DOE/ET/27081-4

GEOPRESSURED - GEOTHERMAL PROGRAM

FINAL REPORT
PAULINE KRAFT WELL NO. 1
NUECES COUNTY, TEXAS

COMPLETION AND TESTING

TESTING GEOPRESSURED GEOTHERMAL RESERVOIRS IN EXISTING WELLS

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

EATON OPERATING COMPANY, INC.
3104 EDLOE, SUITE 200
HOUSTON, TEXAS 77027
713-627-9764

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1.0 EXECUTIVE SUMMARY

Eaton Operating Company, Inc. (Eaton) operates the Wells of Opportunity program under contract to the Department of Energy, Division of Geothermal Energy, to evaluate potential alternative energy sources in geopressured-geothermal (GEO^2) aquifers along the Texas and Lousiana Gulf Coast. This report covers the test of the Pauline Kraft Well No. 1, about 6 miles south of Corpus Christi, Texas.

The Pauline Kraft Well No. 1 was originally drilled to a depth of 13,001 feet by the Coastal States Gas Corporation in 1971, and was abandoned as a dry hole. The well was re-entered by Ross-Pope Drilling Equipment Company in an effort to obtain a source of GEO^2 energy for a proposed gasohol manufacturing plant. Eaton assumed temporary control of the site on December 19, 1980, to test the well for the Wells of Opportunity program.

The well was tested through a 5-inch by 2-3/8 inch annulus. The geological section tested was the Frio-Anderson sand of Mid-Oligocene age. The interval tested was from 12,750 to 12,860 feet. A saltwater disposal well was drilled on the site and completed in a Micocene sand section. The disposal interval was perforated from 4710 to 4770 feet and from 4500 to 4542 feet.

The test well failed to produce water at substantial rates. Initial production was 34 BWPD. A large acid stimulation treatment increased productivity to 132 BWPD, which was still far from an acceptable rate. During the acid treatment, a failure of the 5-inch production casing occurred.

The poor production rates are attributed to a reservoir with very low permeability and possible formation damage. The casing failure is related to increased tensile strain resulting from cooling of the casing by acid and from the high surface injection pressure. The location of the casing failure is not known at this time, but it is not at the surface. Failure as a result of a defect in a "crossover" joint at 723 feet is suspected.

Further remedial work and stimulation were not considered worthwhile, and testing was terminated on March 22, 1981. The location was returned to Ross-Pope Drilling Equipment Company on April 15, 1981. That company plans to further test the well.

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 Pauline Kraft Well No. 1, acquired for this particular test, was drilled by Coastal States Gas Corporation and was plugged and abandoned in August, 1971. The well was originally recommended as a WOO prospect by Myron H. Dorfman, of the Center for Energy Studies at the University of Texas, in his letter dated January 14, 1980 (Exhibit 2-3). Dr. Dorfman had examined the geology of the area, as well as the well itself, and he felt it was a very good prospect, anticipated to have high flow rates. Two additional letters (Exhibits 2-4 and 2-5), were written by Robert A. Morton, Coordinator-Geothermal Studies, Bureau of Economic Geology at the University of Texas, on February 6, 1980 and April 2, 1980. Dr. Morton's letter of February 6, 1980 indicated the reservoir quality appeared marginal; however, from a research viewpoint, he felt that a test in this type sand was needed. In his April 2, 1980 letter, Dr. Morton discussed the marginal reservoir quality of a similar sand in the Getty Bevly Well No. 1. Attempts to re-enter this well encountered well conditions which precluded completion and testing, thus making the Pauline Kraft No. 1 the prime prospect in the area. Mr. Don Ross, of Ross-Pope Drilling Equipment Company, acquired a lease on the Pauline Kraft property to re-enter the well, with plans to utilize the energy to operate a gasohol plant. The re-entry to the original total depth was at Mr. Ross' expense. Eaton was to assume operations after reaching the total depth of 13,000 feet. A contract was finalized with Don Ross on November 28, 1980. Eaton assumed operations on the location on December 19, 1980.

2.2 Location and Geography

The Pauline Kraft Well No. 1 location is approximately 6 miles south of Corpus Christi, Texas, north of Chapman Ranch. Corpus Christi is a major deepwater port and a center of south Texas' oil and gas, chemical, and fishing industries. The population is about 217,000. The specific well location is 467 feet from the north line and 990 feet from the west line of Section 4, Laurels Farm Tracts, in El Rincon De Corpus Christi Grant, Survey A-411. The terrain is flat and is about 32 feet above sea level. The land is normally used for sorghum production. Exhibit 2-1 indicates the location of the Pauline Kraft Well No. 1 in relation to other GEO^2 test wells. Exhibit 2-2 is a topographic map of the area.

2.3 Operator Contracts and Agreements

Ross-Pope Drilling Equipment Company (Ross) was the operator of the test well. Re-entry of the test well was completed December 19, 1980, when Ross reached the total depth of 13,002 feet, and Eaton assumed operations to complete the well for a Geo^2 test. Eaton's legal agreement with Ross can be found in Appendix A.

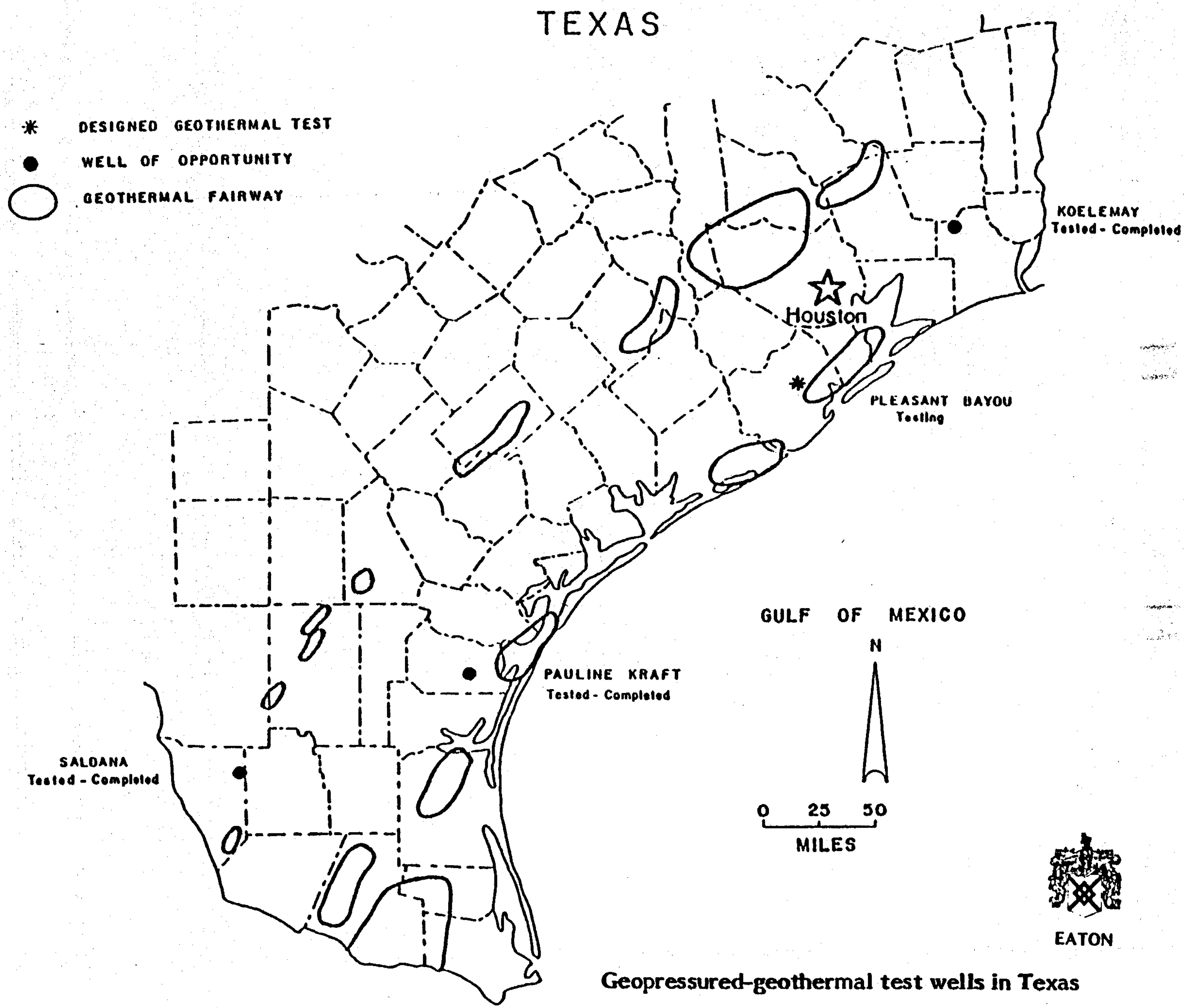
Ross' geothermal lease agreement with the owner of the land, Pauline Kraft, is also in Appendix A.

Ross entered into a contractual agreement for geothermal testing with Dwight Gwyn, who leases the property for farming purposes. A copy of Ross' agreement with Mr. Gwyn is also in Appendix A.

2.4 Rig Contractor Agreement

Target Well Servicing was awarded the contract to complete the test well and drill a disposal well on the site. Target Rig No. 14 performed the work. The rig moved on location in early December, 1980. The rig description and drilling contract can be found in Appendix B.

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



Geopressured-geothermal test wells in Texas

Eaton Industries of Houston, Inc.
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(713) 627-9764

EXHIBIT 2-1

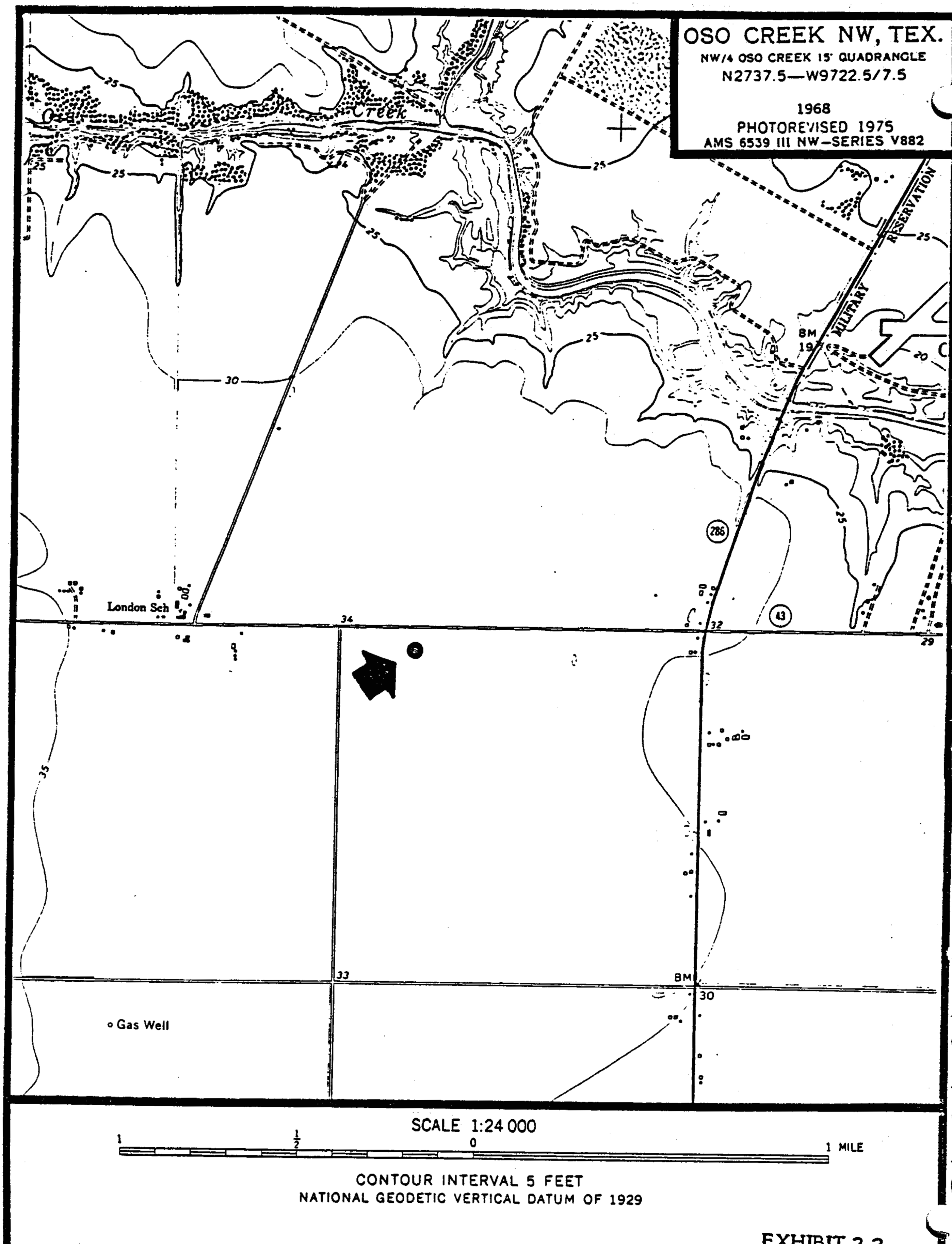

EXHIBIT 2-2

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.

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

THE UNIVERSITY OF TEXAS AT AUSTIN
CENTER FOR ENERGY STUDIES
AUSTIN, TEXAS 78712

Engineering-Science Building 143
(512) 471-7792 and 471-4946

January 14, 1980

Mr. Keith Westhusing
DOE Regional Office
U.S.Federal Building and Court
Room 8620
Houston, Tx 77002

Dear Keith:

As I discussed with you by phone last week, Mr. Don Ross, an oil and gas operator in the Gulf Coast region, who has visited me on several occasions in the course of the last year, has developed a "wells of opportunity" prospect in Nueces County north of the Chapman Ranch Field. This prospect would involve re-entering Coastal States' No. 1 Craft, which was drilled to a total depth of 13,000 ft. I have examined the geology of the area, as well as the individual well, and feel that this would be a very good prospect.

The well has 7" casing set at approximately 11,000 ft., and contains a large sand section beginning at 12,750 ft. and extending to 12,860 ft. which by sonic log indicates a porosity of approximately 18%. I would anticipate reasonable high flow rates and, most interestingly, the small SP deflection indicates an average salinity in the range of 14,000 ppm. Mr. Ross has examined the seismic work and tells me that available seismic indicates no faulting in the area. Our regional geology on this area indicates the location to be on the flank of the large high which encompasses the Chapman Ranch Field without faulting.

As a result of our discussion, I sent Mr. Ross to visit Ben Eaton. I have talked with Ben, who feels as I do. Namely; that this is an excellent prospect for re-entry, and he also tells me that Mr. Ross is prepared to cost-share to the extent of getting a rig and cleaning out the well to total depth. He is also prepared to buy the leases covering this prospect. Given this cost-sharing, I feel we would be well advised to consider this favorably in as much as (a) it is located in an area where we have heretofore had no wells available for testing in Central Texas, and (b) it is one of the few areas we have found containing low salinity fluids with thick sands to indicate reasonably high flow rates. Ben tells me that he is putting together a file in cooperation with Mr. Ross at this time, on the geology and background of the Coastal States' well, and will forward this information to you in the near future. If you have any questions or desire additional information at this point, please let me know.

Sincerely,

Myron H. Dorfman
Director for Geothermal Studies

EXHIBIT 2-3

cs
cc: Dr. Ben Eaton

THE UNIVERSITY OF TEXAS AT AUSTIN
BUREAU OF ECONOMIC GEOLOGY
AUSTIN, TEXAS 78712

University Station, Box X
Phone 512—471-1534
471-7721
474-5994

February 6, 1980

Mr. Charles Boardman
Eaton Operating Company, Inc.
3100 Edloe, Suite 205
Houston, TX 77027

Dear Charlie:

The following statements briefly summarize the geological conditions in the vicinity of the Pauline Kraft No. 1, Nueces County, Texas. The objective sand, which occurs between 12750 and 12900 in the subject well, is approximately 110 to 140 feet thick in adjacent wells. It is approximately 1500 low structurally to updip wells and is faulted out of the Sunray No. 3 manley, west of the subject well.

Reservoir quality appears to be marginal according to analyses of the sand in adjacent deep wells. Sidewall cores taken in the Arco Callaway Gas Unit 1 (Mobil David field) show 18 to 20 percent porosity; permeabilities are 8 to 68 md. Whole core analyses, which are generally more accurate, are available for the Arnold O. Morgan-David Geiser Coastal States, et al., Chapman "C" No. 1. These analyses show 17 to 20 percent porosity; permeabilities are generally low, ranging from 2 to 8 md in the upper ten feet. Highest permeabilities of 20 md occur only within a five foot zone, the remaining sand section has permeabilities of a few millidarcies.

From a research viewpoint, we need a test in this type of sand; therefore, I hope this can become a well of opportunity test.

Sincerely,

Robert A. Morton

Robert A. Morton
Coordinator, Geothermal Studies

jjm

xc: Keith Westhusing

EXHIBIT 2-4

THE UNIVERSITY OF TEXAS AT AUSTIN
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University Station, Box X
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April 2, 1980

Mr. Charles Boardman
Eaton Operating Company, Inc.
3100 Edloe, Suite 205
Houston TX 77027

Dear Charlie:

The prospective geothermal sand at 12,900 feet in the Getty Bevly No. 1, Nueces County, is similar to the sand described in my letter of February 6, 1980 regarding the Pauline Kraft No. 1. This well-developed sand, which occurs over a wide area, is approximately 110 to 140 feet thick in the area of interest. In the objective interval, uncorrected temperature is about 267°F (293°F corrected), and the formation fluid pressure is about 11,000 psi (0.85 psi/ft); porosities and salinities calculated from the electric log are about 11 percent and 35,000 ppm, respectively.

The sand is upthrown and 900 feet high structurally to the Pauline Kraft well. Because of nearby faults, reservoir size is probably limited. As in the Pauline Kraft and adjacent deep wells, reservoir quality appears to be marginal. Core analyses from the objective sand indicate that porosities are 17 to 20 percent, but permeabilities are generally less than 10 millidarcys.

Sincerely,

Bob Morton

Robert A. Morton
Coordinator of Geothermal Studies

jjm

EXHIBIT 2-5

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 the capability to drill, complete, and test wells, the ability 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 wells.

The objectives of the WOO test program in general, and of the Pauline Kraft 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.

4.0 GEOLOGY

4.1 Regional Setting

The Coastal States Pauline Kraft No. 1 geopressured-geothermal well was completed into the Anderson sand in southern Nueces County, Texas. This sand, a unit of the Frio formation, was deposited during the Oligocene period of the Tertiary. The Anderson sand appears to be a lower Frio depositional unit based on UT-BEG correlational T-markers. The sand lies approximately 300 feet below the T-6 marker, personal contact, Morton 5-4-81 placing it lower in the Frio formation than the Pleasant Bayou #2 which is producing within the T-4. The reservoir lies along the southern reaches of the north-central Nueces County fairway (Exhibit 4-1).

The South Texas Frio consists of a massive wedge of sandstone and shale sequences that dip and thicken gulfward. These sediments, of terrigenous origin, were transported across a broad fluvial plain and either deposited as deltaic complexes or reworked by wave action and longshore currents into extensive barrier bars and strandplains. Identification of the Frio formation, because of its homogeneity, is based primarily on diagnostic foraminifers. The top of the formation is identified by the occurrence of the Marginulana vaginata and the base by the Textularia warreni. [Bebout et al 1979]

The region encompassing the geopressured-geothermal test reservoir is dominated by a strandplain-type enviroment. These sands, reworked by marine processes, were deposited in narrow bands, parallel to strike, and they occur as complexes of ridges and bars. [Bebout et al 1975]

4.2 Local Geology

The Frio-Anderson sand is locally manifested as an extensive anticlinal structure bounded on the northwest by a northeast-trending growth fault, (Exhibit 4-2). The fault lies approximately 250 feet northwest of the test well in the Anderson sand and has a displacement of 450 feet, (Exhibit 4-3). The sand exhibits some thinning to the southeast, but remains open in that direction.

Fig. 25. Potential geothermal fairways.

COASTAL STATES NO. I PAULINE KRAFT

BEBOUT ET AL 1975

EXHIBIT 4-1

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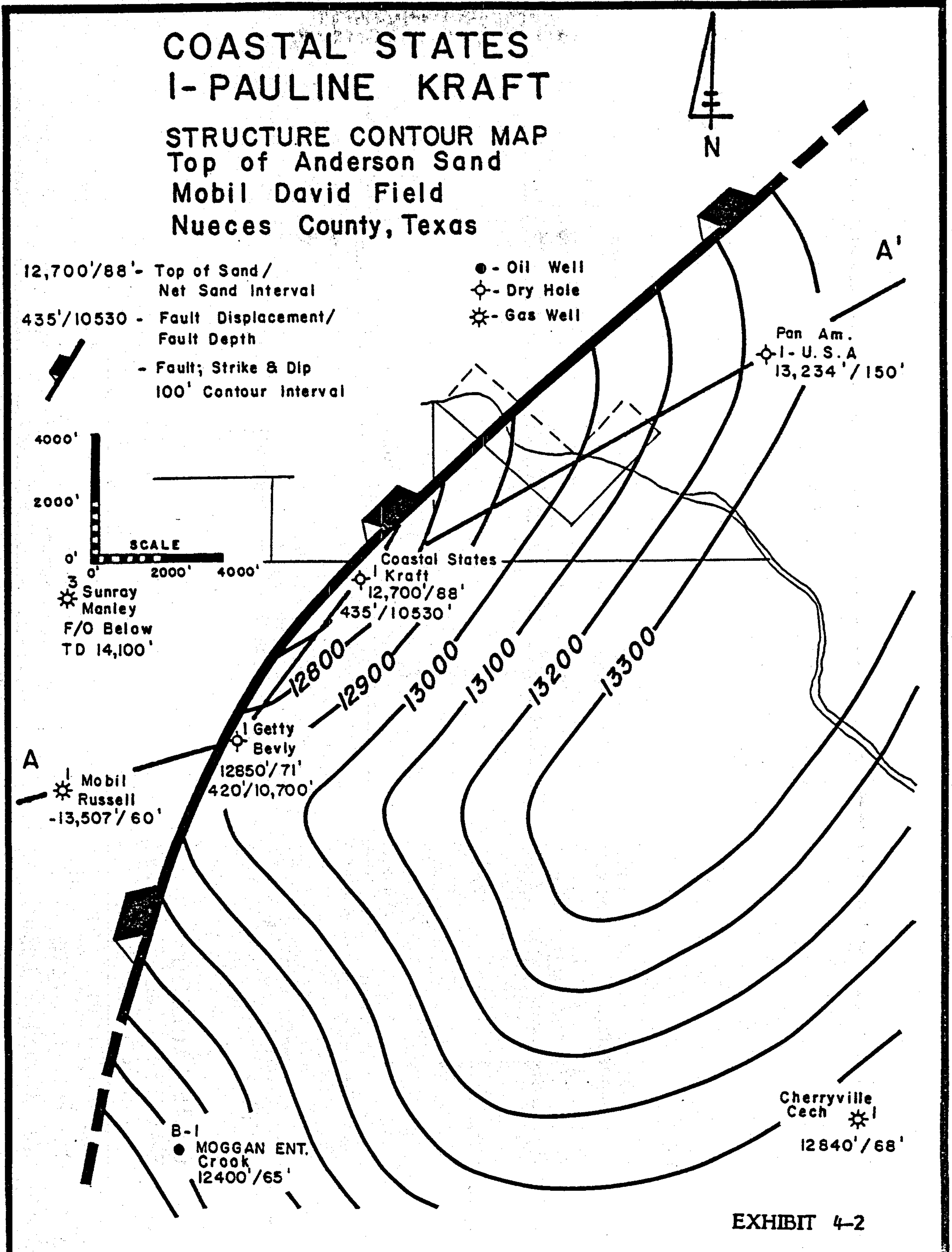

EXHIBIT 4-2

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Eaton Operating Co., Inc.

DOE CONTRACT NO.
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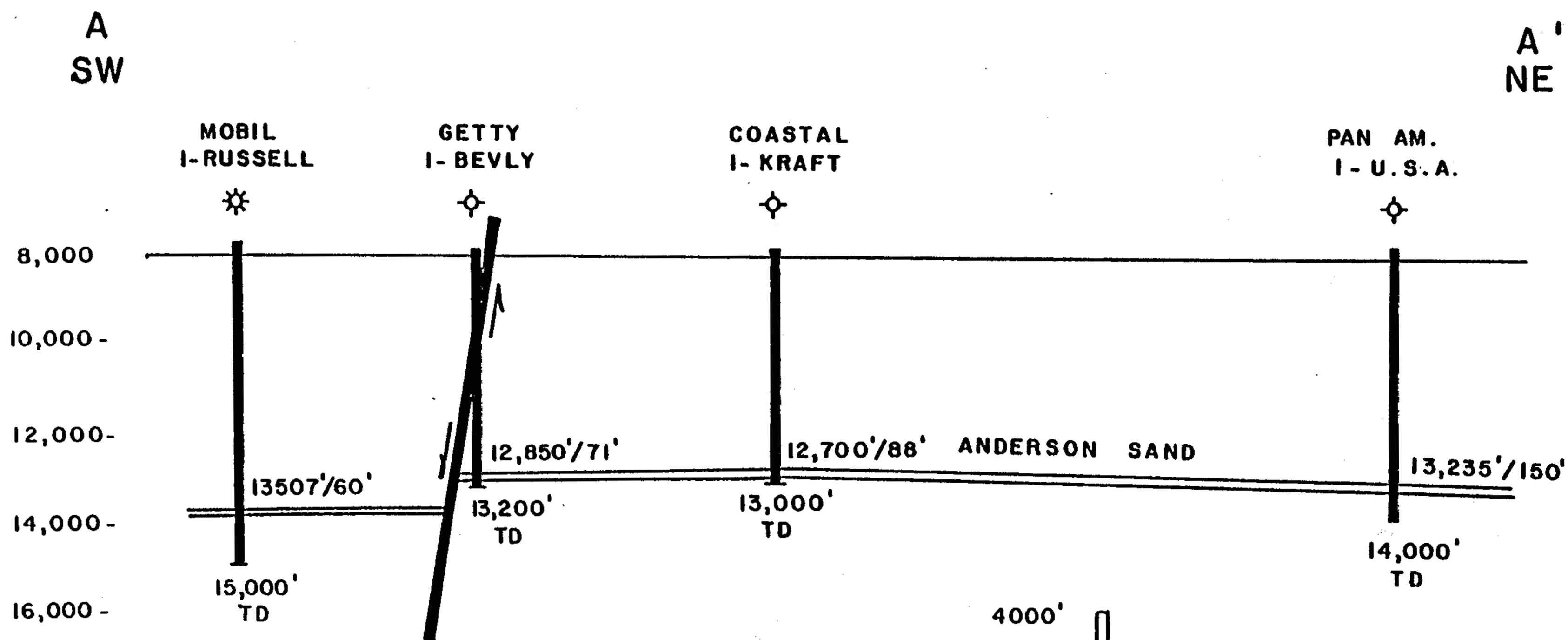
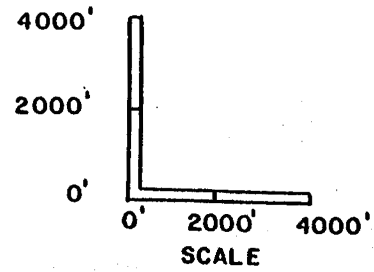
COASTAL STATES
1- PAULINE KRAFT





GENERALIZED
SOUTHWEST - NORTHEAST
CROSS-SECTION A-A'
Top of Anderson Sand
Mobil - David Field
Nueces County, Texas

13,000 TD - TOTAL DEPTH

12,700'/88' TOP OF SAND/ NET SAND INTERVAL

FAULT; DIP & DISPLACEMENT

DRY HOLE

GAS WELL

EXHIBIT 4-3

5.0 PETROPHYSICS

5.1 Open Hole Log Analysis - Test Well

During the drilling stages of the Coastal States Gas Producing No. 1 Pauline Kraft Wildcat, Nueces County, Texas, various downhole surveys were conducted for hydrocarbon evaluation. When Eaton acquired the well from Ross-Pope Drilling Equipment Company, an additional downhole survey was run for evaluation for the DOE Wells of Opportunity program. The following are logs used in the evaluation.

1. Induction - SFL/BHC - 1" (Exhibit 5-1)
2. Dual Induction - SFL - 1" (Exhibit 5-2)
3. Dual Induction - Sonic - 5" (Exhibit 5-3)

These logs contain raw data from which the following formation measurements were determined.

1. spontaneous potential
2. induction
3. sonic time travel
4. computed apparent water resistivity

5.1.1 Porosity

The mean porosity, based on sidewall core analysis, was 23%, with a range of 10% to 26% (Exhibit 5-4). Analysis of the Dual Induction Sonic log yields a mean porosity value of 16%, with a range of 10% to 22%. These parameters are based on a matrix velocity of 18,500 ft/sec, a Δt_{ss} of 76 μsec/ft, and a Δt_{sh} of 94 μsec/ft (Exhibit 5-5).

5.1.2 Sand Thickness

The gross sand thickness over the geopressured-geothermal reservoir interval of 12,750' to 12,860' is 110'. The net sand thickness is estimated to be 109'. This value is based upon analysis of the Dual Induction SFL/Sonic log, using a porosity cutoff of 10% (Exhibit 5-3).

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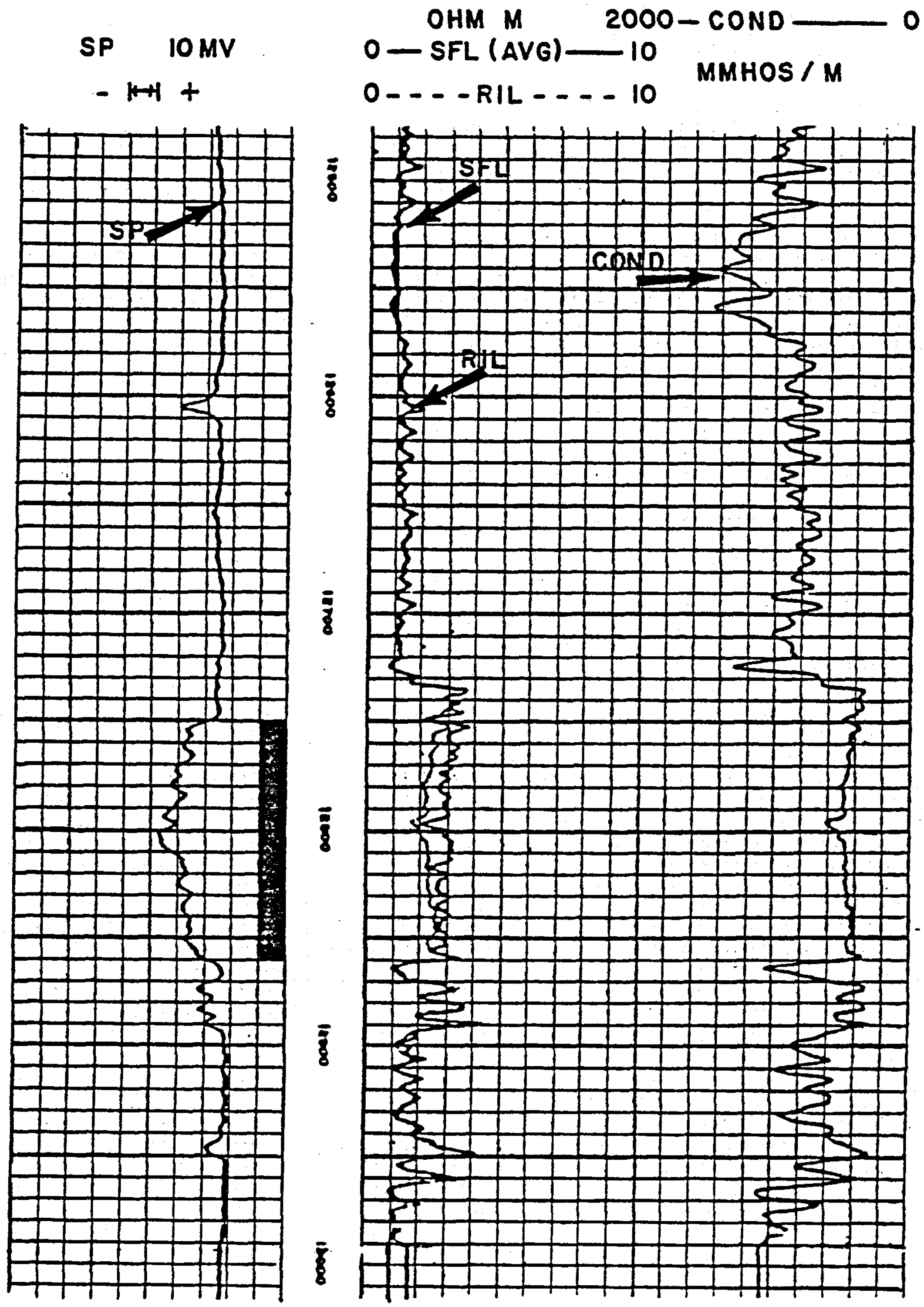

INDUCTION SFL/BHC LOG - ANDERSON SAND

COASTAL STATES NO. 1 PAULINE KRAFT

EXHIBIT 5-1

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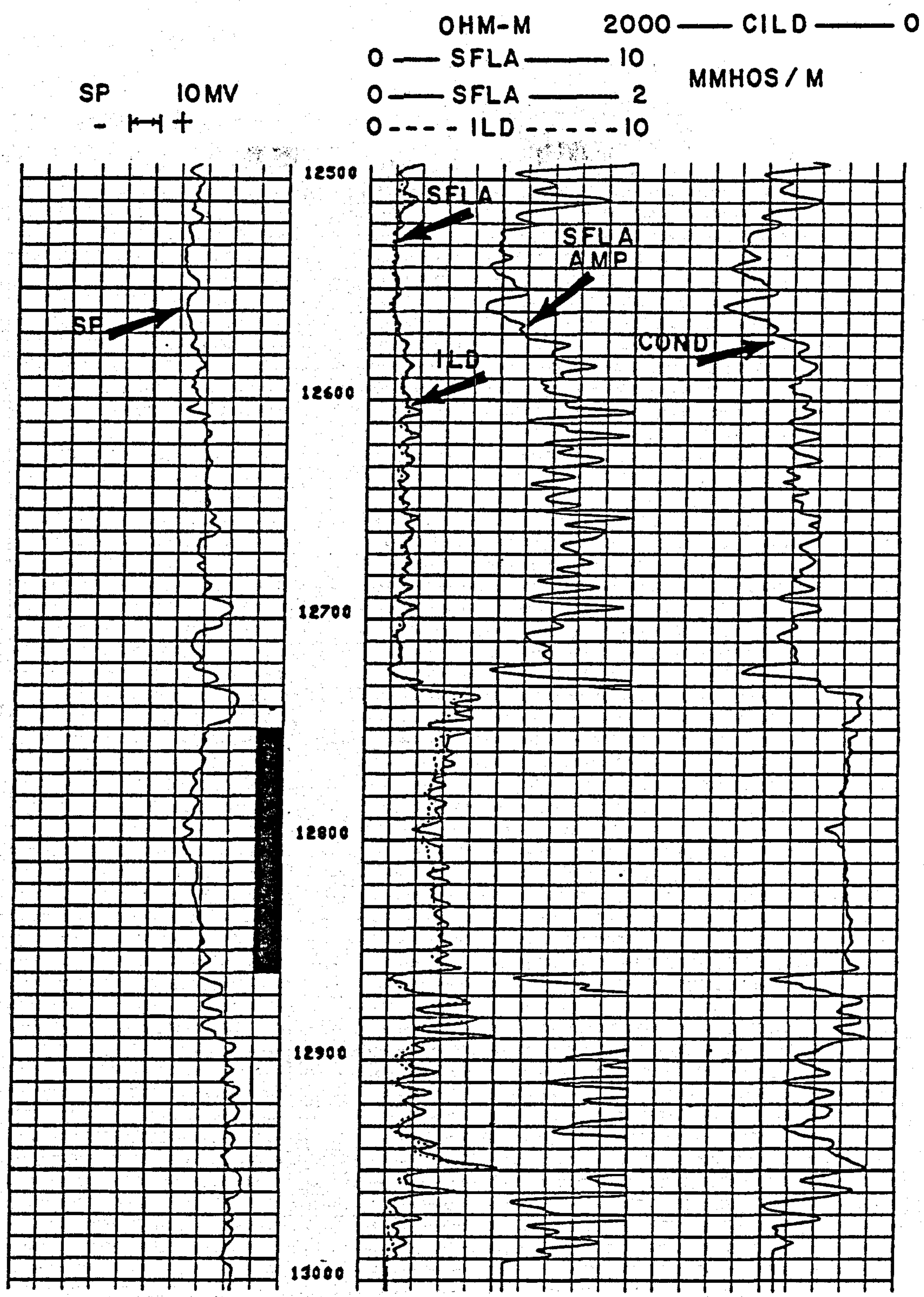
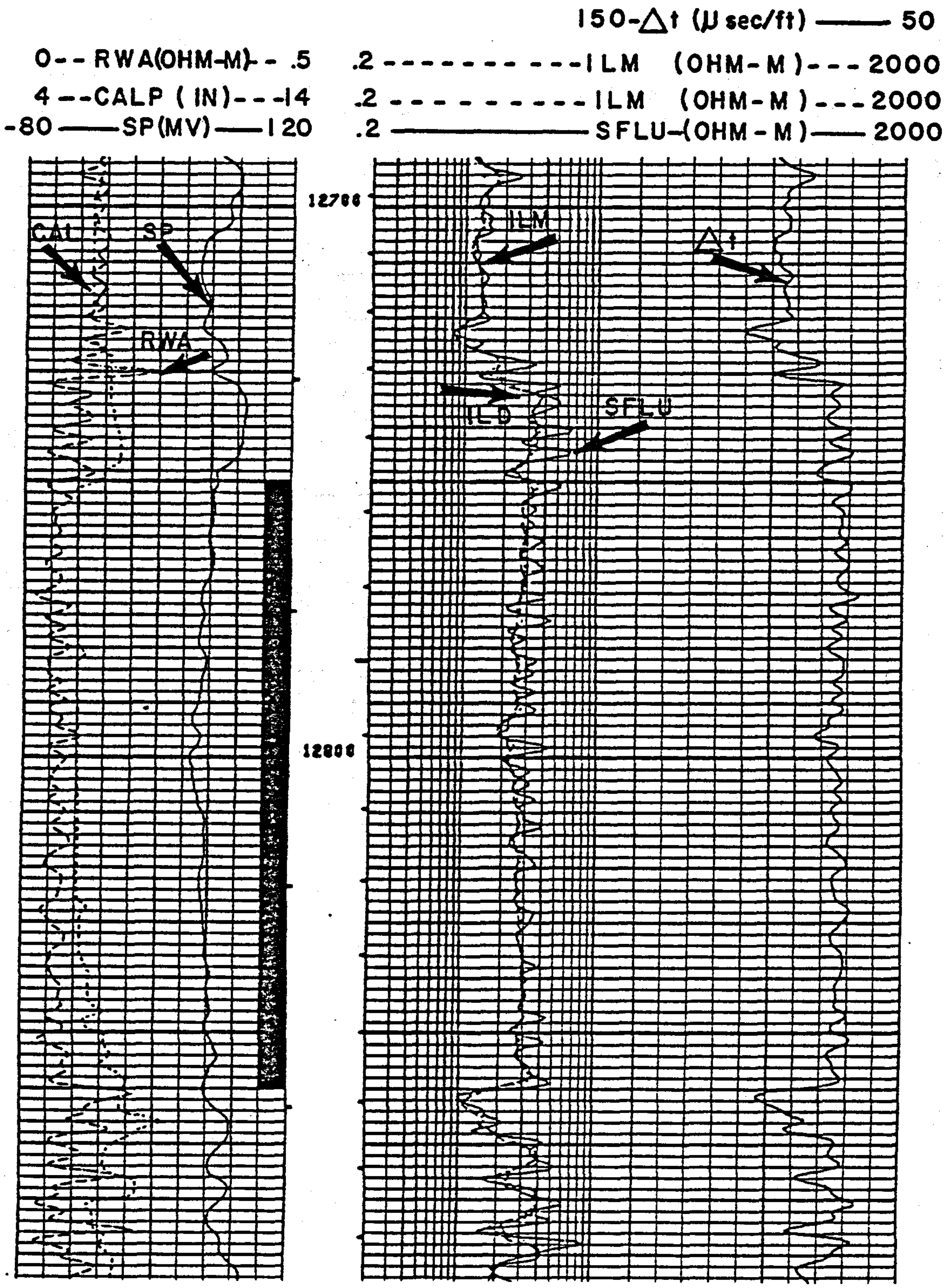


DUAL INDUCTION SFL LOG - ANDERSON SAND
COASTAL STATES NO. I PAULINE KRAFT

EXHIBIT 5-2



DUAL INDUCTION SFL SONIC LOG-ANDERSON SAND

COASTAL STATES NO.1 PAULINE KRAFT

EXHIBIT 5-3

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SIDEWALL CORE ANALYSIS

Depth feet	Recovery* inches	Permeability md	Porosity %	Residual Saturation % Total Water	Lithological* Description
12754	1/2	30	23.8	83.2	vfg slty v lmy sd, no flu
12760	1/2	39	24.0	79.8	vfg.slty v lmy sd, no flu
12772	1/4	59	25.2	76.3	vfg slty v lmy sd, no flu
12788	1/2	35	24.7	76.2	vfg slty v lmy sd, no flu
12794	1/4	83	26.0	79.0	vfg slty v lmy sd, no flu
12802	1/4	40	24.0	77.5	vfg slty v lmy sd, no flu
12823	None	–	–	–	–
12844	1/2	10	19.9	76.4	vfg slty shy lmy sd, no flu
12850	1/4	12	20.3	70.9	vfg slty shy lmy sd, no flu
12872	None	–	–	–	–

* Information obtained through Petroleum Information Well Card

EXHIBIT 5-4

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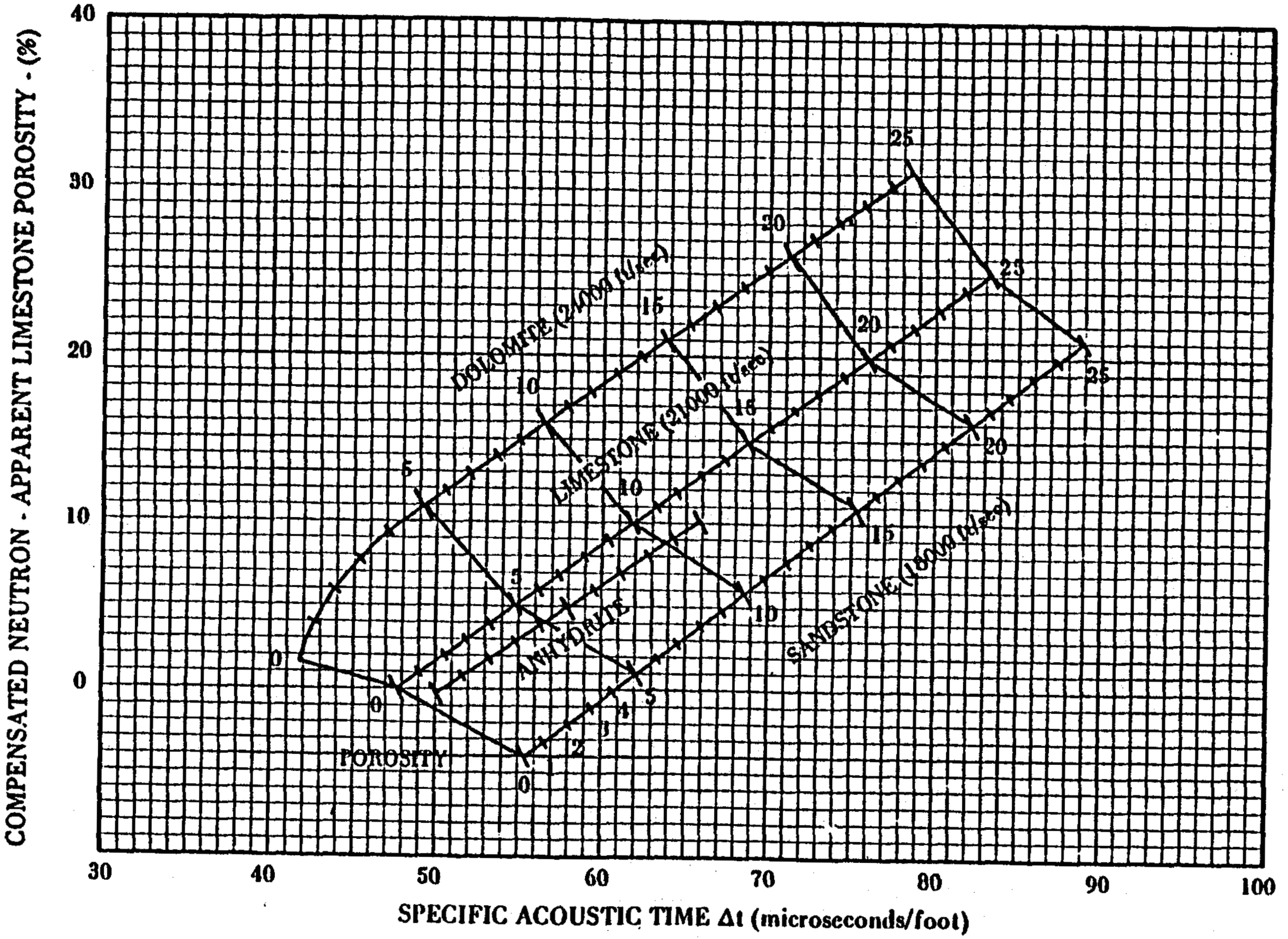
EXHIBIT 5-5



ACOUSTIC POROSITY CHART - DRESSER ATLAS

5.1.3 Permeability

The mean permeability of the Anderson sand is calculated to be 39 md, with a range of 10 to 83 md. These values are based on sidewall core data obtained from files of the original operator, Coastal States. Data from the Petroleum Information well card of the No. 1 Pauline Kraft lists sidewall core recovery and lithological description not included in the information received from Coastal States. The lower quarter of the Anderson sand is described as a very fine-grained, silty shaley limey sand, while the upper three fourths is a very fine-grained, silty, very limey sand. The high lime content in the sand may occur as a secondary cementing agent and therefore reduce the permeability values stated in Exhibit 5-4.

5.1.4 Salinity

A water sample was not obtained from the Anderson sand, and therefore there is no measured water salinity available. The primary reasons for the lack of a sample are lower actual formation permeabilities than calculated and the subsequent completion problems.

The estimated formation water salinity based upon well log analysis ranges from 2000 ppm to 48,000 ppm. These values were determined by the following methods.

1. Conventional SP method
2. RWA method
3. Dunlap Kf method
4. Conductivity - Salinity method
5. Shale Resistivity method

5.1.4.1 Conventional SP Method: The estimated salinity using the Conventional SP (spontaneous potential) method is 37,000 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 Welex "Resistivity Salinity" graph (Exhibit 5-6). The equations used in determining formation fluid resistivity are as follows:

$$SSP = -(60 + 0.133T_f) \log R_{mf}/R_{we} \qquad \text{(Equation 1)}$$

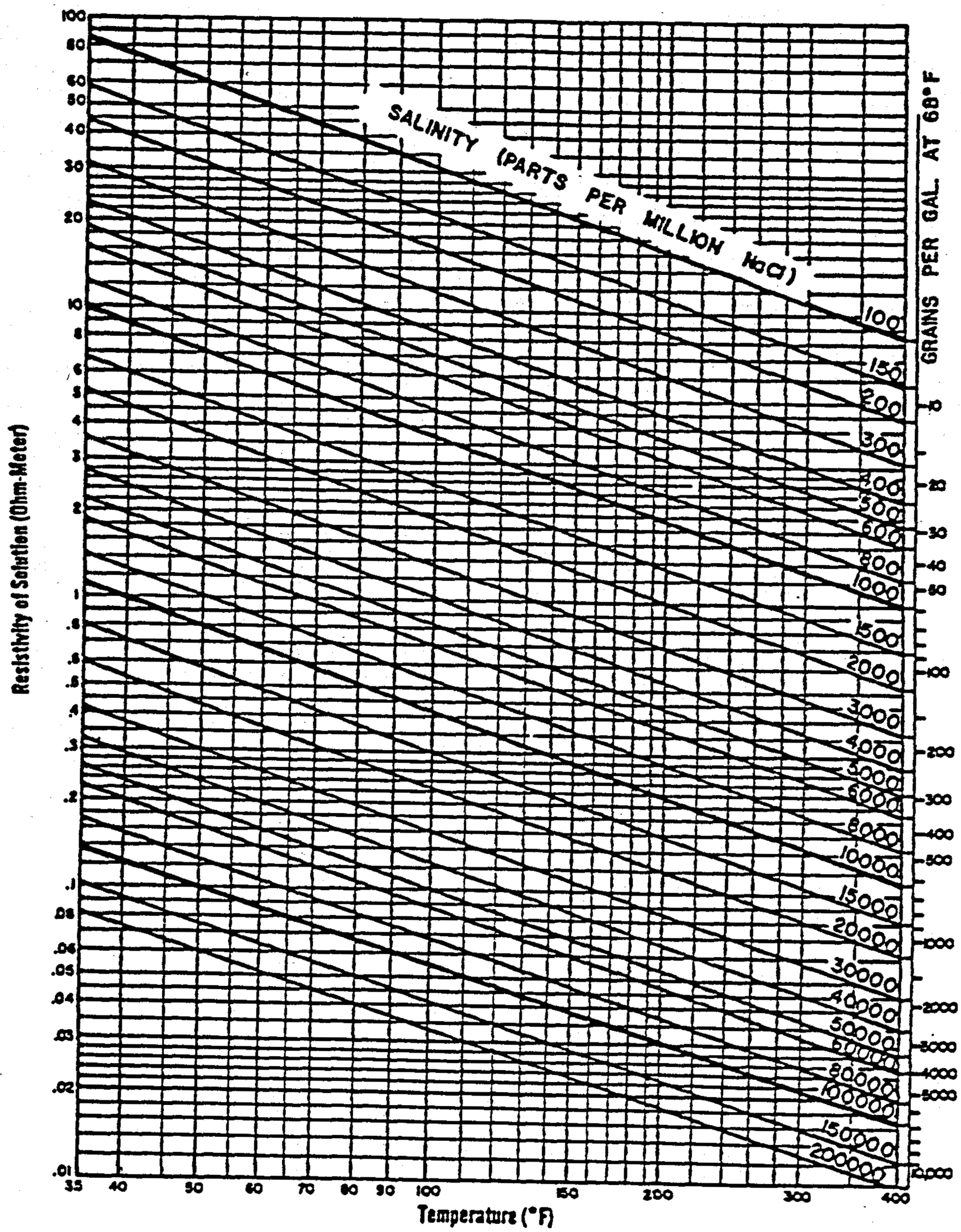
Solving for R_{we}:

$$R_{we} = R_{mf} \left[10^{SSP/(60 + 0.133T_f)}\right] \qquad \text{(Equation 2)}$$

where:

SSP = static spontaneous potential - millivolts

T_f = formation temperature - ^oF



RESISTIVITY SALINITY CHART - WELEX

EXHIBIT 5-6

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R_{mf}	=	resistivity of mud filtrate - ohm-m
R_{we}	=	equivalent formation fluid resistivity - ohm-m

and:

maximum SP (uncorrected)	= -16 mv	
corrected SSP	= -16 mv	(Exhibit 5-7)
temperature (uncorrected)	= 263 F	
R_{mf}	= .484 ohm-m @ 60^{o} F	
	= .12 ohm-m @ 263^{o} F	(Exhibit 5-6)
R_{we}	= .081 ohm-m	(Equation 2)
R_w	= .056 ohm-m	(Exhibit 5-8)
Salinity	= 37,000 ppm	(Exhibit 5-6)

5.1.4.2 **RWA Method:** An estimated salinity of 9600 ppm was calculated using the RWA Method and was determined primarily as a function of porosity and true formation resistivity. The mathematical equation is as follows:

$$F = R_o/R_w \quad \text{(Equation 3)}$$

$$F = .81/\phi^2 \quad \text{(Equation 4)}$$

$$R_o/R_w = .81/\phi^2 \quad \text{(Equation 5)}$$

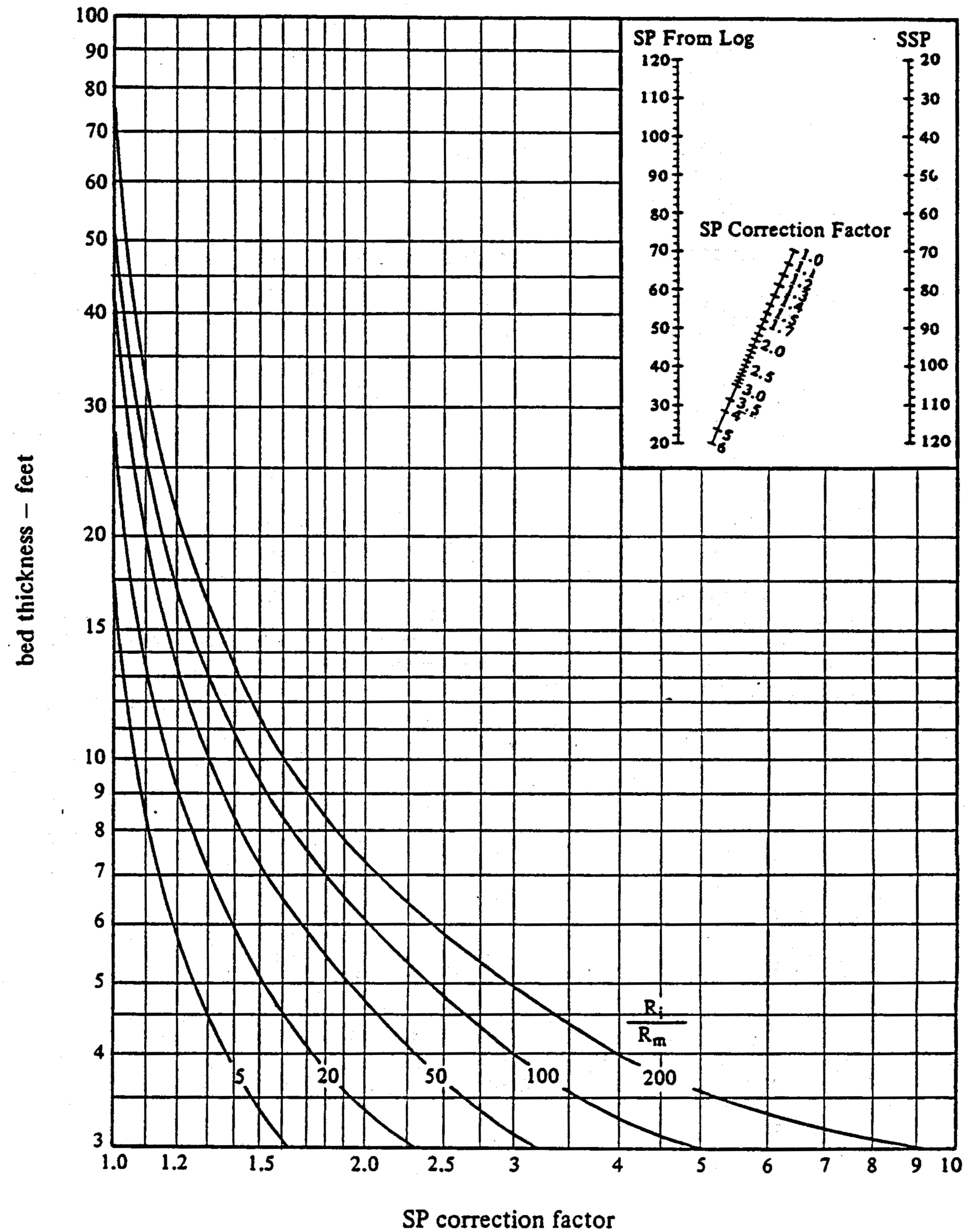
$$R_w = R_o \phi^2/.81 \quad \text{(Equation 6)}$$

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 - %

and:

R_t	=	2.7 ohm-m
ϕ	=	23%



SP CORRECTION CHART — DRESSER ATLAS

EXHIBIT 5-7

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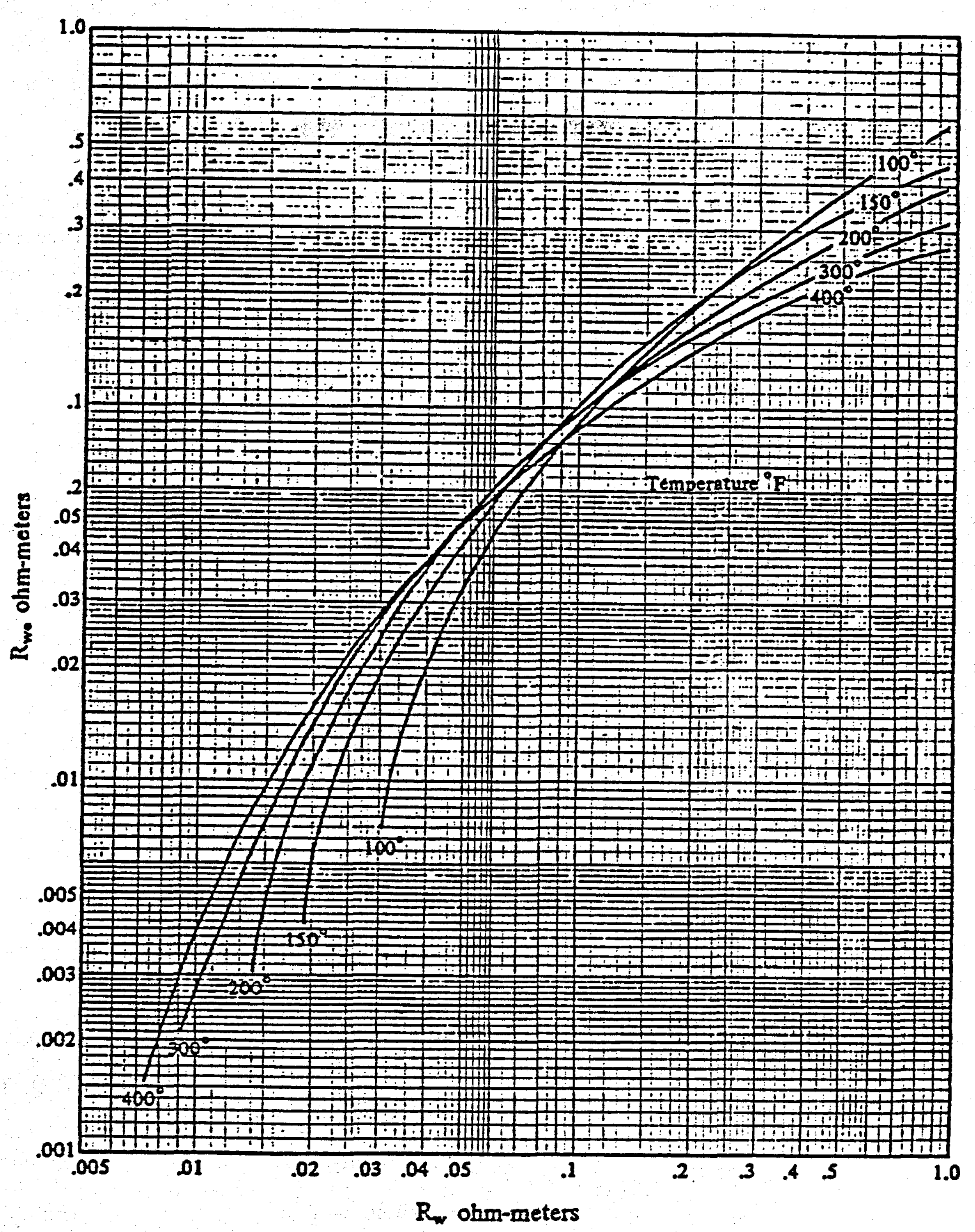


Rw FROM RWE CHART - DRESSER ATLAS

EXHIBIT 5-8

Assuming a 100% water-saturated formation where $R_t = R_o$, (Equation 6), and the previously listed log-derived parameters, an apparent formation water resistivity of 0.176 ohm-m is obtained. Plotting the formation water resistivity on the Welex Resistivity Salinity graph (Exhibit 5-6) yields a salinity of 9600 ppm.

5.1.4.3 **Dunlap K_f Method:** An estimated salinity of 37,000 was calculated using Henry Dunlap's K_f Method. This value was calculated by obtaining a corrected R_{mf} using Dunlap's $K_f = R_{mf}/R_m$ vs. Mud Weight, his geologic age and correction and additional graphs and using the SP Method of salinity determination (Exhibit 5-9 thru 5-11). The equations used in correcting R_{mf} are as follows:

$$K_f = R_{mf}/R_m \qquad \text{(Equation 7)}$$

solving for R_{mf}:

$$R_{mf} = K_f R_m \qquad \text{(Equation 8)}$$

where:

R_{mf} = mud filtrate resistivity - ohm-m

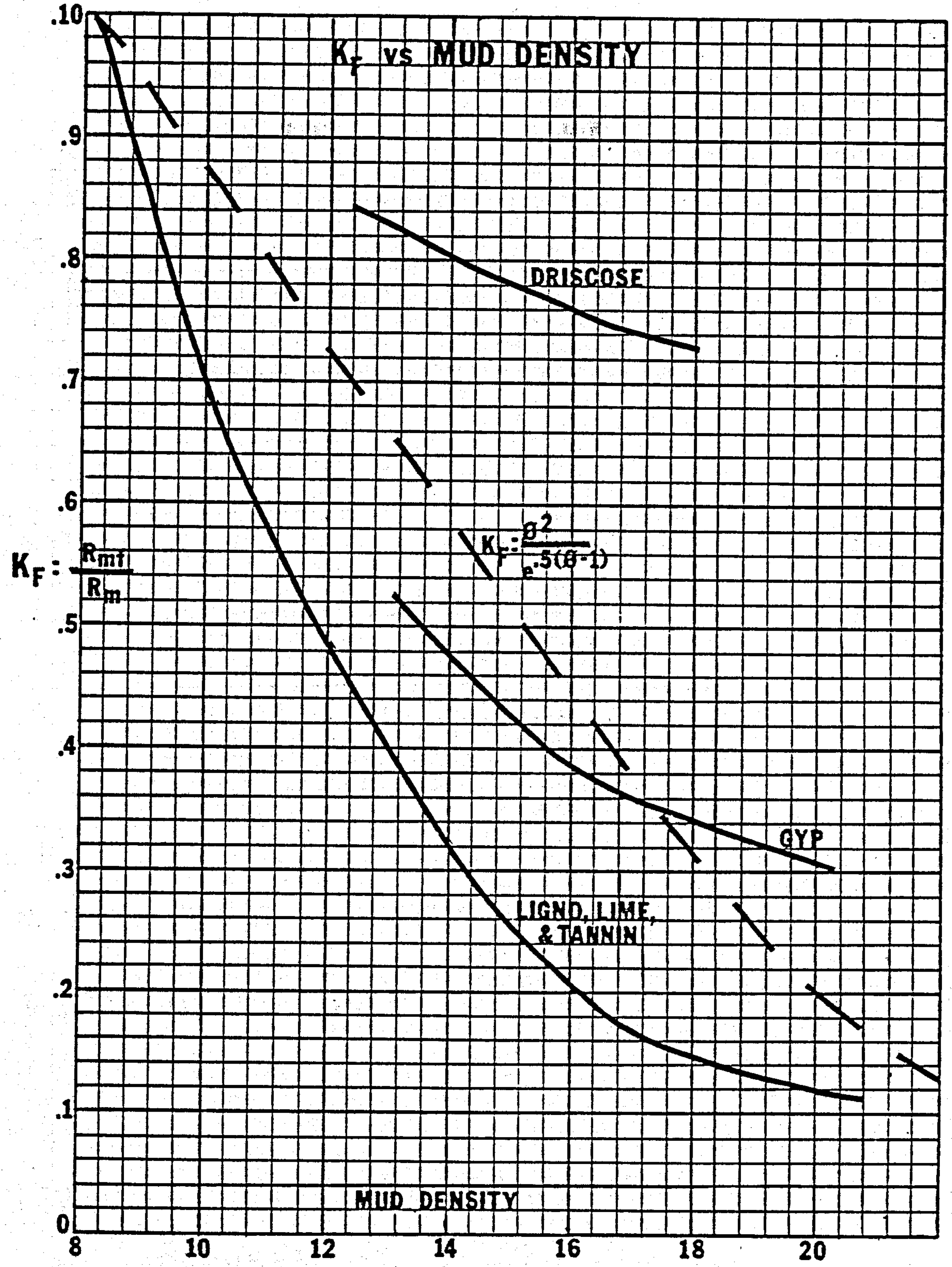
R_m = mud resistivity - ohm-m

K_f = constant - dimensionless

MD = mud density - ppg

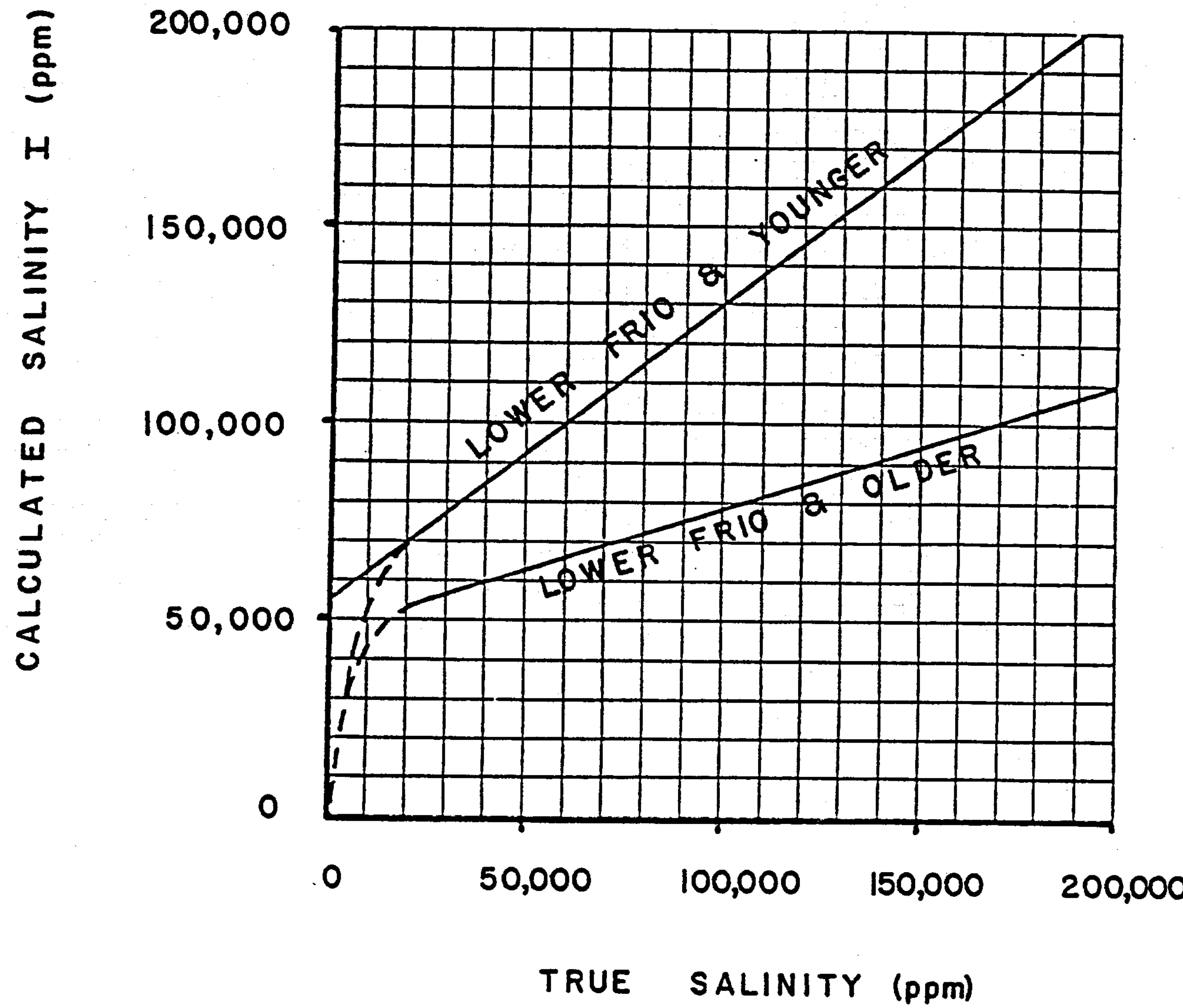
and:

SP (corrected)	= -16 mv	
R_m (uncorrected)	= 1.3 ohm-m @ 60° F	
MD	= 16.6 ppg	
K_f	= .18	(Exhibit 5-9)
R_{mf}	= .234 ohm-m @ 60° F .06 ohm-m @ 263° F	(Equation 8)
R_{we}	= .041 ohm-m	(Equation 2)
R_w	= .043 ohm-m	(Exhibit 5-8)
Salinity (uncorrected)	= 37,000 ppm	(Exhibit 5-6)



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

EXHIBIT 5-9



GEOLOGIC AGE SALINITY CORRECTION

H.F. DUNLAP, FEBRUARY 1981

EXHIBIT 5-10

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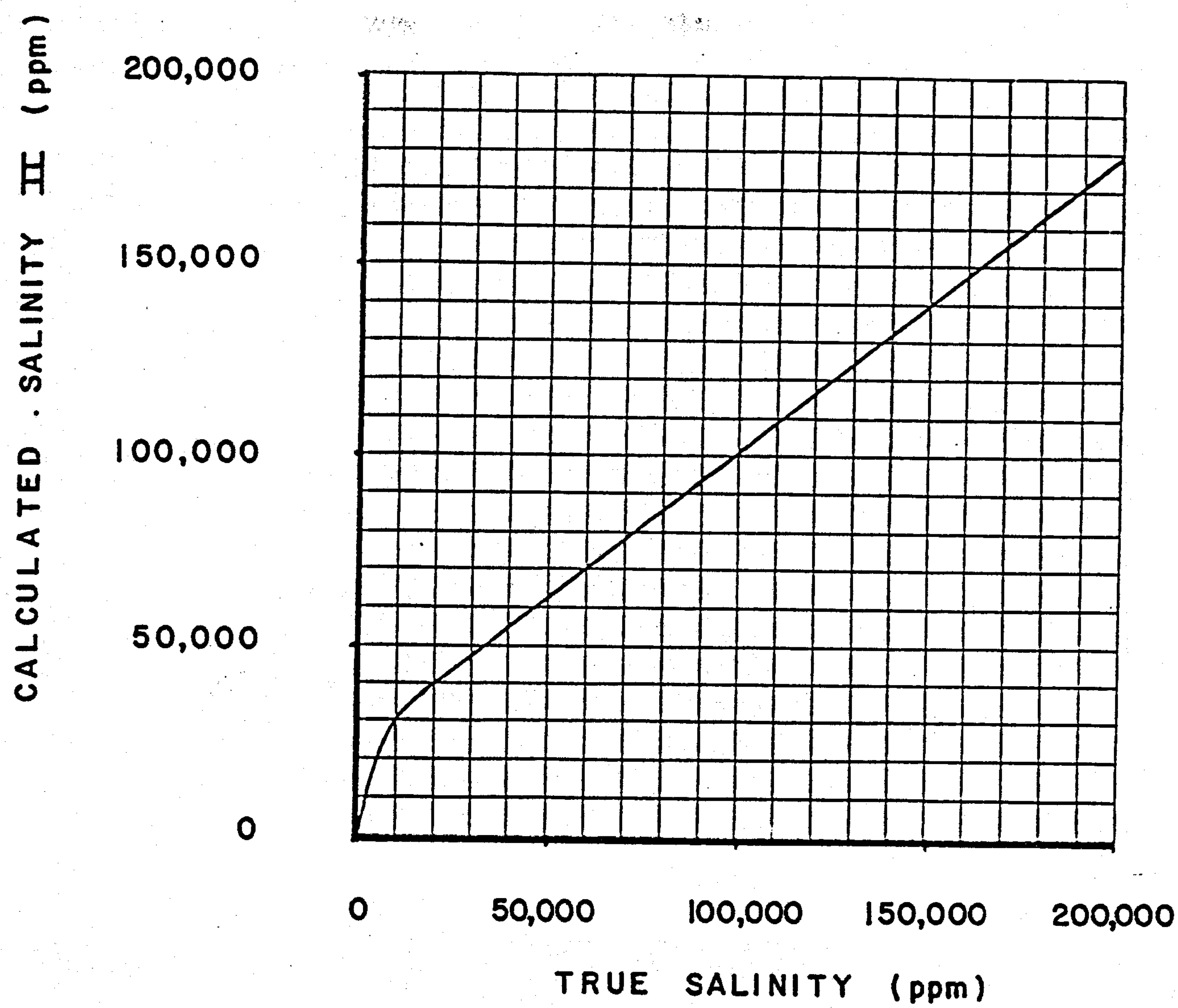

SALINITY CORRECTION CHART II

H.F. DUNLAP, MARCH 1981

EXHIBIT 5-11

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Salinity (corrected I) = 8,000 ppm		(Exhibit 5-10)
Salinity (corrected II) = 2,000 ppm		(Exhibit 5-11)

5.1.5 **Conductivity Salinity Method:** A salinity of 10,000 ppm was calculated using the Conductivity-Salinity method, a variation of the R_{wa} method. In this approach, true formation resistivity is back-calculated by means of using the conductivity of the formation. Once the true formation resistivity is known, applying the R_{wa} method gives an additional value for formation water salinity. The equation for determining this value is as follows:

$$R_t = \frac{1000}{C} \quad \text{(Equation 9)}$$

where:

R_t = true formation resistivity - ohm-m

C = conductivity - mmhos/m

T_f = formation temperature - ^oF (uncorrected)

and

C = 400 mmhos/m

T_f = 263^oF

$\emptyset$ = 23%

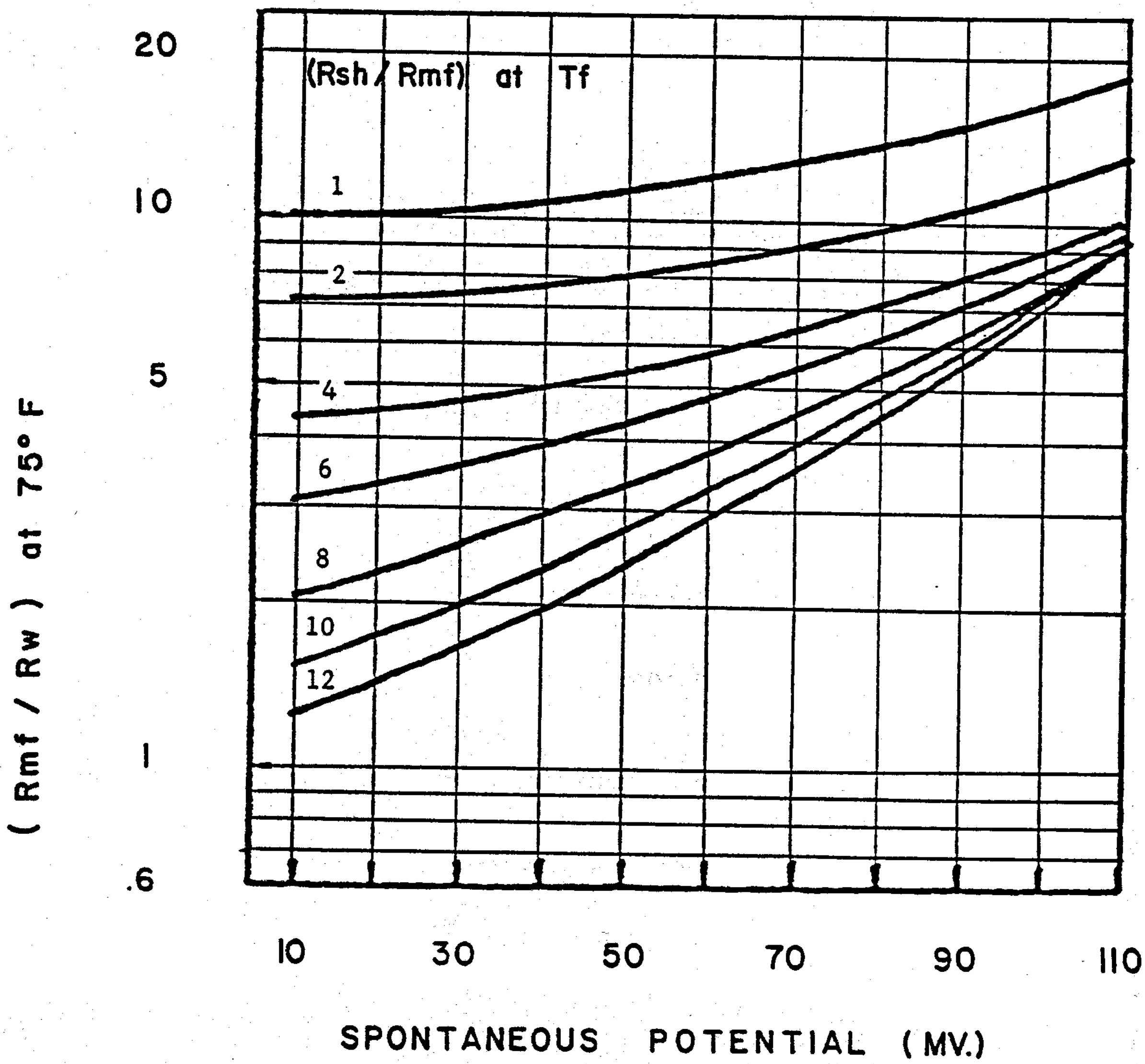
then:

R_t = 2.5 ohm-m (Equation 9)

R_w = .163 ohm-m (Equation 6)

Salinity = 10,000 ppm (Exhibit 5-6)

5.1.6 **Shale Resistivity Method:** A salinity measurement of 18,000 was estimated using Dr. K. Bassiouni's Shale Resistivity method. This value was calculated by using parameters from the SP log and solving for R_w using Bassiouni's Shale Resistivity - SP graph (Exhibit 5-12). The equations used in this calculation are as follows:



NEW SP CHART

SILVA AND BASSIOUNI JUNE 1981

EXHIBIT 5-12

$\frac{R_{sh}}{R_{mf}}$ T_f (Equation 10)

$\frac{R_{mf}}{R_w}$ 75^oF (Equation 11) (Exhibit 5-12)

where:

R_{sh} = shale resistivity - ohm-m

R_{mf} = mud filtrate resistivity - ohm-m

R_w = formation water resistivity - ohm-m

T_f = formation temperature - ^oF

and:

SP = -16 mv.

R_{sh} = 1.58 ohm-m

T_f = 263^oF

R_{mf} = .484 ohm-m @ 60^oF

.400 ohm-m @ 75^oF

.12 ohm-m @ 263^oF (Exhibit 5-6)

$\frac{1.58}{0.12}$ 263^oF = 13.167 (Equation 10)

$\frac{.400}{R_w}$ 75^oF = 1.2 (Exhibit 5-12)

R_w = .333 @ 75^oF (Equation 11)

Salinity = 18,000 ppm (Exhibit 5-6)

The variations in methods of salinity calculation give rise to a range of values from 2000 ppm to 48,000 ppm. At the time of publication a measured salinity value of the Anderson sand is not available to correlate to any of these calculated values.

5.2 Open Hole Log Analysis - Disposal Well

The Pauline Kraft SWD No. 1 well was drilled for saltwater disposal to a depth of 5275 feet. Four potential disposal sands were encountered (Exhibits 5-13 and 5-14) and are identified as follows:

Sand "A"	4702' - 4816'
Sand "B"	4453' - 4556'
Sand "C"	3872' - 3920'
Sand "D"	3748' - 3820'

The disposal well was completed into both Sand "A" and Sand "B". (Exhibits 5-15 and 5-16). These sands exhibit the following log-derived parameters:

	Sand A	Sand B
net sand	93'	97'
porosity	26%	25%
salinity	45,000 ppm	32,000 ppm
temperature	160° F	156° F
pressure	2228 psi	2109 psi

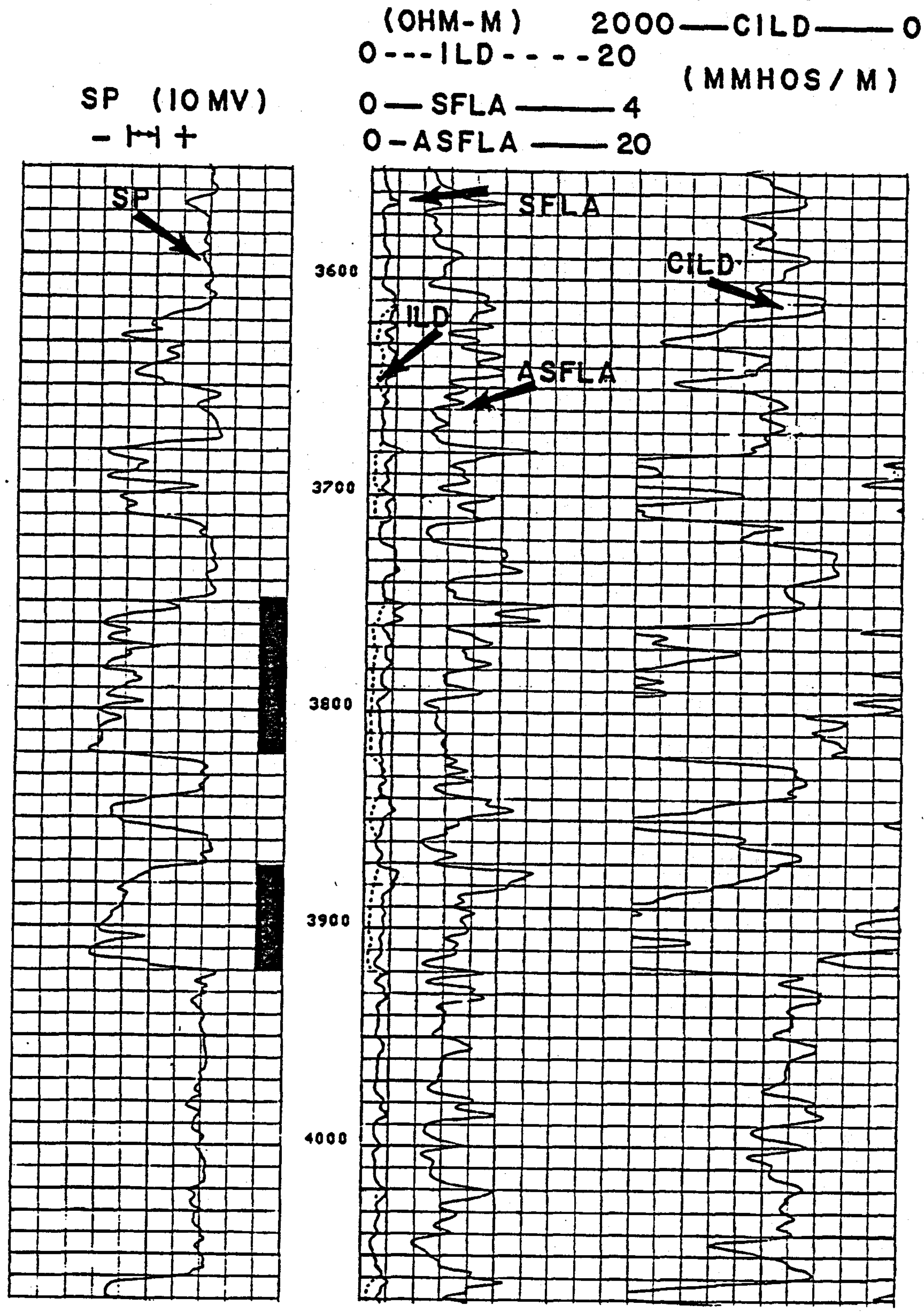
5.3 Cased Hole Log Analysis - Test Well

A Variable Density Cement Bond Log was run in the test well after the cementing of the 5-inch production string. This log gave Eaton the following data:

1. Integrity of casing vs. cement and cement vs. formation bonding.

2. Correlation between open hole and casing collars.

Analysis of the test well cement bond log (Exhibit 5-17) indicated that the Anderson Sand (12,750' to 12,860') was poorly bonded. The first available sand above the Anderson, lying within the 7-inch intermediate casing, showed excellent bonding, thus isolating the test zone.



INDUCTION SFL LOG - CATAHOULA SANDS
COASTAL STATES NO. 1 - SWD PAULINE KRAFT

EXHIBIT 5-13

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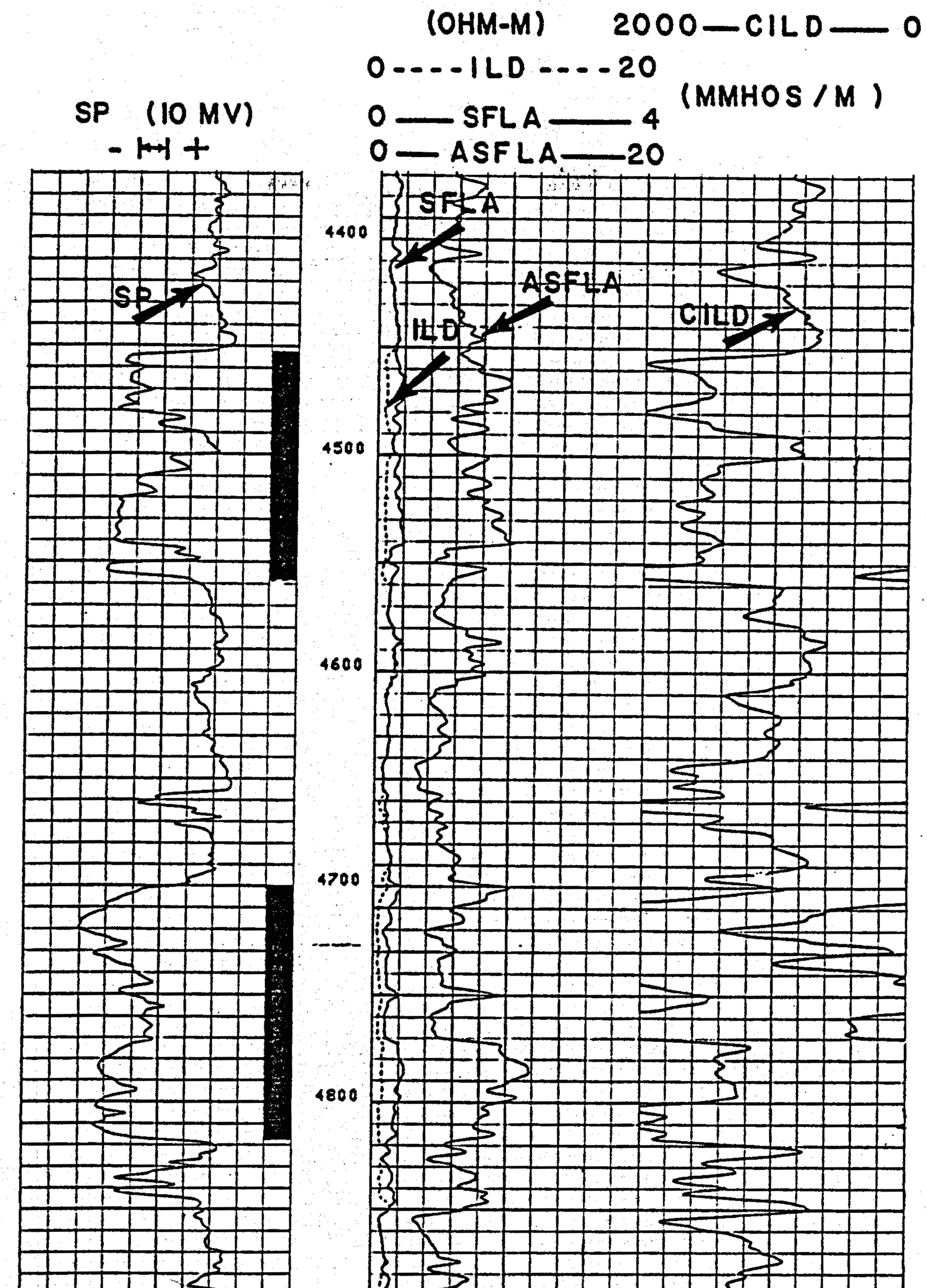
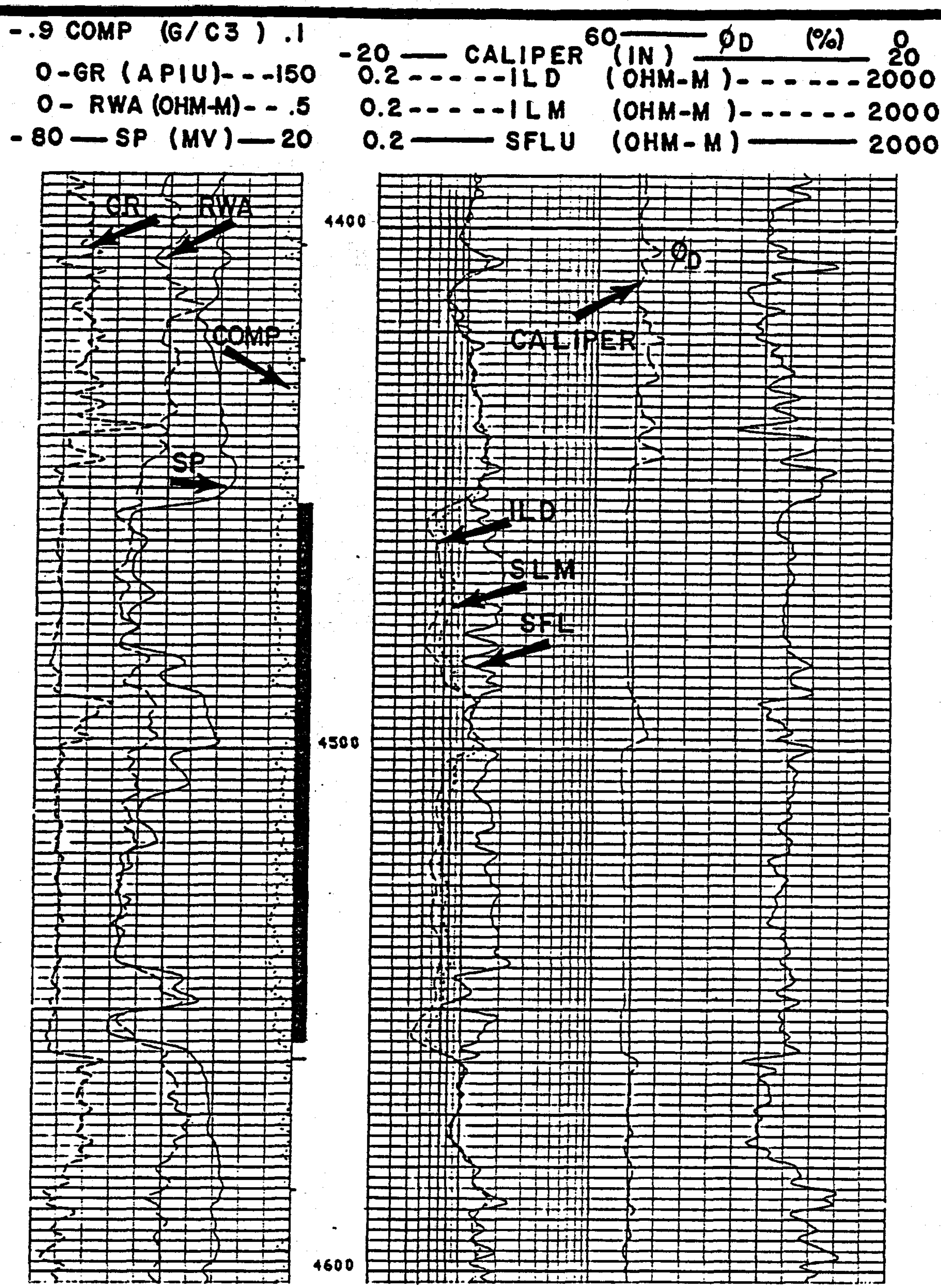


INDUCTION - SFL LOG — CATAHOULA SANDS
COASTAL STATES NO. 1- SWD PAULINE KRAFT

EXHIBIT 5-14



INDUCTION SFL DENSITY LOG - ANDERSON SAND

COASTAL STATES NO. 1 SWD PAULINE KRAFT

EXHIBIT 5-15

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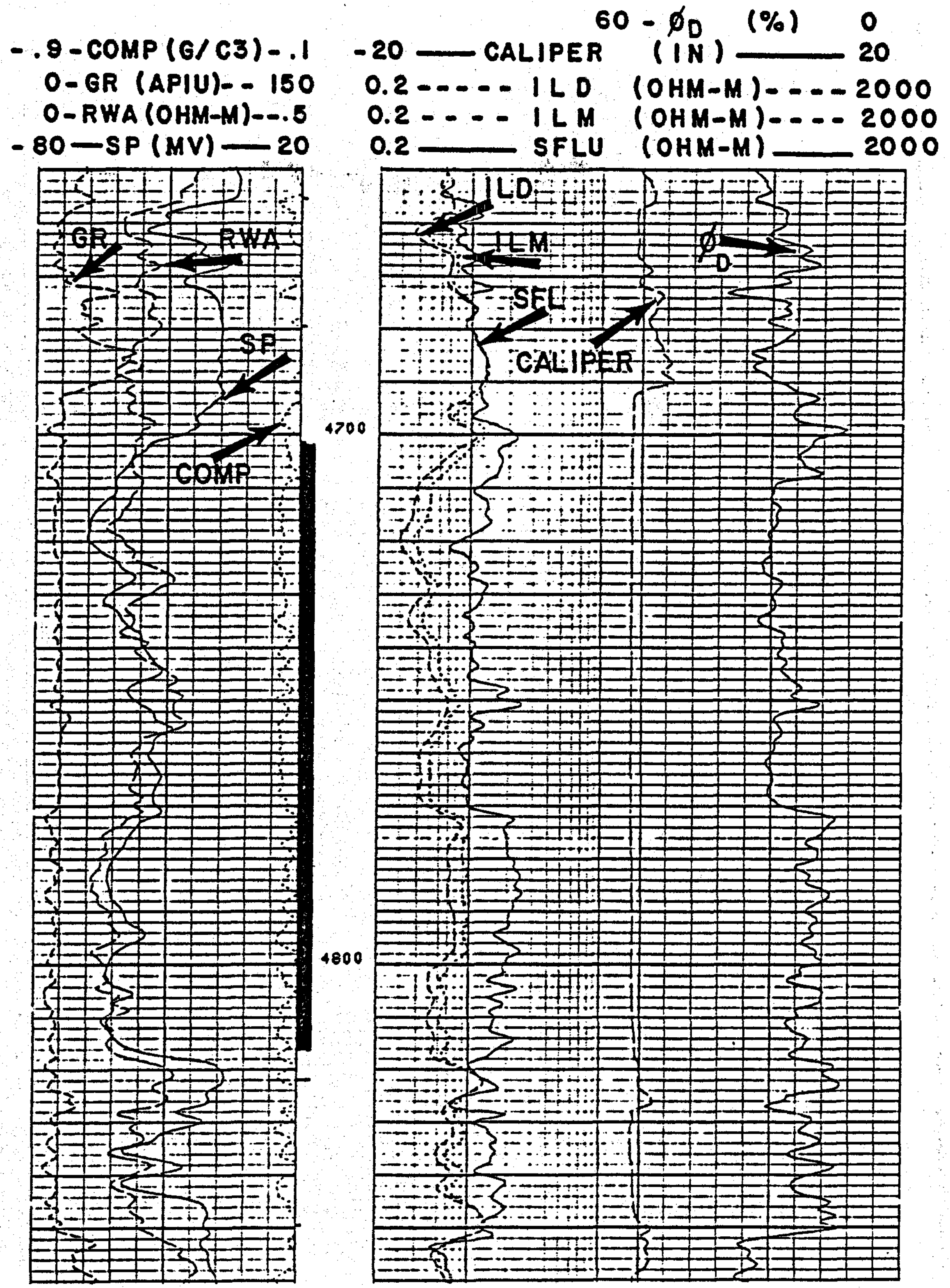
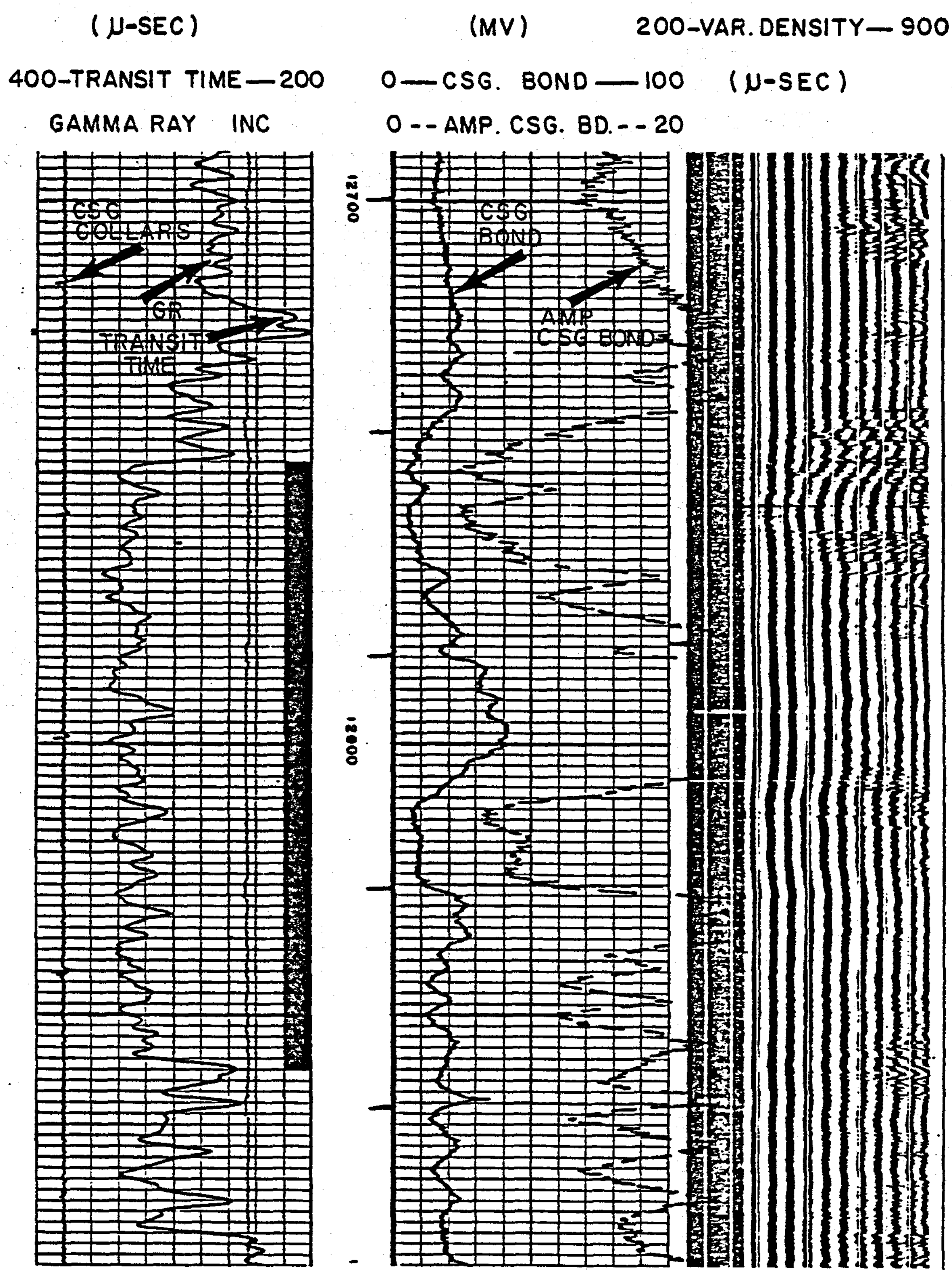


INDUCTION SFL DENSITY LOG - ANDERSON SAND
COASTAL STATES NO.1 - SWD PAULINE KRAFT

EXHIBIT 5-16

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



VARIABLE DENSITY BOND LOG – ANDERSON SAND

COASTAL STATES NO. 1 PAULINE KRAFT

EXHIBIT 5-17

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

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 Exhibit 6-1 accommodated drilling and workover equipment used for completion of the test well and drilling of the disposal well. The site was covered with boards for the support of test equipment after rig operations ceased.

Rain water, waste oil, and grease spillage were trapped and drained into a ditch around the location for disposal.

6.1.2 Living Facilities and Utilities

Air-conditioned living facilities were provided for six individuals. An additional trailer to accommodate four individuals was scheduled for delivery but was never required, due to the early end of the test. Motel accommodations were available in Corpus Christi, Texas.

Water for drilling and other operations was obtained from a 224-foot fresh water well drilled on location. Drinking water was brought to the site by a local water delivery service.

Two telephones were installed in the Eaton house trailers. Electrical power was brought in from a nearby power line.

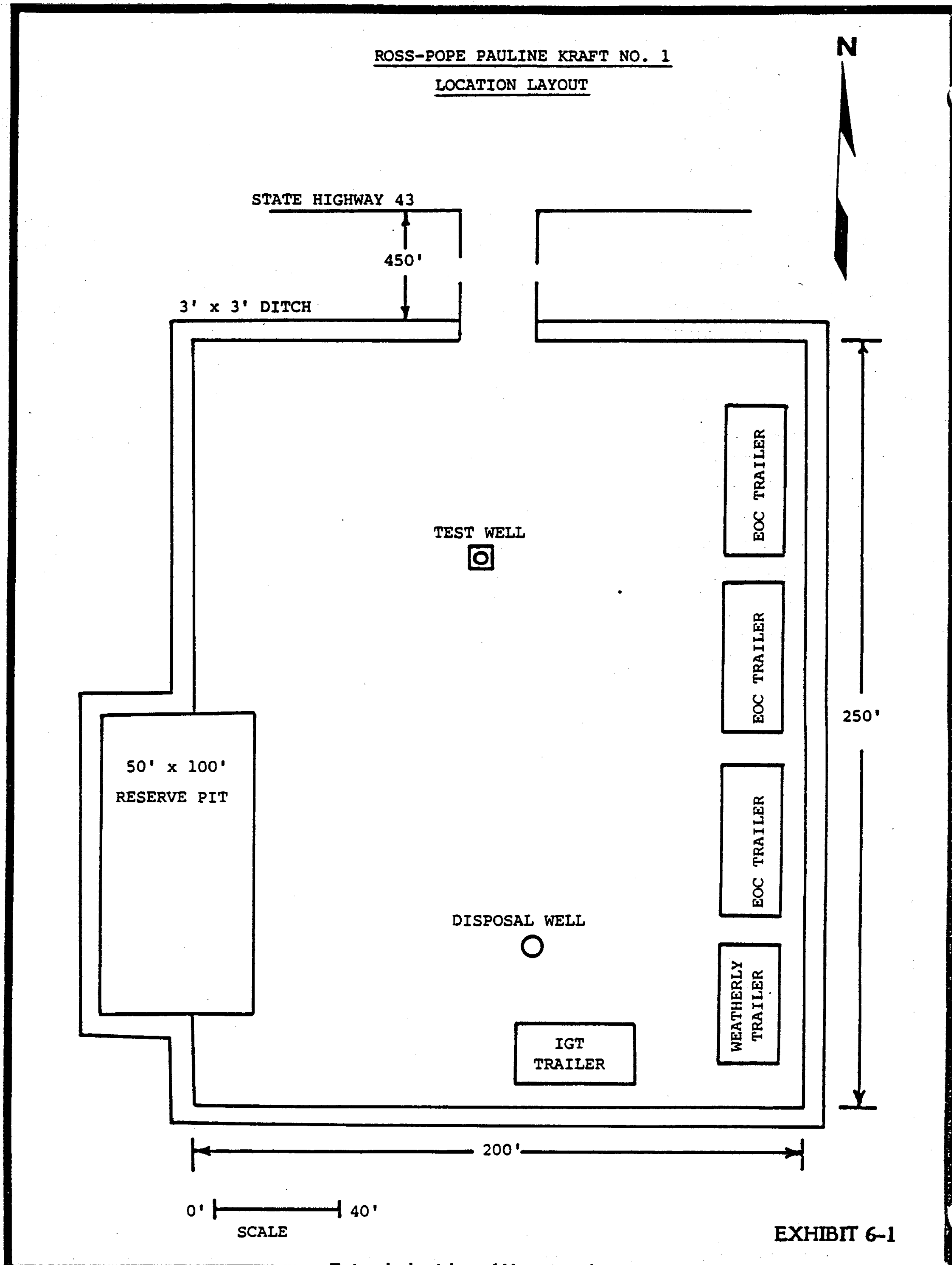

EXHIBIT 6-1

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Photo 6-1 Field of recently planted sorghum. Protection dike in foreground.

Photo 6-2 Entrance road to location. Note electric power lines, left of center.

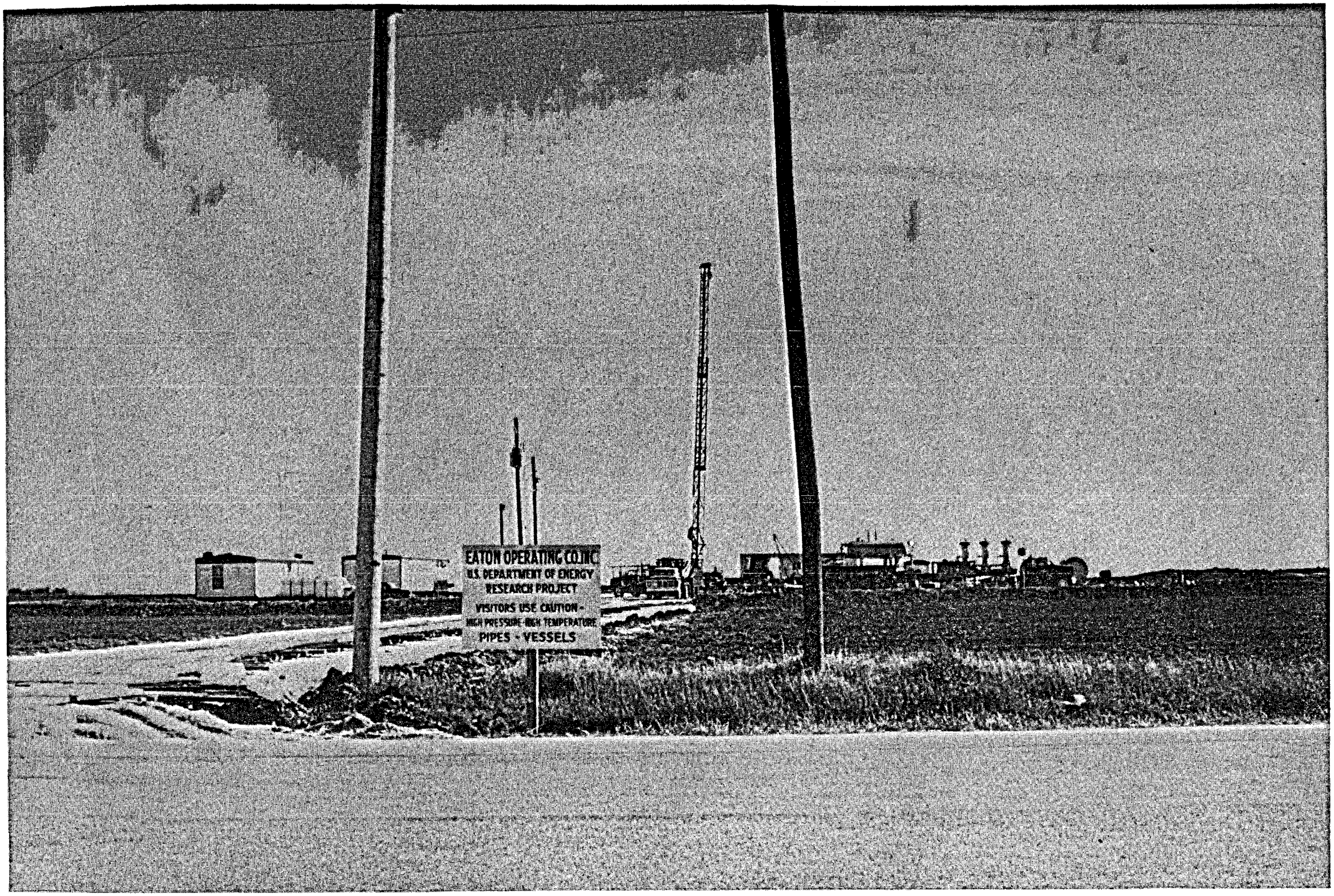


Photo 6-3 View of location from Texas Highway No. 43.

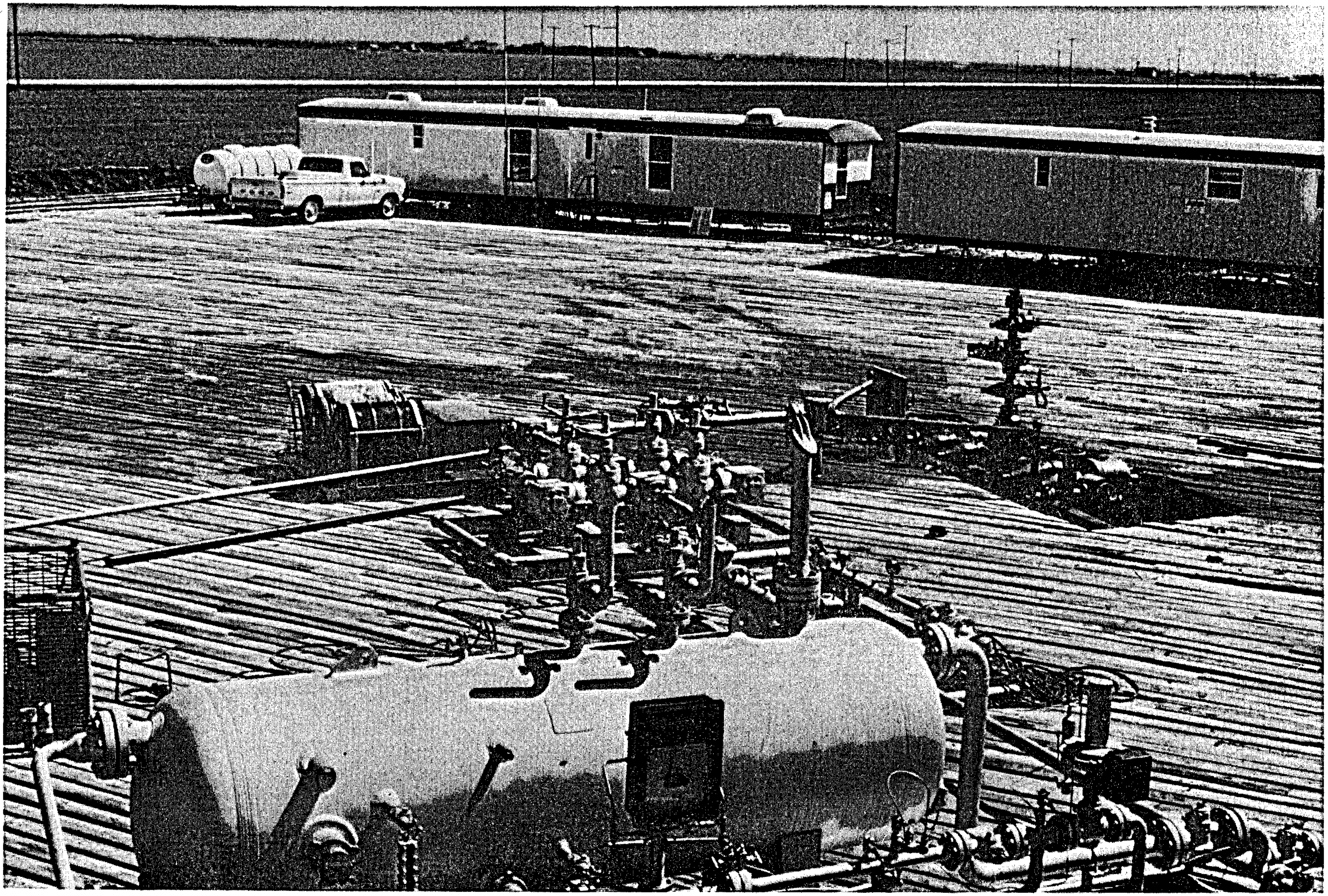
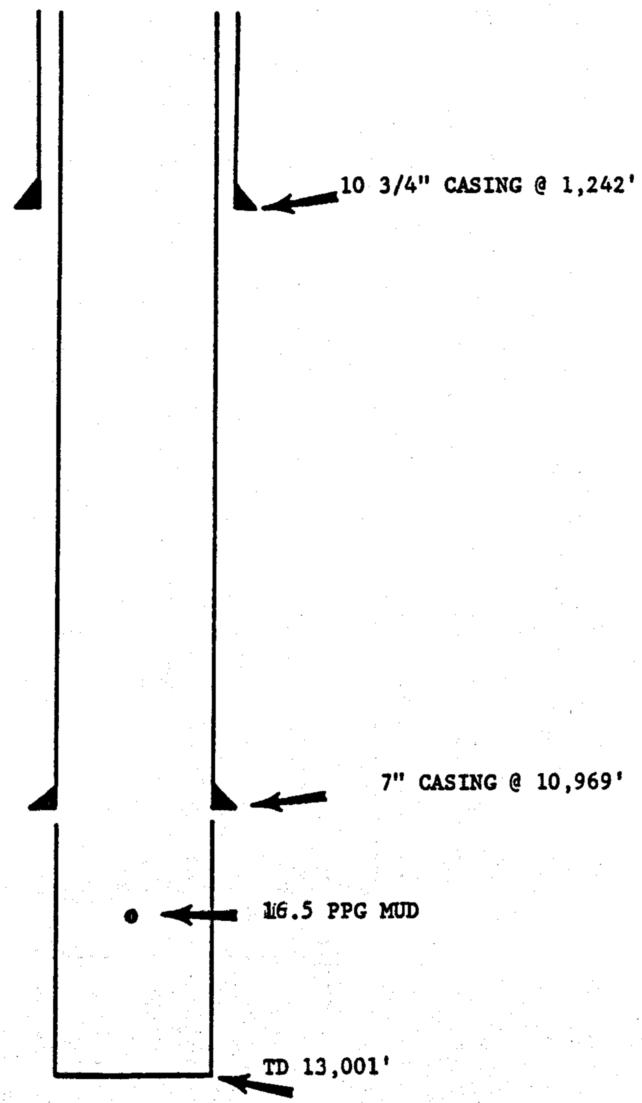


Photo 6-4 Living trailers in background. Drinking water tank to left of trailers.

6.2 Test Well Design

6.2.1 Initial and Actual Well Completion Status

Exhibit 6-2 is a schematic drawing of the test well, showing its condition when Eaton took over operations from Ross-Pope Drilling Equipment Company, Inc. The well had been re-entered, splices had been made on the surface and intermediate casing strings, and the open hole had been cleaned out to the original total depth.



ROSS - POPE PAULINE KRAFT NO. 1
CONDITION AT TIME OF EATON TAKEOVER

EXHIBIT 6-2

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

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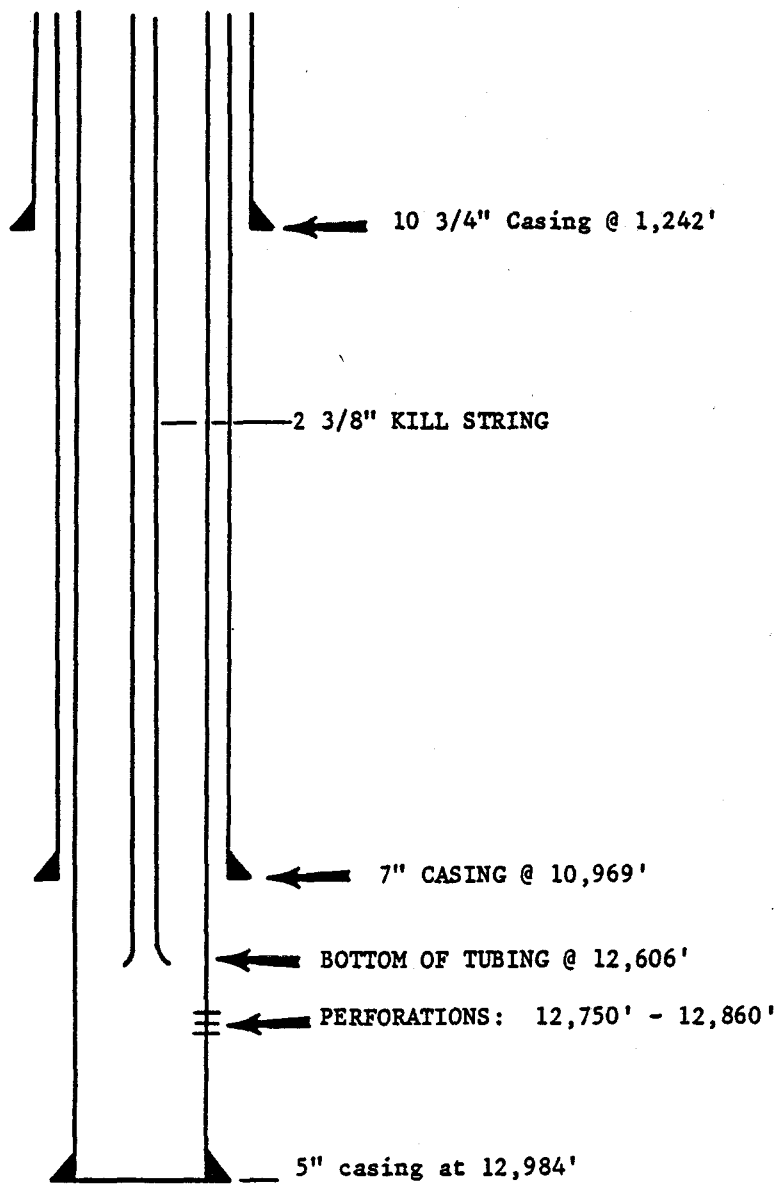
Exhibit 6-3 is a schematic diagram illustrating the tubular configuration of the well as completed for testing. A string of 5-inch casing was set at 12,984 feet. The tubing was hung open-ended in the 5-inch casing. The well was filled with 9.0 pound per gallon saltwater. The well was perforated from 12,750 to 12,860 feet, using wireline perforating guns run through the tubing.



ROSS - POPE PAULINE KRAFT NO. 1
CONDITION DURING TESTING

EXHIBIT 6-3

6.2.2 Tubular Goods Design

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

ROSS-POPE PAULINE KRAFT WELL NO. 1

TUBULAR GOODS 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	NA	NA	NA	NA	NA	NA	NA	*	*	*
Surface Casing	10-3/4	0	1,242	NA	NA	NA	NA	*	*	*
Intermediate Casing	7	0	10,969	NA	NA	NA	NA	*	*	*
Production Casing	5	0	739	18	4.151	P-110	SFJ	2.62	**	1.26
		739	7,244	23	3.919	L-80	FL4S	2.91	**	1.46
		7,244	13,000	18	4.151	L-80	FL4S	**	1.94	**
Tubing	2-3/8	0	12,606	4.7	1.995	N-80	8RD	**	**	1.90

CEMENTING SUMMARY

Casing	O.D. Size (in.)	Hole Size (in.)	Cementing Summary
Surface	10-3/4	NA	NA
Intermediate	7	NA	NA
Production	5	7-1/2	Cemented with 500 sacks Class "H" cement with 35% SSA-2 silica flour, 0.75% CRF-2, 0.4% halad 22-A, 0.4% HR-8 retarder and 3% KCl in a 17.0 slurry. Ran 10 bbls. SAM spacer ahead.

Note: 10-3/4" and 7" casing run, cemented, and tested by Coastal States.

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

** Safety factors either very high or no longer exposed to well bore conditions.

EXHIBIT 6-4

6.2.3 Wellhead Design

Exhibit 6-5 is a schematic of the wellhead and christmas tree used for this well. The tree was designed using some 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 five hand-operated gate valves and two pneumatic-operated surface safety valves. A "swab" valve was installed on top for wireline accessability. Two flow loops were used to balance bending moments and to reduce friction near the top of the tree during maximum flow conditions. Fluid flow through the loops was controlled by a choke manifold located downstream of the point where the flow loops joined.

CHRISTMAS TREE SCHEMATIC

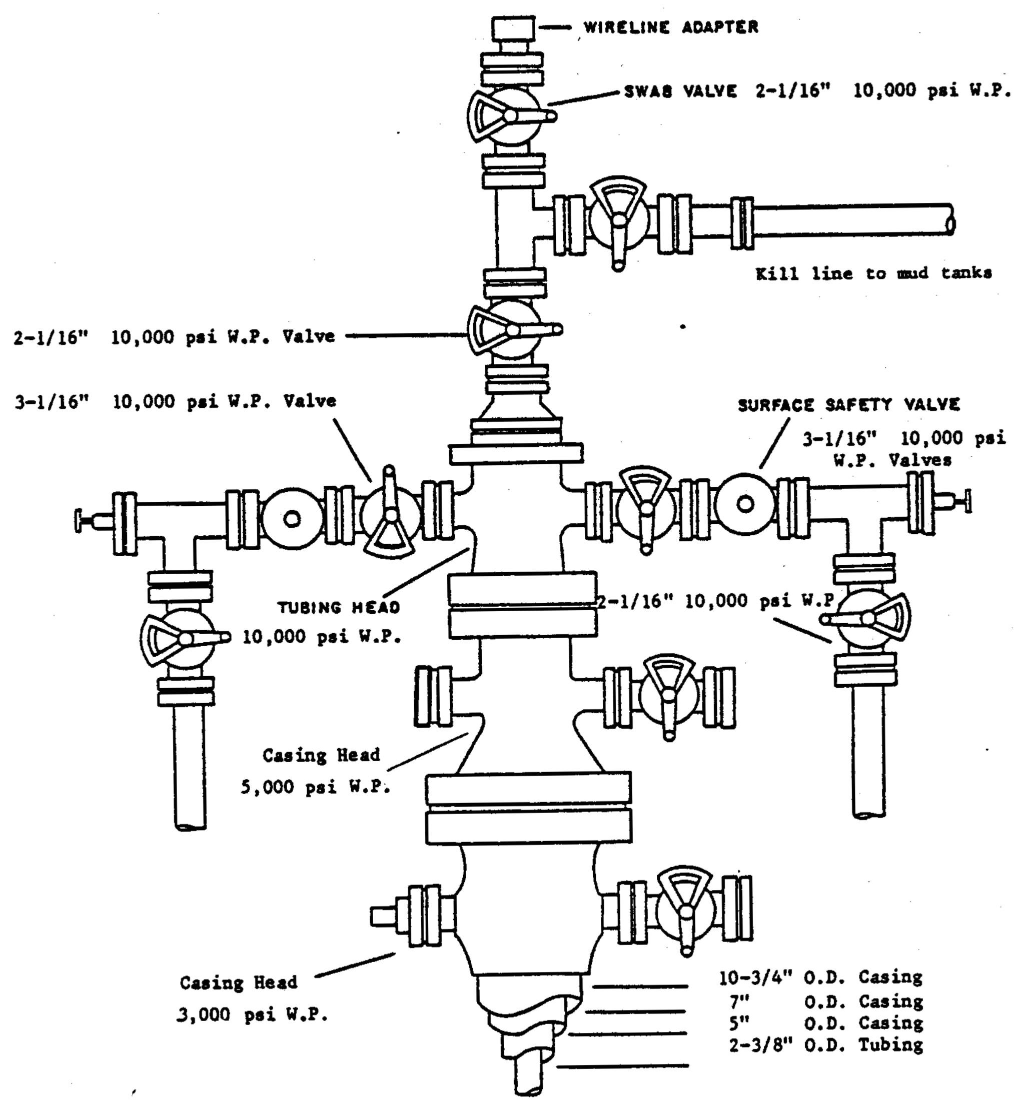


EXHIBIT 6-5

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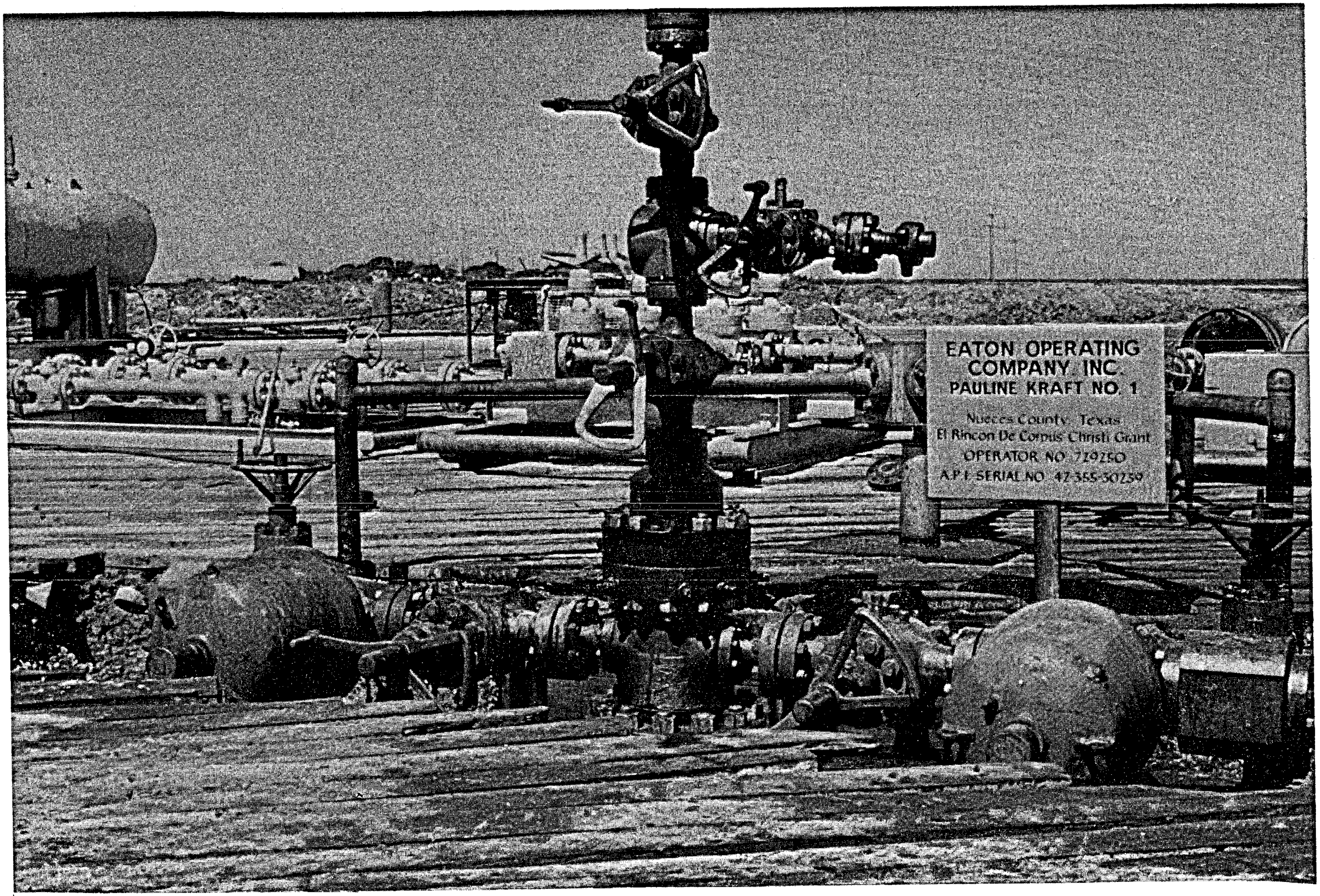


Photo 6-5 Christmas tree designed for annular flow and 10,000 psi working pressure.

Photo 6-6 Test well and surface equipment ready for testing.

6.2.4 Logging Program

After the well was cleaned out, a suite of logs was run to supplement the original logs run by Coastal States. A gamma-ray, cement bond, and casing collar locator log was run, after 5-inch casing had been run and cemented, to evaluate formation isolation and to serve as a reference for perforation operations. Prior to running the 5-inch casing, a casing inspection log was run from the bottom of the 7-inch intermediate casing at 10,969 feet to the surface.

6.3 Re-Entry Operations

The Target Rig Number 14 was moved to the Pauline Kraft No. 1 location in early December, 1980, by Ross to commence re-entry and completion operations on the test well. Eaton assumed operation of the well on December 19, 1980 when Ross reached the original total depth of 13,002 feet. The well was circulated to condition mud, and the drill string was pulled to run a log in the open hole section. Schlumberger ran an ISF-Sonic-Caliper log from total depth of 13,002 feet to the bottom of the 7-inch casing at 10,969 feet. Dia-Log then rigged up and ran a casing inspection log in the 7-inch casing from 10,969 feet to the surface. The casing inspection log indicated the 7-inch casing to be in a safe and satisfactory condition for the operating conditions anticipated.

A 7-1/2 inch underreamer was made up on the drill string and run in the hole. The hole was underreamed from 12,005 feet to 12,990 feet. The drill string and underreamer were pulled from the hole. A 7-inch retrievable bridge plug was made up on the drill string, run in the hole, set at 998 feet, and the drill string was pulled out of the hole. The bell nipple and blowout preventers were nippled down and removed to give access to the 10-3/4 inch and 7-inch casing strings. A spear was made up on the drill pipe, run in the 7-inch casing approximately 100 feet and a hold was made on the 7-inch casing. A pull of 80,000 pounds was made on the 7-inch casing. A cut was made on the 10-3/4 inch casing, and a new 10-3/4 inch collar and nipple were welded onto the 10-3/4 inch casing string to give a safer splice on the casing. The 7-inch casing was then set on conventional casing slips in lieu of the welded plate steel ring previously used. The blowout preventers were nippled up, and the hole filled with mud. The drill string was run in the hole, and the retrievable bridge plug at 998 feet was retrieved. A mill and bit sub were made up on the drill string and run in the hole to 13,002 feet, and the hole was circulated clean in preparation for running production casing.

6.4 Completion Operations

A lay-down machine was rigged up and the drill pipe laid down. Casing tools were rigged up to run 5-inch casing. Production casing consisting of 325 joints of 5-inch 18 lb/ft, L-80 FL4S, 23 lb/ft, L-80 FL4S, and 18 lb/ft P-110 SFJ was set at 12,984 feet. A down-jet float shoe was run on the bottom joint, and a float collar was run one joint off bottom. The casing was reciprocated through a 10-foot stroke before cementing. The hole was circulated clean, and Halliburton rigged up to cement the casing/open hole annulus. The pipe was cemented in place with 500 sacks of Class H cement with 35% SSA-2 silica flour, 0.75% CFR-2, 0.4% Halad 22-A, 0.4% MR-8 retarder, and 3% KCl in a 17.0 pound per gallon slurry. Ten barrels of SAM spacer were run ahead of the cement. Rubber cementing plugs were run ahead of and behind the cement. The cement was displaced with 217 barrels of 16.5 pound per gallon mud. Final pump pressure while pumping cement was 1400 psi. The wiper plug was bumped with 1900 psi and bled to 0 psi, indicating that the float shoe and float collar held. The hydril blowout preventers were closed, and the cement was allowed to set for 24 hours before operations were resumed. The blowout preventers were nippled down, and the casing was set on casing slips with 300,000 pounds, 100,000 pounds over the weight of the casing. The additional 100,000 pounds was set to eliminate the elongation which would otherwise occur as a result of the increased temperature anticipated while testing. The blowout preventors were installed on the 5-inch casing head.

6.4.1 Cased Hole Logs

Schlumberger ran a gamma-ray, cement bond, and collar locator log from 12,942 to 7,000 feet. The log indicated that the test sand was not completely cemented; however, there was good bonding above the test sand. Since the closest sand to the test sand was approximately 2000 feet above the test sand and was protected by both the 7-inch and 5-inch casing, additional cementing was not considered necessary.

6.4.2 Production Tubing

The blowout preventors were removed and a tubing spool installed. A tubing string run in the hole to 12,933 feet consisted of 415 joints of 2-3/8 inch, 4.7 lb/ft, N-80, EUE 8 round tubing. The 16.5 pound per gallon mud was displaced with 9.0 pound per gallon saltwater. Eleven joints of tubing were removed from the tubing string, and the tubing was landed in the tubing head with the bottom of the tubing guide collar at 12,606 feet. The casing was pressure-tested to 6000 psi prior to moving the rig off location. The rig was released on January 4, 1981.

6.4.3 Completion Perforations

The completion interval was first perforated on March 17, 1981. Perforating operations were performed without a rig on location. Through-tubing, 1-11/16 inch, zero-phase perforating guns were used. The first interval perforated was from 12,820 to 12,860 feet with a shot density of 4 holes per foot. Since the casing and tubing were full of 9.0 ppg saltwater, the casing was pressured up to 4500 psi prior to detonation of the gun. It was expected that a bottom-hole pressure surge into the wellbore would occur, raising the surface pressure from 4500 to 5000 psi. Instead, a 200-psi decrease of the surface pressure was noticed almost instantaneously when the gun was fired. This indicated that the bottom-hole pressure was lower than expected.

The well was opened to flow to clean the perforations and flowed approximately one barrel while the pressure dropped from 4000 to 700 psi. The well was shut in until additional intervals could be perforated. The interval from 12,820 feet to 12,860 feet was perforated with an additional four holes per foot. The well was flowed while perforating from 12,800 feet to 12,820 feet. After perforating from 12,800 feet to 12,820 feet with the second gun, the perforating gun stuck at 11,000 feet.

The wireline unit was rigged up with additional weight bars and a sub on bottom with an outside diameter close to the inside diameter of the tubing. This assembly was run into the tubing, and the gun was jarred loose and fell to the bottom of the hole. The well was flowed to the reserve pit while perforating from 12,820 feet to 12,750 feet. Flowing well pressure was 100 psi, with an estimated 35 barrels of water per day producing rate. The well produced an estimated 30 barrels of water during perforating operations from March 17, 1981 to March 19, 1981. Perforating was performed during daylight hours only, and the well was flowed during the same periods and shut in at night.

7.0 DRILLING AND COMPLETION OPERATIONS - DISPOSAL WELL

7.1 Location

The brine disposal well was 100 feet southwest of the test well. Exhibit 7-1 is a surveyor's plat of the location.

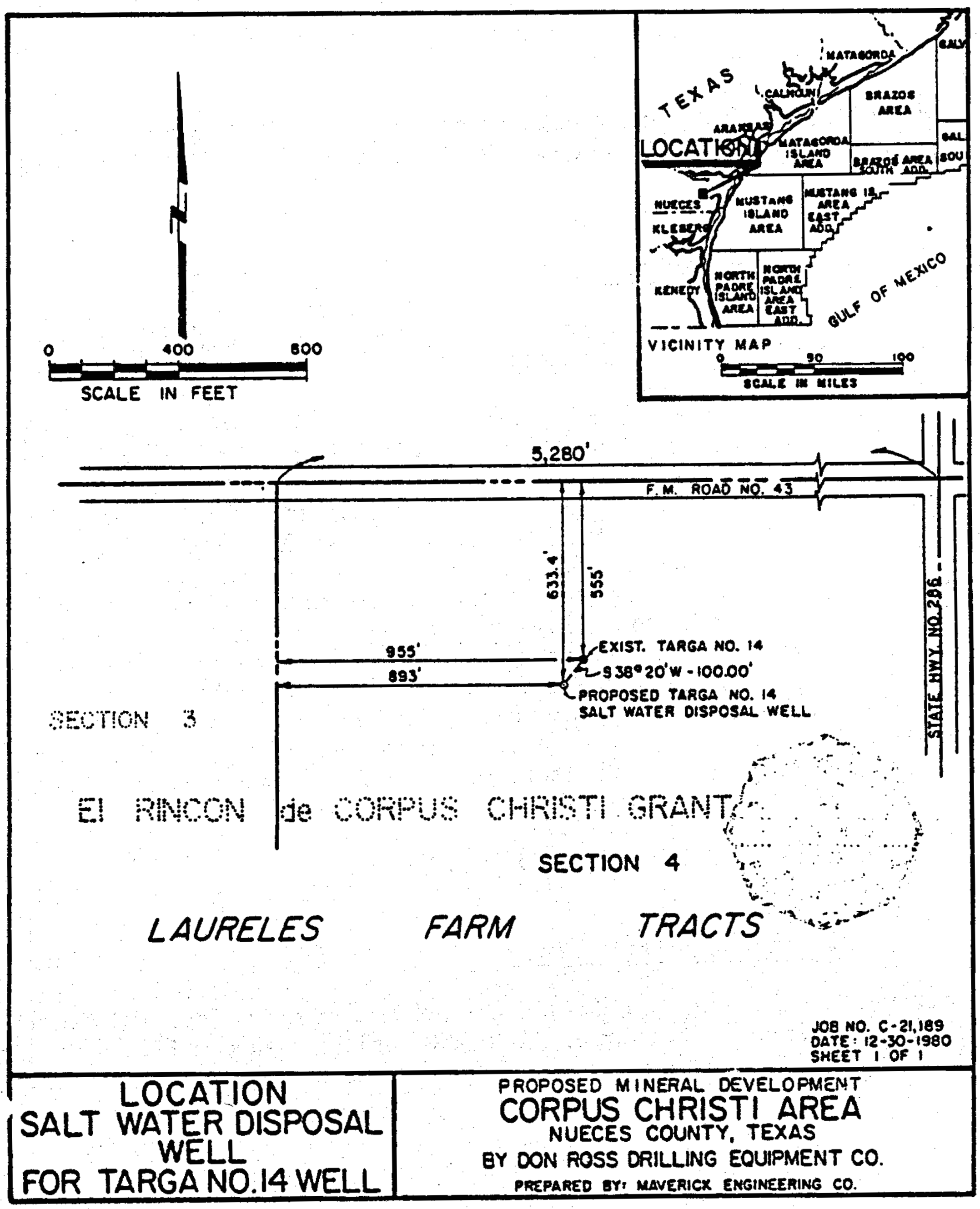


EXHIBIT 7-1

7.2 Design Requirements

A brine disposal well was required for the test because of the large volumes of water to be 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 acceptable disposal aquifer depth below all fresh or brackish water sands.
- 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 Target Rig No. 14, 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. A 224-foot water well was drilled while the rig was being moved.

The rig was moved over the structural casing, and the well was spudded January 5, 1981. The well was drilled to 1212 feet with a 12-1/4" O.D. bit and 8.8 pound per gallon mud. The 9-5/8", 36 pound per foot, K-55 grade, LT&C casing was set at 1207 feet. A down-jet float shoe was run on the bottom of the first joint, and a float collar was installed two joints off bottom. Five centralizers were run on the bottom 3 joints of casing. The casing was reciprocated for 2 hours through a 10-foot stroke prior to cementing. The casing was cemented with 543 sacks of Halliburton Lite Wate cement in a 12.7 pound per gallon slurry, followed by 300 sacks of Class H neat cement in a 15.6 pound per gallon tail slurry. The wiper plug was seated with 1000 psi pump pressure, which was then bled back to 0 psi, indicating that the float valves were holding. A total of 100 barrels of cement was circulated to the surface.

An 8-1/2" hole was then drilled to 5275 feet.

7.4 Selection of Disposal Zone

An induction electric log, gamma-ray, compensated density log, and caliper log were run from 5275 feet to the bottom of the 9-5/8" surface casing at 1210 feet. Analysis of the logs indicated the following potential disposal sands had been penetrated:

Sand	Top	Bottom	Thickness	Average Porosity (%)
A	4702'	4818'	116'	26
B	4453'	4556'	103'	25
C	3872'	3920'	48'	28
D	3748'	3820'	72'	29

It was decided to complete the well in Sands "A" and "B" and reserve Sands "C" and "D" for additional disposal capacity. Sand "D" was considered the best alternate disposal zone.

7.5 Completion Operations

A string of 5-1/2 inch, 15.5 pound per foot, K-55 grade, LT&C casing was run in the hole to 5246 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 joints, and one was installed on each of the next 75 joints. Twenty-four cable wipers were spaced 20 feet apart, from 4410 feet to 4870 feet. The casing string was reciprocated for 2 hours through a 20-foot stroke prior to cementing. The casing string was cemented with a lead slurry of 660 sacks of Halliburton Lite Wate cement in a 12.7 pound per gallon slurry, followed by 500 sacks of Class H neat cement in a 15.6 pound per gallon slurry. The cement was displaced with 123 barrels of 9.5 pound per gallon saltwater. A total of 60 barrels of cement was circulated to the surface. The wiper plug was seated in the float collar with 2100 psi and bled to 0 psi, indicating the float valves were holding.

7.5.1 Perforation and Injectivity Tests

After the rig had been moved off location, a gamma-ray collar locator log was run from 5000 feet up to 3500 feet. The well was perforated from 4710 feet to 4770 feet and from 4500 feet to 4542 feet, with a perforation density of 4 holes per foot.

Injectivity tests were performed at various injection pressures. The highest injection rate achieved was 7920 barrels of water per day at 1500 psi. Exhibit 7-2 is a graph of injection rate versus injection pressure, before stimulation.

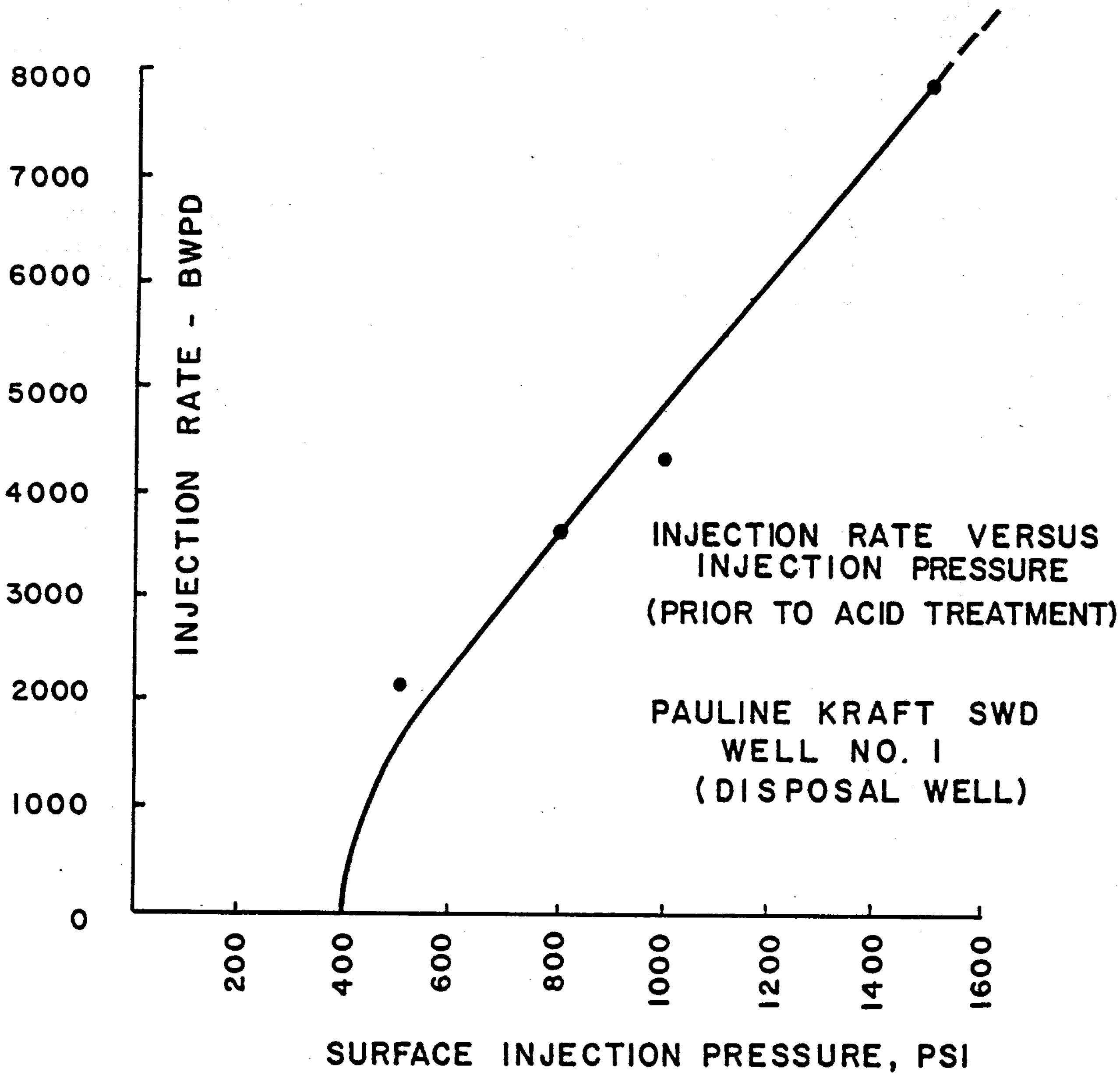


EXHIBIT 7-2

7.5.2 Disposal Well Stimulation

To stimulate acceptance of water by the well, it was treated with 15,000 gallons of acid. After the acid treatment, the well accepted saltwater at 32,400 barrels of water per day at 150 psi surface injection pressure and was capable of accepting all anticipated production from the test well.

7.5.3 Well Setting and Wellhead

Exhibit 7-3 is a schematic diagram of the actual well completion and the surface wellhead.

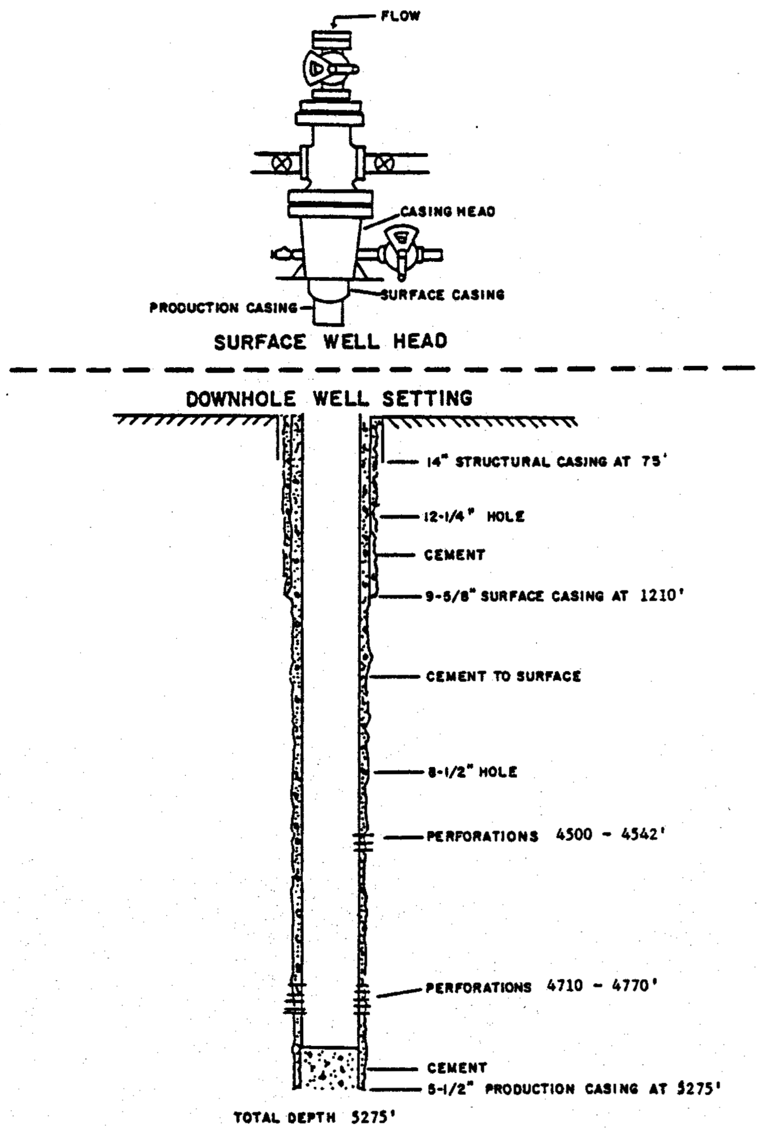


EXHIBIT 7-3

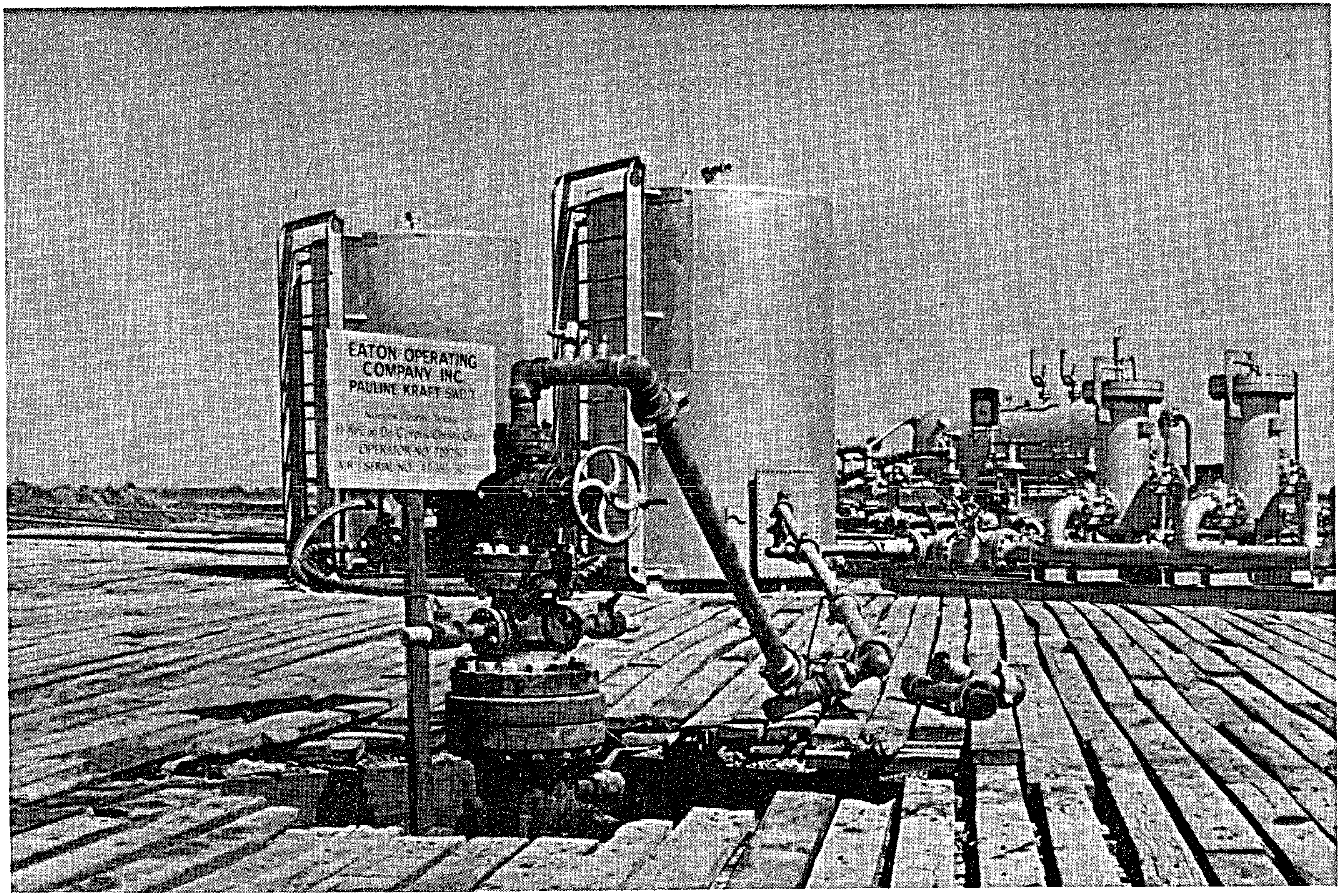


Photo 7-1 Disposal well christmas tree ready for injection.

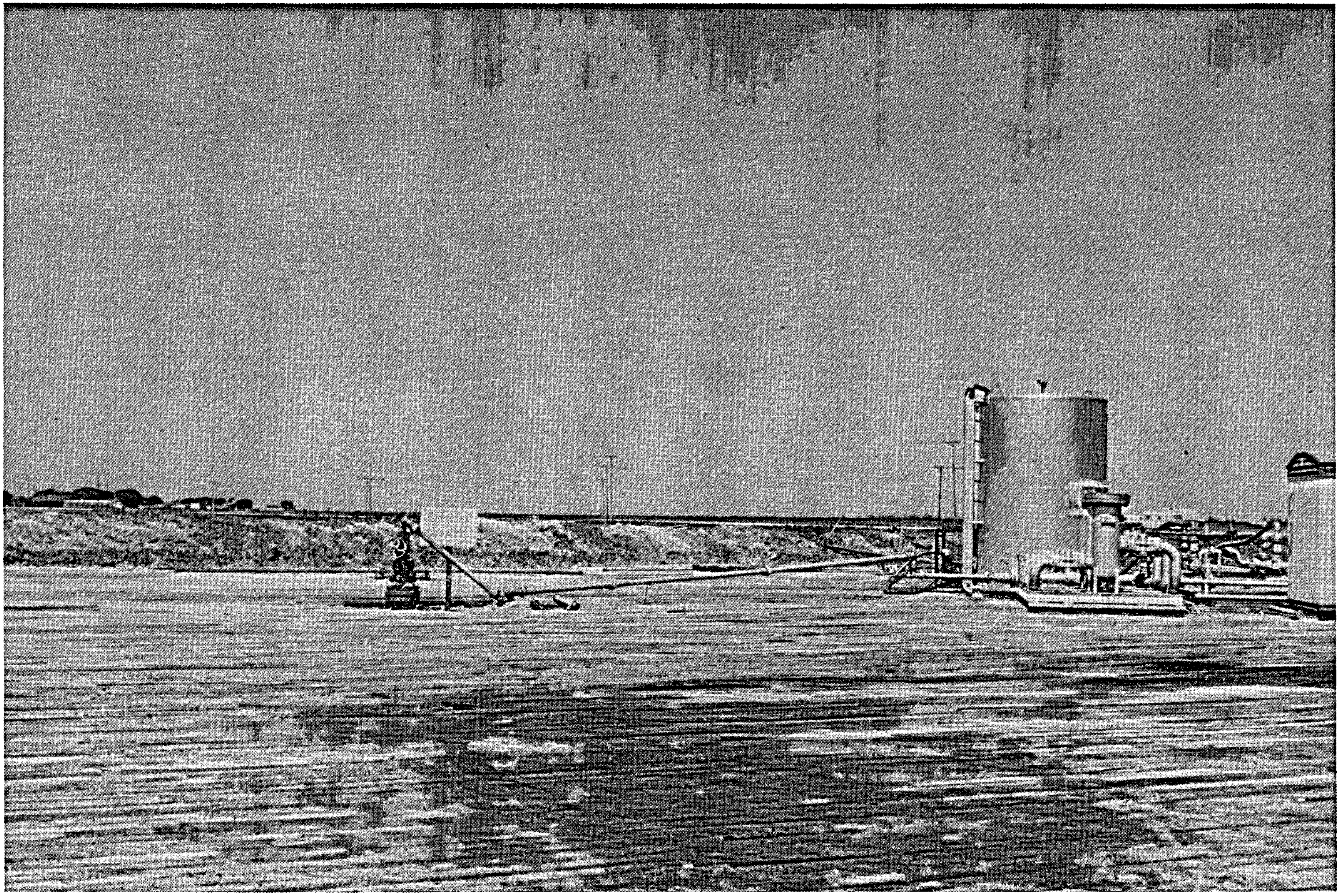


Photo 7-2 Disposal well and injection line from filter towers. Reserve pit dike in background.

8.0 TEST OBJECTIVES

The test equipment and procedures for the Pauline Kraft 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

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 Exhibit 9-1. Design criteria were the following:

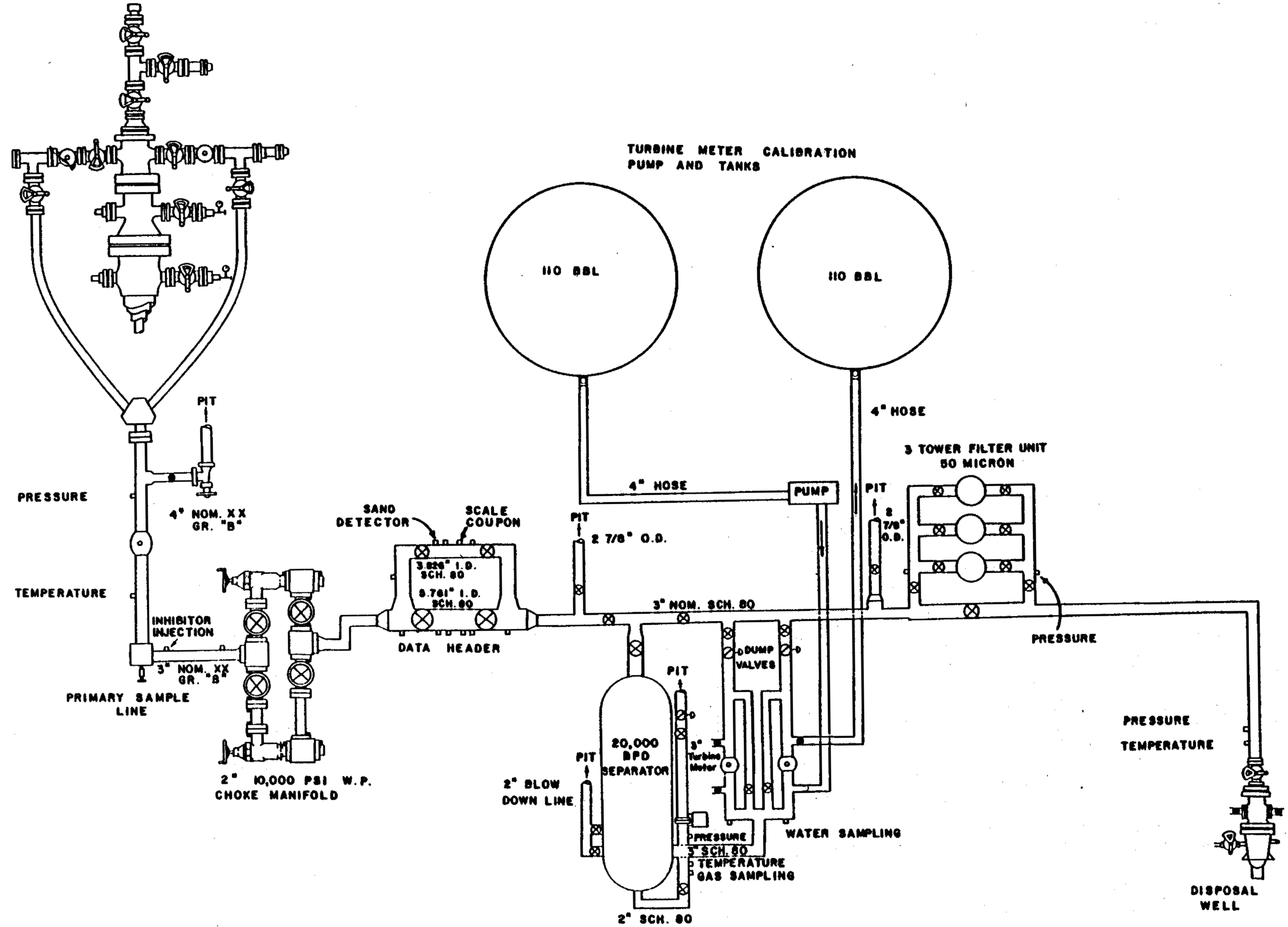
- Wellhead Working Pressure 10,000 psi
- Flow Line Shut In Pressure 8,800 psi
- Temperature 350° F
- Brine Flow Rate 20,000 BPD
- Separator Operating Pressure 1,200 psi
- Filter Operating Pressure 600 psi

9.2 Main Process Equipment

Exhibit 9-1 is a diagram of the surface test equipment. The test equipment was installed as shown in the schematic but was never used because of the poor producing characteristics of the test well. Safety equipment and data gathering and sampling equipment were never installed.

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

SURFACE TEST SCHEMATIC



EATON OPERATING COMPANY, INC.

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
3104 Edloe, Suite 200
Houston, Texas 77027
(713) 627-9764

EXHIBIT 9-1

Photo 9-1 Test equipment - easily transported from one test location to another.

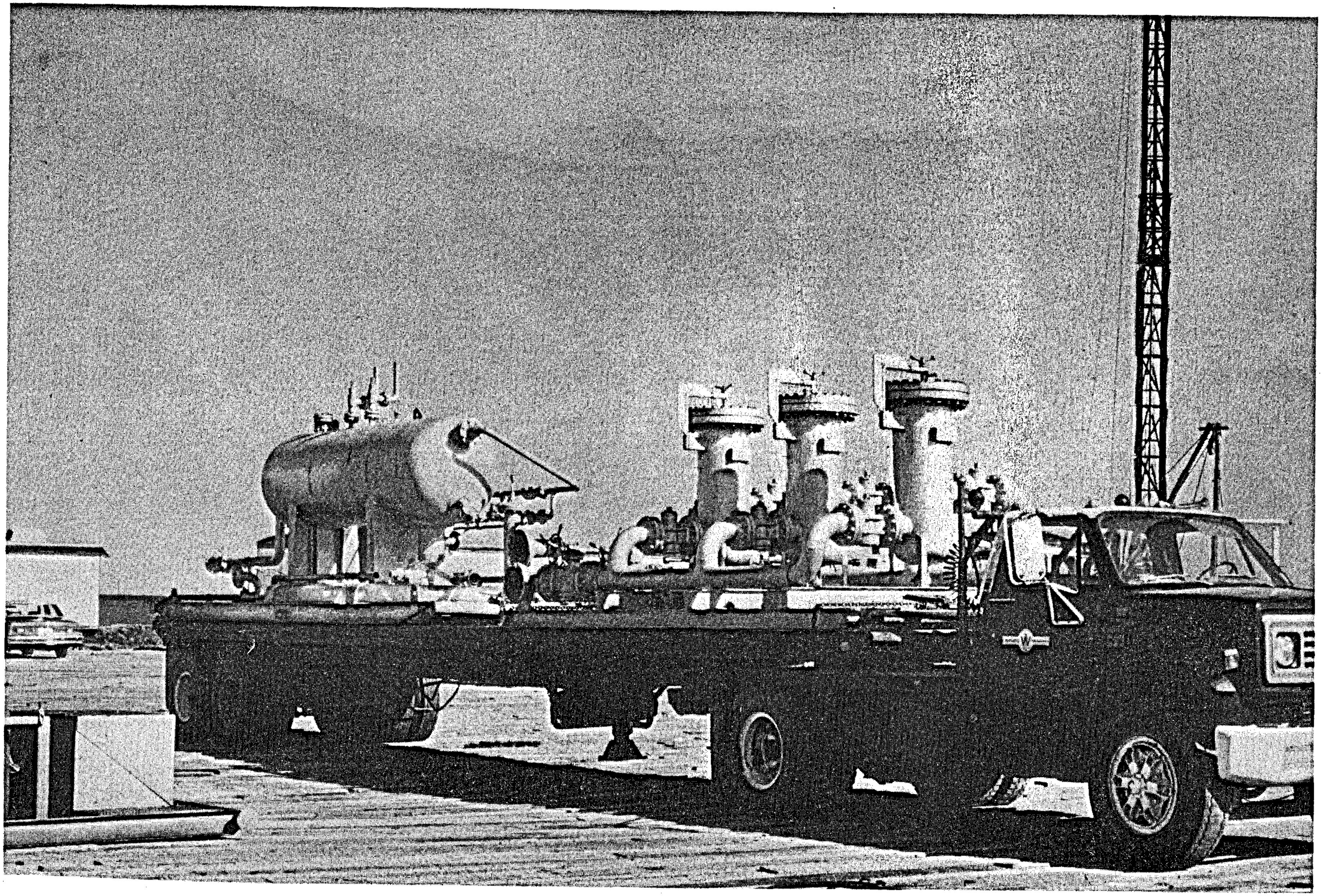


Photo 9-2 Separator and filter towers prior to off-loading.

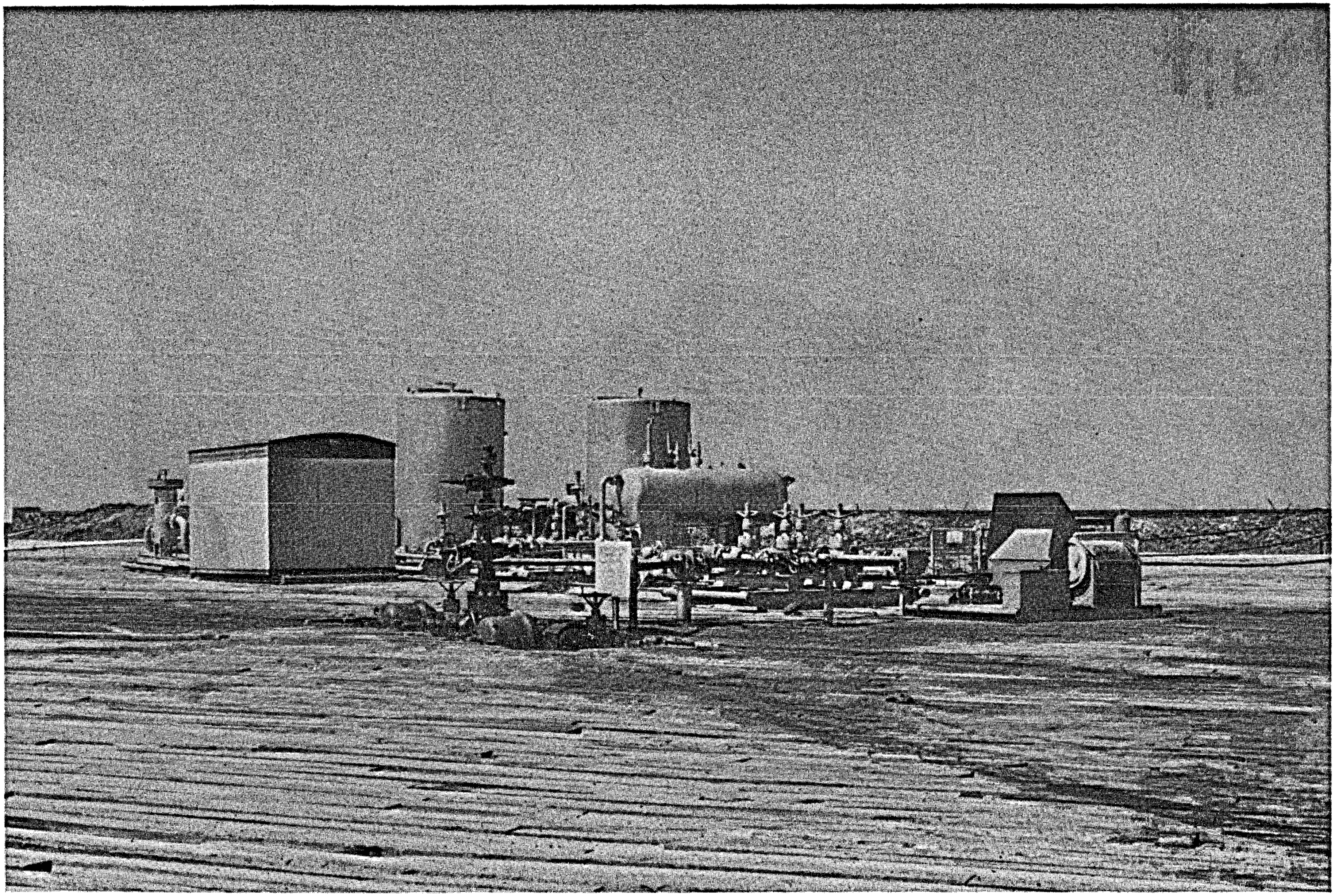


Photo 9-3 Surface equipment in place and ready for testing.

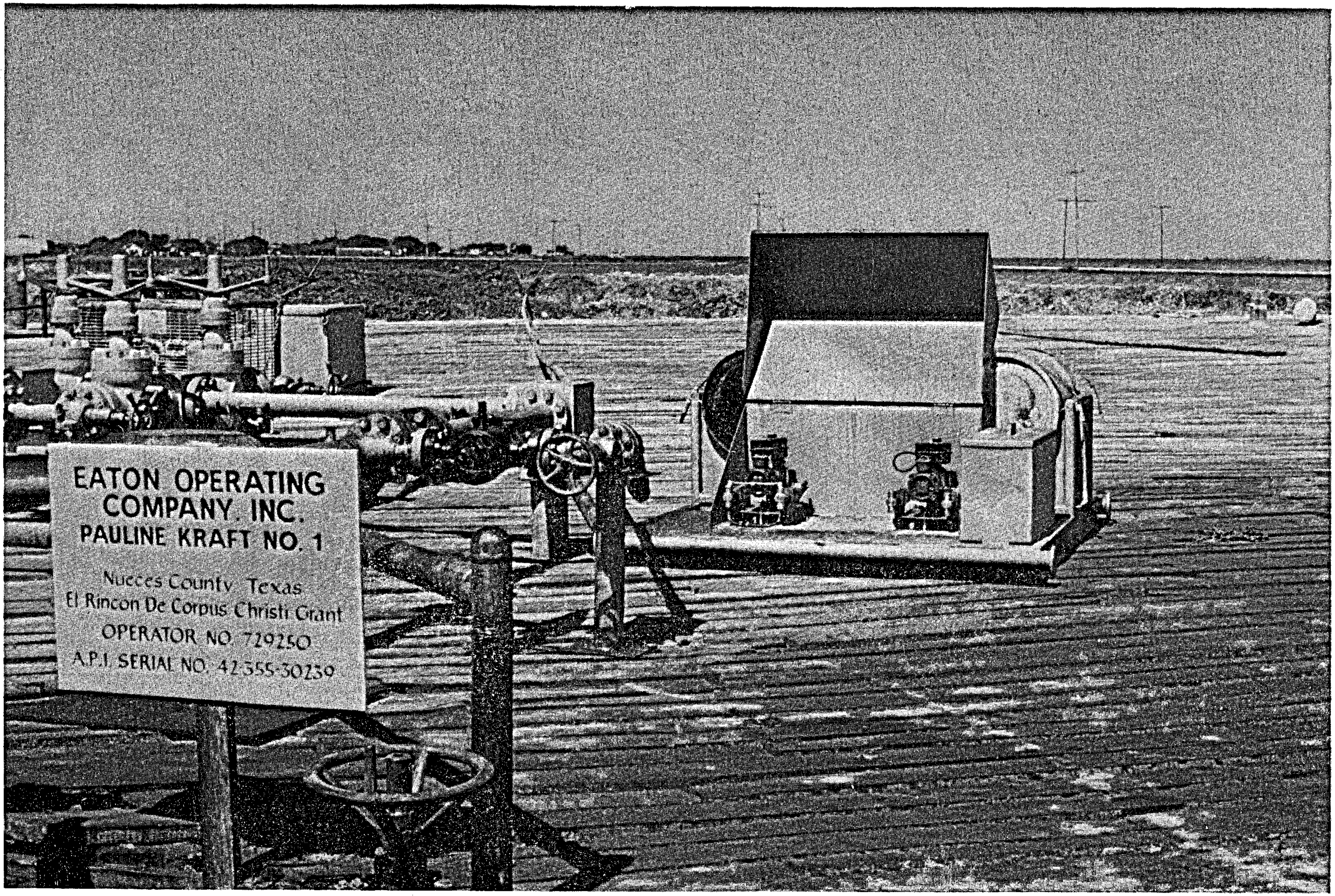


Photo 9-4 Chemical injection skid on right. The two pumps can inject chemicals at 10,000 psi line pressure.

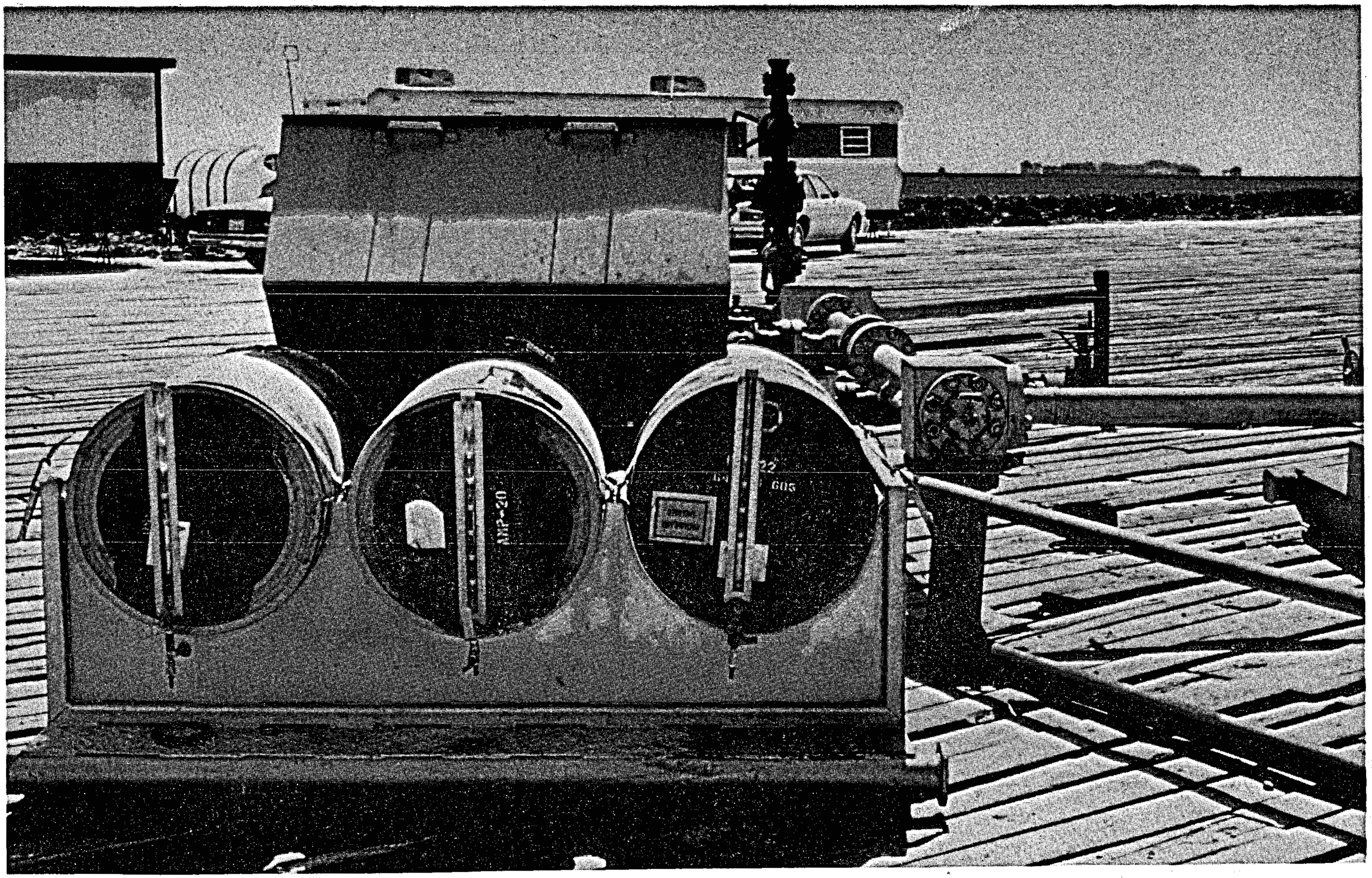


Photo 9-5 The chemical injection skid, allowing experimental treatment with three different chemicals at any given time.

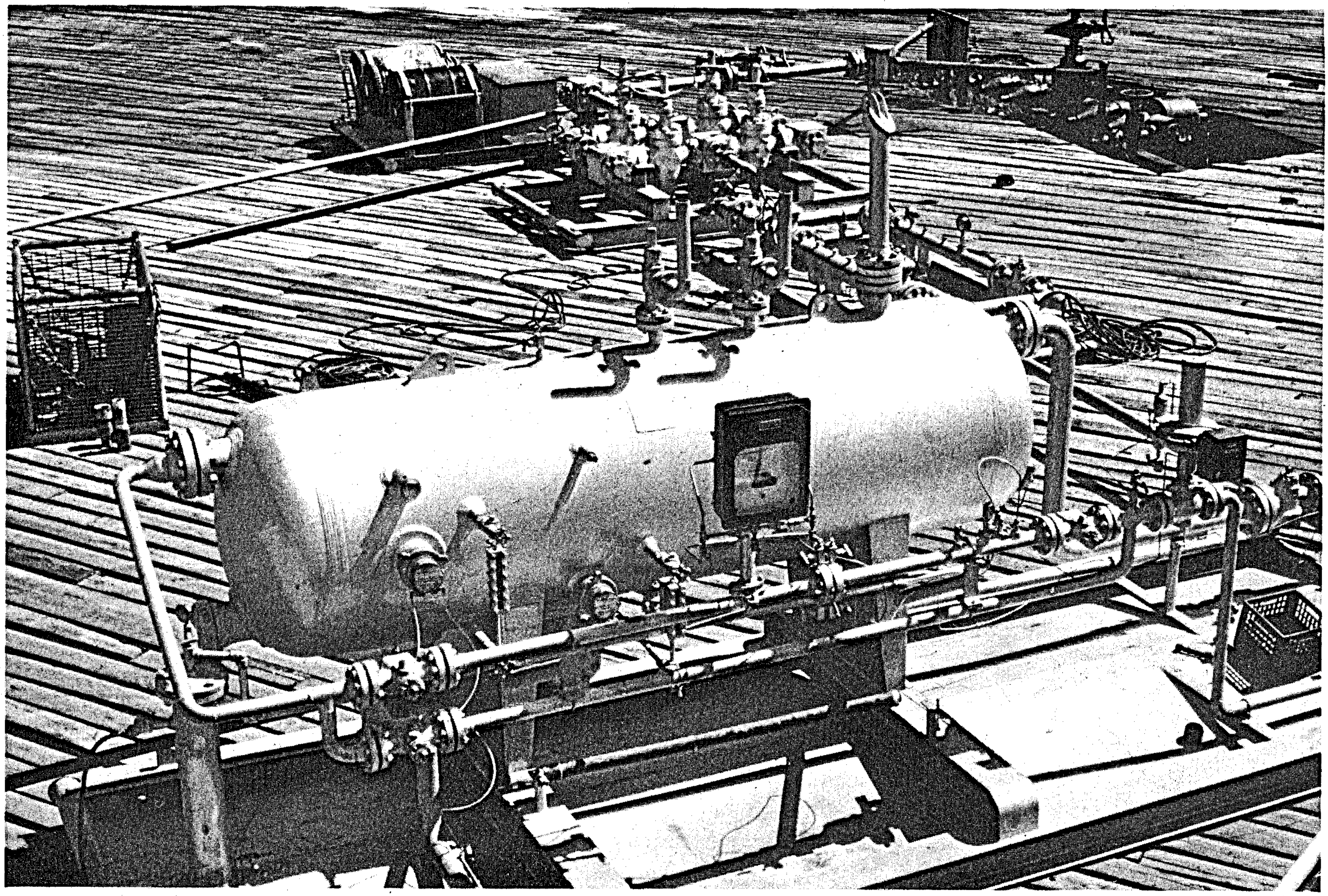


Photo 9-6 Separator, choke manifold, chemical injection skid, and test well.

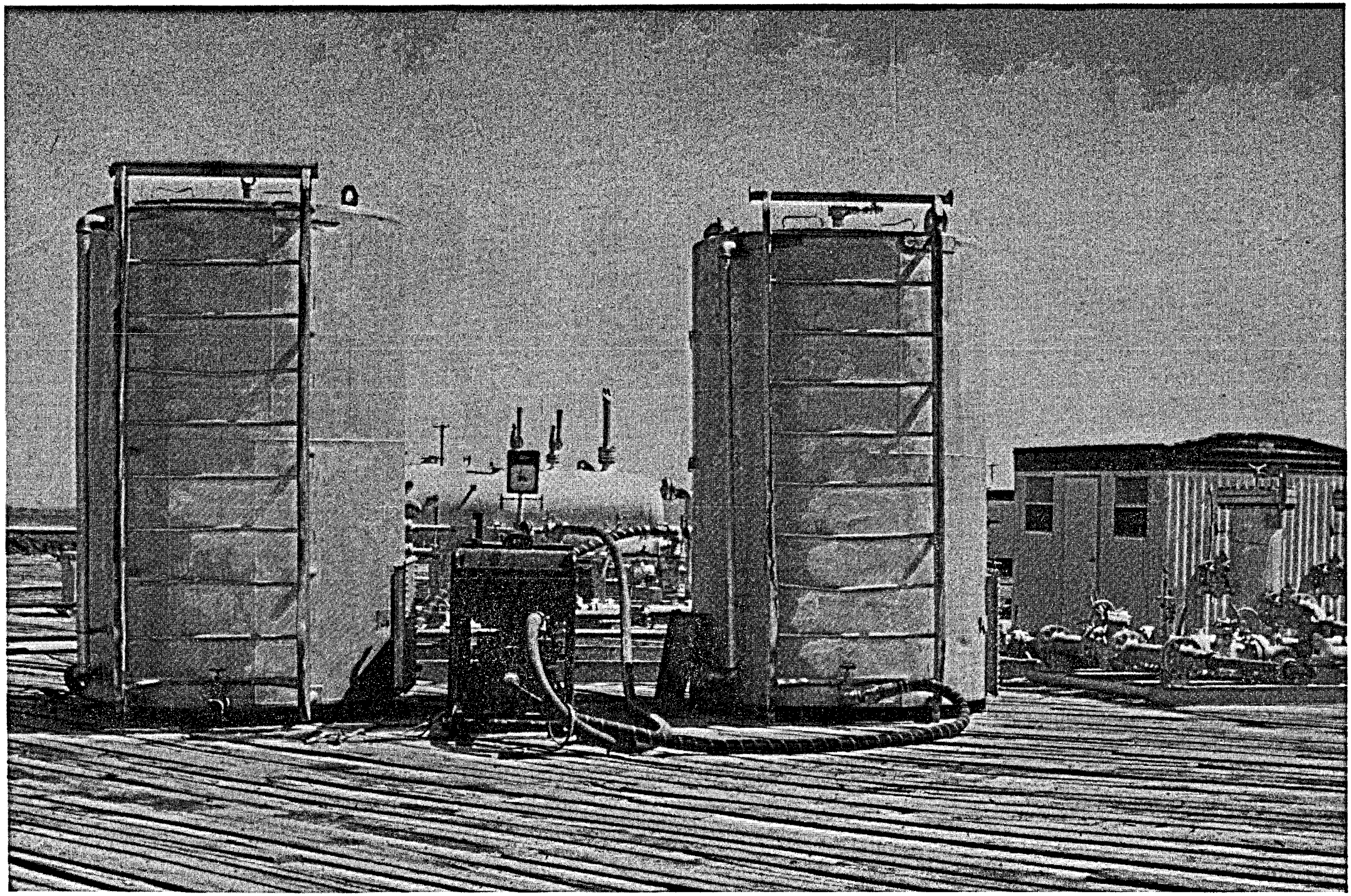


Photo 9-7 110-barrel calibration tanks and pump. Weatherly data collection house to the right.

10.0 TESTING OPERATIONS

After the well had been perforated from 12,860' to 12,750' with 8 holes per foot, the production rate was only 34 barrels of water per day. On March 19, 1981, a Halliburton high pressure pump unit was connected to the tubing valve on the christmas tree. Water was pumped into the well at the rate of 1/2 barrel per minute. While 5 barrels of water were being pumped, the surface pressure increased from 2000 psi to 7100 psi. The pressure was then quickly released, allowing the well to "back-surge" into the well bore. This operation was repeated two more times with about the same pump rates and pressures. Some of the water in the well appeared dirty, so 180 barrels of clean water were circulated down the tubing and out of the casing. A large amount of muddy water was removed from the casing as a result of the circulation. The well was then pumped into again. Eleven barrels of water were pumped, at 1 barrel per minute. The surface pressure increased to 6,900 psi. After the pressure had been released, the well flow was measured again, and it was producing approximately 93 barrels of water per day.

During this time the surface test equipment was being installed and pressure-tested.

The well was allowed to flow to the reserve pit for the next 24 hours. During this time the production rate decreased from 93 to 35 BWPD. Formation damage was suspected, and a decision was made to acidize the well.

10.1 Production Well Stimulation

Halliburton installed a high-pressure steel line on the top of the christmas tree so that acid could be pumped down the tubing and would only contact the 5-inch casing immediately above the perforations. The acid job was performed on March 20, 1981. The acid was pumped as follows:

5,000	Gallons 15% Hydrochloric acid (HCl)
2,000	Gallons Acetic acid (MOD 202)
125	Gallons OWG Diverting agent
2,000	Gallons MOD 202
125	Gallons OWG
2,000	Gallons MOD 202
125	Gallons OWG
2,000	Gallons MOD 202
125	Gallons OWG
2,000	Gallons MOD 202
4,000	Gallons regular Hydrofluoric acid (HF)
1,000	Gallons 15% HCl acid
20,000	Gallons - Total Acid

Photo 10-1 20,000-gallon acid job in progress. Acid is being injected down the tubing.

An acid job of 15,000 gallons of acetic and hydrochloric acid had originally been planned for the well. While the acid job was in progress, 4,000 gallons of hydrofluoric and 1,000 gallons of hydrochloric acid were added to the total volume because the acetic and hydrochloric acids alone were not improving the injectivity into the perforations.

The first 19,000 gallons of acid were pumped at 42 gallons per minute with 5900 psi surface pressure. The last 1000 gallons of acid and 1722 gallons of displacement water were pumped at 84 gallons per minute with 6200 psi. No improvement of injectivity was apparent during the entire acid job.

10.2 Failure of 5-inch Casing

With only 420 gallons of displacement water left to pump, the wellhead jumped up about 4 inches and fell back down to its original position. Mud began spraying out of the 7-inch casing valve. The pumping was stopped, the 5-inch annulus was allowed to flow to the pit, and the 7-inch casing valve was closed. The surface flowing pressure decreased from 6200 to 0 psi in 15 minutes. The well was then produced to a tank for 2-1/2 hours and was gauged at 132 BWPD.

The events described in the above paragraph indicated that a tensile failure had occurred in the 5-inch casing close to, but not at, the surface. Whether the tensile failure was precipitated by a burst failure is not known at this time. Failure as a result of a mechanical defect in a "crossover" joint at 723 feet is suspected. The production of mud from the 7-inch casing valve indicates that the failure occurred below the surface; otherwise water would have been produced initially.

The following 5-inch casing design was run in Pauline Kraft Well No. 1.

Depth	Type	Minimum Joint Strength	Minimum Burst Strength
0'-723'	18# P-110 SFJ	379,000 lbs	13,940 psi
723'-7228'	23# L-80 FL-4S	419,000 lbs	13,380 psi
7228'-12,984'	18# L-80 FL-4S	326,000 lbs	10,140 psi

This entire string was available from DOE stock, including the crossover joints required to connect the different pipe weights and threads. The casing had been hydrostatically pressure-tested, and the end areas had been visually inspected at the storage site. The casing, designed for producing conditions, was cemented to about 7300 feet and pulled in tension after cementing. The weight left on the slips was about 300,000 pounds.

Since the casing failure is related to increased tensile strain resulting from cooling of the casing by acid and from the high surface injection pressure, a detailed analysis of surface tensile loading is presented in the following paragraphs.

To determine the effects of temperature on the tensile load a computer model was used to establish a thermal profile of the well. Calculation of downhole wellbore and earth temperatures is a complex task. Many variables influence the temperatures, which are continuously changing. The computer model used here was developed by Enertech Engineering and Research Company in 1979. The computer calculates downhole temperatures in and near a well during injection, production, and circulation. The model was originally developed from basic engineering principles, tested against exact solutions and laboratory and field temperature data. The program currently performs a fully transient two dimensional heat transfer analysis of a well. Vertical and radial heat conduction in the soil, vertical convection and radial conduction in flowing streams, and natural convection in the wellbore fluids are included in the calculations.

Results of the computer analysis are included in Appendix "E". The analysis is for the period beginning when the well was first perforated and ending when the casing parted. Basically the computer calculations indicate that the average temperature of the uncemented section of 5-inch casing was reduced from 128°F to 101°F during the acid job. The analysis also indicates that the circulation of 180 barrels of water increased the average temperature of the uncemented section of casing by about 1°F. These temperature profiles have been applied to the tensile strain calculations which follow.

The tensile loading of the casing at the surface can be calculated making certain assumptions with respect to temperature and other factors. The following equations, developed by W.R. Cox in 1957, are used in the calculations:

$$W_{mw} = +0.0122\ Di^2 L\,\Delta di$$

$$W_{sp} = +0.471\ Di^2\ (\Delta Pi + 1.67\ Pi)$$

$$W_t = -59.8\ w'\,\Delta t$$

Where:

W_{mw} = Wellhead load due to change in mud weight inside casing, lb.

W_{sp} = Wellhead load due to change in surface pressure, lb.

W_t = Wellhead load due to change in temperature, lb.

Di = Average inside diameter of casing above cement top, inches.

L = Length of uncemented casing, ft.

Δdi = Change in mud weight inside casing after cement sets, ppg.

Pi = Surface pressure inside casing after cement sets, psi.

w' = Average weight of casing above cement top, lb. per ft.

Δt = Average change in casing temperature above cement top, °F.

The values of average inside diameter of the casing, change in mud weight inside casing and average weight of casing are calculated below.

$$Di = \frac{(723 \times 4.276) + (6505 \times 4.044) + (72 \times 4.276)}{7300'} = 4.07 \text{ in.}$$

$$\Delta di = 9.0 - 16.5 = 7.5 \text{ ppg}$$

$$w' = \frac{(723 \times 18) + (6505 \times 23.2) + (72 \times 18)}{7300'} = 22.46$$

It can be assumed that initially the surface weight was 300,000 lb. and that the net weight did not increase or decrease during the time between the end of wellhead installation and the time mud was displaced from the well.

When the 16.5 ppg mud was circulated out of the well and replaced with 9.0 ppg brine, the wellhead load was reduced because of the change of mud weight. The temperature is assumed to have remained unchanged. The reduction in wellhead load is calculated as follows:

$$W_{mw} = + 0.0122 \times (4.07)^2 \times 7300 \times (-7.5)$$

$$= - 11{,}065 \text{ lb.}$$

Thus the maximum tensile load at the surface at the end of the displacement is estimated to have been:

$$300{,}000 - 11{,}000 = 289{,}000 \text{ lb.}$$

After the well was perforated, the muddy brine was displaced with fresh water to lighten the hydostatic head. A decrease in the wellhead load would also have occurred as a result of lighter fluid density in the annulus. This can be calculated as follows:

$$W_{wm} = + 0.0122 \times (4.07)^2 \times 7300 \times (8.3 - 9.0) = - 1033 \text{ lb.}$$

The net wellhead load prior to acidizing operations was:

$$289{,}000 - 1000 = 288{,}000 \text{ lb.}$$

The maximum possible wellhead load at the time of failure is the sum of temperature and pressure effects. The increase due to cooling is calculated as follows:

$$W_t = -59.8 \times 22.46 \times (70 - 101) = 41{,}636 \text{ lb.}$$

The increase due to pump pressure is calculated as follows:

$$W_{sp} = + 0.471 \times (4.07)^2 \times (6200 + (1.67 \times 0)) = 48{,}373 \text{ lb.}$$

The maximum possible wellhead load at time of failure is estimated to have been:

$$288{,}000 + 42{,}000 + 48{,}000 = 378{,}000 \text{ lb.}$$

Exhibit 10-1 is a graphical illustration of the possible surface tensile loading during the various operations discussed above.

The preceeding calculations indicated that the tensile load on the top joint of 5-inch casing approached but did not exceed the strength rating of the casing connection. The point of failure is not known at this time but is obviously not the top joint. A tensile failure at any point in the string would suggest a defect, the most probable point being a "crossover" joint located about 723 feet from the surface.

10.3 Consideration of Hydraulic Fracture Treatment

A hydraulic fracture treatment was investigated as a means of additional formation stimulation. Halliburton's computer analysis indicated that the best possible production rate that could be expected following a frac job would be 729 BWPD. The estimated cost to repair the 5-inch casing and to perform the frac treatment could not be justified.

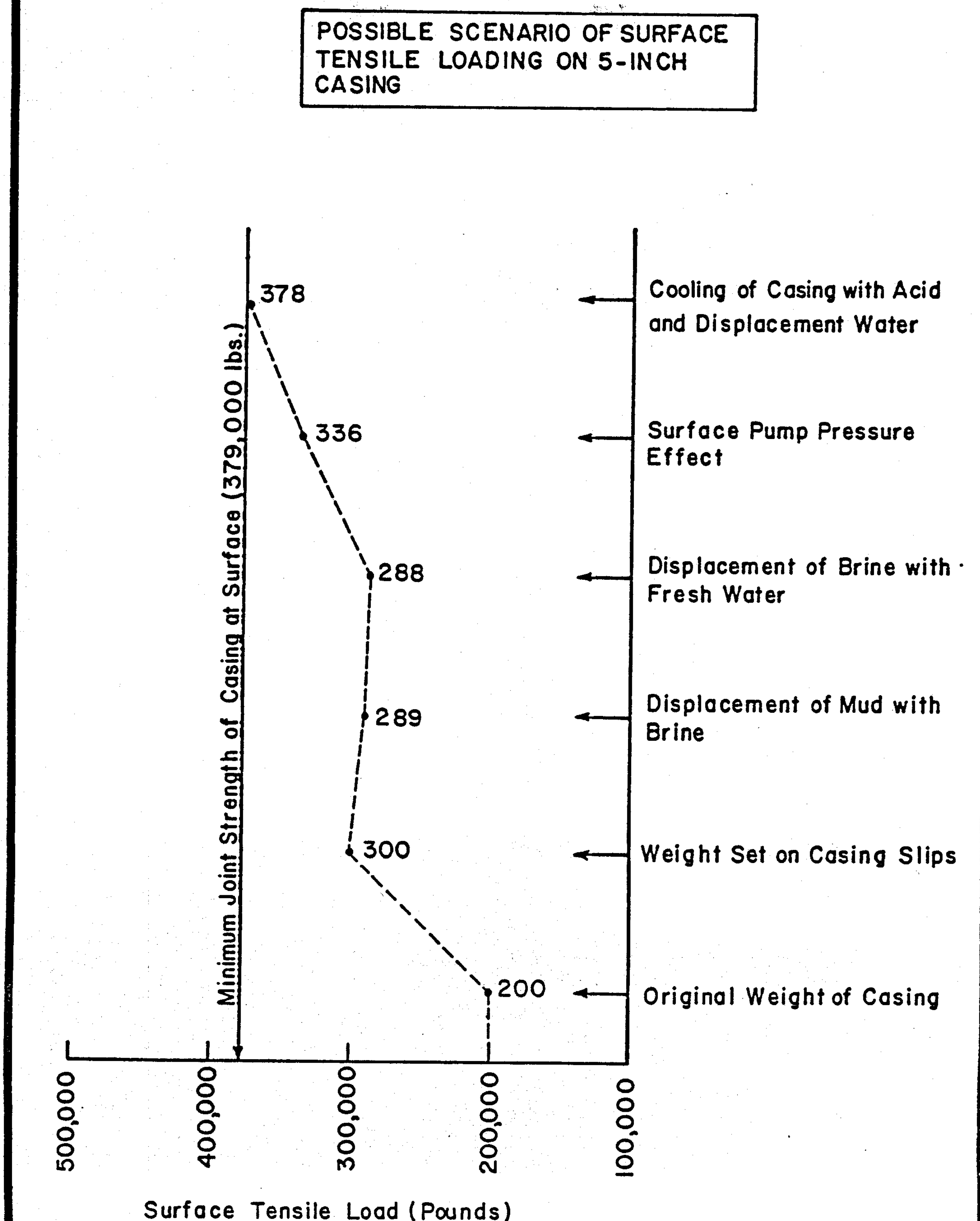

POSSIBLE SCENARIO OF SURFACE TENSILE LOADING ON 5-INCH CASING
378
336
288
289
300
200
Minimum Joint Strength of Casing at Surface (379,000 lbs.)
Cooling of Casing with Acid and Displacement Water
Surface Pump Pressure Effect
Displacement of Brine with Fresh Water
Displacement of Mud with Brine
Weight Set on Casing Slips
Original Weight of Casing
500,000
400,000
300,000
200,000
100,000
Surface Tensile Load (Pounds)

EXHIBIT 10-1

11.0 ABANDONMENT OF WELLS AND LOCATION

The Pauline Kraft Well No.1 was killed on March 22, 1981 by circulating 16.5 ppg mud down the tubing and out of the casing. Eaton recommended that testing operations be terminated and that the test well be plugged and abandoned. The DOE concurred with the above recommendation. The surface testing equipment was removed from the location, and a workover rig was moved on location on March 26, 1981.

While plans were being made to plug the test well, Mr. Don Ross contacted Eaton and DOE and requested permission to take over operations on the location. Mr. Ross wishes to do additional testing before abandoning the well.

The workover rig was released on March 27, 1981, and an agreement was negotiated with Mr. Ross over the next several days. A copy of the agreement can be found in Appendix "A". Basically, the agreement states that Mr. Ross will return the tubing and wellhead equipment to DOE and releases EATON from all expenses and liabilities from the date of the agreement through plugging and abandoning the wells and restoring the location. In return, Mr. Ross will obtain the disposal well and will have an opportunity to further test the Pauline Kraft Well No. 1.

12.0 CONCLUSIONS

The low productivity of the Anderson sand in this well was very surprising to Eaton and the other parties concerned. The insubstantial flow rates from the well may have been caused by one, or a combination, of several conditions discussed below.

Sidewall core data obtained from well records indicated mean porosity and permeability values of 23% and 39 millidarcies, respectively. Analysis of the original electric log (run in 1971 by Coastal States Gas Corporation) indicated an average porosity of 21%.

The well was re-entered by Ross-Pope Drilling Equipment Company ten years after the hole was drilled. During this time some formation damage by drilling mud had occurred. Eaton attempted to "ream out" the sand during completion operations to remove some of the damage. The washed out hole, however, was larger than the underreamer, and little, if any, of the damaged formation was removed. A sonic log run by Eaton to verify formation porosity indicated a reduced mean porosity of 16%. This new value was either indicative of formation damage or was simply a more accurate log reading.

The original sidewall core data also indicated that the Anderson sand had a very high lime content. This lime may have acted as a secondary cementation agent and therefore reduced the effective reservoir permeability.

Other conditions, mechanical in nature, may have contributed to the low productivity of the well. Poor penetration by the perforating guns or a very thick cement sheath surrounding the casing are two examples of possible mechanical problems. The acid injected into the well, however, should have improved production significantly, if formation damage were considerable or if the perforations were ineffective. The poor well performance following the acid treatment is evidence that the reservoir simply has low permeability. The fact that it took about 12 hours for the shut-in surface pressure to build from zero to 4000 psi is evidence that the production problem was more than "skin deep".

It is difficult to completely analyze the 5-inch casing failure without knowing the depth and type of the failure. The cooling effect of the acid job and the high surface pressures encountered during acidizing operations contributed to the failure.

Remedial operations by Mr. Don Ross should provide additional information as to the type of casing failure which occurred.

13.0 REFERENCES

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Cox, W.R. 1957. "Key Factors Affecting Landing of Casing", API Southwestern District Committee Study on Casing Landing Practices, Shreveport, Louisiana.

Dunlap, H.F. "Study of Log Derived Water Resistivity Data in Geo Formations", Center for Energy Studies. Sixth Progress Report, August 1980.

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OSHA, U.S. Department of Labor. "Occupational Safety and Health Standards for General Industry." March, 1979.

Prentice, C.M. 1969. "Maximum Load Casing Design", SPE Paper No. 2560, Dallas, Texas.

Wooley, G.R. 1979. "Computing Downhole Temperature in Petroleum and Geothermal Wells", SPE Paper No. 8441, Las Vegas, Nevada.

APPENDIX A

OPERATOR AND LANDOWNER CONTRACTS

ROSS-POPE DRILLING EQUIPMENT COMPANY CONTRACT

ASHBY & MANN

ATTORNEYS AT LAW

601 SOUTHWEST FIRST STREET

POST OFFICE BOX 699

MINERAL WELLS, TEXAS 76067

April 15, 1981

JIMMY A. ASHBY
BOBBY JOE MANN

AREA CODE 817
325-9559

Eaton Operating Company, Inc.
3104 Edloe, Suite 200
Houston, Texas 77027

Attn: Mr. Ben A. Eaton

RE: Coastal States Gas Producing Company
#1 Pauline Kraft
4-19S-20E
Chapman Ranch Field
Nueces County, Texas

Dear Mr. Eaton:

Please find enclosed the original release and assumption of full liability signed this date by Don Ross pertaining to the above referenced well. Any further inquiries concerning this release should be made directly to Mr. Ross.

Very truly yours,

Bobby J. Mann

Bobby Joe Mann

BJM/bm
enclosure

EATON OPERATING COMPANY, INC.

April 9, 1981

Mr. Don Ross
Ross-Pope Drilling Equipment Company
Ft. Wolters Building 537
Route 3
Mineral Wells, Texas

R E L E A S E

Re: Coastal States Gas Producing Company
#1 Pauline Kraft
4-19S-20E
Chapman Ranch Field
Nueces County, Texas

Dear Mr. Ross:

Pursuant to our written contract with The Department of Energy, we are advised to cease testing operations on the above described well; and, either prepare to plug and abandon said well, or make proper arrangements to turn over said well to you for further operations at your sole risk and expense.

Should you elect to keep testing the well, you are hereby advised as follows, to-wit:

1) As of the date of receipt of this letter, Eaton shall be fully released of ALL liability on said well.

2) Further testing on your part shall be at your sole risk and expense.

3) You must furnish all test data to DOE via Eaton.

4) Should you elect to operate said well, it is expressly agreed the following inventory of equipment shall be left in place on the well site, to-wit:

(A) Location:

(1) 50,000 Sq. Ft. 2-Ply Board Turnaround

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

3104 EDLOE, SUITE 200
HOUSTON, TEXAS 77027

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

(2) 450 LF Board Road

(Ref. P.O. 0492-80-06 - Finished installing February 28, 1981 - 90 days rent paid).

(B) Test Well:

(1) 12,984 LF 5" Casing

(C) Disposal Well:

(1) 1 9-5/8" 11" 3000 OSI Casing Spool w/2" bull plug and 2" ball valve.

You shall be totally responsible for the above listed equipment to The Department of Energy, an agency of the United States of America. This equipment will be returned to Eaton-DOE or replaced in-kind within thirty (30) days of the date of this release with the exception of the 5" casing which is considered to be uneconomical for Eaton to recover.

You agree to plug and abandon both the Pauline Kraft #1 and the saltwater disposal well in accordance with State and Federal regulations governing such operations. You agree to restore the location to the satisfaction of land and mineral owners.

Should any of the items listed above subject to return or replacement become lost or damaged while in your custody, The Department of Energy shall require replacement or repair in kind.

The following equipment presently on the well will be removed by you and delivered FOB location to Eaton immediately after you take over operations.

Test Well

(I) 12,606 LF 2-3/8" N-80 Tubing (404 Jts) w/re-entry guide

(II) 1 2-1/16" 10,000# x 7-1/16" 10,000# Spool

(III) 1 7-1/16" 10,000# x 11" 5000# Hanger

(IV) 2 2-1/16" 10,000# x 3-1/16" 10,000# Spool

(V) 2 2-1/16" 10,000# Blind

(VI) 1 2-1/16" 10,000# WKM Valve w/Flange Cap

Disposal Well

(I)	1	10" 3000# x 10" 2000# DSA SN K01661 (Rented)
(II)	1	5" Casing Hanger w/2 Flanges; (2) 2" Nipples; (2) 2" Ball Valves and (2) 2" Bull Plugs
(III)	1	Adapter Flange Casing Hanger - 3" 2000#
(IV)	1	3" WKM 2000# Valve w/Flange and 3" Pipe Thread

Miscellaneous

(I)	1	Lot - Mixed 9-5/8", 5", and 2-3/8" Thread Protectors

After reading this release and fully understanding the liability you are to assume, kindly sign a duplicate original and return the same to us at your earliest opportunity.

This agreement is subject to approval of The Department of Energy in writing to us. Approval by The Department of Energy has been indicated. When it is received by us a copy of their approval letter will be forwarded to you.

Sincerely yours,
EATON OPERATING COMPANY, INC.

B A Eaton

Ben A. Eaton
President and Project Manager

This release and the assumption of full liability of the subject matter of this letter is accepted in form and substance this 15th day of April, 1981.

ROSS-POPE DRILLING EQUIPMENT COMPANY

Don Ross

Don Ross

cc: Mr. R. T. Stearns
United States Department of Energy

Mr. Thomas E. Lucas

EATON OPERATING COMPANY, INC.

November 20, 1980

Mr. Don Ross
Ross-Pope Drilling Equipment Company
Ft. Wolters Building 537
Route 3
Mineral Wells, Texas 76067

Re: Coastal States Gas Producing Company
#1 Pauline Kraft
4-19S-20E
Chapman Ranch Field
Nueces County, Texas

Dear Mr. Ross:

Today, I was given authority by the United States Department of Energy, Nevada Operations Office (D.O.E.) to inform you that D.O.E. has approved a test of the subject well under our current contract with D.O.E., DE-AC08-80ET27081.

Following is an outline of the EOC - D.O.E. proposal:

1. You will secure the necessary leases, rig and all other materials to re-enter the subject well at your sole cost, risk and expense.

2. You will bear all costs, risk and expense to clean the well out to its original total depth.

3. Eaton Operating Company, Inc., under the contract with D.O.E., will take the well over and log, run production casing and complete the well all at EOC's sole cost, risk and expense.

4. If the well will flow, EOC will then drill and complete a suitable disposal well. (You must already have the landowner's permission for a disposal well.) The disposal well operation will be at EOC's sole cost, risk and expense.

5. EOC will then perform a series of tests that will allow us to fully and accurately evaluate the resource at that site at our sole cost, risk and expense. These data will be furnished to you. All test equipment will be rental equipment.

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

6. You will then install your long term production and disposal equipment at your expense for your plant.

7. EOC will leave the well equipment in place for your use in return for your furnishing to EOC and D.O.E. all future test data.

8. If and when you decide to plug and abandon these wells, you will return to EOC - D.O.E. all salvable equipment that had been purchased by D.O.E. for this project.

We urge you to proceed with this project because long delays will force us to test another well for some other operator. If you accept this offer, we must then disucss scheduling of the actual work. Please return the executed copies immediately.

Thank you very much,

EATON OPERATING COMPANY, INC.

B. A. Eaton

B. A. Eaton
President and Project Manager

ACCEPTED AND AGREED TO THIS 28th DAY OF November, 1980.

ROSS-POPE DRILLING EQUIPMENT COMPANY

Don Ross

Don Ross

GEOTHERMAL LEASE AGREEMENT

BETWEEN

DON ROSS

AND

PAULINE KRAFT

293935

VOL 1671 PAGE 770

GEOTHERMAL LEASE

THIS LEASE AND AGREEMENT entered into this 20th day of November 19 80 by and between PAULINE KRAFT, a feme sole, of 4630 Adkins, Corpus Christi, Texas, 78411

(hereinafter called "Lessor" whether one or more) and DON ROSS of Rt. 3, Mineral Wells, Texas, 76067

(hereinafter called "Lessee");

WITNESSETH

Lessor, in consideration of the sum of Ten Dollars ($10.00) cash in hand paid, the receipt and sufficiency of which is hereby acknowledged, and of the covenants and agreements hereinafter contained on the part of the Lessee to be paid, kept and performed, does hereby grant, demise, lease and let unto the Lessee the following described land together with any reversionary right therein (hereinafter called the "Leased Land") situated in the County of Nueces State of Texas and containing approximately 158 acres:

158 acres of land, more or less, and being all of the North one-half of the North one-half (N.1/2 of N.1/2) of Section 4 of the Laureles Farm Tracts, said Farm Tracts Subdivision being shown by map of record in Volume 3, Page 15 of the Map Records of Nueces County, Texas, save and except the 2-acre tract in the Northeast corner thereof described in Deed dated December 3, 1923, from Pauline Kraft et al to Moreman Gin Company and recorded in Volume 144, Page 534 of the Deed Records of Nueces County, Texas.

For the purpose of and together with the sole and exclusive right and privilege of exploring, drilling or reentering any existing well upon said Leased Land for the purpose of producing, extracting, removing, utilizing, selling and disposing of Geothermal Resources and of extracting minerals therefrom where such minerals are deemed to be owned by Lessor (hereinafter called "Extractable Minerals") and artificially injecting fluids and gases into the Leased Land; and constructing, erecting, using, operating and maintaining upon the Leased Land any and all facilities as the Lessee may deem necessary in order to produce, save, utilize and process Geothermal Resources and Extractable Minerals and in order to generate electricity from Geothermal Resources; together with ingress and egress upon the Leased Land in order to exercise any of the rights granted herein. For the purpose of this Lease "facilities" shall include, but not be limited to, wells, pumps, pipes, pipelines, buildings, plants, sumps, tanks, brine pits, reservoir watertanks, pumping stations, roads, electric power generation plants, transmission lines, electric, telegraph and telephone lines.

For the purpose of this Lease: (a) The term "Geothermal Resources" shall mean all products of geothermal processes, embracing indigenous steam, hot water and hot brines; steam and other gases, hot water and hot brines resulting from water, gas, or other fluids artificially introduced into geothermal formations; and heat or other associated energy found in geothermal formations. (b) The term "Extractable Minerals" shall mean any mineral or minerals (specifically including oil and hydrocarbon gases) which are produced in solution with Geothermal Resources from any well drilled or reentered by Lessee on the Leased Land.

This Lease shall be for a term of one (1) /years from the date hereof (herein called "Primary Term") and so long thereafter as Geothermal Resources or Extractable Minerals are being produced in commercial quantities or drilling operations are conducted either on the Leased Land or on land pooled therewith; all subject to the following terms and conditions:

1. Lessee shall pay to the Lessor on or before the last day of the calendar month after the month of commencement of production in commercial quantities of Geothermal Resources or Extractable Minerals or both and thereafter on a monthly basis: (a) A royalty of 10% of the value of the Geothermal Resources produced from the Leased Land or allocated thereto ~~xxxxxxxxxxxxxxxxxxxxxxx~~; and (b) A royalty of 2% of the value of the Extractable Minerals produced from the Leased Land or allocated thereto, if same shall be deemed to be owned by Lessor.

It is agreed that "value" shall be deemed to be the gross proceeds from the sale of the Geothermal Resources or Extractable Minerals, or, if not sold, their fair market value at the well head if they are used by the Lessee for commercial purposes other than in the producing or processing of other Geothermal Resources or Extractable Minerals. If the Lessee elects to process any Extractable Minerals prior to sale, then the Lessor's royalty shall bear its proportionate share of the cost of processing.

2. Lessee has paid to Lessor the rental in full for a period of one (1) year from the date hereof. Commencing with the second year of the term hereof and on each anniversary date thereafter during the Primary Term, if during the preceding year Lessee has not conducted drilling operations on or if there was no production from the Leased Land or land pooled therewith then, subject to the provisions of paragraph 4 hereof, Lessee shall pay or tender to Lessor annually, in advance, as rental, the sum of N/A For the purposes of calculating any payments hereunder based on acreage, Lessee may act as if the Leased Land contains the number of acres set forth above unless the Lessor or Lessee shall obtain a final adjudication that the acreage is different at which time Lessee shall, as of the next due date, adjust his payments accordingly but without retroactive obligation. Lessee shall make any payments hereunder by mailing or delivering a check or draft to Lessor at N/A

3. If Geothermal Resources or Extractable Minerals are found in commercial quantities in any well or wells drilled on the Leased Land or land pooled therewith, Lessee may, at any time and from time to time, either before or after production, suspend or shut-in the operations of such well or wells and production therefrom. If operations are not being conducted hereunder or if there is no paying production attributable to this Lease, then commencing with the first day of the calendar month following the expiration of thirty (30) days from the date of such suspension or shut-in and on each Lease anniversary date thereafter, Lessee shall pay Lessor annually an amount equal to the rental provided for in paragraph 2 above, based upon the number of acres then covered by this Lease in absence of pooling or unitization, as shut-in royalty until such time as the operation of one such well is resumed or operations or paying production attributable to this Lease take place, whichever shall first occur. The maximum payment for such shut-in royalty in any Lease year shall in no event be greater than the amount computed for rental in paragraph 2 above regardless of the number of wells shut-in or suspended in any Lease year. Such shut-in royalty shall be deemed to be an advance royalty to be repaid to Lessee from royalties thereafter payable to Lessor hereunder. Any shut in well for which the foregoing payment is being paid shall be considered under all the provisions of this Lease as a producing well.

4. Lessee may at any time release or surrender this Lease in whole or in part or as to any zone, strata or depth, by placing of record a release or quitclaim deed in the county office where this Lease is recorded, and thereupon Lessee shall be released of all further obligations and duties as to the portion of the Leased Land so surrendered or released; and thereafter all payments to Lessor provided for herein, except royalties on actual production, shall be reduced in the same proportion that the acreage covered hereby is reduced. All land so surrendered or released shall remain subject to rights-of-way and easements for facilities necessary or convenient for Lessee's operations on the Leased Land retained or on land pooled therewith.

5. No well shall be drilled nearer than 300 feet to any house, barn or structure on the Leased Land, without the prior written consent of Lessor. Lessee shall pay for damages caused by its operation to growing crops and presently existing buildings and roads on the Leased Land. Lessee shall have the right at any time to remove all facilities placed on the Leased Land including the right to draw and remove casing. In addition to the right to produce Geothermal Resources and Extractable Minerals, Lessee shall have the right to use such water or water rights in, on, produced from or appurtenant to or crossing the Leased Land as Lessee may reasonably require in connection with its operations, provided that such use by Lessee of any water or water rights, as aforesaid, existing as of the date hereof, shall not interfere with Lessor's requirements for Lessor's own use thereof for domestic or agricultural purposes on the Leased Land and shall not be in violation of any applicable governmental law or regulation. Any brine, fluid or surplus water resulting from Lessee's activities or operations may be disposed of by reinjection or may be utilized or dealt with by Lessee in such lawful manner as Lessee shall deem appropriate.

6. Lessee shall pay all taxes levied against its improvements on the Leased Land. All taxes assessed against the Geothermal Resources and Extractable Minerals covered by this Lease, and all taxes, assessments or charges of whatever kind now or hereafter assessed, levied or collected by reason of the production, sale or removal of Geothermal Resources or Extractable Minerals from the Leased Land shall be borne by the par

OIL & GAS REC[illegible]

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ties hereto in the proportion of the royalty share by Lessor and the remainder by Lessee. Lessor shall pay, before delinquency, all other taxes and assessments on the Leased Land and improvements thereon.

7. Lessee may, at any time and from time to time during the Primary Term hereof, pool and combine the Leased Land, or any portion hereof, into an operating unit with other lands in the vicinity, another lease or other leases, or any portion thereof, when in the Lessee's judgment, it is necessary or advisable to do so in order to properly explore or develop or operate the Leased Land or to prevent waste or to avoid drilling unnecessary wells or to comply with applicable governmental laws, regulations or orders, provided that the total acreage in such pooled unit shall not exceed 2560 acres. Such pooling shall be effected by Lessee executing and filing in the office where this Lease is recorded an instrument describing and identifying the pooled acreage. The production of Geothermal Resources or Extractable Minerals so pooled and the development of and operation on any portion of the pooled unit shall be considered and construed and shall have the same effect, except for the payment of royalties, as production, development and operation on the Leased Land under the terms of this Lease. The royalties herein provided shall accrue and be paid to Lessor on pooled substances produced from any unit in the proportion that Lessor's interest in the land covered hereby and placed in the unit bears to the total acreage placed in each unit.

8. Lessee shall have the right at any time to commingle for the purpose of utilizing, storing, transporting, selling or processing Geothermal Resources or Extractable Minerals produced from the Leased Land or Land pooled therewith with like substances produced from other lands or units.

9. Upon the violation of any of the terms or conditions of this Lease by Lessee and the failure to begin to remedy the same with due diligence ninety (90) days after written notice from Lessor so to do, then, at the option of Lessor, this Lease shall forthwith cease and terminate, and all rights of Lessee in and to the Leased Land shall be at an end, saving and excepting the drill site for each producing well in respect of which Lessee is not in default, and saving and excepting rights-of-way necessary for Lessee's operations. The drill site referred to shall consist of a tract, designated by Lessee, of forty (40) acres, if there be so much, surrounding each producing well. The Lessee shall have a reasonable time from the termination for any reason of said Lease to remove all facilities, specifically including all permanent buildings placed on the Leased Land, and also including the right to draw and remove casing.

10. The obligations of Lessee hereunder shall be suspended while Lessee is prevented from complying therewith, in whole or in part, by strike, lockout, action of the elements, accidents, rules and regulations of the federal, state, municipal, or other governmental agencies, inability to obtain materials or supplies in the open market, or other matters or conditions beyond the control of Lessee, whether similar to matters or conditions herein specifically enumerated or not.

11. If Lessor owns less than the entire and undivided fee simple interest in ~~xxxxxxxxxxxxxxxx~~ the Geothermal Resources and Extractable Minerals, then royalties and rentals shall be paid to Lessor only in the proportion that his interest bears to the whole and undivided fee. If Lessor hereafter acquires any additional interest in the Leased Land, then this Lease shall cover after-acquired interest, provided that Lessor's share of rentals shall be increased to cover the interest so acquired at the next succeeding rental payment date after Lessee has been notified of such after-acquired interest or of any reversion having occurred. Any interest in the production from the Leased Land to which the interest of Lessor may be subject shall be deducted from the royalties provided for herein.

12. Lessor hereby warrants and agrees to defend the title to the Leased Land and agrees that Lessee may at its option pay and discharge any mortgage, taxes, assessments, or liens or encumbrances existing, levied or assessed against the Leased Land and be subrogated to the rights of the holder thereof, and Lessee shall have the right to apply to Lessee's repayment any rentals or royalties accruing to the Lessor hereunder.

13. Any notice from Lessor to Lessee shall be given by sending the same by registered or certified mail, addressed to Lessee at 4630 Adkins, Corpus Christi, Texas, 78411 and any notice from Lessee to Lessor shall be given by sending the same by registered or certified mail, addressed to Lessor at Rt. 3, Mineral Wells, Texas 76067
The address of either party may be changed by written notice as provided for above.

14. If the estate of either party hereto is assigned, and the privilege of assigning in whole or in part or as to any zone, strata or to any depth is expressly allowed, the covenants hereof shall extend to such assignee, his heirs, devisees, executors, administrators, successors, and assigns but no change in the ownership of the Leased Land or assignment of rentals or royalties shall be binding on the Lessee until thirty (30) days after Lessee has been furnished with a written transfer or assignment or certified copy thereof. Rentals hereunder shall not be apportioned upon assignment as to a particular zone, strata or depth, but shall continue as a single obligation to be paid by either party. In the event of any partial assignment production in commercial quantities on any portion of the Leased Land shall continue the Lease in force as whole to the same extent as if no assignment had been made. Any assignment shall, as to the extent of the assignment, relieve and discharge Lessee of all obligations hereunder and, should the assignee default in any of the obligations of this Lease, such default shall not operate to invalidate or affect this Lease insofar as it covers any part of the Leased Land or interest therein not included in the assignment.

15. Notwithstanding any other provisions of this lease should any governmental authority, federal or state, pass any legislation, rules, or regulations pertaining to the ownership requirements of any form of Geothermal Resources or Extractable Minerals, this Lease shall nevertheless be binding upon all the parties hereto, their heirs, devisees, executors, administrators, successors and assigns and shall not be affected in any way by such subsequent legislation rules, or regulations.

16. This Lease shall be binding upon the parties hereto, their heirs, devisees, executors, administrators, successors and assigns and may be executed in any number of counterparts with the same force and effect as if all parties had executed the same instrument. The failure of any person owning an interest in the Leased Land to execute a geothermal lease covering all or a portion of the Leased Land or the failure of any person named as a Lessor to execute a counterpart hereof, shall not affect the binding force of this Lease as to those who have executed or shall execute a counterpart hereof.

IN WITNESS WHEREOF, this Lease and Agreement is executed as of the date first above written.

Pauline Kraft

PAULINE KRAFT - LESSOR

STATE OF TEXAS
COUNTY OF NUECES

On this 26th day of November 1980 before me, Carolyn Schilpers a Notary Public in and for said County and state, personally appeared PAULINE KRAFT, to me known to be the person or persons who executed the within and foregoing instrument and acknowledged to me that she executed the same as her free and voluntary act and deed the uses and purposes therein set forth.

WITNESS my hand and official seal the day and year above written.

Carolyn Schilpers CAROLYN SCH
Notary Public in and for Nueces County, Texas

My Commission Expires 3-31-81

DON ROSS AGREEMENT WITH DWIGHT GWYN

STATE OF TEXAS §
§ **CONTRACTUAL AGREEMENT**
COUNTY OF NUECES §

WHEREAS Don Ross has previously leased a 158 acre tract of land, being a portion of the North half of the North half of Section 4 of Laureles Farm Tract in Nueces County, Texas (a complete legal description is labeled "Exhibit A" and attached hereto and expressly made a part of this contractual agreement for all purposes) from Pauline Kraft for the purpose of testing and developing certain potential Geothermal Resources;

WHEREAS Dwight Gwyn has the same property leased for farming purposes;

WHEREAS both Don Ross and Dwight Gwyn are desirous of entering into a mutual agreement pertaining to damages for the use of said property, the adequacy of the consideration therefor being acknowledged by both parties as satisfactory and adequate;

NOW THEREFORE for the mutual consideration and covenants herein expressed Don Ross and Dwight Gwyn do hereby agree that Don Ross will pay to Dwight Gwyn $1,500.00 representing surface damages at the time a drilling rig enters upon said premises. Said $1,500.00 shall be all of the damages due Dwight Gwyn as a farming tenant on said property if the Geothermal Resources test properly and Don Ross undertakes his development proceedings. If the well does not test properly and the well is abandoned and plugged Don Ross agrees to pay Dwight Gwyn and Dwight Gwyn agrees to accept $1,000.00 in additional damages as a final complete settlement of all damage issues between Don Ross and Dwight Gwyn.

Don Ross (signature)
____
Don Ross

Dwight Gwynn (signature)
____
Dwight Gwynn

EXHIBIT A

BEING that lot, tract or parcel of land and being approximately 158 acres of land, more or less, all of the North half of the North half of Section 4 of Laureles Farm Tract. Said Farm Tract being a Subdivision shown by map of record in Vol. 3 Page 15 of the Map Records of Nueces County, Texas.

SAVE AND EXCEPT the two acre tract in the Northeast corner thereof described in a deed dated December 3, 1923 from Pauline Kraft et al to Moreman Gin Company and recorded in Vol. 144, Page 534 of the Deed Records of Nueces County, Texas.

APPENDIX B

RIG CONTRACT

CONTRACT WITH TARGET WELL SERVICING

TARGET
WELL
SERVICING
CORPUS CHRISTI TEX.

RATE SCHEDULE

EFFECTIVE OCTOBER 1ST, 1980

TARGET WELL SERVICING

CORPUS CHRISTI, TEXAS
(A DIVISION OF ATCO LTD.)
P. O. BOX 9548 • 7454 LEOPARD ST. • CORPUS CHRISTI, TEXAS 78408
PHONE 512-883-6363

HOUSTON SALES OFFICE:
713-757-1045

Target Well Servicing, Rig No. 14

Franks 700 double drum back-in oilwell servicing and workover rig with 112' derrick of 300,000# capacity mounted on a self-propelled carrier with twin 8V92 (375 HP) diesel engines and Allison CLT 750 torque converters transmissions, hydrotarder brake system with 100 barrel water cooling tank and 9' x 40' rig base.

1 National JWS 400 mud pump with 12V79 (500 HP) engine with torque converter and air control.

1 National 300 mud pump with 8V71 (273 HP) for standby.

1 200 barrel mud tank.

1 Shaffer 10,000# double ram blowout preventer complete with H_2S trim 2 x 4 flanged openings.

1 Set Foster 58 - 93 hydraulic tongs.

1 Set Advance C slips with full circle.

1 Koomey 3 valve closing unit with 80 gallon capacity with dual separately powered air/electric poser, manual with air controls on rig floor.

1 16' Substructure Idesco SR-175F rotary table.

2 Sets pipe racks.

1 National 80 swivel.

1 Set King elevators and links suitable for 2-3/8" x 2-7/8" tubing.

1 10,000# Manifold H_2S trimmed.

1 Toolpusher trailer.

1 Crew dog house with A.C. workshop and generator house complete with 50 and 75 KW generators.

1 Set miscellaneous tools and inserts to handle 2-3/8" and 2-7/8" regular tubing.

1 3-1/2" x 36' Kelly.

1 10,000# Manifold H_2S trimmed.

CONDITIONS AND TECHNICAL PROVISIONS

CTP-01. LOCATION

Well Name and Number Pauline Kraft #1 County Nueces
State Texas Field Name Wildcat Well Location and
Land Description 467 FNL & 990 FWL of Section 4, Laureles Farm Tract, El Rincon de Corpus Christi Grant A-411

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 ______________ 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: See Tentative Drilling Program, Attachment ____

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 ______ 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.

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.

CTP-11. ACCOMMODATIONS

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 MISALIGHMENT

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

	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

(To Be Provided By And At Expense Of)

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.

APPENDIX C

RE-ENTRY OF TEST WELL

APPENDIX C

SUMMARY OF RIG OPERATIONS
ROSS - PAULINE KRAFT NO.1
RE-ENTRY OF TEST WELL

Daily Drilling Report Date	Day No.	Operations
12-20-80	1	Circulated and washed open hole. Reached T.D. of 13,002 feet. Circulated out gas-cut mud and conditioned mud to 16.5 pound per gallon. Pulled the drill string out of hole. Rigged up Schlumberger and ran ISF-Sonic Log. Rigged down Schlumberger.
12-21-80	2	Rigged up Dia-Log and ran mechanical casing inspection (wall thickness) log from 10,900 feet to the surface. Rigged down Dia-Log and made up 7-1/2 inch underreamer. Went in hole with underreamer on drill string to 6500 feet. Closed in well and locked blowout preventer rams.
12-22-80	3	Continued in hole with underreamer to 12,700 feet. Underreamed from 12,005 feet to 12,700 feet. Underreamed from 12,805 feet to 12,920 feet. Washed from 12,920 feet to 12,990 without underreaming. Circulated hole clean and pulled out of hole with drill string and underreamer.
12-23-80	4	Completed pulling out of hole with drill string and underreamer. Ran retrievable 7-inch bridge plug and set it at 998 feet. Pulled out of hole with drill string. Nippled down bell nipple and hydril blowout preventer. Waited on new 10-inch 3000-psi casing flange.
12-24-80	5	Nippled down blowout preventers, flanges, and bradenhead. Dug out celler to 9 feet. Made up spear on drill pipe, got hold on 7-inch casing with spear, pulled with 80,000 pounds on 7-inch casing and cut off plate welded to casing. Made bottom cut on 10-3/4 inch casing and dug out cellar an additional foot to allow room to weld on 10-3/4 inch casing collar. Welded casing collar onto top of 10-3/4 inch casing. Screwed threaded 10-3/4 inch nipple with bradenhead into welded collar.

12-25-80	6	Set 7-inch casing slips in 10-inch 3000-psi casing flange with 80,000 pounds. Bolted on double-studded adapter. Welded seals in casing spool. Tightened bolts on casing spool and tested to 3000 psi. Nippled up blowout preventers, hydril, and flowline. Filled hole with mud, closed and locked blind rams, and shut down for Christmas.
12-26-80	7	Shut down for Christmas.
12-27-80	8	Serviced rig, opened blind rams, and went in hole with drill string, retrieved bridge plug at 998 feet, and pulled out of hole. Picked up mill and bit sub and went in hole with drill string. Unloaded 355 joints of 5-inch casing on pipe racks. Circulated hole clean at 12,002 feet and conditioned mud. Rigged up drill pipe lay-down machine and started laying down drill pipe.
12-28-80	9	Completed laying down drill pipe and drill collars. Disconnected kelly and rigged up pipe tongs, elevators, and slips to run 5-inch casing. Ran 9 joints of 5-inch casing with centralizers and cable wipers. Casing stopped going in hole. Pulled out of hole with casing and found the centralizers were moving up the casing and breaking cable wipers and stacking up at casing collars. Cut off damaged centralizers and wipers and continued running 5-inch casing.
12-29-80	10	Completed running 325 joints of 5-inch casing consisting of 18 lb/ft L-80 FL4S casing, a crossover joint, 23lb/ft L-80 FL4S casing, a crossover joint, and 18 lb/ft P-110 SFJ casing with a down-jet float shoe on the bottom joint of casing and a float collar one joint up from the bottom. Set casing at 12,984.69 feet. Rigged up and circulated hole clean. Mixed and pumped 500 sacks of Class H cement with 35% SSA-2 silica flour, 0.75% CFR-2, 0.4% Halad 22-A, 0.4% MR-8 retarder and 3% KCL in a 17.0 lb/gallon slurry. Ran 10 barrels of SAM spacer ahead of cement. Displaced cement with 217 barrels of 16.5 lb/gallon mud. Final pump pressure was 1400 psi. Bumped cementing plug with 1900 psi and bled pressure to 0-psi. Held o.k. Closed hydril and waited for cement to set.

12-30-80	11	Waiting for cement to set.
12-31-80	12	Waited for cement to set while rig crew dug cellar for salt water disposal well.
01-01-81	13	Unloaded 413 joints of 2-3/8 inch 4.7 lb/ft. N-80 EUE 8 round tubing onto racks. Worked on cellar for salt water disposal well.
01-02-81	14	Nippled down blowout preventers, set casing slips with 300,000 pounds pull (100,000 pounds over casing weight). Made casing cut and layed down air equipment casing tools. Nippled up blowout preventers and rigged up Schlumberger. Ran gamma-ray, cement bond, collar locator log from 12,942 feet to 7000 feet. Estimated cement top at 7310 feet. Log was run with 2000 psi on casing. Nippled down blowout preventers, made final cut on 5-inch casing and installed tubing spool with pack-off. Rigged up tongs and equipment to run tubing.
01-03-81	15	Picked up and went in hole with 415 joints of 2-3/8 inch, 4.7 lb/ft, N-80, EUE 8 round tubing to 12,933 feet and rigged up Halliburton. Displaced 210 barrels of 16.5 pound per gallon mud with 9.0 pound per gallon salt water. Pulled up 11 joints of tubing and landed tubing in tubing head with bottom of tubing guide collar at 12,606 feet. Nippled down blowout preventers and installed tubing adapter. Tested casing to 6000 psi. Started dismantling rig and layed down elevators and kelly.
01-04-81	16	Moving rig to disposal well location.

APPENDIX D

DISPOSAL WELL DRILLING

APPENDIX D

SUMMARY OF RIG OPERATIONS
ROSS - PAULINE KRAFT NO.1
DISPOSAL WELL DRILLING

Daily Drilling Report Date	Day No.	Operations
01-03-81	1	Welded 12-inch 3000-psi flange to 14-inch conductor pipe. Boarded up cellar, dug shale pit, and leveled location.
01-04-81	2	Moved rig to location. Drilled 224-foot water well. Rigged up equipment, nippling up, racked drill collars. Picked up power swivel, kelly, and bit.
01-05-81	3	Drilled rat hole and mouse hole. Layed down power swivel. Installed bell nipple and rigged up 6-inch diverter line to pit. Welded collar on conductor pipe for fill-up line and installed flowline. Welded extension on bell nipple. Made up 12-1/4 inch bit and stabilizer on kelly and spudded well at 10:00 p.m. Drilled down kelly, broke off stabilizer and bit, picked up and made up 8-inch drill collar and began drilling.
01-06-81	4	Repaired main pump while circulating with standby pump. Drilled to 500 feet. Ran inclination survey at 400 feet which indicated $1/4^{\circ}$ deviation from vertical. Conditioned mud with desander working improperly. Drilled to 610 feet, circulated, and pulled out of hole. Bit balled up with mud. Cleaned cutting out of mud tank and went back in hole. Washed down 4 joints when going in hole. Drilled from 610 feet to 673 feet with only one pump. Clutch went out on small pump, and swabs leaking on main pump. Called for Halliburton pump truck.

01-07-81	5	Drilled from 673 feet to 800 feet. Ran inclination survey at 800 feet which showed no deviation from vertical. Drilled 800 feet to 1212 feet. Washed down kelly and circulated hole clean. Broke out kelly and ran inclination survey at 1212 feet which showed 1° deviation from vertical. Pulled out of hole and layed down 8-inch drill collars. Rigged up casing tongs, elevators, slips, and equipment to run surface casing. Ran 30 joints of 9-5/8 inch,36 lb/ft. J-55. ST&C with float shoe, float collar, and 5 centralizers to 1210 feet.
01-08-81	6	Rigged down casing tools and rigged up Halliburton cementing equipment. Ran 10 bbls of water and bottom-cementing plug, and cemented with 543 sacks of Halliburton Lite Wate cement in a 12.7 pound per gallon slurry, followed by 300 sacks of Class H neat cement in a 15.6 pound per gallon slurry. Displaced cement with 90 barrels of 9.0 pound per gallon mud on top of plug. Bumped plug from final pump pressure of 400 psi up to 1000 psi. Bled pressure to 0 and plug held. Waited for cement to set.
01-09-81	7	Waited for cement to set and prepared to cut conductor pipe and top of 9-5/8 inch surface casing. Layed down hydril blowout preventers. Made final cut on surface casing and welded on bradenhead flanges. Tested weld to 1100 psi. Nippled up blowout preventers. Tested blowout preventers, hydril, and manifold to 3000 psi. Welded and connected bell nipple and flow lines.
01-10-81	8	Welded extension on bell nipple. Went in hole with drill pipe and bit, and tagged top of cement plug at 1113 feet. Drilled cement to 1207 feet and formation to 1230 feet. Bit balled up with mud. Circulated well clean while trying to remove mud ball from bit. Pulled out of hole. Changed kelly bushing and hooked up pump No. 2 in tandem with pump No. 1. Went in hole with drill pipe and bit. Drilled from 1230 feet to 1357 feet.

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
3104 Edloe, Suite 200
Houston, Texas 77027
(713) 627-9764

01-11-81	9	Pulled out of hole to run stabilizer. Made up stabilizers and ran back in hole. Washed down 150 feet. Drilled from 1400 feet to 1545 feet. Tried different circulating rates, bit weights, and rotary speeds to improve drilling rate. Maximum rate obtained was 30 feet per hour.
01-12-81	10	Pulled drill string out of hole and found washed-out jet in bit. Changed bit and went in hole. Found 1-1/2 feet of sand in mud tank. Pulled bit up into surface casing while cleaning mud tanks. Filled mud tanks with fresh water and mixed gel and caustic soda. Went back to bottom of hole with bit and circulated hole clean of aerated mud, and conditioned mud. Drilled from 1545 feet to 1670 feet. Fixed leak in swivel union on kelly hose. Drilled from 1670 feet to 1732 feet.
01-13-81	11	Drilled from 1732 feet to 1762 feet. Worked on both mud pumps. Drilled from 1762 feet to 1846 feet. Ran inclination survey at 1800 feet which showed $1/4^{\circ}$ deviation from vertical. Attempted to drill with both pumps, but seals blew out on one when pressure reached 1200 psi. Started out of hole to change bit nozzles. Changed dies in slips and finished pulling out of hole. Cleaned and inspected bit, and changed nozzles to 12/32 inch. Repaired fluid end on mud pump. Went in hole and worked on pump lines. Drilled from 1856 feet to 1916 feet.
01-14-81	12	Drilled from 1916 feet to 1946 feet. Tightened bolts on mud pump lines. Drilled from 1946 feet to 1976 feet. Changed washed-out seal on fluid end of mud pump. Drilled from 1976 feet to 2183 feet. Rigged up Halliburton pump truck and drilled from 2183 feet to 2300 feet. Ran inclination survey at 2300 feet which showed 0° deviation from vertical. Drilled from 2300 feet to 2628 feet.

01-15-81	13	Drilled from 2628 feet to 2800 feet. Ran inclination survey at 2800 feet which showed $1/4^{\circ}$ deviation from vertical. Drilled from 2800 feet to 3300 feet. Ran inclination survey at 3300 feet which showed 1° deviation from vertical. Drilled from 3300 feet to 3405 feet.
01-16-81	14	Drilled from 3405 feet to 3800 feet. Ran inclination survey at 3800 feet which showed $1/4^{\circ}$ deviation from vertical. Drilled from 3800 feet to 4000 feet.
01-17-81	15	Motor on small pump failed to start. Changed fill-up line to large pump and set back kelly. Pulled out of hole and changed bit. Unloaded six 6-1/4 inch drill collars. Ran 6 stands of drill collars in hole and picked up 6 more drill collars from pipe rack and went in hole with drill string. Drilled from 4090 feet to 4327 feet. Ran inclination survey at 4327 feet which showed $1/4^{\circ}$ deviation from vertical. Drilled from 4327 feet to 4456 feet.
01-18-81	16	Drilled from 4456 feet to 4800 feet. Ran inclination survey at 4800 feet which showed $1/4^{\circ}$ deviation from vertical. One pump went out on Halliburton truck. Changed Halliburton pump trucks. Drilled from 4800 feet to 5275 feet. Ran inclination survey at 5275 feet which showed $1/4^{\circ}$ deviation from vertical. Circulated hole clean and started out of hole with drill string to run log.
01-19-81	17	Finished pulling out of hole. Rigged up Schlumberger. Started in hole with logging tool and could not get past 1306 feet. Spudded with wire line but could not move bridge in hole. Rigged down Schlumberger. Went in hole with drill string and bit. Applied 5000 pounds of weight at 1300 feet before breaking through bridge. Continued to bottom of hole at 5275 feet and circulated hole clean. Pulled drill string out of hole. Rigged up Schlumberger and ran induction, gamma-ray, density log with caliper from total depth to bottom of 9-5/8 inch surface casing. Rigged down Schlumberger. Went in hole with drill string to circulate.

01-20-81	18	Circulated hole clean while waiting on laydown machine. Pulled out of hole laying down drill pipe and drill collars. Rigged up to run 5-1/2 inch casing. Started running casing.
01-21-81	19	Finished running 133 joints of 5-1/2 inch 15.5 lb/ft, K-55, LT&C with float shoe and float collar at top of second joint. Ran 4 centralizers on bottom 2 joints and one on each of next 75 joints. Casing set at 5248 feet. Rigged down casing tools and rigged up Halliburton cementing equipment. Cemented casing with 660 sacks of Halliburton Lite Wate cement in a 12.7 pound per gallon slurry and followed with 500 sacks of Class H neat cement in a 15.6 pound per gallon slurry. Used top and bottom rubber cementing plugs and displaced cement with 123 barrels of 9.5 pounds per gallon saltwater. Final pump pressure was 1600 psi. Bumped plug with 2100 psi and bled off to 0 psi. Plug held. Plug was down at 1430 hrs. Got 60 bbls of good cement returns to surface. Broke out and raised blowout preventers and set casing slips. Made cut on 5-1/2 inch casing. Removed blowout preventers and made final cut on 5-1/2 inch casing. Completed assembly of christmas tree and tested to 2000 psi. Started cleaning mud tanks and rigging down rig equipment. Released rig.

APPENDIX E

ENERTECH COMPUTER THERMAL ANALYSIS

EnerTech
ENGINEERING AND RESEARCH CO.

2727 Kirby Drive, Suite 201
Houston, Texas 77098
Telephone: (713) 521-9033

July 10, 1981

Mr. Richard Z. Klauzinski
Chief Petroleum Engineer
Eaton Operating Company, Inc.
3104 Edloe, Suite 200
Houston, TX 77027

Re: Thermal Analysis of Pauline Kraft Well No. 1

Dear Mr. Klauzinski:

Enclosed are the WELLTEMP results that you requested on the subject well. Two printouts are included. One simulates the entire flow history of the operations between March 17, 1981 and March 20, 1981, and the other simulates only the injection period of the acid treatment. As you can see by comparing the two outputs, the effect of the prior history on the wellbore temperatures is small, generally less than two degrees.

The printout for each of the two cases consists of two parts, the well definition data and the temperature distributions at various times. Each temperature distribution is preceded by data that describes the flowing conditions for the specified time period.

We are pleased to be of service. If you have any questions or need additional information, please don't hesitate to contact us.

Very truly yours,

Malcolm A. Goodman

Malcolm A. Goodman

EATON THERMAL ANALYSIS OF PAULINE KRAFT WELL NO. 1

(Entire Flow and Injection Operations from March 17 to March 20, 1981)

T U B I N G   A N D   C A S I N G   D I M E N S I O N S

STRING	ID, IN	OD, IN	DEPTH, FT	CEMENT INTERVAL, FT	ANNULUS FLUID
1	1.995	2.375	12606.	0.	1
2	4.276	5.000	12750.	5450.	2
3	6.366	7.000	10969.	2969.	2
4	10.050	10.750	1242.	1242.	2

H O L E   D E V I A T I O N   D A T A

WELL NOT DEVIATED
TOTAL MEASURED DEPTH = 12750. FT

G R I D   P A R A M E T E R S

VERTICAL DEPTH INCREMENT = 500. FEET
NUMBER OF RADIAL POINTS = 10
MAXIMUM RADIUS = 50. FEET

G E O T H E R M A L   P R O F I L E

DEPTH FT.	TEMPERATURE F
0.	70.
12750.	274.

F L U I D   P R O P E R T I E S

FLUID # 1
DENSITY = 8.3 LBM/GAL
PLASTIC VISCOSITY = 1.00 CENTIPOISE
YIELD POINT = 0.0 LBF/100 FT2

FLUID # 2
DENSITY = 16.5 LBM/GAL
PLASTIC VISCOSITY = 44.00 CENTIPOISE
YIELD POINT = 14.0 LBF/100 FT2

O P T I O N S   S E L E C T E D

OPTION: PRINT

REGULAR PRINT

E N D   O F   W E L L   D E F I N I T I O N

* *

S E T   V A R I A B L E S   AT TIME =   0.00 HOURS
FLOWING OPTION = PRODUCTION
FLUID #   1 PRIMARY FLUID
INLET TEMPERATURE = 274. F
FLOW RATE =   30. BBL/DAY
TIME TO CHANGE DATA =   12.00 HOURS

(Flow after Perforating, March 17, 1981)

* *

TIME =   12.00 HOURS

T E M P E R A T U R E   D I S T R I B U T I O N, F

MEASURED DEPTH, FT.	FLUID	ANNULUS	SOIL RADIUS, FT. 0.4	SOIL RADIUS, FT. 1.2	UNDISTURBED
0.	70.8	70.0	70.0	70.0	70.0
10.	71.1	70.6	70.6	70.2	70.2
500.	78.9	78.5	78.4	78.1	78.0
1000.	86.9	86.5	86.4	86.1	86.0
1500.	94.8	94.5	94.4	94.1	94.0
2000.	102.8	102.5	102.4	102.1	102.0
2500.	110.8	110.5	110.4	110.1	110.0
3000.	118.8	118.5	118.4	118.1	118.0
3500.	126.8	126.5	126.4	126.1	126.0
4000.	134.8	134.5	134.4	134.0	134.0
4500.	142.8	142.5	142.5	142.1	142.0
5000.	150.8	150.5	150.4	150.0	150.0
5500.	158.8	158.5	158.5	158.1	158.0
6000.	166.8	166.5	166.4	166.0	166.0
6500.	174.8	174.5	174.5	174.1	174.0
7000.	182.9	182.5	182.4	182.0	182.0
7500.	190.8	190.5	190.5	190.1	190.0
8000.	198.9	198.5	198.4	198.0	198.0
8500.	206.8	206.5	206.5	206.1	206.0
9000.	214.9	214.5	214.4	214.0	214.0
9500.	222.8	222.5	222.5	222.1	222.0
10000.	230.8	230.4	230.4	230.0	230.0
10500.	238.9	238.6	238.5	238.1	238.0
11000.	247.0	246.8	246.5	246.0	246.0
11500.	255.4	255.1	254.9	254.1	254.0
12000.	262.3	262.2	262.0	262.0	262.0
12606.	274.0	273.6	273.1	271.9	271.7
12750.		274.0	274.0	274.0	274.0

S E T   V A R I A B L E S   AT TIME =   12.00 HOURS
FLOWING OPTION = PRODUCTION
FLUID #   1 PRIMARY FLUID
INLET TEMPERATURE = 274. F
FLOW RATE =   0. BBL/DAY
TIME TO CHANGE DATA =   24.00 HOURS
(Shut-in Period, March 17, 1981)

* *

TIME =   24.00 HOURS

T E M P E R A T U R E   D I S T R I B U T I O N, F

MEASURED DEPTH, FT.	FLUID	ANNULUS	SOIL RADIUS, FT. 0.4	1.2	UNDISTURBED
0.	70.0	70.0	70.0	70.0	70.0
10.	70.5	70.5	70.5	70.2	70.2
500.	78.4	78.3	78.3	78.1	78.0
1000.	86.4	86.3	86.3	86.1	86.0
1500.	94.3	94.3	94.3	94.1	94.0
2000.	102.4	102.3	102.3	102.1	102.0
2500.	110.3	110.3	110.3	110.1	110.0
3000.	118.3	118.3	118.3	118.1	118.0
3500.	126.4	126.3	126.3	126.1	126.0
4000.	134.3	134.3	134.3	134.1	134.0
4500.	142.4	142.3	142.3	142.1	142.0
5000.	150.3	150.3	150.3	150.1	150.0
5500.	158.4	158.3	158.3	158.1	158.0
6000.	166.3	166.3	166.3	166.1	166.0
6500.	174.4	174.3	174.3	174.1	174.0
7000.	182.3	182.3	182.3	182.1	182.0
7500.	190.4	190.3	190.3	190.1	190.0
8000.	198.3	198.3	198.3	198.1	198.0
8500.	206.4	206.4	206.3	206.1	206.0
9000.	214.3	214.3	214.3	214.1	214.0
9500.	222.4	222.4	222.4	222.1	222.0
10000.	230.3	230.3	230.3	230.1	230.0
10500.	238.4	238.4	238.4	238.1	238.0
11000.	246.3	246.3	246.3	246.1	246.0
11500.	254.6	254.6	254.5	254.2	254.0
12000.	262.0	262.0	262.0	262.0	262.0
12606.	272.7	272.6	272.6	272.0	271.7
12750.		274.0	274.0	274.0	274.0

S E T   V A R I A B L E S   AT TIME =   24.00 HOURS
FLOWING OPTION = PRODUCTION
FLUID # 1 PRIMARY FLUID
INLET TEMPERATURE = 274. F
FLOW RATE =   30. BBL/DAY
TIME TO CHANGE DATA =   36.00 HOURS

(Flow after Perforating, March 18, 1981)

* *

TIME =   36.00 HOURS

T E M P E R A T U R E   D I S T R I B U T I O N, F

MEASURED			SOIL RADIUS, FT.		
DEPTH, FT.	FLUID	ANNULUS	0.4	1.2	UNDISTURBED
0.	71.0	70.0	70.0	70.0	70.0
10.	71.2	70.8	70.8	70.3	70.2
500.	79.0	78.7	78.6	78.1	78.0
1000.	87.0	86.7	86.6	86.1	86.0
1500.	95.0	94.6	94.6	94.1	94.0
2000.	103.0	102.6	102.6	102.1	102.0
2500.	111.0	110.6	110.6	110.1	110.0
3000.	119.0	118.6	118.6	118.1	118.0
3500.	127.0	126.7	126.6	126.1	126.0
4000.	135.0	134.6	134.6	134.1	134.0
4500.	143.0	142.7	142.6	142.1	142.0
5000.	151.0	150.6	150.6	150.1	150.0
5500.	159.0	158.7	158.6	158.1	158.0
6000.	167.0	166.6	166.6	166.1	166.0
6500.	175.0	174.7	174.6	174.1	174.0
7000.	183.0	182.6	182.6	182.1	182.0
7500.	191.0	190.7	190.6	190.1	190.0
8000.	199.0	198.6	198.6	198.1	198.0
8500.	207.0	206.7	206.6	206.2	206.0
9000.	215.0	214.6	214.6	214.1	214.0
9500.	223.0	222.7	222.7	222.2	222.0
10000.	231.0	230.6	230.6	230.1	230.0
10500.	239.0	238.7	238.7	238.2	238.0
11000.	247.3	247.1	246.8	246.1	246.0
11500.	255.4	255.2	255.0	254.2	254.0
12000.	262.6	262.5	262.3	262.0	262.0
12606.	274.0	273.7	273.3	272.1	271.7
12750.		274.0	274.0	274.0	274.0

S E T   V A R I A B L E S   AT TIME =   36.00 HOURS
FLOWING OPTION = PRODUCTION
FLUID #   1 PRIMARY FLUID
INLET TEMPERATURE = 274. F
FLOW RATE =   0. BBL/DAY
TIME TO CHANGE DATA =   48.00 HOURS

(Shut-in Period, March 18, 1981)

* *

TIME =   48.00 HOURS

T E M P E R A T U R E   D I S T R I B U T I O N, F

MEASURED			SOIL RADIUS, FT.		
DEPTH, FT.	FLUID	ANNULUS	0.4	1.2	UNDISTURBED
0.	70.0	70.0	70.0	70.0	70.0
10.	70.7	70.7	70.7	70.3	70.2
500.	78.5	78.5	78.5	78.2	78.0
1000.	86.5	86.5	86.5	86.2	86.0
1500.	94.5	94.5	94.5	94.2	94.0
2000.	102.5	102.5	102.5	102.2	102.0
2500.	110.5	110.5	110.5	110.2	110.0
3000.	118.5	118.5	118.5	118.2	118.0
3500.	126.5	126.5	126.5	126.2	126.0
4000.	134.5	134.5	134.5	134.2	134.0
4500.	142.5	142.5	142.5	142.2	142.0
5000.	150.5	150.5	150.5	150.2	150.0
5500.	158.5	158.5	158.5	158.2	158.0
6000.	166.5	166.5	166.5	166.2	166.0
6500.	174.5	174.5	174.5	174.2	174.0
7000.	182.5	182.5	182.5	182.2	182.0
7500.	190.5	190.5	190.5	190.2	190.0
8000.	198.5	198.5	198.5	198.2	198.0
8500.	206.5	206.5	206.5	206.2	206.0
9000.	214.5	214.5	214.5	214.2	214.0
9500.	222.5	222.5	222.5	222.2	222.0
10000.	230.5	230.5	230.4	230.2	230.0
10500.	238.6	238.6	238.6	238.2	238.0
11000.	246.5	246.5	246.5	246.2	246.0
11500.	254.7	254.7	254.7	254.3	254.0
12000.	262.2	262.2	262.2	262.0	262.0
12606.	272.9	272.8	272.8	272.1	271.7
12750.		274.0	274.0	274.0	274.0

S E T   V A R I A B L E S   AT TIME =   48.00 HOURS
FLOWING OPTION = INJECTION
FLUID #   1 PRIMARY FLUID
INLET TEMPERATURE =   70. F
FLOW RATE =   21. GAL/MIN
TIME TO CHANGE DATA =   48.50 HOURS

(Surging of Perforations, March 19, 1981)

* *

TIME =   48.50 HOURS

T E M P E R A T U R E   D I S T R I B U T I O N, F

MEASURED			SOIL RADIUS, FT.		
DEPTH, FT.	FLUID	ANNULUS	0.4	1.2	UNDISTURBED
0.	70.0	70.0	70.0	70.0	70.0
10.	70.0	70.3	70.5	70.3	70.2
500.	74.6	76.2	77.5	78.2	78.0
1000.	82.8	84.3	85.6	86.2	86.0
1500.	90.9	92.3	93.6	94.2	94.0
2000.	98.9	100.3	101.6	102.2	102.0
2500.	106.9	108.3	109.6	110.2	110.0
3000.	114.9	116.3	117.6	118.2	118.0
3500.	122.9	124.3	125.6	126.2	126.0
4000.	130.9	132.3	133.6	134.2	134.0
4500.	138.9	140.3	141.6	142.2	142.0
5000.	146.9	148.3	149.6	150.2	150.0
5500.	154.9	156.3	157.6	158.2	158.0
6000.	162.9	164.3	165.6	166.2	166.0
6500.	170.9	172.3	173.6	174.2	174.0
7000.	178.9	180.3	181.6	182.2	182.0
7500.	186.9	188.3	189.6	190.2	190.0
8000.	194.9	196.3	197.6	198.2	198.0
8500.	202.9	204.3	205.6	206.2	206.0
9000.	210.9	212.3	213.6	214.2	214.0
9500.	218.9	220.3	221.6	222.2	222.0
10000.	226.9	228.3	229.6	230.1	230.0
10500.	234.9	236.3	237.6	238.2	238.0
11000.	241.7	242.4	245.9	246.2	246.0
11500.	248.4	249.5	254.1	254.3	254.0
12000.	256.3	257.4	261.7	262.0	262.0
12606.	266.2	267.3	272.2	272.1	271.7
12750.		274.0	274.0	274.0	274.0

S E T   V A R I A B L E S   AT TIME =   48.50 HOURS
FLOWING OPTION = FORWARD CIRCULATION
FLUID #   1 PRIMARY FLUID
INLET TEMPERATURE =   70. F
FLOW RATE =   210. GAL/MIN
TIME TO CHANGE DATA =   49.10 HOURS

(Circulating 180 barrels of clean water, March 19, 1981)

* *

TIME =   49.10 HOURS

T E M P E R A T U R E   D I S T R I B U T I O N, F

MEASURED DEPTH, FT.	FLUID	ANNULUS	SOIL RADIUS, FT. 0.4	1.2	UNDISTURBED
0.	70.0	79.0	70.0	70.0	70.0
10.	70.1	79.1	74.5	70.4	70.2
500.	73.8	85.1	81.0	78.2	78.0
1000.	78.5	91.5	88.3	86.2	86.0
1500.	83.9	98.4	95.7	94.2	94.0
2000.	89.8	105.4	103.3	102.2	102.0
2500.	96.1	112.7	111.0	110.2	110.0
3000.	102.8	120.1	118.7	118.2	118.0
3500.	109.7	127.7	126.5	126.2	126.0
4000.	116.9	135.3	134.4	134.2	134.0
4500.	124.2	143.0	142.3	142.2	142.0
5000.	131.7	150.8	150.2	150.2	150.0
5500.	139.2	158.6	158.1	158.2	158.0
6000.	146.9	166.4	166.1	166.2	166.0
6500.	154.6	174.3	174.0	174.2	174.0
7000.	162.4	182.1	181.9	182.2	182.0
7500.	170.2	189.9	189.9	190.2	190.0
8000.	178.0	197.6	197.8	198.2	198.0
8500.	185.7	205.1	205.6	206.2	206.0
9000.	193.3	212.2	213.3	214.1	214.0
9500.	200.6	218.6	220.7	222.2	222.0
10000.	207.4	223.7	227.6	230.1	230.0
10500.	213.3	226.8	233.7	238.2	238.0
11000.	218.5	229.2	243.6	246.1	246.0
11500.	222.9	231.2	251.3	254.2	254.0
12000.	226.1	231.1	257.8	262.0	262.0
12606.	227.7	227.7	266.1	272.1	271.7
12750.		274.0	274.0	274.0	274.0

3650' average	129°	128°

S E T   V A R I A B L E S   AT TIME =   49.10 HOURS
FLOWING OPTION = INJECTION
FLUID #   1 PRIMARY FLUID
INLET TEMPERATURE =   70. F
FLOW RATE =   42. GAL/MIN
TIME TO CHANGE DATA =   49.28 HOURS

(Second Surging of Perforations, March 19, 1981)

* *

TIME =   49.28 HOURS

T E M P E R A T U R E   D I S T R I B U T I O N, F

MEASURED DEPTH, FT.	FLUID	ANNULUS	SOIL RADIUS, FT. 0.4	1.2	UNDISTURBED
0.	70.0	70.0	70.0	70.0	70.0
10.	70.4	72.6	74.1	70.4	70.2
500.	77.4	79.5	80.7	78.2	78.0
1000.	84.3	86.3	87.8	86.2	86.0
1500.	91.2	93.4	95.2	94.2	94.0
2000.	98.5	100.7	102.7	102.2	102.0
2500.	105.9	108.2	110.3	110.2	110.0
3000.	113.4	115.8	118.0	118.2	118.0
3500.	121.1	123.5	125.8	126.2	126.0
4000.	128.8	131.2	133.6	134.2	134.0
4500.	136.6	139.1	141.5	142.2	142.0
5000.	144.4	146.9	149.4	150.2	150.0
5500.	152.2	154.8	157.3	158.2	158.0
6000.	160.1	162.7	165.2	166.2	166.0
6500.	168.0	170.6	173.1	174.2	174.0
7000.	176.0	178.5	181.1	182.2	182.0
7500.	183.9	186.4	189.0	190.2	190.0
8000.	191.7	194.3	196.9	198.1	198.0
8500.	199.5	202.1	204.7	206.2	206.0
9000.	207.2	209.7	212.3	214.1	214.0
9500.	214.6	217.0	219.7	222.2	222.0
10000.	221.5	223.8	226.6	230.1	230.0
10500.	227.6	229.7	232.5	238.1	238.0
11000.	230.8	231.3	242.8	246.1	246.0
11500.	232.9	234.2	250.4	254.2	254.0
12000.	236.3	237.5	256.8	262.0	262.0
12606.	238.9	239.9	264.7	272.0	271.7
12750.		274.0	274.0	274.0	274.0

S E T V A R I A B L E S AT TIME = 49.28 HOURS
FLOWING OPTION = PRODUCTION
FLUID # 1 PRIMARY FLUID
INLET TEMPERATURE = 274. F
FLOW RATE = 93. BBL/DAY
TIME TO CHANGE DATA = 55.28 HOURS

(Flowing Well Prior to Acid Job, March 19-20, 1981)

* *

TIME = 55.28 HOURS

T E M P E R A T U R E D I S T R I B U T I O N, F

MEASURED DEPTH, FT.	FLUID	ANNULUS	SOIL RADIUS, FT. 0.4	1.2	UNDISTURBED
0.	75.0	70.0	70.0	70.0	70.0
10.	74.5	74.0	73.8	70.6	70.2
500.	81.6	81.0	80.9	78.4	78.0
1000.	88.9	88.4	88.3	86.3	86.0
1500.	96.5	96.0	95.8	94.3	94.0
2000.	104.1	103.6	103.5	102.2	102.0
2500.	111.9	111.4	111.2	110.2	110.0
3000.	119.7	119.2	119.0	118.2	118.0
3500.	127.5	127.0	126.8	126.2	126.0
4000.	135.4	134.9	134.7	134.2	134.0
4500.	143.3	142.8	142.6	142.2	142.0
5000.	151.2	150.7	150.6	150.1	150.0
5500.	159.2	158.7	158.5	158.1	158.0
6000.	167.1	166.6	166.4	166.1	166.0
6500.	175.1	174.6	174.4	174.1	174.0
7000.	183.0	182.5	182.4	182.1	182.0
7500.	191.0	190.4	190.3	190.1	190.0
8000.	198.9	198.4	198.2	198.1	198.0
8500.	206.7	206.2	206.1	206.1	206.0
9000.	214.4	213.9	213.7	214.0	214.0
9500.	222.0	221.6	221.4	222.0	222.0
10000.	228.7	228.3	228.2	229.9	230.0
10500.	236.1	235.5	235.3	237.8	238.0
11000.	245.7	245.3	244.2	245.9	246.0
11500.	251.3	251.3	251.3	253.9	254.0
12000.	257.0	256.6	256.0	261.4	262.0
12606.	274.0	273.2	271.0	271.8	271.7
12750.		274.0	274.0	274.0	274.0

S E T   V A R I A B L E S   AT TIME =   55.28 HOURS

FLOWING OPTION = PRODUCTION

FLUID #   1 PRIMARY FLUID

INLET TEMPERATURE = 274. F

FLOW RATE =   64. BBL/DAY

TIME TO CHANGE DATA =   67.28 HOURS

(Flowing Well Prior to Acid Job, March 19-20, 1981)

* *

TIME =   67.28 HOURS

T E M P E R A T U R E   D I S T R I B U T I O N, F

MEASURED			SOIL RADIUS, FT.		
DEPTH, FT.	FLUID	ANNULUS	0.4	1.2	UNDISTURBED
0.	74.7	70.0	70.0	70.0	70.0
10.	74.2	73.7	73.6	71.0	70.2
500.	81.5	81.1	80.9	78.7	78.0
1000.	89.1	88.7	88.6	86.6	86.0
1500.	96.8	96.4	96.3	94.5	94.0
2000.	104.6	104.2	104.1	102.5	102.0
2500.	112.5	112.0	111.9	110.4	110.0
3000.	120.3	119.9	119.8	118.4	118.0
3500.	128.3	127.8	127.7	126.4	126.0
4000.	136.2	135.7	135.6	134.3	134.0
4500.	144.1	143.7	143.6	142.3	142.0
5000.	152.1	151.6	151.5	150.3	150.0
5500.	160.0	159.6	159.5	158.3	158.0
6000.	168.0	167.6	167.5	166.3	166.0
6500.	176.0	175.5	175.4	174.3	174.0
7000.	184.0	183.5	183.4	182.3	182.0
7500.	191.9	191.5	191.4	190.3	190.0
8000.	199.9	199.4	199.3	198.2	198.0
8500.	207.7	207.3	207.2	206.2	206.0
9000.	215.5	215.1	215.0	214.1	214.0
9500.	223.3	222.9	222.8	222.1	222.0
10000.	230.1	229.8	229.8	229.8	230.0
10500.	238.6	238.0	237.9	237.8	238.0
11000.	247.6	247.4	246.8	246.0	246.0
11500.	253.2	253.1	252.9	253.8	254.0
12000.	261.9	261.4	260.6	261.3	262.0
12606.	274.0	273.7	273.2	272.0	271.7
12750.		274.0	274.0	274.0	274.0

S E T V A R I A B L E S AT TIME = 67.28 HOURS
FLOWING OPTION = PRODUCTION
FLUID # 1 PRIMARY FLUID
INLET TEMPERATURE = 274. F
FLOW RATE = 35. BBL/DAY
TIME TO CHANGE DATA = 73.28 HOURS

(Flowing Well Prior to Acid Job, March 19-20, 1981)

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TIME = 73.28 HOURS

T E M P E R A T U R E D I S T R I B U T I O N, F

MEASURED DEPTH, FT.	FLUID	ANNULUS	SOIL RADIUS, FT. 0.4	1.2	UNDISTURBED
0.	74.5	70.0	70.0	70.0	70.0
10.	73.8	73.4	73.3	71.1	70.2
500.	81.3	80.8	80.7	78.8	78.0
1000.	88.9	88.5	88.4	86.7	86.0
1500.	96.6	96.3	96.2	94.6	94.0
2000.	104.5	104.1	104.0	102.5	102.0
2500.	112.4	112.0	111.9	110.5	110.0
3000.	120.3	119.9	119.8	118.5	118.0
3500.	128.2	127.8	127.7	126.4	126.0
4000.	136.1	135.7	135.7	134.4	134.0
4500.	144.1	143.7	143.6	142.4	142.0
5000.	152.0	151.6	151.6	150.4	150.0
5500.	160.0	159.6	159.5	158.4	158.0
6000.	168.0	167.6	167.5	166.4	166.0
6500.	175.9	175.6	175.5	174.4	174.0
7000.	183.9	183.5	183.5	182.3	182.0
7500.	191.9	191.5	191.4	190.3	190.0
8000.	199.9	199.5	199.4	198.3	198.0
8500.	207.7	207.4	207.3	206.3	206.0
9000.	215.6	215.2	215.1	214.2	214.0
9500.	223.4	223.0	223.0	222.2	222.0
10000.	230.4	230.1	230.0	229.9	230.0
10500.	238.9	238.4	238.3	237.9	238.0
11000.	247.5	247.3	247.0	246.1	246.0
11500.	253.8	253.6	253.4	253.8	254.0
12000.	262.1	261.8	261.4	261.4	262.0
12606.	274.0	273.7	273.3	272.0	271.7
12750.		274.0	274.0	274.0	274.0

S E T V A R I A B L E S AT TIME = 73.28 HOURS
FLOWING OPTION = INJECTION
FLUID # 1 PRIMARY FLUID
INLET TEMPERATURE = 70. F
FLOW RATE = 42. GAL/MIN
TIME TO CHANGE DATA = 80.82 HOURS

(Acid Job, March 20, 1981)

* *

TIME = 80.82 HOURS

T E M P E R A T U R E D I S T R I B U T I O N, F

MEASURED DEPTH, FT.	FLUID	ANNULUS	SOIL RADIUS, FT. 0.4	1.2	UNDISTURBED
0.	70.0	70.0	70.0	70.0	70.0
10.	70.3	70.3	70.4	70.9	70.2
500.	71.2	71.6	72.2	78.1	78.0
1000.	73.4	74.3	75.3	85.6	86.0
1500.	77.1	78.5	79.8	93.3	94.0
2000.	82.1	83.7	85.4	101.1	102.0
2500.	87.9	89.8	91.7	108.9	110.0
3000.	94.4	96.5	98.6	116.8	118.0
3500.	101.5	103.6	105.9	124.7	126.0
4000.	108.9	111.1	113.4	132.7	134.0
4500.	116.5	118.8	121.1	140.6	142.0
5000.	124.3	126.6	128.9	148.6	150.0
5500.	132.1	134.4	136.8	156.6	158.0
6000.	140.0	142.4	144.8	164.6	166.0
6500.	148.0	150.3	152.7	172.6	174.0
7000.	155.9	158.3	160.7	180.6	182.0
7500.	163.9	166.3	168.7	188.6	190.0
8000.	171.9	174.2	176.6	196.5	198.0
8500.	179.8	182.2	184.6	204.5	206.0
9000.	187.8	190.2	192.6	212.5	214.0
9500.	195.7	198.1	200.5	220.4	222.0
10000.	203.6	206.0	208.3	228.2	230.0
10500.	211.5	213.8	216.2	236.1	238.0
11000.	218.0	219.3	229.3	244.9	246.0
11500.	223.8	225.4	236.4	252.6	254.0
12000.	230.2	231.9	243.3	260.2	262.0
12606.	238.5	240.3	252.6	270.6	271.7
12750.		274.0	274.0	274.0	274.0

S E T V A R I A B L E S AT TIME = 80.82 HOURS
FLOWING OPTION = INJECTION
FLUID # 1 PRIMARY FLUID
INLET TEMPERATURE = 70. F
FLOW RATE = 84. GAL/MIN
TIME TO CHANGE DATA = 81.02 HOURS

(Acid Job, March 20, 1981)

* *

TIME = 81.02 HOURS

T E M P E R A T U R E D I S T R I B U T I O N, F

MEASURED DEPTH, FT.	FLUID	ANNULUS	SOIL RADIUS, FT. 0.4	SOIL RADIUS, FT. 1.2	UNDISTURBED
0.	70.0	70.0	70.0	70.0	70.0
10.	70.2	70.3	70.4	70.9	70.2
500.	70.8	71.3	72.1	78.1	78.0
1000.	72.4	73.6	75.0	85.6	86.0
1500.	75.3	77.1	79.4	93.2	94.0
2000.	79.4	81.8	84.8	101.0	102.0
2500.	84.6	87.4	90.9	108.8	110.0
3000.	90.5	93.8	97.7	116.7	118.0
3500.	97.2	100.7	104.9	124.7	126.0
4000.	104.2	107.9	112.4	132.6	134.0
4500.	111.7	115.5	120.1	140.6	142.0
5000.	119.3	123.2	127.9	148.5	150.0
5500.	127.0	131.0	135.7	156.5	158.0
6000.	134.9	138.9	143.7	164.5	166.0
6500.	142.8	146.8	151.6	172.5	174.0
7000.	150.8	154.8	159.6	180.5	182.0
7500.	158.7	162.7	167.6	188.5	190.0
8000.	166.7	170.7	175.5	196.5	198.0
8500.	174.6	178.7	183.5	204.5	206.0
9000.	182.6	186.6	191.4	212.4	214.0
9500.	190.6	194.6	199.4	220.3	222.0
10000.	198.5	202.5	207.2	228.1	230.0
10500.	206.4	210.3	215.1	236.1	238.0
11000.	212.8	215.0	228.6	244.9	246.0
11500.	218.2	220.8	235.8	252.5	254.0
12000.	224.3	227.1	242.6	260.1	262.0
12606.	232.2	235.1	251.9	270.6	271.7
12750.		274.0	274.0	274.0	274.0

M

S E T V A R I A B L E S AT TIME = 81.02 HOURS
FLOWING OPTION = INJECTION
FLUID # 1 PRIMARY FLUID
INLET TEMPERATURE = 70. F
FLOW RATE = 84. GAL/MIN
TIME TO CHANGE DATA = 81.36 HOURS

(Acid Job, March 20, 1981)

* *

TIME = 81.36 HOURS

T E M P E R A T U R E D I S T R I B U T I O N, F

MEASURED			SOIL RADIUS, FT.		
DEPTH, FT.	FLUID	ANNULUS	0.4	1.2	UNDISTURBED
0.	70.0	70.0	70.0	70.0	70.0
10.	70.2	70.2	70.3	70.9	70.2
500.	70.7	71.2	71.8	78.1	78.0
1000.	72.1	73.2	74.5	85.6	86.0
1500.	74.7	76.4	78.5	93.2	94.0
2000.	78.4	80.7	83.6	100.9	102.0
2500.	83.2	86.0	89.5	108.7	110.0
3000.	88.9	92.0	96.0	116.6	118.0
3500.	95.2	98.6	103.0	124.5	126.0
4000.	102.0	105.7	110.3	132.5	134.0
4500.	109.3	113.1	117.9	140.5	142.0
5000.	116.8	120.7	125.7	148.4	150.0
5500.	124.4	128.4	133.5	156.4	158.0
6000.	132.2	136.3	141.4	164.4	166.0
6500.	140.1	144.2	149.3	172.4	174.0
7000.	148.0	152.1	157.3	180.4	182.0
7500.	156.0	160.1	165.3	188.4	190.0
8000.	163.9	168.0	173.2	196.3	198.0
8500.	171.9	176.0	181.2	204.3	206.0
9000.	179.8	184.0	189.1	212.3	214.0
9500.	187.8	191.9	197.1	220.2	222.0
10000.	195.7	199.8	205.0	228.0	230.0
10500.	203.6	207.7	212.8	235.9	238.0
11000.	209.7	211.7	227.2	244.8	246.0
11500.	214.6	217.1	234.5	252.4	254.0
12000.	220.2	222.9	241.2	260.0	262.0
12606.	227.6	230.5	250.4	270.5	271.7
12750.		274.0	274.0	274.0	274.0

3650' average 101° 128°

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EATON SIMULATION OF ACID TREATMENT WITHOUT PRIOR HISTORY

(Simulation of Acid Job Alone for Comparison Only)

T U B I N G   A N D   C A S I N G   D I M E N S I O N S

STRING	ID, IN	OD, IN	DEPTH, FT	CEMENT INTERVAL, FT	ANNULUS FLUID
1	1.995	2.375	12606.	0.	1
2	4.276	5.000	12750.	5450.	2
3	6.366	7.000	10969.	2969.	2
4	10.050	10.750	1242.	1242.	2

H O L E   D E V I A T I O N   D A T A

WELL NOT DEVIATED
TOTAL MEASURED DEPTH = 12750. FT

G R I D   P A R A M E T E R S

VERTICAL DEPTH INCREMENT = 500. FEET
NUMBER OF RADIAL POINTS = 10
MAXIMUM RADIUS = 50. FEET

G E O T H E R M A L   P R O F I L E

DEPTH FT.	TEMPERATURE F
0.	70.
12750.	274.

F L U I D   P R O P E R T I E S

FLUID # 1
DENSITY = 8.3 LBM/GAL
PLASTIC VISCOSITY = 1.00 CENTIPOISE
YIELD POINT = 0.0 LBF/100 FT2

FLUID # 2
DENSITY = 16.5 LBM/GAL
PLASTIC VISCOSITY = 44.00 CENTIPOISE
YIELD POINT = 14.0 LBF/100 FT2

O P T I O N S   S E L E C T E D

OPTION: PRINT

REGULAR PRINT

E N D   O F   W E L L   D E F I N I T I O N

* *

S E T V A R I A B L E S AT TIME = 0.00 HOURS
FLOWING OPTION = INJECTION
FLUID # 1 PRIMARY FLUID
INLET TEMPERATURE = 70. F
FLOW RATE = 42. GAL/MIN
TIME TO CHANGE DATA = 7.54 HOURS
(Acid Job Alone, March 20, 1981)

* *

TIME = 7.54 HOURS

T E M P E R A T U R E D I S T R I B U T I O N, F

MEASURED DEPTH, FT.	FLUID	ANNULUS	SOIL RADIUS, FT. 0.4	1.2	UNDISTURBED
0.	70.0	70.0	70.0	70.0	70.0
10.	70.0	70.0	70.0	70.1	70.2
500.	70.7	71.1	71.5	77.4	78.0
1000.	72.7	73.5	74.4	85.0	86.0
1500.	76.1	77.4	78.7	92.7	94.0
2000.	80.9	82.5	84.1	100.5	102.0
2500.	86.6	88.5	90.4	108.3	110.0
3000.	93.1	95.1	97.2	116.3	118.0
3500.	100.1	102.3	104.5	124.2	126.0
4000.	107.5	109.7	112.1	132.2	134.0
4500.	115.1	117.4	119.8	140.2	142.0
5000.	122.9	125.3	127.7	148.2	150.0
5500.	130.8	133.2	135.6	156.2	158.0
6000.	138.8	141.2	143.6	164.2	166.0
6500.	146.8	149.1	151.6	172.2	174.0
7000.	154.8	157.1	159.6	180.2	182.0
7500.	162.8	165.1	167.6	188.2	190.0
8000.	170.8	173.1	175.6	196.2	198.0
8500.	178.8	181.1	183.6	204.2	206.0
9000.	186.8	189.1	191.6	212.2	214.0
9500.	194.8	197.1	199.6	220.2	222.0
10000.	202.8	205.1	207.6	228.2	230.0
10500.	210.8	213.1	215.6	236.2	238.0
11000.	217.4	218.7	228.7	244.8	246.0
11500.	223.3	224.9	236.2	252.7	254.0
12000.	229.9	231.6	243.3	260.6	262.0
12606.	238.2	239.9	252.1	270.3	271.7
12750.		274.0	274.0	274.0	274.0

SET VARIABLES AT TIME = 7.54 HOURS
FLOWING OPTION = INJECTION
FLUID # 1 PRIMARY FLUID
INLET TEMPERATURE = 70. F
FLOW RATE = 84. GAL/MIN
TIME TO CHANGE DATA = 7.74 HOURS

(Acid Job Alone, March 20, 1981)

* *

TIME = 7.74 HOURS

TEMPERATURE DISTRIBUTION, F

MEASURED DEPTH, FT.	FLUID	ANNULUS	SOIL RADIUS, FT. 0.4	SOIL RADIUS, FT. 1.2	UNDISTURBED
0.	70.0	70.0	70.0	70.0	70.0
10.	70.0	70.0	70.0	70.1	70.2
500.	70.4	70.9	71.4	77.4	78.0
1000.	71.8	72.8	74.2	85.0	86.0
1500.	74.5	76.2	78.3	92.6	94.0
2000.	78.4	80.7	83.5	100.4	102.0
2500.	83.4	86.2	89.6	108.3	110.0
3000.	89.3	92.5	96.4	116.2	118.0
3500.	95.8	99.3	103.5	124.2	126.0
4000.	102.9	106.6	111.1	132.1	134.0
4500.	110.3	114.1	118.8	140.1	142.0
5000.	118.0	121.9	126.6	148.1	150.0
5500.	125.8	129.7	134.5	156.1	158.0
6000.	133.7	137.7	142.5	164.1	166.0
6500.	141.6	145.6	150.5	172.1	174.0
7000.	149.6	153.6	158.5	180.1	182.0
7500.	157.6	161.6	166.5	188.1	190.0
8000.	165.6	169.6	174.5	196.1	198.0
8500.	173.6	177.6	182.5	204.1	206.0
9000.	181.6	185.6	190.5	212.1	214.0
9500.	189.6	193.6	198.5	220.1	222.0
10000.	197.6	201.6	206.5	228.1	230.0
10500.	205.6	209.6	214.5	236.1	238.0
11000.	212.1	214.3	228.1	244.8	246.0
11500.	217.6	220.3	235.6	252.7	254.0
12000.	223.8	226.6	242.6	260.6	262.0
12606.	231.8	234.7	251.4	270.2	271.7
12750.		274.0	274.0	274.0	274.0

S E T V A R I A B L E S AT TIME = 7.74 HOURS
FLOWING OPTION = INJECTION
FLUID # 1 PRIMARY FLUID
INLET TEMPERATURE = 70. F
FLOW RATE = 84. GAL/MIN
TIME TO CHANGE DATA = 8.08 HOURS

(Acid Job Alone, March 20, 1981)

* *

TIME = 8.08 HOURS

T E M P E R A T U R E D I S T R I B U T I O N, F

MEASURED			SOIL RADIUS, FT.		
DEPTH, FT.	FLUID	ANNULUS	0.4	1.2	UNDISTURBED
0.	70.0	70.0	70.0	70.0	70.0
10.	70.0	70.0	70.0	70.1	70.2
500.	70.4	70.8	71.3	77.4	78.0
1000.	71.6	72.5	73.8	84.9	86.0
1500.	74.0	75.5	77.6	92.5	94.0
2000.	77.5	79.6	82.4	100.3	102.0
2500.	82.1	84.7	88.2	108.2	110.0
3000.	87.6	90.7	94.7	116.1	118.0
3500.	93.8	97.3	101.7	124.0	126.0
4000.	100.7	104.3	109.1	132.0	134.0
4500.	107.9	111.7	116.7	140.0	142.0
5000.	115.4	119.3	124.4	148.0	150.0
5500.	123.1	127.1	132.3	156.0	158.0
6000.	130.9	135.0	140.2	164.0	166.0
6500.	138.8	142.9	148.2	172.0	174.0
7000.	146.8	150.9	156.2	180.0	182.0
7500.	154.7	158.9	164.2	188.0	190.0
8000.	162.7	166.9	172.2	196.0	198.0
8500.	170.7	174.9	180.2	204.0	206.0
9000.	178.7	182.9	188.2	212.0	214.0
9500.	186.7	190.9	196.2	220.0	222.0
10000.	194.7	198.9	204.2	228.0	230.0
10500.	202.7	206.9	212.2	236.0	238.0
11000.	208.9	210.9	226.7	244.7	246.0
11500.	213.9	216.4	234.2	252.6	254.0
12000.	219.6	222.3	241.2	260.5	262.0
12606.	227.1	230.0	249.9	270.1	271.7
12750.		274.0	274.0	274.0	274.0