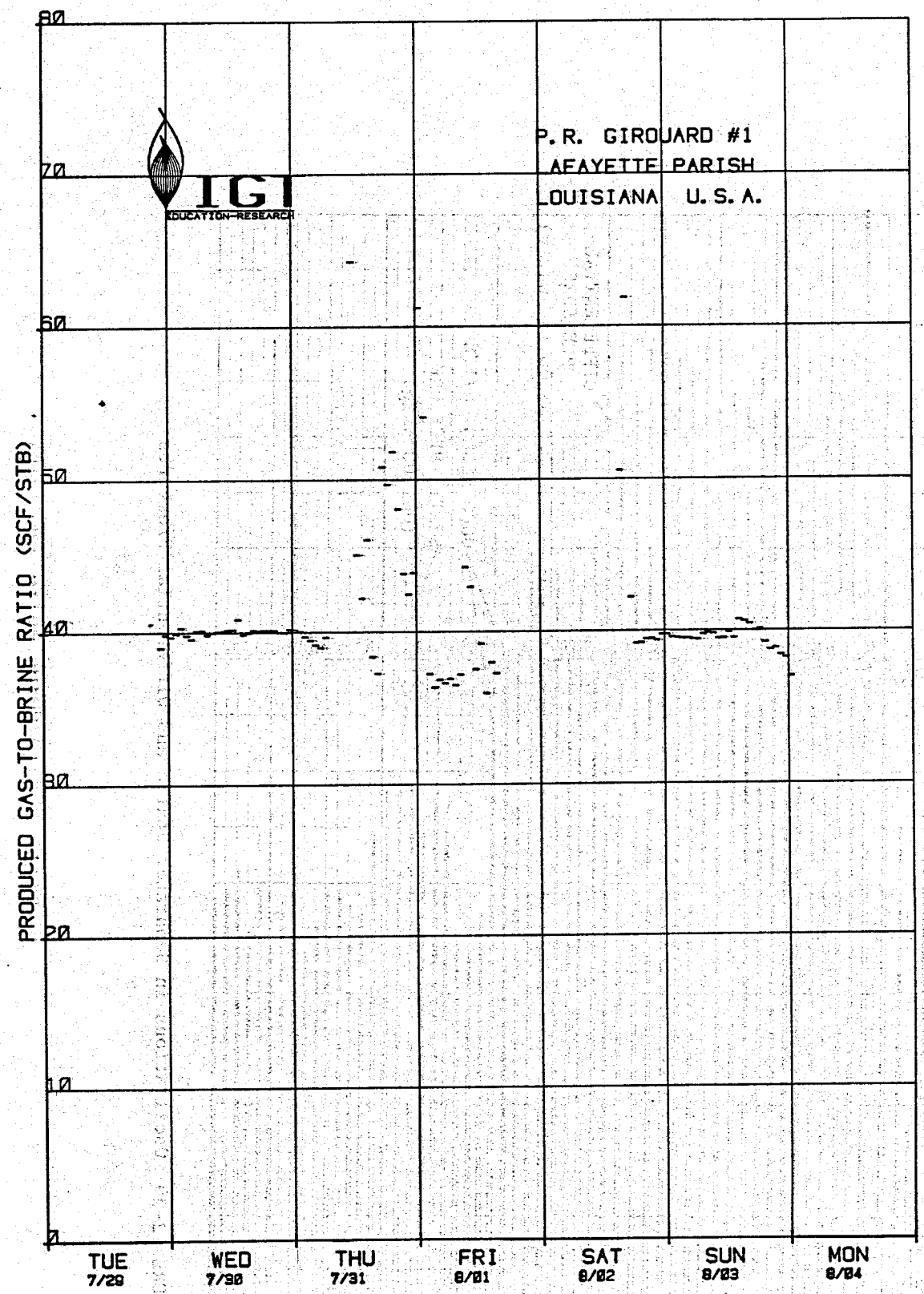

FIGURE 12-28, Part 2. Hourly Values of Gas-to Brine Ratio

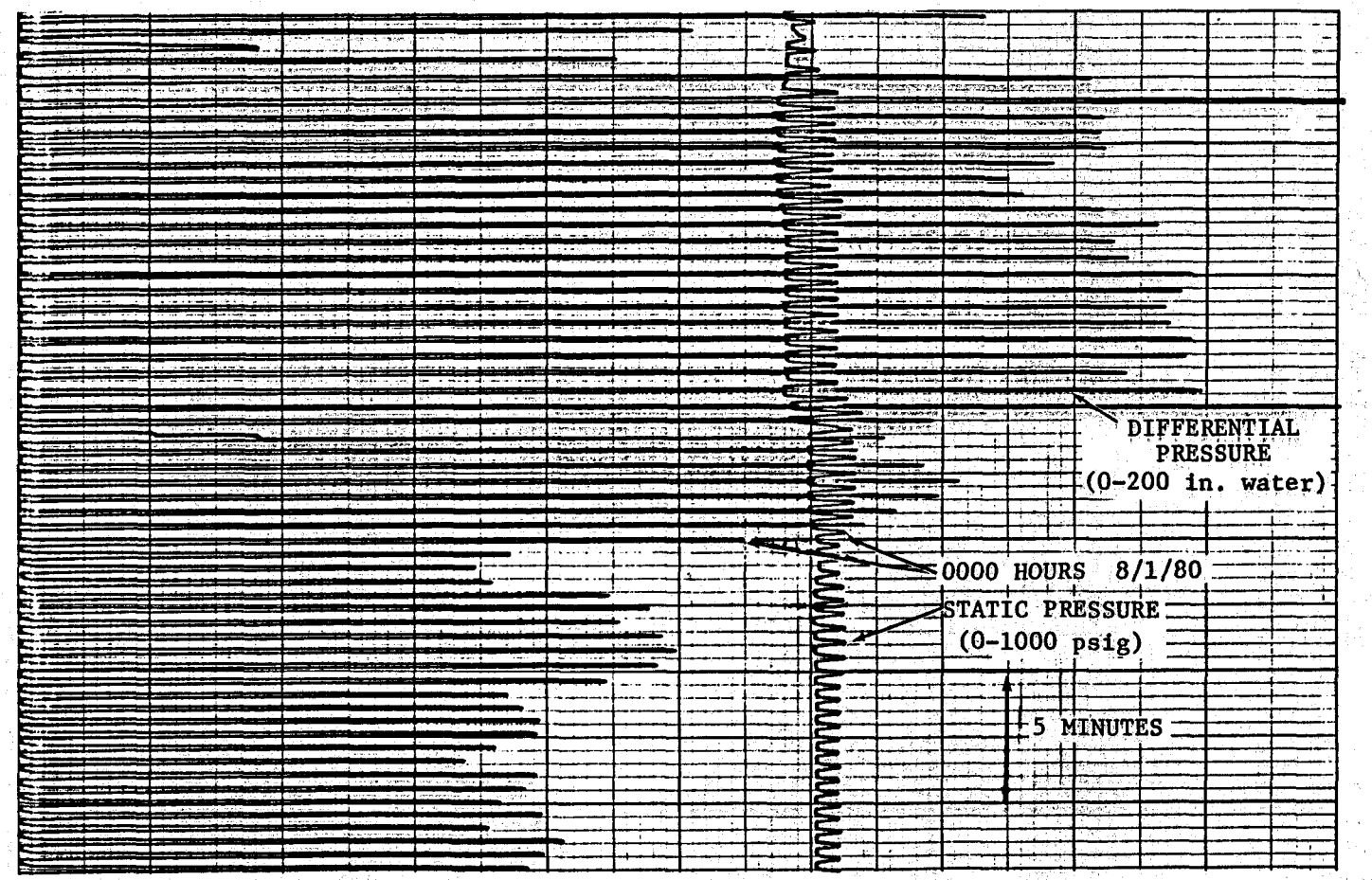

FIGURE 12-29 Oscillations in Separator Static and Differential Pressures

• Fourth Production Flow Test (8/2/80 through 8/4/80): During the first 24 hours of the test, the calculated gas/water ratio averaged about 39.5 SCF/STB. This is very close to the 40 SCF/STB from the first two flow tests and is considered less accurate because differential pressure was relatively low (8 to 16 inches of water). The most significant aspect of the fourth flow test is the consistency in calculated gas/brine ratio for variations in separator pressure between extremes of 396 psig and 689 psig. Between these extremes the correction for gas remaining in solution in brine to the disposal well varied from 2.92 to 4.86 SCF/STB. With this correction, values of calculated gas/brine ratio were consistent within about 1 SCF/STB. This consistency in calculated gas/brine ratio over a wide range in separator pressure provides validation of the six-step data interpretation procedure used.

Cumulative production and overall average values of gas-to-brine ratio for the four instrumented flow tests are as follows:

Test	Brine STB	Thermal Energy, MMBtu	Dry Gas MCF	Dry Gas MBtu	Gas to Brine Ratio SCF/STB
1	4,009	113.3	159.2	155.3	39.71
2	10,132	398.2	404.5	394.7	39.92
3	13,398	598.2	579.5	565.5	43.25
4	9,537	363.0	384.1	374.8	40.27
Total	37,075	1,472.7	1,527.2	1,490.3	

Since the gas-to-brine ratio for Test 3 is known to be erroneously high, due to averaging during separator oscillations, the overall gas-to-brine ratio has been calculated from the sum of gas and brine production for Tests 1, 2, and 4 only. The result is 40.06 SCF/STB.

12.6.3.2 Comparison With Laboratory and Published Data on Methane Solubility: As discussed above, analysis of field data has concluded that the most probable value of the produced gas-to-brine ratio is 40 SCF/STB. Figure 12-30 provides a basis for comparing this result with laboratory data concerning methane solubility in brine at reservoir temperature and pressure.

Methane solubilities in brine as a function of pressure for RDI's measured reservoir temperature of 274°F are plotted using:

- Curve 1: The equation published by C. W. Blount (Ref. 1) and a salinity of 23,000 ppm (Curve 1)

- Curve 2: The computer algorithm developed by S. K. Garg (Ref. 2) to fit the data of Culbertson and McKetta for methane solubility in distilled water.

- Curve 3: The equation developed by J. L. Haas (Ref. 3) to approximate data from multiple laboratory studies and a salinity of 23,000 ppm.

All three of these curves suggest that the previously deduced 40 SCF of dry gas (including CO_2)/STB of brine is less than the saturation value for methane solubility at reservoir temperature and pressure. Applying the Eaton Operating Company factor of 0.88[1] to Blount's equation at RDI's measured reservoir temperature and pressure yields an estimate of 44.5 SCF/bbl for methane solubility. This is more than 10% greater than the 40 SCF/STB deduced from production data.

Finally, Figure 12-30 contains data points from the recombination and differential liberation studies on separator samples collected on August 1, 1980, by J. Neal of Weatherly Laboratories. (Unfortunately, production data interpretation suggests that the produced gas-to-brine ratio at the time of sample collection was only about 38 SCF/STB. However, this should not effect the validity of the laboratory work). The points plotted were developed from the complete report in Appendix H, as follows:

- Recombination points were obtained by addition of 1) values obtained by flashing separator brine samples, and 2) the amount of separator gas added to separator brine at 274°F to reach the four observed bubble points. The plotted values for dissolved gas have been corrected for the difference in pressure base between the State of Louisiana value of 15.024 psi and the value of 14.73 psi used for production data interpretation.

- The point at reservoir pressure is based upon extrapolation due to pressure limitations as explained in Appendix H. The value plotted of 44.9 SCF/STB includes the pressure base adjustment.

- The four differential liberation points shown at pressures of 1500, 3000, 4500 and 6000 psia are from Appendix H and have been adjusted to a pressure base of 14.73 psi.

Note 1.: The EOC factor of 0.88, to be applied to Blount's equation, has been derived empirically, by comparing actual field results with those calculated by the equation.

The Weatherly Laboratory data from actual samples of produced gas and produced brine lies within the range of various fits to laboratory studies using pure methane, distilled water, and sodium chloride. It is interesting to note that the Weatherly value of 44.9 SCF/STB for a pressure base of 14.73 psi is virtually identical to the value of 44.5 SCF/bbl obtained by multiplying the value calculated with the Blount equation by 0.88.

These comparisons imply that the gas content of reservoir brine is 10% or more below the saturation value or that the bubble point in the reservoir is at least 2000 psi below reservoir pressure. However, it is not clear that such a conclusion is warranted.

One major reason for doubting whether gas content of the reservoir is actually below saturation is the lack of increase of gas-to-brine ratio toward 44 to 45 SCF/STB during the fourth flow test. There is little doubt that pressure drawdown near the well bore was substantially in excess of 2000 psi during the 15,000 barrels/day portion of the third flow test. Thus a small amount of liberated gas should have accumulated in reservoir pores near the well bore during that time. If the reservoir brine were indeed undersaturated, this liberated gas should have dissolved in brine near the wellbore during the 24 hour buildup between the third and fourth flow tests. This additional dissolved gas would in turn have increased the gas-to-brine ratio during the fourth flow test.

The lack of scatter in hour-by-hour gas-to-brine ratios during periods of stable separator operation eliminates random error as a possible explanation for the difference of more than 10% between gas-to-brine ratio from production data and from laboratory analyses. However, the possibility of systematic error in data collection or interpretation cannot be eliminated. Three conceivable sources of systematic error are:

- Reservoir Temperature:

The single measurement of temperature gave a value 18°F higher than anticipated. Calibration of the downhole sensor was checked to within 2°F on the surface in boiling water. However, this check did not involve the same surface electronics as the downhole measurement. Also, only the temperature sensor, rather than the entire downhole assembly, was heated to the boiling point on the surface. At reservoir pressure, the sensitivity of the laboratory data (in Figure 12-30) to temperature is 1 SCF/bbl per 5°F.

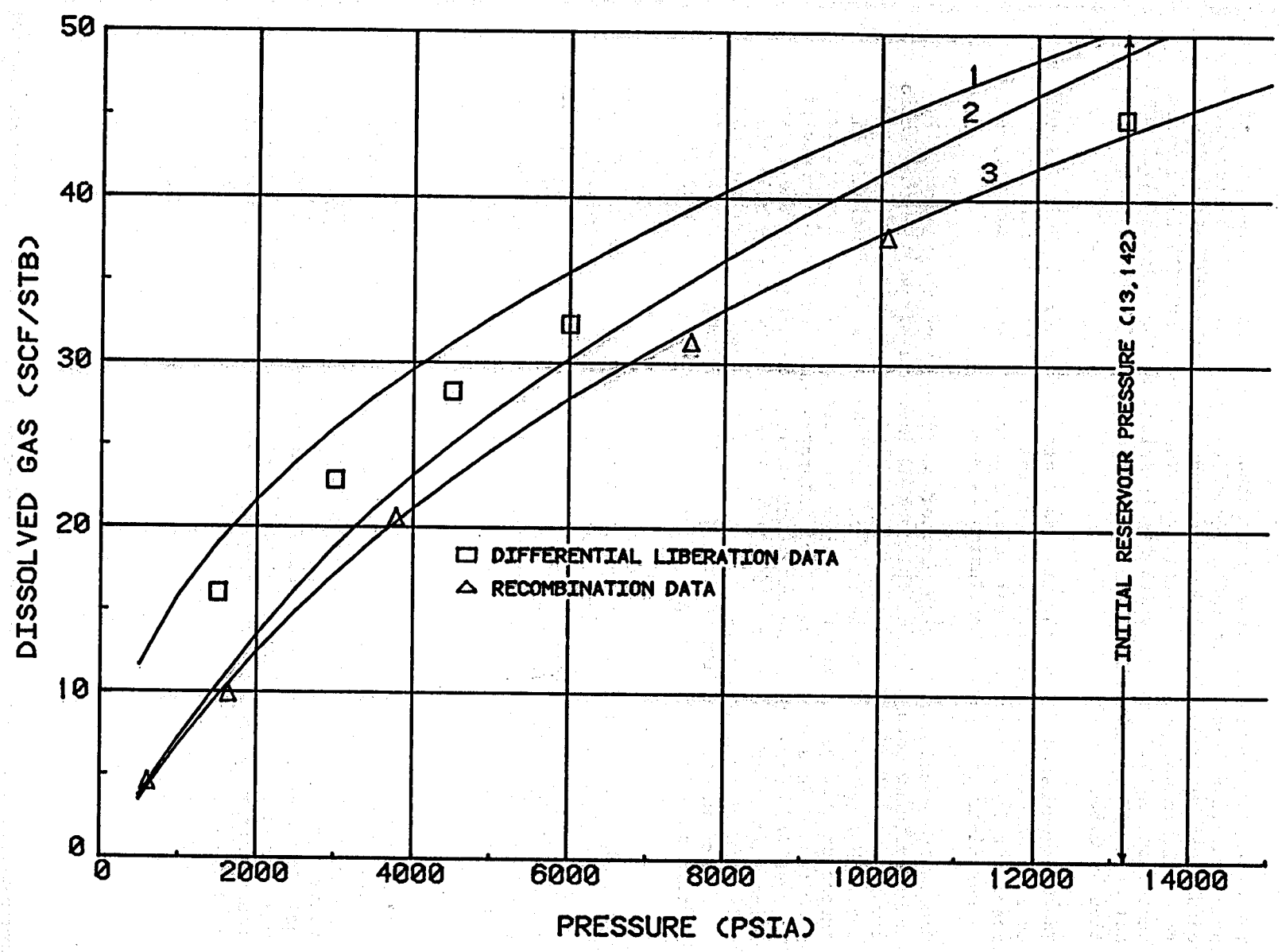

FIGURE 12-30 Laboratory and Published Data on Methane Solubility

- Orifice Meter Correction for Steam:

The correction procedure used assumes that steam obeys the ideal gas law in mixing with the other gases present. It is also assumed that the partial pressure of steam in the orifice corresponds to gas stream temperature, not the (roughly) 30°F higher temperature of brine in the separator. Possible steam-related systematic errors have not been evaluated.

- Gas Entrainment in Disposal Well Brine:

Flow dynamics at the IGT collection point for separator output brine samples mitigate against collection of any entrained gas bubbles in the samples flashed to determine gas content of brine to the disposal well. The very close agreement between flashes of IGT samples and the Weatherly Laboratory samples from the separator vessel itself at about the same time reduces likelihood of significant systematic error due to gas bubbles entrained in disposal well brine. If the brine leaving the separator contained 4 SCF/bbl of entrained gas, such gas would occupy slightly over 10% of stream volume at 250 psig and only 1.5% at 700 psig.

12.6.3.3 Gas Flashed From High-Pressure Brine Samples:

Independent measurements of produced gas/brine ratio were obtained by flashing high-pressure brine samples collected upstream from the large choke manifold. The intent was to validate conclusions reached from interpretation of measurements on separator output streams. The primary sampling point used was intended to be an advancement over sampling procedures used by IGT on the December 1979 test of the Pleasant Bayou No. 2 well. Samples were taken at wellhead pressure on Pleasant Bayou from a cross at the chokes, where the flow was highly turbulent at the production rate of about 15,000 barrels/day. On Wainoco P. R. Girouard No. 1, the primary sampling point involved a 1/4-inch ID "stinger" extended from a flange to a concentric position inside a 3-1/2 inch Schedule 160 spool from the wellhead. Samples from this location were collected after flowing many sample volumes using a fixed choke on the outlet end of the sample vessel to be flashed.

The procedure used did not provide data of sufficient quality to be useful in validating conclusions reached from the outputs of separator streams. No analyses were performed on gas from these samples. No direct measure of flow limited by the small choke downstream of the sample vessel was provided. Flow through the choke was estimated by assuming a velocity equal to the velocity of sound in water for each of the four choke sizes used.

Plans for future Wells of Opportunity tests include providing "turbolizers" upstream of the sample point plus a small turbine in the sample line so that sample velocity into the stinger can be controlled in relation to flow line fluid velocity.

Figure 12-31 provides details on gas-to-brine ratios from flashing of samples collected after flowing through the sample vessel with very different conditions at the tip of the stinger. The first set of samples was collected one at a time during flow tests when pressure drop was occurring at both the small choke on the wellhead (upstream of the sample point) and the large choke manifold (downstream from the sample point). At the times of sampling, pressure at the primary sampling point was between 3300 and 3850 psi. At this pressure, about 1.5% of the flowing fluid is expected to be in the gaseous phase. However, the flow rate of about 4300 barrels/day is too low for confidence that turbulence is sufficient to provide uniform distribution of gas bubbles in the 3-inch diameter flowing stream. The second set of samples was collected during production at over 15,000 barrels/day of brine. Pressure at the tip of the sampling stinger was only about 500 psi. Under these conditions more than 20% of the flowing stream volume is expected to be in the gaseous phase at the tip of the stinger. The very low values of gas-to-brine ratio observed clearly indicate that valid samples were not obtained.

Figure 12-31
Measured Gas/Water Ratios, Wainoco

Date	Time,	Inner Diameter of Choke, in.	Total Flow bbl/day	Pressure In Sample Vessel During Brine Flow, psi	Sample Point Pressure, psi	Gas/Water Ratio, ft^3/bbl	Ratio of Velocities*
7/23	1152	0.076	4240	2700	3300	27.2	6.47
7/23	1309	0.062	4260	3000	3300	43.1	3.88
7/23	1350	0.040	4280	3450	3400	34.9	1.40
7/23	1505	0.015	4285	3600	3450	19.5	0.19
7/23	1855	0.015	4350	3650	3550	20.2	0.19
7/31	—	0.094	15410	300		13.9	1.72
7/31	1637	0.076	15410	550		12.1	1.13
7/31	1650	0.076	15257	600		11.3	1.14
7/31	1743	0.062	15100	600		9.1	0.77
7/31	1803	0.040	15100	700		7.9	0.32
7/31	1817	0.040	15100	650		7.2	0.32
7/31	1833	0.015	15100	750		4.4	0.04

* Calculated assuming flow velocity through the choke tube to be equal to the velocity of sound in water.

12.6.4 Downhole Sampling

Two downhole fluid samples were taken on July 28 with Gearhart-Owen samplers. Recovered samples were analyzed. Results of gas analyses are presented in this section along with clues to actual sampling depths and details regarding operating experience with the sampler in this well. Results of brine analysis for the samples are presented in Section 12.6.4.3.

12.6.4.1 Sample Collection: Details of collection of each of the two samples are provided under the following sub-headings. Additional evidence regarding actual depth of filling for the samples is discussed in sub-section 12.6.4.3.

- First Sampling Operation (July 28, A.M.)

Between 11:00 a.m. and 11:30 a.m., the first sampler was lowered to 14,800 feet in the perforated interval, which extended from 14,717 to 14,824 feet. The well had previously been shut in since 1945 hours on July 23. The well was flowed about 5 barrels in about 45 minutes. after which the filling signal was transmitted. The sampler was at 14,800 feet for about 25 minutes.

Upon retrieval the sampler was full, though the detonator had not fired. This indicated that the sampler had filled prior to signalling. Later, examination revealed this to have been caused by failure of the rupture disk inside the sampler. A collar locator run with the sampler stopped working at 14,500 feet. This observation, coupled with the fact that it requires substantial pressure to make the rupture disk fail, prompted Gearhart-Owen personnel to surmise that the sampler filled at this depth, causing the collar locator to stop functioning.

- Second Sampling Operation (July 28, P.M.)

The second sampler was started into the hole at 1500 hours and reached 14,800 feet at 1530 hours. The well was flowed for about 10 minutes before the sampler reached 14,800 feet and before transmitting the actuation signal. This was to minimize time at depth and thereby reduce the likelihood of another failure.

Upon retrieval, it was found that premature filling had occurred again, this time due to extrusion of the O-ring used to seal the rupture disk. O-ring extrusion was enhanced because the disk retainer had only been tightened finger tight in assembly.

There are fewer clues as to when and where the second sampler filled. It was initially assumed that failure occurred at a much shallower depth than the first sampler since O-ring extrusion would occur at a lower pressure than rupture.

12.6.4.2 Sampler Handling and Gas Analysis: The first sampler was flashed to one atmosphere on the day of collection to determine gas-to-brine ratio. The liberated gas (31.0 SCF/BBL) was then analyzed with the field gas chromatograph. Its composition is shown in Figure 12-32. Brine from the sampler was handled and analyzed as described in subsection 12.6.4.3.

The second sampler was transported to Chicago before opening. Eight days after collection, flashing of the sample revealed a gas content of 30.8 SCF/BBL. Mass spectrometric analysis of the gas provided the composition shown in Figure 12-32.

Figure 12-32 also shows the average composition of flare line gas samples. Several differences in composition are apparent. The most significant of these are:

- H_2: The second downhole sample, which remained in the sampler for eight days, contained .37 mole percent H_2. The sample also contained a higher concentration of iron in solution. These observations are hypothesized to be due to reaction of the brine with sampler internal components during the eight days. A qualitative validation of this hypothesis resulted when H_2 gas and Fe_2O_3 were produced by placing synthetic brine in a bottomhole sampler and heating at temperatures up to 280°F during a four day period. The brine used contained 94,000 mg/ℓ NaCℓ and 1500 mg/ℓ $NaHCO_3$.

- CO_2: Both bottomhole samples contained less CO_2 than surface samples during production. This may reflect CO_2 loss by reactions during the 4.5 day residence time of brine in the well bore before sampling plus the additional eight days that the second sample remained in the sampler. Alternatively, the lower CO_2 may be due to less generation by precipitation of $CaCO_3$ from the downhole samples. This may be consistent with the higher Ca content of downhole sampler brine discussed in sections 12.6.4.4 and 12.7.4.5.

- C_2+ Fraction: The first downhole sample contained a lower mole percent of propane and heavier hydrocarbons than surface flare line samples. For the second downhole sample, presumably from shallower depth, ethane and heavier hydrocarbons were even less abundant.

- CH_4: The higher fraction of ethane in downhole samples results from normalizing the sum of fractions for all species to one.

12.6.4.3 Depth of Sample Collection: Previously stated field observations concerning depth of sample collection are:

- Collar locator failure at a depth of 14,500 feet on the way down for sample #1 may have been due to shorting of wiring to the detonator at the time of filling.

- Lack of a dome due to pressure on the aluminum rupture disk on the second sampler suggests that it filled at lower pressure than the first.

The gas-to-brine ratio and the composition of gas from the samplers provide additional clues to depth of sampling. Observed gas-to-brine ratios of 31.0 and 30.8 for the two samplers are substantially below the 40 SCF/STB from surface measurements during production. Therefore, assuming no leakage, the maximum possible depth of sampling can be estimated from gas solubility data, plus the temperature and pressure gradients in the well. Assuming the temperature gradient measured before production and gas solubility of 0.88 times the value calculated with the Blount equation, the maximum pressure and depth for a solubility of 31 SCF/STB are 11,000 psi at 10,000 feet. On the other hand, if the temperature gradient is a straight line from 274°F at the perforation to 235°F at the surface, the pressure and depth for a solubility of 31 SCF/STB are 8,000 psi and 3000 feet. If temperature was midway between these extremes at the time of sampling (4.5 days after the first flow test) the observed solubility would have existed at a depth of 6000-7000 feet. It is possible that either sampler could have filled at shallower depth <u>if</u> a portion of gas in the sampler entered as small bubbles rather than as gas in solution.

The analyses of gas from the bottomhole sampler plus the analyses of gas from each step in differential liberation by Weatherly Laboratories (Appendix H) provide an additional clue to depth of sampling. For the first sample, the mole percentages of ethane and propane are consistent, within measurement uncertainty, with those expected from flashing brine from an initial pressure in excess of wellhead pressure at the time of downhole sampling. In contrast, the low content of ethane and propane in the second sample suggests possible filling of the sampler while charging the lubricator to wellhead pressure.

Consideration of all the information discussed above suggests that the first sample was probably obtained at roughly 6000 feet and a pressure of roughly 9,000-10,000 psi. This conclusion requires that the observed failure in the collar locator be independent of sampler filling.

The second sample may well have been collected inside the lubricator while it was being charged to the wellhead pressure of about 6,500 psi. Since gas solubility is only about 20 SCF/STB under these conditions, about 1/3 of the gas in the second sample would have entered in the form of small entrained bubbles exsolved during the buildup of pressure in the lubricator.

This analysis suggests that both samples contained brine that had been inside well bore tubulars for more than 4.5 days after shut-in of the first flow test.

Figure 12-32
Gas Composition for Downhole Samples and Flare Line

	Gas Composition (Mole Percent)		
	Downhole Samples		Average of Flare Line Samples
	#1	#2	
N_2	0.2	0.12	.11
CO_2	4.8	3.72	5.88
H_2	0.01	0.37	<.01
CH_4	92.7	94.30	91.72
C_2H_6	1.9	1.32	1.82
C_3H_8	0.2	0.13	.3
$n\text{-}C_4H_{10}$	0.03	0.01	.05
$i\text{-}C_4H_{10}$	0.05	0.02	.10
pentanes	0.005	0.00	.02
benzene		0.01	

#1 Analyzed at well site on sampling date. (7/28/30)
Showed a gas/water ratio of 31.0 SCF/BBL; 0.161 moles total gas.

#2 Analyzed in Chicago - sampler opened 8/5/80.
Showed a gas/water ratio of 30.8 SCF/BBL; 0.155 moles total gas.

12.6.5 Brine Sample Collection and Analysis

Brine samples were obtained from the inlet to the brine metering skid (downstream of the separator) and by use of a downhole sampler in the test well. Details of collection and analyses for each of these sample points, a discussion of analytical results, recommended procedure changes, and a summary of third party samples are presented in the following subsections.

12.6.5.1 Separator Output Sampling: To the greatest extent practicable, surface brine sample collection and analyses were performed in accordance with the current draft of a uniform plan for geopressured aquifers under development by a panel of experts chaired by Dr. B. E. Hankins of McNeese State University. That plan, including minor changes to minimize cost by using existing IGT facilities, is described in Appendix J of Volume II.

Surface samples for brine analysis were collected from a tap at the inlet to the brine metering skid. This tap is downstream from the separator vessel by about 15 feet of 3-inch piping and upstream of the separator dump valves. The sampling point is at the same pressure and temperature as the separator.

Results of analyses performed in the field and in IGT's Chicago laboratories are presented in Figures 12-33 and 12-34.

Elapsed time between sample collection and field analyses was much greater than specified in the plan for the first flow test and for some of the analyses during subsequent flow tests. This was due to severe limitations on the accuracy of the analytical balance caused by vibration at the onsite location. The vibration problem delayed preparation of standard procedures that required the balance in subsequent tests. Many of the successful field analyses were possible only because McNeese State University loaned a Mettler analytical balance to IGT. This balance is less affected by vibration and electrical power fluctuation than the Arbor Model 126a automatic balance IGT took to the field.

12.6.5.2 Departures From Planned Procedures: Several changes were made in the analytical procedures during both the field and laboratory phases of the analysis. The changes are listed below.

- pH

The time span between sample collection and the reading of its pH varied widely. This was due to the urgency of other analyses and the inability of the electrodes to adequately respond to, and compensate for, the very high temperature of the fresh samples.

FIGURE 12-33: Results of On-Site Analysis of Post-Separator Brine

Sample Date and Time	Temp.	pH	Specific Conductance, μmhos/cm	Suspended Solids, mg/ℓ	Alkalinity $mgHCO_3^-/\ell$	CO_2, mg/ℓ	Dissolved Solids, mg/ℓ	Chloride, mg/ℓ	Silica, mg/ℓ	Sulfide,† mg/ℓ	Ammonia, mg/ℓ
22 July 80 2258	82°C	7.0	39,400 @ 35°C	--	3500	840	22,500	13,200	--	0.01	9.6
23 July 80 1110	82°C	7.0	62,500 @ 68°C	--	1800	--	23,500	--	--	--	9.2
23 July 80 1830	86°C	7.0	56,000 @ 59°C	--	2600	540	22,900	--	--	0.02	9.5
29 July 80 2330	99°C	7.2	64,500 @ 63°C	4.0	1700	490	23,200	13,500	110	--	8.1
30 July 80 1535	114°C	7.4	51,000* @ 51°C	4.1	1600	1100	23,200	13,500	110	--	6.8
31 July 80 1430	117°C	8.0	34,200 @ 23°C	--	1700	700	24,300	12,900	--	--	10.0
1 Aug 80 1000	114°C	8.0	39,000 @ 25°C	--	1500	400	24,400	13,000	--	--	10.0
2 Aug 80 1645	102°C	7.3	34,300 @ 24°C	--	2500	550	23,500	13,800	--	--	10.0
3 Aug 80 1000	104°C	7.9	32,900 @ 25°C	--	2700	--	23,300	13,500	--	--	9.0
Estimated Accuracy	±1°C	±0.1	±100	±0.1	±100	±10	±100	±100	±10	±0.01	±0.1
Mean	99°C	7.4	46,000	4.1	2200	660	23,400	13,300	110	0.02	9.1
Standard Deviation	13°C	0.4	1,200	--	600	220	600	300	--	--	1.0

* Subsequent measurements on the same sample as it cooled yielded: 46,000 @ 50°C; 37,000 @ 33°C; 35,000 @ 30°C; 32,000 @ 25°C. A possible discrepany exists because the measurement of 46,000 ppm at 50°C was performed at a frequency of 60 Hz whereas all other conductance measurements were performed at a frequency of 1000 Hz.

FIGURE 12-34 Concentrations of Elements and Compounds in the Post-Separator Brine

Sample Date and Time	Concentration, mg/ℓ																			
	F^-	Cl^-	SO_4^{2-}	As	B	Ba	Ca	Cd	Cr	Cu	Fe	Hg*	K	Mg	Mn	Na	Pb	Si	Sr	Zn
2 July 80 2230	2.45	13,000	490	0.011	81	0.82	126	0.083	0.11	<0.02	6.35	<0.1	41.8	16.7	0.20	8,650	0.008	76	22.8	1.06
23 July 80 1830	2.23	12,800	520	0.021	84	0.56	59	0.005	0.10	<0.02	1.60	<0.1	41.5	16.3	0.08	8,500	0.004	66	22.2	0.07
30 July 80 1535	1.94	12,000	480	0.008	71	0.40	42	0.007	0.08	<0.02	1.30	<0.1	41.5	16.4	0.08	9,600	0.002	78	12.5	0.89
31 July 80 1430	2.14	12,000	540	0.010	77	0.49	25	0.007	0.14	<0.02	1.40	<0.1	42.0	16.5	0.06	8,750	0.016	96	8.7	0.28
1 Aug 80 1030	2.08	13,500	490	0.009	80	0.40	19	0.010	0.10	<0.02	0.45	<0.75	41.3	15.8	0.02	8,950	0.002	65	9.1	0.03
3 Aug 80 1000	2.05	13,100	480	0.002	89	0.37	23	0.006	0.26	<0.02	0.35	<0.1	41.2	15.8	0.03	8,600	0.003	53	9.8	0.03
Est. Accuracy of Measurement	±0.01	±100	±10	±0.001	±1	±0.01	±1	±0.001	±0.01	±0.01	±0.05	±0.05	±0.1	±0.1	±0.01	±50	±0.001	±1.0	±0.1	±0.01
Mean	2.15	12,700	500	0.009	80	0.51	49	0.020	0.13	<0.02	1.91	<0.75	41.6	16.3	0.08	8,850	0.006	72.0	14.2	0.39
Standard Deviation	0.16	600	20	0.003	6	0.15	37	0.028	0.06	--	2.04	--	0.3	0.3	0.06	350	0.005	13.0	6.0	0.42

* Hg concentrations are in μg/ℓ.

- Specific Conductance

Measurements were made at various temperatures, as noted in Figure 12-33. Believing that exsolving carbon dioxide was materially altering the measurement as the sample cooled, it was decided that speed was essential. This led to temperature variation arising from somewhat different initial temperatures and unregulated periods of cooling prior to analysis.

- Alkalinity

All samples were titrated to an end point pH of 4.5. This end point was adopted due to problems discussed in subsection 12.6.4.4. The value of 4.5 was selected on location and in coordination with Dr. B. E. Hankins of McNeese State University.

- Silicon (Silica)

In the laboratory, elemental silicon (Si) was analyzed by atomic absorption spectrometry (AAS) rather than using the proposed calorimetric procedure for silica (SiO_2). The Si values in Figure 12-34 may be converted to mg SiO_2/ liter by multiplying by the gravimetric factor 2.14. This yields values higher than those reported in the field, because the AAS method measures Si in all forms present, while the calorimetric procedure only measures Si in SiO_2.

- Barium

Atomic emission in a nitrous oxide-acetylene flame was used instead of atomic absorption because of its superior sensitivity.

- Sulfate

Because of the low sulfate concentrations encountered in the samples, a turbidimetric procedure was used instead of the proposed gravimetric procedure.

- Strontium

Only lanthanum was added to the samples instead of the suggested mixture of lanthanum and potassium. This follows established IGT laboratory procedure. The analyses were checked using standard additions.

- Potassium

Cesium was substituted for sodium because it has a lower ionization potential and, therefore, acts as a so-called ionization buffer more

readily. The need for any added reagent is doubtful, since the solutions contained 8000 to 9000 ppm of sodium as received.

- Manganese

This element was determined directly by graphite furnace AAS rather than by flame AAS after extraction, as the two methods have similar sensitivities, and the former requires less effort.

12.6.5.3 Downhole Sampling:

As previously discussed, two downhole samples were successfully collected from an unknown depth on July 28, 1980, between the first and second flow tests. One of these samples was flashed on location on the day of collection to determine gas-to-brine ratio. Liquid content of the sampler was then analyzed using the same field and laboratory procedures as for the surface brine samples. The second sample was transported to IGT's laboratories in Chicago and then flashed to determine gas-to-brine ratio 8 days after collection. Brine analyses were then performed in Chicago.

Results of brine analyses for these two samples are shown in Figure 12-35. Some of the differences between analytical results for the two bottomhole samples are believed to be due to reactions of brine with components of the sampler that was not opened until 8 days after sample collection. The results are as follows:

- The increased Fe and H_2 in the sample opened in Chicago 8 days after collection, as compared with the sample flashed at the well site, is qualitatively consistent with chemical interactions between the brine and the sampler. However, the details of this interaction are not fully understood. The increase in Fe from 10.1 to 32.8 mg/l is one-half the amount expected from the increase of 0.37 mole percent hydrogen if the reaction were a clean acid-iron reaction. Additional hydrogen may have been produced by the interaction of acid with other, more reactive metals, present to a lesser extent in the sampler alloy.

- The increase in Zn content from 0.74 to 1.28 mg/l is believed to be due to the high zinc content of the lubricant for the numerous "O" rings in the sampler.

- The lower NH_3 content reported for the sample opened in the field is believed erroneous due to addition of insufficient HCl to the brine sample after removal from the downhole sampling vessel.

- The differences in Ca and Ba concentrations is not understood. Since sample collection depths are not known, any attempted explanation would be highly conjectural.

Figure 12-35
Results of Analysis of Acidified Downhole Brine Samples, mg/l

Sample Description	B	Ba	Ca	Cl	F	Fe	K	Mg	Na	NH_3	$S^{=}$	Si	$SO_4^{=}$	Sr	Zn	Alkalinity HCO_3	Dissolved Solids
WDH - 1	95	0.21	129	13,500	2.37	10.1	38.5	15.2	9,200	6.7	INS	95	480	20.0	0.74	1900	
WDH - 2	98	0.70	196	12,800	2.20	32.8	37.5	17.2	9,400	11.2	INS	98	520	21.8	1.29	2000	24,000

INS = Insufficient sample for analysis.

REF. 43903-06
September 29, 1980

Sample Identification:

WDH - 1: First sample, flashed on location within hours of collection.

WDH - 2: Second sample, flashed in Chicago 8 days after collection.

FIGURE 12-35

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
3100 Edloe
Houston, Texas 77027
(713) 627-9764

DOE CONTRACT NO.
DE-AC08-80ET-27081

12.6.5.4 Discussion of Analytical Results: Measured concentrations of several species were constant within experimental uncertainty throughout the test series and were the same for both surface and downhole samples. For these species, the average of measured concentrations are believed representative of the brine in the reservoir. These are:

- Total Dissolved Solids
- Cl^-
- Ammonia
- $SO^=_4$
- F^-
- Mg
- Na
- K.

Additional species for which analyses of surface samples gave consistent results probably representative of the reservoir, but for which analyses of downhole samples were not performed due to the limited downhole sample volume are:

- Cr
- Cu
- SiO_2 (two samples only)
- Sulfide (two analyses, courtesy of USGS).

Analytical results for several species exhibited variations outside the range of experimental uncertainty. The possible significance of each of these in relation to reservoir properties and production is discussed below.

- Minimal Significance

For these species, a monotonic decrease in concentration with time suggests cleanup of material introduced by man. Whether any significant amounts of the materials are produced from reservoir rock is questionable, and the concentrations shown in the tables can be regarded as maximums. These are:

- Zn
- As
- Pb
- Cd.

- Possible Significance

For these species, concentrations varied substantially with time, but the levels observed may be significant in relation to corrosion, scaling, or environmentally acceptable brine disposal.

- Fe:

  Concentrations in surface samples declined monotonically with time. However, the high concentration and H_2 generation in a bottomhole sample suggests that corrosion of well bore tubulars may be the source. If the minimum measured concentration of 0.35 mg/l on the last sample reflects a corrosion source, iron loss from well bore tubulars would be about 4500 pounds in 10 years of production at 10,000 barrels/day.

- Sr:

  After an initial decline, the concentration appears to have leveled out at 9±1 mg/l.

- Mn:

  Concentration declined with time to a minimum of about 0.02 mg/l.

- Hg:

  Six determinations showed less than 0.1μg/l. Whether the seventh value of 0.75 mg/l is an anomaly or representative of production on August 1, 1980 cannot be resolved.

- Si:

  The laboratory atomic absorption measurement on six filtered surface samples varied between extremes of 53 and 96 mg/l with no apparent pattern. The unfiltered downhole sample analyses yielded concentrations of 95 and 98 mg/l. Most of these concentrations are too high for all of the Si to be in SiO_2 molecules for which measured concentration is 110±10mg/l. Whether these high values are due to solids small enough to pass through a 0.45 micron filter or due to silicon species in solution is an unresolved question.

- Ba:

  After the first flow test and the downhole sample collection, concentration appears to have leveled out at about 0.4+0.1 mg/l. However, this concentration is more than 100 times greater than expected for equilibrium at surface pressure and temperature with the SO_4 concentration of 500+50 mg/l. Thus, slow buildup of barite scale on surface plumbing may occur during long-term production.

- Major Significance

The concentrations of these parameters and/or their variations are significant for reasons of scaling or environmental concerns.

- Boron:

  Although the mean total dissolved solids concentration of 23,500 ppm may be low enough to consider surface disposal of the brine after dilution, the boron concentrations of 71 to 98 ppm are too high. Without massive dilution, concentrations would be toxic to almost all plant life in the area if surface disposal was attempted.

- Ca^{++}:

  Concentrations of calcium differed between surface and downhole samples by more than analytical uncertainty. In chronological order, the concentrations reported in Figures 12-34 and 12-35 are:

		Ca^{++} Concentration, mg/l	
Date	Time	Surface	Downhole
7/22	22:30	126	
7/23	18:30	59	
7/28	am		129
7/28	pm		196
7/30	15:35	42	
7/31	14:30	25	
8/1	10:30	19	
8/3	10:00	23	

  Sample analysis accuracy is believed to be 10% or better. Thus, differences between measured concentrations are probably reflections of operating conditions in relation to precipitation of $CaCO_3$. Some possibly significant correlations follow:

  - Bottomhole samples were collected before removal of any CO_2 gas, whereas about 800 mg /l of CO_2 was removed by the separator

before collection of surface samples. Additional CO_2 escaped from all samples during the delay between placing them in plastic bottles and their subsequent analyses.

- The measured concentration of Ca has an inverse correlation with separator pressure at the time of sample collection. For the last four surface samples that correlation is:

Separator Pressure	Ca^{++}
250	42
400	23
460	25
600	19

- Bottomhole samples were not filtered before analysis, whereas the surface samples were collected through a 0.45 micron filter.

Finally, two analytical procedures produced wide fluctuations in results due to problems in implementation of the procedures:

- Alkalinity:

  Measurements reported as mg HCO_3^-/1 vary from 1500 to 3500 mg/1 for surface samples. The behavior of the pH reading during the addition of titrant aliquots indicated that the samples were heavily buffered. This introduces some uncertainty into the pH value recorded for each aliquot added and causes scatter in the pH vs. titrant volume plot. Another complicating factor was the relatively low alkalinity of the sample. The total volume of titrant added usually ranged from 0.8 to 2.0 ml. These factors combined to produce a plot in which the inflection point (end point) was very difficult to determine. After discussions between IGT personnel and Dr. B.E. Hankins on the location, titration to an end point pH of 4.5 was used by both IGT and McNeese State University.

  Experiments subsequently conducted in the laboratory in Chicago indicate the presence of some weak base in the brine other than carbonate. In these experiments, brine returned from the site in a pressure vessel was analyzed for total carbonate and alkalinity. The alkalinity of the sample was determined on a portion of the sample which had been neutralized with a known amount of strong base as it was released from the pressurized container. This prevents any loss of carbon dioxide through exsolution. The amount of strong base used is subtracted from the total amount determined to be present in the

sample. The results of these preliminary experiments indicate that the sample contained 1,600 mg CO_2/liter and had a total alkalinity (i.e. due to carbonate and other basic components) expressed as 2,000 mg CO_2/liter. By difference the non-carbonate basic components in the sample are equivalent to 400 mg CO_2/liter. The identity of this component in the brine is presently unknown and under investigation.

- Total CO_2:

  A unit weight alkalimeter was used in accordance with prescribed procedures. The scatter in Figure 12-33 reflects two problems that stem from the low level of CO_2 in these samples compared with those for which the procedure was developed. First, weight differences had to be measured to milligram accuracy for apparatus weighing more than 100 grams using a balance plagued by vibration problems. Second, the amount of CO_2 liberated was less than the volume required to displace air from the apparatus. To the unknown extent that liberated CO_2 remained inside the apparatus, values in Figure 12-33 are low because the measured weight loss is low due to such CO_2. Also, it should be noted that CO_2 released in this procedure was generally less than the roughly 800 mg/l previously removed from brine by the separator.

12.6.5.5 Modifications to Brine Sample Collection and Onsite Analysis Procedures: Several modifications specified below are being adopted by IGT for future tests of Wells of Opportunity. It is recommended that they be adopted for all tests of geopressured geothermal wells, because they do the following:

- Decrease field manpower requirements

- Provide consistent samples for each suite of field measurements to be performed onsite using raw, untreated (RU) samples

- Provide increased accuracy without changing the basic chemical processes involved.

In a form suitable for direct substitution in the procedures in Appendix J these changes are: (Note: Only procedures to be changed are listed.)

"A. <u>SAMPLE COLLECTION</u>

The brine samples from the well will be collected in three Teflon-lined stainless steel cylinders of 500-ml capacity. For

sampling, the cylinders will be linked in series to the sampling port. An alternative method would be to collect brine in one cylinder at a time. The cylinders will be flushed with several volumes of brine to purge the air from the cylinders before the sample is taken. The valves on the cylinders will be closed, outlet first, inlet last, to trap and seal the sample under pressure. The sample cylinders will be cooled to near ambient temperature before analysis. The pressure in each cylinder will be maintained until the sample is ready for analysis.

The three steel cylinders, (A, B, and C), of RU brine are to be used for pH and specific conductance (Cylinder A), alkalinity (Cylinder B), and for gas analysis, total dissolved CO_2, including carbonate and bicarbonate species, and sulfide (Cylinder C).

Brine samples are also to be collected in plastic bottles cleaned first with dilute HNO_3(1:5) and rinsed four times with deionized water. Brine collected in these containers will first be passed through a loose plug of glass wool to reduce or remove oily matter. The samples in these bottles will be used for temperature measurements and for tests requiring raw acidified (RA), filtered untreated (FU), and filtered acidified (FA) samples.

Treatment	Tests
RU (Raw, untreated)	pH, Temperature, Total Dissolved CO_2, Alkalinity , Specific Conductance, Suspended Solids, Sulfide, Gas Analysis
RA (Raw, acidified with 3 ml HNO_3/liter)	Radioactivity
FU (Filtered through 0.45 m membrane, untreated)	Dissolved Solids, B, Cl^-, F^-, NH_3, SiO_2
FA (Filtered through 0.45 m membrane, acidified with 1:1 HNO_3 to a pH of 1.5. Note the amount of acid used)	As, Ba, Ca, Cd, Cl^-, Cr, Cu, Fe, K, Mg, Mn, Na, Pb, SO_4, Sr, Zn

B. TEST PROCEDURES FOR LIQUID SAMPLES

1. pH

Use a pH meter with automatic temperature compensation. Calibrate the pH meter with pH buffers of 7.0 and 4.0. Drain a

portion of the sample from Cylinder A into a beaker and record the pH immediately. Do not stir the sample. The pH may drift down, then up, as the solution exsolves CO_2; record the lowest pH reading.

2. Temperature

Record the flowing brine temperature and measure the temperature of the brine in a freshly filled bottle or container.

3. Specific Conductance

Use a commercial instrument that has been calibrated with KCl at various temperatures for specific conductance. Record the temperature of the brine and the specific conductance in mhos/cm.

5a. Alkalinity

Pipet 50.00 ml of the sample brine from Cylinder B into a 250 ml beaker. Place the electrodes of a calibrated pH meter into the sample and titrate with 0.02 N H_2SO_4. Add the standard acid in increments of 1 to 2 ml at the beginning of the titration and change the increments to 0.25 to 0.50 ml at pH = 5.0. The incremental volumes should be determined by the actual titration and the speed with which the pH is changing. Titrate the solution until the pH is 2.0. Tabulate values of pH and ml and determine the end point graphically from a plot of pH versus ml.

Calculate and report the alkalinity as mg HCO_3/liter. This procedure determines the total alkalinity, including the portion attributable to organic anions.

5b. Total CO_2

The brine in Cylinder C is used to determine total dissolved CO_2 (dissolved CO_2 and HCO_3) after the gas has been flashed off for GC analysis. The brine is drained from the steel cylinder into a volumetric cylinder to determine the brine volume for the gas to brine ratio. After measuring the volume, the brine is immediately made alkaline to phenolphthalein with drops of 10 M NaOH (40 g NaOH to about 100 ml). Transfer 50 ml of this solution to the carbonate train. Add about 30 ml of

water, acidify with 30 to 40 ml of 1:1 HCl, and purge the CO_2 into the tared Nesbitt bulb with nitrogen for 1 hour. Reweigh the Nesbitt bulb for the weight gain due to CO_2. Report as mg CO_2/liter.

10. Sulfide

The remaining alkaline brine solution from Cylinder C is used for the sulfide determination. Use a specific ion electrode and follow the manufacturer's instructions."

Note that the majority of changes are in sample collection and handling of pressure cylinders. The only substantive change in analytical procedures is a procedure for total CO_2 analysis that bypasses the major problem in applying the alkalimeter to brine samples with small CO_2 content in relation to the samples for which the alkalimeter was developed.

Despite the above-noted changes, problems remain with the procedure for alkalinity. A decision should be reached whether an automatic titrating apparatus is required, at a cost of several thousand dollars, whether interfering species such as phosphates and organic anions should be identified, or whether the current uncertainty and scatter in measurements is acceptable.

12.6.5.6 Third Party Brine Sampling and Analysis: Brine samples known to have been collected by or for third parties are set forth in the sample log (Appendix L). The only third party analytical results provided in writing to IGT at the time of this report are radioactivity analyses by USGS and the two USGS onsite sulfide analyses previously reported in Figure 12-33.

An October 16, 1980, letter from Mr. Thomas F. Kraemer of the USGS Gulf Coast Hydroscience Center provided the following table of measured ^{226}Ra content of produced brine.

Date	Time	^{226}Ra Content of Produced Brine, dpm/l
7/22	10:55 pm	73
7/23	3:03 am	64
7/29	11:30 pm	80
7/30	3:35 pm	65
7/31		64
8/2	3:38 pm	75
8/2	7:50 pm	82
8/3	10:00 am	75
8/3	4:20 am	77

12.7 SOLIDS PRODUCTION, SCALING, AND CORROSION

These topics are discussed together because the vast majority of solids detected at the surface were precipitates of chemical compounds normally found in scale. However, only a small fraction of such precipitates actually bonded to steel in the form of scale. A substantial fraction of both precipitates and produced formation material passed through the surface plumbing, through the 50-micron filter elements, and into the disposal well. Quantitative data leading to this observation are presented in the following subsections.

12.7.1 Scale and Corrosion Observations

Scale-corrosion coupons were installed in the data header between the choke manifold and the separator. The coupons were weighed before and after testing. Scaling makes the coupons gain weight. Corrosion has the reverse effect.

After 4009 barrels of brine had been produced in the first flow test, no scale was visible on the coupon, but it showed a weight gain of 0.0186 grams per 1000 barrels of brine per square inch of surface area. Further, no indication of scaling or corrosion was found on visual inspection of the inside of piping of the tree, between the wellhead and separator, or between the filters and the disposal well. It was decided, therefore, that neither scale nor corrosion inhibitors would be injected for the remainder of the test.

After the fourth flow test, a second corrosion coupon was examined. It had gained 0.0278 grams per 1000 barrels of brine per square inch. Further, visual inspection of surface piping revealed uniform buildup of about 1/32-inch of scale on all steel surfaces downstream of the choke. In addition, up to an inch of granular material was found in larger diameter piping where flow velocities had been minimal. This additional material was not cemented and not bonded to the steel.

Assuming that the surface piping and vessels had an overall length of 200 feet and an average inside diameter of 4 inches, the internal surface area is about 30,000 square inches. For the weight gain exhibited by the second corrosion coupon, the total weight of scale is estimated to be about 68 pounds.

12.7.2 Sand Detector and Filter Pressure Drop

An OIC Sand System, Inc. sonic sand detector was installed in the surface data header between the choke manifold and the separator. The original

intent was to reduce the flow rate if sand production were observed in order to avoid erosion of surface piping. There were no plans to quantitatively measure sand production.

In practice, the onset of the sand detector signal was at a very low signal level. Characteristics of the observed areas are as follows:

- First Flow Test: The signal was about 10% of the most sensitive scale for a 1-hour period early in the test. Sand detector output then remained at zero for 17 hours. Near the end of the first flow test, the sand detector signal increased from 10% to 15% of the most sensitive scale and remained at that level for 3 hours. During this flow test, the pressure drop across the single filter chamber in use increased to only 5 psi. Inspection of the small wellhead choke revealed a small amount of erosion. The choke stem and seat were replaced before the second flow test.

- Second Flow Test: A constant signal of about 4% of the most sensitive scale was recorded for the first 13 hours of this test. Sand detector output then dropped to zero for about 13 hours. Sand detection then began again at about 5% of the most sensitive scale and slowly increased for the next 8 hours to 8% of the most sensitive scale at the end of the second flow test. At the beginning of this test, pressure-drop across the filters rapidly increased to 30 psi. This is presumed to be partly due to washing of sand onto the filter at the higher flow rate. The pressure drop decreased during the remainder of the test to a time value of 28 psi. Periods of increased production rate correlate well with fluctuations in bottomhole and wellhead pressure but poorly with detector output. It appears that the flow rate increases were due more to opening of additional perforations than to choke erosion after sand reached the surface. Choke erosion probably did contribute to the increasing flow rate observed during this test. The choke stem and seat were replaced before the third flow test.

- Third Flow Test: During the first 6 hours of the 15,000 barrel/day portion of this test, the sand detector signal increased smoothly from 15% to 30% of the most sensitive scale. The signal then decreased to about 20% of this scale when separator pressure was increased from 460 psig to 600 psig. After reducing the rate to 9500 barrels/day, the sand detector signal remained constant at about 10% of the most sensitive scale. During the 8 hours of production at maximum rate, the single filter previously in use reached its maximum rated pressure drop of 50 psi. The two additional filter chambers were placed in operation, and pressure drop across the three filters again increased to 30 psi by the time flow rate was reduced to 9500 barrels/day. Filter pressure drop was

about 38 psi at the end of the flow test. Filter elements were replaced before the fourth flow test. Choke equipment replacement was not required after this test. This is presumed to be due to the larger opening for high rates allowing passage of grains without erosion.

- Fourth Flow Test: The sand detector output was between 5% and 15% of the most sensitive scale throughout this test. Variations in amplitude correlated with changes in separator pressure.

The test began with a single new filter chamber on line. Pressure-drop across that filter increased to only 5 psi during 16 hours of production at a separator pressure of 530 psi. During the 5 hours after reducing separator pressure to 400 psi, pressure drop across the filter increased to 37 psi with no change in flow rate. The subsequent increase in production rate from 6,500 to 11,000 barrels/day was accompanied by rapid increases in pressure drops across the filters. The test was terminated after all three filters reached the maximum rated pressure drop of 50 psi in 2-1/2 hours. Since the detector signal increased to only 10% of the most sensitive scale, the rapid accumulation of solids on the filter is presumed to be due to washing of accumulation from surface piping by the higher flow rate.

Visible choke erosion did not occur during the fourth flow test. Also, inspection of surface piping plus subsequent pressure tests provided no indication that erosion had occurred due to solids production.

- Sand Detector Chart Interpretation: After the test, calculations were performed to estimate the quantity of sand produced from the sand detector record. Figure 12-36 is a tabulation of the data and the calculation performed to estimate sand production. Total estimated sand production is 220 pounds. This value has a large uncertainty because the sand detector signal is rate sensitive, and fluid velocities in the data header were low in relation to optimal detector operation. Also, the detector is sensitive to flow line noises other than those caused by sand grain impact upon the detector.

FIGURE 12-36 Sonic Sand Detector Data Calculations

Date	Flow Rate(Q) BWPD	Fluid Velocity Ft/Sec	Average Sonic Sand Detector Reading	Sand Production Lbs./Day	Time of Sand Production Hrs.	Actual Sand Production Lbs.
7-29-80	7,000	5.7	10	63.4	18.0	47.3
7-31-80	8,460	6.9	12	51.9	12.0	25.1
7-31-80	15,567	12.67	50	64.2	13.0	36.0
8-2-80	6,924	5.63	12	78.0	20.0	65.0
8-2-80	6,924	5.63	14	91.0	12.0	45.5
						Total 218.9
8-6-80	18,460	15.0	13	11.90	0.5	.25

Sample Calculation:

(For Data on 8-6-80)

$$\text{Sand Production lb./Day} = \frac{206 \times \text{SSD Reading}}{\text{Velocity}^2}$$

$$= \frac{206 \times 13}{15^2} = 11.90 \text{ lbs./Day}$$

Note: A physical measurement of sand production for the data point on 8-6-80 indicated an actual sand production of 0.65 lbs. of sand versus 0.25 lbs. calculated from the sand detector data.

12.7.3 Solids Production Test

On August 9, a fifth flow test of 4 hours duration was performed at maximum flow rate to provide additional understanding of solids production. The well was initially flowed at a metered rate of 6500 barrels/day through the separator to the disposal well. The rate was then slowly increased to 15,000 barrels/day through the separator. Flow was then diverted from upstream of the separator to two 220-barrel open-top steel tanks. The indicated wellhead flow meter rate increased to 18,500 barrels/day of two-phase flow. During 30 minutes, 385 barrels of brine were produced and flowed into the tanks.

The brine was slowly drained from the tanks, after which a total of 36 pounds of scale, sand, and tank rust was recovered from the bottom of the tanks. This is 93.5 pounds of solids per 1000 barrels of produced brine.

After collecting small mixed samples for laboratory analysis, the 36 pounds of solids was treated with concentrated acid to remove carbonate deposits. Liquid was then slowly poured off the residue and a small amount of rust was magnetically removed from the residue. After oven drying at about 300°F, only 0.65 pounds of fine formation sand remained. Thus, the sand portion of solids collected in the tanks was only about 1.8%.

While the 220-barrel tanks were being filled, the sand detector signal was 15% to 20% of the most sensitive scale. This is near the maximum value observed during any of the fully instrumented flow tests. Interpretation of the sand detector record using the same procedures as previously discussed for Figure 12-36 indicates production of 0.25 pounds of sand to the tanks in contrast to the 0.65 pounds measured.

12.7.4 Analysis of Solids Samples

Three categories of solid samples were collected during the test series:

1) suspended solids trapped by a 0.45-micron membrane filter while collecting brine samples.

2) scale from various points after the fourth flow test, and

3) sludge from the separator after the fourth flow test plus from the 220-barrel tanks after the solids production test.

Each of these are described in the following subsections.

12.7.4.1 Suspended Solids From Filter Paper: Results from X-ray diffraction analysis of suspended solids trapped on the 0.45-micron filters are shown in Figure 12-37. These qualitative results are consistent with quantitative conclusions drawn from analysis of scale and sludge samples. The significant point to be made from data in Figure 12-37 is that the relative abundance of barium decreased during the test series. This probably indicates a decreasing fraction of residual drilling mud in the produced fluids.

12.7.4.2 Scale Analyses: After the fourth flow test, no scale was upstream of the choke on the wellhead. However, scale samples for analysis were obtained from several points downstream of the choke. Scale samples were analyzed in accordance with the following procedure:

- Perform X-ray diffraction analysis for mineral identification
- Analyze a portion of each sample for carbonate by evolution of CO_2 with acid and subsequent trapping of CO_2 on Ascarite
- Filter the acidic solution and then analyze the filtrate for Na, Ca, Mg, Ba, and Sr
- Re-examine the filterable solids by X-ray diffraction.

Results of the two X-ray diffraction analyses and of the analyses of filtrate are given in Figure 12-38.

Calculations were made using the five measured cation concentrations in an attempt to form a material balance for the solid material. Assuming the calcium and magnesium to be present as carbonates, the others to be present as chlorides, and including the acid insoluble residue, approximately 96% of the material could be accounted for in these samples. Comparison of the determined CO_2 from the carbonate analyses and the carbon dioxide calculated from the assumed calcium and magnesium carbonates showed close agreement, indicating that the scale was primarily calcium carbonate. The calculated CO_2 evolution and the calculated material balance are shown for each sample in Figure 12-38.

12.7.4.3 Sludge Analyses: Samples of sludge, in contrast to cemented scale, were obtained from the filter elements and from the separator vessel after the fourth flow test. In addition, sludge was collected from the two open 220-barrel tanks after the solids production test.

Figure 12-37
Composition Of Suspended Solids Samples By
X-Ray Diffraction

Sample Date and Time	Identified Compounds*
23 July 80 0530	$BaSO_4$ NaCl
29 July 80 2330	$BaSO_4$ SiO_2 $CaCO_3$
30 July 80 1535	NaCl $BaSO_4$ SiO_2 $CaCO_3$
31 July 80 1535	NaCl, SiO_2 $BaSO_4$ $CaCO_3$
1 Aug 80 1000	NaCl, SiO_2 $BaSO_4$ $CaCO_3$
3 Aug 80 1200	NaCl $BaSO_4$ $CaCO_3$

* Elements and compounds listed in probable order of decreasing abundance. Those on the same line are approximately equal.

Ref. 43742, 43864-43869

FIGURE 12-38 ANALYSES OF SCALE SAMPLES COLLECTED AUG. 4, 1980

Sample Description	Energy Diffraction* Identified Compounds		Analysis of Acid Solution Concentration wt %							Residue	Total
	as received	acid insoluble	Na	Sr	Ca	Mg	Ba	CO_2	Calculated	wt %	wt %
Average of 2 scale samples from between the Wellhead and the operator	Calcite ($CaCO_3$) Aragonite ($CaCO_3$)	Muscovite Silica	.3	1.7	36.0	.55	0.1	41.2	40.6	.85	96.7
Separator Scale	Calcite Aragonite Silica (SiO_2)	Muscovite Silica	.3	1.4	36.1	0.7	0.1	41.1	40.9	1.8	97.8
Scale from Dump Valve Seal	Calcite Aragonite Silica	Muscovite	.2	1.2	33.7	0.8	2.2	38.0	38.5	3.8	96.9
Sludge in separator	Silica Calcite Wallostonite ($CaSiO_3$)	Silica	2.8	0.1	2.3	0.2	2.5	3.3	2.8	74.0	85.9

* Compounds listed in probable order of decreasing abundance

* Calculated based upon Ca and Mg as carbonates

† Calculated based upon Ca and Mg as carbonates plus Na, Ba, Sr as chlorides and residue.

Several gallons of sludge were recovered from both the separator vessel and the filter housings. Analyses of samples from these sources are included in Figure 12-38. The material caught by the 50 micron filters was primarily carbonate precipitate and was similar in composition to the scale samples. In contrast, the sludge from the separator was 74% acid insoluble residue produced from the reservoir rock. This large difference in composition apparently reflects washing of fine grain and lower density solids from the separator by flowing brine so that only the larger sand grains remained.

12.7.4.4 Grain Size Distribution of Solids in Sludge: Grain size distributions were measured for solids recovered from the separator and from the open tanks used in the sand detector test. The data obtained are shown in Figure 12-39.

Interpretation of the sludge analysis data in Figures 12-38 and 12-39 plus the reported 1.8% sand content of the sludge from the solids production test requires careful attention to details of sample building and analysis for each test or analytical procedure. The major point is that very harsh acid treatment is required to determine carbonate content by CO_2 evolution. For the analyses in Figure 12-38, each sample was boiled in concentrated (~6N) HCl to ensure that all carbonate mineral was reacted and that all CO_2 was evolved and recovered. In contrast, sample preparation for grain-size distribution measurement of residues involved treatment with 1N HCl at room temperature. A further complication is that the Coulter counter used for particles smaller than 50 microns could not be meaningfully used on "as received" samples because of reactions between the solids and the electrolyte in the Coulter counter.

With these details in mind, the significance of the grain size distribution measurements for each sample is discussed below:

- Sludge From Separator

The harsh acid treatment for carbonate analysis left 74% insoluble residue, whereas insoluble residue for grain size distribution measurement was 95.1%. It is therefore apparent that the abundance of large particles in the "as received" sample is a reflection of carbonate cementation of smaller grains. Microscopic examination of a 3/16-inch diameter pellet from the separator revealed loose carbonate cementation of a large number of small grains of formation material. The very high visible porosity of this pellet leads to the belief that the cementation resulted from carbonate precipitation in the produced stream.

FIGURE 12-39 Screen Analysis of Solid Materials From Wainoco P.R. Girouard No. 1 Well Before and After Treatment With Dilute Hydrochloric Acid and X-ray Analysis of the Sub-75 Micron Material

Screen Effective Diameter Microns	Fraction Larger Than Effective Diameter of Screen, Weight Percent						
	Sludge From Bottom of Separator 8-4-80		Deposits From Outside of Filter Elements 8-3-80		8-7-80		Girouard Sand Test 8-7-80 Resulting Sand from 10 lbs. Material Acidified
	As Rec'd	Acid Insol.	As Rec'd	Acid Insol.	As Rec'd	Acid Insol.	As Rec'd
1,700	27.3	0.0	0.7	0.1	0.0	0.0	0.0
1,180	9.5	0.4	1.2	0.1	0.0	0.0	0.0
850	6.1	1.6	1.0	<0.1	<0.1	0.0	<0.1
600	7.3	3.0	1.2	0.1	0.5	0.7	0.2
425	6.7	3.4	1.3	0.5	0.8	1.1	0.4
300	6.6	4.8	2.1	1.4	1.0	1.6	1.1
210	4.6	5.6	3.4	3.1	0.7	2.0	2.5
150	3.2	5.6	8.4	8.7	0.8	2.5	6.3
106	2.7	5.3	18.8	17.4	1.4	5.2	22.3
75	2.6	5.0	31.7	29.8	2.2	6.7	29.4
50.8	(23.4)	15.0	(30.2)	22.4	(92.5)	9.4	28.4
40.3		8.9		6.0		4.7	5.4
32.0		10.3		4.0		6.8	1.7
25.4		7.6		2.4		8.6	0.9
20.2		5.7		1.4		9.5	0.5
16.0		3.9		0.7		8.1	0.3
12.7		3.3		0.5		7.1	0.2
10.1		2.7		0.4		6.3	0.2
8.0		2.5		0.3		6.0	0.1
6.4		2.6		0.4		5.9	0.2
5.0		1.6		0.2		4.2	0.1
4.0		1.5		0.1		3.7	<0.1
X-Ray		$BaSO_4$		SiO_2		SiO_2	SiO_2
Analysis		SiO_2		$BaSO_4$		$BaSO_4$	$BaSO_4$

* Material as received was acid insoluble residue.

† From 50.8 to 4.0 microns, results are from Coulter counter. Particles <4.0 microns were not included in normalization of these results. As Received samples were not analyzed by Coulter Counter.

- Deposits From Filter

The harsh acid treatment for carbonate analysis by CO_2 evolution resulted in 2.5% residual solids. In contrast, sample preparation for grain size distribution measurements left 39% residual solids. This large difference leaves a question as to whether the larger particles in the grain size distribution were the result of some residual cementation. Nevertheless, it is apparent that more than 60% of the material caught by filters was carbonate, rather than sand or shale from the formation. Further, more than 20% of the material recovered from the filters had a grain size of less than the nominal filter opening of 50 microns. This is presumed to reflect a decrease in the effective opening by filter loading.

- Sludge From Sand Test

Collection of these samples involved bypassing of the separator, filter housings, and the majority of surface piping . The material collected from the 220-barrel open tanks is believed representative of total produced solids. The sample of material received as acid insoluble material is a portion of the 0.65 pounds of sand from treating 36 pounds of slude with concentrated hydrochloric acid plus some nitric acid. Separation of liquid and solids during and after acid treatment of this material was by pouring, rather than filtering, with associated loss of fine-grained residue.

Another sample from the 36 pounds of sludge was treated with 1N HCl and filtered for grain size distribution measurement. It has 12.1% residue in contrast to 1.8% from the harsh acid treatment and separation by pouring. This grain size distribution is believed to be most representative of produced solids. It reveals:

- About 90% of solids have a grain size of less than the nominal filter opening of 50 microns
- More than 85% of produced solids are carbonates
- More than 50% of produced acid insoluble particles (sand and shale) probably have diameters smaller than the nominal filter opening of 50 microns.

12.7.4.5 Discussion of Solids Production: The totality of analytical data previously reported has been used to develop an estimate of solids production and ultimate disposition. One possible scenario is the following:

- The solids production test to open tanks revealed production of 93.5 pounds of solids per 1000 barrels of brine. Assuming a uniform ratio of solids to brine, the total production of 37,000 barrels would have been accompanied by 3460 pounds of solids.

- The total solids were roughly 90% carbonate precipitate. Thus, the approximate weights of "sand" and precipitates produced were 345 pounds of sand and 3115 pounds of carbonates.

- An independent estimate of carbonate precipitation is made possible by the difference of about 110 to 170 mg/l observed for the Ca^{++} concentration in downhole and subsequent surface brine sample analyses. This difference translates to 3170 to 5400 pounds of $CaCO_3$ precipitate.

- Total weight of scale adhering to surface piping and vessels was previously estimated to be about 68 pounds on the basis of corrosion weight gain and an estimated surface area of 30,000 square inches. Since harsh acid treatment left only about 2% residual material, this scale is estimated to consist of about 6 pounds of "sand" and 62 pounds of carbonate precipitate. It therefore appears that only about 2% of the estimated total carbonates became scale on surface facilities.

- Several gallons, or roughly 100 pounds, of solids containing less than 25% carbonate were found in the separator. Thus the amounts of "sand" and "precipitate" in the separator were roughly 80 pounds and 20 pounds, respectively.

- The filter housings are estimated to have collected about 200 pounds of solids, of which 2.5% to 40% was acid soluble. Thus, the filter housing contained roughly 40 pounds of sand and 160 pounds of carbonate precipitate.

- Combining the above estimates leads to the conclusion that about 120 pounds or 1/3 of about 350 pounds of total produced formation material was caught by the separator and filter. Similarly, only about 185 pounds, or 0.5% of carbonate precipitate remained in surface facilities as scale, separator sludge, and filtered residue.

- Solids injected into the disposal well appear to have consisted of about 220 pounds of sand and 3000 pounds of carbonate precipitates. It is possible that some of the estimated carbonates remained in solution in the disposal aquifer.

The above estimated disposition of solids is summarized as follows:

Estimated Production and Disposition of Solids

Disposition	Formation Material	Carbonate Precipitate, lb.
Scale	6	62
Sludge in Separator	80	20
Trapped by Filter	40	160
Injected to Disposal Well	220	3000
Total Production	346	3242

For total brine production of 37,000 barrels.

12.8 Test Equipment Performance and Problems

12.8.1 Choke Manifold

The four-inch Gray choke manifold was too large for proper control of start-up and shut-in at rates below 10,000 BWPD. The choke manifold had been built originally for another GEO^2 test well (Tenneco Fee) and was designed for flow rates in the order of 40,000 BWPD. It was necessary to use the back-up chokes on the christmas tree to control the main flow. The four-inch choke was then used to place back-pressure on the flow line. Since flow was choked at the christmas tree, fluid in the flow line between the main choke manifold and the wellhead was not representative of fluid at tubing conditions. A smaller two-inch choke manifold will be fabricated for use on future Eaton WOO tests.

12.8.2 Camco Turbine Meter

The Camco three-inch turbine meter did not agree with the Halliburton flow meters, which had been calibrated with known volumes of water. Part of the problem may have been the two-phase (gas and water) flow through the meter. The Camco electronic readout unit was replaced with a Halliburton readout unit, which improved the quality of the readings, but the meter never agreed with the calibrated separator meters. Since the Camco meter was used only to approximate flow at start-up times, the production tests were not affected by the accuracy problem. More testing should be conducted with the Camco meter in order to determine its merit as a metering device for GEO^2 wells.

12.8.3 Wireline and Lubricator

Reservoir Data, Inc. experienced problems while trying to return the original wireline cable back into the well for bottomhole sampling operations, after the end of the first flow test. Leaks could not be corrected in the lubricator. The cable and lubricator were returned to RDI's Houston operational base where examination of the wireline revealed that the cable was worn and several strands of wire were broken and frayed. The worn wireline resulted in leaks in the flow tube seal section of the lubricator. No lubricator leaks were experienced during the remainder of the tests; however, the replacement wireline had manufacturing defects. The new cable had internal separations causing loss of signal from the Hewlett-Packard downhole pressure gauge. The second cable was replaced by another new wireline. No problems were experienced with the third wireline.

It was later learned that the frayed wireline had been used to run a tubing caliper survey in the Pleasant Bayou Well No. 2.

12.8.4 Hewlett-Packard Downhole Pressure Gauge

The Hewlett-Packard pressure-sensing instrument performed very well. A surface computer software programming problem, experienced when the Hewlett-Packard gauge was lowered into the well, was quickly corrected by RDI.

The switching mechanism for converting from pressure readings to temperature readings and vice versa failed to operate during the initial run into the well. No further attempts were made to run dual pressure and temperature sensors.

12.8.5 Bottomhole Fluid Sampler

The two Gearhart-Owen downhole fluid samples were obtained at unknown depths due to internal failure. The failure process involved an explosively driven cutter, rupture disk and rupture disk "O" ring. The "O" ring failed and allowed brine to enter the air-filled space around the detonator. The rupture disk failure prevented the detonator from firing and resulted in premature filling of the sampler. Gearhart-Owen Industries have successfully redesigned the sampler in October, 1980. The rupture disk has been replaced by a small diameter seal pin. The seal pin assembly is held in place by shear pins designed to hold over 40,000 psi of fluid pressure below the seal pin. The holding pins are sheared by detonating a small black gunpowder charge to activate filling of the sampler.

12.8.6 Separator Stability

The separator performed very well in general; however, when production rates reached 15,000 BWPD large oscillations in separator pressure were experienced. The problem was solved by replacing the 3" water dump valve seat with a 2-inch seat. Stable separator operation was then achieved, but the reason for the initial oscillations is still not clear. Scale buildup was observed in the 3-inch valve seat when it was removed, and this or sand production may have been responsible for the erratic operation of the dump valve.

12.8.7 Choke Erosion

The stainless steel tapered stem tip of the adjustable choke, on the wellhead, was found to be scarred and slightly eroded upon inspection at the end of the first flow test. The stem was replaced prior to the second flow period. At the end of the second flow test, erosion of the stem tip was again observed. A third stem was installed prior to the third flow test. The third stem did not show signs of erosion during subsequent flow tests. The erosion of the first two stems may have occurred because of the high pressure drops and close spacing of the tip to the seat at small settings. At high flow rates the pressure drop across the choke is low, and the space between the stem tip and the seat is relatively large, allowing passage of sand grains without erosion.

12.8.8 Filter Plugging

A substantial portion of scale-forming precipitates and produced formation material passed through the 50-micron filter elements and into the disposal well. Considerable filter plugging was observed during the third and fourth flow tests. More than 60% of the material caught by the filters was carbonate, rather than sand. More than 20% of the material recovered from the filters had a grain size of less than 50 microns. Replacement of the fiber filter cartridges during long term production periods on a well such as the Girouard No. 1 would be expensive and not practical. A self-cleaning 5-micron filter system might be more cost effective.

12.8.9 Analytical Balances

The Arbor Model 126a automatic balance used initially in the field was sensitive to vibrations and electrical power fluctuations on the location.

McNeese State University loaned a Mettler analytical balance to IGT, allowing many successful analytical procedures to be performed in the field. The Mettler analytical balance is less affected by vibration and electrical power fluctuations than the Arbor balance.

13.0 PLUG AND ABANDONMENT

13.1 Plugging of Test Well

The test well was killed on August 7, 1980, by pumping 109 barrels of 17.3 ppg mud down the tubing. Initial pump-in pressure was 6,500 psi. Final shut-in pressure on the well was zero psi.

A workover rig was moved on the well on August 24, 1980. The christmas tree was removed and blowout preventers were installed on the 9-5/8 inch casing head. An attempt was made to squeeze the perforations through the production packer. The packer leaked and 225 sacks of cement were spotted on top of the packer.

While pulling out of the hole, the well started to flow. The mud was circulated to get it in balance at 17.5 ppg. Some cement was carried up the hole during the circulation operations, and it was necessary to drill out the cement in order to set a cement retainer in the 7-5/8 inch liner. The well "kicked" while drilling cement at 13,500 feet and was killed with 18.5 ppg mud.

A cement retainer was set at 12,409 feet and 420 sacks of cement were pumped into the well. The 9-5/8 inch casing was then cut at 2,917 feet. The casing would not pull free and was cut at 3,024 feet. The casing still would not come free, so it was then cut at 5 feet. The casing slips were removed, and the remaining 9-5/8 inch casing was then pulled out of the hole.

A cement retainer was set at 2,000 feet in the 13-3/8 inch casing, and cement was spotted on top of the retainer. A cement plug was then spotted at the surface, and the surface casing and drive pipe were cut off 4.5 feet below ground level.

The workover rig was released on September 17, 1980.

13.2 Plugging of Disposal Well

A workover rig was not required to plug the disposal well, since a tubing string was not in the hole, and all casing was cemented in place. The plugging procedure consisted of pumping 500 sacks of cement down the hole. The drive pipe, surface casing and 5-1/2 inch casing were cut off 4.5 feet below ground level. The abandonment work on the disposal well was completed on August 8, 1980.

14.0 CONCLUSIONS

Data obtained during testing varied from expectations in several instances. The listing below compares pre-test projections with actual field measurements.

Item	Pre-Test Expectations	Actual Data Measurements
Original Reservoir Pressure	13,226 psia	13,203 psia
Original Reservoir Temperature	256°F	274°F
Salinity	36,000 ppm	23,500 ppm
Gas-To-Water Ratio	42 SCF/BBL	40 SCF/BBL
Reservoir Size	3,520 Acres	305 Acres (minimum)

The measured reservoir temperature was 18°F higher than a corrected electric log temperature. Two observations support the 274°F value. First, calibration of the downhole sensor was verified against a laboratory thermometer by immersing both instruments in boiling water on location. Second, observed surface temperatures as high as 253°F were measured while flowing at rates in excess of 10,000 BWPD. Since individual flow durations were less than 1.5 days, a 20°F temperature drop in the fluid on its way up the well bore would be expected. The implication here is that log temperatures and current correction methods are subject to errors greater than 7%.

Total dissolved solids were 23,500 ppm compared to the 36,000 ppm salinity anticipated from log analysis. Electric log derived salinities are subject to errors from such factors as incorrect or variable mud filtrate information. The state of the art of log salinity derivation methods needs to be improved.

The gas-to-water ratio was lower than expected. Laboratory recombination studies conducted by Weatherly Laboratories, Inc. indicated that the saturation value was about 44.5 SCF/BBL. It appears that the reservoir brine is possibly undersaturated with gas. (See page 124.)

The reservoir appears much smaller than originally anticipated, although the limits of the reservoir were not found during drawdown flow tests. The reservoir is projected as a much smaller one because flow test data indicates a pinching out of the sand formation relatively close to the well itself.

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16.0 ILLUSTRATIONS

Photograph No.	Subject
1.	Testing in progress. Well producing 600,000 standard cubic feet of gas per day.
2.	Christmas tree and work platform.
3.	Mathieu Rig No. 16 performing completion operations on test well.
4.	Christmas tree, flowline, choke manifold, and data header.
5.	Side view of location. Note "kill" line to casing at lower left.
6.	Overall view of test equipment.
7.	Closeup of christmas tree. Note secondary adjustable choke at top center.
8.	Reservoir Data Inc. wireline equipment prior to rig-up on test well.
9.	Casing head as installed on 9-5/8 inch casing. Pressure-relief and choke lines are at upper right.
10.	Pneumatic safety shut-in valve with nitrogen supply line.
11.	High pressure sampling block used for performing experiments at wellhead conditions.
12.	High-pressure flow meter, safety by-pass system, and "Y" block with flow loops.
13.	Gray 4-1/16 inch high pressure choke manifold.
14.	Choke manifold and data header.
15.	Data header with safety pilot. Sand, scale, and corrosion data are obtained here.
16.	Three-phase separator with 20,000 BWPD capacity.

Photograph No.	Subject
17.	Valves are used to divert flow from data header to separator, pit, or to disposal well.
18.	Air compressor system used to supply air pressure to operate separator control values.
19.	Liquid level sight glass located on the side of the separator.
20.	Separated gas flows through a 2-inch line pipe manifold.
21.	Closeup of temperature and pressure recording instruments and gas flow control value.
22.	Water metering skid with dual turbine meters, calibration connections and water flow control valves.
23.	Ground view of water metering skid.
24.	Water leaving the metering skid enters the filter unit at lower right.
25.	Water flow control valve located on metering skid.
26.	Digital turbine meter recorders located on metering skid.
27.	View of location from far side of reserve pit.
28.	Three tower water filter unit. Each tower is designed to filter up to 20,000 BWPD.
29.	Pressure safety sensor located on filter unit.
30.	Water leaving filter unit enters the disposal well.
31.	Manual safety shut in control point with nitrogen supply bottles.
32.	Disposal well with pressure and temperature recording instruments.
33.	IGT strip chart data recording panel.
34.	IGT work table and computer modules.

Photograph No.	Subject
35.	IGT chemistry lab.
36.	IGT chemist obtaining a fluid sample.
37.	Gas being flared at the rate of 600,000 standard cubic feet per day.
38.	Approximately 6,700 BTU of heat energy are being generated every second.

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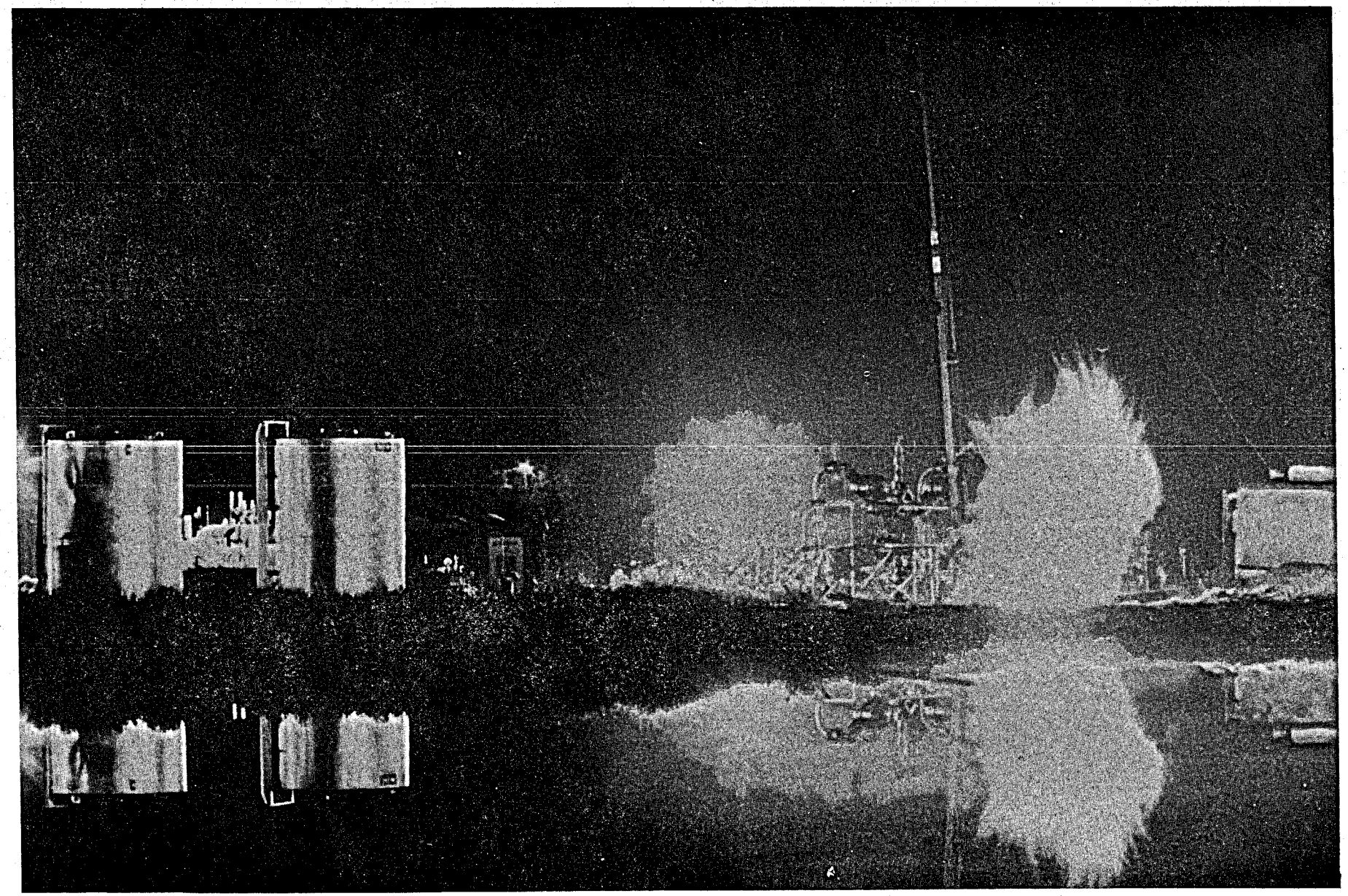

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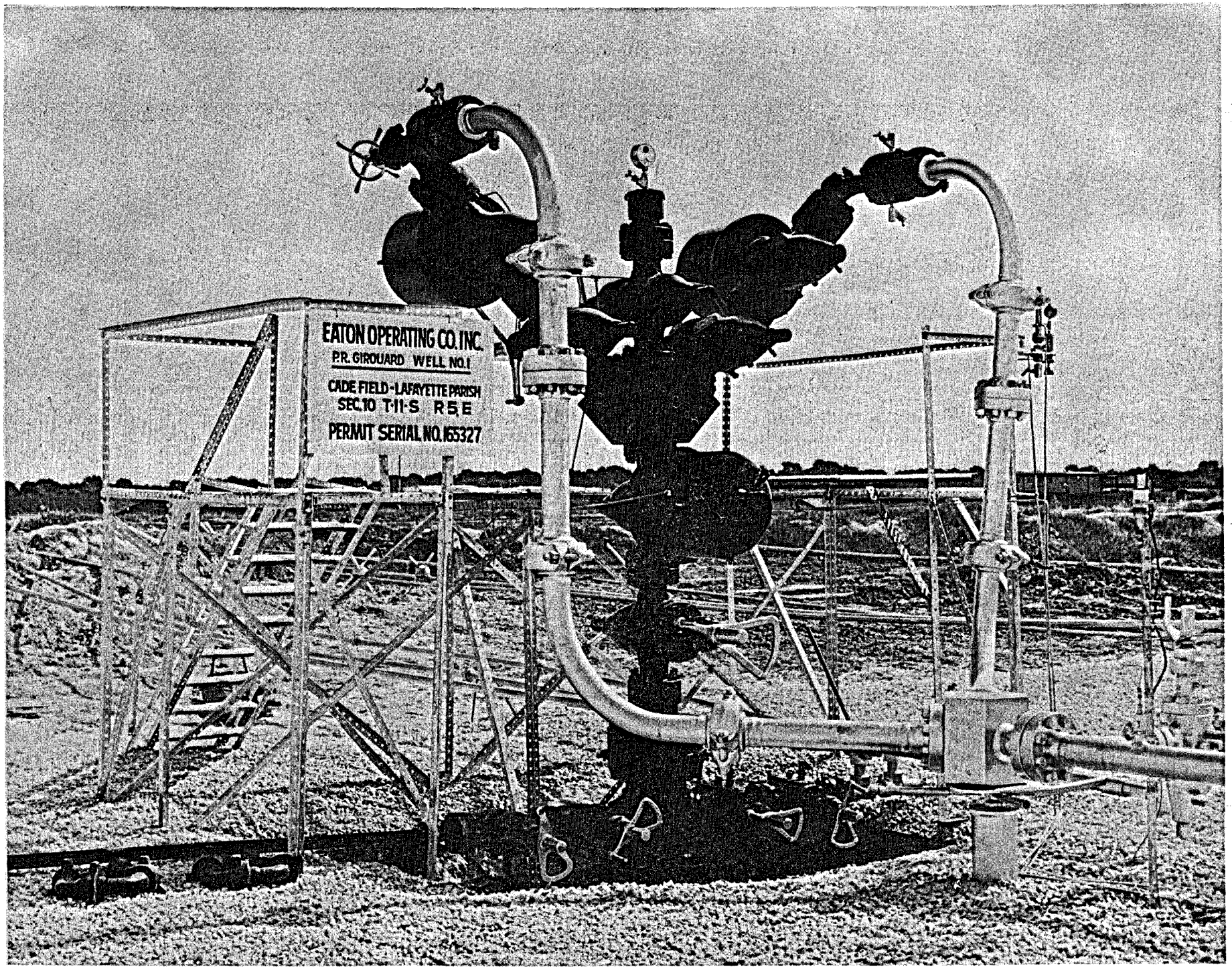
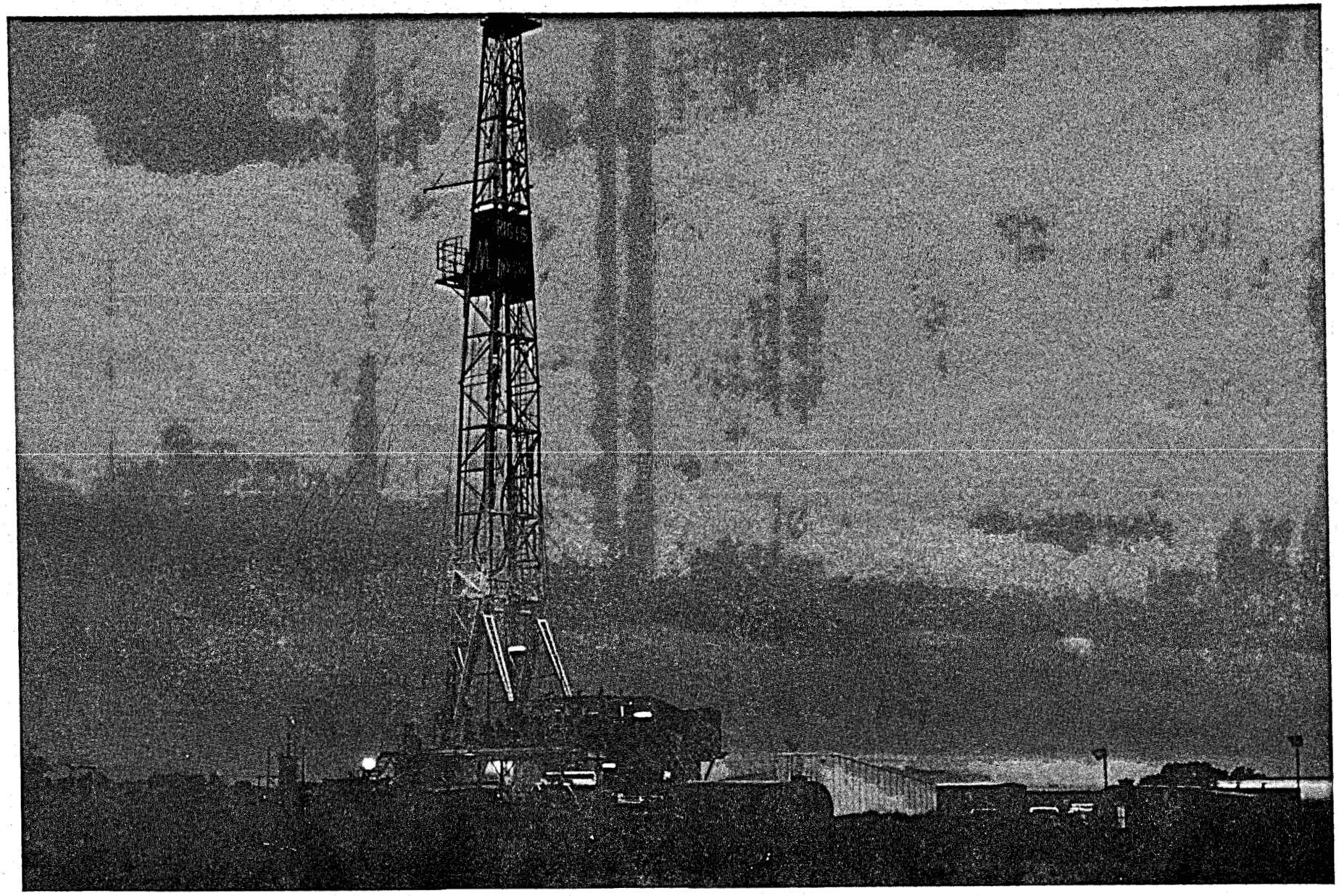
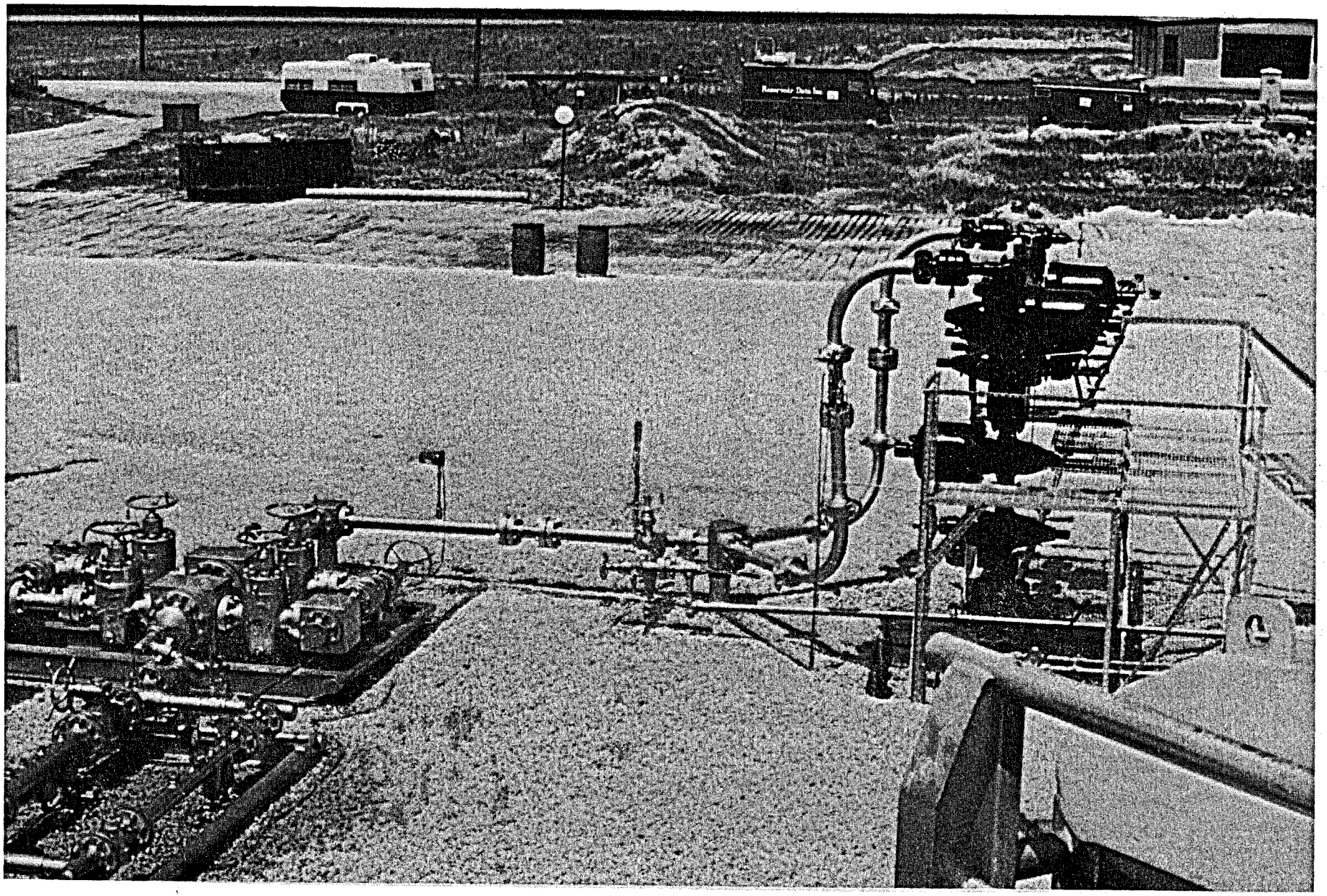


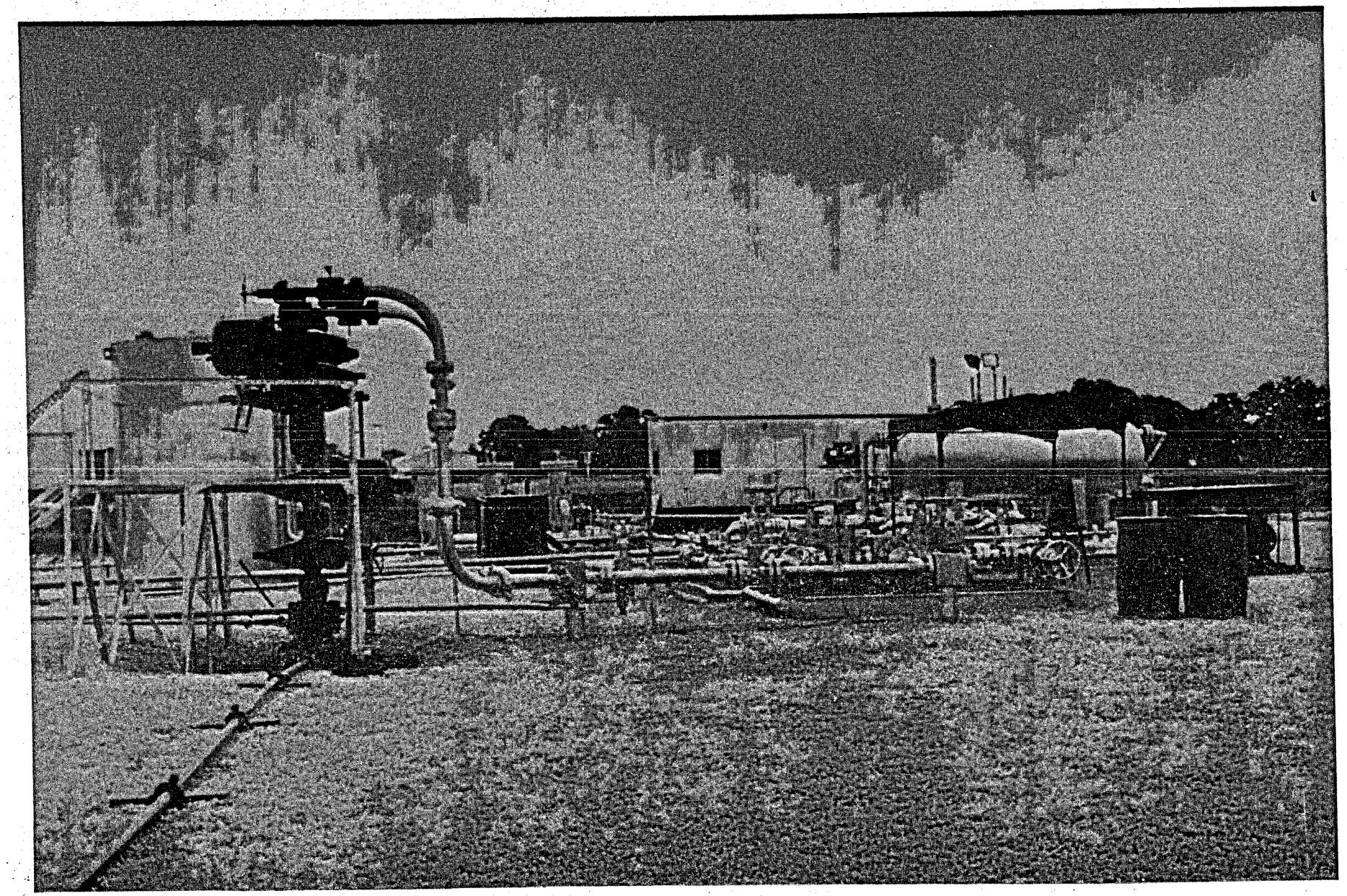
2. Christmas tree and work platform.



3. Mathieu Rig No. 16 performing completion operations on test well.

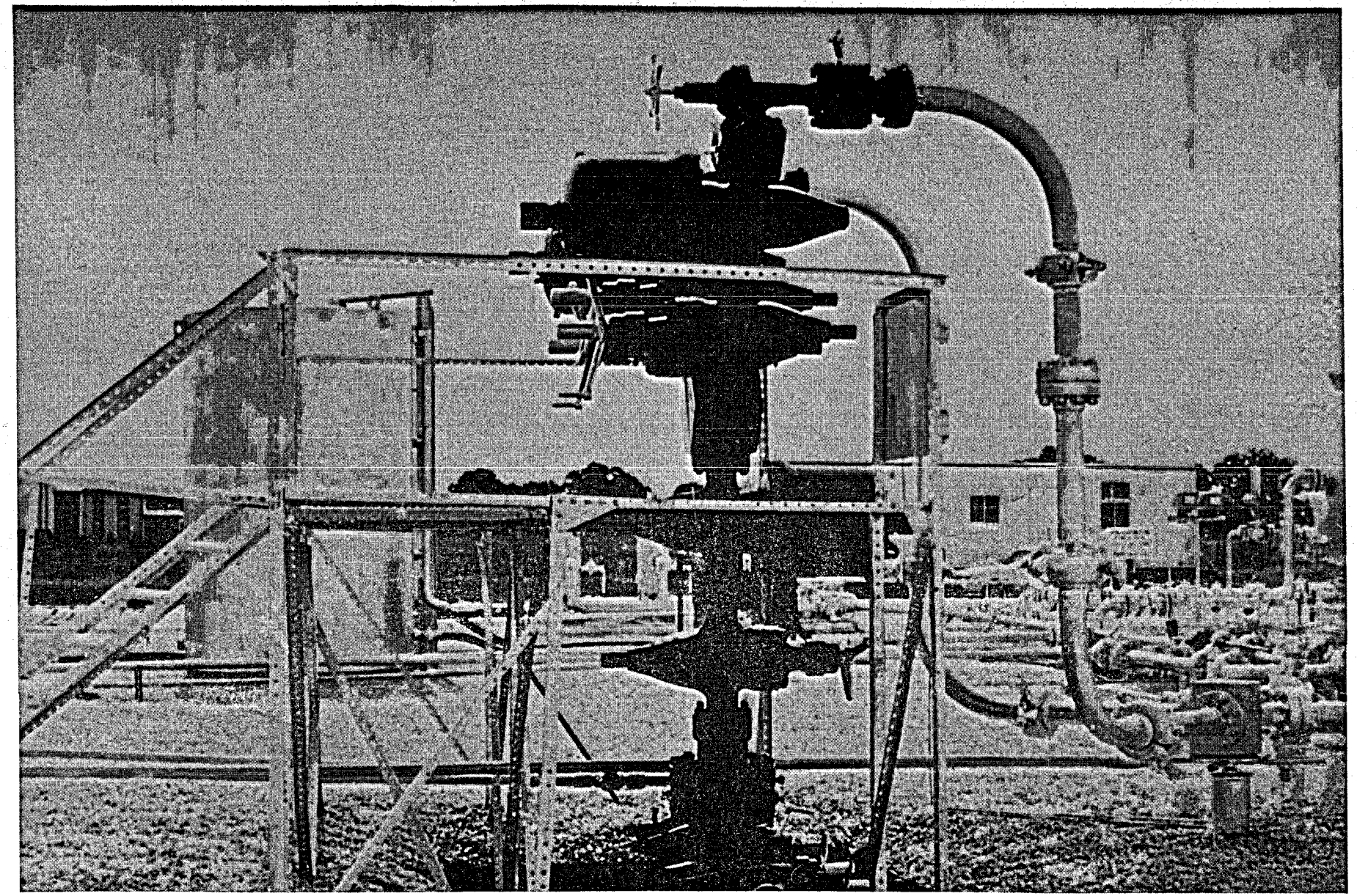


4. Christmas tree, flow line, choke manifold and data header.

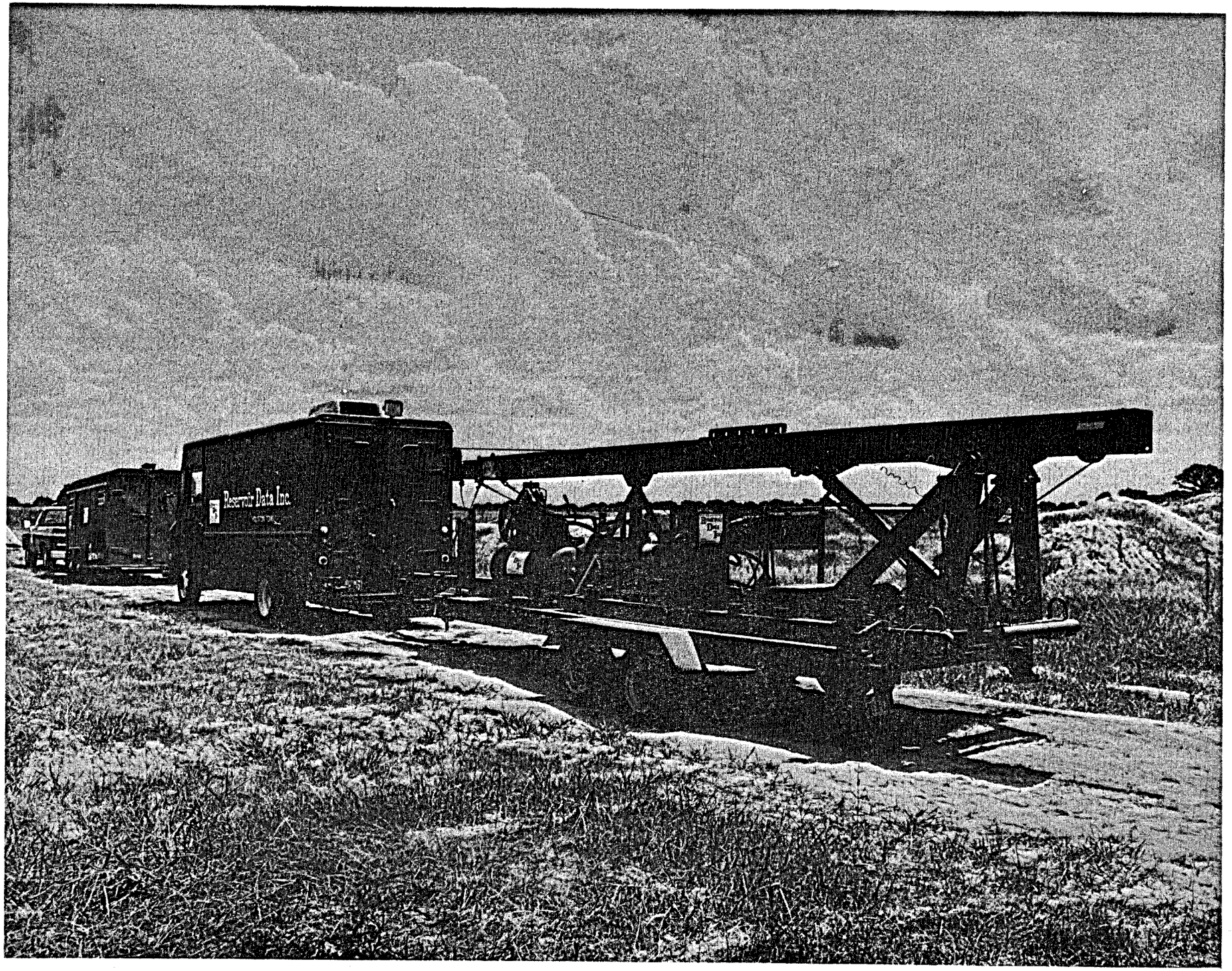


5. Side view of location. Note "kill" line to casing at lower left.

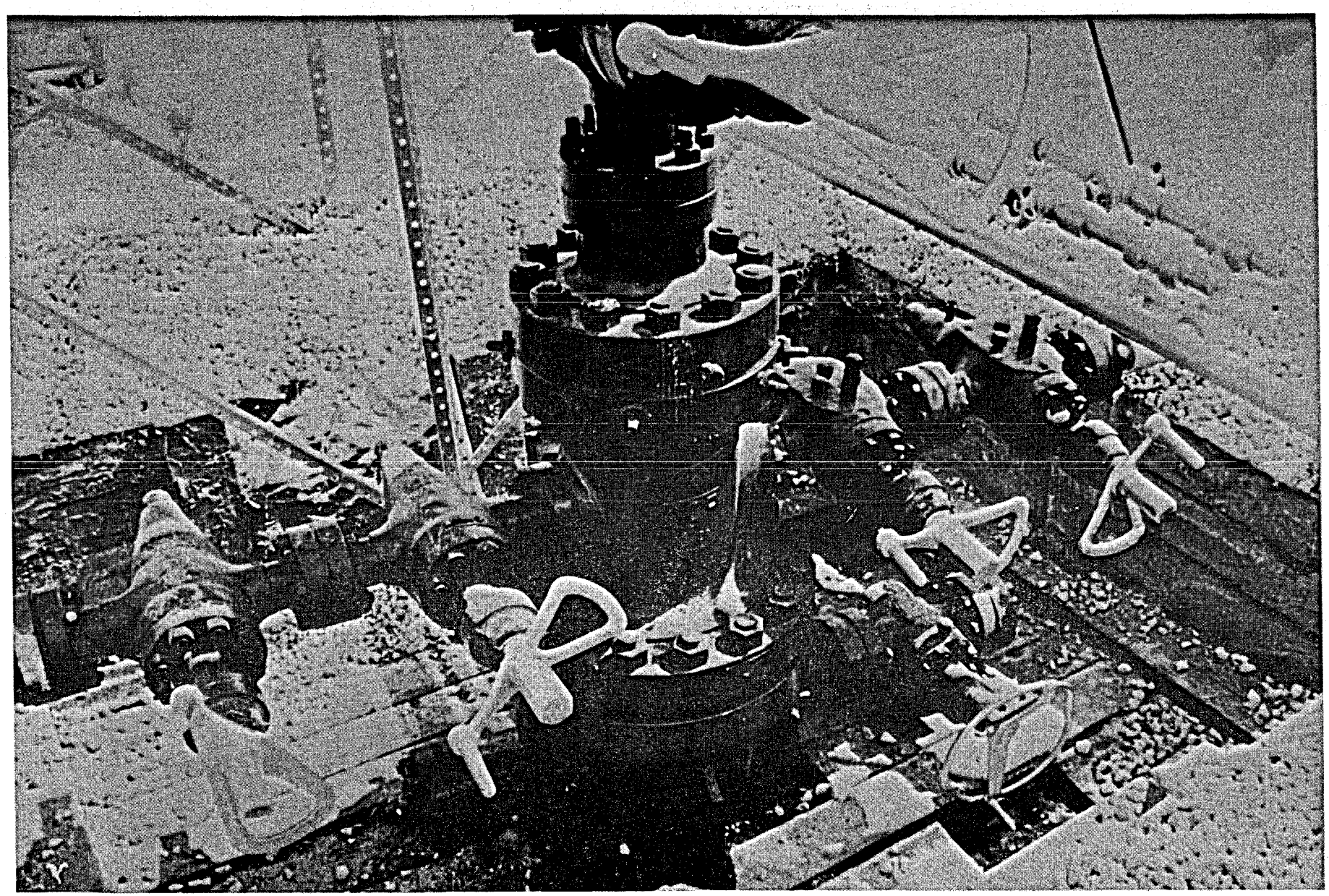
6. Overall view of test equipment.



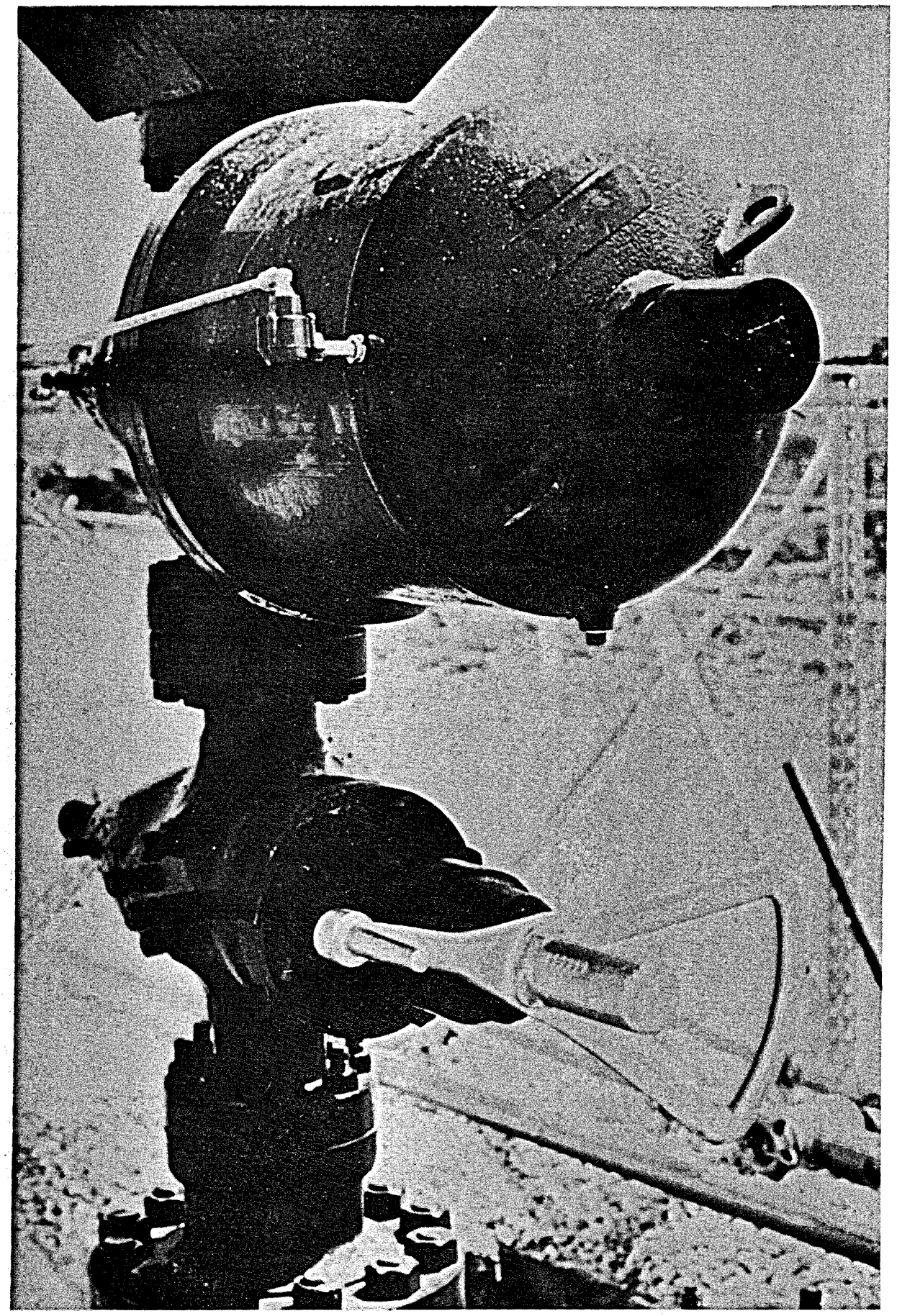
7. Close-up of christmas tree. Note secondary adjustable choke at top center.



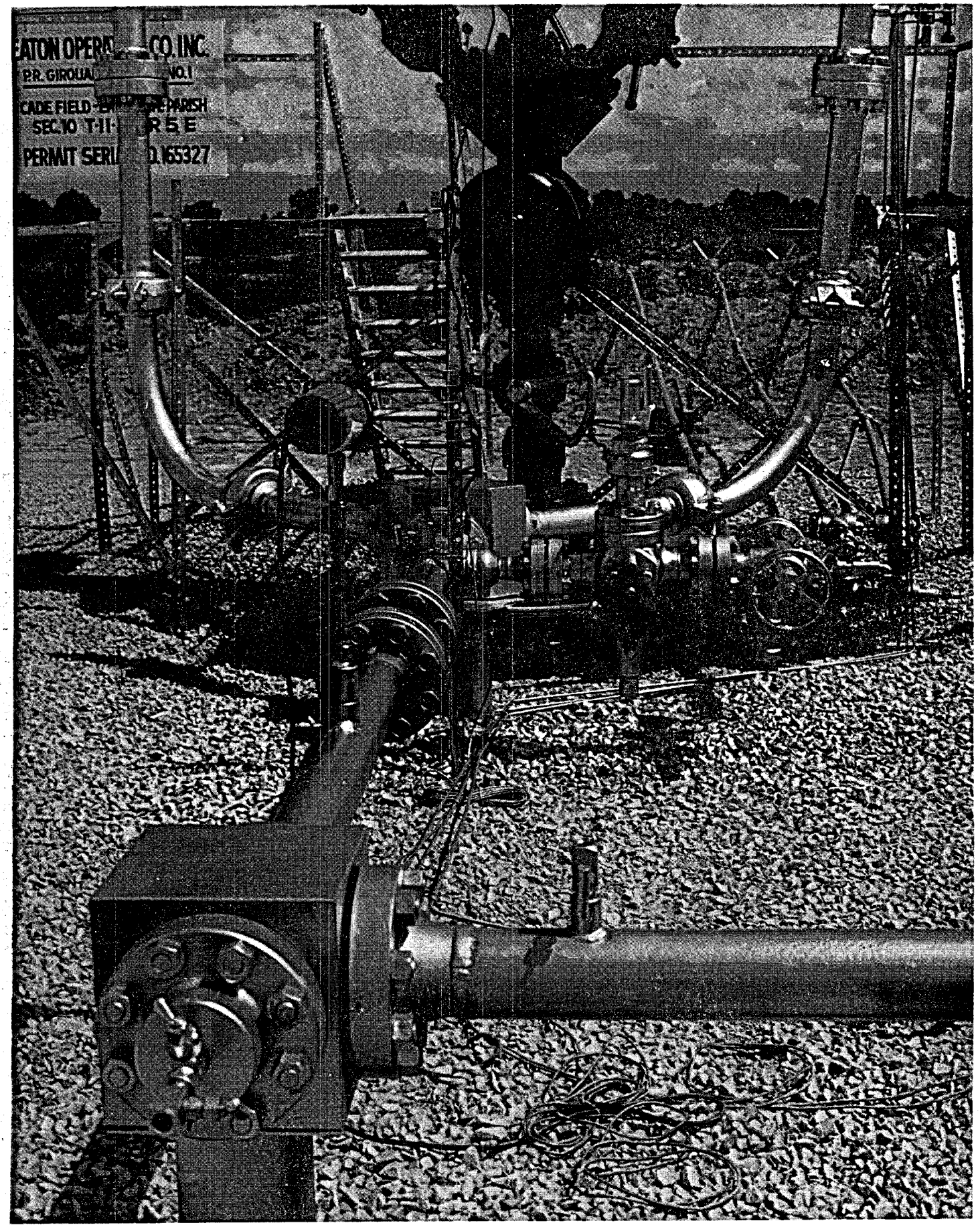
8. Reservoir Data, Inc. wireline equipment prior to rig up on test well.



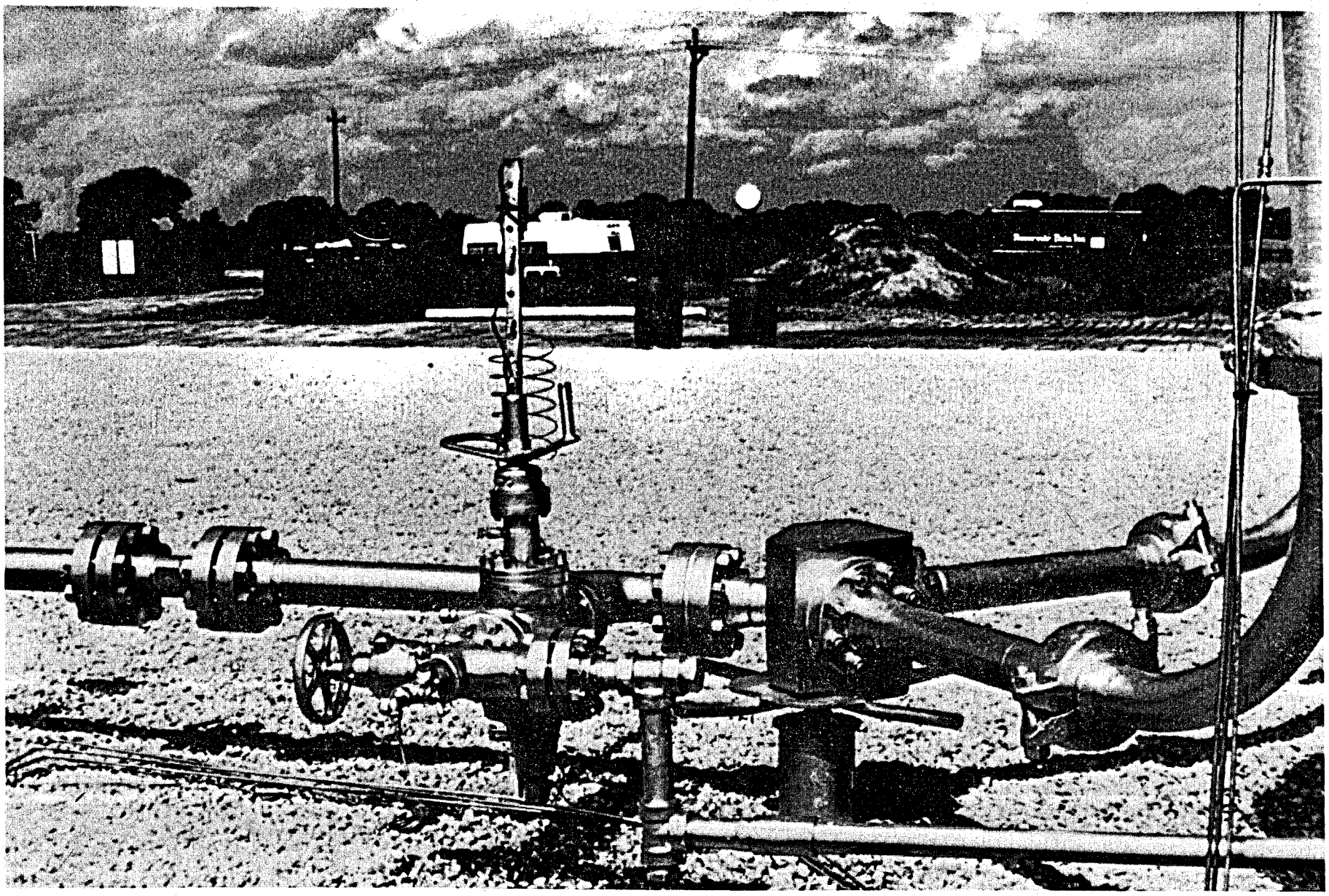
9. Casing head as installed on 9-5/8-inch casing. Pressure relief and choke lines are at upper right.



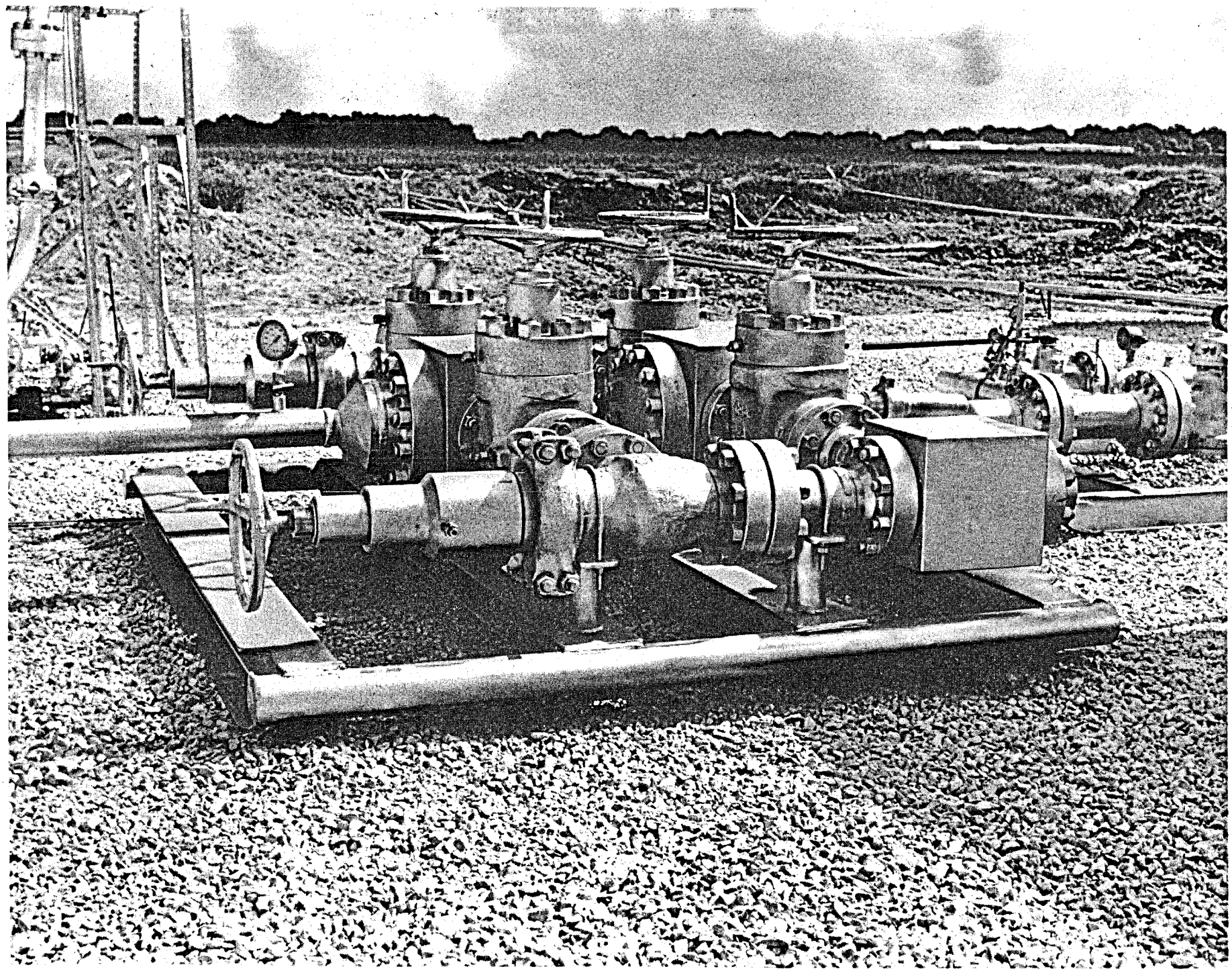
10. Pneumatic safety shut-in valve with nitrogen supply line.



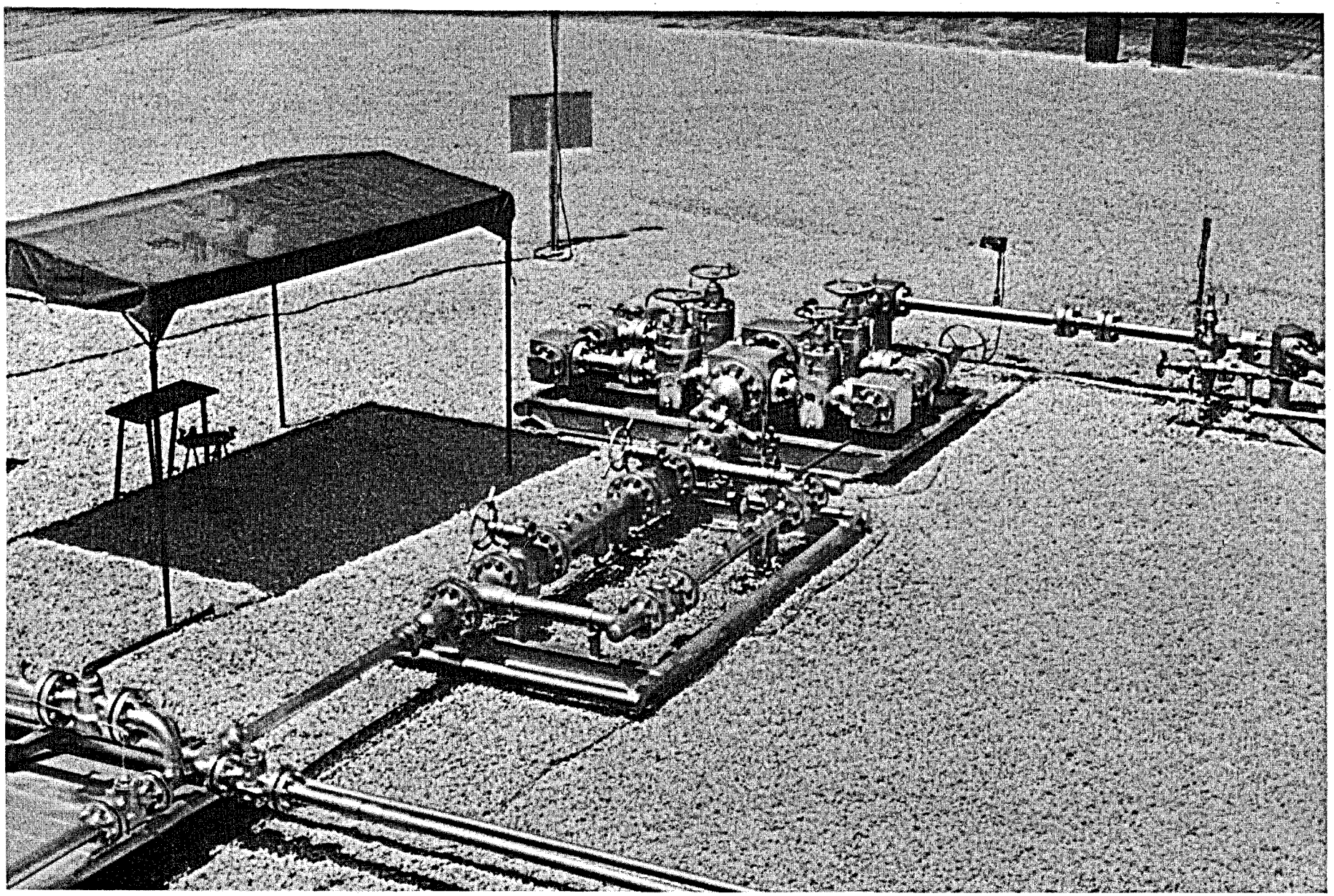
11. High pressure sampling block used for performing experiments at wellhead conditions.



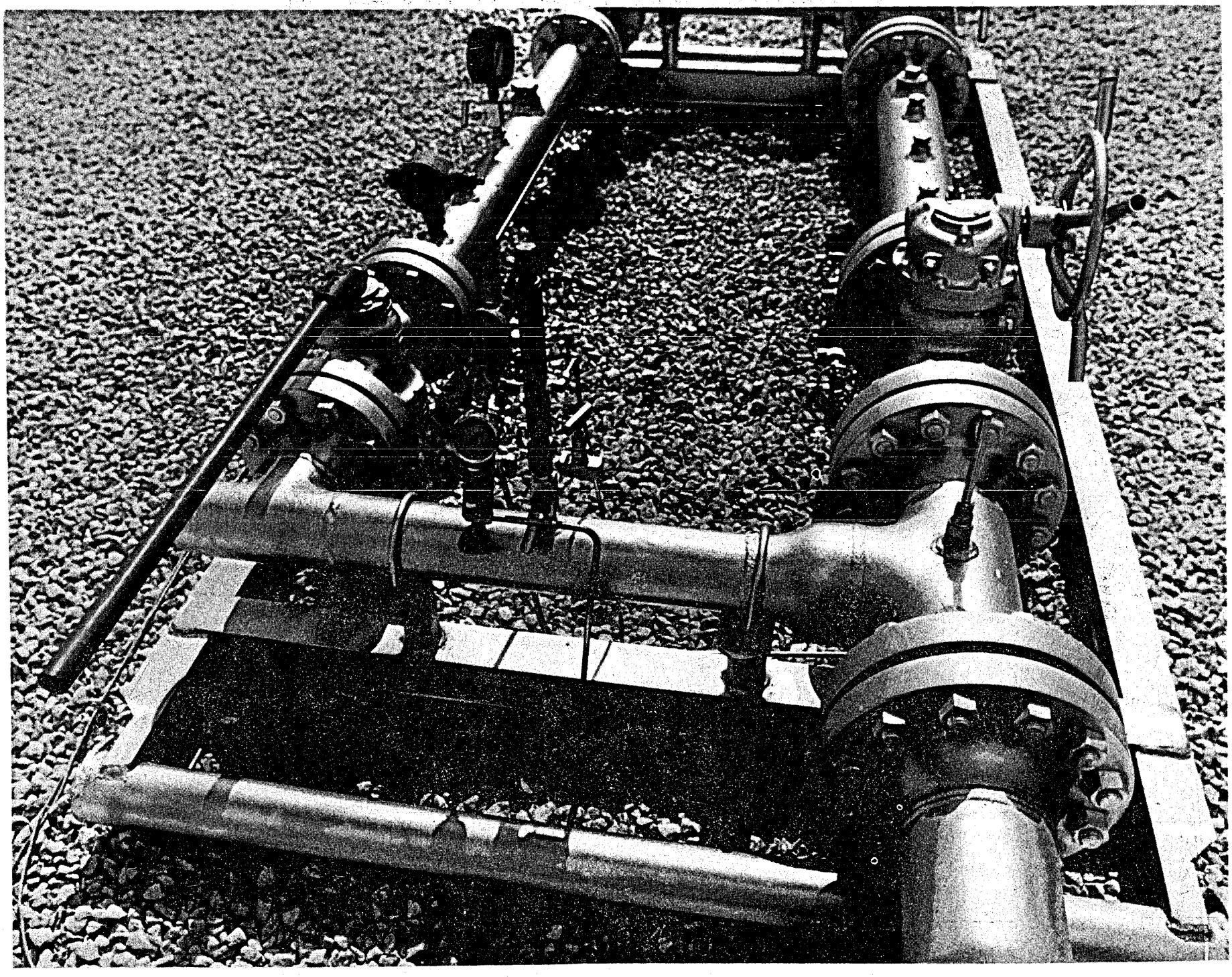
12. High pressure flow meter, safety by pass system and "y" block with flow loops.



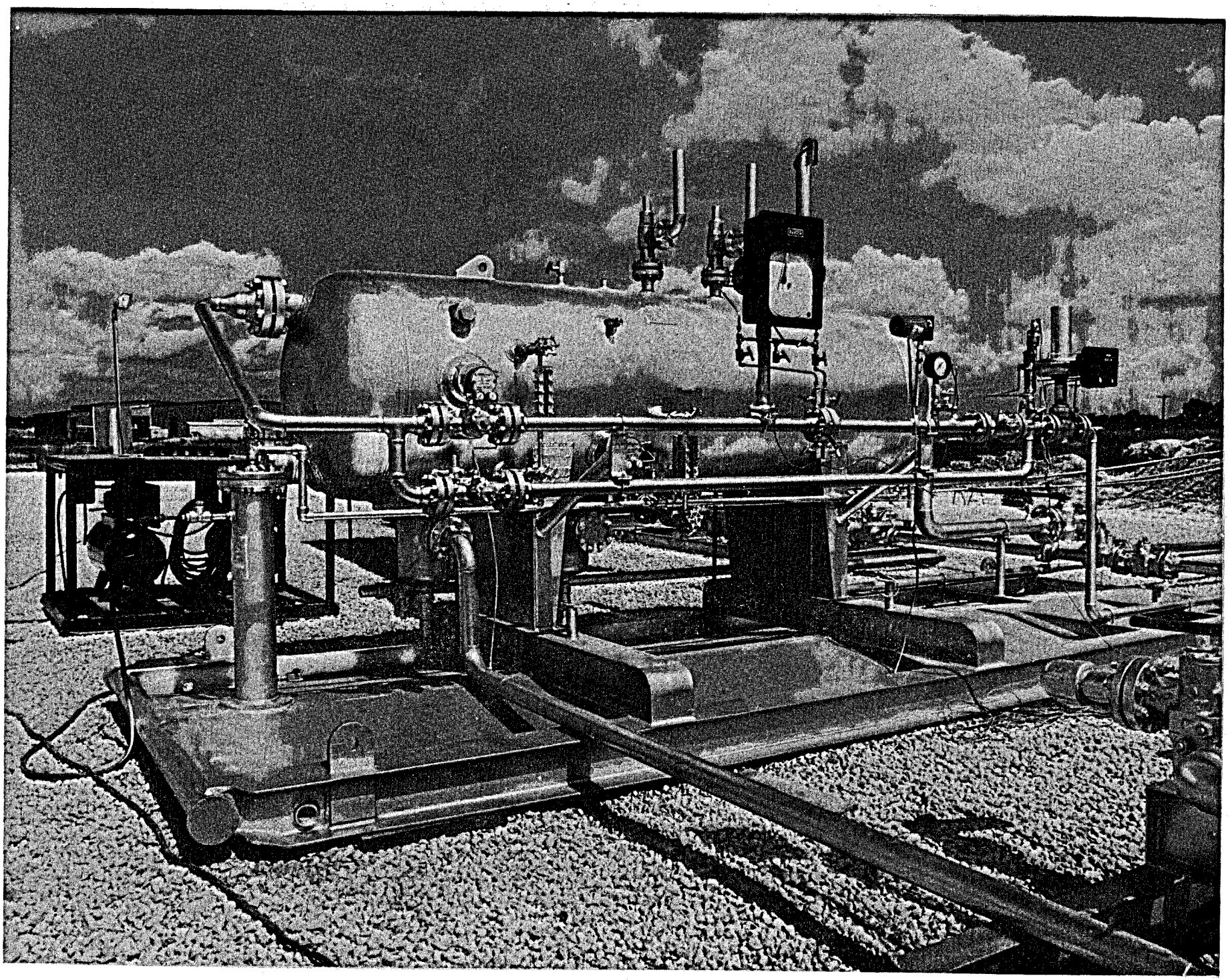
13. Gray 4-1/16-inch high pressure choke manifold.



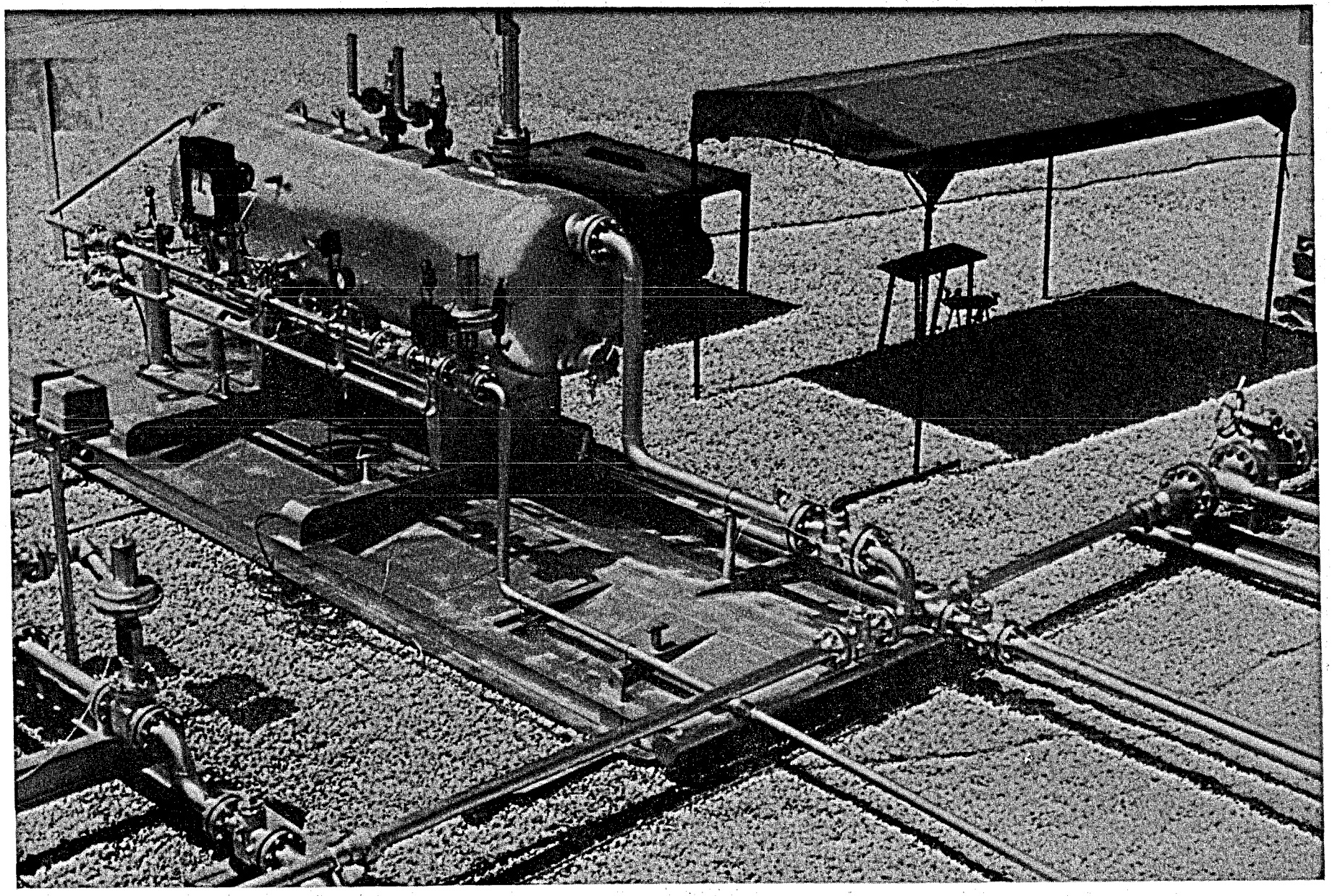
14. Choke manifold and data header.



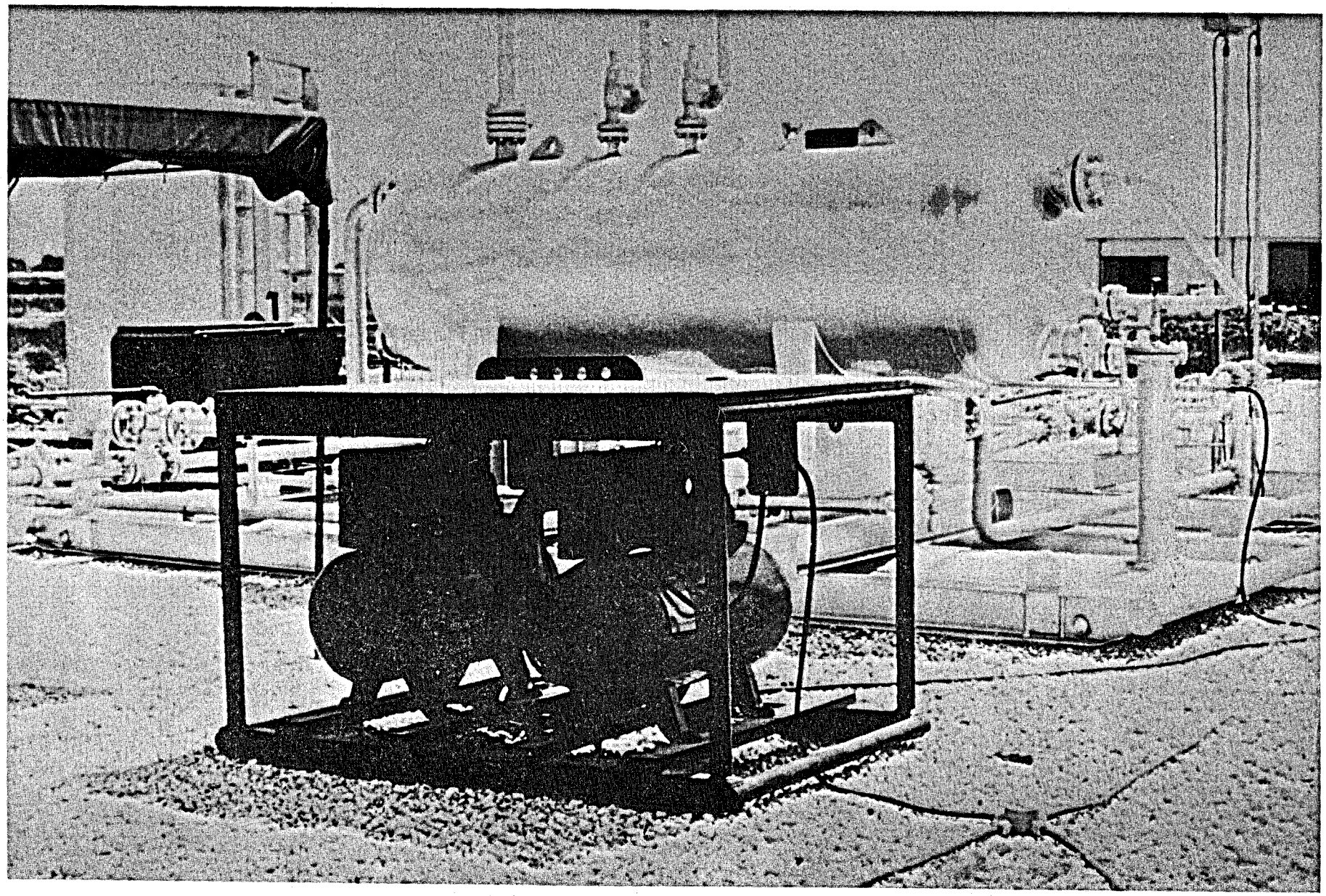
15. Data header with safety pilot. Sand, scale and corrosion data are obtained here.



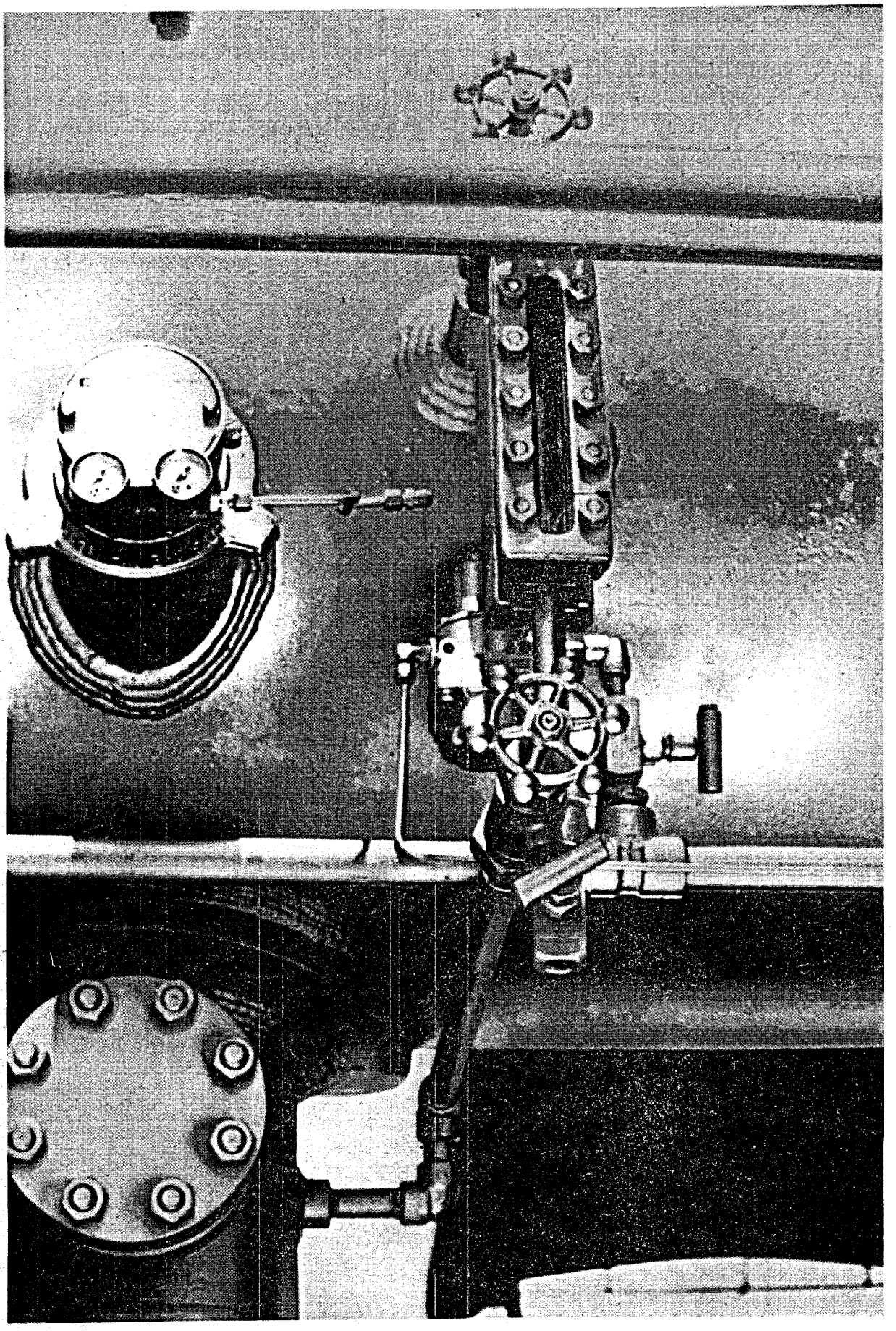
16. Three phase separator with 20,000 BWPD capacity.



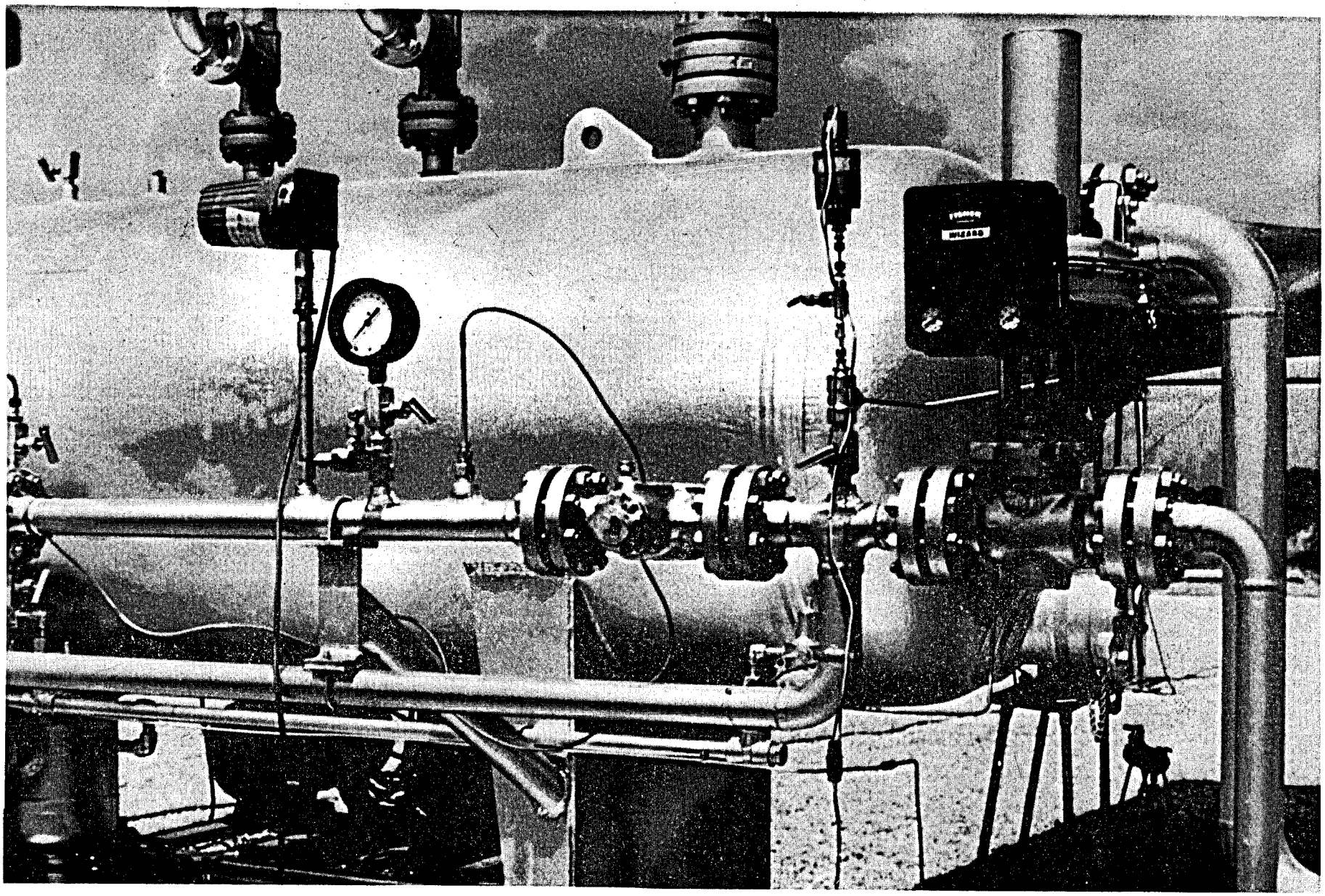
17. Valves are used to divert flow from data header to separator, pit, or to disposal well.



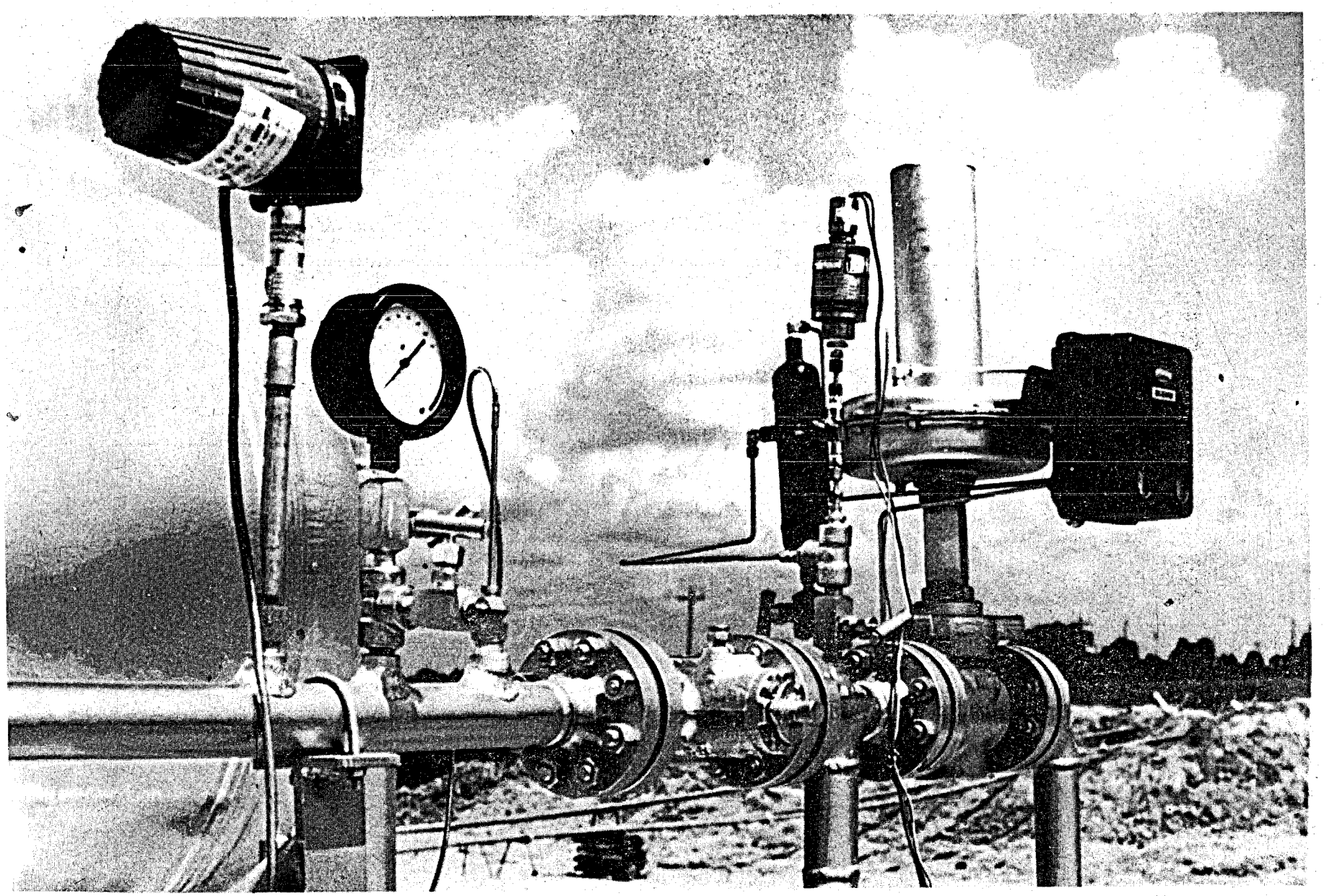
18. Air compressor system used to supply air pressure to operate separator control valves.



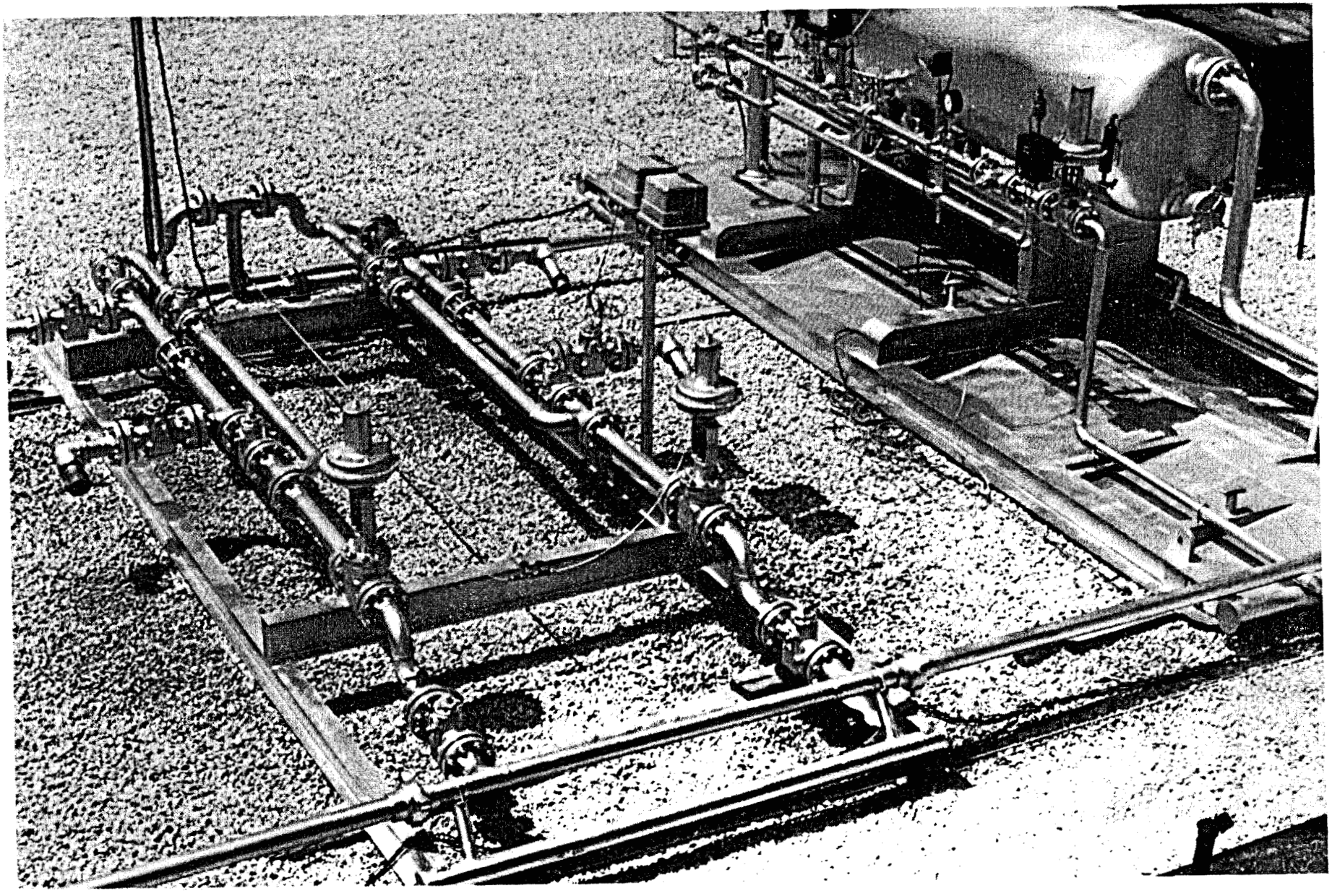
19. Liquid level sight glass located on the side of the separator.



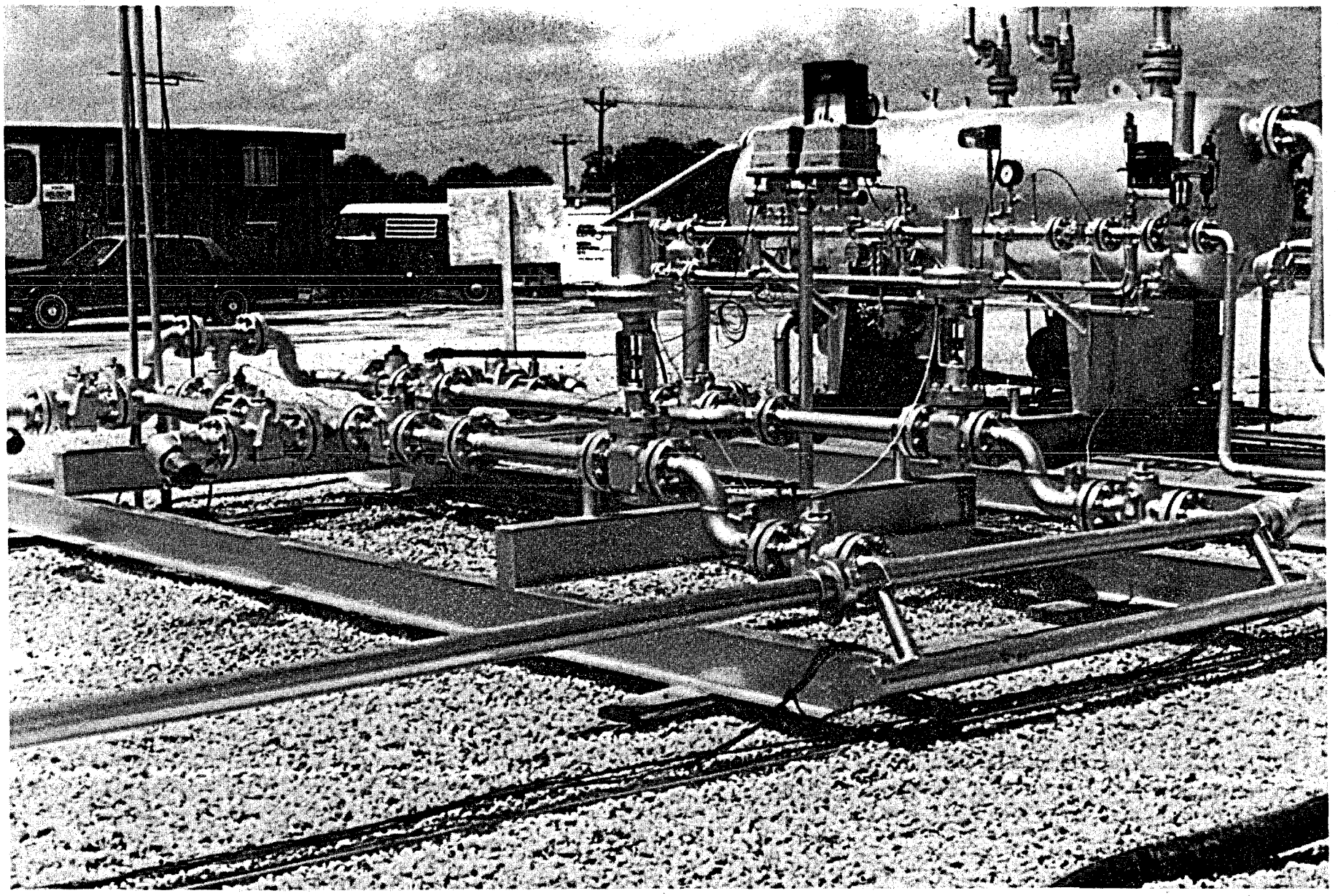
20. Separated gas flows through a 2-inch line pipe manifold.



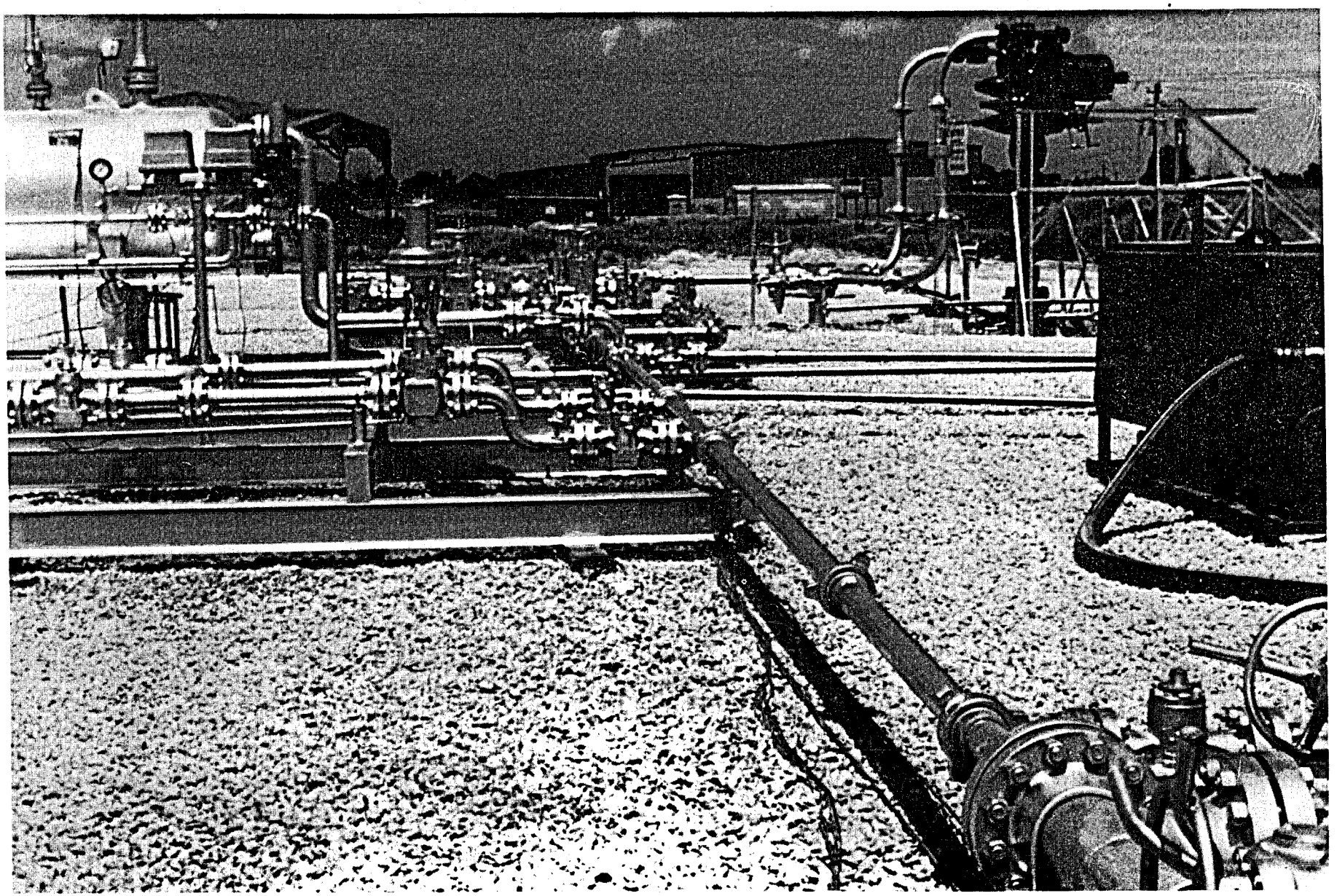
21. Close-up of temperature and pressure recording instruments and gas flow control valve.



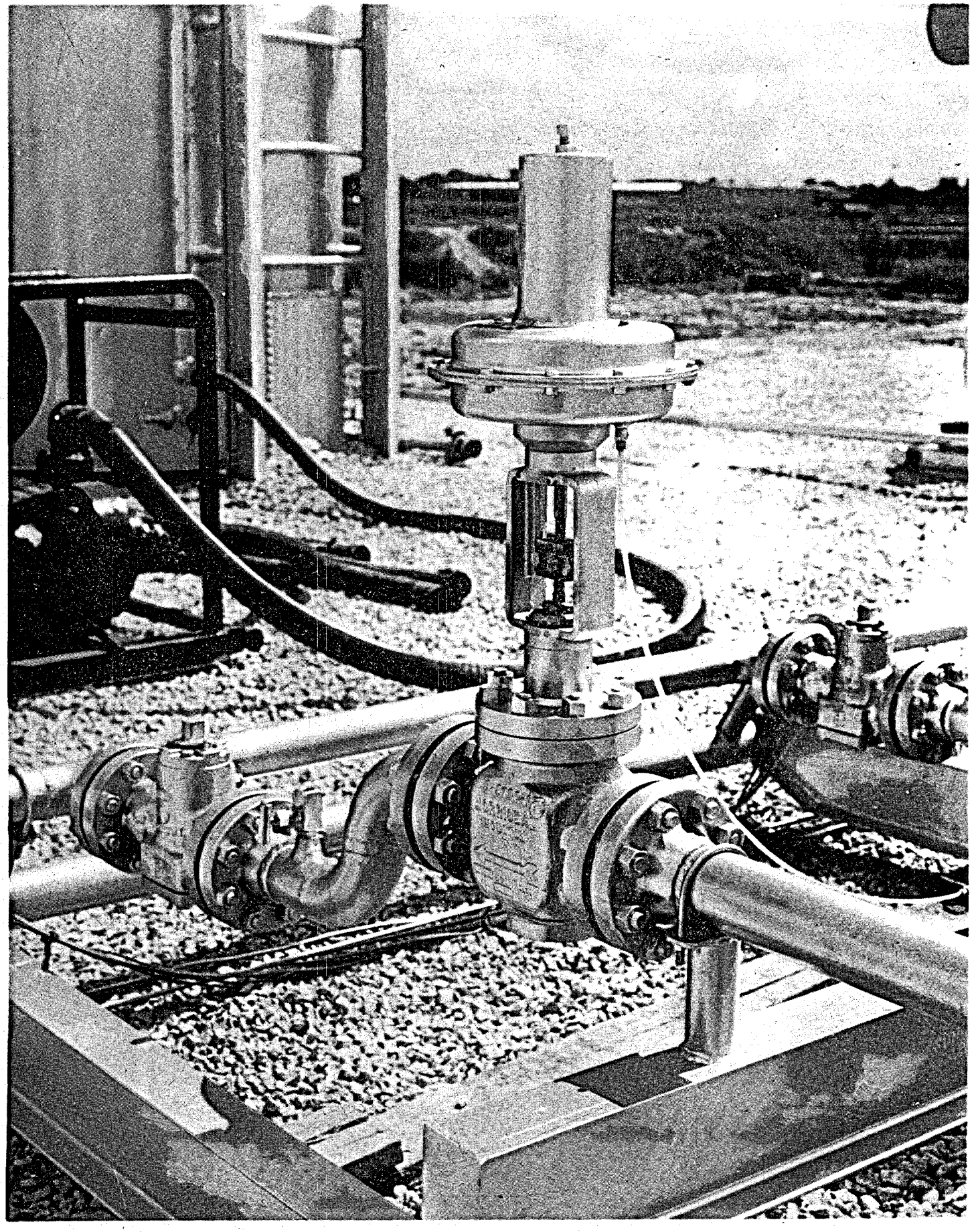
22. Water metering skid with dual turbine meters, calibration connections and water flow control valves.



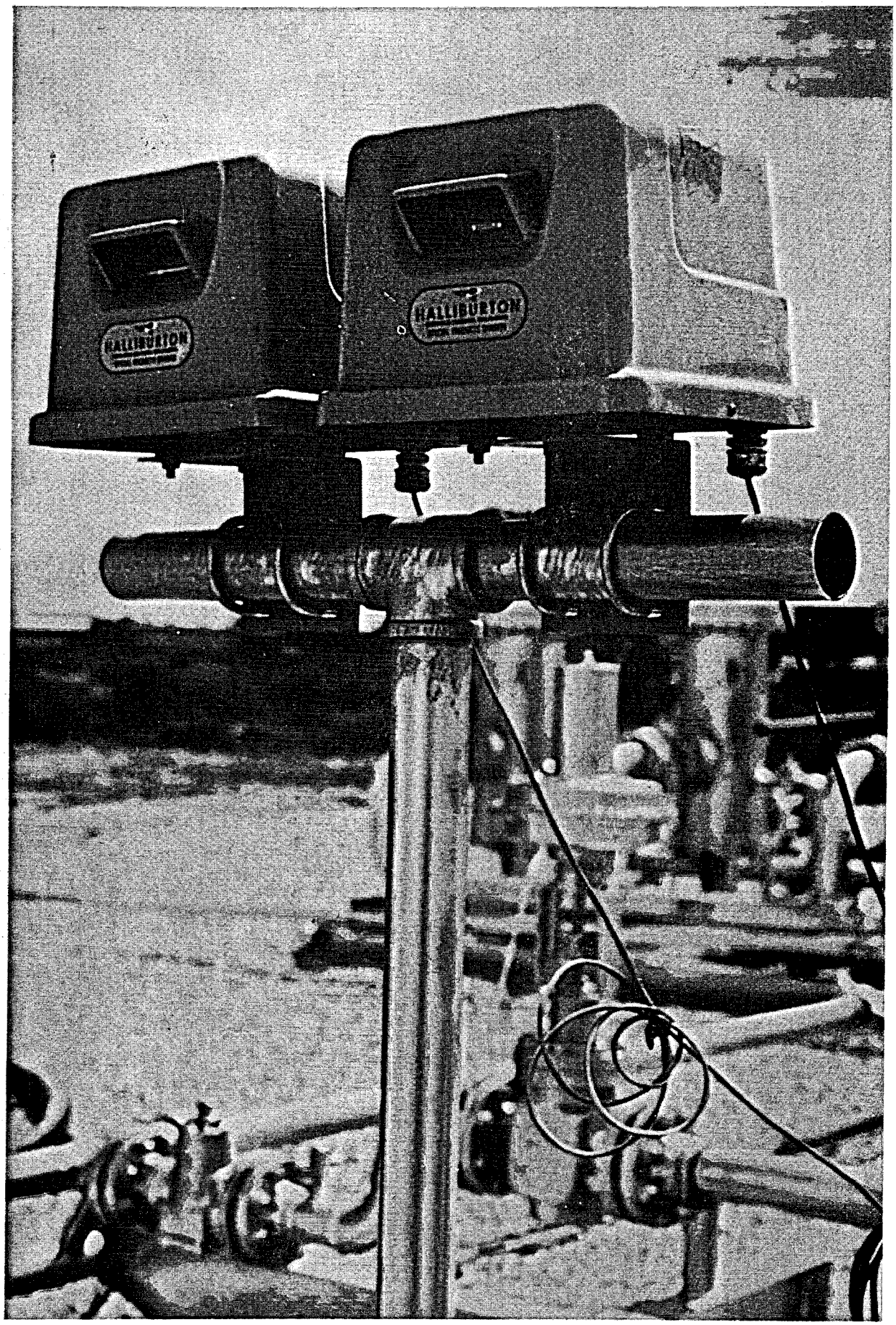
23. Ground view of water metering skid.



24. Water leaving the metering skid enters the filter unit at lower right.

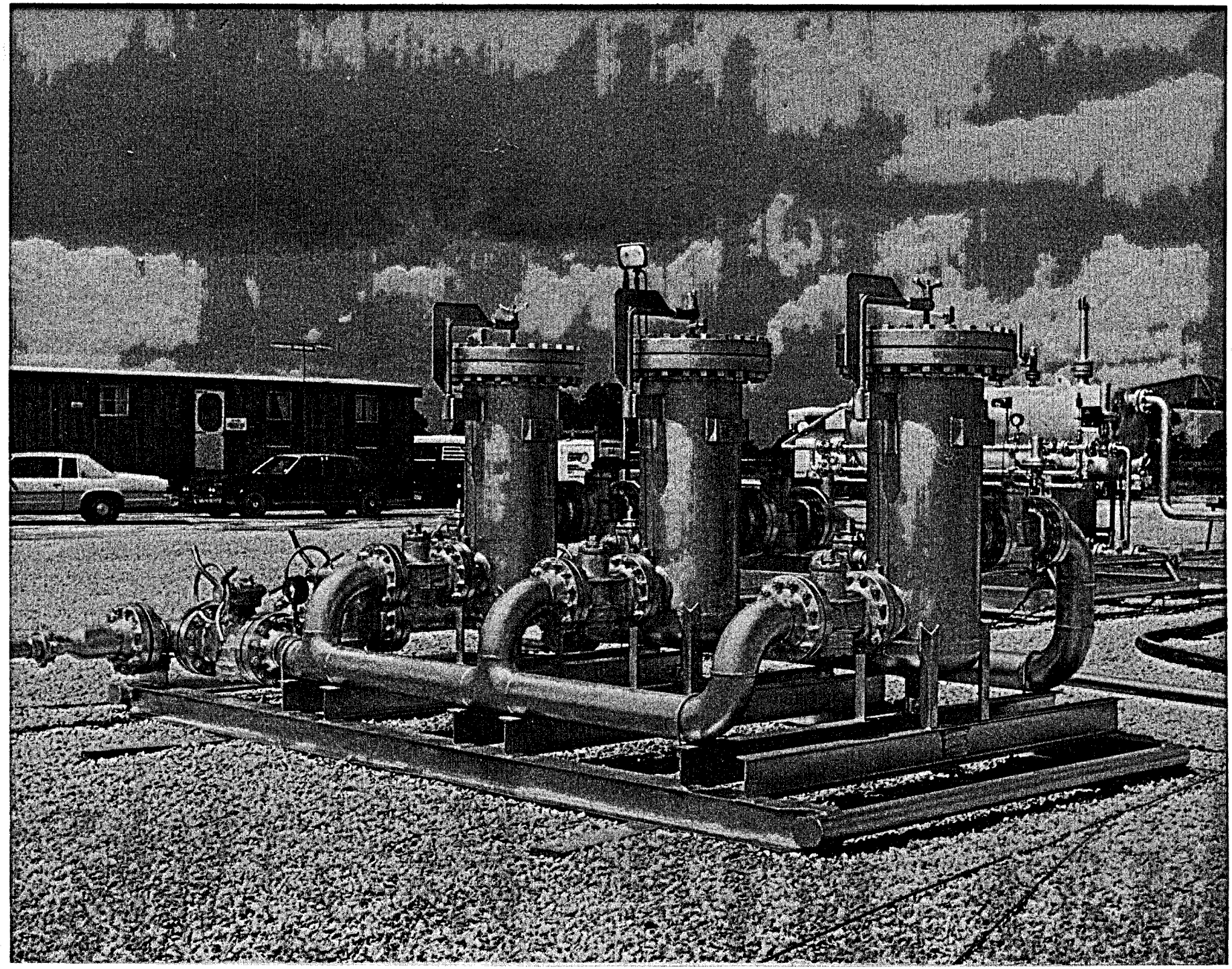


25. Water flow control valve located on metering skid.

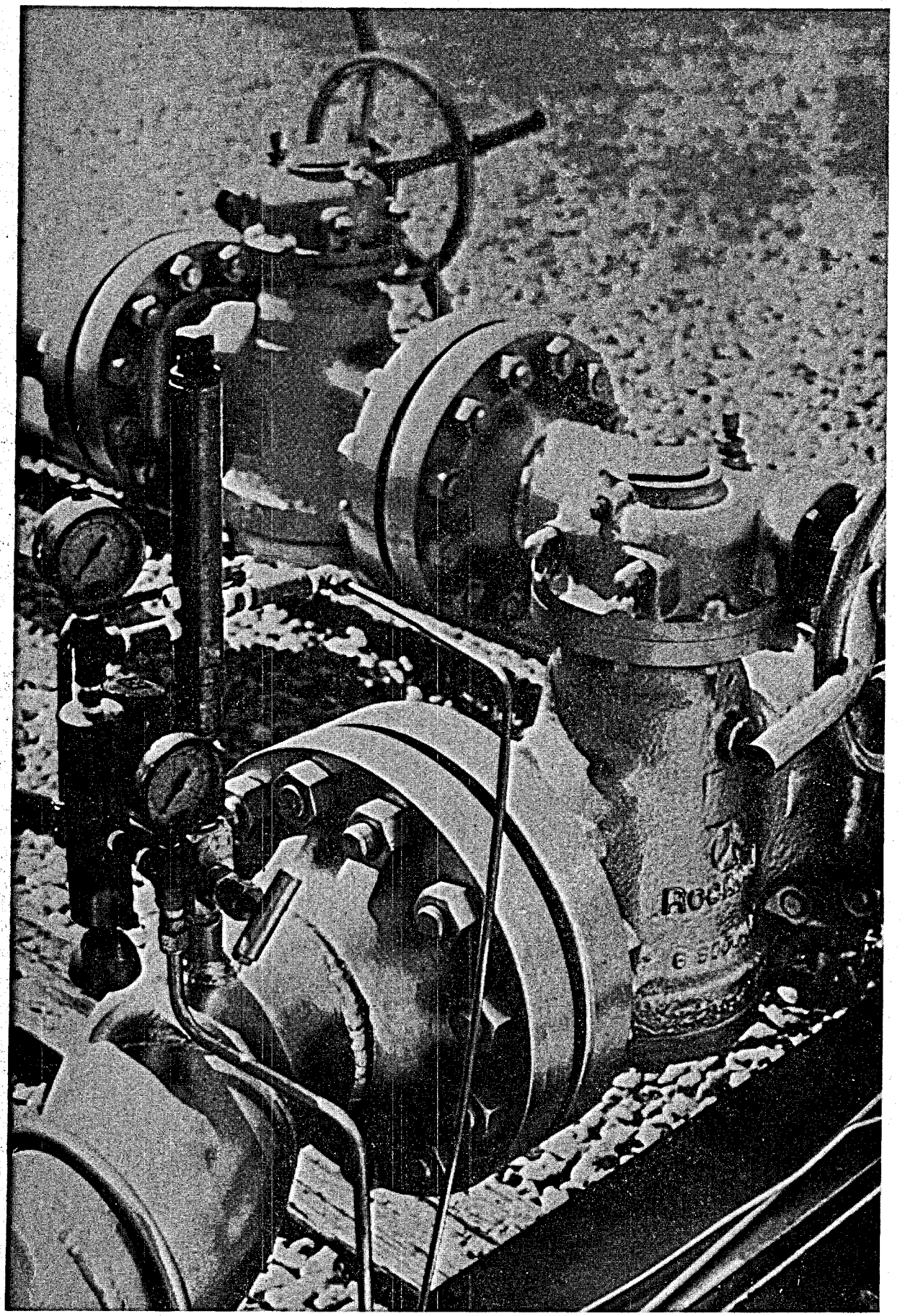


26. Digital turbine meter recorders located on metering skid.

27. View of location from far side of reserve pit.

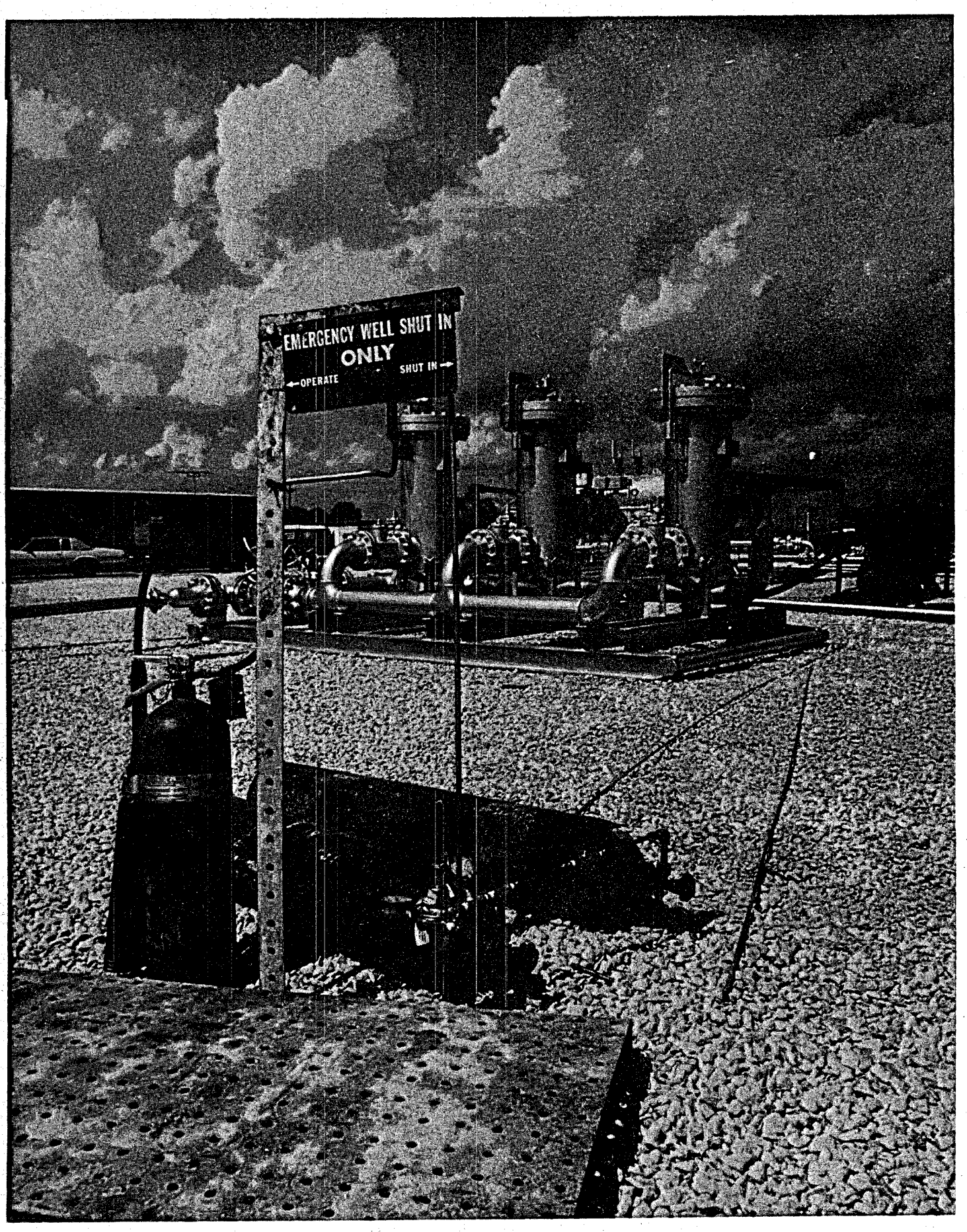


28. Three tower water filter unit. Each tower is designed to filter up to 20,000 BWPD.

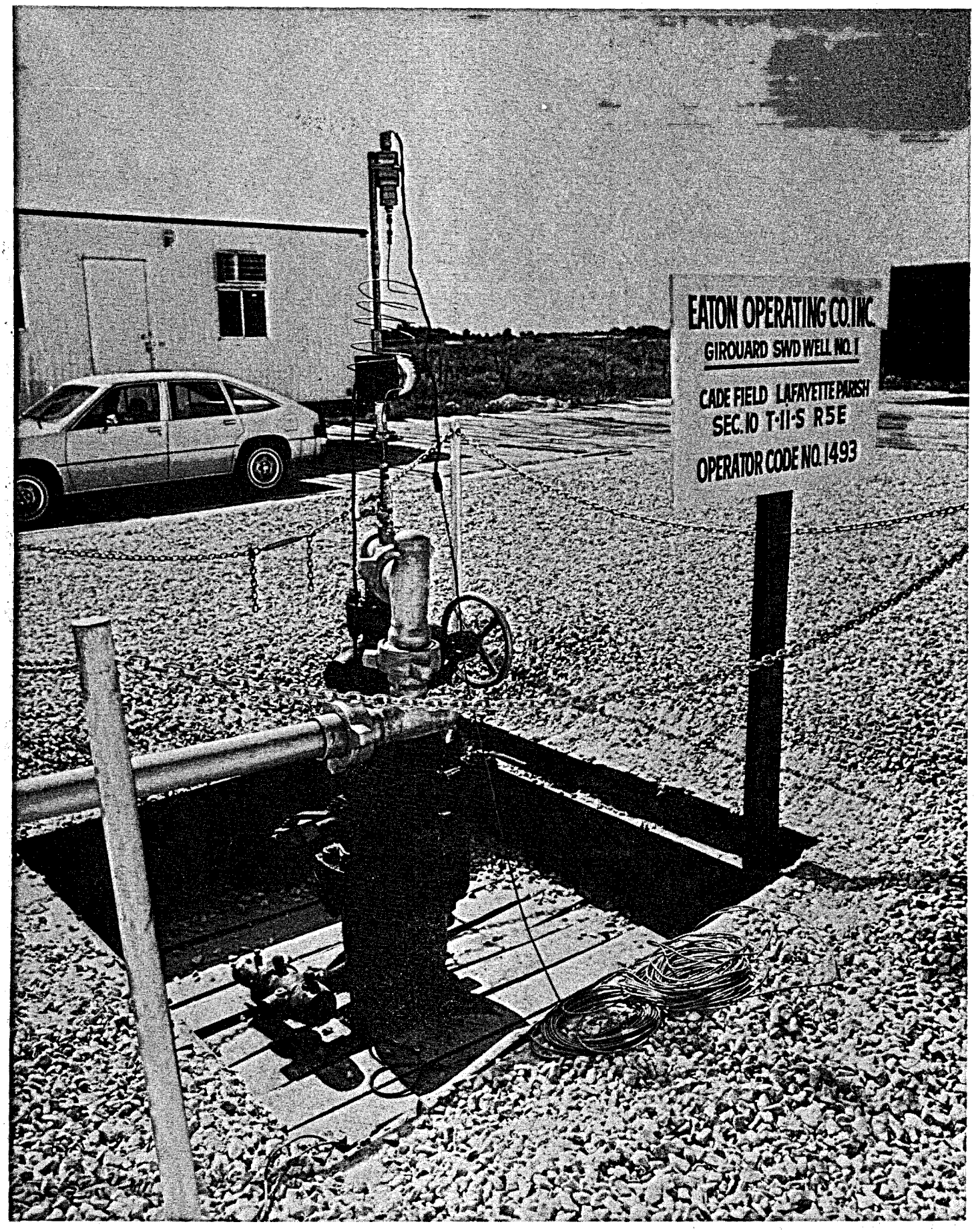


29. Pressure safety sensor located on filter unit.

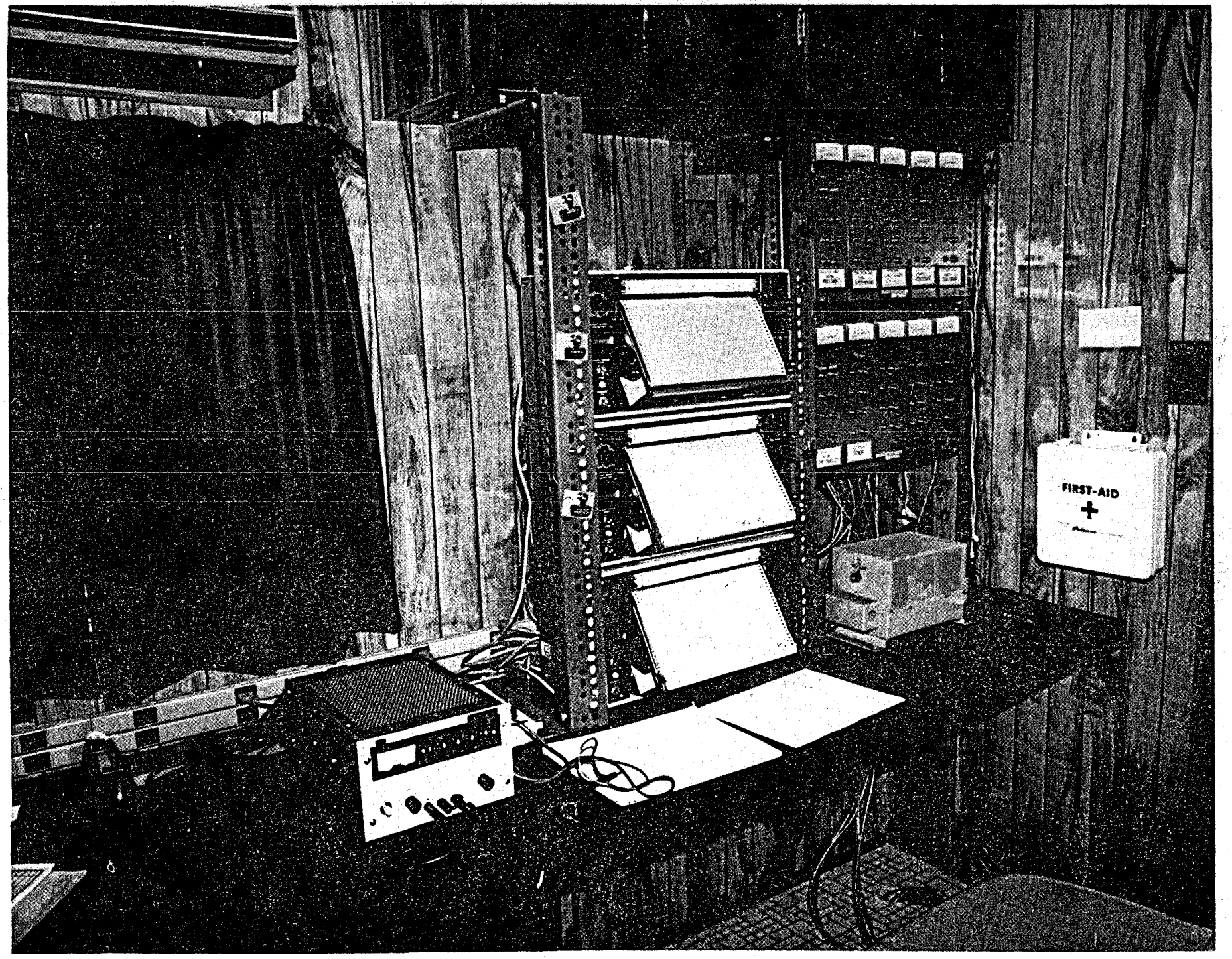
30. Water leaving filter unit enters the disposal well.



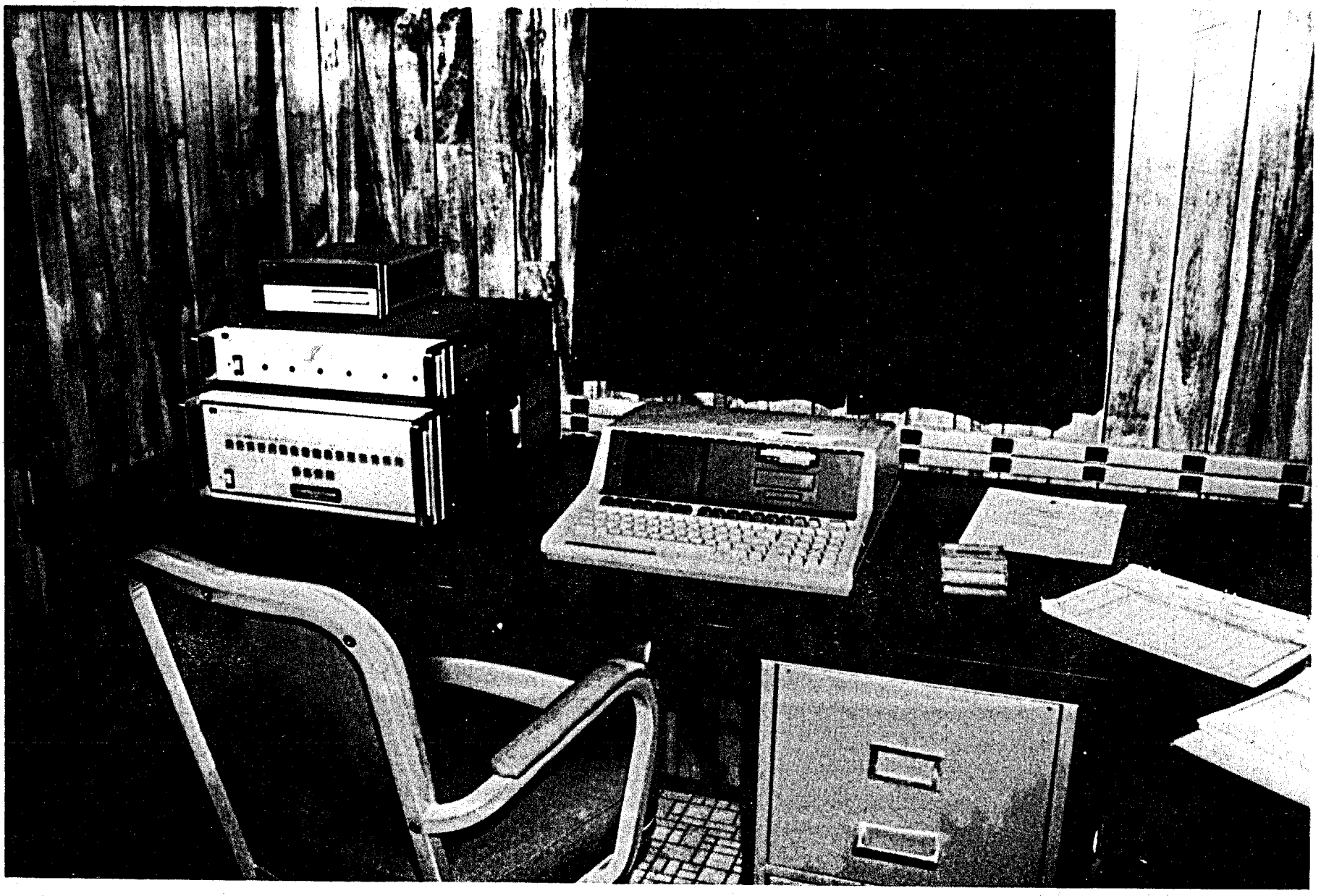
31. Manual Safety shut-in control point with nitrogen supply bottles.



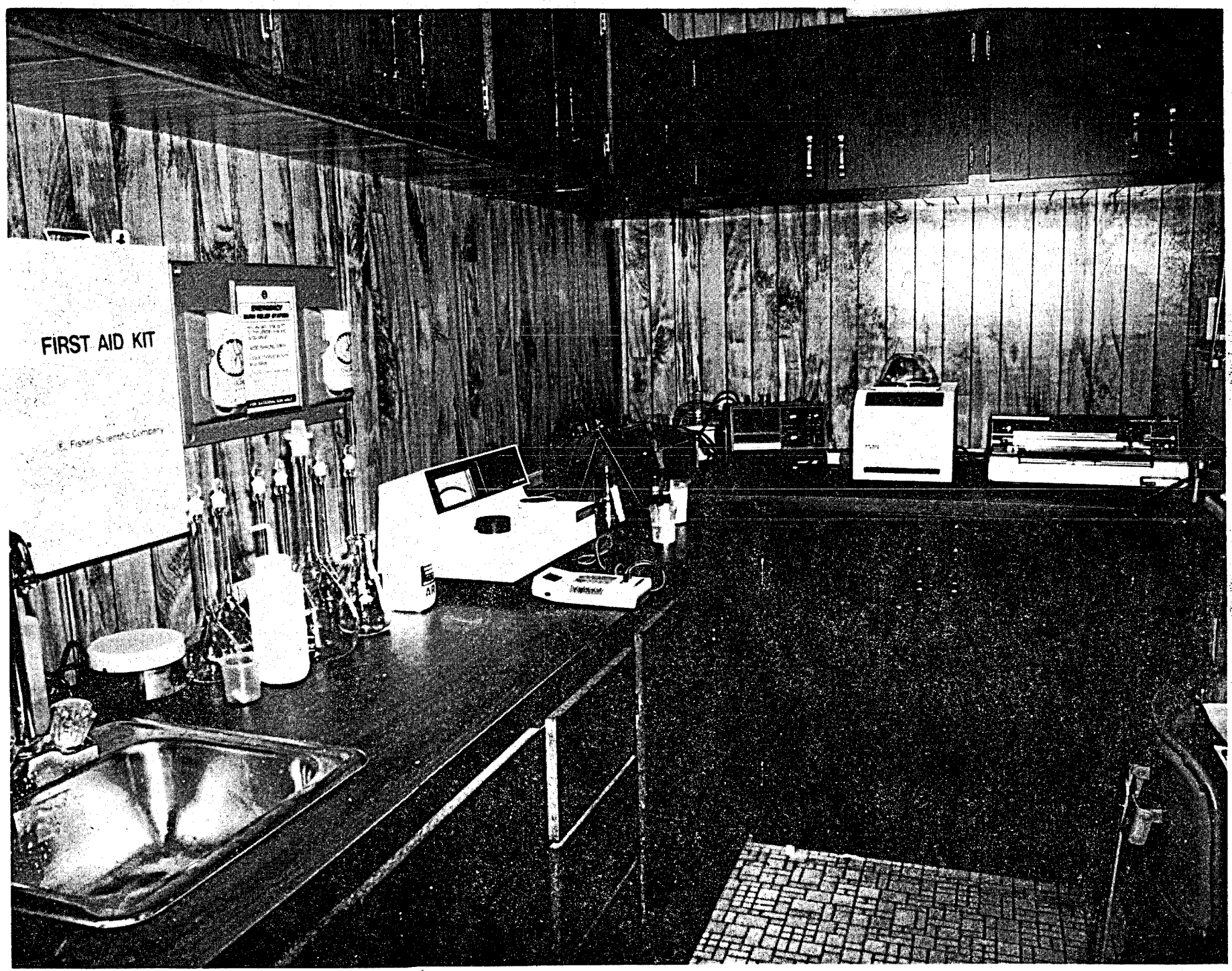
32. Disposal well with pressure and temperature recording instruments.



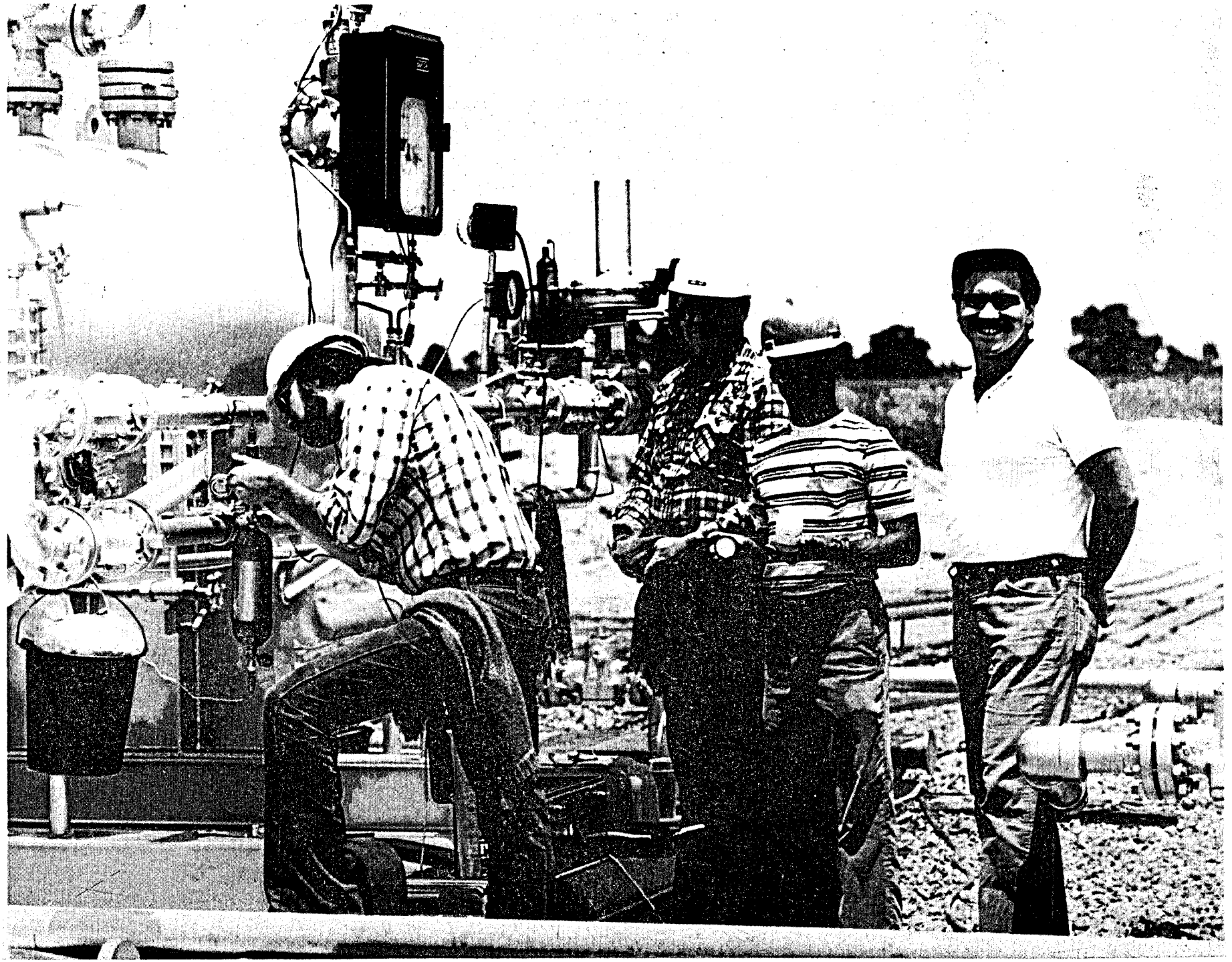
33. IGT strip chart data recording panel.



34. IGT work table and computer modules.

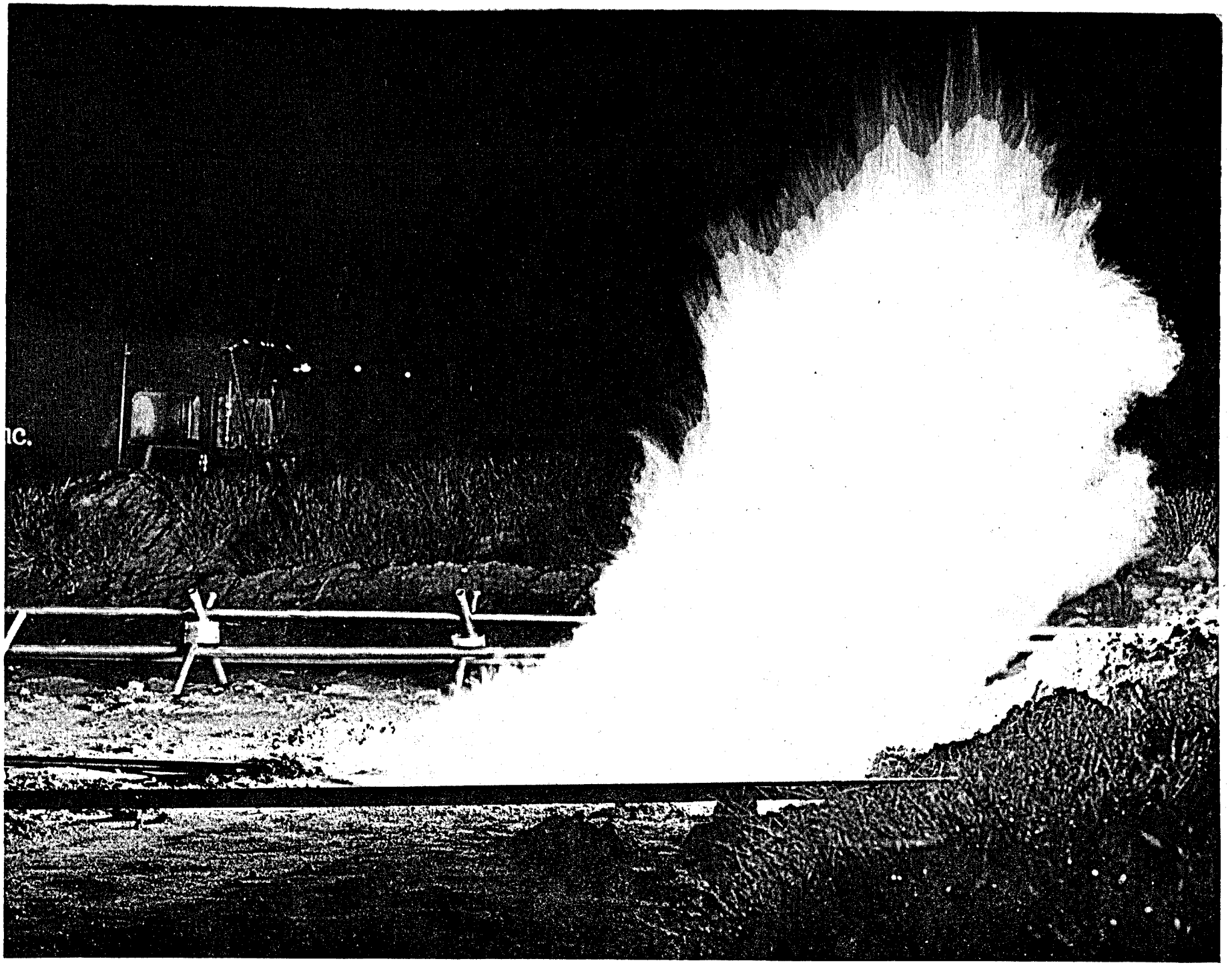


35. IGT chemistry lab.



36. IGT chemist obtaining a fluid sample.

37. Gas being flared at the rate of 600,000 standard cubic feet per day.



38. Approximately 6,700 BTU of heat energy are being generated every second.

APPENDIX A

OPERATOR AND LANDOWNER CONTRACTS

WAINOCO OIL & GAS COMPANY CONTRACT

EATON OPERATING COMPANY, INC.

May 1, 1980

Wainoco Oil & Gas Company
Two Allen Center
1200 Smith Street, Suite 1500
Houston, Texas 77002

Attention: Mr. Lanny Frazier

Re: Wainoco 1 J. Therence Girouard
Section 10-T11S-R5E
Lafayette Parish, Louisiana

Gentlemen:

This letter, if accepted by you and two signed copies thereof are returned to us by May 9, 1980, shall constitute the basis of an agreement between Wainoco Oil & Gas Company (Wainoco) and Eaton Operating Company, Inc. (Eaton) as to the following matters.

I.

A. Eaton is a party to a contract with the United States government represented by the Division of Geothermal Energy, Department of Energy (D.O.E.), to carry out research, field testing and evaluation of well sites in Texas - Louisiana Frio-Miocene trend where reservoir and production data can be obtained to assess the energy potential (dissolved gas and heat) of Gulf Coast geopressured-geothermal aquifers.

B. Wainoco has drilled the above referenced well to a total depth of 15,700 feet and has elected to plug the well as non-commercial.

II.

Eaton is of the opinion that the subject well qualifies as a well of opportunity candidate within the definition of the Eaton-D.O.E. contract, and Eaton recommends a production test of one or more aquifers within the well bore for D.O.E. approval, sponsorship and sole financial support.

III.

A. Eaton shall be responsible for:

PHONE 713-627-9764
TWX 910-881-1793
EDEC-HEC-HOU

3100 EDLOE, SUITE 205
HOUSTON, TEXAS 77027

U.S. DEPARTMENT OF ENERGY
CONTRACT NO.
DE-AC08-80ET27081

1. Obtaining all federal, state and local governmental permits required for such operations.

2. Providing insurance coverage through the length of the testing and research, at limits of $40,000,000.00 liability and $25,000,000.00 cost of well control.

3. Providing well test data information to Wainoco at the conclusion of test.

4. Assumption of all liabilities associated with further operations of test.

5. Eaton would pay Wainoco the sum of $95,000 in cash, as a fee for use of the well bore.

6. Eaton will drill a salt water disposal well near the well in question to dispose of all brines, flare the gas, if any, and plug the well on completion of the test. All of this shall be accomplished by methods approved by the appropriate regulatory agency.

7. Eaton would agree to complete the testing and research in approximately 180 days.

B. Wainoco shall be responsible for:

1. Wainoco shall be the sole corporation liable to fairly and equitably distribute the payment to any other working interest partners, if any, and Eaton and D.O.E. shall be held harmless from such distribution if any, by Wainoco.

IV.

This letter agreement does not convey to Eaton any ownership interest in the land, nor does Eaton have any vested interest in any mineral or energy resources produced during any of the tests, and it is expressly agreed between Eaton and Wainoco that no mineral or energy resource will be saved or sold.

V.

Eaton shall be furnished the complete name (or names) and address (or addresses) of the fee owner and mineral owner, if not the same, and it is agreed that this agreement shall be of no force and effect without the informed written consent of said owner.

VI.

Eaton hereby agrees to indemnify and hold Wainoco, et. al. harmless from ANY and ALL claims for injury or damages the cause of which may occur in connection

with Eaton's operation of the said well, limited to $40,000,000 liability and $25,000,000 well control as provided through insurance coverage as decribed in section III-A-2.

VII.

Eaton further expressly states that any and all portions of this agreement shall be subject to the approval of the D.O.E. and should said agency disapprove any of this agreement in whole or in part, then this agreement shall be null and void.

VIII.

Whenever notice is required or permitted under the terms of this agreement, same shall be in writing and shall be deemed to have been given if sent by telegram, certified or registered mail, or delivered by hand addressed to the respective parties as follows:

If to Wainoco:

Wainoco Oil & Gas Company
Two Allen Center
1200 Smith Street, Suite 1500
Houston, Texas 77002

Attention: Mr. Lanny Frazier
Telephone: 713/658-9900

If to Eaton:

Eaton Operating Company, Inc.
3100 Edloe, Suite 205
Houston, Texas 77027

Attention: Mr. B. A. Eaton
Telephone: 713/627-9764

IX.

This agreement shall be binding on the legal representatives, successors, and assigns of the parties hereto.

X.

Attached hereto are the following documents incorporated by reference herein as set out and marked as Exhibit I and Exhibit II.

If the above conforms to your understanding of the agreement between us, please sign and return two copies to us in the time specified above.

Sincerely yours,

EATON OPERATING COMPANY, INC.

By B. A. Eaton
B. A. Eaton
President and Project Manager

ACCEPTED AND AGREED TO THIS 2nd DAY OF May, 1980.

WAINOCO OIL & GAS COMPANY

By Leonard K. Bray
Leonard K. Bray, Land Manager

* Wainoco's acceptance is subject to the Conditional Letter of Acceptance dated May 2, 1980, attached hereto.

ACCEPTED AND AGREED TO THIS _____ DAY OF _____, 1980.

GRAHAM ENERGY SERVICES, INC.

By _____

ACCEPTED AND AGREED TO THIS 10th DAY OF May, 1980.

ENTEX, INC.

By _____

ACCEPTED AND AGREED TO THIS _____ DAY OF _____, 1980.

MISSION RESOURCES

By_____

ACCEPTED AND AGREED TO THIS _____ DAY OF _____, 1980.

WAYNE E. GLENN ASSOCIATES, INC.

By_____

AGREEMENT WITH MR. PAUL RAY GIROUARD

EATON OPERATING COMPANY, INC.

May 5, 1980

Mr. Paul Ray Girouard
P. O. Drawer B
Broussard, Louisiana 70518

Re: Wainoco Oil & Gas Company #1 J. Therence Girouard
Section 10-T11S-R5E
Lafayette Parish, Louisiana

Dear Mr. Girouard:

Eaton Operating Company, Inc. (hereinafter referred to as "Eaton"), a Texas Corporation, is a party to a contract with the Department of Energy (hereinafter referred to as "DOE") which calls for "Eaton" to carry out research, field testing and evaluation of well sites in the Louisiana - Texas Gulf Coast area where reservoir and production data can be obtained to assess the energy potential of the Gulf Geopressured-Geothermal Aquifers.

"Eaton" is seeking well locations which, if they are not presently productive of oil or gas, can be taken over for a short test when the operator has made the decision to plug and abandon such a well.

Under our proposed operational plan, "Eaton" would take over the #1 J. Therence Girouard Well from the operator, Wainoco Oil & Gas Company (hereinafter referred to as "Wainoco"), use the present drill site and roads, use the existing well bore site to perform precise temperature, pressure and gas contact measurements at various flow rates, evaluate same and make written reports to the DOE. Samples will be collected for analysis of the reservoir conditions. Any produced salt water will be reinjected through a salt water disposal well drilled on the site. At the conclusion of these short tests, "Eaton" will plug and abandon the well and disposal well in accordance with the Louisiana Office of Conservation rules and regulations and clean up the site. All of our operations will be under the control of the Louisiana Conservation Commission and all other state agencies having jurisdiction.

"Wainoco" has informed "Eaton" that they have made a decision to plug and abandon the #1 J. Therence Girouard Well and accordingly suspend from any further production.

PHONE 713-627-9764
TWX 910-881-1793
EDEC-HEC-HOU

3100 EDLOE, SUITE 205
HOUSTON, TEXAS 77027

U.S. DEPARTMENT OF ENERGY
CONTRACT NO.
DE-AC08-80ET27081

Subject to the consent of the Lessors, "Eaton" has expressed the desire to take over the said well bore site from "Wainoco" and conduct testing operations. "Eaton" agrees it will complete the tests, plug the well and clean up the location site ~~within one year from date this agreement is executed~~. by Jan. 1, 1981. BAE PRG

"Eaton" shall have no rights in the lease, in the land and minerals or any production attributable thereto. As stated, this is strictly a research project of the geothermal aquifers.

"Eaton" maintains insurance coverage of not less than Forty Million Dollars ($40,000,000) liability and Twenty-Five Million Dollars ($25,000,000) control of well coverage and "Eaton" will agree to assume full liability for operations within this coverage.

Subject to DOE approval, "Eaton" is willing to pay you the sum of $20,000 for the right to conduct said operations. In addition, "Eaton" will be responsible for any and all damages resulting from the operations. Furthermore, you would be furnished a copy of the results of the tests when this information is available. If you are willing to assist in a vital energy resource assessment, which at this time is of the utmost importance to our national interest, it would be appreciated if you would give your consent to our use of the well for proposed operations.

Your consent may be given by signing and returning two (2) copies of this letter in the enclosed stamped envelope. Upon receipt of your signed letter, we will forward a check to you.

Yours very truly,

EATON OPERATING COMPANY, INC.

B A Eaton

B. A. Eaton, President and Project Manager

CONSENT FOR EATON OPERATING COMPANY, INC. TO CONDUCT SAID TEST IS HEREBY GIVEN.

EXECUTED THIS _____ DAY OF _____, 1980.

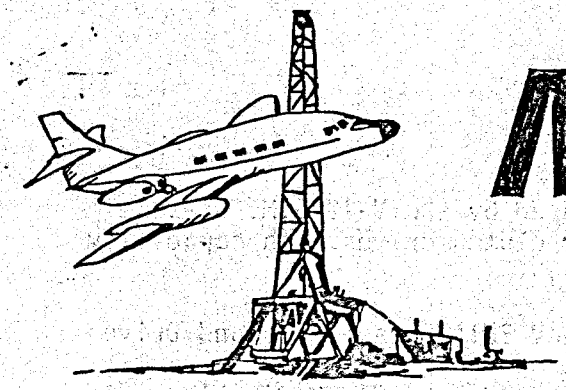
Paul Ray Girouard

Mr. Paul Ray Girouard

APPENDIX B

RIG CONTRACTS

CONTRACT WITH MATHIEU DRILLING, INC.



MATHIEU DRILLING, INC.

2204 Justice, Monroe, Louisiana 71201

Rig 16
"MR. JOE"

COMPLETE DRILLING RIG:	12,000 Ft. Unit-15, powered by Cat Diesel
ASSOCIATED EQUIPMENT ON RIG:	
DERRICK	132 Ideal, 13,500', 4½" DP Derrick, equipped with 2 Booms Cat Line Sheave, lay down line sheave, 1 rotary crown equipped for 8 line operation, 1 dead line stabilizing unit and racking board, complete with stand pipe. Ladder from rig floor to crown with 2 rest areas attached to derrick, water table with safety hand rails surrounding crown assembly. 617,000 lbs. gross nominal capacity.
SUBSTRUCTURE	12'x22'x52', 1,000,000#/cap. mud matted.
DRAWWORKS	Unit-15 drawworks with Parkersberg 15" (triple) hydromatic brake. Compound equipped with 3 caterpiller diesel engins, 330 horses each. All engins equipped with gauges and necessary equipment for operation. Drawworks and rotary table driven through a torque converted compound.
ROTARY TABLE	Oilwell 21" with Bass Ross Model #2RCH bushings
BLOCK AND HOOK	National 250 T 5 Sheave blocks equipped with BJ 4200 hook.
SWIVEL	Gray 300 Ton
TONGS	BJ Type (B)
ROTARY HOSE	White Stripe 3"x55'
CLOSING UNIT	Stewart-Stevenson, remote and central
TORQUE INDICATOR	Martin Decker
KELLY	OMSCO 5¼"x41'

ASSOCIATED EQUIPMENT ON
RIG: RIG 16
page 2

PUMPS	Continental Emsco F-650 powered by two V-12 G.M. Diesels rated at 525 H.P. each. Air clutch drives with capability of single engine performance.
	Continental Emsco F-650 with V Belt Sheave compound Drive
LIGHT PLANTS	Two 200 KW Kato generator powered by 8-71 GM Diesel engines
WEIGHT INDICATOR	Martin Decker Clipper AA15
FUEL TANK	One 9000 gallon tank skid mounted
WATER TANK	One 9000 gallon tank skid mounted
DOG HOUSE	7'x8'x34' with 12 lockers, knowledge box, benches, shelves, drawers, storage cabins and heater. Skid mounted on master skid with 7'x6'x8' tool storage house and 7'x8'x10' covered area for light plant.
DRILL PIPE	11,000' Grade E Drill Pipe
DRILL COLLARS	Ten 6½"x2½"
KELLY BUSHINGS	5¼" Varco
CAT WALK	58'x7'11" complete with V-door and headache post
PIPE RACKS	Eight 4'x42"x26' triangle pipe racks
DRILL LINE	1 1/8"x5000' drilling line
DESANDER	Sweco 2x8" Cone Unit with electric power unit
SHALE SHAKER	Brandt - Double Decker
MUD TANKS	Three 40'x8'x5' with lightning agitators and jets
B.O.P.	10" Double with Hydrill-pipe and blind rams with closing unit. Series 1500 H_2S trim. Hydril.
CHOKE MANIFOLD	2 1/16" Manual adjustable 1500 Series, H_2S Trim
PUMPS (Water)	Two 2x3 electric drive centrifugal pumps
AIR COMPRESSOR	Two 175 CFM compressor - One electric, one diesel powered.
MUD MIXERS SYSTEMS	Two -6x8 Centrifugal pumps
KELLY SPINNER	International Tool Co., Forward/reverse
DRILL PIPE SPINNER	Spinner Hawk Weatherford-Lamb 2 7/8" - 11" O.D.
TOOL PUSHER QUARTERS	Elder International 10'x42' 2 BR w/office.

DATA ON EQUIPMENT TO BE USED ON THE JOB

Mathieu Drilling, Inc.
Company

May 9, 1980
Date

Rig and equipment to be furnished by Subcontractor. (To be completed by prospective bidder. Award of Subcontract is subject to rig inspection.)

Subcontractor's Rig Number: Rig #16 "MR. JOE"

Drawworks: Unit - 15-A

Engines-Number, Make, Model and HP: Cat. Diesel (3) 3406 - 330 H.P. (ea.)

Slush Pumps-Make, Model, and Size: (2) F-650 Triplex

Auxiliary Pump and Power: (2) 5 x 6 R Centrifugals

Derrick or Mast-Make, Size and Capacity: Ideal 132', 13,500', 4-1/2 DP, 617,000 Gross

Substructure-Height and Capacity: 12' X 22' X 52', 1,000,000/capacity

Drill Pipe-Sizes and Amounts: 11,000', 4-1/2" Grade E

Drill Collars-Sizes and Numbers: (10) 6-1/2" X 2-1/2"

Mud Pump-GPM and PSI: 5-1/2" Liners, 140 SPM, 8 barrel per min. (2600)

Centrifugal Pump for Water Transfer-Size, etc.: 2(2X3)

Blowout Preventers-Power Actuated: 10" series 1500, (2) Rams, Shaffer (bag type)

H_2S trim, 80 gal. closing unit.

Blank

CONDITIONS AND TECHNICAL PROVISIONS

CTP-01. LOCATION

Well Name and Number No. 1 J. Therence Girouard County Lafayette
State Louisiana Field Name Cade Well Location and
Land Description

CTP-02. COMMENCEMENT AND COMPLETION

The Subcontractor shall complete mobilization within five (5) calendar days after the date of receipt of Notice to Proceed and shall complete the entire work under the Unit Price Schedule approx. 45 days after the date of receipt of Notice to Proceed. The contract completion date will be extended by the amount of time spent on Contractor-Directed Operations and Standby, to the extent that is deemed necessary.

CTP-03. STATEMENT OF WORK

A. General Description of Work. The Subcontractor's work consists of furnishing all personnel, equipment, materials and services, and supplies as specified herein, for conducting the following work:

1. Run tubing and complete test well.

2. Drill and complete disposal well.

B. Minimum Equipment and Services. The minimum equipment, facilities, services, and items required to complete the work is specified in CTP-07. All contractor-furnished items will be delivered to and picked up from the drill site by others. The minimum equipment and services designated to be furnished and operated by the Subcontractor will be at no additional cost to the Contractor.

C. Workweek and Personnel Requirement. The Subcontractor shall furnish minimum five man qualified drilling crew, including toolpusher, to maintain a 24-hour day, 7-day week operation.

CTP-04. MUD PROGRAM

Contractor agrees to furnish all mud additives and chemicals and will arrange to purchase all necessary engineering services. Mud program will be designed as dictated by hole conditions.

CTP-05. STRAIGHT HOLE SPECIFICATIONS

Except as authorized by the Contractor, the maximum allowable deviation of the hole is not to exceed one degree per 100-feet and not to exceed five degrees total depth.

CTP-06. PROPOSED CORING PROGRAM

None planned.

CTP-07. MINIMUM EQUIPMENT AND SERVICES

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
1. Trucking service and other transportation, hauling or winching services as required to move Subcontractor's property to location, rig up Subcontractor's rig, and remove all of Subcontractor's property from location.		XX
2. Drilling bits, reamers, stabilizers, reamer cutters, and other drilling tools as required.	XX	
3. Fishing tool services and fishing tool rental.	XX	
4. Derrick timbers.		XX
5. Normal strings of drill pipe and drill collars. (See Items No. 43 and 44)		XX
6. Conventional drift indicator.		XX
7. Earthen mud pits and reserve pits.	XX	
8. Steel mud tanks if required.		XX
9. Necessary pipe racks and rigging up material.		XX
10. Normal storage for mud and chemicals.		XX
11. Necessary spools, flanges and fittings to connect blowout preventers.		XX

240

	To Be Provided By And At Expense of	
	Contractor	Subcontractor
12. Furnish and maintain adequate roadway to location, rights-of-way, including rights-of-way for fuel and water lines, river crossings, highway crossing, gates and cattle guards.	XX	
13. Staked, levelled and compacted location, including earth pits.	XX	
14. Rat and mouse holes to meet subcontractor's requirement.		XX
15. Test tanks with pipe and fittings.	XX	
16. Separator with pipe and fittings.	XX	
17. Labor to connect and disconnect Subcontractor's mud tank.		XX
18. Labor to disconnect and clean test tanks and separator.	XX	
19. Drilling mud, chemicals, lost circulation materials and other additives.	XX	
20. All tubular goods, miscellaneous line pipe and fittings.	XX	
21. All testing tools including inflatable and retrievable packers.	XX	
22. Special tools, casing scraper, etc.	XX	
23. Special mud pump capacity in excess of rig requirements.	XX	
24. Wireline split and conventional core barrels and wireline core catchers: two each ten-feet long split core barrel; one each twenty-feet long conventional barrel.	N/A	
25. Conventional core bits, barrels and catchers.	XX	
26. Diamond wireline core bits.	N/A	
27. Cement and cementing service.	XX	
28. Logging services.	XX	

		To Be Provided By And At Expense Of	
		Contractor	Subcontractor
29.	Directional, caliper, or other special services.	XX	
30.	Gun or jet perforating services.	XX	
31.	Core boxes, wrapping supplies, and storage facilities.	XX	
32.	Formation testing, hydraulic fracturing, acidizing, and other related services.	XX	
33.	Equipment for drill stem testing.	XX	
34.	Mud Logging Services.	XX	
35.	Sidewall Coring Services.	XX	
36.	Welding Service (Except for Subcontractor's equipment).	XX	
37.	Casing, tubing, liners, screen, float collars, guide and float shoes, and associated equipment.	XX	
38.	Casing scratchers and centralizers.	XX	
39.	Wellhead and connections for all equipment to be installed in or on well or on the premises for use in connection of well.	XX	
40.	Water at Source and Water Hauling Service.	XX	
41.	Water storage tanks 1000 gallon capacity.		XX
42.	Fuel and lubricants for Subcontractor's equipment. Contractor to reimburse Subcontractor for diesel fuel in excess of .0 per gallon.	XX	
43	Drill pipe. Other than 4-1/2"	XX	
44.	Drill collars. Other than 6-1/2"	XX	
45.	Handling tools, clamps, etc., for each drilling assembly. (Other than subcontractor furnished)	XX	
46.	Weight indicator.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
47. If applicable, drill pipe protectors for Kelly joint and each joint of drill pipe running inside of casing for use with normal strings of drill pipe.	XX	
48. Automatic driller (Optional).	N/A	
49. Materials for "boxing in" rig and derrick.	N/A	
50. Conventional core barrel.	XX	
51. Drilling recorder-minimum 2-pin.	XX	
52. Extra labor for running and cementing casing.	XX	
53. Casing tools.	XX	
54. Running of casing-conductor.	XX	
55. Running of casing-surface.	XX	
56. Running of casing protection, if applicable.	XX	
57. Running of casing production, if applicable.	XX	
58. Running of casing liner, if applicable.	XX	
59. Power casing tongs.	XX	
60. Tubing tools.	XX	
61. Power tubing tong.	XX	
62. Swabbing unit with swabbing line	XX	
63. Swab.	XX	
64. Swab lubricator.	XX	
65. Swab rubbers.	XX	
66. Light plant-adequate capacity for night-time operations, Subcontractor requirements.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
67. Drill rig-minimum failing 1500 rotary rig or approved equal for continuous wireline coring and drilling to ± 1500 feet.	N/A	
68. Two adequate circulating pumps and adequate mud mixing pumps.		XX
69. 1000 gallon water truck with driver for hauling water within two miles of work sites.	N/A	
70. Minimum of one two-way communications system.	N/A	
71. IADC Daily Drilling Report, Bit Record and Tally Forms.		XX

The above Subcontractor designated items are the minimum acceptable requirements for the Subcontractor drilling equipment. This is not intended to be a complete list of items to be furnished by the Subcontractor. The Subcontractor is required to furnish all drilling maintenance tools, materials, and equipment not herein designated, but which are normal components for a complete drilling rig required for drilling and testing operations described in these specifications.

CTP-08. UNIT PRICE SCHEDULE ITEMS DEFINED

Paragraph headings in this Special Condition correspond to items of the Unit Price Schedule.

1. Mobilization. The Subcontractor shall move in and rig up his equipment, rig up any lower-tier Subcontractor's equipment, and pick up first drilling assembly. Mobilization shall be considered complete when all the equipment is on location and rigged up ready to spud. The Subcontractor shall be paid for the above mobilization work under Item 1 of the Unit Price Schedule.

2. Contractor-Directed Operations. Operations under this category shall include, but are not limited to: Contractor-furnished surveying, plug backs, drilling, coring, reaming, hydrologic testing, inserting and retrieving casing, placing cement and regaining lost circulation. All operations will be done as directed by the Contractor. All work on an hourly rate basis shall be performed with a full complement of operating personnel and at the direction of the Contractor. If it becomes necessary to shut down Subcontractor's rig for repairs while performing work on an hourly rate basis, Subcontractor shall be allowed compensation for such repair time at the applicable hourly rate. The number of hours devoted to repair work for which the Subcontractor may be compensated shall be limited to an accumulated total of 12 hours for each 15 day period.

Contractor-directed operations will be paid for Item 02. of the Unit Price Schedule.

3. Standby Ready. When directed by the Contractor, the Subcontractor shall cease all operations and standby in a ready condition. A full complement of personnel and equipment shall be maintained at the work site ready to resume operations immediately. Operations under this category shall include Geophysical Logging, Cement Hardening Time, or any operations not requiring the use of rig engines or drill assembly. Standby ready time will be paid under Item 03. of the Unit Price Schedule.

4. Demobilization. Upon completion of the work under this Subcontract, the Subcontractor shall remove all rubbish and debris from the drill site and shall remove all of his equipment within ten calendar days. The Subcontractor will not be responsible for levelling the work site or draining and backfilling pits. Demobilization will be paid under Item 04. of the Unit Price Schedule.

CTP-09. RECORDS AND OBSERVATIONS

Providing the following records and observations shall be a part of the Subcontractor's general responsibility for which no additional payment will be made.

1. A Daily Drilling Report shall be kept on the IADC official Standard Daily Drilling Report. The Unit Price Schedule quantities for pay estimate purpose will be taken from the IDAC Daily Drilling Report. The general remarks section shall contain an accurate record of hole conditions, work performed, and time required for all work to the nearest quarter-hour. The original and two copies of the Daily Drilling Report shall be submitted to the Contractor or his authorized representative.

2. Bit Records shall be maintained daily and posted in the doghouse. A complete bit record shall be furnished the Contractor at the completion of a hole. Records must show bit types, sizes, footages, depths, rotary speeds, bit weights, manufacturer, and serial number.

3. Accurate Pipe Tallies shall be the Subcontractor's responsibility and shall be available at the drill site for inspection at all times. Copies of steel tape measurements of drill pipe and casing shall be furnished by the Contractor.

CTP-10. SUBSURFACE INFORMATION

1. The subsurface information and data furnished both in these specifications and at the Contractor's office are not intended as representations or warranties, but are furnished for information only.

2. It is anticipated that the information contained herein generally represents the conditions that will be encountered in the performance of the Subcontract; however, any interpretation or conclusion reached by the Subcontractor in preparing his Unit Price Schedules will be his sole responsibility.

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The Subcontractor will be required to make his own arrangements with his employees for housing and feeding. The Subcontractor may locate toolpusher's house trailer near the drilling location, as designated by the Contractor.

CTP-12. DERRICK MISALIGNMENT

If, at any time, the Subcontractor's derrick becomes misaligned over a hole, the Subcontractor shall be required to commence realignment operations within eight hours of the misalignment. If such misalignment occurs as the result of fault or negligence on the part of the Subcontractor, the Subcontractor shall receive no compensation for the time or cost spent in realignment. If the misalignment is not the fault of, or caused by, Subcontractor negligence, the Subcontractor shall be compensated under Item 2. of the Unit Price Schedule.

CTP-13. LOSS OF HOLE

A hole shall be termed "lost" if the Contractor determines that the condition of the hole will prevent its successful completion, or if for any reason the Contractor deems it impractical to continue drilling. If the Contractor determines that a hole has been lost before required depth has been attained, and that further attempts to complete it will be impractical, he shall order work on the hole stopped, shall investigate the circumstances in contributing to its loss, and shall notify the Subcontractor of his decision in writing. The Contractor may, at his option, order the commencement of work at an alternate location.

Contractor shall assume liability, while work is being performed under Contractor-directed operations, for loss of, damage to, or destruction of the hole, Subcontractor's in-hole equipment, including, but not limited to, drill pipe, drill collars, subs, stabilizers, and bits, unless such loss, damage, or destruction shall be caused by the Subcontractor's fault or negligence.

CTP-14. ABANDONMENT

In the event that, prior to completion of the work required, a hole covered by this Subcontract is abandoned, upon direction of the Contractor, the Subcontractor will be paid for work performed under the applicable items of the Unit Price Schedule.

The term "abandonment" as used in this paragraph shall mean abandonment to suit the convenience of the Contractor, as directed by the Contractor, under conditions which do not come within the scope of the paragraph entitled "Loss of Hole" of these specifications.

CTP-15. STANDARD FOR PRESSURE VESSELS

All Subcontractor's compressed air equipment and accessories shall be designed, fabricated, inspected, and certified in accordance with the SAME Boiler and

Pressure Vessel Code, Section VIII. For equipment fabricated under the 1968 Code, either Division I or Division II (but not both) of the Code may be used.

CTP-16. PRESERVATION OF ANTIQUITIES, WILDLIFE, AND LAND AREAS

Federal law provides for the protection of antiquities located on land owned or controlled by the U. S. Government. Antiquities include Indian graves, or campsites, relics, and artifacts. The Subcontractor shall control the movements of his personnel and his Subcontractor's personnel at the jobsite to ensure that any existing antiquities discovered thereon will not be disturbed or destroyed by such personnel. It shall be the duty of the Subcontractor to report the existence of any antiquities so discovered. The Subcontractor shall also preserve all vegetation except where such vegetation must be removed for survey or construction purposes. Further, all wildlife shall be protected.

CTP-17. RESPONSIBILITY FOR LOSS OF OR DAMAGE TO EQUIPMENT

1. Subcontractor's Surface Equipment. Subcontractor shall be liable at all times for damage to or destruction of Subcontractor's surface equipment including all drilling tools, machinery, and appliances for use above the surface and for any other type of equipment including in-hole equipment when such in-hole equipment is above the surface, regardless of when or how such damage or destruction occurs. The Contractor shall be under no liability to compensate the Subcontractor for any such loss except loss of damage thereto caused by negligence of the Contractor, its agents, or employees.

2. Loss of Tools in the Hole

a. Contractor-Directed Operations. When it is necessary to fish for tools in the hole, while working under Contractor-Directed Operations, the Subcontractor shall notify the Contractor or his authorized representative of the existing conditions immediately, to be confirmed in writing as soon as practicable, and initiate such action as is required to commence fishing operations as soon as practicable. The Contractor will review and evaluate the circumstances resulting in the loss of tools in the hole.

i. If the investigation by the Contractor shows that the Subcontractor was neither negligent nor in violation of good drilling practice, the Subcontractor will not be held responsible for costs resulting from the loss of tools or for costs of fishing efforts conducted to recover lost tools. The value of Subcontractor-owned tools lost or damaged in the hole during hourly rate operations will be equitably compensated.

ii. If the Contractor's investigation shows that the Subcontractor was negligent or was in violation of good drilling practice in the performance of his duties, the Subcontractor will not be compensated for the value of Subcontractor-owned tools or equipment which may have been lost or damaged. Additionally, the Subcontractor

will be held responsible to the Contractor for the value of any Contractor-furnished tools or equipment which may be lost or damaged. All costs incident to such loss of or damage to the Contractor-furnished tools or equipment will be determined by the negotiated agreement of the parties.

iii. Any dispute concerning a question of fact under this paragraph iii. shall be subject to Article 11, "Disputes", of the General Provisions.

b. Contractor-Furnished Equipment. Except as provided for in paragraph ii. above, "Loss of Tools in the Hole", all machinery, tools, materials and equipment furnished by the Contractor, shall, at the completion or abandonment of the hole, be returned to the Contractor in as good condition as when received by the Subcontractor, ordinary wear and tear excepted. The Subcontractor shall be liable to the Contractor for any loss or damage to such equipment beyond such ordinary wear and tear, and for loss or damage due to the negligence or carelessness of the Subcontractor.

CTP-18. CONTRACTOR MINIMUM EQUIPMENT REQUIREMENTS AND STANDARDS

The following American Petroleum Institute Standards and Recommended Practices of the latest issue, as of the date of bid opening, are a part of these specifications whenever applicable to standardized equipment.

1.	API Std. 4A	Specifications for Steel Derricks
2.	API Std. 4E	Specifications for Drilling and Servicing Structures
3.	API Std. 7	Specification for Rotary Drilling Equipment
4.	API Std. 8A	Specification for Hoisting Equipment
5.	API Std. 9A	Specification for Wire Rope
6.	API RP-5C1	Recommended Practice for Care and Use of Casing, Drill Pipe and Tubing
7.	API RP-9B	Recommended Practice on Application, Care and Use of Wire Rope for Oil Field Service
8.	API RP-13B	Recommended Practice and Standard Procedures for Testing Drilling Fluids
9.		Manufacturer's Ratings Shall Apply for Equipment not Covered by the API Standards.

CONTRACT WITH WELLTECH, INC.

WellTech, Inc.

Louisiana Division
Post Office Box 51933, O.C.S.
Lafayette, Louisiana 70505
318/232-3413

RIG #2

Wilson Mogul Model "42" self-propelled drive-in Winchmobile powered by 420 HP twin 671-N GM Diesel Engine. Selective controls permit operation of either engine if desired or should loss of one engine occur. Engines are equipped with Allison-Torque-O-Matic drive, with an additional 2-speed chain box air clutch auxiliary transmission. Unit is equipped with 1" drill line, water circulation brakes, rotary drive, one 22" single Parkersburg hydrotarder. Mast is 110' tubular capable of racking 18,000' 2-7/8" tubing or 28,000' 2-3/8" tubing. Crown consists of 5 sheaves, allowing 8-line string up. Installed is one hydraulically operated breakout cylinder.

2	Oilwell 310HP 48 PHD triplex pump, with 4" liners powered by 8V-71N GM diesel engines, 4-speed transmission and chain drive.
1	5" x 6" Mission mud mixing pump powered by 6-71N GM Diesel engine with all necessary mud mixing lines.
1	Gardner Denver 2-1/2" centrifugal fresh water transfer pump powered by Lister diesel engine.
1	18' x 18' x 16' high hydraulically raised substructure equipped with 17-1/2" oil well rotary.
1	Baash Ross 4-sheave, 150-ton Shorty traveling block.
1	Baash Ross Kelly 3" x 38' with 2-7/8" I.F. pin connection and 4-1/2 API LH box connection.
1	60-C Oil Well Swivel.
1	3" x 40' rotary hose, 3000# working pressure.
2	6" Series 1500 Cameron type QRC blowout preventers with 2-3/8", 2-7/8" and blind rams, 4" and 2" series 1500 flanged outlets between rams.
1	Series 1500 choke manifold.
1	6" Series 1500 Hydril preventer Type "GK".
1 set	Koomey accumulators with 10-gallon capacity and 3000# working pressure.
1 set	2-3/8" and 2-7/8" tubing elevators.
1	Advance air spider Model "C" 2-3/8" and 2-7/8" slips.

WellTech, Inc.

Louisiana Division
Post Office Box 51933, O.C.S.
Lafayette, Louisiana 70505
318/232-3413

RIG #2 - Continued

1	180,000# Martin Decker Weight Indicator.
1	50KW AC light plant powered by 471 GM diesel engine.
1	30KW AC light plant powered by 471 GM diesel engine (standby).
1	Shale Shaker
1 set	Vapor proof fluorescent lighting system.
2	200 barrel mud tanks with mud hopper and mud mixing lines installed.
1 set	Hillman Kelley hydraulic pipe tongs with 2-3/8" and 2-7/8" jaws used for tubing jobs.
2 sets	Pipe racks, ramp and catwalk.
1	Air - conditioned living quarters.

All necessary mud lines and hand tools.

CONDITIONS AND TECHNICAL PROVISIONS

CTP-01. LOCATION

Well Name and Number P. R. Girouard County Lafayette
State Louisiana Field Name Cade Well Location and
Land Description

CTP-02. COMMENCEMENT AND COMPLETION

The Subcontractor shall complete mobilization within five (5) calendar days after the date of receipt of Notice to Proceed and shall complete the entire work under the Unit Price Schedule approximately 10 days after the date of receipt of Notice to Proceed. The contract completion date will be extended by the amount of time spent on Contractor-Directed Operations and Standby, to the extent that is deemed necessary.

CTP-03. STATEMENT OF WORK

A. General Description of Work. The Subcontractor's work consists of furnishing all personnel, equipment, materials and services, and supplies as specified herein, for conducting the following work:

Plug & Abandonment of Girouard #1

B. Minimum Equipment and Services. The minimum equipment, facilities, services, and items required to complete the work is specified in CTP-07. All contractor-furnished items will be delivered to and picked up from the drill site by others. The minimum equipment and services designated to be furnished and operated by the Subcontractor will be at no additional cost to the Contractor.

C. Workweek and Personnel Requirement. The Subcontractor shall furnish minimum three man qualified drilling crew, including toolpusher, to maintain a 24-hour day, 7-day week operation.

CTP-04. MUD PROGRAM

Contractor agrees to furnish all mud additives and chemicals and will arrange to purchase all necessary engineering services. Mud program will be designed as dictated by hole conditions.

CTP-05. STRAIGHT HOLE SPECIFICATIONS

Except as authorized by the Contractor, the maximum allowable deviation of the hole is not to exceed one degree per 100-feet and not to exceed five degrees total depth.

CTP-06. PROPOSED CORING PROGRAM

CTP-07. MINIMUM EQUIPMENT AND SERVICES

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
1. Trucking service and other transportation, hauling or winching services as required to move Subcontractor's property to location, rig up Subcontractor's rig, and remove all of Subcontractor's property from location.	XX	
2. Drilling bits, reamers, stabilizers, reamer cutters, and other drilling tools as required.	XX	
3. Fishing tool services and fishing tool rental.	XX	
4. Derrick timbers.		XX
5. Normal strings of drill pipe and drill collars. (See Items No. 43 and 44)		XX
6. Conventional drift indicator.		XX
7. Earthen mud pits and reserve pits.	XX	
8. Steel mud tanks if required.		XX
9. Necessary pipe racks and rigging up material.		XX
10. Normal storage for mud and chemicals.		XX
11. Necessary spools, flanges and fittings to connect blowout preventers.		XX

	To Be Provided By And At Expense of	
	Contractor	Subcontractor
12. Furnish and maintain adequate roadway to location, rights-of-way, including rights-of-way for fuel and water lines, river crossings, highway crossing, gates and cattle guards.	XX	
13. Staked, levelled and compacted location, including earth pits.	XX	
14. Rat and mouse holes to meet subcontractor's requirement.		XX
15. Test tanks with pipe and fittings.	XX	
16. Separator with pipe and fittings.	XX	
17. Labor to connect and disconnect Subcontractor's mud tank.		XX
18. Labor to disconnect and clean test tanks and separator.	XX	
19. Drilling mud, chemicals, lost circulation materials and other additives.	XX	
20. All tubular goods, miscellaneous line pipe and fittings.	XX	
21. All testing tools including inflatable and retrievable packers.	XX	
22. Special tools, casing scraper, etc.	XX	
23. Special mud pump capacity in excess of rig requirements.	XX	
24. Wireline split and conventional core barrels and wireline core catchers: two each ten-feet long split core barrel; one each twenty-feet long conventional barrel.	N/A	
25. Conventional core bits, barrels and catchers.	XX	
26. Diamond wireline core bits.	N/A	
27. Cement and cementing service.	XX	
28. Logging services.	XX	

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
29. Directional, caliper, or other special services.	XX	
30. Gun or jet perforating services.	XX	
31. Core boxes, wrapping supplies, and storage facilities.	XX	
32. Formation testing, hydraulic fracturing, acidizing, and other related services.	XX	
33. Equipment for drill stem testing.	XX	
34. Mud Logging Services.	XX	
35. Sidewall Coring Services.	XX	
36. Welding Service (Except for Subcontractor's equipment).	XX	
37. Casing, tubing, liners, screen, float collars, guide and float shoes, and associated equipment.	XX	
38. Casing scratchers and centralizers.	XX	
39. Wellhead and connections for all equipment to be installed in or on well or on the premises for use in connection of well.	XX	
40. Water at Source and Water Hauling Service.	XX	
41. Water storage tanks 1000 gallon capacity.		XX
42. Fuel and lubricants for Subcontractor's equipment. Contractor to reimburse Subcontractor for diesel fuel in excess of 0 per gallon.		XX
43 Drill pipe.		
44. Drill collars.		
45. Handling tools, clamps, etc., for each drilling assembly.		
46. Weight indicator.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
47. If applicable, drill pipe protectors for Kelly joint and each joint of drill pipe running inside of casing for use with normal strings of drill pipe.	XX	
48. Automatic driller (Optional).	N/A	
49. Materials for "boxing in" rig and derrick.	N/A	
50. Conventional core barrel.	XX	
51. Drilling recorder—minimum 2-pin.	XX	
52. Extra labor for running and cementing casing.	XX	
53. Casing tools.	XX	
54. Running of casing-conductor.	XX	
55. Running of casing-surface.	XX	
56. Running of casing protection, if applicable.	XX	
57. Running of casing production, if applicable.	XX	
58. Running of casing liner, if applicable.	XX	
59. Power casing tongs.	XX	
60. Tubing tools.	XX	
61. Power tubing tong.	XX	
62. Swabbing unit with swabbing line	XX	
63. Swab.	XX	
64. Swab lubricator.	XX	
65. Swab rubbers.	XX	
66. Light plant-adequate capacity for night-time operations, Subcontractor requirements.		XX

	To Be Provided By And At Expense Of	
	Contractor	Subcontractor
67. Drill rig-minimum failing 1500 rotary rig or approved equal for continuous wireline coring and drilling to ± 1500 feet.	N/A	
68. Two adequate circulating pumps and adequate mud mixing pumps.		XX
69. 1000 gallon water truck with driver for hauling water within two miles of work sites.	N/A	
70. Minimum of one two-way communications system.	N/A	
71. IADC Daily Drilling Report, Bit Record and Tally Forms.		XX

The above Subcontractor designated items are the minimum acceptable requirements for the Subcontractor drilling equipment. This is not intended to be a complete list of items to be furnished by the Subcontractor. The Subcontractor is required to furnish all drilling maintenance tools, materials, and equipment not herein designated, but which are normal components for a complete drilling rig required for drilling and testing operations described in these specifications.

CTP-08. UNIT PRICE SCHEDULE ITEMS DEFINED

Paragraph headings in this Special Condition correspond to items of the Unit Price Schedule.

1. Mobilization. The Subcontractor shall move in and rig up his equipment, rig up any lower-tier Subcontractor's equipment, and pick up first drilling assembly. Mobilization shall be considered complete when all the equipment is on location and rigged up ready to spud. The Subcontractor shall be paid for the above mobilization work under Item 1 of the Unit Price Schedule.

2. Contractor-Directed Operations. Operations under this category shall include, but are not limited to: Contractor-furnished surveying, plug backs, drilling, coring, reaming, hydrologic testing, inserting and retrieving casing, placing cement and regaining lost circulation. All operations will be done as directed by the Contractor. All work on an hourly rate basis shall be performed with a full complement of operating personnel and at the direction of the Contractor. If it becomes necessary to shut down Subcontractor's rig for repairs while performing work on an hourly rate basis, Subcontractor shall be allowed compensation for such repair time at the applicable hourly rate. The number of hours devoted to repair work for which the Subcontractor may be compensated shall be limited to an accumulated total of 12 hours for each 15 day period.

Contractor-directed operations will be paid for Item 02. of the Unit Price Schedule.

3. Standby Ready. When directed by the Contractor, the Subcontractor shall cease all operations and standby in a ready condition. A full complement of personnel and equipment shall be maintained at the work site ready to resume operations immediately. Operations under this category shall include Geophysical Logging, Cement Hardening Time, or any operations not requiring the use of rig engines or drill assembly. Standby ready time will be paid under Item 03. of the Unit Price Schedule.

4. Demobilization. Upon completion of the work under this Subcontract, the Subcontractor shall remove all rubbish and debris from the drill site and shall remove all of his equipment within ten calendar days. The Subcontractor will not be responsible for levelling the work site or draining and backfilling pits. Demobilization will be paid under Item 04. of the Unit Price Schedule.

CTP-09. RECORDS AND OBSERVATIONS

Providing the following records and observations shall be a part of the Subcontractor's general responsibility for which no additional payment will be made.

1. A Daily Drilling Report shall be kept on the IADC official Standard Daily Drilling Report. The Unit Price Schedule quantities for pay estimate purpose will be taken from the IDAC Daily Drilling Report. The general remarks section shall contain an accurate record of hole conditions, work performed, and time required for all work to the nearest quarter-hour. The original and two copies of the Daily Drilling Report shall be submitted to the Contractor or his authorized representative.

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3. Accurate Pipe Tallies shall be the Subcontractor's responsibility and shall be available at the drill site for inspection at all times. Copies of steel tape measurements of drill pipe and casing shall be furnished by the Contractor.

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1. The subsurface information and data furnished both in these specifications and at the Contractor's office are not intended as representations or warranties, but are furnished for information only.

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A hole shall be termed "lost" if the Contractor determines that the condition of the hole will prevent its successful completion, or if for any reason the Contractor deems it impractical to continue drilling. If the Contractor determines that a hole has been lost before required depth has been attained, and that further attempts to complete it will be impractical, he shall order work on the hole stopped, shall investigate the circumstances in contributing to its loss, and shall notify the Subcontractor of his decision in writing. The Contractor may, at his option, order the commencement of work at an alternate location.

Contractor shall assume liability, while work is being performed under Contractor-directed operations, for loss of, damage to, or destruction of the hole, Subcontractor's in-hole equipment, including, but not limited to, drill pipe, drill collars, subs, stabilizers, and bits, unless such loss, damage, or destruction shall be caused by the Subcontractor's fault or negligence.

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In the event that, prior to completion of the work required, a hole covered by this Subcontract is abandoned, upon direction of the Contractor, the Subcontractor will be paid for work performed under the applicable items of the Unit Price Schedule.

The term "abandonment" as used in this paragraph shall mean abandonment to suit the convenience of the Contractor, as directed by the Contractor, under conditions which do not come within the scope of the paragraph entitled "Loss of Hole" of these specifications.

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All Subcontractor's compressed air equipment and accessories shall be designed, fabricated, inspected, and certified in accordance with the SAME Boiler and

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a. Contractor-Directed Operations. When it is necessary to fish for tools in the hole, while working under Contractor-Directed Operations, the Subcontractor shall notify the Contractor or his authorized representative of the existing conditions immediately, to be confirmed in writing as soon as practicable, and initiate such action as is required to commence fishing operations as soon as practicable. The Contractor will review and evaluate the circumstances resulting in the loss of tools in the hole.

i. If the investigation by the Contractor shows that the Subcontractor was neither negligent nor in violation of good drilling practice, the Subcontractor will not be held responsible for costs resulting from the loss of tools or for costs of fishing efforts conducted to recover lost tools. The value of Subcontractor-owned tools lost or damaged in the hole during hourly rate operations will be equitably compensated.

ii. If the Contractor's investigation shows that the Subcontractor was negligent or was in violation of good drilling practice in the performance of his duties, the Subcontractor will not be compensated for the value of Subcontractor-owned tools or equipment which may have been lost or damaged. Additionally, the Subcontractor

will be held responsible to the Contractor for the value of any Contractor-furnished tools or equipment which may be lost or damaged. All costs incident to such loss of or damage to the Contractor-furnished tools or equipment will be determined by the negotiated agreement of the parties.

iii. Any dispute concerning a question of fact under this paragraph iii. shall be subject to Article 11, "Disputes", of the General Provisions.

b. Contractor-Furnished Equipment. Except as provided for in paragraph ii. above, "Loss of Tools in the Hole", all machinery, tools, materials and equipment furnished by the Contractor, shall, at the completion or abandonment of the hole, be returned to the Contractor in as good condition as when received by the Subcontractor, ordinary wear and tear excepted. The Subcontractor shall be liable to the Contractor for any loss or damage to such equipment beyond such ordinary wear and tear, and for loss or damage due to the negligence or carelessness of the Subcontractor.

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8.	API RP-13B	Recommended Practice and Standard Procedures for Testing Drilling Fluids
9.		Manufacturer's Ratings Shall Apply for Equipment not Covered by the API Standards.

APPENDIX C

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APPENDIX "C"
SUMMARY OF RIG OPERATIONS
WAINOCO - GIROUARD NO. 1
RE-ENTRY OF TEST WELL

Daily Drilling Report Date	Day No.	Operations
5-12-80	1	Prepared location for drilling rig. Started moving in Mathieu Drilling Rig No. 16.
5-13-80	2	Moved in rig and started rigging up.
5-14-80	3	Rigging up 60% complete. Tanks and pumps spotted. Prepared to raise derrick.
5-15-80	4	Continued rigging up. A compressed air tank was damaged during the rig move. Did not get repaired in time to raise derrick.
5-16-80	5	Continued rigging up. Raised derrick. Unloaded drill pipe. Moved in two trailers and hooked up water, sewage lines and lights. Filled mud tanks with 300 bbls. of 17.8 pound per gallon mud.
5-17-80	6	Started drilling rat hole. Rig shut down 18 hours due to heavy rains and high water.
5-18-80	7	Completed drilling rat hole. Started nippling up blowout preventers.
5-19-80	8	Rigged up blowout preventer lines. Tested Hydril annular preventer to 3000 psi. Tested pipe rams, choke manifold, choke and kill lines, and blind rams to 5000 psi. Tested casing to 2850 psi. Tested TIW lower kelly valve and inside blowout preventer to 5000 psi. Tested standpipe and pump line valves to 3000 psi. Nippled up the bell nipple and connected the flow line.

Daily Drilling Report Date	Day No.	Operations
		Picked up an 8-3/4 inch O.D. bit and 9-5/8 inch O.D. casing scraper for 47#/ft. casing. Ran in the hole with 3-1/2 inch O.D. drill pipe and twelve 4-3/4 inch O.D. drill collars.
5-20-80	9	Picked up 3-1/2 inch O.D. drill pipe while running in the hole. Picked up kelly and circulated to condition mud with the bit at 2000 feet, 4082 feet, 6155 feet and 8262 feet.
5-21-80	10	Continued picking up 3-1/2 inch O.D. drill pipe and running into the well. Circulate to condition mud with bit at 10,018 feet and at 12,124 feet.
5-22-80	11	Displaced well bore with 17.8 pound per gallon mud. Drilled out to top of 7-5/8 inch O.D. liner at 12,321 feet. Tested casing and liner top to 1500 psi for 1/2 hour.
5-23-80	12	Pulled the drill string out of the hole. Changed the bottom hole assembly. Started back into the hole with a 6-1/2 inch O.D. bit.
5-24-80	13	Ran in the hole and stopped to circulate every 4000 feet. Drilled cement from 12,232 feet to 12,363 feet. The drill string was torquing up while drilling through the perforations at 12,324 feet to 12,348 feet. Tested the casing to 1500 psi for 15 minutes. Continued in hole picking up drill pipe and circulating the well bore every 10 joints.
5-25-80	14	Continued running in the hole and tagged the EZSV cement retainer at 14,851'. Washed and drilled to 14,853'. Circulated bottom mud to the surface and recovered some cement and a few pieces of metal,

Daily Drilling Report Date	Day No.	Operations
		indicating that the bit was running on the EZSV retainer. Pressure tested the well bore to 1500 psi for 20 minutes.
5-26-80	15	Pulled out of the hole. Rigged up Welex and ran a gamma-ray cement bond log. Picked up a Halliburton RTTS packer for a cement squeeze job and made up on the drill string.
5-27-80	16	Started running RTTS packer. Received orders not to cement squeeze. Started laying down drill pipe while pulling back out of the hole. Removed the RTTS packer. Ran the remaining drill pipe and the drill collars back in the well. Rigged up drill pipe handling equipment. Started pulling back out of well laying down each joint of drill pipe.
5-28-80	17	Finished laying down the drill string and rigged down the drill pipe handling equipment. Ran a gauge ring and junk basket in the well on electric wireline, but could not get below the top of the liner at 12,232 feet. The gauge ring showed two indentations. Made a special guide and ran with the gauge ring and junk basket. Still could not go below the liner top.
5-29-80	18	Started picking up 3-1/2 inch O.D. tubing. Ran in the well with a TIW liner dressing mill. Had problems with power tubing tongs. Replaced tongs.
5-30-80	19	Ran 3-1/2 inch O.D. tubing to top of liner and dressed the liner top. Pulled out of the well with tubing. Ran gauge ring and junk basket on electric wireline. Still could not go below liner top.

Daily Drilling Report Date	Day No.	Operations
5-31-80	20	Ran a 6.44 inch O.D. gauge ring on electric wireline. Still could not get through the top of the liner. Ran a 6.299 inch O.D. gauge ring which stuck in the liner top. A 2.3 foot long tube segment broke off and remained stuck in the liner top. Rigged up fishing tools to try to recover the segment.
6-1-80	21	Ran a fishing spear on tubing and attempted to recover the gauge ring segment. Pulled back out of well, but did not recover the gauge ring. Started running back into the well with a tapered mill and jars.
6-2-80	22	Ran in well to the top of the liner and milled a 3 foot tight spot. Continued in the well turning the mill through the perforations at 12,324 feet to 12,348 feet. Suspended operations to work on master drive chain and clutch bearing.
6-3-80	23	Finished repairs. Continued to bottom with tubing and mill. Circulated and conditioned mud. Pulled tubing and layed down the mill and jars. Ran an empty perforating gun with a casing collar locator on electric wireline. Tagged bottom at 14,855 feet. Pulled out of well.
6-4-80	24	Finished dummy run with collar locator. Ran an Otis permanent production packer. Had to work through tight place at the top of the liner. Set the packer at 14,570 feet. Nippled down the blowout preventers and the casing hanger spool. Nippled up the hanger spool and the blowout preventers.
6-5-80	25	Finished installing the blowout preventers. Attempted to pressure test the wellhead but found the tubing spool was not properly

Daily Drilling Report Date	Day No.	Operations
		seated. Rigged down the blowout preventers and tubing spool. Found that the casing stub was too short to get a good packoff in the tubing spool seals. Welded an extension onto the 9-5/8 inch O.D. casing stub. Ground the weld smooth and then cut and beveled the stub to the proper height of 5 inches. Rigged up the tubing spool and tested to 3000 psi. Installed the blowout preventers and checked the operation of the blind rams, annular preventer, choke and manifold valves. Tested the pipe rams. Started rigging up Gator Hawk tubing testing equipment.
6-6-80	26	Completed rigging up tubing testing equipment. Made up an Otis seal assembly on the tubing string. Ran the tubing into the well and tested every joint to 8000 psi.
6-7-80	27	Lowered tubing seal assembly into packer bore. Pressure tested the tubing/casing annulus to 1000 psi. Pressure tested the tubing hanger to 800 psi. Pulled the seal assembly out of the packer. Displaced the mud in the tubing with saltwater to give 2000 psi differential pressure from the formation into the well bore. Lowered the packer seal assembly back into the packer bore. Bled off tubing pressure. Started rigging down the blowout preventers.
6-8-80	28	Finished rigging down the blowout preventers and installed the christmas tree. Pressure tested the tree to 8000 psi. Ran a 2 inch O.D. through-tubing perforating gun and a collar locator to 14,869 feet. Could not accurately locate the collars. Pulled the perforating gun and collar locator. Ran a

Daily Drilling Report Date	Day No.	Operations
		gamma ray log for correlation purposes. Reran the perforating gun and collar locator and correlated with the gamma ray log. Perforated the 7-5/8 inch O.D. casing from 14,778 feet to 14,798 feet and 14,799 feet to 14,819 feet with 4 shots per foot. Tubing pressure increased to 1500 psi.
6-9-80	29	Pulled out of the well with the perforating tools. Rigged up the tree to flow the well. Flowed 8 barrels of saltwater. Ran in the well with a through-tubing perforating gun and perforated the interval 14,744 feet - 14,779 feet with 4 shots per foot. When pulling out of the hole, the perforating gun stuck at 14,593 feet. While attempting to free the gun, the electric wireline pulled free at the rope socket connection to the gun. Pulled the wireline out of the well.
6-10-80	30	Ran back in the well with a no-go locator mandrel, sinker (weight) bars, wireline jars, and a collar locator. Ran into the stuck perforating gun and jarred free. Followed the perforating gun to bottom and pulled out of the hole with the wireline tools. Rigged up a flow line and flowed 100 barrels of mud and saltwater. Produced fluid was all saltwater at the time the well was shut-in. Installed a WKM back-pressure valve in the tree. The rig was released at 1900 on June 9, 1980. Started rigging down rotary equipment.
6-11-80	31	Moving rig to disposal well location.

APPENDIX "C"
SUMMARY OF RIG OPERATIONS
WAINOCO - GIROUARD NO. 1
PLUGGING AND ABANDONMENT
TEST WELL

Daily Drilling Report Date	Day No.	Operations
8-24-80	1	Moving in and rigging up WellTech Rig No. 3.
8-25-80	2	Rigging up.
8-26-80	3	Removed christmas tree. Installed 6-inch 5000 psi blowout preventers. Started setting substructure.
8-27-80	4	Spotted substructure and rigged up floor. Installed and tested blowout preventers. Picked up tubing. Filled casing with drilling fluid and pumped 36 barrels.
8-28-80	5	Picked up hanger joint and stung into packer with 30,000 pounds weight. Rigged up Howco and pumped 225 sacks class "H" cement with 35% Oklahoma #1 sand, 75% CRF-2, 5.5 pounds per sack hi-dense #2, 70% HR-12. Attempted to squeeze, but packer leaked. Pulled out of packer and spotted 225 sacks above packer. Pulled out of hole to approximately 13,395 feet. Spotted 10-barrel slug of 20 ppg mud on top of cement plug and began pulling out of hole. Progress slow because of crew problems.
8-29-80	6	Pulled 3-1/2 inch drill pipe up into hole to 11,600 feet. Drill pipe contained mud. Placed heavy slug of mud in drill pipe to force mud down hole. Slug did not work. Mixed second slug. Mud column unbalanced

Daily Drilling Report Date	Day No.	Operations
		and well had tendency to flow. Cement apparently not set. Circulated and conditioned mud at 17.4 ppg through choke manifold. Well still trying to flow. Pumped 85 barrels of 19.5 ppg mud to 11,600 feet. Circulate to get mud in balance at 17.5 ppg.
8-30-80	7	Finished conditioning mud to 17.5 ppg. Slugged drill pipe with heavy mud and pulled out of hole. Shut down for 3-1/2 hours for lack of rig crew. Installing Welex lubricator.
8-31-80	8	Finished rigging up Welex. 6-1/2 inch gauge ring would not go below the wellhead. Drained blowout preventers. Found cement in the top of 9-5/8 inch casing. Rigged down Welex. Made up bottom hole assembly with 6-1/2 inch bit and scraper. Cleaned out 4 feet of cement at top of casing. Pulled out of hole and rigged up Welex lubricator. Ran gauge ring and junk basket to 11,338 feet. Hit bridge. Pulled out of hole with same. Found several pieces of cement in junk basket. Rigged down Welex. Picked up 6-1/2 inch bit and scraper and tripped in hole breaking circulation every 45 stands, (approximately 2700 feet).
9-01-80	9	Trip into hole to 8400 feet and broke circulation. Continue into hole to 10,820 feet. Stopped going in hole to remove one foot of barite and cuttings from mud pits. After pits cleaned filled 2/3 full of 19.5 ppg mud and cut and conditioned to 17.5 ppg.
9-02-80	10	Tripped in hole and tagged bridge 185 stands in. Tried to rotate down with tongs. Circulated to condition mud. Stopped circulating to condition mud in surface tanks. Circulated and conditioned mud using Halliburton.

Daily Drilling Report Date	Day No.	Operations
		Rigged down Halliburton and picked up Kelly. Shut down to weld bell nipple and flow line. While down began dressing Kelly. Once finished pulled and layed down 10 joints drill pipe. Ran 5 stands back in hole. Tried to drill but rotary torqued up. Chain jumped off rotary drive.
9-03-80	11	Finished repairing rotary chain. Drilling and washing cement from 11,180 feet to 11,970 feet. Repaired hydromatic valve on drawworks. Conditioned mud and changed out Howco pump trucks.
9-04-80	12	Washed and reamed from 12,140 feet to 12,832 feet. Repaired centrifugal pump and hopper hose while building and conditioning 150 barrels mud to 17.5 ppg.
9-05-80	13	Finished conditioning mud in pits to 17.5 ppg. Washed from 12,832 feet to 13,045 feet. Mud coming back cut to 16.9 - 17.3 ppg. Waiting on vacuum truck to build mud weight back to 17.5 ppg. Ran tubing and washed out tight spots to 13,500 feet. Well came in; shut-in, built mud weight in pits to 18.5 ppg. 1200 psi on casing and 350 psi on tubing. Rigged up line from casing valve to choke manifold and frac tank. Rigged up Howco and tested same to 5000 psi. Rigged up Howco and displaced tubing with 102 barrels of 18.5 ppg mud. Shut in well. 0 psi on tubing and 1275 psi on casing. Started to mix 17.5 ppg mud in suction pit.
9-06-80	14	Repacked centrifugal pump and repaired 4" discharge hose. Attempted to kill well with 17.5 ppg mud - failed. Weighted mud up to 18.5 ppg and killed well with same. Drill pipe pressure - 1200 psi at 3 barrels per minute to 1400 psi at 3 barrels per minute. Maximum shut-in casing pressure = 3400 psi.

Daily Drilling Report Date	Day No.	Operations
		Kill information: 102 barrels of 18.5 ppg mud down tubing. 950 barrels of 17.5 ppg mud. Makes a total of 1052 barrels kill mud pumped on first circulation. Second circulation - pumped 600 barrels of 18.5 ppg mud for a total of 1652 barrels at 0700 on 9-6-80. At 0600, the shut-in casing pressure was 350 psi with a mud weight of 18.0 ppg. Cumulative mud pumped was 1880 barrels.
9-07-80	15	Pumped 77 barrels 18.5 ppg mud in an attempt to kill well with 350 psi on casing. Pump rate was 3 barrels per minute. Tubing pressure was 1400 psi. Built mud volume in pit and weighted to 18.5 ppg. Pumped 200 barrels of 18.5 ppg mud and circulated well. Well dead with 1600 psi tubing pressure - 0 psi on casing. Circulated 200 barrels of 18.5 ppg mud at 1600 psi. Choke open, return mud weight ranged from 16.2 to 17.3 ppg. Wait for 600 barrels of 18.5 ppg mud to arrive. Circulated hole with 150 barrels of 18.5 mud. Total tubing pressure - 1600 psi. Casing - 0 psi.
9-08-80	16	Pumping to kill well, opened rams and circulated and conditioned mud. Closed rams and attempted to pump 18.5 ppg mud into formation. Could not pump in at 2000 psi. Opened rams and continued to circulate and condition mud. Rig up fill-up line and tongs and start out of the hole. Repack centrifugal pump and replace 3-1/2 inch rams in the blowout preventers. Pulled out of hole a total of 170 stands. (Approximately 10,200 feet.)
9-09-80	17	Finished pulling out of the hole. Rigged up Welex and ran an easy drill cement retainer and set same at 12,409 feet. Pulled out of the hole. Rigged up Welex and installed bell nipple. Made up retainer stinger and went in hole to 4600 feet.

Daily Drilling Report Date	Day No.	Operations
9-10-80	18	Tripped in hole with stinger to 4950 feet. Picked up kelly and circulated at 4950 feet. Tripped in hole to 10,050 feet. Picked up kelly and circulated. Tripped in hole while picking up tubing off pipe racks. Rigged up new cable on tongs. Tripped in hole while picking up tubing off pipe racks. Rigged up new cable on tongs. Tripped in hole while picking up tubing and tagged retainer at 12,409 feet. Broke out pup (short) joints and spaced out in retainer. Rigged up Howco and circulated hole. Stung into retainer and pressured casing to 1000 psi. Broke down formation with 4200 psi and pumped in 5 barrels of 18.5 ppg mud with 3800 psi at 2-1/2 barrels per minute. Mixed and pumped 420 sacks class "H" cement with 35% Silica Flour, 26 pounds per sack hi-dense, .75 of 1% CRF-2, .25 pounds per sack D-AIR-1 and .4 of 1% HR-5 to yield 1.38 cubic feet per sack mixed at 18.5 ppg. Displaced tubing with 84 barrels 18.5 ppg mud, pulled out of retainer and spotted a 30 sack cement plug on top of retainer. Pulled 30 stands to approximately 10,475 feet. Rigged down Howco and broke down pump-in sub. Moved 19.5 ppg mud from frac tank to surface pits. Pumped 15-barrel slug of 19.3 ppg mud to pull out of hole.
9-11-80	19	Pulled out of hole with wet drill pipe. Mixed and pumped a 19.6 ppg slug and put wiper rubber on drill pipe. Pulled 140 stands out of hole and racked in derrick. Laid down 3-1/2 inch drill pipe. Finished laying down 3-1/2 inch drill pipe. Put drill collar clamp on every joint and laid down bottom hole assembly. Removed blow-out preventers.

Daily Drilling Report Date	Day No.	Operations
9-12-80	20	Installed 3-3/8 inch blowout preventers, bell nipple and flow line. Worked blowout preventer and bell nipple (Hydril). Worked o.k. Picked up bit and scraper. Drilled out cement in top of 9-5/8 inch casing and laid down bit and scraper. Rigged up Welex and ran junk basket to 8500 feet and ran Halliburton bridge plug. Set same at 8480 feet and rigged down Welex. Went in hole open-ended to lay down drill pipe.
9-13-80	21	Continuing in hole open-ended. Began pulling out of hole laying down drill pipe. Finished laying down drill pipe and began going in hole with tubing to 4080 feet. Put flange on blowout preventer and tested casing to 1000 psi for 20 minutes. Cleaned mud tanks and filled with water. Displacing mud out of hole with water.
9-14-80	22	Finished displacing mud with fresh water. Pulled out of hole. Rigged up Welex to cement 9-5/8 inch casing and run cutter in to 1820 feet. Could not get down. Pulled cutter out and added weight to cutter but could not get beyond 1820 feet. Broke cutter off at top of 9-5/8 inch casing on way out of hole. Called out a welder and made a tool to fish cutter out of 9-5/8 inch casing. Made up scraper and bit. Scraper would not go in casing. Received new scraper and tripped in hole to 2000 feet. Circulated out at 2000 feet. Tripped in hole to 4000 feet. Circulated out at 4000 feet.
9-15-80	23	Pulled out of hole with bit and scraper. Rigged up Welex and ran casing cutter in hole and cut casing at 3,917 feet. Rigged up Frank's casing tools and pulled on casing with 215,000 pounds. Would not pull free. Laid down casing spear. Rigged up Welex wireline and ran in cutter and cut casing at

Daily Drilling Report Date	Day No.	Operations
		3817 feet. Pulled out of hole and rigged down wireline. Picked up casing spear and circulated with 500 pounds. Pulled 245,000 pounds on casing, but casing would not pull free. Rigged up wireline and ran cutter back in hole and cut casing at 3024 feet. Pulled out of hole and rigged down Welex. Pulled on casing with 245,000 pounds but could not pull casing. Picked up 9-5/8 inch casing cutter and cut casing 5 feet below casing slips and layed down cutter. Picked up spear and pulled out the 5 feet of 9-5/8 inch casing. Ran spear in hole and pulled on casing. 9-5/8 inch casing slips would not come through bell nipple. After bell nipple cut off by welder, pulled and layed down casing spear.
9-16-80	24	Laid down 3019 feet of 9-5/8 inch casing and rigged down Frank's casing tools. Rigged up Welex wireline while waiting on cement retainer. Tripped in the hole and set easy-drill cement retainer at 2900 feet. Rigged down Welex. Picked up and tripped in hole with retainer stinger. Finished in hole with 45 stands drill pipe and tagged in retainer. Rigged up Halliburton, mixed and pumped 450 sacks cement on top of retainer. Pulled 12 stands drill pipe and rigged down Halliburton. Pulled out of hole laying down tubing.
9-17-80	25	Finished laying down tubing and pumped 75 sacks class "H" cement in top of hole. Rigged down Halliburton and layed down 4 joints tubing. Removed blowout preventer and loaded out same. Rigging down and cleaning surface mud tanks. Released rig at 0300 on 9-17-80. Continued to rig down.

Daily Drilling Report Date	Day No.	Operations
9-18-80	26	Rigging down and loading out rental equipment. Cut off wellhead 4-1/2 feet below ground level and welded a steel plate on the 13-3/8 inch casing.
9-19-80	27	House trailer, generator, and fuel tank were picked up. Septic and water tanks were picked up by Oilfield Supply. Location boards being picked up by Oilfield Construction Company.

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APPENDIX D

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APPENDIX "D"
SUMMARY OF RIG OPERATIONS
WAINOCO - GIROUARD NO. 1
DISPOSAL WELL DRILLING

Daily Drilling Report Date	Day No.	Operations
6-7-80	-	International Hammers Services Company drove 14 inch nominal O.D. (.357 inch wall thickness) structural casing to 58 feet below ground level, using a Delmag D-12 diesel-operated hammer. The final blow count was 130 blows per foot.
6-11-80	1	Moving Mathieu Drilling Rig No. 16 to disposal well location.
6-12-80	2	Moving rig from test well and rigging up at disposal well location.
6-13-80	3	Rigging up rotary drilling rig. Installed annular preventer on structural casing. Excavated shale pit.
6-14-80	4	Completed rigging up. Drilled rat hole and mouse hole. Spudded at 0415 on 6-14-80.
6-15-80	5	Drilled for one hour. Stopped drilling to repair drawworks. Drilled to 201 feet.
6-16-80	6	Suspended drilling to repair the drum shaft bearings in the rig drawworks.
6-17-80	7	Finished repairing the drawworks. Ran bit back in hole and started drilling. Built mud volume in pits. Pulled out of hole to clean sand from mud pits. Went back to bottom and started drilling. Drill string stuck. Worked pipe loose and conditioned mud. Started drilling ahead.
6-18-80	8	Drilled to 1544 feet. Pulled out of hole to change bottom hole assembly. Ran back in hole and circulated and conditioned mud.

Daily Drilling Report Date	Day No.	Operations
		Lost 100 barrels of mud. Started pulling out of hole to run casing. Took two inclination surveys while pulling the drill string from the well. Started running 9-5/8 inch O.D. casing.
6-19-80	9	Ran 9-5/8 inch O.D. 43.5#/ft. N-80 LT&C casing in well bore to 1534 feet. Rigged up cementing head and cementing lines. Circulated well and worked pipe. Cemented casing with a 12.8 pound per gallon lead slurry of 320 sacks of Halliburton Lite Wate cement with 3% salt. The lead slurry was followed by a 15.6 pound per gallon tail slurry of 300 sacks of Class "H" cement with 2% calcium chloride. A wiper plug was used to displace the cement. When the plug seated in the float collar, the pump pressure increased to 1400 psi. The pressure was bled to zero and flowback occurred, indicating the back pressure valves were holding. While circulating the cement, full mud circulation was monitored at the surface. No cement was observed in the mud returns. A string of 1-1/4 inch O.D. tubing was run to 120 feet in the casing hole annulus. The annulus was cemented with 50 sacks of Class "H" cement with 2% calcium chloride. No cement returns were noted, so another annular cement job was performed at 60 feet using the same volume. Cement was tagged in the annulus at 10 feet below ground level. After the annular preventer had been rigged down, the casinghead was welded on to the 9-5/8 inch O.D. casing.
6-20-80	10	After testing the casinghead, rigged up the blowout preventers. Changed the pipe rams from 3-1/2 inch O.D. to 4-1/2 inch O.D.

Daily Drilling Report Date	Day No.	Operations
		Attempted to test blowout preventers. Pipe rams would not hold. Removed rams to repair inserts.
6-21-80	11	Installed new inserts in 4-1/2 inch O.D. pipe rams. Tested blind rams and casing to 1500 psi. Tested pipe rams, annular preventer, choke and kill lines, upper kelly valve, TIW lower kelly valve, and the inside blowout preventer to 2000 psi. Ran in hole with 8-1/2 inch O.D. bit and tagged cement at 1451 feet. Shut down to repair drawworks.
6-22-80	12	Installing new main shaft in drawworks.
6-23-80	13	Finished rig repairs. Ran in hole with an 8-1/2 inch O.D. bit and drilled cement from 1451 feet to 1455 feet, the float collar at 1455 feet and the shoe at 1533 feet. Started drilling new formation.
6-24-80	14	Drilled to 2406 feet. Obtained an inclination survey at 2174 feet showing 1° deviation from vertical.
6-25-80	15	Drilled to 2573 feet. Pulled out of hole for a new bit. Ran back in hole and drilled to 2976 feet. Obtained an inclination survey which indicated 1-1/4° deviation from vertical. Drilled ahead to 3250 feet.
6-26-80	16	Drilled to 3965 feet. Took an inclination survey which indicated 1/2° deviation. Drilled ahead and circulated 1 hour due to excessive sand in mud returns. Drilled to 4580 feet.
6-27-80	17	Drilled to 4606 feet. Circulated and conditioned mud and ran an inclination survey. The survey showed 1° inclination at 4606 feet. Pulled out of hole and ran induction log and formation density log. Ran back in hole and drilled to 4616 feet. Started

Daily Drilling Report Date	Day No.	Operations
		pulling out of the hole and laying down drill pipe. The final mud properties were: mud weight, 9.0 pounds per gallon; funnel viscosity, 42 sec./qt.; plastic viscosity, 14 centipoise; yield point, 7 lb./100 sq.ft; initial and 10 minute gel strength, 2 and 6 lb./100 sq.ft.; ph, 10; API water loss, 18cc/30 min.; chlorides, 1800 mg/L. Bit weight was 10,000 to 20,000 lbs., and rotary rpm was 110. Hydraulics while drilling consisted of approximately 300 gpm circulation rate through three 10/32 inch nozzles with 1300-1600 psi pump discharge pressure.
6-28-80	18	Continued pulling out of hole and laying down the drill string. Change the pipe rams in the blowout preventers to run 5-1/2 inch O.D. 15.5 pound per foot casing. Ran 126 joints of casing to 4607 feet. Cemented with 1850 sacks lead slurry of Halliburton Lite Wate cement followed by 500 sacks Class "H" cement tail slurry. Had full surface mud returns while circulating cement. The displacement wiper plug was seated in the float collar with 2200 psi. Started nippling down blowout preventers. Set slips in casinghead and started cutting off casing.
6-29-80	19	Finished nippling down blowout preventers and cutting casing. Installed 6 inch x 10 inch Brewster tubing head and tested to 2000 psi. Unloaded 2-7/8 inch drill pipe. Nippled up 6 inch 5000 psi working pressure blowout preventers. Picked up a 2-7/8 inch O.D. kelly, drill collars, and a 4-3/4" O.D. bit.
6-30-80	20	Picked up 2-7/8 inch O.D. drill pipe and ran in well. Tagged cement at 4520 feet. Displaced mud in the well bore with 9.5 pound per gallon saltwater. Tested casing

Daily Drilling Report Date	Day No.	Operations
		to 1500 psi. Pulled out of the hole. Ran gamma-ray and cement bond logs. Ran a gauge ring and junk basket to 4520 feet. Found no obstructions.
7-1-80	21	Pulled gauge ring and junk basket. A 3-1/8 inch O.D. casing perforation gun was run and the casing perforated from 4340 feet to 4420 feet with 4 shots per foot. Ran in hole with a Halliburton RTTS packer and 2-7/8 inch O.D. drill pipe and set at 4313 feet. Pressure tested the drill pipe/casing annulus to 1000 psi. Opened the circulating port in the packer and displaced tubing with 14,636 standard cubic feet of nitrogen. Bled off nitrogen pressure at the surface to try and flow the well. Did not flow. Opened circulating port in the packer and tried to reverse circulate with 60 barrels. Had no flow at the surface. Rigged up Halliburton to perform injectivity test. Injected saltwater at the rate of 2-1/4 barrels per minute at 1300 psi.
7-2-80	22	Rigged up a coiled tubing unit. Released packer and reset at 4251 feet. Ran the coiled tubing inside the drill pipe to 3000 feet. Started jetting with nitrogen at 300 standard cubic feet per minute to wash sand out of drill pipe. Hit sand bridge at 3155 feet. Installed foaming equipment and jetted with foam from 3155 feet to 3268 feet. Total recovery was approximately 120 bbls. of fluid (saltwater and mud) plus a large amount of very fine sand.
7-3-80	23	Continued jetting with coiled tubing while getting 20 barrels per hour saltwater returns. Rigged down coiled tubing unit and pulled out of the hole with the drill pipe.

Daily Drilling Report Date	Day No.	Operations
		Ran a Halliburton EZ bridge plug on wireline and set at 4220'. This was the maximum depth which could be reached due to sand in the well bore. Ran back in the hole with 2-7/8 inch O.D. drill pipe. Started laying down drill pipe.
7-4-80	24	Completed laying down 2-7/8 inch O.D. drill pipe. Started rigging down the drilling rig. The rig was released at 1700 hours on July 3, 1980.
7-5-80	25	Operations partially suspended while waiting on rig to be moved. No truck transportation was available due to holiday. Moved some rental tools and equipment.
7-6-80	26	Operations partially suspended while waiting on rig to be moved. WKM service representatives rearranged flow loops on the test well tree.
7-7-80	27	Moving the rig off location. Rig 80% moved.
7-8-80	28	Moved the rig off location.
7-9-80	29	Cleaned up location for wireline work.
7-10-80	30	Cleaned and leveled location.
7-11-80	31	Rigged up Welex and Halliburton and perforated well from 2,870 to 3,000 feet with 3-1/8 inch casing guns, 4 holes per foot. Made 7 runs and performed injection test after each run. After perforating, Welex tagged bottom at 4,217 feet.
7-12-80	32	Rigged up Halliburton and acidized well with 5,000 gallons of FE acid with 250 gallons of OWG diverter and 8 gallons of HAI-55 corrosion inhibitor followed by 10,000

Daily Drilling Report Date	Day No.	Operations
		gallons of HF acid with 16 gallons of HAI-55 corrosion inhibitor. Displaced acid with 130 barrels of saltwater and performed injection test.