DOE/ID/12578-3

CONTRACTOR FOR GEOPRESSURED-GEOTHERMAL SITES

Final Contract Report, Volume 1

Fiscal Years 1986 - 1990 (5 Years)

Testing of Wells through October 1990

(Revised September 1992)

Appendix A, Volume 2
Gladys McCall Site (Cameron Parish, LA)

Appendix B-1, Volume 3
Pleasant Bayou Site

Appendix B-2, Volume 4
Pleasant Bayou Site

Appendix C, Volume 5
Willis Hulin Site

Work Performed Under Contract No. DE-AC07-85ID12578

For
U. S. Department of Energy
Office of Industrial Technologies
Washington, D.C.

By
Eaton Operating Company, Inc.
Institute of Gas Technology (IGT)
The Ben Holt Co.

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Prepared for the
U.S. Department of Energy
Under DOE Idaho Operations Office
Sponsored by the Office of the Assistant Secretary
for Conservation and Renewable Energy
Office of Industrial Technologies
Washington, D.C.

Prepared by
Eaton Operating Company, Inc.
Institute of Gas Technology (IGT)
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CONTRACTOR FOR GEOPRESSURED-GEOTHERMAL SITES

EATON OPERATING COMPANY, INC.

FINAL CONTRACT REPORT

FISCAL YEARS 1986 - 1990 (5 YEARS)

(Testing of Wells Through October 1990)

(Revised September 1992)

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CONTRACTOR FOR GEOPRESSURED-GEOTHERMAL SITES

EATON OPERATING COMPANY

FINAL CONTRACT REPORT

FISCAL YEARS 1986-1990 (5 YEARS)

1.0 EXECUTIVE SUMMARY

Eaton Operating Company (EOC) (Houston, TX) and its two prime subcontractors, the Institute of Gas Technology (IGT) (Chicago, IL) and The Ben Holt Co. (BHC) (Pasadena, CA) assumed operation of the Department of Energy's (DOE) three Gulf Coast Geopressured-Geothermal Field Sites in September 1985 for five years (fiscal years 1986-1990). This Final Report covers the activities completed during this period. (Other reports (shown in References) were made of operations by other contractors prior to this contract period.)

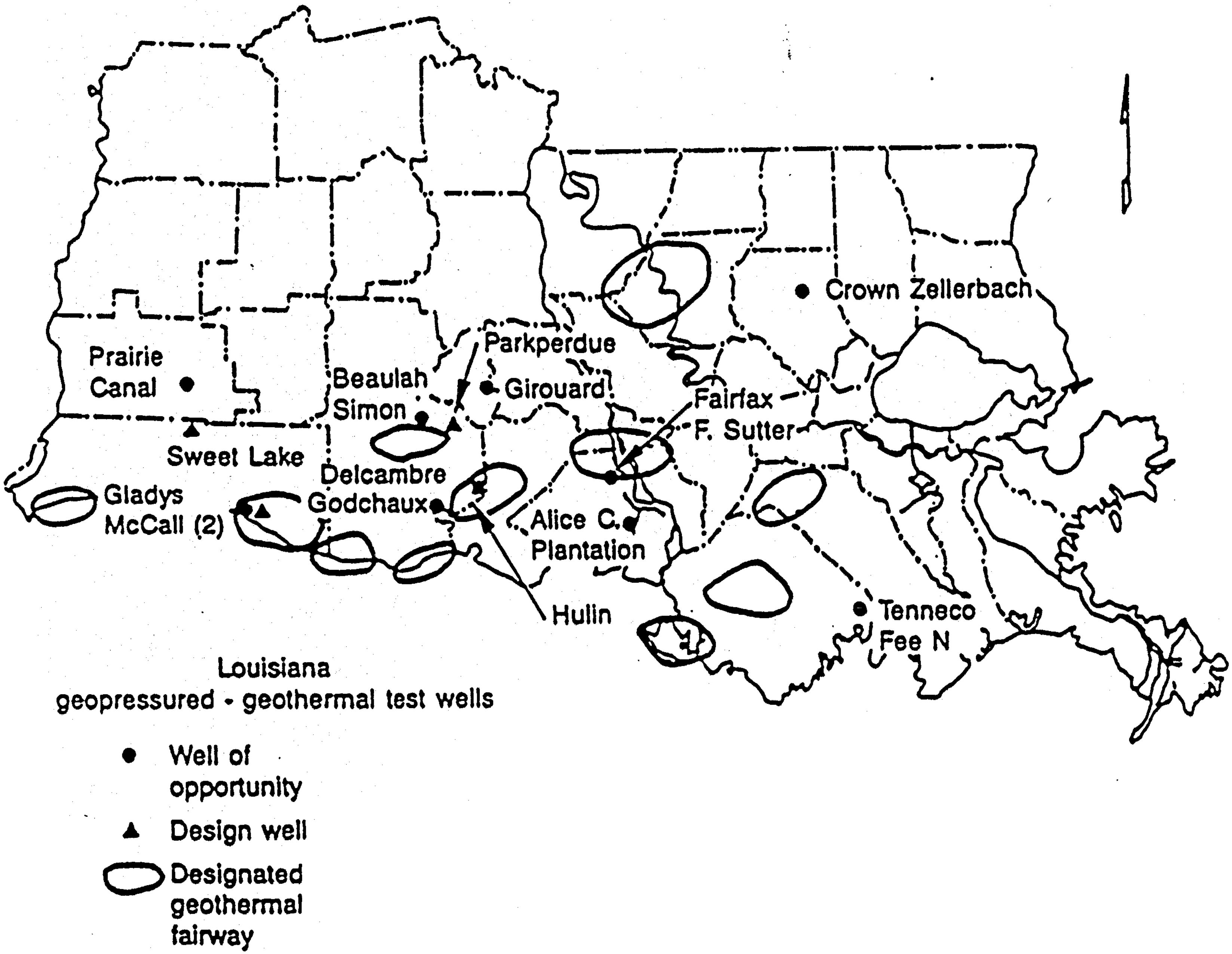
The Gulf of Mexico sedimentary basin contains large reservoirs of abnormally high pressured (geopressured), hot (geothermal) brines. These reservoirs contain gas, primarily methane, dissolved in the brine, with the amount in solution dependent on brine salinity, pressure, temperature and source of the methane. The reservoirs may also contain free gas (see Glossary). The free gas is usually accumulated at the geologic structural top of the reservoir. The free gas has been commercially exploited for years by the petroleum industry, but the geopressured-geothermal brines containing dissolved gas have not been commercially utilized.

Geopressured-geothermal reservoirs have been tested along the Louisiana-Texas Gulf Coasts under two prior DOE programs (see Exhibits 1-1 and 1-2):

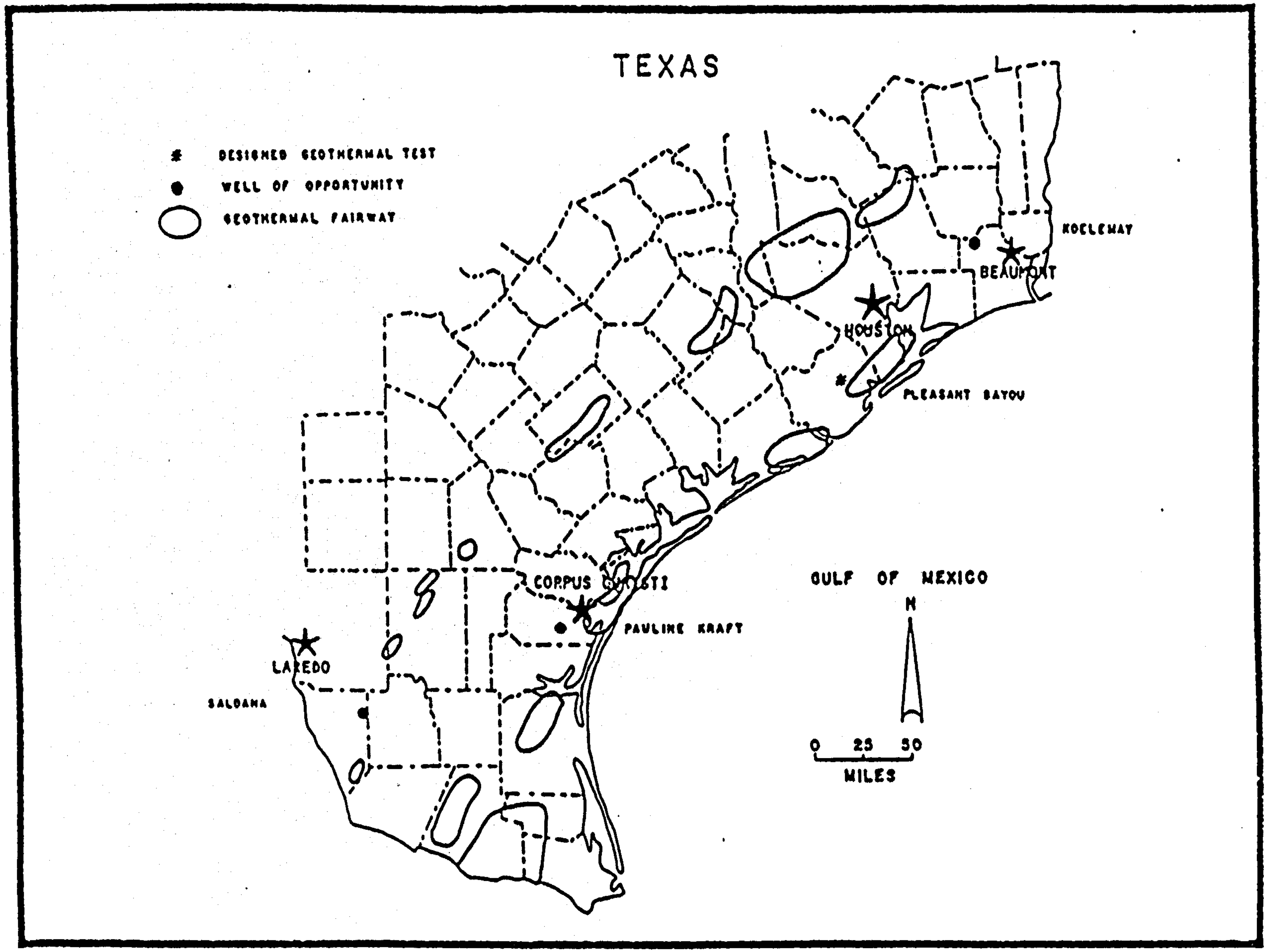
- In the "Wells of Opportunity Program" (1977-1982), twelve wells were taken over by DOE from industry, before being abandoned as not being commercial for initial or continued hydrocarbon production. Nine of these wells were tested for short terms of less than a month. Another well, the Willis Hulin well in Vermilion Parish, LA, was acquired in 1984, but was not tested until done under this contract.

- The original "Design Well Program" (1979-1985) in which four wells were drilled and completed for long-term testing. Tests were completed on two wells and were continued on the other two under this contract (FY 1986-1990). The two design wells currently testing are: the Gladys McCall Well No. 1 in Cameron Parish, LA; and the Pleasant Bayou Well No. 2 in Brazoria County, TX.

The five technical goals of DOE for development of the brines under the geopressured-geothermal research program have been to:



Louisiana geopressure-geothermal test wells.



Texas Geopressured-geothermal Fairways and Test Wells.

- o Confirm the existence of the resource.
- o Establish its magnitude.
- o Measure its characteristics.
- o Develop a technology to recover its energy.
- o Formulate a predictive model of the recovery process.

To date, the research program has achieved the first two goals, made excellent progress toward the next two, and begun work on the fifth (Goldsberry and Lombard, 1988).

The Gladys McCall well in Cameron Parish, LA produced over twenty five million stock tank barrels (4,000,000 m^3) of brine, was shut in for three years, and has recovered to almost its original reservoir pressure. This, as well as the Pleasant Bayou production of over eleven and a half million barrels (STB) (1,828,354 m^3) (Sept. 1990), has established that long-term, high volume (20,000 to 40,000 BPD) (3,000 to 6,400 m^3) production is possible from these reservoirs. A Binary Cycle Hybrid Power Electrical Generation System (HPS) was installed and successfully operated for several months at the Pleasant Bayou site in Brazoria County, TX. This system utilized the geothermal energy of heat and gas, as well as using exhaust heat from gas engine generators, utilizing the produced gas as fuel. Gas sales were made at both sites.

All of the wells tested to date, with the exception of the Hulin well, were tested in intervals from 9,700 feet (2,970 m) to 16,700 feet (5,101 m) with bottom hole pressures of 13,000 psi (91.03 Pa) or less, and temperatures of 300°F (149°C) or less. The design wells had solution gas/water ratios less than 30 ft^3/Bbl (5.3 m^3/m^3) (corrected to stock tank volume).

DOE acquired the Willis Hulin No. 1 well in Vermilion Parish, LA from The Superior Oil Company in 1984 as a "Well of Opportunity". The well had ceased natural gas production in 1983 and had mechanical problems requiring rework to restore it to production, which was done under this contract. This well contains several deep, geopressured-geothermal brine reservoirs. These reservoirs are deeper - ±21,000 feet (±6,400 m), have higher pressures - ±17,300 psi (119.3 Pa), and have higher temperatures -340°F (171°C), than any well tested to date in this program, as shown on a short-term flow test in 1990. (See Appendix C - "Hulin Site" for details.) This well has more potential for proving the economic feasibility for geothermal energy than any well tested to date.

Scale deposition problems, which had plagued the earlier tests at Gladys McCall and Pleasant Bayou, were overcome in cooperation with Dr. Mason Tomson of Rice University. At Hulin, the scale index, developed by Rice University personnel, indicates that scale inhibition will not be effective in surface facilities at pressures below about 500 psi unless the brine is cooled to below ±300°F.

Other support in this project was supplied by The University of Texas (Austin, TX), S-Cubed (La Jolla, CA), the Texas Bureau of Economic Geology (Austin, TX), the University of Southwestern Louisiana (Lafayette, LA), Louisiana Geological Survey, Louisiana State University (Baton Rouge, LA), as well as EG&G (Idaho).

Due to budget limitations, complete testing was not accomplished on any of the wells. Significant data were obtained on all of the wells in spite of significant problems that had to be overcome. These problems included:

1.1 Gladys McCall Site

- o Successfully reworked the disposal well which had sanded up.

- o Developed and installed larger diameter and stainless steel piping sections to minimize corrosion-erosion in critical areas of the surface production facility. This experience was applied in the design of production facilities installed later.

- o Successfully performed two scale inhibition squeezes in the production well, allowing production of almost nineteen million barrels (2,971,434 m^3) with no scaling in the tubing or high pressure production system after the treatments.

- o Pressure build-up experiment with downhole measurements.

1.2 Pleasant Bayou Site

- o Assumed custody of the production well which had experienced many months of fishing and had been temporarily abandoned for over three years. Successfully cleaned out the well and restored it to production.

- o Successfully cleaned out the disposal well which had sanded up, and have maintained high volume disposal for a year of production.

- o Successfully assembled, installed and operated a surface production facility, utilizing old equipment which had been out of service for several years.

- o Have increased the life of valves and wellheads by using different elastomers and lubricants based on the Gladys McCall experience, particularly the flow control choke.

- o Successfully assembled, installed and operated a Binary Hybrid Power System, utilizing outdated equipment that had been unused for as long as ten years and modified from its original design (i.e., turbine).

- o Successfully minimized corrosion by use of design experience gained at the Gladys McCall well in design of the production facilities and by chemical treatment.

- o Successfully injected two scale inhibition squeezes into the production well and produced over eleven million barrels (1,748,860 m^3) of brine with no scaling of the tubing or high pressure production equipment.

- o Negotiated a contract for the sale of gas to Panhandle Gas and the sale of electricity to Houston Lighting & Power.

- o With the use of insulation and coverings (tarps), maintained production during the unusual freezes experienced in the winter of 1989-1990, when many industry oil and gas wells were shut down for several days.

1.3 Hulin Site

- o Assumed custody of the production well from industry after it had been damaged from excess pressure used to attempt to reactivate the well after it ceased production in 1983. The well was shut in. Funds were not available for rework until 1989 (6 year shut-in). In spite of mud dehydration, from years of exposure to extremely high pressures and temperatures, design limitation of tools and logging equipment, and small annular clearances, the well was successfully cleaned out and recompleted for production.

- o Successfully drilled and completed a salt water disposal well and made a short-term flow test of the well.

1.4 General

- o Completed the major tasks of the program in spite of yearly underfunding of requirements. Maintained strict financial controls to finish the job under budget.

- o Successfully planned and executed a much more stringent Environmental Safety and Quality Control Program than had ever existed in the prior programs.

- o In spite of complicated workovers and production operation involving rigs, cranes, etc., have maintained an excellent safety record.

- o Successfully executed the assigned task of collecting and analyzing ground/surface water samples on a quarterly basis from each site, which established a bench mark, as well as confirming that the quality of these waters had not been compromised.

Future flow testing of all of these wells, particularly the Hulin well, is necessary to fully complete the original test objectives outlined above. The continuation of this program is very important to our nation's future energy needs.

2.0 PROGRAM DESCRIPTION

2.1 Program Objectives and Limitations

The program objectives of this research were to conduct field tests and studies to determine the production behavior of geopressured-geothermal reservoirs and their potential as future energy resources.

The five technical goals of DOE for development of the brines under the Geothermal Research Program have been to:

- o Confirm the existence of the resource.
- o Establish its magnitude.
- o Measure its characteristics.
- o Develop a technology to recover its energy.
- o Formulate a predictive model of the recovery process.

To date, the research program has achieved the first two goals, made excellent progress toward the next two, and begun work on the fifth (Goldsberry and Lombard, 1988). The primary limitation of the project has been that funds available have been less than that needed to carry out the planned project activities. This has resulted in delays of implementation, so that not all of the desired research could be completed. The results have been significant. It is extremely important that this research be carried to completion in the future to help solve our Nation's future energy needs.

The project involved three sites. Each site now has a brine production well and a disposal well. These are:

- o The Gladys McCall site in Cameron Parish, LA.
- o The Pleasant Bayou site in Brazoria County, TX.
- o The Willis Hulin site in Vermilion Parish, LA.

The original request for proposal (RFP) provided for high volume testing of two of the wells to determine reservoir production drive mechanisms and the physical and chemical changes that may occur with various production rates and conditions.

The flow tests were to consist of flowing the wells while dropping the pressure to separate the gas, other hydrocarbons, and the geopressured liquids. The gas was to be treated appropriately and sold to a commercial pipeline, or used on-site for operational requirements or experimental purposes; however, under circumstances in which none of these alternatives were appropriate, the gas could be flared. The brines could be used to generate electric power or to provide heat to experimental processes on-site prior to disposal through injection. A Hybrid Electrical Power

Generation System (HPS) was to be installed and operated at the Pleasant Bayou site, with an option to operate another Electrical Generation System at one of the other sites.

At the end of the testing, site restoration activities were to be performed, at the direction of DOE-ID, to include plugging and abandonment of the primary and disposal wells. Due to budget restrictions, all desired flow testing was not completed, and none of the wells have been plugged and abandoned. The results from flow testing accomplished in these three wells are representative of the following formations: 1) the Texas Frio geopressured-geothermal reservoir at Pleasant Bayou, and 2) the Lower Miocene reservoir in Louisiana, in the Gladys McCall and the Hulin wells. The original proposed program is shown in Exhibit 2-1. The actual work performed is shown in Exhibit 2-2.

Specific objectives obtained were accurate, reliable, long-term information concerning the following (as quoted from Eaton WOO Final Report 1982):

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

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

" o 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."

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

" o Analysis of the long-term environmental effects of an extensive commercial application of geopressured-geothermal energy, to the extent determinable during testing (i.e., ground water sampling and analysis and subsidence evaluation)."

Other objectives included:

o Reservoir limits determination.

o Long-term scaling and corrosion prevention.

o Long-term disposal well performance.

The long-term future (past the term of this contract) (Level III) objectives of the Geopressured-Geothermal Program include:

ORIGINAL
Basic Statement of Work

Geopressured Wells Operation

FISCAL YEARS

```
                              |  1986  |  1987  |  1988  |  1989  |  1990  |
------------------------------+--------+--------+--------+--------+--------+--------+
                              |        |        |        |        |        |        |
                              |        |        |        |        |        |        |
                              |        |        |      Plug &      |        |        |
                              |         Standby          Abandon  |        |        |
I.  GLADYS McCALL SITE        --0--------------------------0      |        |        |
    (Cameron Psh., LA)        |                          |        |        |        |
                              | /\     |        |        |        |        |        |
                              | Transfer        |        |        |        |        |
                              | Of Well|        |        |        |        |        |
                              | To EATON        |        |        |        |        |
                              |        |        |        |        |        |        |
                              |    Operate      |        |      Plug &     |        |
                              |  EPRI Experiment  Standby       Abandon    |        |
II. PLEASANT BAYOU SITE       -----0-----------0----------------------0    |        |
    (Brazoria Co., TX)        | /\                                |        |        |
                              | Rework |        |        |        |        |        |
                              | Well and        |        |        |        |        |
                              | Install|        |        |        |        |        |
                              | EPRI   |        |        |        |        |        |
                              | System |        |        |        |        |        |
                              |        |Clean Out|Rework  |        |      Plug &     |
                              |  Mud   |  Well  |  Well  |  Flow Test   Abandon     |
III. WILLIS HULIN SITE        -----------------0--0------0---0-------0---------0-----0
     (Vermilion Psh., LA)     | filled                /\          Comprehensive     |
                              |        |        | Install         |  Final Report   |
                              |        |        | Production      |        |        |
                              |        |        |  System         |        |        |
                              |        |        |        |        |        |        |
------------------------------+--------+--------+--------+--------+--------+--------+
```

EXHIBIT 2-1

Actual Work Performed

Geopressured Wells Operation

```
                                           FISCAL YEARS

                                 |   1986   |   1987   |   1988   |   1989   |   1990   |
---------------------------------+----------+----------+----------+----------+----------+----------+
                                 |          |          |          |          |          |          |
                                 |          |          |          |          |                     |
                                 |                     |              Pressure           Final     |
                                 |          Flow Test              Buildup Test          Report    |
  I.  GLADYS McCALL SITE         |0--------------------0-------------------------------------0    |
      (Cameron Psh., LA)         |          (2yrs)                    (3yrs)             |         |
                                 |                     |          |          |          |          |
                                 |Transfer  |          |          |          |          |          |
                                 |Of Well   |          |          |          |          |          |
                                 |To EATON  |          |          |                     |          |
                                 |          |          |          |          Flow Test             |
                                 |                     |     Flow Test       (Well & HPS) Final    |
                                 |    /       Shut-in   \ /   (18mo)        \  \/       Report     |
  II.  PLEASANT BAYOU SITE       |--0-0----------------o-----0-----------o--------0-------0----0   |
      (Brazoria Co., TX)         |       (2yrs)                         (7mo)     (8mo)     |      |
                                 |  /\                 /\                /\             /\         |
                                 |  Reworked |       Installed    |   Installed     Flow Test      |
                                 |   Wells   |       Prod Equip   |      HPS           Well        |
                                 |           |                    |           |                    |
                                 |           |                    |                                |
                                 |           |                    |            Flow      Final     |
                                 |                 Shut-in                     Test      Report    |
  III.  WILLIS HULIN SITE        |-----------------------------------0-0------------00--------0    |
      (Vermilion Psh., LA)       |           |     (3yrs)          (3mo)  (10mo) (2mo) (8mo)       |
                                 |           |                        /\      /\        /\   |     |
                                 |           |          |    Clean Out   Shut-in    Shut-in        |
                                 |           |          |    & Initial                             |
                                 |           |          |    Completion           |          |     |
                                 |           |          |                         |          |     |
                                 |           |          |          |              |          |     |
                                 |           |          |          |              |          |     |
---------------------------------+-----------+----------+----------+--------------+----------+-----+
```

EXHIBIT 2-2

- o Develop techniques to increase confidence in the ability to locate and evaluate geopressured resources. (These techniques should be of sufficient quality that at least 90% of wells recompleted for geopressured development are subsequently shown to be economic.)

- o Determine the drive mechanisms for the design well reservoirs.

- o Develop a test procedure which has sufficient accuracy to predict the capability of any geopressured reservoir to be produced for a period five times as long as the test period.

- o Prove the long-term injectability of large volumes of spent fluid into injection wells.

- o Develop a modified scale inhibition procedure.

- o Determine source and flow mechanisms for the liquid hydrocarbons and methane obtained from producing geopressured reservoirs.

- o Determine if fluids can be disposed of in an environmentally acceptable manner.

- o Develop surface fluid handling facilities (pumps, separators, valves, compressors, etc.) which can be safely operated from a remote monitoring location.

- o Develop material specifications, equipment specifications, and maintenance procedures which will guarantee over 95 percent annual availability with only a two-week annual shutdown for routine maintenance.

- o Develop hybrid conversion technology with thermal efficiency at least 20% greater than that from separate combustion and geothermal power cycles.

2.2 Resource Development Status

The DOE Research and Development Program for Geopressured-Geothermal Resources was developed as two testing programs for the resource assessment of the Gulf Coast Basin. These testing programs were the "Wells of Opportunity" and "Design Wells" programs (see Exhibits 1-1 and 1-2).

The Wells of Opportunity programs tested industry wells (nine) that were to be abandoned for lack of commercial hydrocarbon bearing sands on initial drilling, or because hydrocarbon zones had been depleted to where they were no longer economic. The tests on these wells were of short terms (less than a month) and usually in less than an optimum structural position. These tests were in both Texas and Louisiana. The Design Wells (four) were developed to acquire information on all reservoir fluid production and environmental parameters in favorable prospects identified by geologic studies. Tests were completed on two and are continuing on the remaining two, the Gladys McCall Well No. 1 in Cameron Parish, LA, and the Pleasant Bayou Well No. 2 in Brazoria County, TX. Another well, which was obtained as a Well of Opportunity in 1984 but not tested at that time, the Willis Hulin No. 1 Well in Vermilion Parish, LA, is also now being tested.

Substantial amounts of valuable data have been obtained and are being analyzed. However, due to budget limitations, the wells have not flowed enough to make final evaluations of drive mechanisms and producibility. Flow tests of these three wells must be continued, to answer these questions. Post production coring and analysis, with comparison to the original cores, taken when the wells were drilled, might give additional insight into some of the less obvious drive mechanisms, such as formation compaction and shale dewatering, etc., that may be active in these reservoirs in addition to the "normal" drive mechanisms, such as rock and fluid compressibility.

2.3 Geography and Geology

"The Texas and Louisiana regions of the Gulf Coast are as varied in their surface geography as they are in the subsurface geology. The geographical conditions range from the semi-arid to the semi-tropical, and geological sedimentary processes vary from the continental to deep water turbidites. The great variety of conditions in these areas makes research exceptionally challenging." (Langford, D., D. Garrett, and R. Klauzinski (EOC), Wells of Opportunity, 1982).

2.3.1 Geography

The initial areas investigated under the Wells of Opportunity (WOO) program were the geopressured-geothermal fairways developed in Texas by the Bureau of Economic Geology, of The University of Texas, and in Louisiana by the Department of Natural Resources, Louisiana State University. The particular regions of interest were delineated primarily on the basis of reservoir temperatures in excess of 300°F and cumulative reservoir volumes greater than three (3) cubic miles.

It was observed early in the program that drilling operations were being conducted throughout the entire Gulf Coast. Regions lying between the fairways, though exhibiting lower temperatures and small reservoir volumes, provided an equal, if not greater, number of potential WOO candidates. Therefore, the area of investigation was extended beyond the designated fairways.

The physiography of the region is quite varied but, with the exception of South Texas, can be divided into two general categories: the lowlands and the highlands. The lowlands range in elevation from sea level to approximately 125 feet and consist primarily of marshes and swamps along the coastline, grading landward into cultivated areas of rice and soybeans. The highlands contain some cultivated areas but consist primarily of dense pine forests which serve the lumber industry. The elevation ranges from approximately 125 feet to 300 feet above sea level.

The three wells covered in this report all lie in the lowland regions of Texas and Louisiana on the edge of, or in, swampy marsh areas.

2.3.2 Geology

The area of geopressured-geothermal study has been confined to the Texas and Louisiana regions of the Northern Gulf Basin. This region is commonly known as the Gulf of Mexico Geosyncline and is composed of three major depositional embayments: the Rio Grande Embayment, East Texas Embayment, and Mississippi Embayment (Exhibit 2-3). The formations of interest occur within sediments of Upper Cretaceous and Tertiary age (Exhibit 2-4).

In Texas, the formations of greatest potential were the deep upper Wilcox and Marine Frio. The Yegua and southern Vicksburg were also promising, but to a lower degree. In Louisiana, the lower and middle Miocene and the Frio were the primary zones of interest; although, the Wilcox and Tuscaloosa were potential test zones to a lesser extent.

2.3.2.1 Wells of Opportunity Program (WOO)

(Following are quotes from EOC Final Report 1982)

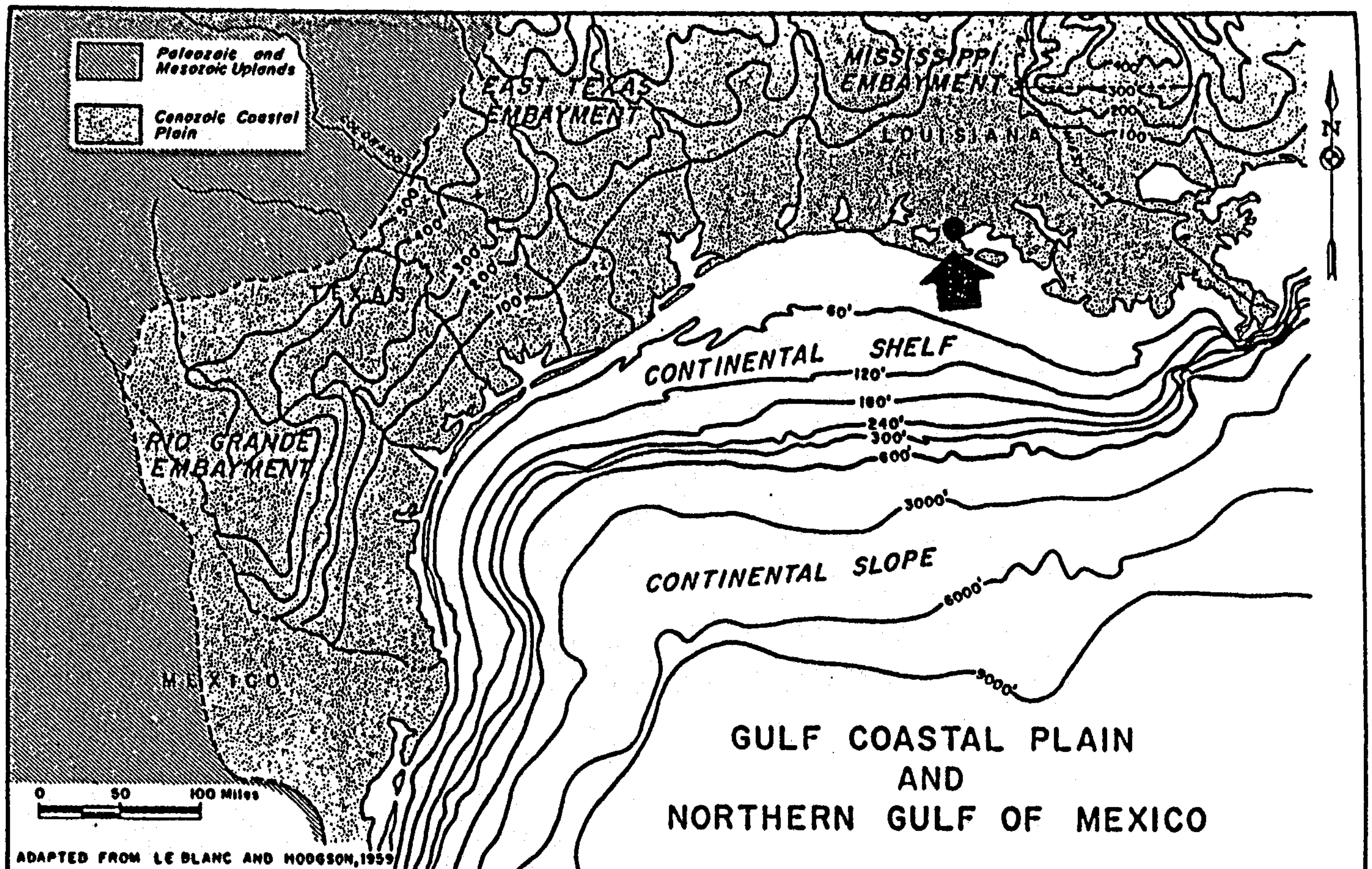
" Six geopressured-geothermal wells were tested by Eaton under the (1981-1982) DOE/WOO program. The wells sampled a great variety of reservoirs, and only one viable zone of interest was left untested by the WOO program: the lower Oligocene Vicksburg. The six reservoirs tested were the following:

Formation		Lease Name		Location
Frio	(Basal)	Pauline Kraft	-	Texas
	(Marg. Tex.)	Girouard	-	Louisiana
	(Hackberry)	Prairie Canal	-	Louisiana
Yegua	("Leger")	Koelemay	-	Texas
Wilcox	(1st Hinnant)	Saldana	-	Texas
Tuscaloosa		Crown Zellerbach	-	Louisiana

" The WOO tests, originally oil and gas prospects, were drilled in areas of hydrocarbon trapping. These traps, generally structural or stratigraphic, limit migration of hydrocarbons through the substratum and are exhibited as either anticlines or sealed monoclines. In addition to the trap, the reservoirs were restricted in one or more direction by down-to-the-coast growth-type faults. Four of the six wells were bounded monoclines, while the remaining two wells were drilled on anticlines."

" While the structures provide means for hydrocarbon trapping, they also restrict reservoir extent. This was the major trade-off in the WOO program: lower cost per test by not having to drill the well, versus a reservoir severely limited by the location of the well.

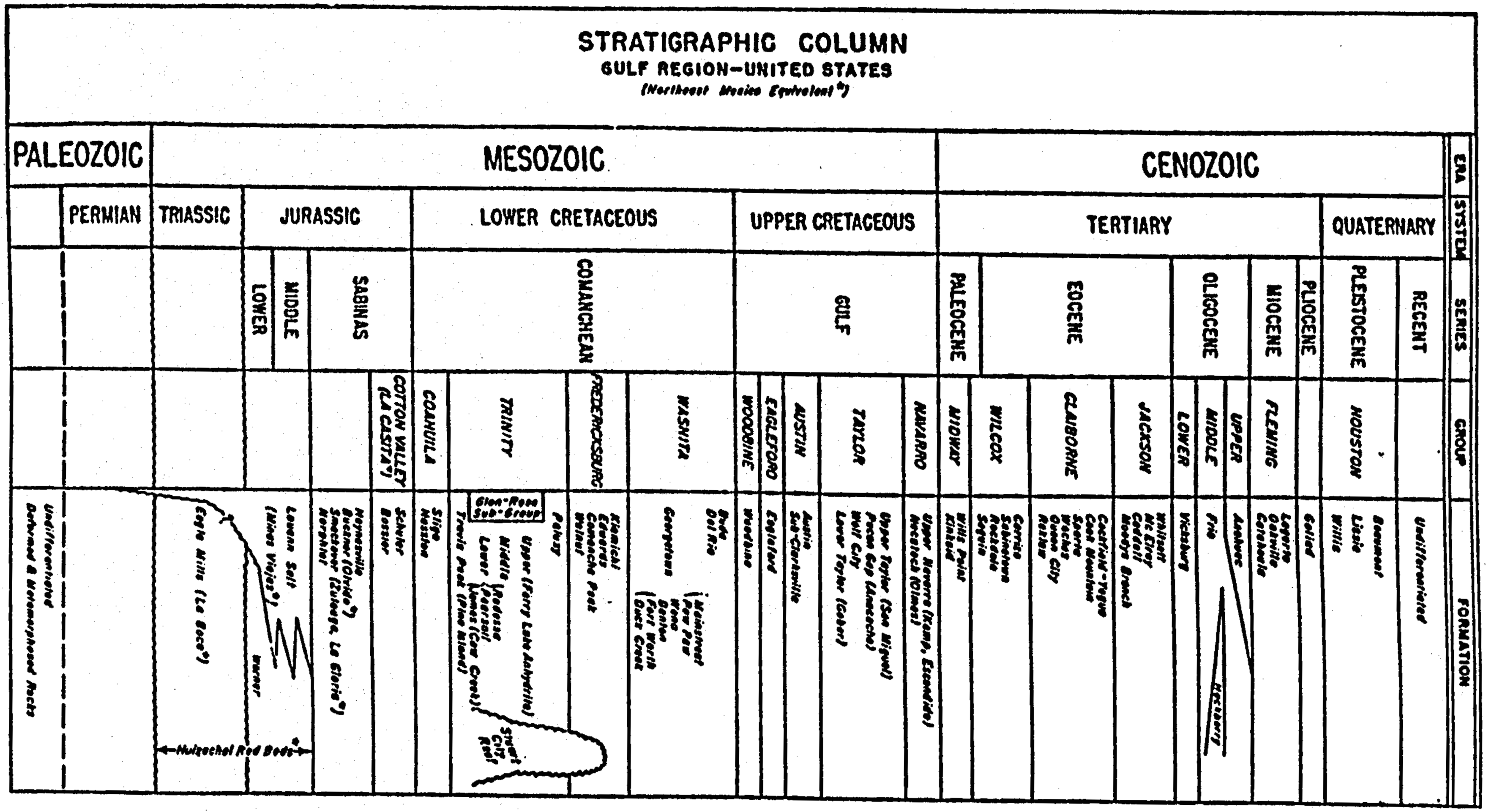
" The WOO program had different goals from the Design Well program, where wells were drilled to test favorable prospects identified through extensive geologic studies. The main objectives of the WOO program were to determine fluid characteristics and some reservoir parameters through short-term tests from a variety of reservoirs throughout the Texas and Louisiana Gulf Coast. This



CENOZOIC GULF GEOSYNCLINE (Jones, 69)

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

EXHIBIT 2-3



Halbouty (1979)

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

EXHIBIT 2-4

program was quite successful, because of the variety of geologic formations tested and the geographical distribution of the tests throughout the Gulf Coast.

"Some general trends were noted during the screening analyses of the multitude of wells covered in the WOO program. Some of these trends have been listed in previous Bureau of Economic Geology studies, but are relevant to the discussion of the program."

"First, in Texas, a general salinity increase was noted in formations as one progressed from the lower towards the upper Texas Gulf Coast. There were many exceptions, of course, such as the Koelemay test, but a definite trend was noted."

"Conversely, a decline in porosities and permeabilities, along with an increase in bottom hole temperatures, was noted as one progressed from the upper to the lower Texas Gulf Coast. Conversations with oil operators showed that wells in the geopressured-geothermal areas of South Texas were drilled primarily for gas. Whenever gas was discovered, the reservoirs were almost always hydrofractured because of the low permeabilities, usually much below 10 millidarcies. In addition, whenever porosities were encountered in the low permeability formations, oil was present."

"The geopressured areas in the Texas Wilcox were generally found to be of low porosity, less than 18%. The Vicksburg often had much lower than 10% porosity and was very tight. The Yegua had abundant sand development throughout the region but consisted primarily of 25-50 foot stringers through the gross sand intervals, too limited for desired high rates of water production. The best reservoir developments were noted in the Marine Frio sections, particularly in the coastal counties of Matagorda, Brazoria and Galveston, and in the Hackberry sands of Jefferson County. This can be noted by the location of the #2 Pleasant Bayou Design Well."

"In Louisiana, the only trend noticed during the course of log analysis of the region was that of the abundance of thick sections of Miocene sand. Although the entire Wilcox group and the Tuscaloosa and Frio formations had many possible reservoirs for testing, it was the Miocene series of sands which held the greatest potential for extensive thick sand development. This series of sediments has been extensively studied by various groups at Louisiana State University in Baton Rouge. Four previous WOO wells and two Design Wells have attempted to test portions of the Miocene. At present, this section of sediments appears to have the greatest potential for geopressured-geothermal applications in the entire northern Gulf Basin."

2.3.2.2 Design Well Program

Four wells were tested under the Design Well program, in the following reservoirs:

Series	Group	Well Name	State
Oligocene	Frio	Pleasant Bayou No. 2	Texas
	Upr. Frio	L. R. Sweezey No. 1	Louisiana
	Miogypsinoides	Amoco Fee No. 1 (Sweet Lake)	Louisiana
Miocene	Lwr.	Gladys McCall No. 1	Louisiana

(Goldsberry and Lombard, 1988)

2.3.2.3 Present Program

Two wells of the Design Program are still under test, the Gladys McCall Well No. 1 in Cameron Parish, LA, and the Pleasant Bayou Well No. 2 in Brazoria County, TX. A third well, the Hulin Well No. 1 in Vermilion Parish, LA, was acquired as a WOO well in 1984 but was not tested until 1989, after an extensive clean-out operation. As shown above, the two Design Wells are in the Oligocene Frio (TX) and Lower Miocene (LA), respectively. The Hulin Well No. 1 is completed in the Lower Miocene, Planulina zone. (Tyler, BEG 1987).

2.3.2.3.1 Gladys McCall Site (Cameron Parish, LA)

The geology of the location is summarized in the following quotations from a published report. (John (LGS) 1988)

" This well lies in the Miocene geopressured-geothermal trend. Wells in this area have penetrated some of the thickest geopressured sand sections in Louisiana or Texas . . . The anomalous sand thickness may be due to local variations in sand supply and deposition, combined with subsidence and growth faulting . . . The test well penetrated upper (4,000-6,000 ft) (1,219-1,828 m), middle (6,000-11,000 ft) (1,828-3,352 m), and lower Miocene (11,000-(TD)16,510 ft) (3,352-5,032 m) sections, with the section below 14,400 ft (4,389 m) being geopressured . . . Approximately 1,150 ft (350 m) of net sand was seen in this well from 14,412-16,320 ft (4,392-4,974 m). A generalized structure map of the prospect area is shown in Exhibit 2-5 . . . There are a large number of wells in the area, but very few are deep enough to have reached the geopressured reservoir observed in the test well. Hydrocarbon production in this area is from horizons shallower than the target section at Gladys McCall Well No. 1. The locations of the faults controlling the north-south extent of the geopressured reservoir were determined using available seismic lines."

" A dip (north-south) cross section of the area through the Gladys McCall test well is shown in Exhibit 2-6. Log correlations are relatively straightforward at shallower depths but tend to get more complex below 15,000 ft (4,572 m). Paleontologic analysis has helped to confirm the correlations . . . indicating that sands constituting the target section were probably deposited in a shelf environment by distributary channel systems."

" There is a good correlation between sands seen in the Gladys McCall Well No. 1 and the Union of California, Dr. Miller No. 1 well located to the south, but the former shows a thicker section . . . (Paleo) . . . indicates a large missing section

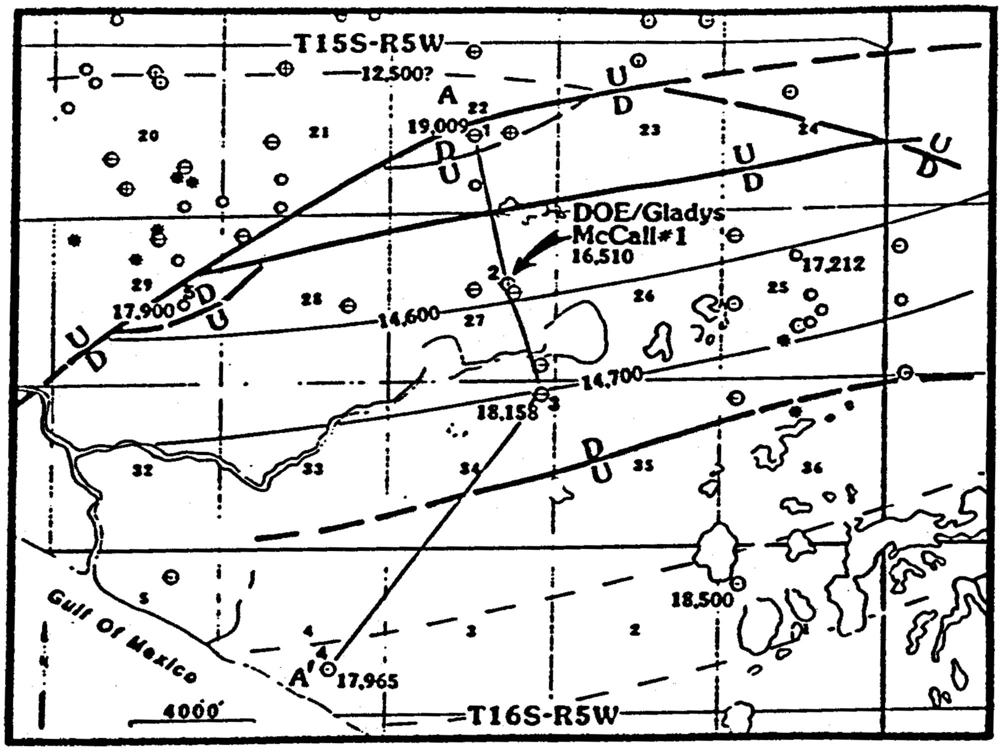


EXHIBIT 2-5 Structure of the Gladys McCall prospect area, contoured at the 14,560ft sand in the T-F&S/DOE Gladys McCall No. 1 well by Magma Gulf Company (adapted from Technadril-Fenix and Scisson, 1982, pp. 4-10). (See for well identification.) (From John, 1988)

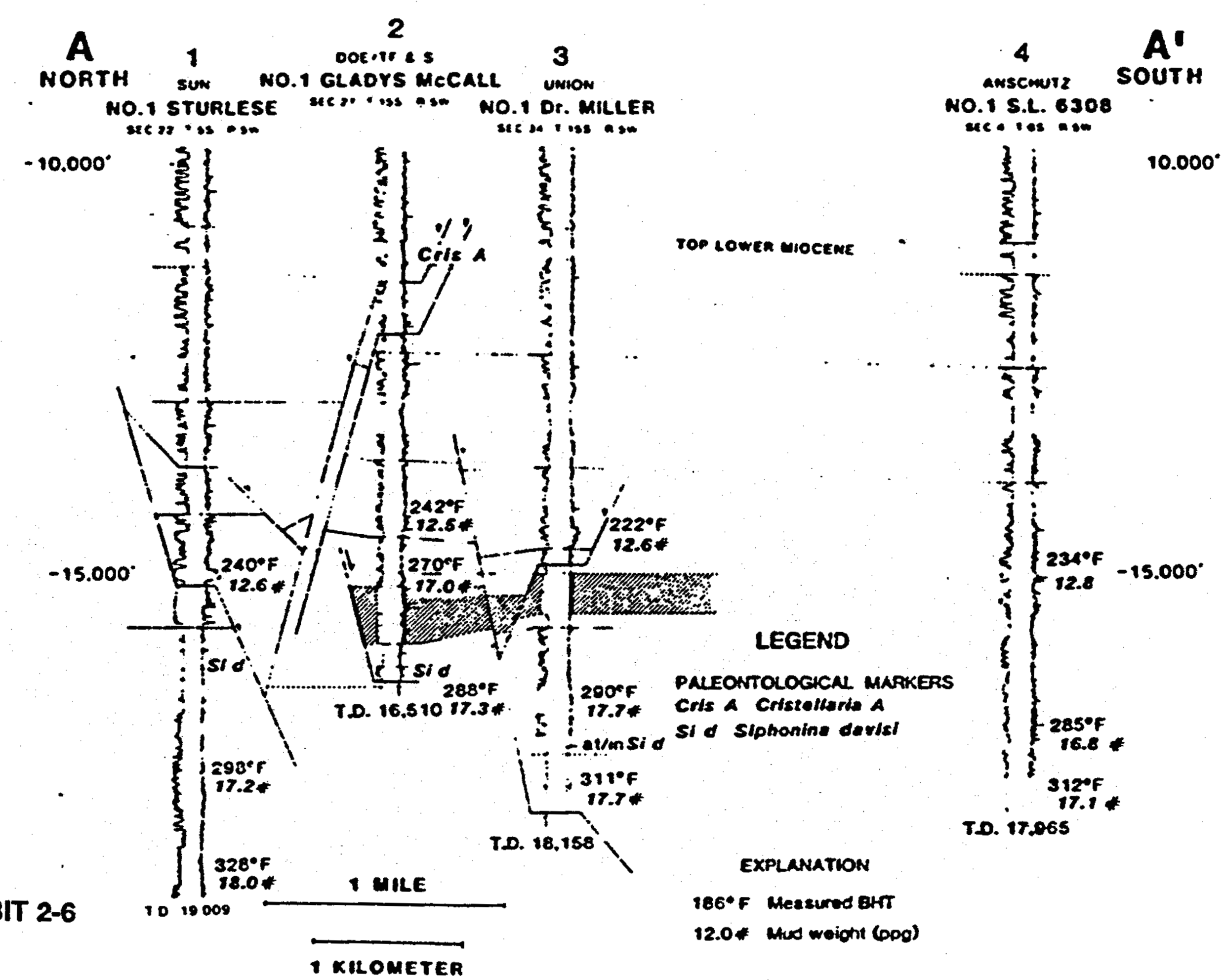


EXHIBIT 2-6 Dip cross section of the prospect area, showing log correlations, paleontological markers, temperature and mud weights (modified from Bebout et al., 1983, p. 86). (See Fig. 5 for line of cross section.)

(approximately 1,200 ft, or 365 m) in the Gladys McCall well and the presence of a large fault cutting the Gladys McCall well. This fault, at 16,350 ft (4,983 m) in the test well, cuts out the lower thick sandstone seen in the Miller well . . . The north or reverse dip in the target section indicates a rollover fault. Contemporaneous fault movement and sand deposition with subsidence increase the thickness of the shale and sand sections above the fault. The fault to the south of the Gladys McCall well was drawn (see Exhibit 2-5) to explain the absence of Siphonina davisi in the Pan Am SL 4079 Well (TD 18,500 ft, or 5,638 m) to the total depth of the well . . . It may or may not be a sealing fault."

" Lack of deep well control in the east-west direction results in poor definition of the reservoir boundaries. The target sand seen at Gladys McCall is absent in the Cherryville No. 1 Miller well (TD 17,900 ft, or 5,455 m) (Well No. 5 in Exhibit 2-6), as both the faults north or the test well merge to the west and cut the Miller well at approximately 16,100 ft (4,907 m). An additional fault may be present on the east side, as shown by the dashed line in Exhibit 2-5, but its existence cannot be proved definitely because of the lack of deep well and seismic data in this area."

2.3.2.3.2 Pleasant Bayou Site (Brazoria County, TX)

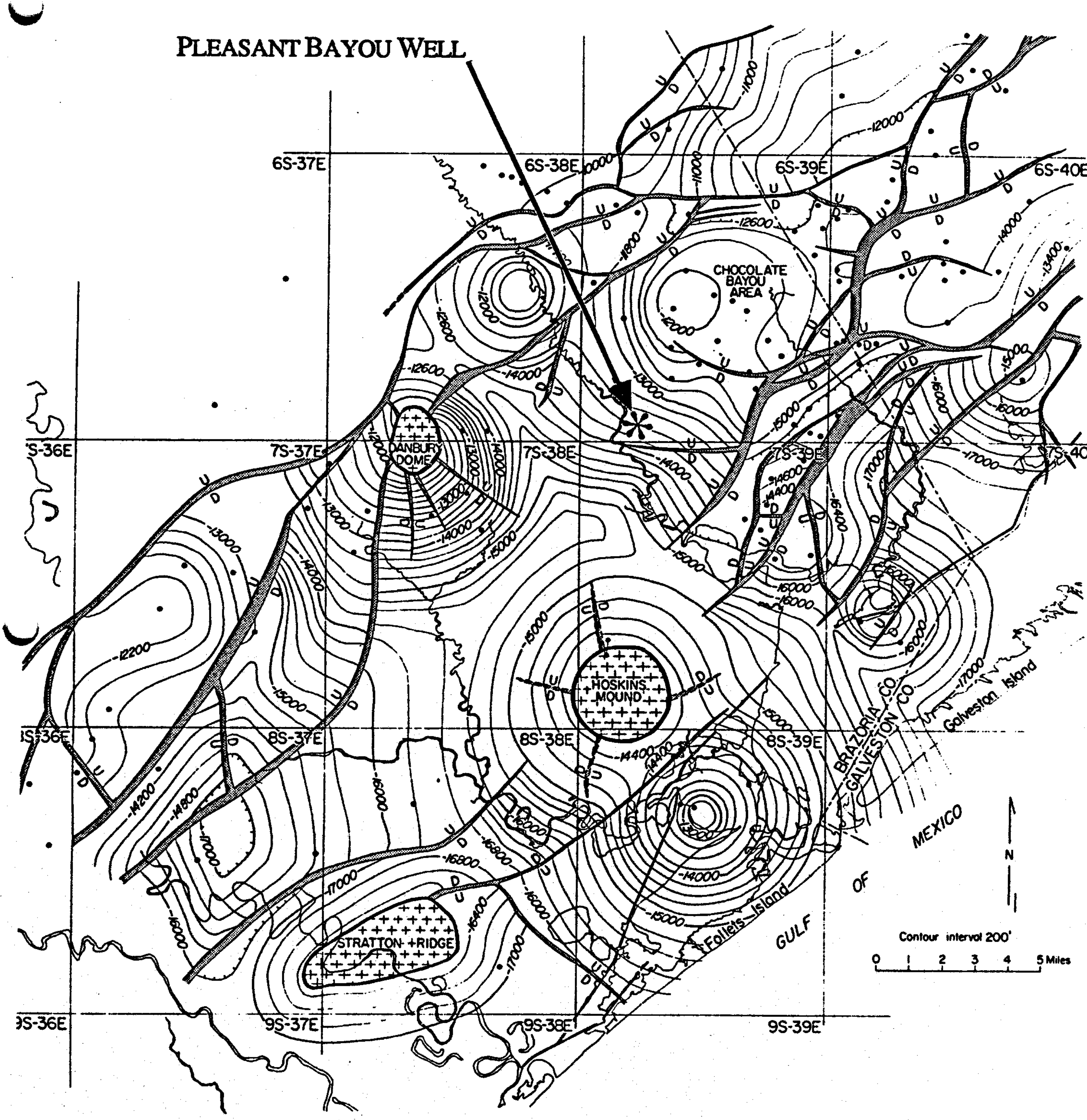
The geology of the location is summarized in the following quotations from a published report. (Rodgers, J.A., (1982) Gruy Petroleum Technology, Inc.)

" . . . sandstone distribution maps, along with isothermal maps, identified five fairways with thick accumulations of geopressured sand containing water over 300°F. These five fairways, the Hidalgo, Armstrong, Corpus Christi, Matagorda, and Brazoria Fairways, generally occur gulfward of the depocenters. In selecting areas for the DOE geopressured-geothermal testing program, the Brazoria Fairway in Brazoria and Galveston Counties met the requirements for an adequate geopressured-geothermal reservoir, which were: (1) reservoir volume of 3 cubic miles, (2) subsurface temperature of at least 300°F, and (3) permeability high enough to allow production of 40,000 barrels of water per day."

" . . . Exhibit 2-7 shows the structure at the top of T5, Brazoria Fairway, in the vicinity of the geothermal well. The map shows the well to be in a salt-withdrawal basin which supplied salt for the Danbury Dome to the north and the Hoskins Mound and Stratton Ridge on the south. Deeper salt movement may also account for the other domal structures paralleling the coast north and south of the Pleasant Bayou area. The Pleasant Bayou site lies near the western edge of a dendritic network of faults. An east-west spur fault may be seen just south of the well. Other smaller faults may be present which do not show on the map."

" Exhibit 2-8 is a correlation diagram developed on a regional strike cross-section C-C′ (Exhibit 2-9) which takes into account paleontological markers and similar wireline log patterns."

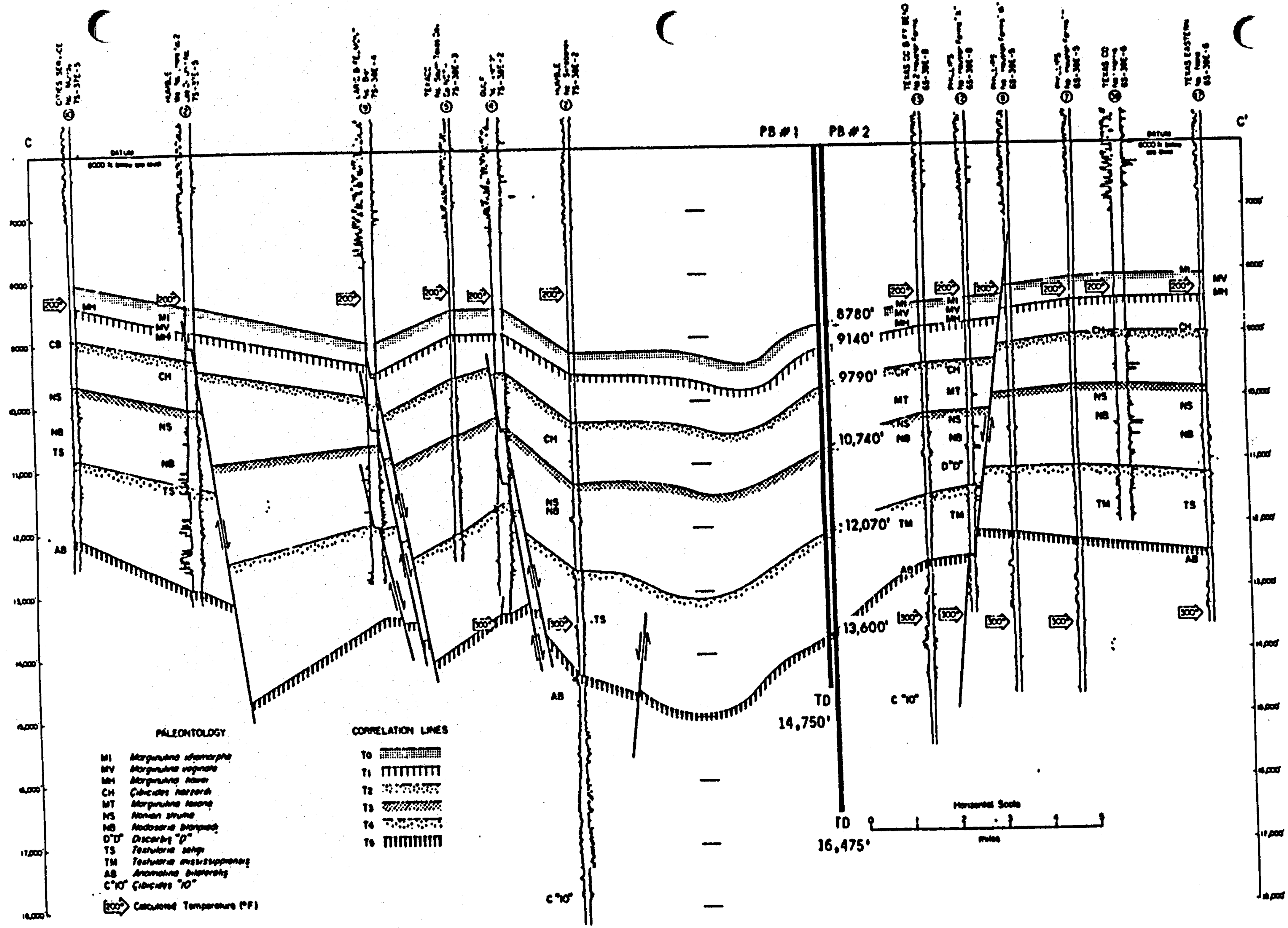
" By careful scaling, the "T(Time)-zone" markers were identified at the following depths at the Pleasant Bayou Well No. 2:



STRUCTURE MAP ON THE TOP OF THE T5 MARKER

(Bebout, Loucks, and Gregory, 1978)

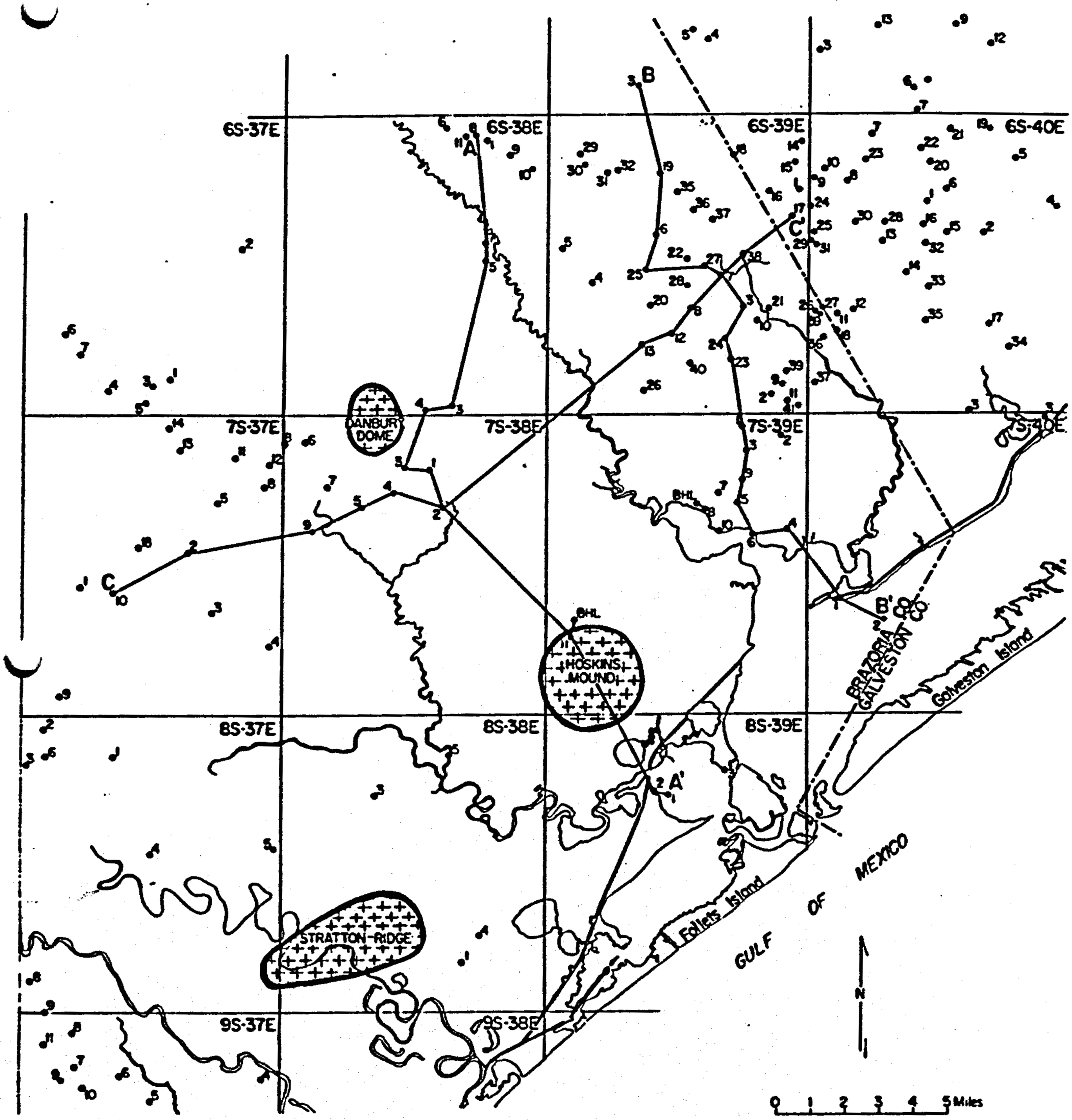
(From Gruy, 1982)
EXHIBIT 2-7



--Cross-section showing Pleasant Bayou No. 1 and Pleasant Bayou No. 2 with depths of "T" markers for Pleasant Bayou No. 2 (Bebout, Loucks, and Gregory, 1978).

(From Gruy, 1982)

EXHIBIT 2-8



--Map showing location of strike cross-section C-C'.

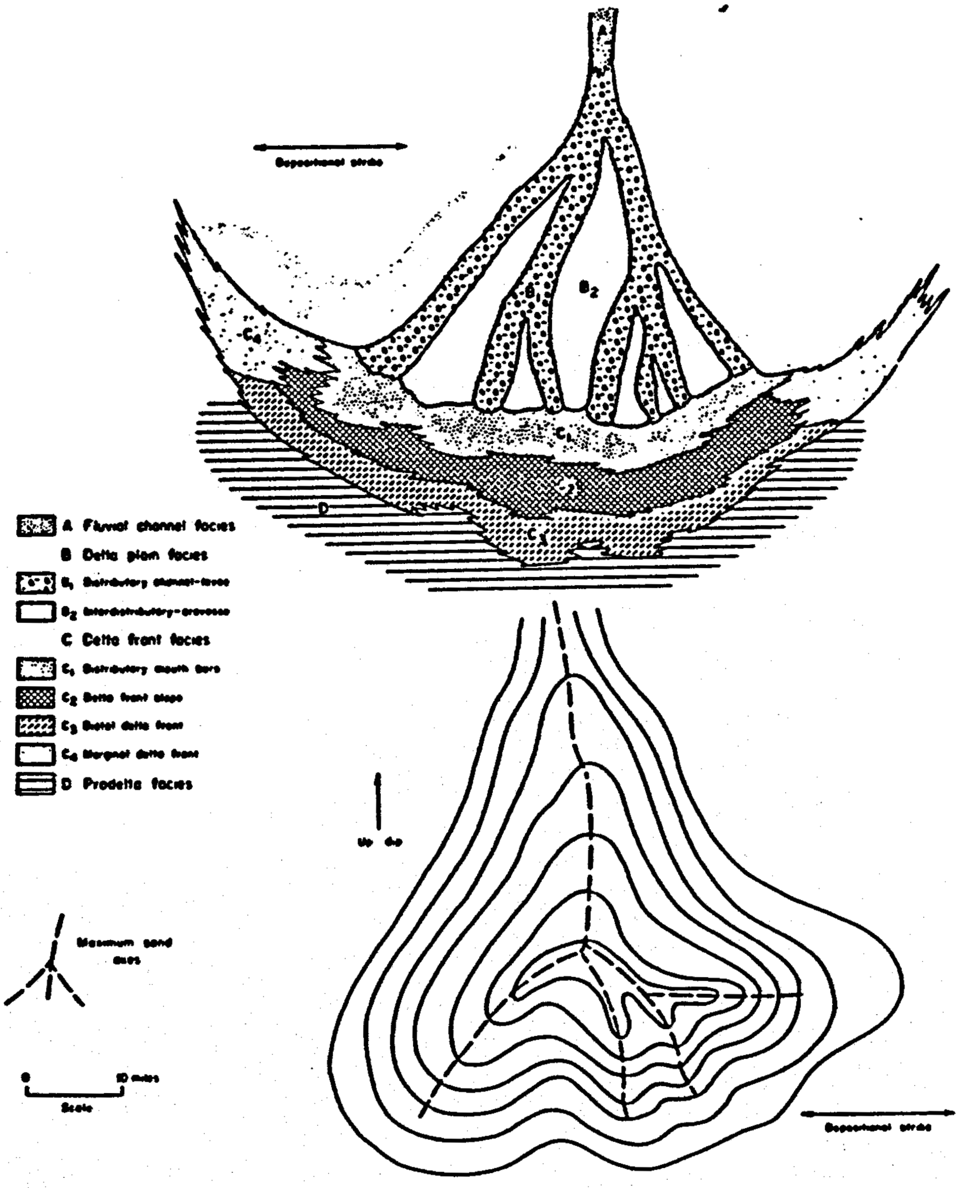
(From Gruy, 1982)

EXHIBIT 2-9

"T" Marker Zone	Depth (ft)	Paleontological Markers
T0 - T1	-8,780 to -9,140 (-2,676 to -2,786 m)	MI, MV, MH
T1 - T2	-9,140 to -9,740 (-2,786 to -2,969 m)	CH, MT
T2 - T3	-9,740 to -10,740 (-2,969 to -3,273 m)	NS, NB
T3 - T4	-10,740 to -12,070 (-3,273 to -3,679 m)	TM
T4 - T5	-12,070 to -13,600 (-3,679 to -4,145 m)	
T5 - T6	-13,600 to ? (-4,145 to ? m)	

- The 300°F isotherm was intercepted at about 14,500 feet (4,420 m). Comparison of prominent wireline log "events" in Pleasant Bayou No. 1 and No. 2 in the interval from 2,000 to 14,730 feet (610 to 4,490 m) . . . reveals upward displacement of Pleasant Bayou No. 2 with respect to Pleasant Bayou No. 1 . . . The displacement is especially pronounced below a depth of 10,240 feet (3,121 m). Above 10,240 feet (3,121 m), upward, vertical displacement of "events" in Pleasant Bayou No. 2 is fairly small; randomly varying from -2 to 13 feet (-6 to 4 m). The thickness of "events" is fairly consistent between the wells. Here, the displacement of "events" probably reflects depositional variations superimposed on regional dip. Below 10,240 feet (3,121 m), displacement of the "events" increases with depth, and events on the relative low side (Pleasant Bayou No. 1) are thicker. This indicates differential penecontemporaneous subsidence or a growth fault which was active only during "events" below 10,240 feet (3,121 m). Wireline stretch may also account for some of the differences noted."

- In general, all Frio sediments in the geopressured zone were deposited seaward of the main sand depocenter, probably within a shelf environment. The test well lies downdip from the main sand depocenter of the Brazoria Fairway. The 8,000 foot (2,438 m) Frio section is composed of shale with less than 10 percent sand in the immediate area of the test well. An estimated 800 to 900 feet (244 to 274 m) of net sand is present in the test areas. The T5 - T6 zone contains 20 to 30 percent sand in the test area. Core analysis suggests the test zone, from 14,644 to 14,706 feet (4,463 - 4,482 m), represents bedload deposits in a fluvial channel. The location of the well, with respect to six major depositional sequences, . . . indicates the sand may represent one of a number of sand deposits shown in Exhibit 2-10."



Principal depositional environments and sand patterns, high constructive lobate delta systems, Gulf Coast Basin (Fisher, 1969).

(From Gruy, 1982)

EXHIBIT 2-10

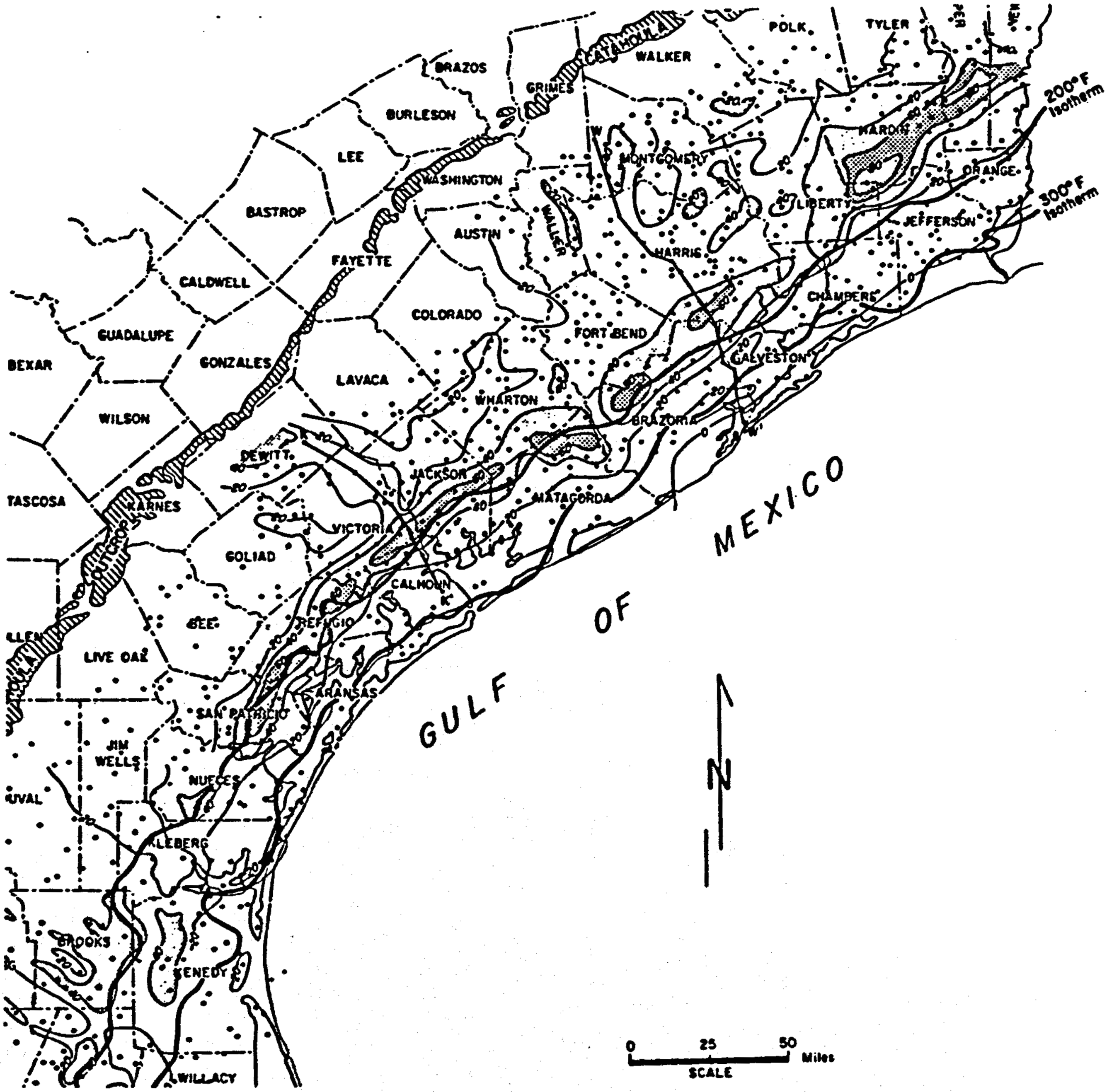
"The temperature in the area is between 200° and 300°F (Exhibit 2-11). A temperature versus depth curve (Exhibit 2-12), plotted for Pleasant Bayou No. 2 and surrounding wells, indicated the 300°F temperature value was obtained at 14,500 feet (4,420 m). The exhibit shows the difference between the gradient given by Bebout, et al., 1978, and the gradient derived from temperature data for the surrounding wells."

"Studies indicate porosities in the test area are the best in the fairway. Thicker sands are found near Danbury Dome to the west; however, due to the rapid accumulation of these sands, a greater degree of compaction has occurred, subsequently reducing porosity and permeability. Porosity and permeability were preserved in the test area as less sand was deposited with less resulting compaction. Basinward of the site, smaller accumulations of silty, finer-grained sand occurs. Well tests and core analysis also indicated permeability following the same pattern as the porosity distribution."

2.3.2.3.3 Hulin Well Site (Vermilion Parish, LA)
The following discussion is from a report by Tyler (BEG), 1987.

"... Top of geopressure at the Hulin well site is at about 13,000 ft (3,962 m). From near top of geopressure to total depth (21,546 ft) (6,567 m), the well penetrates the lower Miocene, Planulina zone, an interval restricted to southwestern Louisiana and offshore Jefferson County, Texas. The Planulina zone consists of deep-water (bathyal), continental slope sequences that grade updip and up section into shelf-margin deltaic deposits. The Planulina zone overlies bathyal to abyssal shales in the Anahuac Formation (Abbeville zone) and underlies the fluvial-deltaic Oakville Formation. The prospective sandstone is 600 ft (183 m) thick and appears to be a slope canyon fill or proximal submarine fan deposit similar to thick, Frio Hackberry sandstones at the Port Arthur Field, Jefferson County, TX. It is probably dip elongate but unattached to shelf-margin deltaic sandstones up slope. At least four thin (<10 ft) (3 m) shale interbeds vertically compartmentalize the reservoir. Regionally, the Planulina zone is characterized by complex structural configuration and heterogeneous facies distribution that have made correlation difficult."

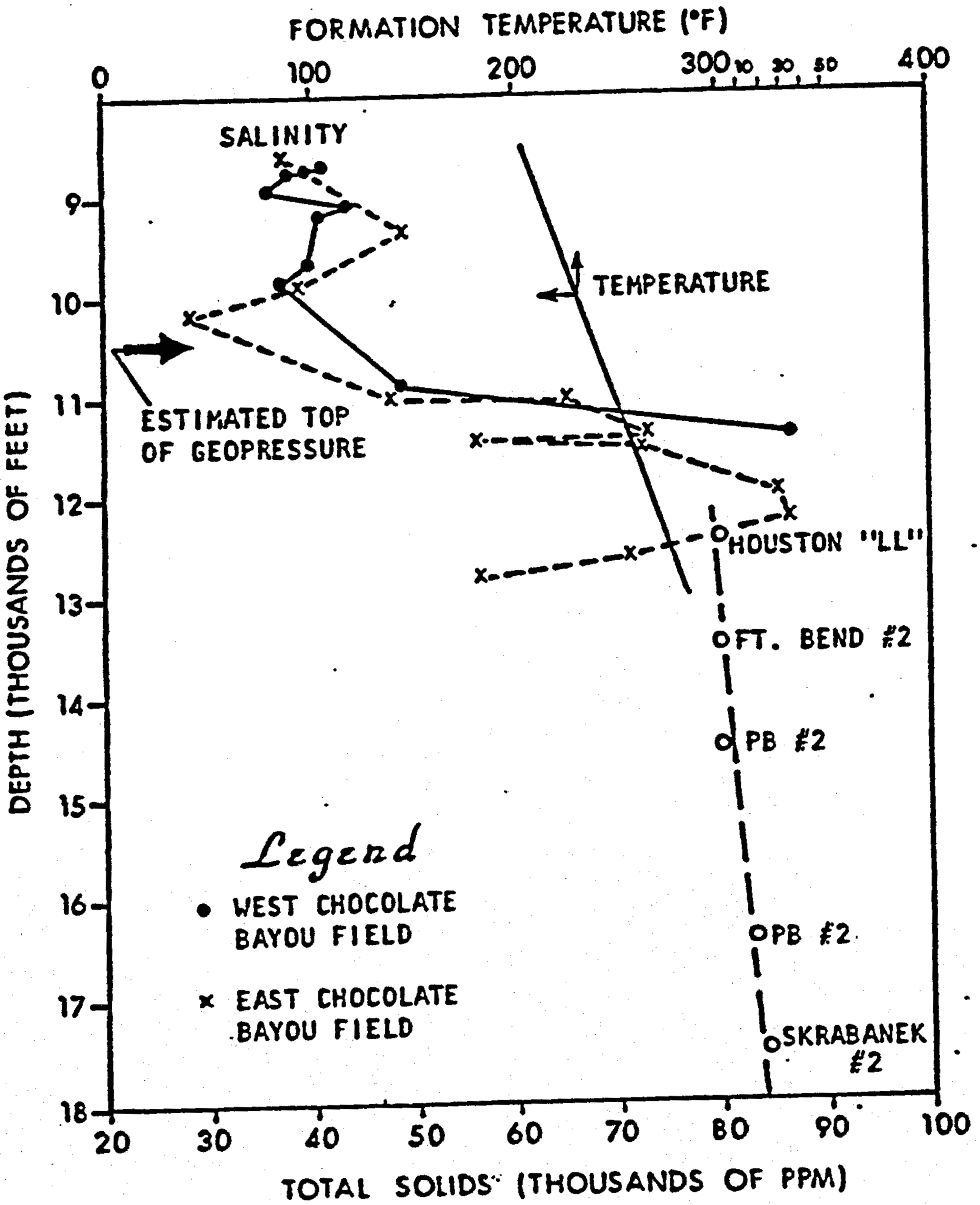
"The Hulin well is located on the axis of a dip oriented, north-south trending structural trough adjacent and subparallel to an uplifted ridge of salt that includes the Five Islands salt domes. The structural trough is related to deep-seated salt withdrawal. Isopach and net-sandstone patterns indicate the trough was a persistent zone of sediment transport and deposition on the Planulina continental slope and rise. Net-sandstone contours for the entire Planulina zone (about 7,000 ft (2,134 m) thick at the Hulin well) are closely spaced and dip directed at the Hulin well site but diverge into more lobate patterns several miles basinward (south). These sandstone geometries, along with the occurrence of deep-water fauna in associated shales, support the submarine canyon and fan interpretation. The Hulin well is located in a fault block that is approximately 12 miles long (east-west) by 5 miles wide (north-south) and bounded by large arcuate growth faults. Smaller faults occur within the block."



--Map showing sand percentage of T5-T6 unit with 200° and 300°F isotherm lines (Bebout, Loucks, and Gregory, 1978).

(From Gruy, 1982)

EXHIBIT 2-11



--Salinity and temperature of formation waters, Chocolate Bayou field, Brazoria County, Texas (adapted from Bebout et al., 1978).

(From Gruy, 1982)

EXHIBIT 2-12

- Because it is penetrated only by the Hulin well, a more precise depositional setting for the prospective sandstone could not be determined. If the sandstone is confined in a narrow erosional channel, it may extend only a few miles east-west. Alternatively, the structural trough may have been the site of a broader, topographically irregular, slope canyon, produced and filled by slumping and mass-movement processes. A third possibility is as a series of intraslope fault-bounded salt-withdrawal basins. Ponded sediments would accumulate in each basin to the filling point before spilling over into the next lower basin. All of these features exist on the Pleistocene-Holocene continental slope in the northwestern Gulf of Mexico. In any case, abrupt sandstone thickness changes and internal reservoir heterogeneity characterize slope systems."

- The geopressured-geothermal aquifer of interest . . . is a 600 ft (183 m) section of sand with the top at 20,100 ft (6,126 m). The sand is fairly clean with few intervening shale lenses . . ." (Peterson (EOC) 1986).

The reservoir volume is discussed in this excerpt from an LGS quarterly report (John, et al (LGS) 1990).

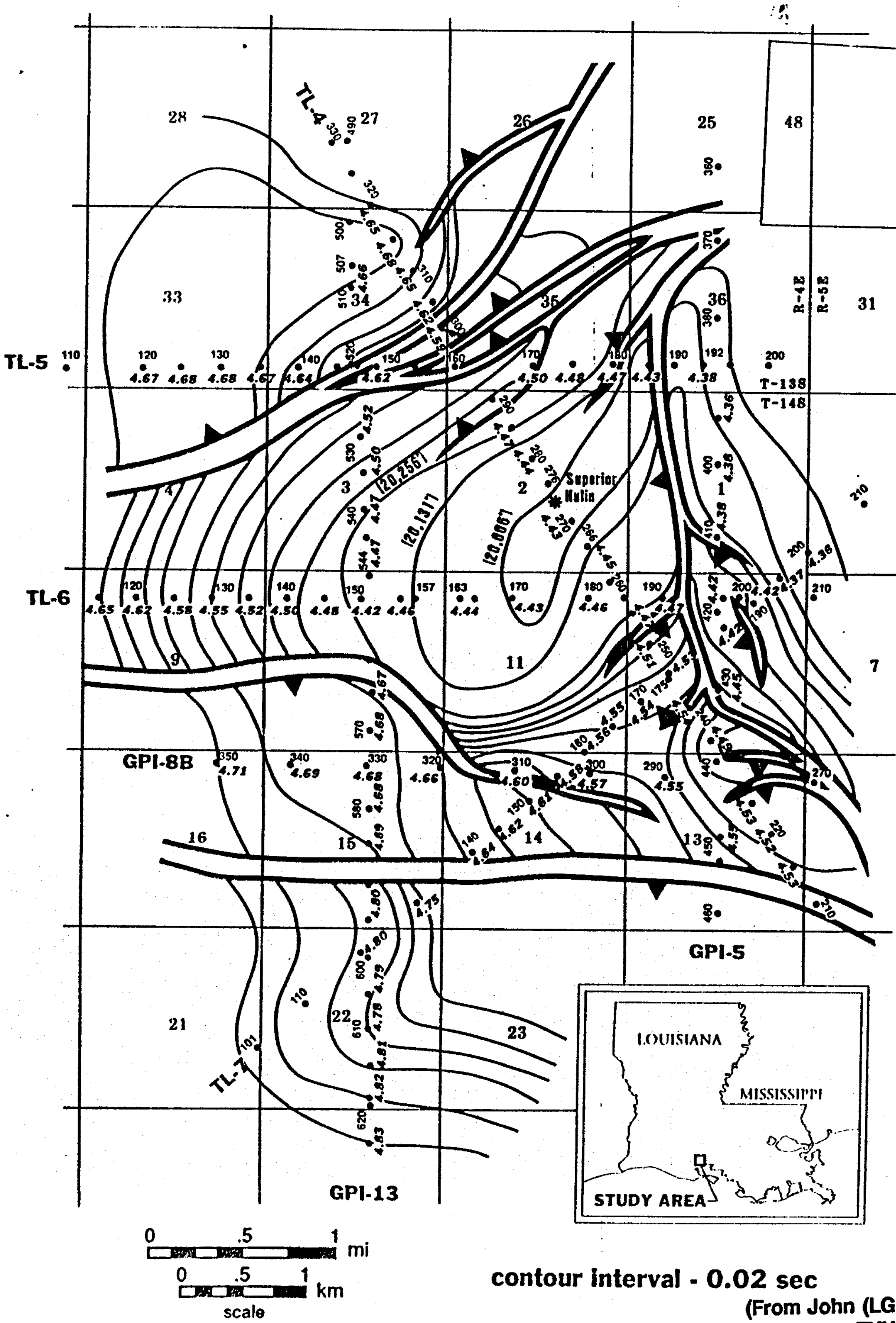
- The areal extent of the Hulin prospect continues to be studied. A preliminary revised structure map made at the top of the geopressured sandstone using deep reflection seismic data around the Hulin prospect has been completed. This latest structural interpretation shows a reasonable estimate of the Hulin prospect's areal extent to be approximately 2.6 mi^2. Assuming a volumetric reservoir of 2.6 mi^2 by 470 feet thick (from well log analysis) and a porosity of 20%, a total volume of approximately 1 billion barrels was obtained. This figure was obtained using a standard calculation for recoverable fluids:

  A = 7,758 barrels in an acre-foot
  B = 0.20; assumed porosity
  C = 0.80; assumed recovery factor
  A x B x C = 1,241 barrels/acre

  T = 470; assumed thickness in feet (from log)
  F = 1,665; areal extent from structure map (acres)
  X = 1,241 barrels/acre
  T x F x X = 971,114,550 barrels of brine

- Rounding off of the above gives an approximate value of 1 billion barrels of brine reserves in the Hulin geopressured-geothermal target reservoir. As experience has shown, applying a general recoverable fluid calculation to brine is not very reliable. The Hulin prospect sits on a closed high contour, bounded to the north, south, and east by faults. However, the western boundary is not presently defined. Upon production testing, unlimited recharge may come from the west across bounding faults or from interconnected reservoirs. How far the sand continues areally from the well remains unknown. No other well in the area has been drilled deep enough to encounter the Hulin target sand."

A structure map is shown in Exhibit 2-13.



contour interval - 0.02 sec

(From John (LGS), 1990)

EXHIBIT 2-13

2.4 Well Descriptions

2.4.1 Gladys McCall Site (Cameron Parish, LA)

The original drilling, completion and initial testing of this well prior to October 1985, is described in Technadril-Fenix & Scisson reports: 1) Volume I - Drilling and Completion (Gladys McCall), Jan. 1982, 2) Volume II - Testing Plan, Jan. 1982, and 3) Volume II - Well Workover and Production Testing for the Period February 1982 - October 1985. A summary overview of the location is provided by the quotations below.

" . . . Eleven potential production zones, numbered sequentially, have been defined within the geopressured section; the electric log, production zones and generalized lithology are shown in Exhibit 2-14. Three diamond cores were taken in the target sand from 15,167 to 15,177 ft (4,622 to 4,625 m), 15,179 to 15,192 ft (4,626 to 4,630 m), and 15,348 to 15,374 ft (4,678 to 4,685 m). Twenty-eight sidewall cores were shot between 15,460 ft (4,712 m) and 16,455 ft (5,015 m). The analysis of all these cores showed that the reservoirs were made up of fine-grained, well-consolidated and mostly silica-cemented sandstone." (Technadril-Fenix and Scisson, 1982). No sand was produced during production tests.

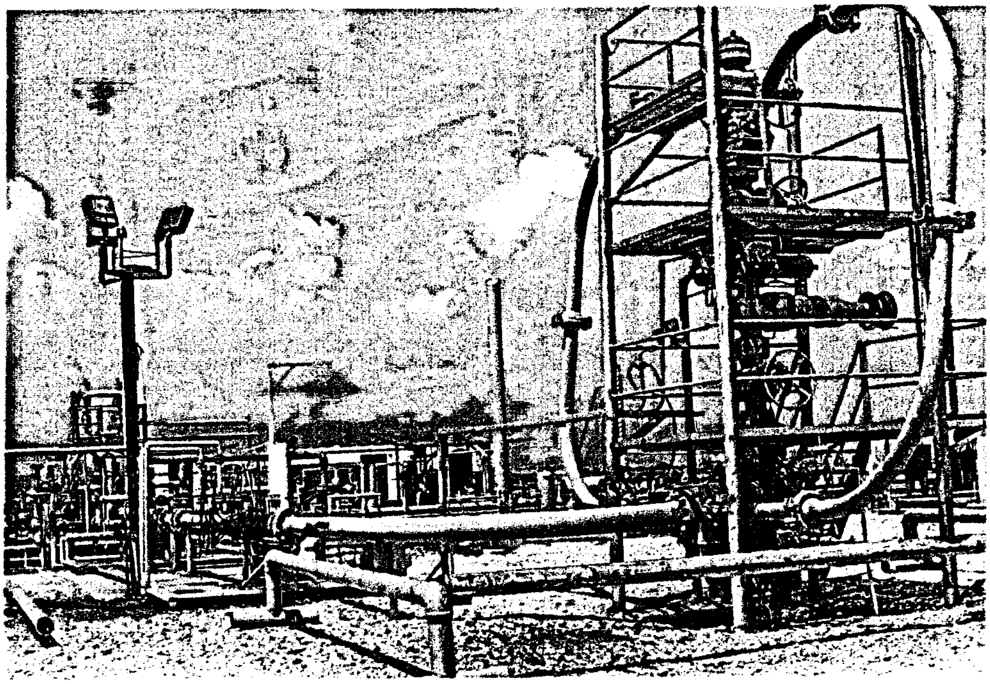
" . . . The average Gulf Coast geothermal gradient is approximately 1.5°F/100 ft (1.5°F/30 m). The average gradient at the test site was found to be 1.55°F/100 ft (1.55°F/30 m) and 1.67°F/100 ft (1.67°F/30 m) between 12,600 and 15,600 ft (3,840 and 4,754 m) (Technadril-Fenix and Scisson, 1985)."

" . . . After gas separation, the brine was disposed of by injecting it into a nearby disposal well. The brine disposal well, originally the Gerry-Buttes No. 1 well, was drilled in 1965 as a hydrocarbon prospect well to 15,598 ft (4,754 m). It was re-entered and completed as a disposal well at 3,514 ft (1,071 m). Exhibit 2-15 shows the electric log, disposal zones, and the generalized lithology of the brine disposal well. The well log shows Pliocene sandstones that are thick and porous and hence suitable for brine disposal. Major fault displacement is unlikely at these depths and hence sandstones will have good lateral continuity. A possible practical benefit of this information may be the use of brine in aiding secondary production. No detrimental environment aid effects have yet been attributed to testing and brine disposal." (Van Sickle et al. (LGS), 1988). . . (John (LGS), 1988).

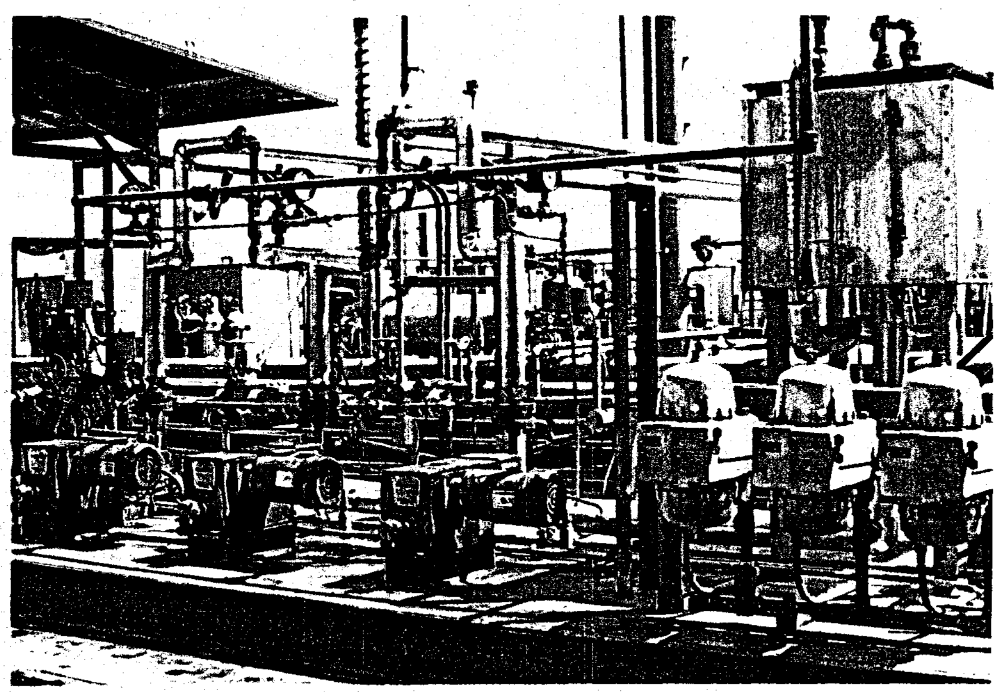
2.4.1.1 Production Well - Gladys McCall No. 1

The production well is completed as shown in well schematic - Exhibit 2-16. No workovers have been necessary on this well during this contract. The original reservoir pressure and temperature of the original completion in Sand Zone 9 were reported as 12,936 psia (89.19 Pa) and 298°F at 15,511 ft (4,728 m).

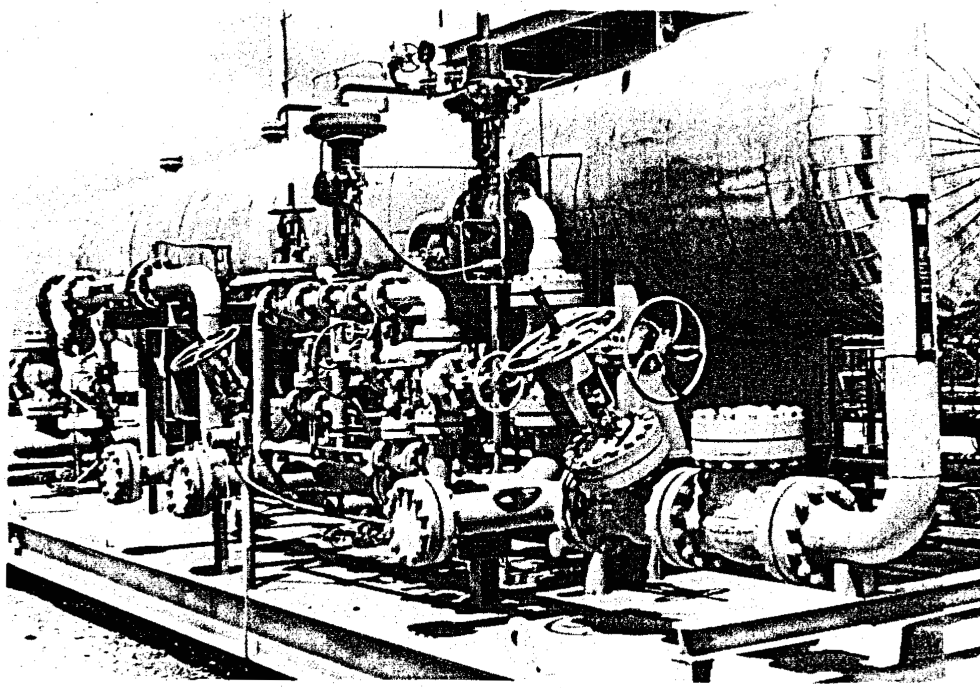
The original (September 1983) reservoir pressure and temperature of the present completion in Sand Zone 8 were reported as 12,821 psia (88.39 Pa) and 288°F at a depth of 15,160 ft (4,621 m) (TF&S, 1985).



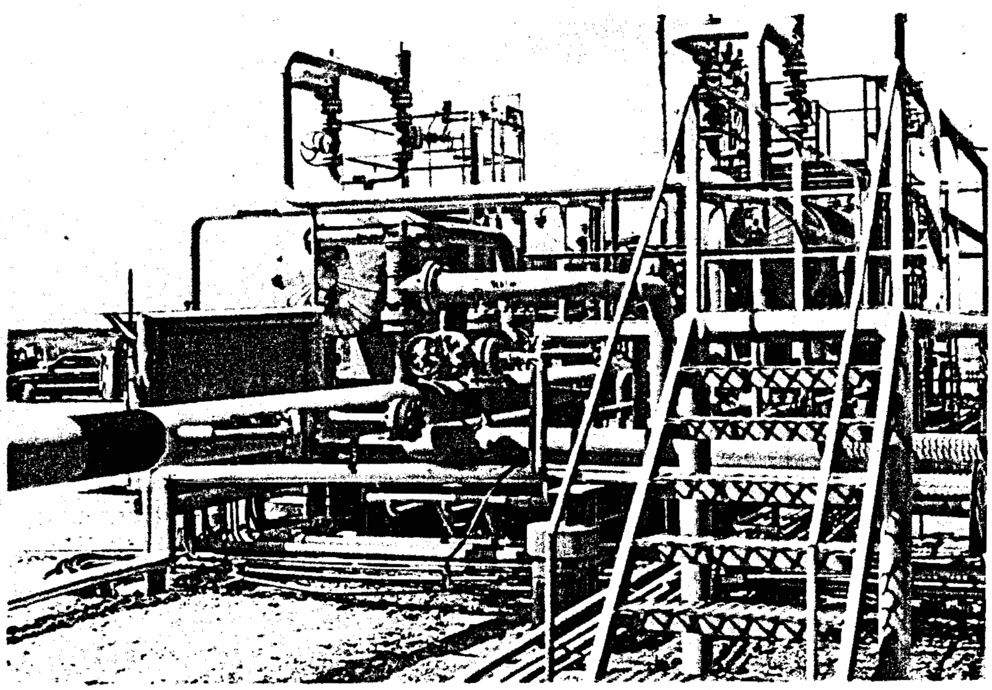
PRODUCTION WELLHEAD



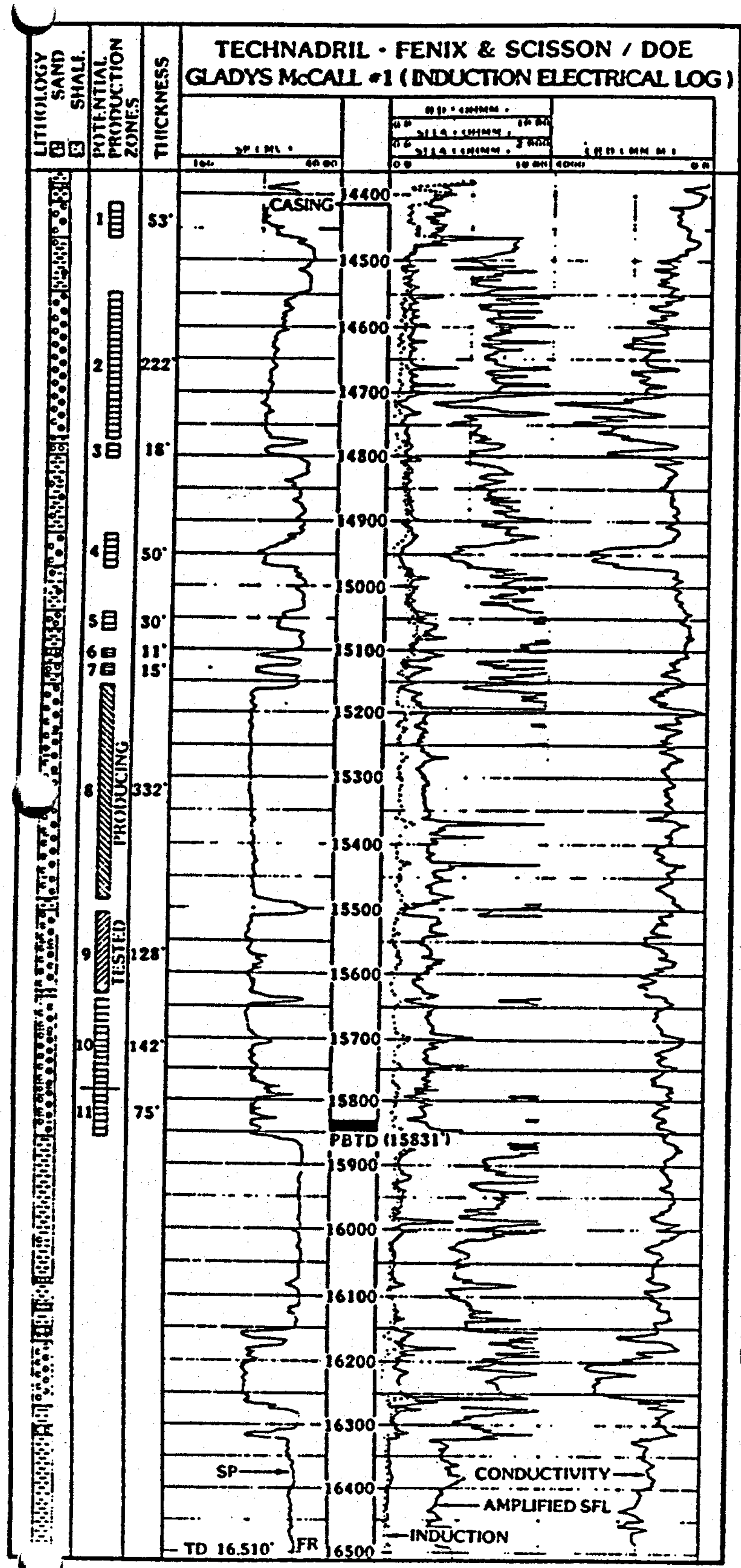
SURFACE EQUIPMENT SCALE CONTROL



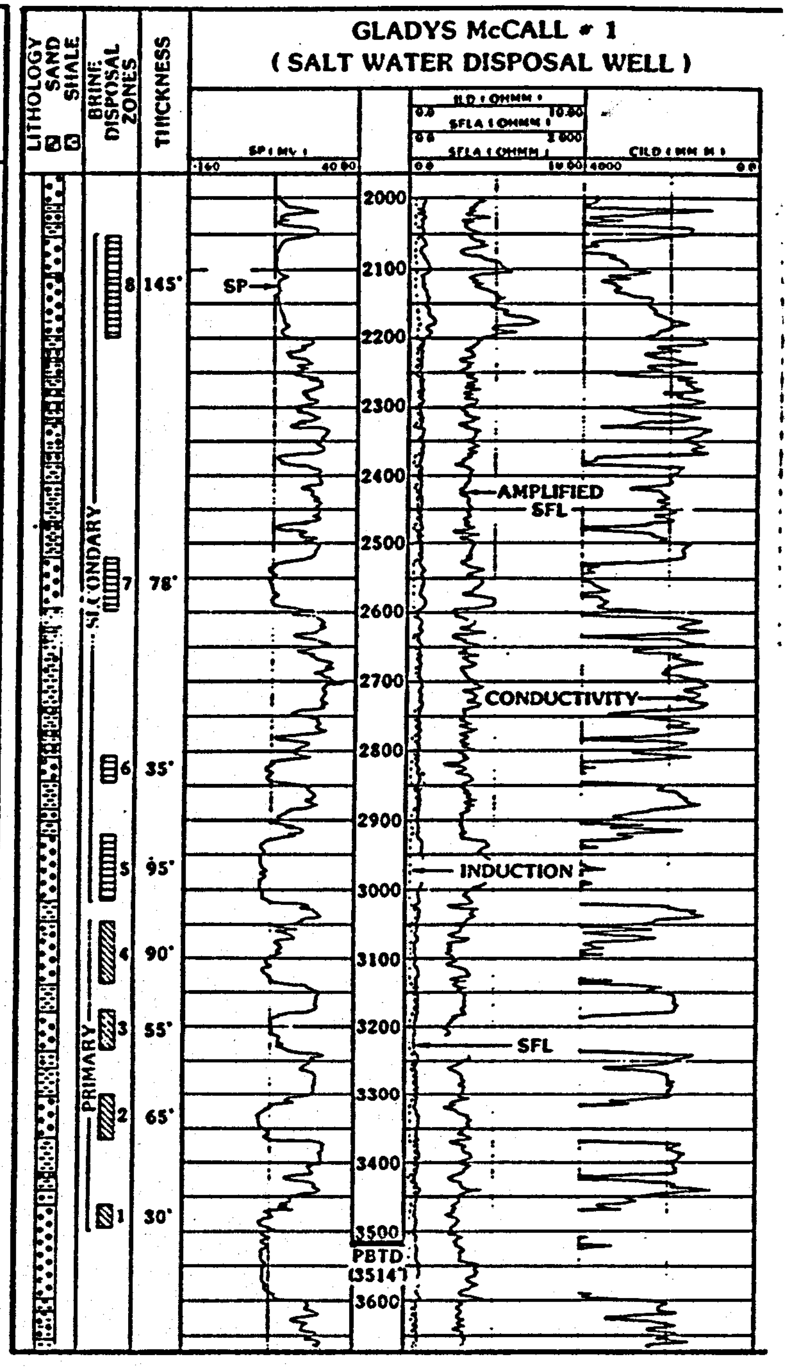
BRINE SEPARATOR PIPING MANIFOLD



40,000 BBLS/DAY CAP. BRINE SEPARATORS



Electric log, potential production zones, thickness, and generalized lithology of the test well



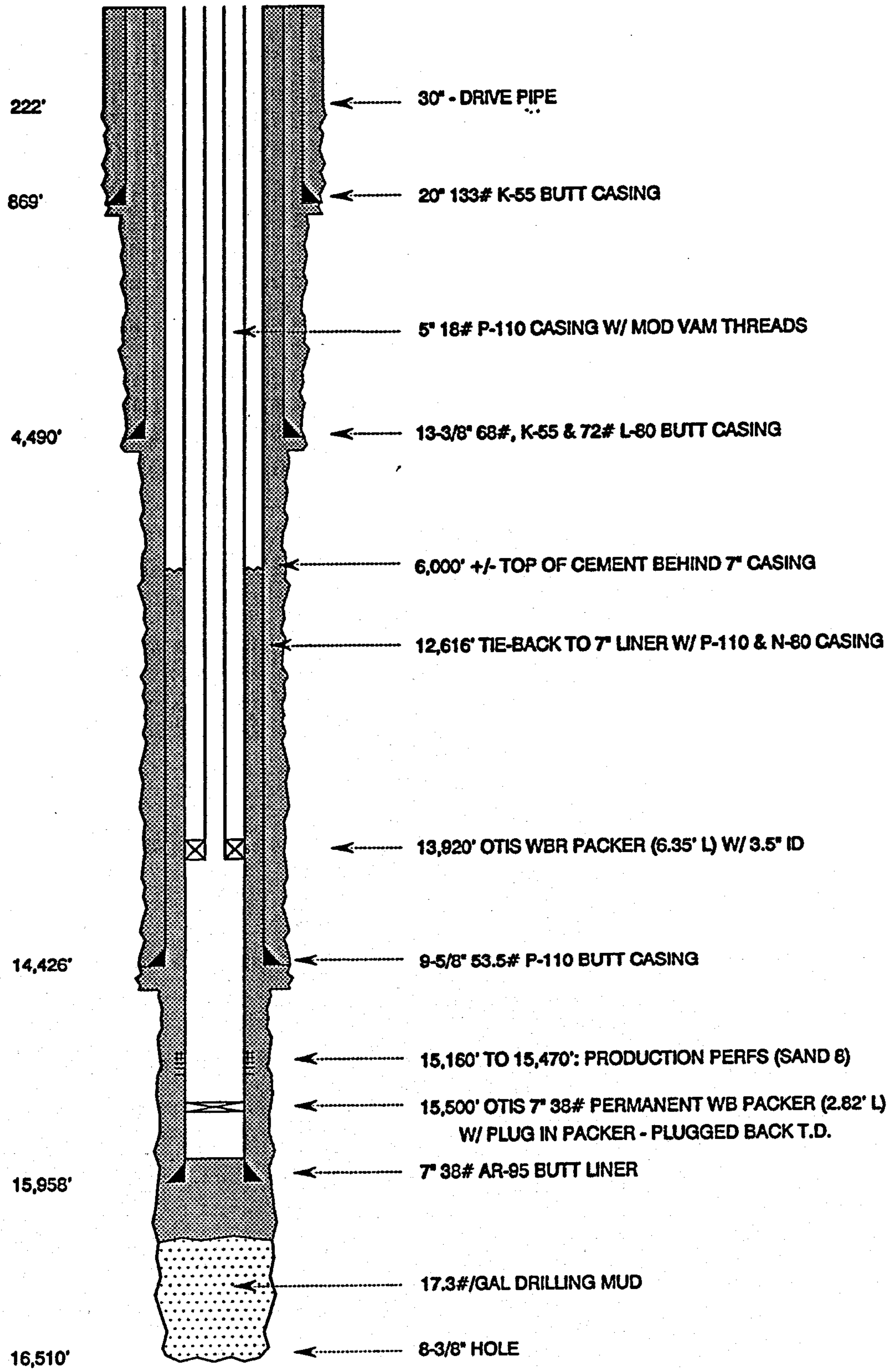
Electric log, brine injection zones, thickness, and generalize lithology of the brine disposal well

(From John (LGS), 1988)

EXHIBIT 2-14

EXHIBIT 2-15

GLADYS McCALL NO. 1
Cameron Parish, Louisiana



EATON

Well Schematic As Recompleted By T-F&S - 8/15/83.

EXHIBIT 2-16

The last recorded values after producing over 27,000,000 Bbl (not STB) (4,343,163 m^3) of brine and being shut-in almost three years was 12,008 psia (82.79 Pa) and 299.3°F and 15,150 ft (4,618 m) in May 1990 (EOC Monthly Report, 1990).

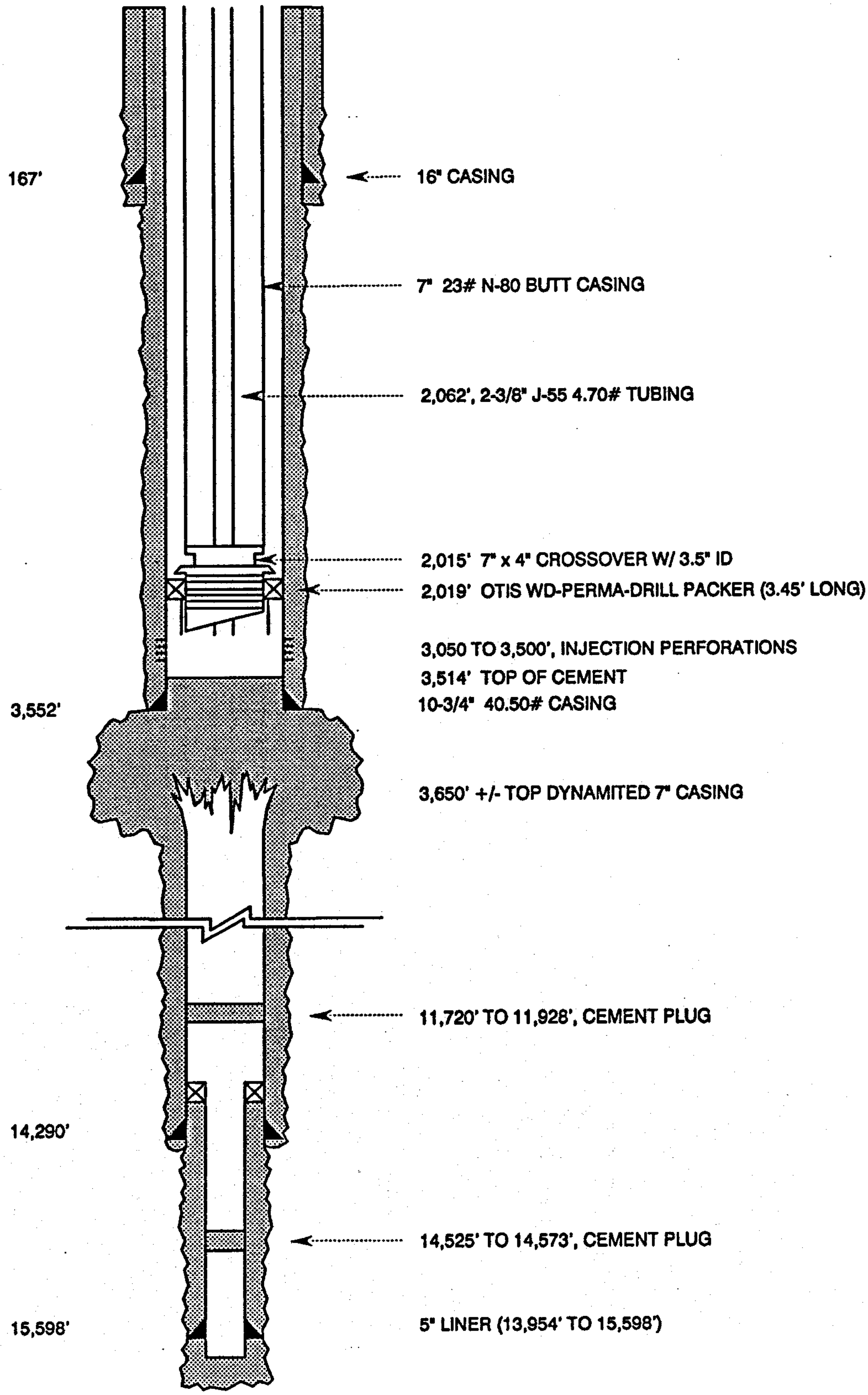
Two scale inhibition squeezes ("pills") were injected into the production well formation during this contract. The first was in 1985. This allowed the production of 3,416,359 Bbl (543,158 m^3) before indications of scaling were found on the filters in the low pressure portion of the production system. This treatment consisted of 100 Bbl (15.9 m^3) of a 6% phosphonate solution. An additional 2,014,051 Bbl (320,208 m^3) was produced after this occurred (5,430,410 Bbl - 863,366 m^3 total) by adding a small amount of scaling inhibitor in the low pressure portion of the system. No scaling deposits were found in the high pressure side of the system.

The second phosphonate squeeze was done on February 4, 1986. After this, 3,261,359 Bbl (518,515 m^3) of brine was produced before scaling occurred on the filters. This treatment used a 3% phosphonate solution (50% reduction in concentration). Additional brine was produced with surface inhibition, for a total of 13,259,353 Bbl (2,108,068 m^3) after the second squeeze, for a total of 18,689,763 Bbl (2,971,434 m^3) after the two squeezes. No scale was apparent in the high pressure side of the system at this point when the well was shut in for a three year buildup.

2.4.1.2 Salt Water Disposal Well - Gladys McCall (SWDW) No. 1

The salt water disposal well (SWDW) is completed as shown in well schematic - Exhibit 2-17. It was necessary to wash sand out of this well during January 1986.

GLADYS McCALL SWDW-1
Cameron Parish, Louisiana



EATON - KPP

Well Schematic As Completed By EOC On 3/2/86.

EXHIBIT 2-17

2.4.2 Pleasant Bayou Site (Brazoria County, TX)

The original drilling, completion and initial testing of this well prior to October 1985 is described in the following reports:

1) Drilling and completion of Pleasant Bayou No. 2, Brazoria County, TX, Vol. 1 - Final Report, John A. Rodgers, Gruy Petroleum Technology, Inc. for Fenix & Scisson, Inc., December 31, 1982.

2) Pleasant Bayou Geopressured/Geothermal Testing Project Brazoria County, TX - Final Report, Fenix & Scisson, Inc., July 1985.

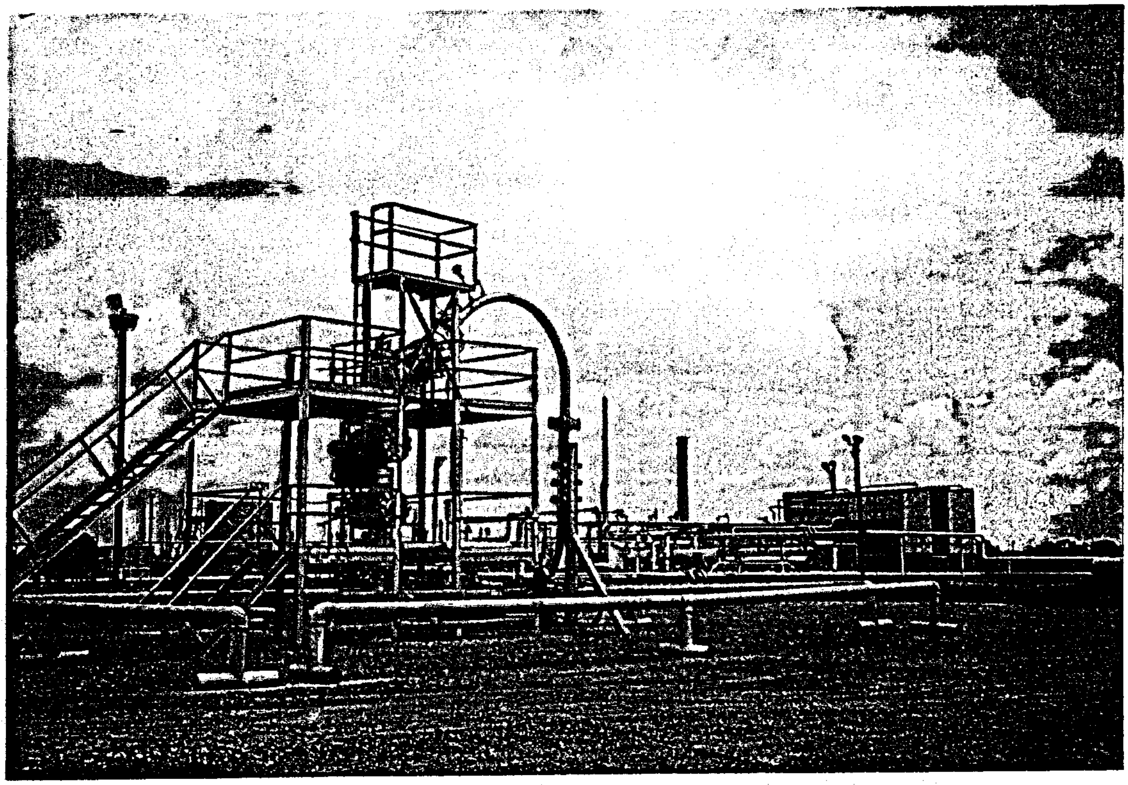
2.4.2.1 Production Well - Pleasant Bayou Well No. 2

An electric log of the producing well, showing the production zone, is shown in Exhibit 2-18. Prior to this contract, a tubing failure had occurred and a fishing job, lasting several months, had been suspended, and the well was placed in a temporarily abandoned status (1983), as shown in Exhibit 2-19. Eaton assumed the well after its being shut in for over three years (after an unsuccessful attempt of several months fishing). The well was successfully cleaned out and recompleted, as shown in Exhibit 2-20 (EOC, 1986).

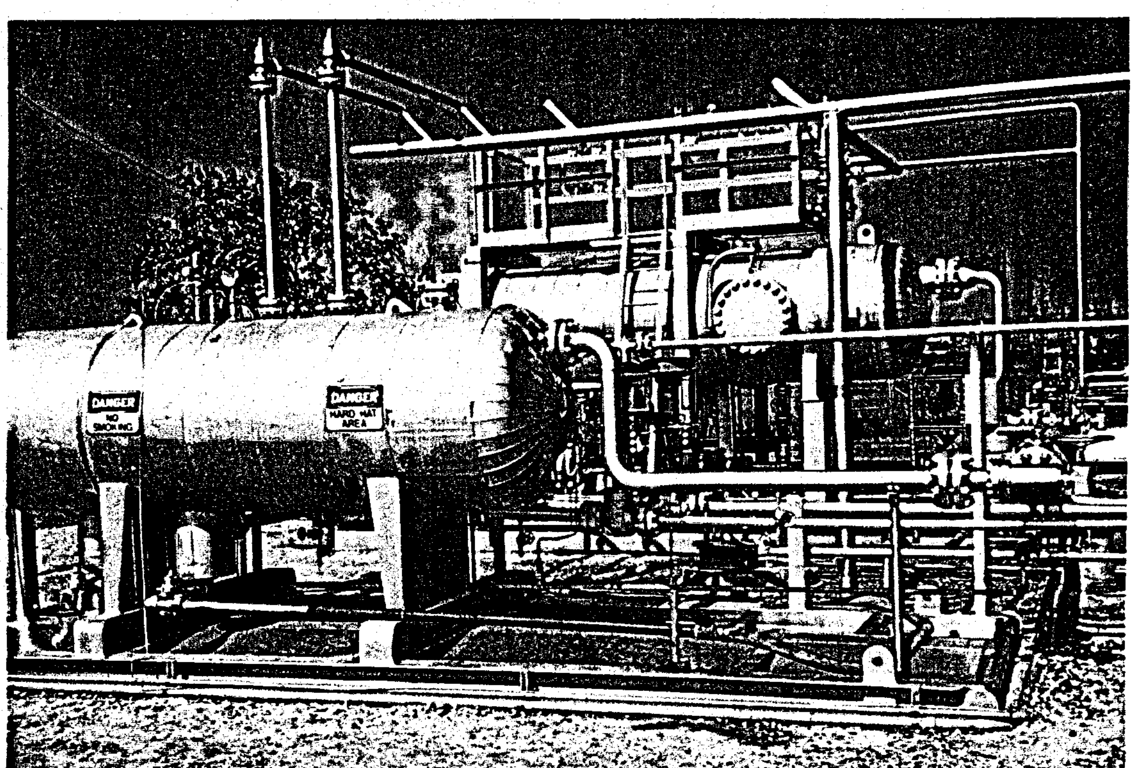
Two successful scale inhibitor squeezes were performed in this well. The first was done in April 1988. After producing 4,950,000 Bbl (786,987 m^3), some scaling was detected in the low pressure system. Surface inhibition was begun, and a total of 7,720,000 Bbl (1,227,382 m^3) was produced after this squeeze, until November 1989. A second squeeze was performed at this time. From this date, 2,750,000 Bbl (437,215 m^3) was produced before surface inhibition was started on May 16, 1990. The well has continued to produce 2,098,753 Bbl (333,674 m^3), for a total of 4,848,753 Bbl (770,889 m^3) (as of October 31, 1990) after the second squeeze. Grand total of 12,568,753 Bbl (1,998,268 m^3) after two squeezes (EOC Monthly Report, 1990).

2.4.2.2 Salt Water Disposal Well - Pleasant Bayou SWDW No. 1

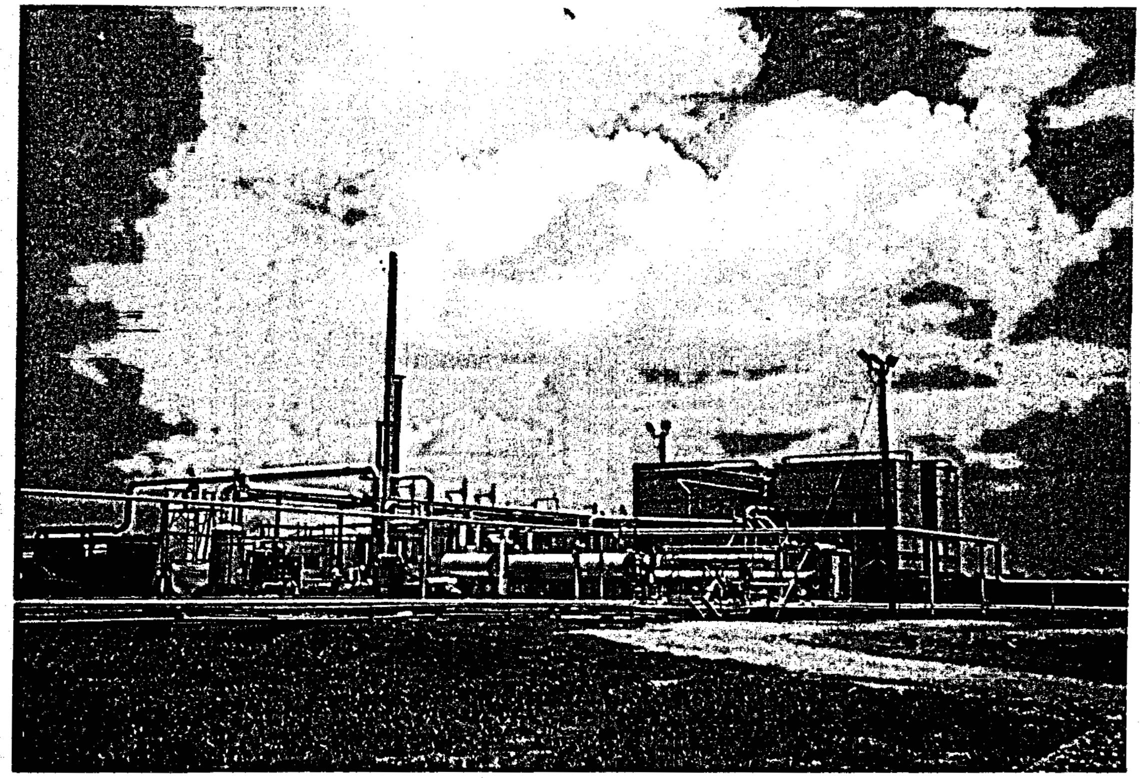
An electric log, showing the disposal zones as originally completed, is shown in Exhibit 2-21. The well was sanded up and had a tubing leak so that it could not be used when Eaton assumed the well in October 1985. Eaton reworked and recompleted the well in October 1986 (prior to flow testing). It was necessary to wash sand out of the well in June of 1988 (Meahl, EOC, 1988). Due to increased injection pressures, additional intervals were perforated (as shown on Exhibit 2-22) on May 26, 1989. A schematic of the well at that time is shown on Exhibit 2-23. The well sanded up again and was reworked and recompleted in July 1990, as shown on Exhibits 2-24 and 2-24.1.



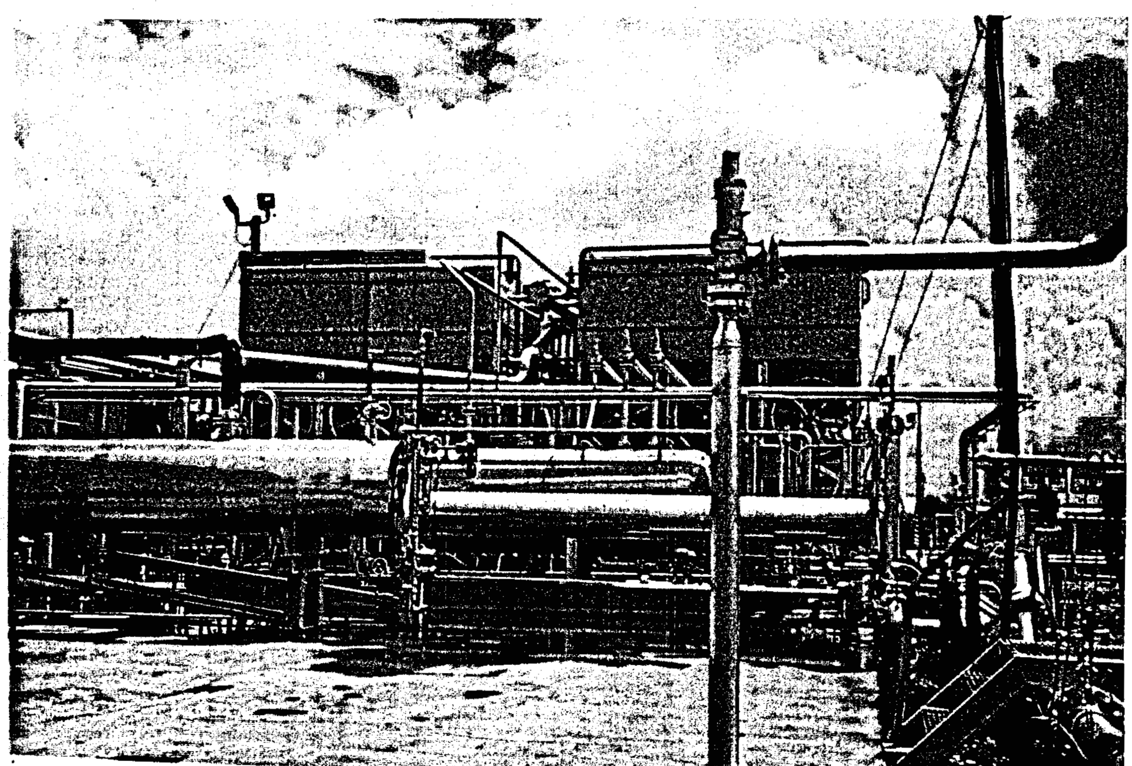
PRODUCTION WELLHEAD



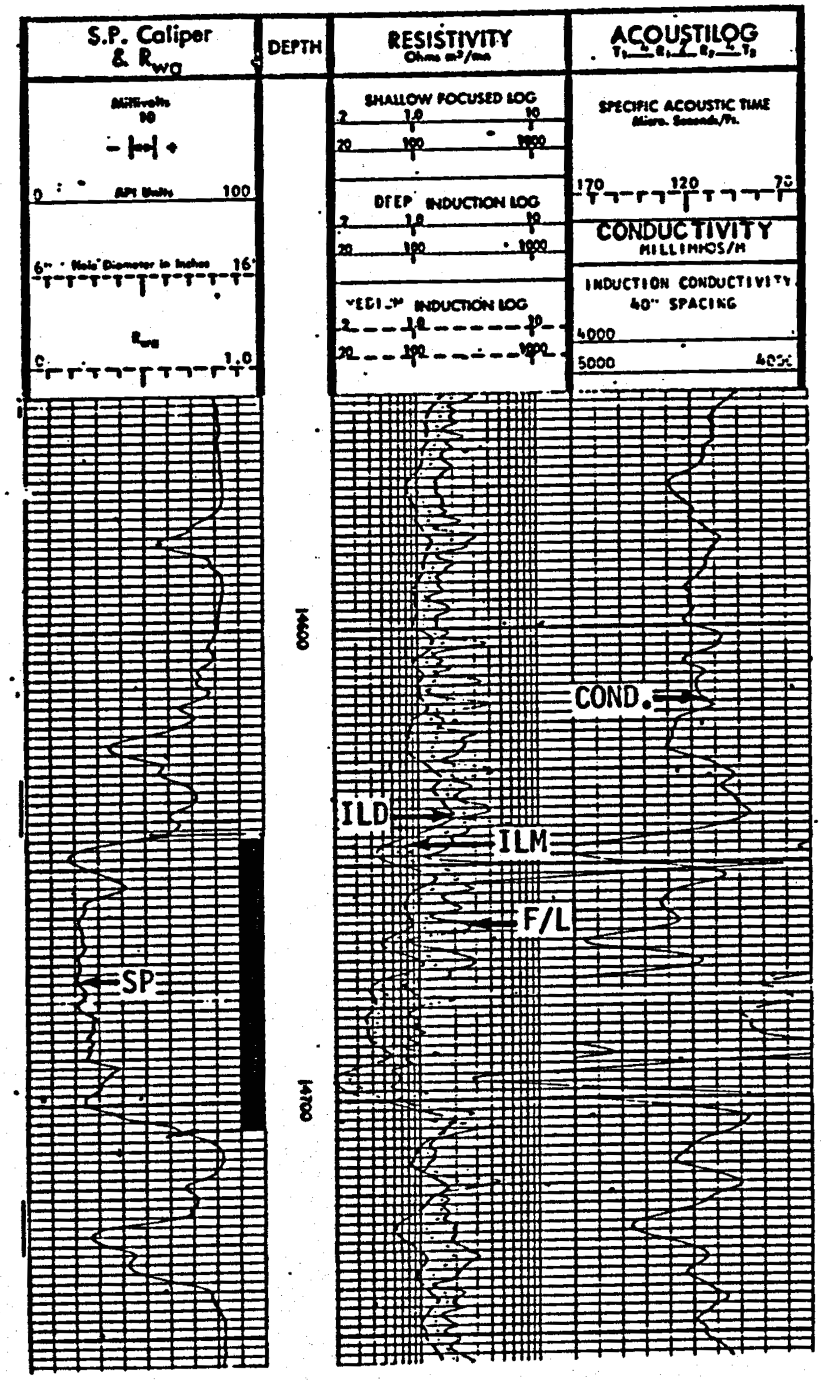
BRINE/GAS SEPARATING SYSTEM



1 MEGAWATT HYBRID POWER SYSTEM (HPS)



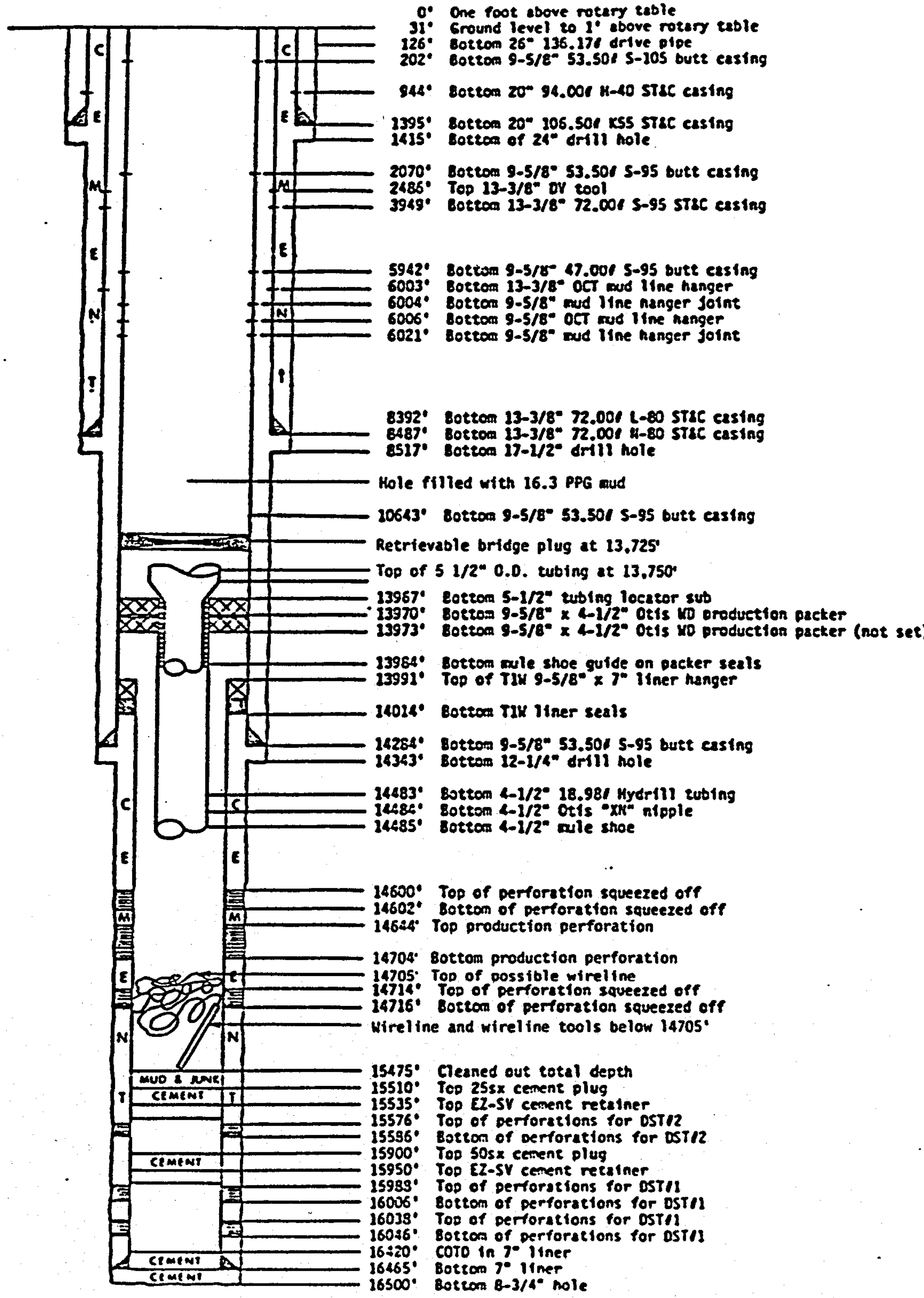
HPS HEAT EXCHANGERS/ISOBUTANE CONDENSERS



--Pleasant Bayou No. 2 dual induction focused log test zone, 14,644' to 14,706'.

(From Gruy, 1982)

EXHIBIT 2-18

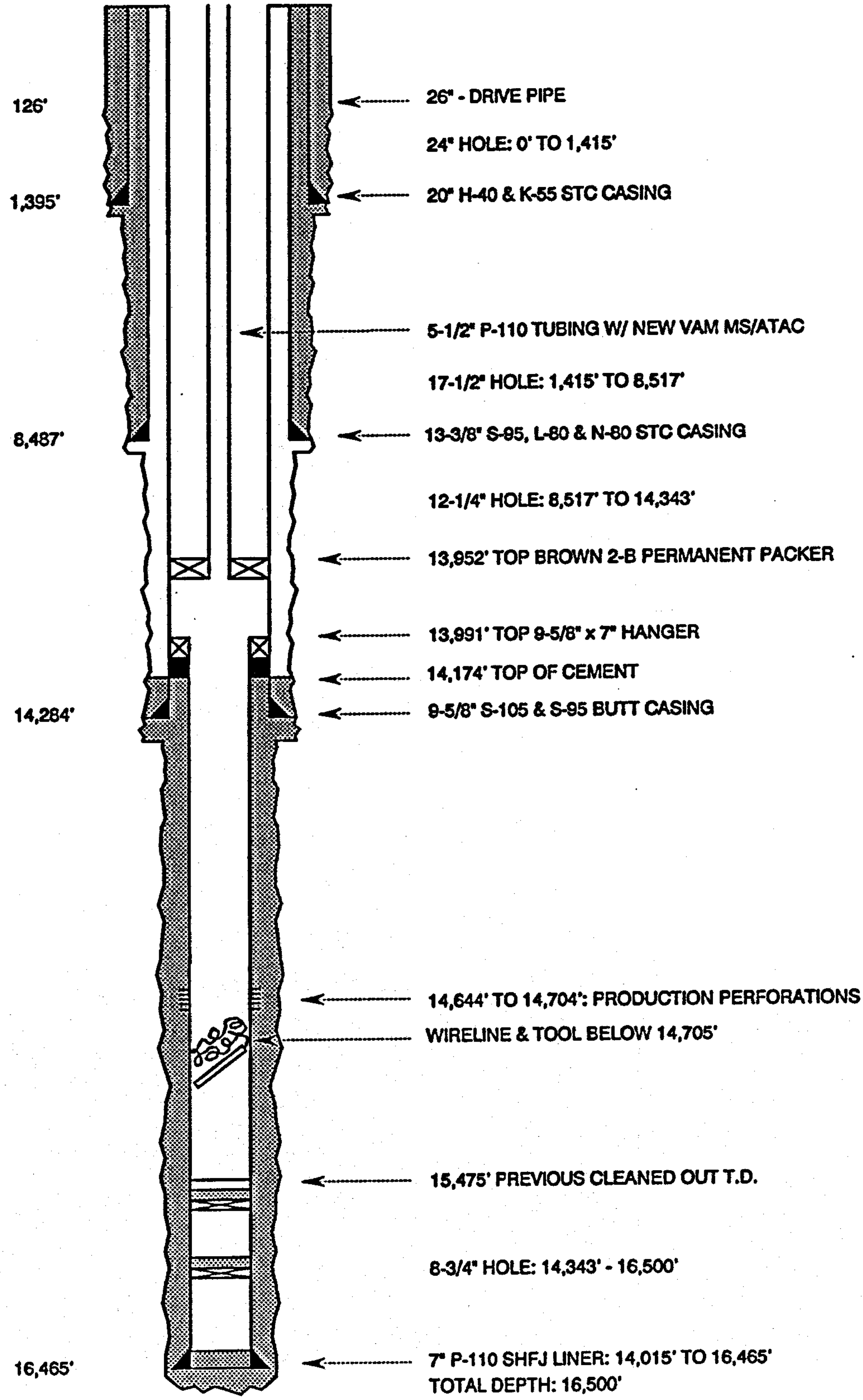


CONDITION OF No. 2 WELL 8/15/83

(From Fenix & Scisson, 1985)

EXHIBIT 2-19

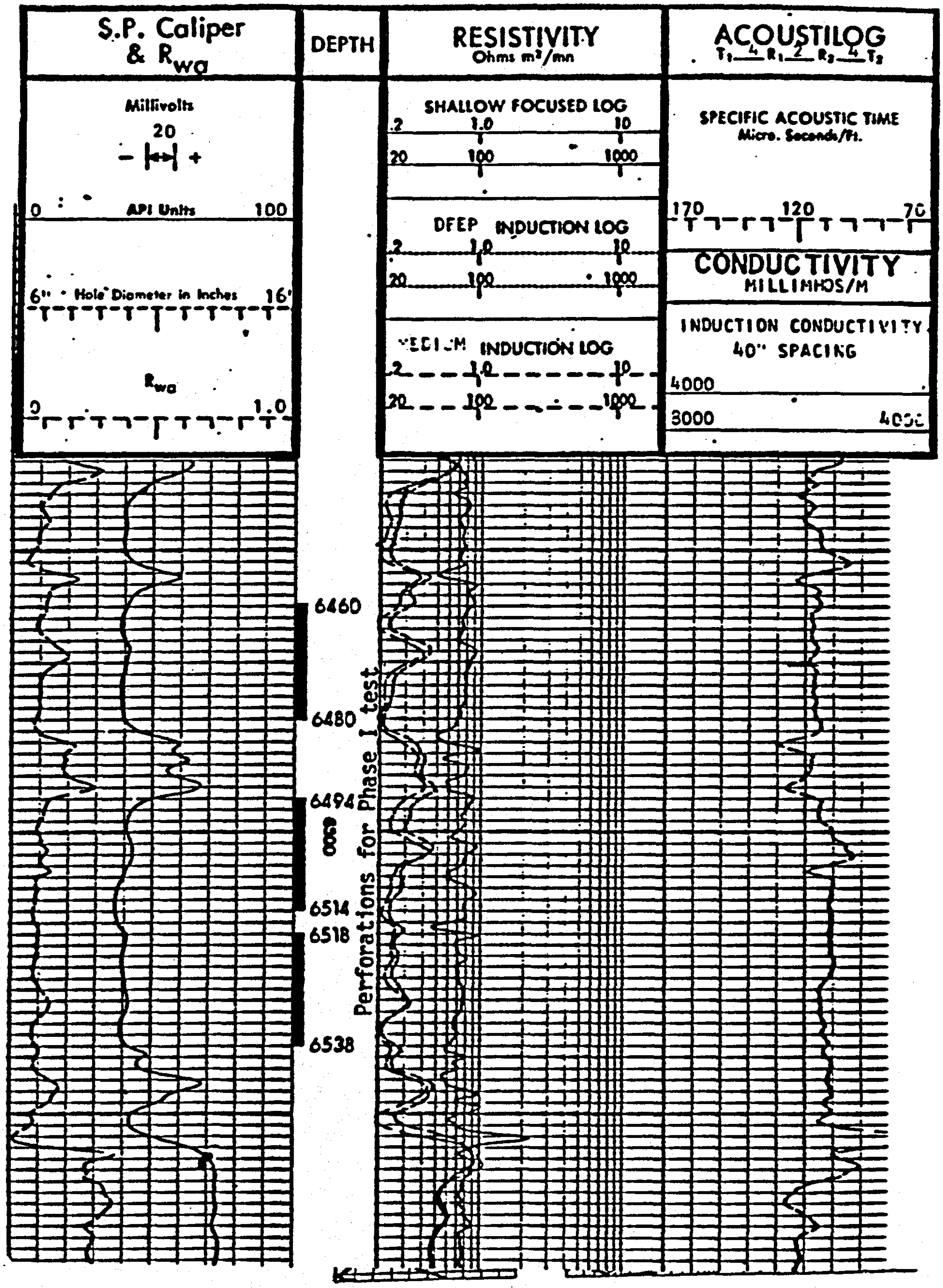
EOC/DOE PLEASANT BAYOU No. 2
Brazoria County, Texas



EATON

Well Schematic As Recompleted By EOC - 4/3/86.

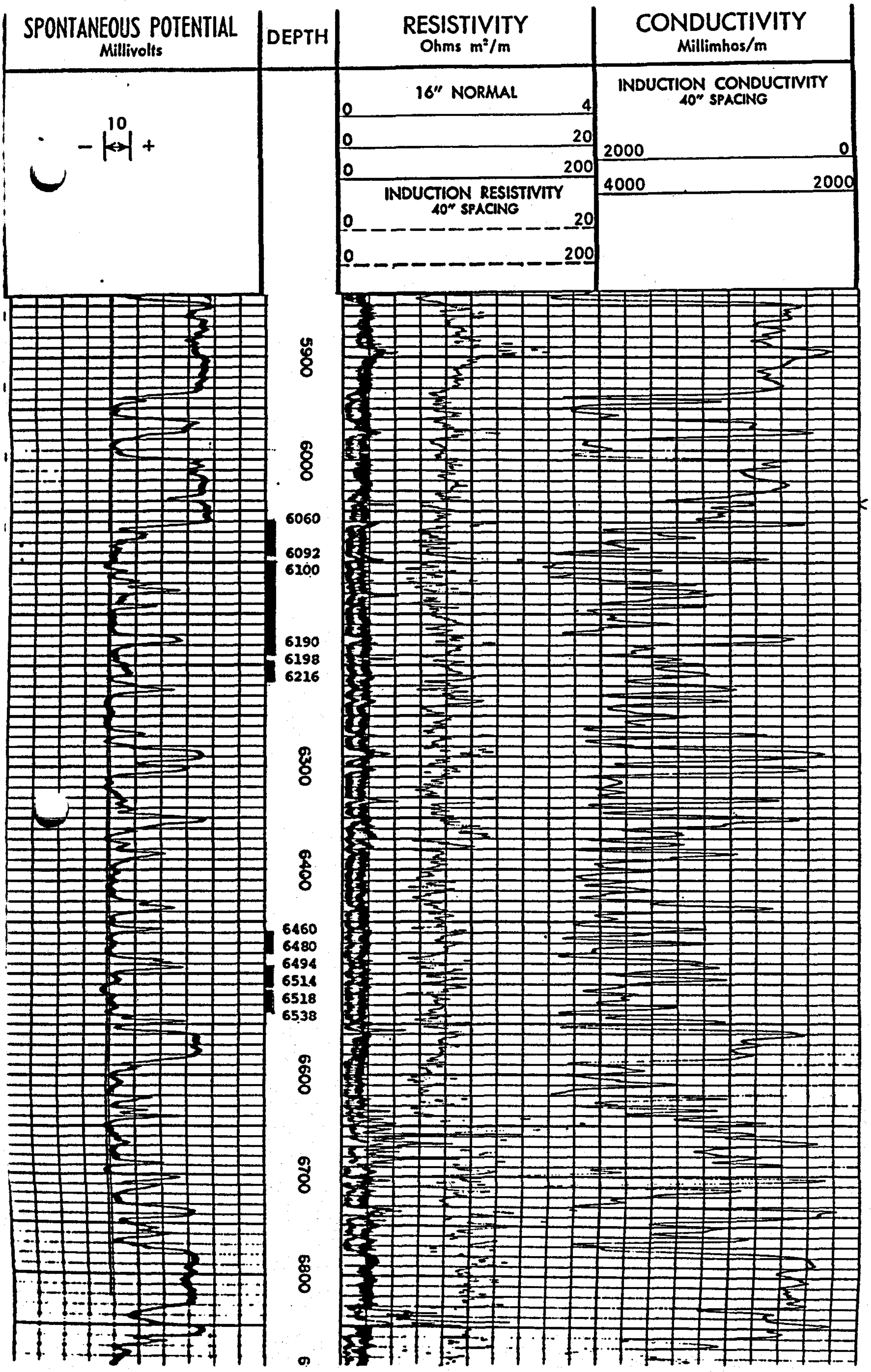
EXHIBIT 2-20



-- Well log of Pleasant Bayou No. 1 showing perforated zones for Phase I test.

(From Gruy 1982)

EXHIBIT 2-21

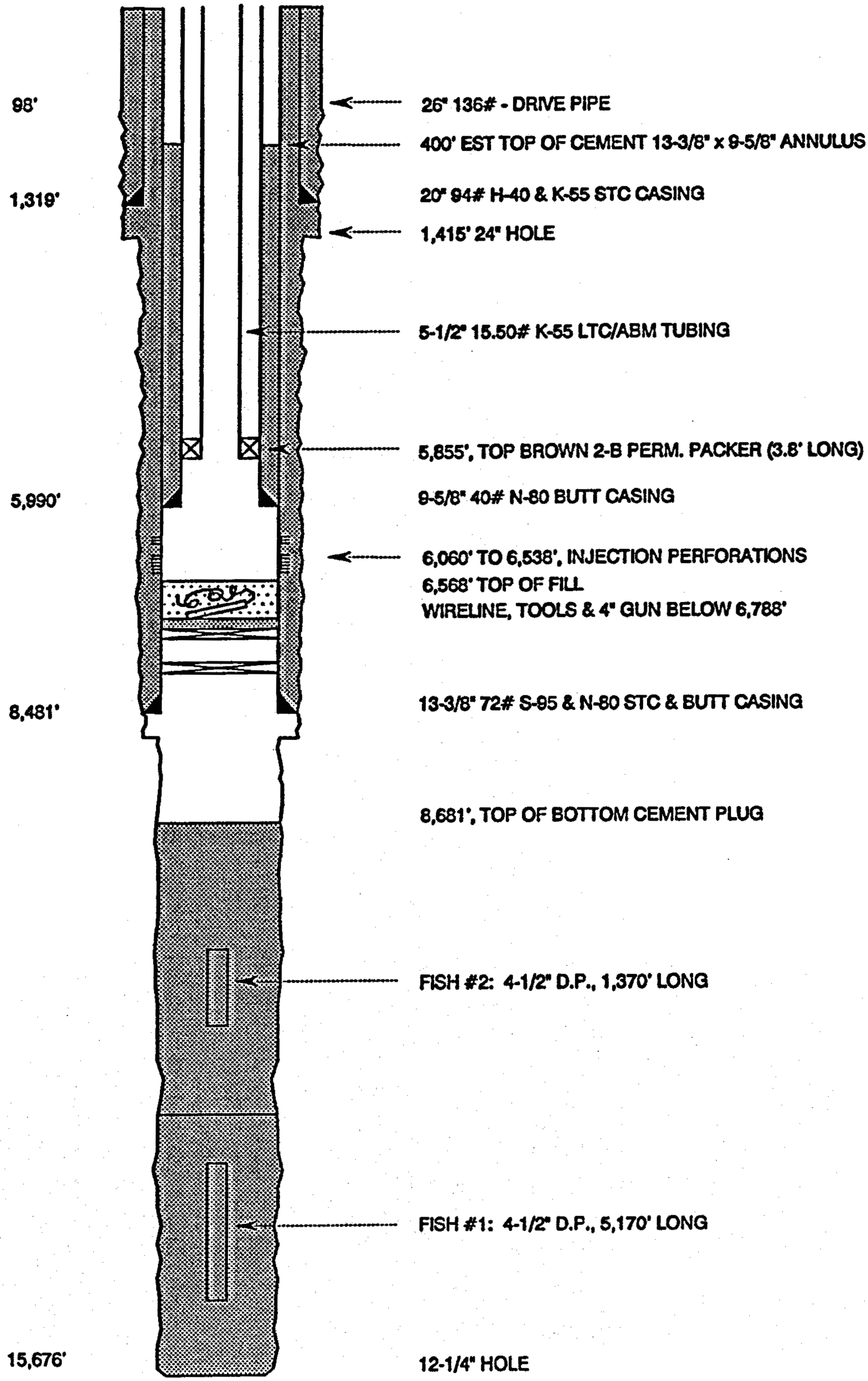


PLEASANT BAYOU NO. 2

DISPOSAL ZONES (MAY 1989)

EXHIBIT 2-22

EOC/DOE PLEASANT BAYOU SWDW No. 1
Brazoria County, Texas

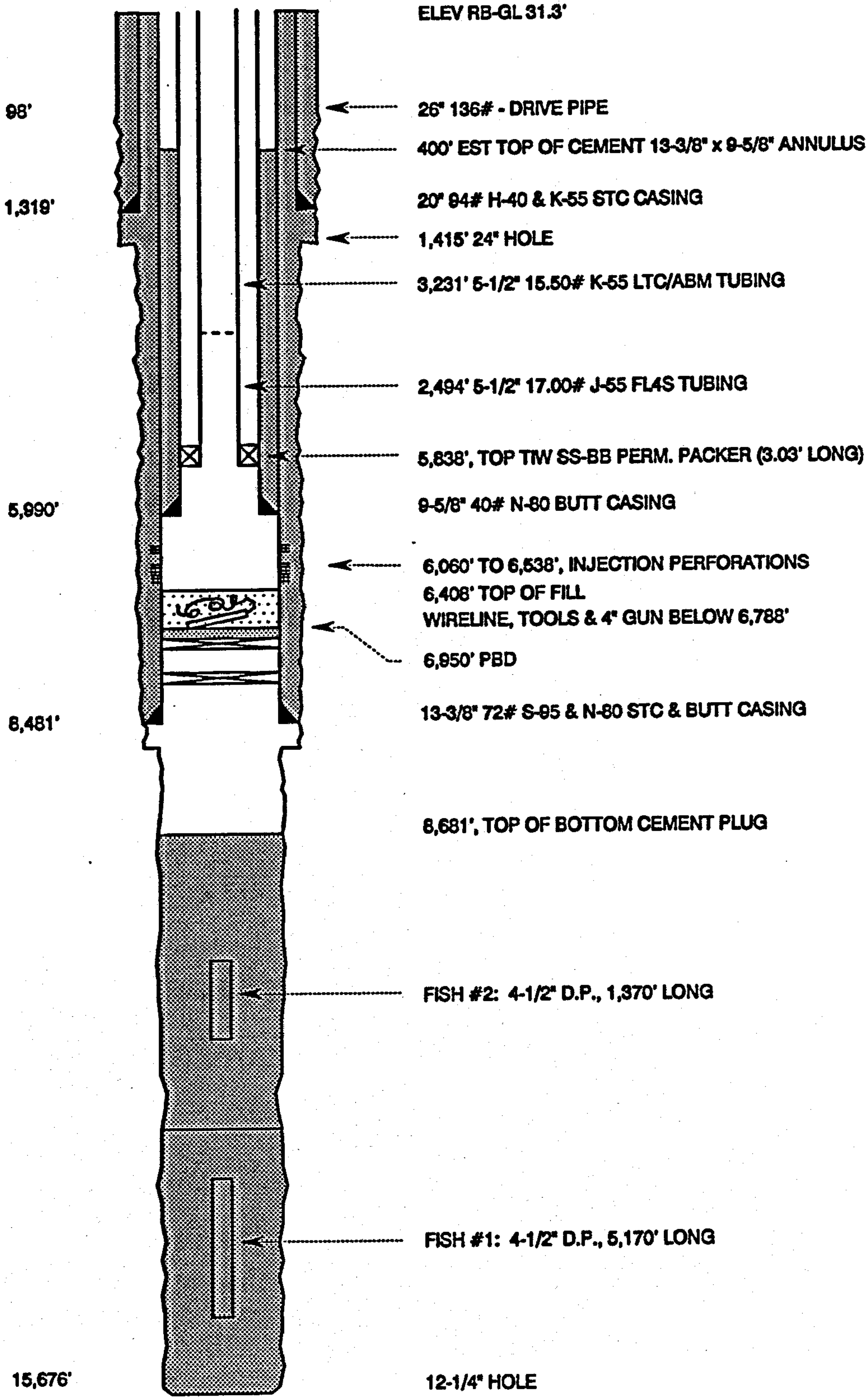


EATON

Well Schematic As Recompleted By EOC - 5/26/89.

EXHIBIT 2-23

EOC/DOE PLEASANT BAYOU SWDW No. 1
Brazoria County, Texas

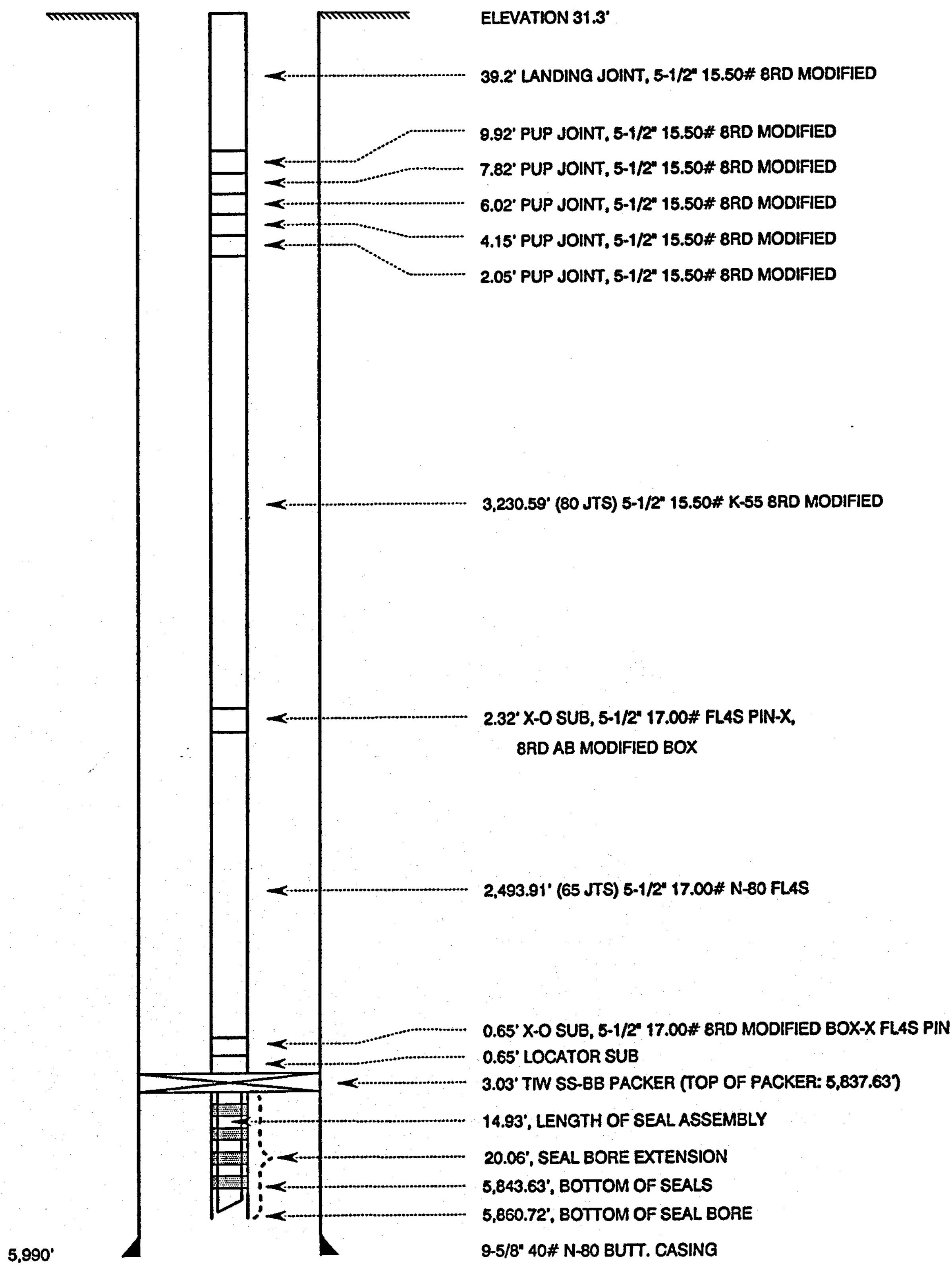


EATON

Well Schematic As Recompleted By EOC - 7/22/90.

EXHIBIT 2-24

EOC/DOE PLEASANT BAYOU SWDW No. 1
Brazoria County, Texas



EATON

Injection Tubing Make-up Schematic As Recompleted By EOC - 7/22/90.

EXHIBIT 2-24.1

2.4.3 Hulin Site (Vermilion Parish, LA)

The Willis Hulin Well No. 1 was drilled as a gas well by The Superior Oil Company (Superior). It was started in 1978. While drilling at 21,000 ft (6,401 m), the drill pipe was stuck. After unsuccessfully attempting to recover the drill pipe, a fish was left in the original hole, and the well was sidetracked around it to 21,546 ft (6,567 m). The well was completed as a gas well in the interval 21,059 to 21,094 ft (6,418.8 to 6,429.5 m) in 1981. Natural gas production ceased in 1983. Mechanical problems occurred while attempting to restore the well to production. To clean out the well to recomplete it, or to plug and abandon it would have required a very expensive workover which could not be justified by the remaining gas reserves in the producing sand. Superior offered the well to DOE as a "Well of Opportunity". Even though an extensive workover would be necessary to recomplete the well, this rework would cost much less than the several million dollar cost of drilling a new well. This well had deeper sands, with higher temperatures, and the potential for higher solution gas ratios than any well tested to date. DOE accepted the well in 1984. A well schematic of the well at that time is shown in Exhibit 2-25.

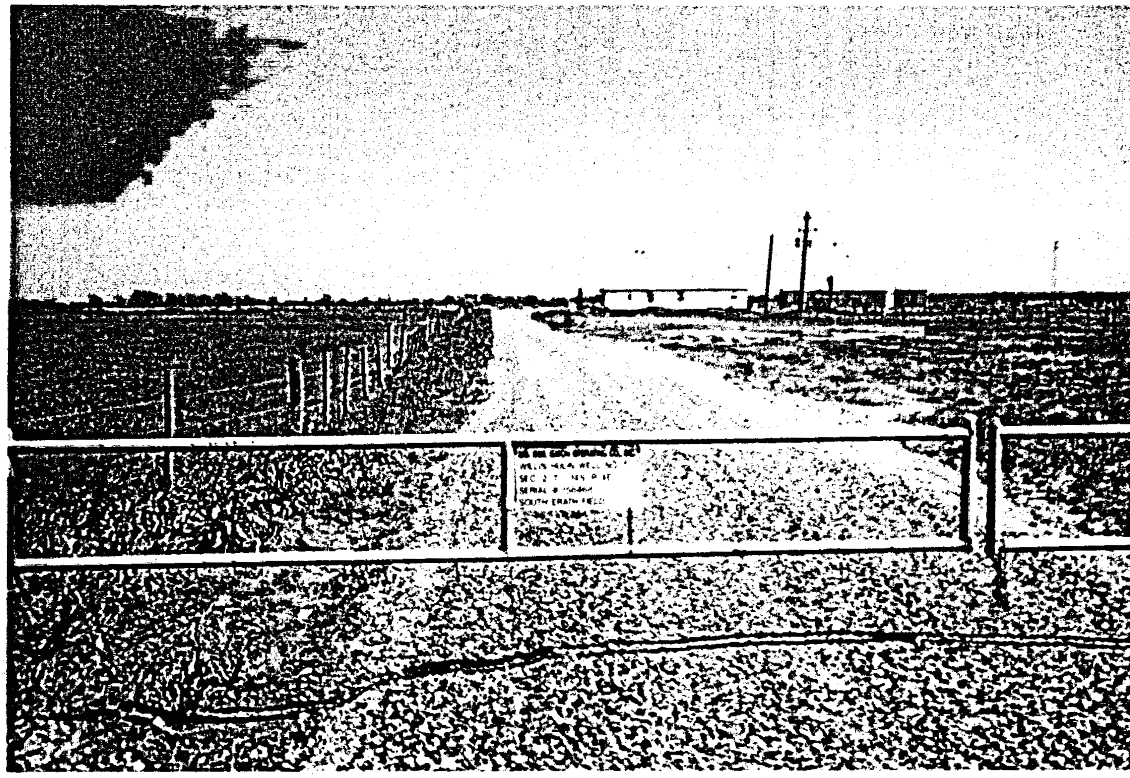
Funds were not available to begin the clean-out of this well until November 1988. Due to the apparent loss of mechanical integrity of the downhole tubings and packer, at least partial pressure communication existed between the different casing and tubing annuli, as evidenced by increasing pressures on the annuli. Since these pressures were unequal, it was not known exactly how the communication was occurring. This complicated the planning for the clean-out operation and made it more dangerous. The difficulty was increased by the type of well completion used (see Exhibit 2-25). This completion consisted of a small kill string tubing inside of the production tubing. Heavy wall tubings and casings were used to contain the high well pressures. The very limited clearances existing between these tubular strings prevented the use of the normal pipe recovery technique of washing over the inner strings with wash pipe so they could be retrieved.

Because of the unknown mechanical condition at the bottom of the well in the existing original production zone and the additional cost to reach it, a decision was made to only attempt to clean the well out to below the bottom of the Planulina sand at 20,700 ft (6,309.3 m) and plug off the original production zone below. This would be done in a manner to allow deeper clean-out in the future, if it was desired to return to the original completion zone.

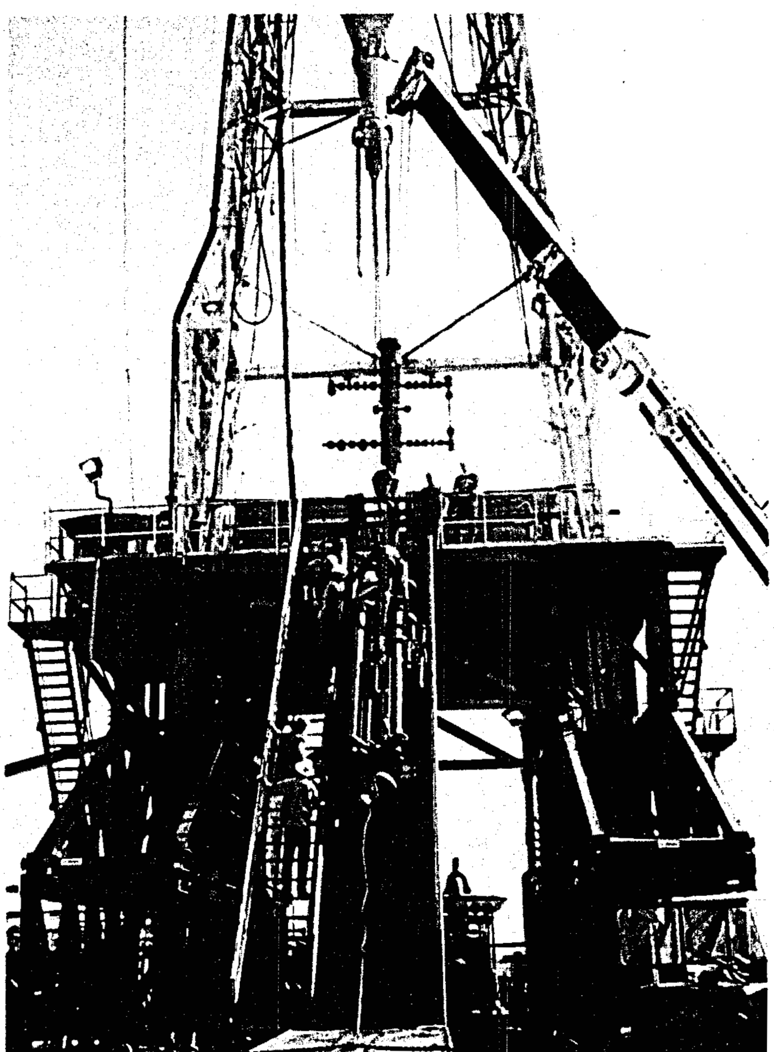
The work was further complicated by the fact that very heavy mud of 17.2#/gal ($\pm$2,061 kg/m^3) had been left in the tubing-casing annuli. After ten years, this mud was very dehydrated and gelled as a result of the high temperatures and pressures, and separated into liquid and solid fractions due to settling of the high gravity solids (i.e., barite weighting material) in the mud.

To provide safety while working under the possible high pressures, it was determined that operations would be started with a small hydraulic snubbing unit. This equipment allowed the entering and removal of tubulars under pressure.

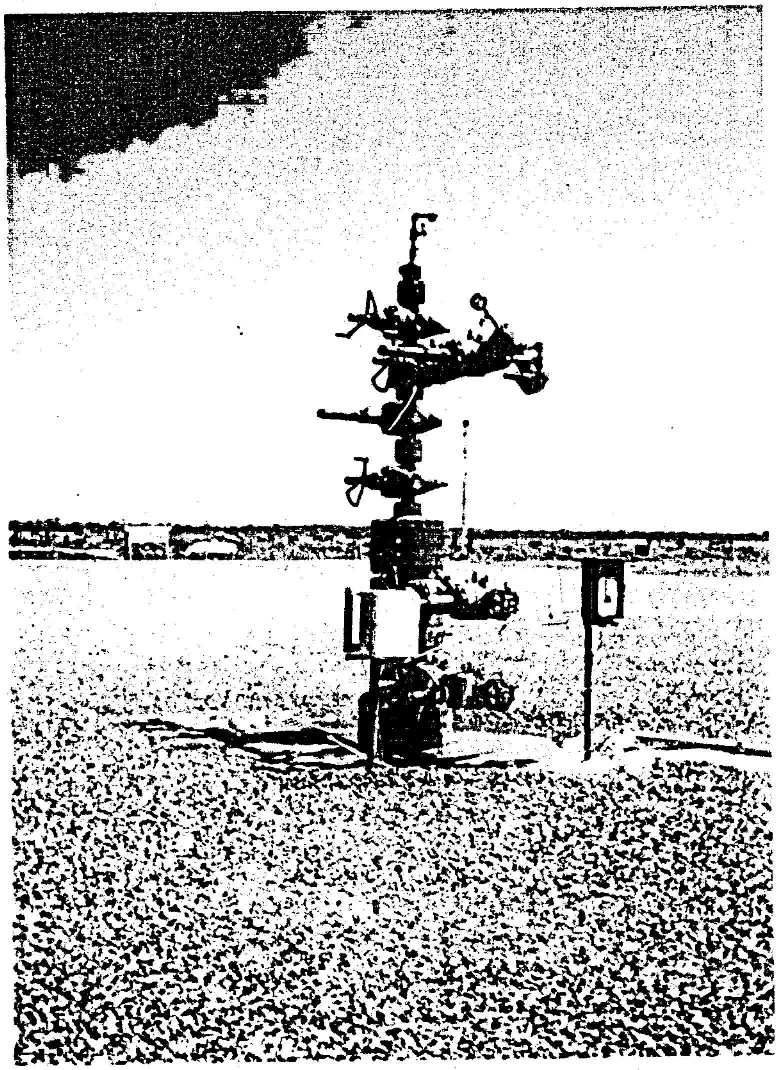
WILLIS HULIN



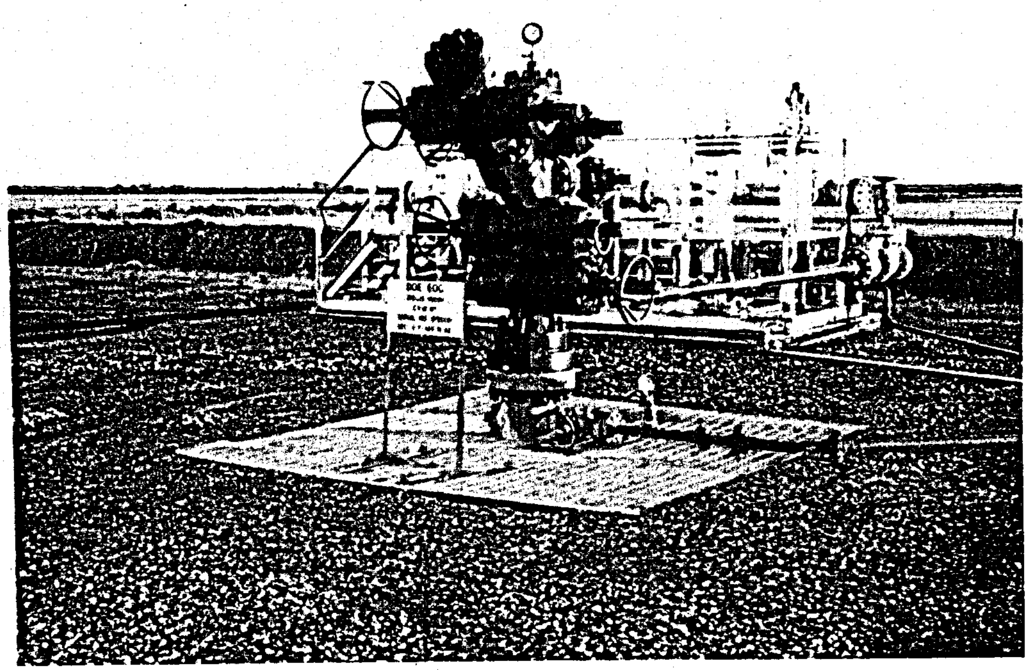
FACILITY ACCESS



WORKING OVER THE PRODUCTION WELL



PRODUCTION WELLHEAD



DISPOSAL WELLHEAD

WILLIS HULIN No. 1

Vermilion Parish, Louisiana

EATON - KPP

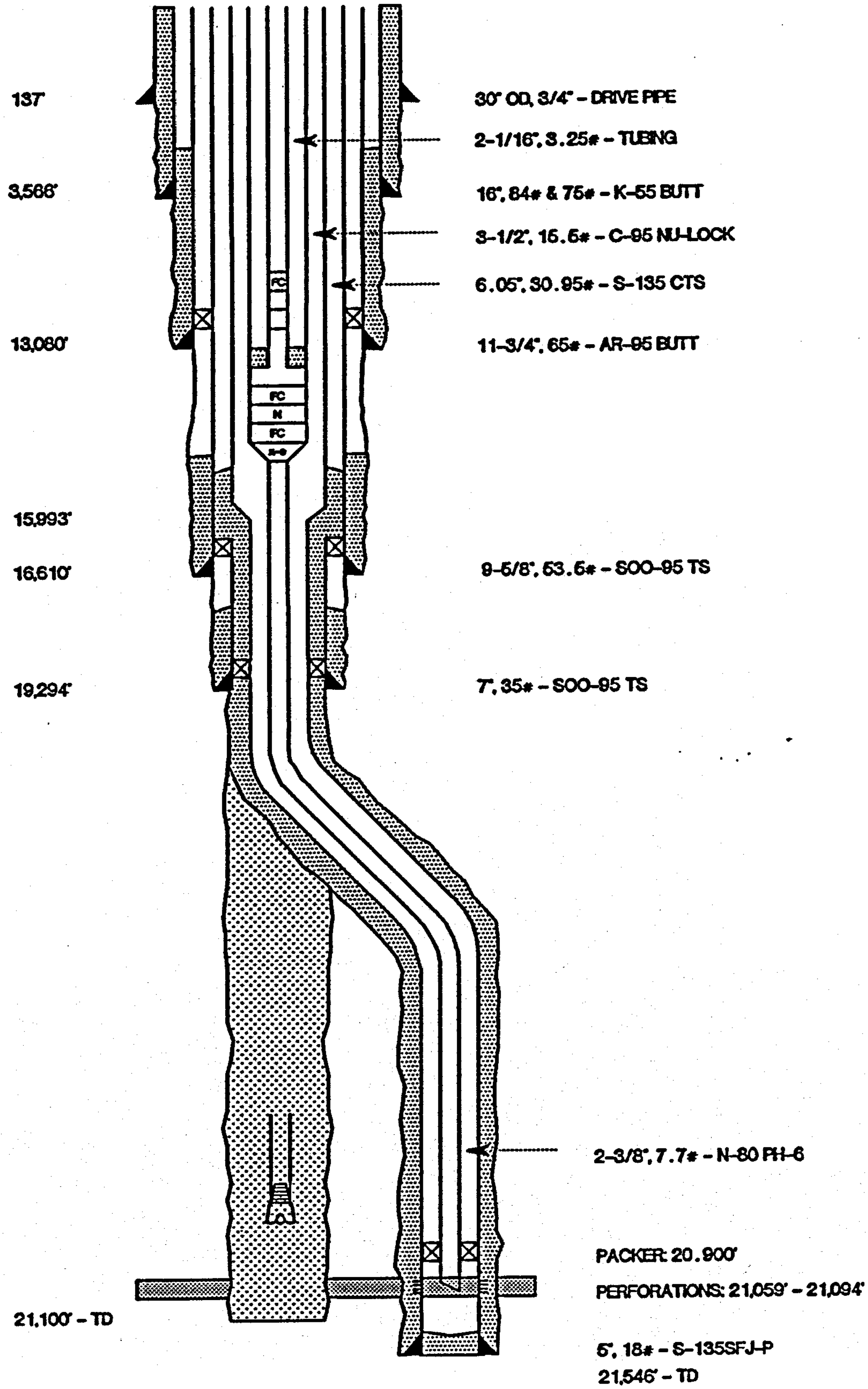


Figure 1. Well Schematic As Completed 6/29/79.

EXHIBIT 2-25

Dehydrated mud and sand were washed out of the 2-1/16" (5.24 cm) tubing. The 2-1/16" (5.24 cm) tubing was then removed, after new, heavy mud had been displaced on the inside to balance formation pressures below. (Due to dehydrated mud preventing removal by pulling, this tubing had to be fished out in sections.)

Once the small tubing had been removed and adequate heavy mud circulated in the well, fishing operations did not have to be done under pressure with a snubbing unit. A conventional blowout preventer was used from this point. The remaining tubing in the well was plugged with dehydrated mud. Due to the very small annular spaces outside the tubing, it was necessary to wash inside, fire explosive charges ("back offs"), and remove short sections at a time. This was a slow process. Due to the high pressure and temperatures below 17,000 ft (5,181 m), the design limits of the fishing tool explosive charges were reached, and many misfires began to occur, increasing the time. Also, due to the great depths and thick, heavy mud increasing the resistance to pipe rotation, it became increasingly difficult to transmit turning force (torque) to the desired point downhole (where it was desired), to unscrew the pipe. Special pipe dopes (thread lubricants) were used to increase the torque resistance in the pipe being used for fishing. The original mud in the deeper sections of the hole had become so dehydrated by the extreme pressures and temperatures that it had the consistency of peanut butter. There was a coating on the casing wall of a "leather-like" nature. Overcoming all of these problems, the well was cleaned out in a remarkably short time. The existing contaminated mud in the well was replaced with fresh, chemically conditioned mud.

"State of the art" logging tools were run to log the well. In spite of having pressure ratings of 22,000 psi (151.7 Pa), two logging tools collapsed at pressures of ±17,500 psi (120.6 Pa), due to the time exposure in the high temperatures present. Due to the tool failures, only a partial Density, Neutron, Gamma Ray, Caliper Electric Well Log was obtained. A cement plug was set from 20,725 to 20,785 ft (6,317 to 6,335 m), with a cast iron retainer on top to isolate the old production interval. The well was then completed. The total cost of this extensive workover was only about one-fourth the cost of drilling and completing a new well to the same depth (Featherston, Jones & Meahl (EOC), 1989).

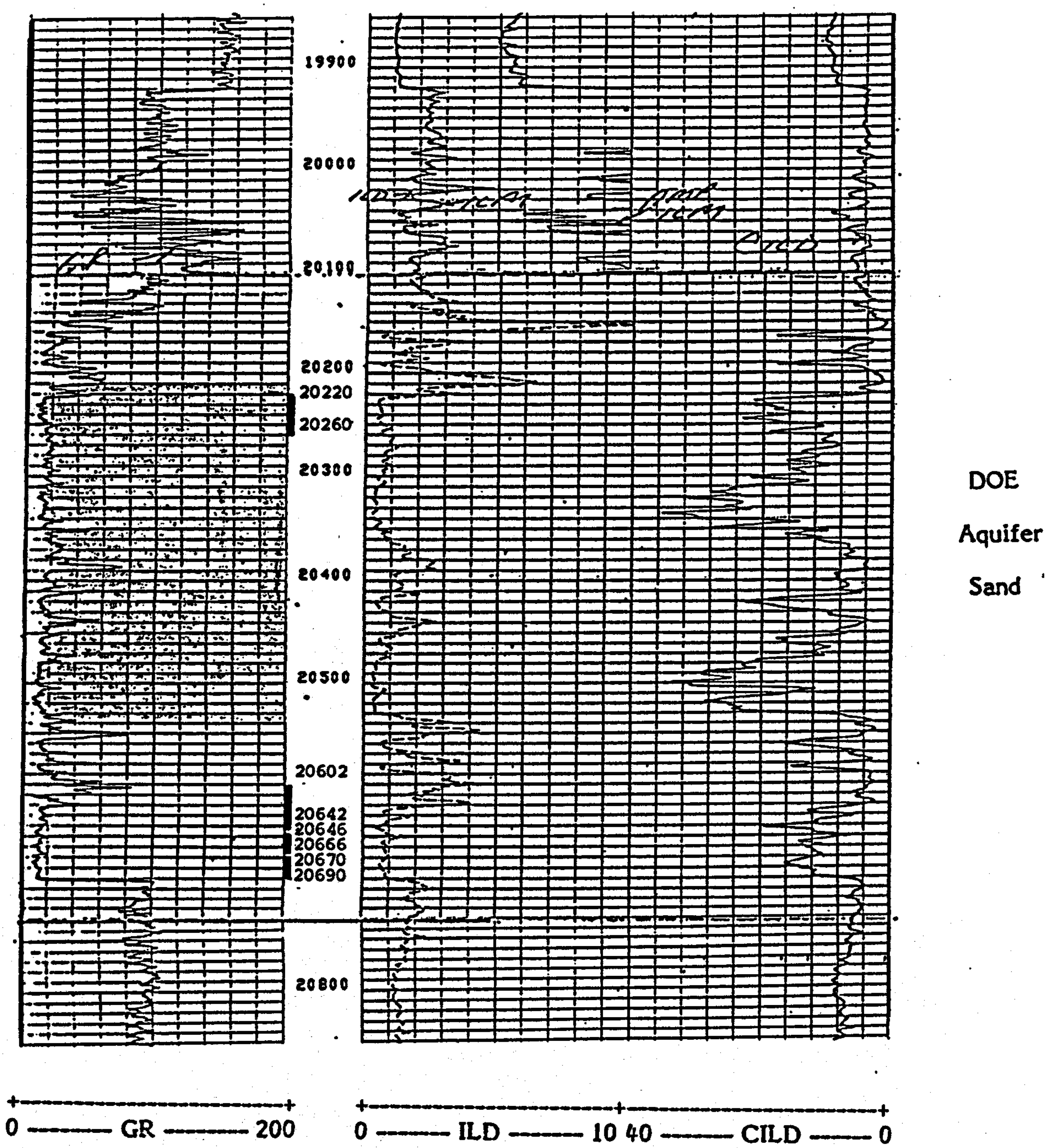
2.4.3.1 Production Well - Willis Hulin No. 1

An electric log of the production zone in this well is shown in Exhibit 2-26. A short-term flow test of this well was done in December 1989 and January 1990. The first interval tested was from 20,670 to 20,690 ft (6,300.2 to 6,306.3 m). During the test, additional intervals were perforated, first 20,602 to 20,642 ft (6,279.5 to 6,291.7 m) and 20,646 to 20,666 ft (6,292.9 to 6,299.0 m), then later 20,220 to 20,260 ft (6,163.0 to 6,175.2 m). The well is now completed as shown in the well schematic of Exhibit 2-27. The entire sand between these intervals will be perforated for long-term testing. Funds will not be available for further testing of this well until fiscal year 1991.

2.4.3.2 Salt Water Disposal Well (Class V) - Willis Hulin CV Well No. 1

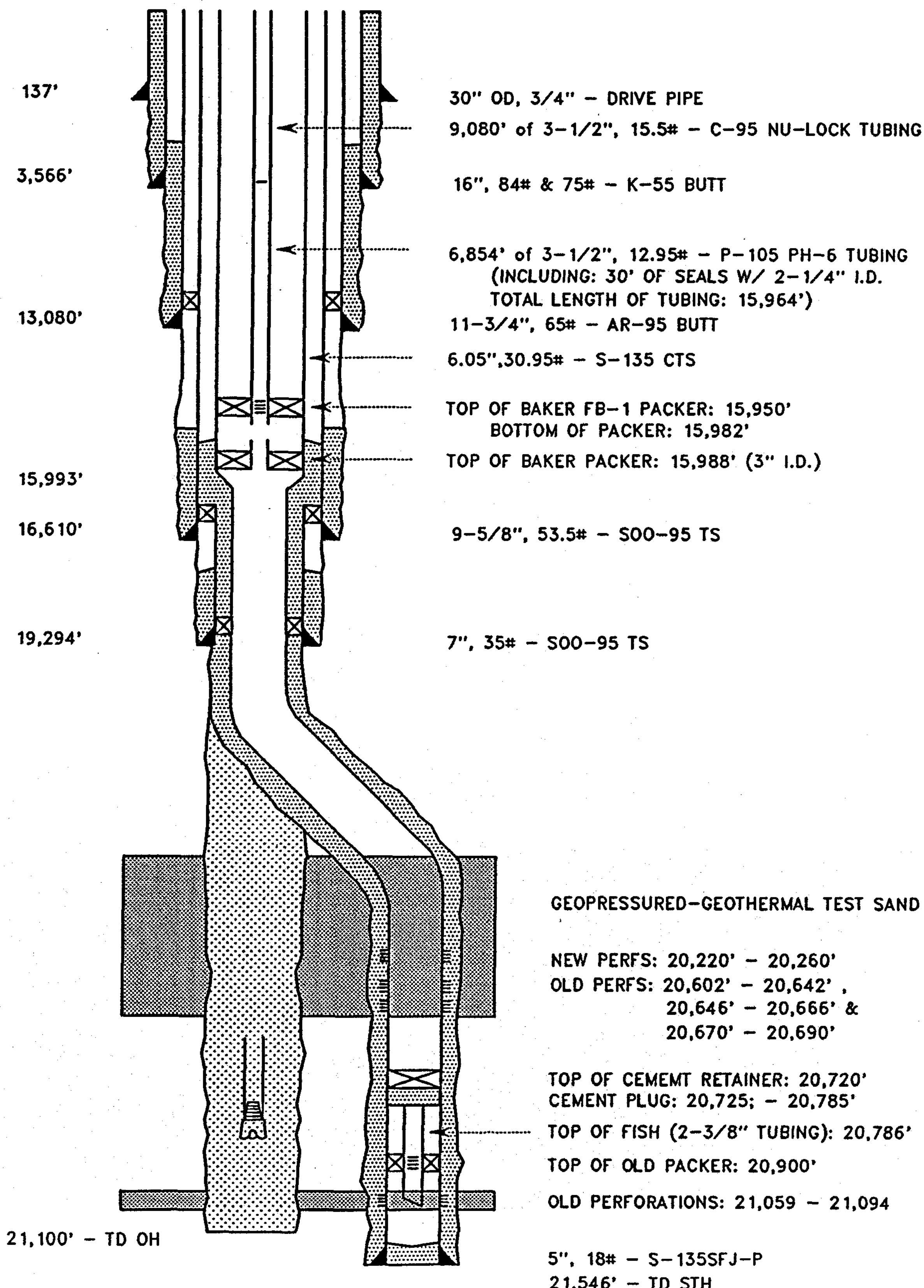
A salt water disposal well was drilled and completed. An electric log is shown in Exhibit 2-28. As shown in well schematic (Exhibit 2-29), the well is perforated from 6,530 to 6,590 ft (1,990.3 to 2,008.6 m). This was adequate for the short term, but additional intervals will be perforated and acidized for long-term testing.

Superior 1-Hulin



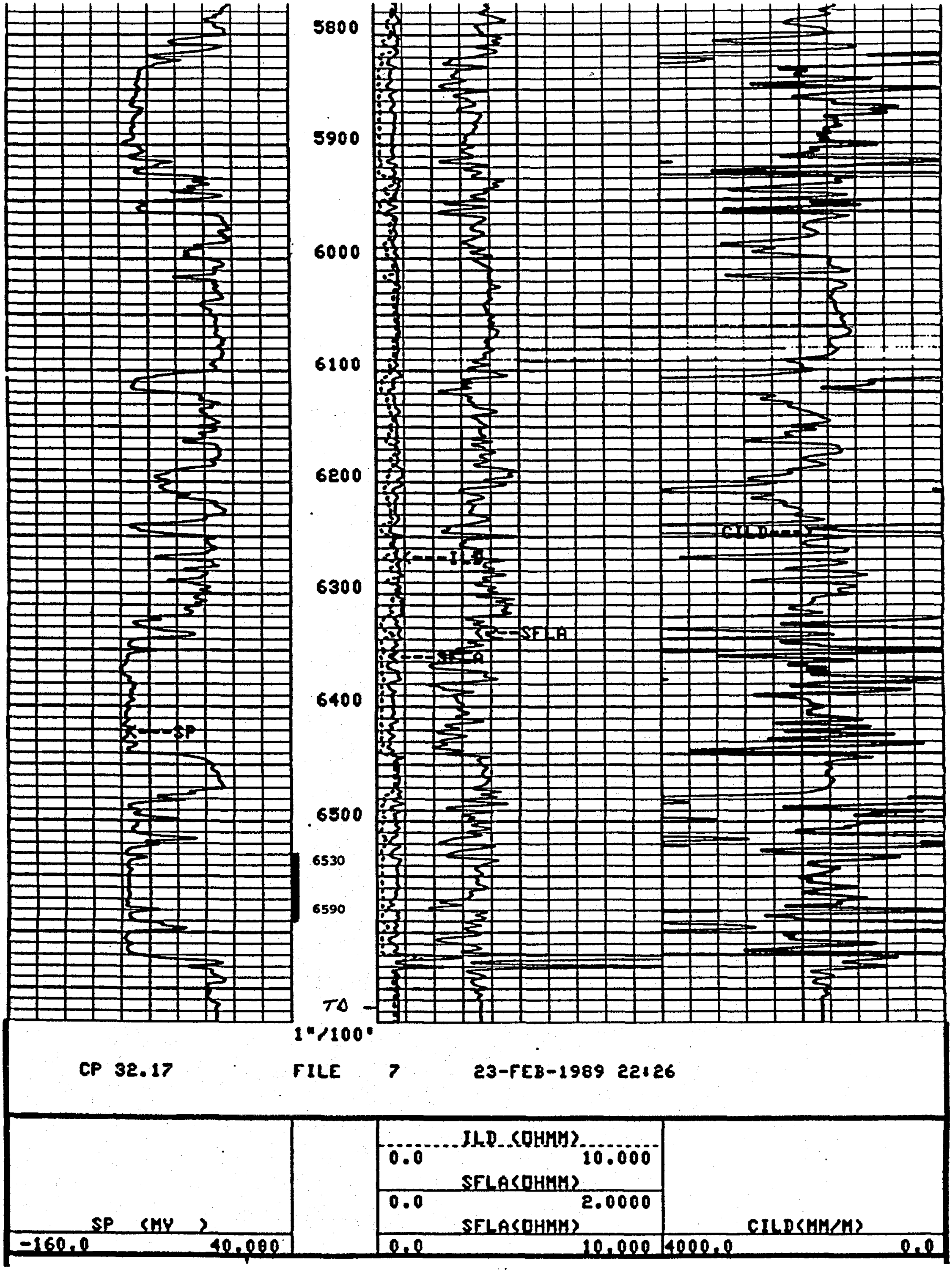
DOE 20,100' aquifer sand, 1" ISF/SONIC Log

WILLIS HULIN No. 1
Vermilion Parish, Louisiana



Well Schematic As Completed By EOC - 1/3/90

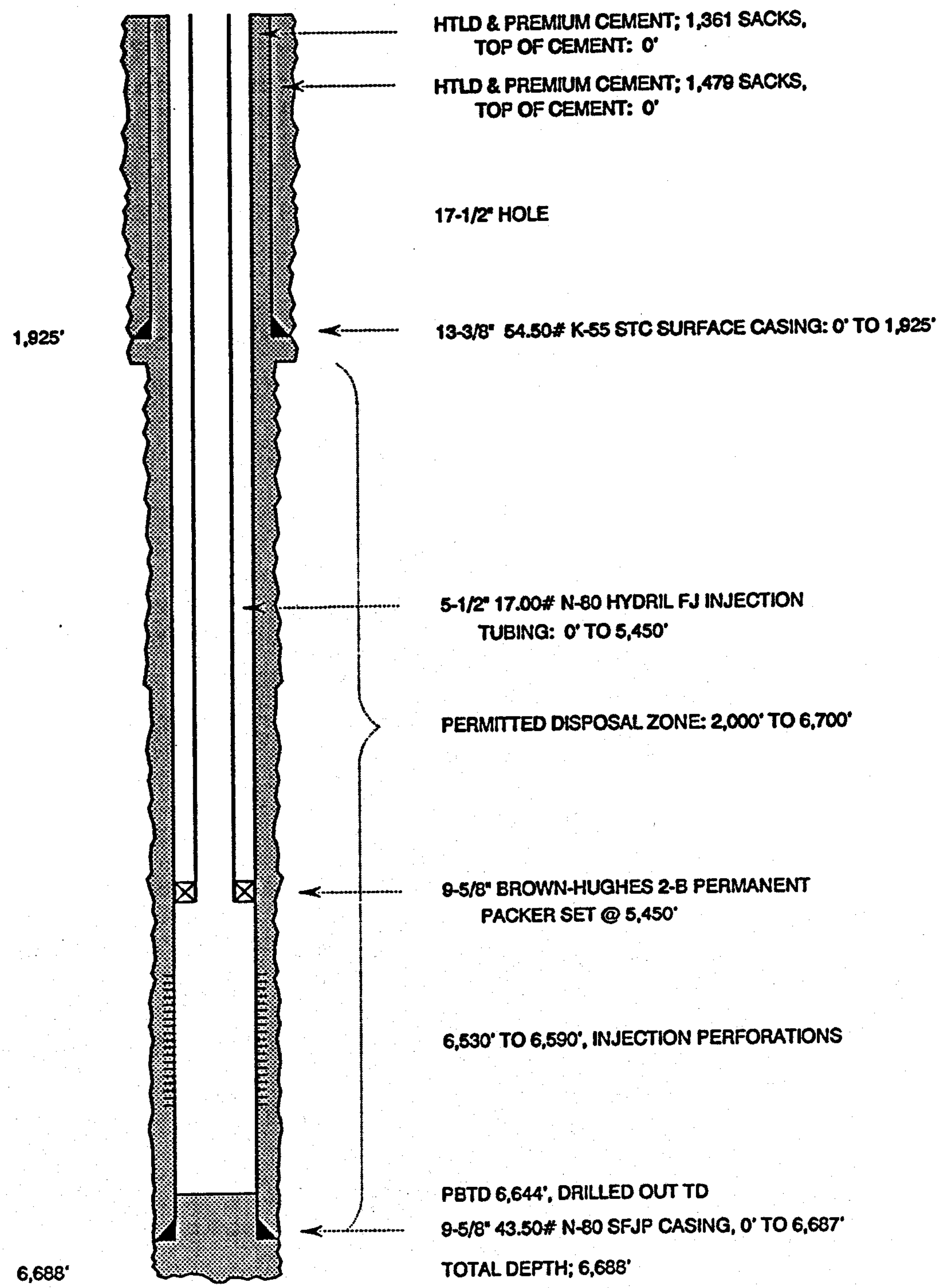
EXHIBIT 2-27



DUAL INDUCTION-SFL-SONIC LOG
WILLIS HULIN CLASS V SALTWATER DISPOSAL WELL NO. 1
(As Perforated 11/21/89)

EXHIBIT 2-28

WILLIS HULIN CVW NO.1
Vermilion Parish, Louisiana



EATON

Well Schematic As Completed By EOC - 2/28/89.

EXHIBIT 2-29

3.0 TEST RESULTS

3.1 Gladys McCall Site (Cameron Parish, LA)

3.1.1 (General) Review of Past Production History

Two reservoir zones were tested, Sand #8 and Sand #9. Testing of the well was initiated by the DOE contractors who were managing the project prior to Eaton Operating Company. Descriptions of the initial equipment installation, operation, and initial results have been previously reported (TF&S, 1982; and TF&S, 1985). For this report the results of all of the earlier testing are summarized together with the results under the current contract in order to present the overall findings of the project.

3.1.2 Test Results

The surface test equipment and the results of testing of Sand #8 and Sand #9 are summarized under headings below (see Appendix A for details).

3.1.2.1 Surface Test Equipment

A schematic diagram of the surface equipment installed to process the produced brine is shown in Exhibit 3-1. The numbered points indicate where samples were taken. To accommodate the high brine flow rate a block "Y" was installed on the wellhead which diverted the flow up the well into two 45° heavy walled flow loops. These two flow loops made sweeping curves to the ground to another steel flow block which recombined the flow into a single stream before it entered the horizontal surface pipe. The brine flow rate was controlled by a Willis choke. The carbide disks in the Willis choke withstood the forces of the large pressure drop (several thousand psi) quite well. The intense turbulence of the fluid leaving the choke, however, caused erosion of the interior pipe wall. This section of pipe was initially low carbon steel but, under this contract, was subsequently clad with stainless steel which had the metallurgical toughness to withstand the abrasive high flow rate turbulence of the brine exiting from the choke.

The piping and valves to carry brine flow were generally 5 inch diameter, or larger, to accommodate rates up to 40,000 barrels per day. Equipment down-stream of the choke was designed to operate at pressures up to 1,200 psi and temperatures up to 300° F. The separators were of standard design with an internal diameter of 54 inches and a length of 30 feet, and normal rating of 1440 psi. Brine exiting the separators was filtered prior to injection into the disposal well. The gas from the separator was cooled and dehydrated prior to sale. Some gas was occasionally flared on location due to compressor malfunction or other reasons when the gas could not be sent to sales. Carbon dioxide was not removed since a sales contract was obtained which allowed up to 10% carbon dioxide in the gas. Detailed engineering drawings of the original equipment installation are given in Technadril-Fenix & Scisson Final Report, 1985.

During the test there were several modifications or improvements made to the system. Initially, there was only one separator in the system, but in July, 1984 the second separator was added. The two separators operated in series. Gas was

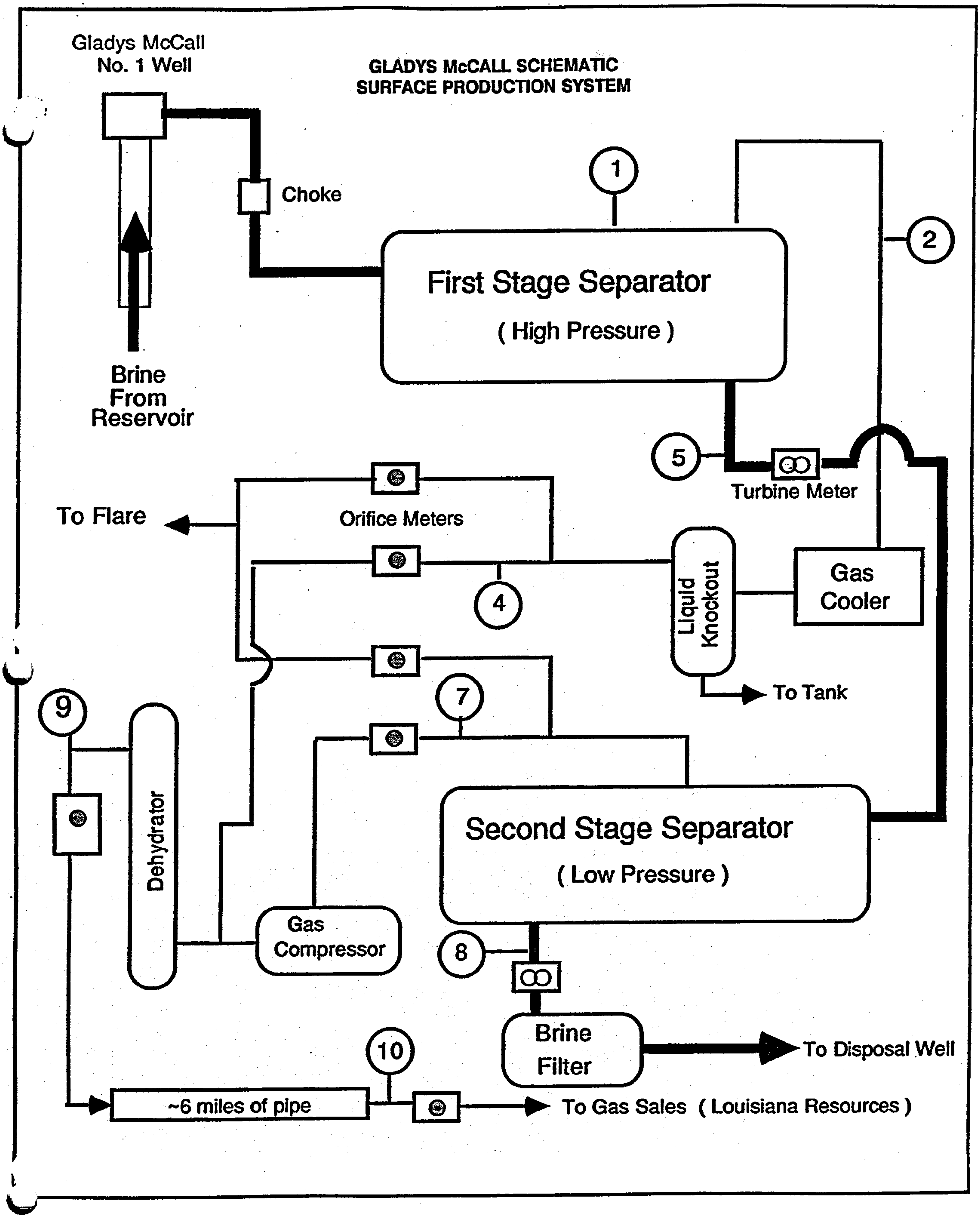

Gladys McCall
No. 1 Well
GLADYS McCALL SCHEMATIC
SURFACE PRODUCTION SYSTEM
Choke
1
2
First Stage Separator
(High Pressure)
Brine
From
Reservoir
5
Turbine Meter
To Flare
Orifice Meters
4
Liquid
Knockout
Gas
Cooler
To Tank
7
9
Dehydrator
Second Stage Separator
(Low Pressure)
Gas
Compressor
8
Brine
Filter
To Disposal Well
10
~6 miles of pipe
To Gas Sales (Louisiana Resources)

EXHIBIT 3-1

separated from the brine in the first separator at pressures high enough to enter the gas into the sales line without further compression. This was typically 1000 psig. The carbon dioxide content from this separator was normally below the 10% sales contract limit. The brine then passed to the second separator which was operated at a lower pressure. This lower pressure was sufficient to drive the spent brine down the disposal well and at the same time control the amount of carbon dioxide in the gas. The gas from the second separator was richer in carbon dioxide, and exceeded the 10% sales contract limit, due to the difference in solubility of carbon dioxide at the lower pressure. This second separator was therefore operated at a pressure (typically 400-500 psi) such that when its gas was commingled with the gas from the first separator the resultant concentration of carbon dioxide in the gas sent to sales would not exceed the 10% sales contract limitation. Gas from the second separator had to be compressed back up to the sales line pressure. The dissolved gas remaining in the brine after passing through the low pressure separator went into the disposal well.

While an inhibitor chemical was injected into the surface equipment and piping to prevent formation of calcium carbonate scale no corrosion inhibitor was used. Internal corrosion of the surface piping and equipment was thus moderate and required occasional repair or replacement of some parts of the flow system, such as valves, flanges, or pipe segments, when corrosion induced leaks developed.

3.1.2.2 Sand #9 Gas/Brine Testing

The brine flow periods between December 2, 1982 and December 22, 1982 were for the initial well clean up and sampling. Samples of gas and brine were taken on December 22nd. Exhibits 3-2 and 3-3 give the results of analyses by Weatherly Labs in Lafayette, Louisiana.

Exhibit 3-2
Analysis of Brine from Gladys McCall Sand #9

Specific Gravity	1.045
Total Dissolved Solids	96,300 ppm
Chlorides	57,900 ppm
Calcium	4,130 ppm
Sulfate	< 5 ppm

Exhibit 3-3
Gas Chromatographic Analysis for Sand #9

	Component	Concentration (MOL %)
Sample Date	12/22/82*	3/23/83**
Methane	86.91	86.93
Ethane	2.45	2.43
Propane	0.56	0.55
Isobutane	0.09	0.08
N-Butane	0.09	0.08
Isopentane	0.02	0.04
N-Pentane	0.01	0.03
Hexanes	0.03	0.51
Heptanes Plus	0.06	0.15
Nitrogen	0.28	0.26
Carbon Dioxide	9.50	8.94

* Separator at 500 psig
** Separator at 700 psig

To determine the gas/brine ratio a separator study was made and a laboratory PVT analysis was performed by Weatherly Labs. This study found the bubble point pressure to be 12,936 psia for a gas/brine ratio of 30.4 scf/bbl at 298°F. This laboratory measurement compared well with the actual bottom hole pressure of 12,911 psia measured at a depth of 15,460 (also at a temperature of 298°F). The close agreement between the laboratory bubble point measurement and actual bottom hole pressure indicated that the Sand #9 reservoir brine was saturated with gas. This was the basis for the initial reports that the brine was saturated with gas (Technadril-Fenix & Scisson, 1982).

Subsequent review of the early test data, performed under this contract, gave reason to suspect that the brine in Sand #9 was not fully saturated, but was in fact undersaturated similar to the brine in Sand #8. The reason for this had to do with the difficulty the field personnel had in getting accurate gas flow measurements from the orifice meters during the first few months of the project. The procedures used to calculate the gas rate for the brine produced from Sand #9 test resulted in the field measurement values for gas production being too high. Consequently, when Weatherly Labs did the recombination test they did it for an incorrectly high gas/brine ratio and obtained a bubble point that was higher than the actual bubble point in the reservoir. Had Weatherly Labs done the recombination studies for a gas/brine ratio less than 30.4 scf/bbl they would have obtained a bubble point less than the reservoir pressure, and it would have been concluded that the reservoir was undersaturated.

3.1.2.3 Sand #9 Reservoir Limit Testing

The flow from March 21, 1983 through April 17, 1983 was for a reservoir limit test of Sand #9. A bottom hole pressure gauge was lowered into the hole and operational most of the time from April 14th to April 17th. A total of 99,416 barrels of brine were produced in 23.8 days for an average rate of 4,181 bbls/d. The following build-up test was interrupted early when the mast on the truck supporting the wireline collapsed, causing the wireline to drop into the hole.

The draw-down and build-up data were independently analyzed by four parties; 1) J. Donald Clark, Petroleum Consultant, 2) Dowdle, Fairchild and Ancell, 3) S-Cubed, and 4) Scientific Software-Intercomp. Their results were as follows:

Clark (Technadril-Fenix & Scisson, 1985; and Clark, 1985) noted five possible straight line slopes on the semi-log plot of bottom hole pressure ranging from 16.7 psi/cycle to 45.2 psi/cycle during the first 24 hours. None of the adjacent segments reached the 2:1 ratio indicative of a boundary, therefore he concluded that the changes were due to lenticularity of the formation rather than being caused by sealing geological faults. He calculated a hydraulic flow capacity of 10,153 md-ft, a permeability to brine of 84.6 md, and a skin factor of +1.98. He further calculated that the transient pressure wave explored the reservoir to a radial distance of 13,019 feet and that the in-place volume of brine was about 170 million barrels. These calculations were all done with generally accepted petroleum engineering methods based on various plots of the data.

Dowdle, Fairchild and Ancell (Technadril-Fenix & Scisson, 1985) used a single phase, two dimensional, numerical reservoir simulator to match the experimental pressure data. The active grid blocks and properties of the grid blocks were adjusted until the calculated pressures were a good match to the experimental pressures. This match resulted for a model that assumed two separate reservoirs and parallel faults, one about 750 feet from the well, and the other about 1000 feet from the well. The resulting flow capacity was about 11,700 md-ft and the permeability was about 90 md. The transient pressure wave was calculated to have explored the reservoir to a distance of about 20,000 feet and that the in-place brine was about 184 million barrels. Predictive calculations for flow rates in the range of 15,000 — 35,000 barrels/day showed that this level of production would exhaust this size of a reservoir in about a year.

S-Cubed (Technadril-Fenix & Scisson, 1985) noted that the semi-log plot of the draw-down data had slopes of 25,46 and 92 psi/cycle in the first 100 hours of the test and that a doubling of the initial slope occurred at about 29 hours. From this they concluded that there was a boundary at a distance of about 960 feet from the well. From a Horner plot they derived a permeability of 67 md and a skin factor of +0.54. Noting that the last 145 hours of the test gave an apparent constant slope of 0.332 psi/hr they calculated that the in-place brine was at least 85 million barrels. They cautioned, however that this was a minimum value, and that the reservoir could be larger.

Scientific Software-Intercomp (Technadril-Fenix & Scisson, 1985) (Scientific Software-Intercomp, 1983) first analyzed the data using the normal plots of the data and reservoir engineering methods to determine the reservoir properties. From the semi-log pressure draw down plot they derived a flow capacity of 9544 md-ft, a permeability of 74.6 md and a skin factor of -0.74. From a Horner type pressure build-up plot they calculated the flow capacity to be 10,689 md-ft, the permeability to be 83.5 md and a skin factor of +0.17. Finally, they used a numerical reservoir simulator (BETA II) to model the test. The grid blocks and properties of the reservoir rock in the grid blocks were adjusted as needed in repeated simulation runs until the calculated pressures matched the experimental pressures. The final match model had an in-place brine volume of about 135 million barrels.

Although there are some differences in the exact values of the reservoir parameters as calculated by the four different groups they are in general agreement that the reservoir was rather small and would not support long term production. With this conclusion there was no need to further test this sand. Sand #9 was therefore plugged back and attention was next given to the next higher aquifer, Sand #8.

3.1.2.4 Sand #8 Initial Reservoir Limit Testing

The first pressure transient test of Sand #8 was initiated on September 27, 1983. The flow rate started at 14,520 bbl/d and then was reduced to 13,703 bbl/d. This test lasted only 9 hours due to several equipment problems that required removing the bottom-hole pressure tool from the hole and discontinuing production. This brief test did however provide adequate data for an initial interpretation of the reservoir properties, as reported by J.D. Clark (Clark, 1985). He reported a productivity of 39,568 md-ft and a skin factor of +1.05. Assuming 300 feet of net pay, the permeability was 132 md.

After repair of the equipment the pressure transient test was restarted on October 7, 1983 with an initial flow rate of 13,407 bbl/d. Flow was continued for 21 days, until October 28, with an average production rate of 12,985 bbls/d. The bottom-hole pressure gauge was placed in the hole on October 5th and removed on November 30th, thus providing a continuous record for the draw-down and 32 days of the build-up. The data were analyzed by both J.D. Clark and S-Cubed.

J.D. Clark reported (Clark, 1985) that the curved lines resulting on the semi-log graphs he used to interpret the data were an excellent example of lenticular type sand deposits. and that there was no evidence of a linear type permeability barrier (such as a near by sealing fault). For the early time production data he calculated a productivity and a reservoir volume with a graphical method that indicates when steady state production apparently occurs. This graph indicated a reservoir volume of about 550 million barrels of brine. Similar graphical analysis of the pressure build up data yielded an initial productivity of 39,752 md-ft. The line on the semi-log time plot and Horner plot was straight only for times less than one day, therefore the reported value for productivity of approximately 39,000 md-ft is valid for only a limited volume of reservoir near the wellbore. Clark made no attempt to interpret the data once it deviated upwards away from the straight line portion of the semi-log plot.

S-Cubed did a similar, but more extensive, analysis of the October-November 1983 pressure transient test data (Pritchett, Riney, S-Cubed, 1985). They fitted both the draw-down and build-up data to four straight line segments on a semi-log time plot, as is commonly done for petroleum engineering analysis. They then made conjectures about how each of these straight line segments related to the reservoir geometry. On the basis of the slopes of the plots doubling at 9.5 hours and 31.5 hours they estimated the distances to the two nearest faults as being 780 feet and 1410 feet. Using the second straight line segment on the draw down plot they calculated a reservoir permeability of 113 md. Similar calculations for the build-up data gave a calculated productivity of 44,090 md-ft and a permeability of 133 md. To estimate the reservoir volume they hypothesized that the pressure was approaching the final pressure exponentially. With this hypothesis (later found to be incorrect) they calculated a reservoir volume of 433 million barrels.

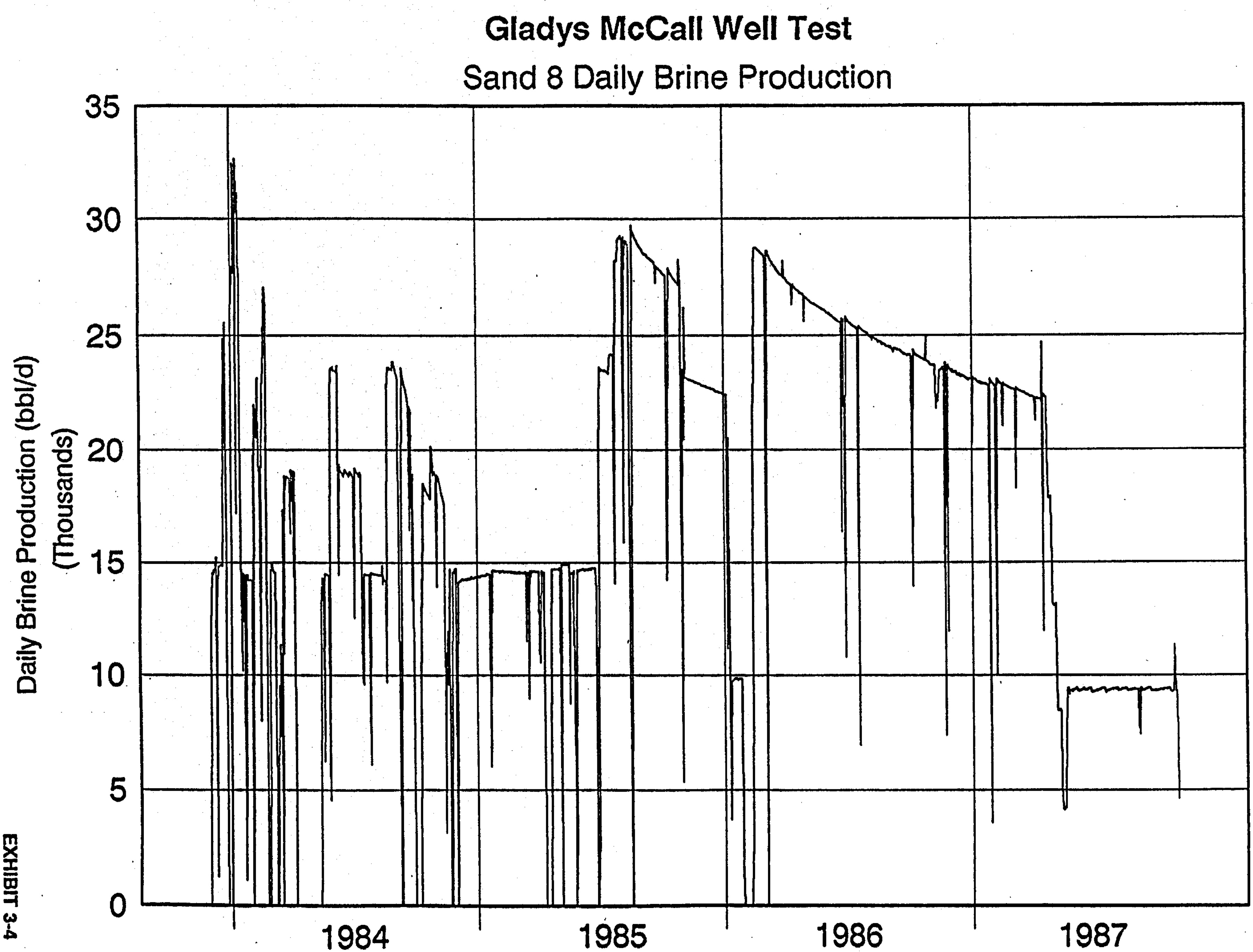
For numerical simulation, S-Cubed used a simple rectangular reservoir with parallel edges at the distances of 780 and 1410 feet from the well, as estimated from their analysis of the pressure transient data. This was a reasonable assumption based on the geological analysis of east-west growth faults through the reservoir area. With these widths and a height of 328 feet, the long distance out to the end boundaries was 10,827 feet. By using a permeability of 160 md near the wellbore and 20 md for distances beyond 3600 feet they were able to calculate a pressure draw-down and build-up curve that closely matched the actual reservoir limit test data.

3.1.2.5 Sand #8 Long Term Flow Testing

Long term flow testing was initiated in December 1983 and concluded in October 1987. This test was the most definitive test of the well. Sand #8 proved to be a much larger reservoir than estimated from the initial reservoir limit test and capable of sustaining long term brine production.

A test program was established where the flow rates and other production measurements were manually taken at two hour intervals and then manually summarized each day for daily reports. Although a computerized data acquisition system was installed in January, 1986 it was operated in parallel with the manual data acquisition and the manually obtained data continued to be the reported data.

The initial daily reported data included the production and gas sales, but did not include the gas remaining in solution and sent to the disposal well or account for the fact that the brine flow measurements were made at non standard conditions. Much of these field data have been previously reported (Technadril-Fenix & Scisson, 1985). These manual data were revised by IGT (after the end of the test) to standard conditions and to include the gas remaining in solution after going through the separators. Plots of these revised data for brine production and gas production for Sand #8 are shown in Exhibits 3-4 and 3-5. The gas/brine ratio is given in Exhibit 3-6 which plots the gas volumes in Exhibit 3-4 divided by the brine volumes in Exhibit 3-5. If the brine and gas measurements had been perfect, the gas/brine ratio plot would be a straight line. In practice, however, since there were some difficulties in the manual reading and reporting (especially in the first few months) there are spurious high or low spikes in the plot.



Gladys McCall Well Test
Sand 8 Daily Brine Production
Daily Brine Production (bbl/d) (Thousands)
35
30
25
20
15
10
5
0
1984
1985
1986
1987

EXHIBIT 3-4

Gladys McCall Well Test

Sand 8 Daily Gas Production

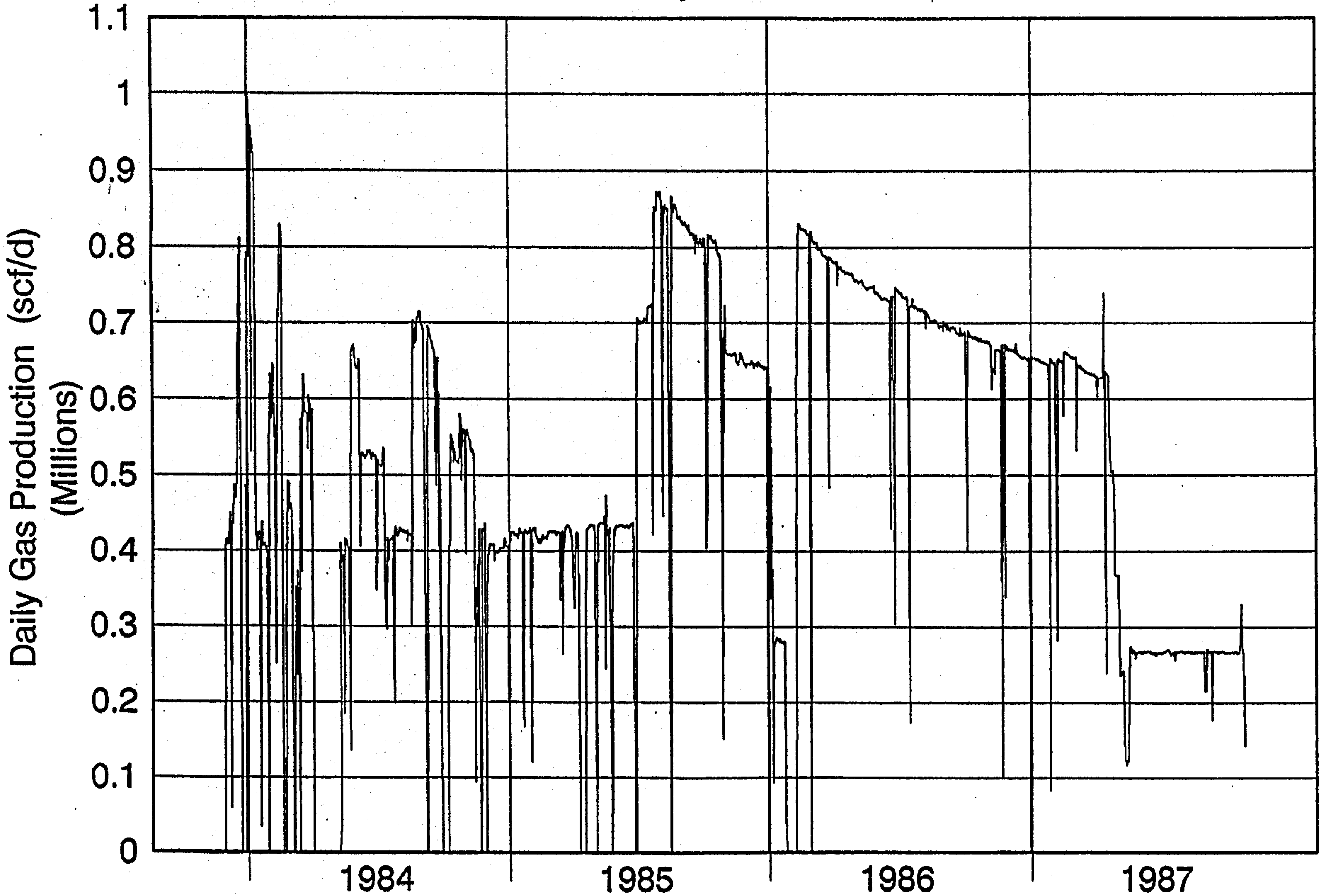


EXHIBIT 3-5

Gladys McCall Well Test

Sand 8 Gas/Brine Ratio

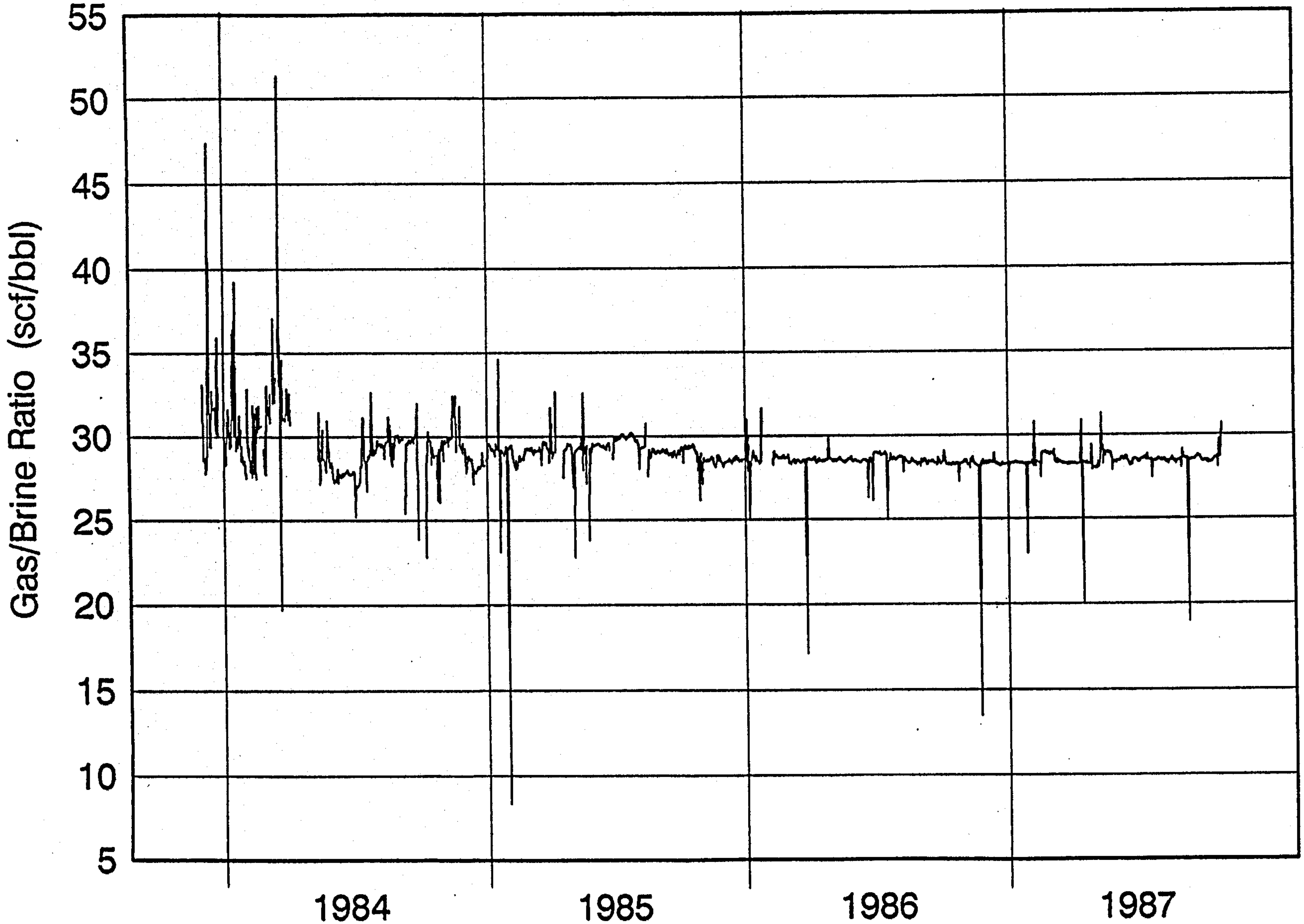


EXHIBIT 3-6

Flowing bottom hole pressure was well above the bubble point pressure in the reservoir through 1985. Thus, in fact, the produced gas/brine ratio could not have changed. Whether the reported fluctuations were due to problems in measuring gas rates or brine water was not reported and cannot now be deduced from the reported data.

3.1.2.6 Sand #8 Gas/Brine Ratio

Cumulative gas production versus cumulative brine production from these calculations is presented in Exhibit 3-7. The overall gas to brine ratio (the slope of the line) is 28.9 SCF/STB for production up to about 10 million barrels. A slight bend in the curve then occurs for a gas to brine ratio of 28.6 SCF/STB. This slight change in the ratio (slope) at 10 million barrels is believed to be due to problems in the data acquisition, and not a real change in the gas/brine ratio. The overall average gas/brine ratio is calculated to be 28.7 SCF/STB as it is produced from the well. The gas to sales is lower than the gas produced since it excludes the unrecovered gas that stays dissolved in the brine sent to the disposal well, and the losses that occurred through leaks in the system and occasional flaring.

Throughout the long term flow test IGT periodically took complete suites of samples from the various gas and brine streams from which the composition of the gas could be determined which would be representative of the total gas as it was produced from the well. This sampling included stripping the remaining gas out of samples of brine being sent to the disposal well. Exhibit 3-8 gives the composition of the gas streams and calculated total composition of the produced gas.

Sand 8 Cumulative Production

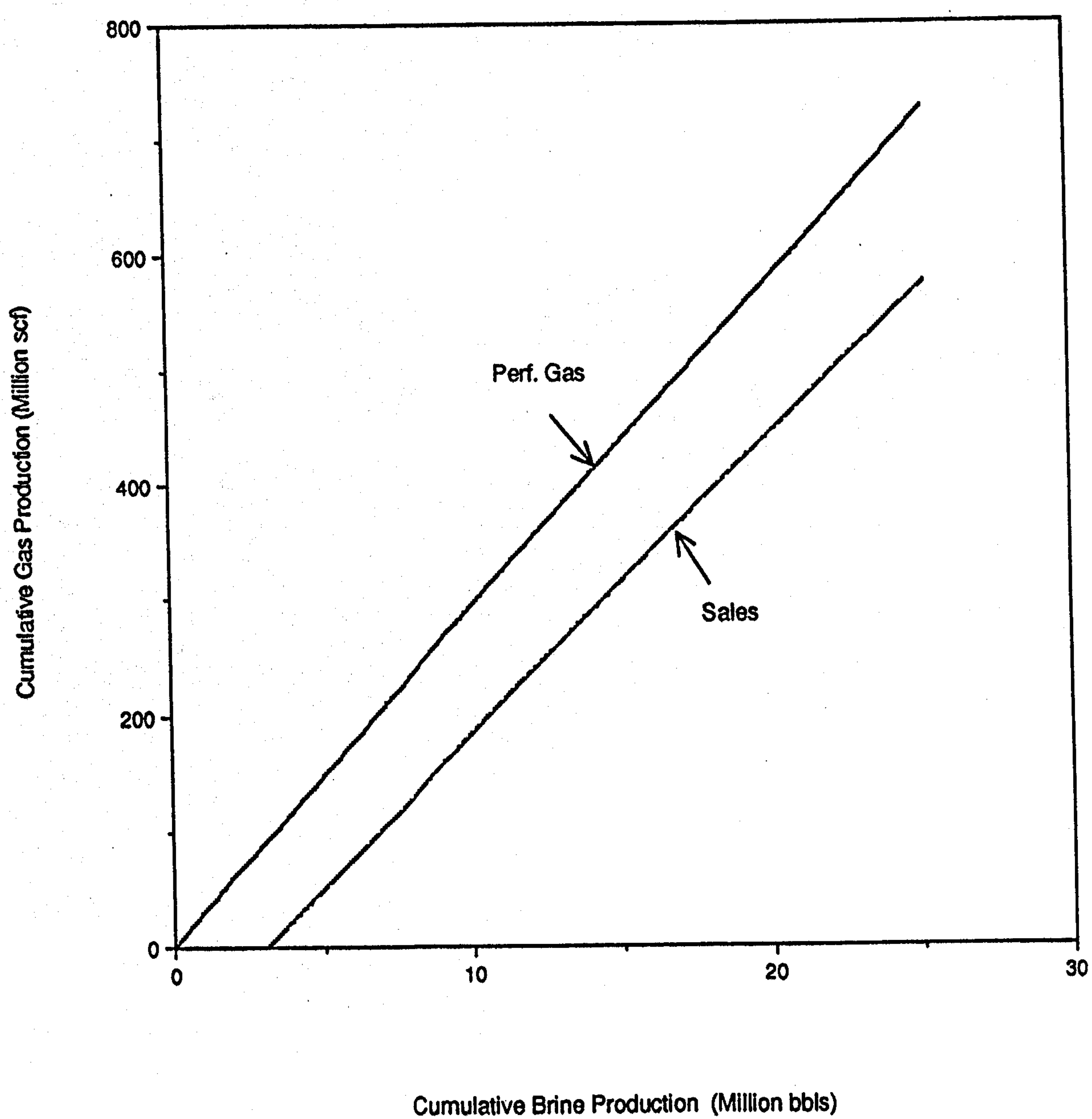


EXHIBIT 3-7

Exhibit 3-8
Typical Gas Analyses, 2/19/87

Sample Source	HP Sep Gas	LP Sep Gas	Gas in Brine Leaving LP Sep	Total Gas, Calculated
Pressure, psia	1,015	285	285	
GWR, SCF/STB	22.86	4.44	1.75	29.05
<u>Mole Percent of</u>:				
Carbon Dioxide	7.91	20.52	37.39	11.61
Nitrogen	0.25	0.16	0.81	0.27
Methane	88.57	77.22	60.25	85.13
Ethane	2.40	1.64	1.05	2.20
Propane	0.53	0.24	0.10	0.46
Iso-Butane	0.08	0.02	0.01	0.07
N-Butane	0.07	0.02	0.00	0.06
Iso-Pentane	0.02	0.01	0.00	0.02
N-Pentane	0.02	0.00	0.00	0.02
C6+	0.15	0.17	0.08	0.15
Gas Grav (air = 1)	0.656	0.769	0.927	0.690
Heating Value, Btu/SCF	968	828	637	927
Liquids	0.93	0.60	0.35	0.85

The gas-brine ratio of 29.0 SCF/Bbl compares well to the value of 28.7 SCF/Bbl from the real time results from the IGT computed data systems.

The methane content remaining in the brine after removal of gas in the separator is consistent with Henry's Law in that its solubility is close to a linear dependence. For every 100 psi of methane partial pressure, 0.56 SCF/STB of methane will remain in the brine. This value for the Gladys McCall well can be compared to similar values for other DOE projects. A value of 0.62 SCF/STB/100 psi was obtained for the Wainoco P.R. Girouard #1 well, 0.60 SCF/STB/100 psi for the Pleasant Bayou #2, well and 0.53 SCF/STB/100 psi for the HO&M Prairie Canal #1 well.

Samples of brine were also periodically analyzed (details are shown in IGT Exhibit 9.0-1 in Appendix A). Exhibit 3-9 gives the composite average of nine different analyses for samples taken between November,1983 and September 1986.

Exhibit 3-9
Composite Average of 9 McCall Brine Samples

Component	Units	Average	Std.Dev.***
Alkalinity	mg HCO_3/L	314	76
Ammonium	mg NH_4/L	118	84
Arsenic	mg As/L	<0.32	0.88
Barium	mg Ba/L	269	228
Boron	mg B/L	34	12
Cadmium	mg Cd/L	0.05	0.06
Calcium	mg Ca/L	3871	209
Chloride	mg Cl/L	56767	1484
Chromium	mg Cr/L	<0.09	0.16
Copper	mg Cu/L	<0.08	0.16
Fluoride	mg F/L	0.25	0.13
Iodide	mg I/L	44	(only one sample)
Iron	mg Fe/L	30.5	22.5
Lead	mg Pb/L	<0.09	0.06
Lithium	mg Li/L	25.4	0.85
Magnesium	mg/L	321	29
Manganese	mg Mn/L	2.0	0.48
Potassium	mg K/L	796	151
Silica	mg SiO_2/L	126	14
Sodium	mg Na/L	32811	2544
Strontium	mg Sr/L	430	58
Sulfate	mg SO_4/L	<2.6	2.8
Zinc	mg Zn/L	<0.28	0.1
T.D.S.*	mg/L	94350	2203
Gross Alpha	pCi/L	55**	15
Gross Beta	pCi/L	393**	80
Gross Gamma	pCi/L	200**	40

* Total Dissolved Solids.
** One unreasonable measurement omitted from the average.
*** Components with wide scatter in the measurements may have Standard Deviations larger than the average.

3.1.2.7 Gas Exsolution in the Reservoir

The laboratory PVT studies found the bubble point of the gas in the #8 Sand to be 9200 psia which was considerably lower than the measured reservoir pressure of 12,821 psia (at 15,160 ft). This indicates that the reservoir is undersaturated and initially should flow only brine and no free gas. Once the pressure in the reservoir is lowered below the bubble point however, it is possible for some of the gas to come out of solution into a free gas phase.

Calculated bottomhole pressure for the long term flow test is shown in Exhibit 3-10. During most of 1986 and the early part of 1987 the bottomhole pressure (and pressure in the reservoir near the wellbore) was below the 9200 psia bubble point pressure. Gas could thus come out of solution in the reservoir before it reached the wellbore and become trapped in the pores of the reservoir rock.

IGT monitored gas rates and composition following a step increase in drawdown on two occasions as a "bubble test" to determine whether free gas might have come out of solution and accumulated in the reservoir rock near the reservoir. If a bubble had accumulated in the reservoir then a step change in the reservoir flow rate would cause the trapped gas to expel a bubble of free gas that would be seen as a temporary increase in the gas/brine ratio. The first was on February 12, 1986 and the second was on April 14, 1987. Both tests found only small changes in the gas/brine ratios and compositions which only suggested, but did not conclusively prove, that the bottomhole pressure was below the bubble point pressure such that free gas had accumulated in the reservoir. If free gas had accumulated in reservoir rock pores at near wellbore it was a very small amount (a few MCF or less).

3.1.2.8 <u>Sand #8 Long Term Reservoir Modeling Studies</u>
When S-Cubed prepared their paper on the numerical model of the McCall reservoir for the Sixth Geopressured-Geothermal Conference in 1985 (Pritchett & Riney, S-Cubed, 1985), they had one year's worth of production data from the long term flow test in addition to the previous short term reservoir limit test data. From these new data, they found that the actual bottom-hole pressures were higher than the pressures predicted by the previous calculations. They therefore needed to increase the size of the reservoir in their model to match the new data. Since the previous model calculation fit the early time well, they simply added the additional volume to the remote ends of the model. There was no accurate geological information as to where the extra volume should be placed to match the actual reservoir. Several cases with different assumptions of volume were run, and a good fit to the data was found for a revised reservoir volume of 1.2 billion barrels. This revised volume was approximately three times the volume initially deduced from the 21 day pressure transient test.

During the four years of production S-Cubed periodically updated the model in light of the most recent data. In April, 1985 and January,1986 there were short term build-up tests from which the flow capacity could be recalculated. For both of these tests the flow capacity was calculated to be 28,340 md-ft rather than the previous 44,090 md-ft. These tests were done after scale inhibitor injection into the well so S-Cubed interpreted this reduction due to partial plugging of the perforations or formation below a shale stringer in the formation. The numerical model was therefore modified to include a stringer in the production interval that partially penetrated the formation. There were also increases in the skin factor attributed to the inhibitor injection. To continue matching the pressure data with the model in 1986, the total reservoir volume in the model needed to be increased from 1.2 billion barrels to 2.5 billion barrels.

To match the reservoir pressure after three years of pressure build-up (following the long term flow test), S-Cubed found that the total volume in the model needed to be increased even more. Exhibit 3-11 shows the dimensions of the

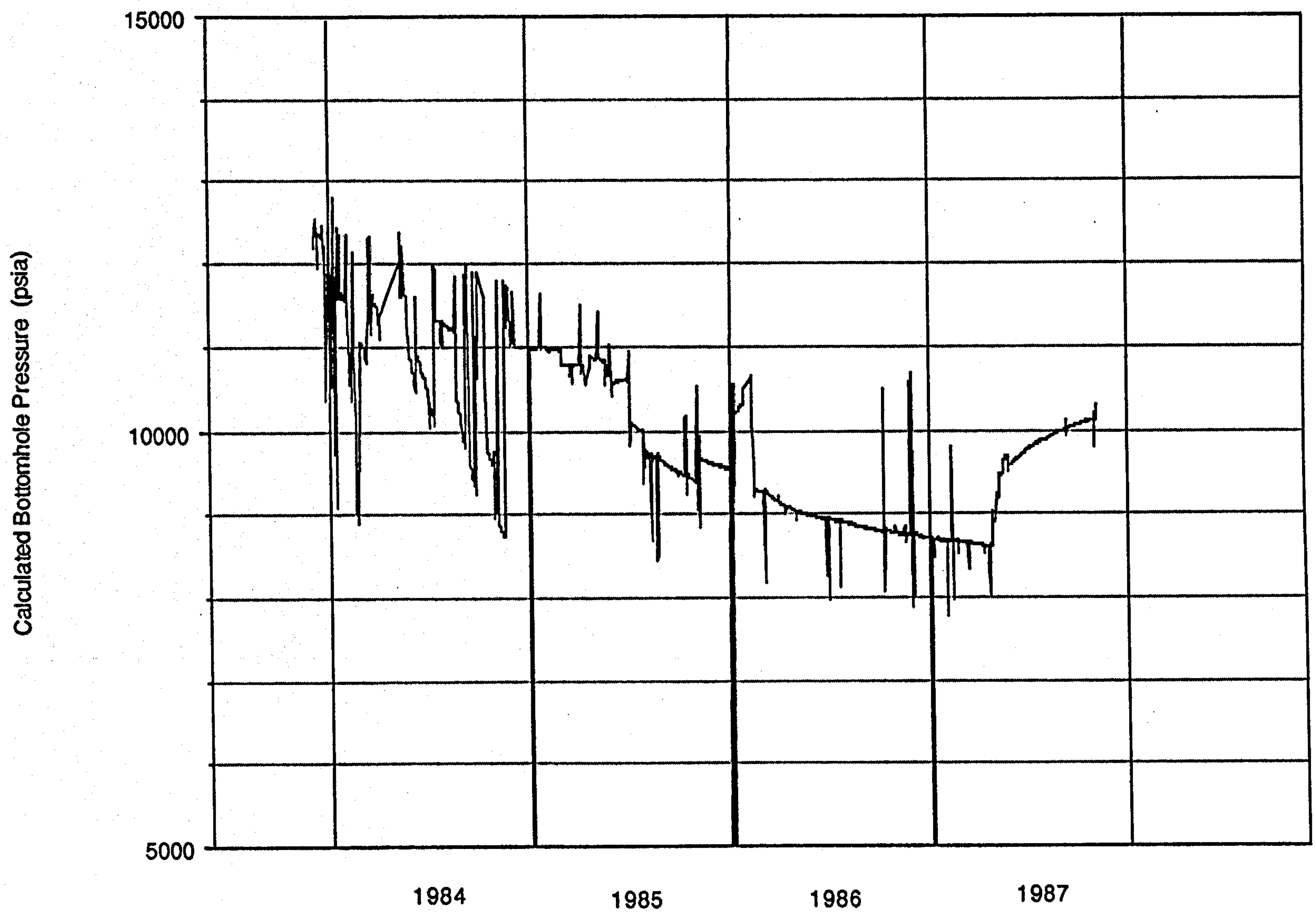
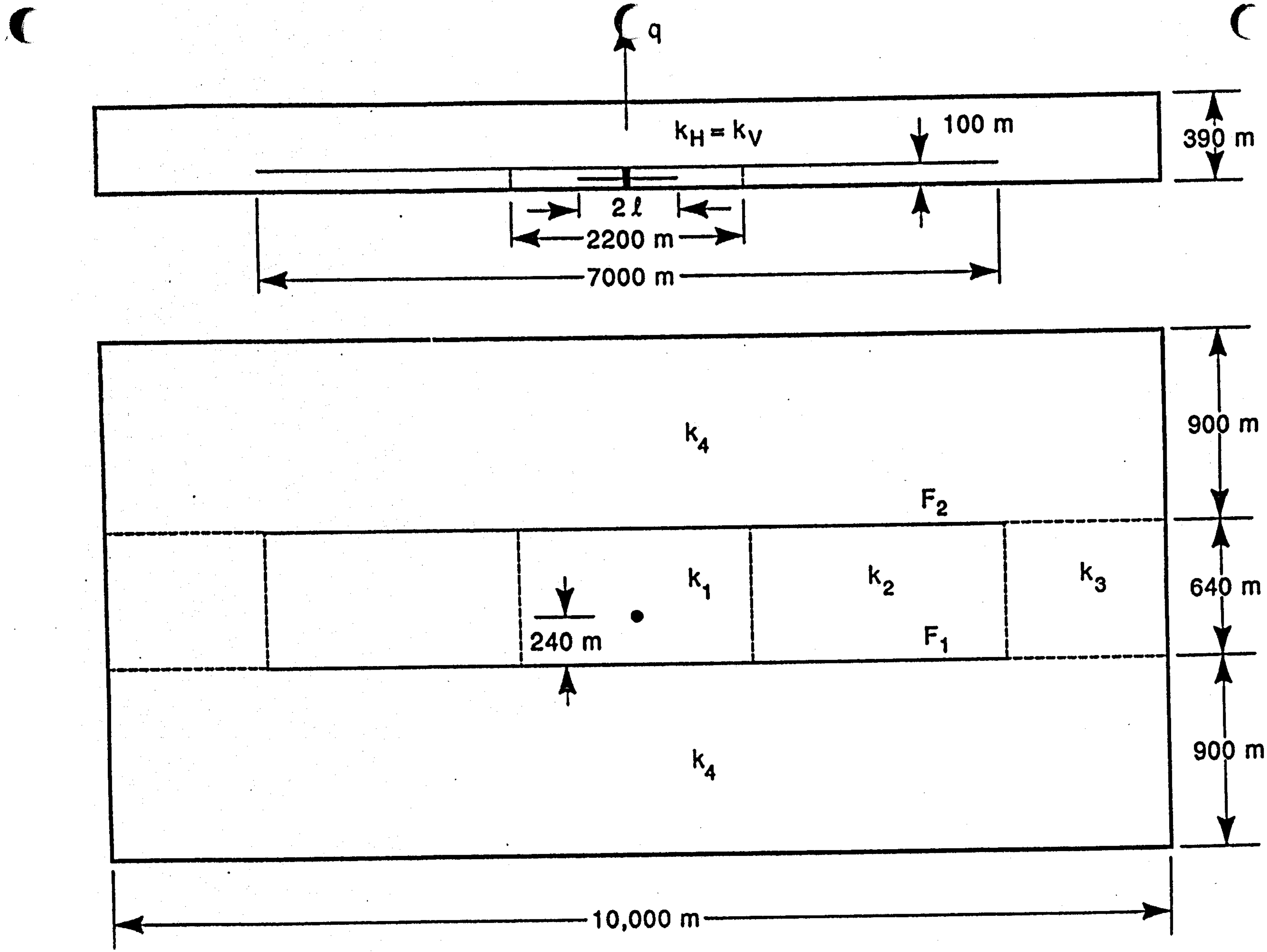

15000
10000
5000
Calculated Bottomhole Pressure (psia)
1984
1985
1986
1987

EXHIBIT 3-10



GLADYS McCALL - S-CUBED RESERVOIR MODEL

EXHIBIT 3-11

model as it had evolved by 1990 (Riney, S-Cubed, 1990). The reservoir volume needed to match the pressure data had to be increased from the previous 2.5 billion barrels to a new volume of 7.8 billion barrels. The bottomhole pressure build-up, which continued to rise beyond the upper limits that would occur for the smaller volume models. Where the influx of fluid (presumed to be water) came from was unknown, but it was speculated to be influx from sands either above, below or adjacent to Sand #8. There may also have been some shale dewatering. In the 1990 revision of the model the needed additional reservoir volume was placed above the previous grid and partially isolated from the previous grid by a partial penetrating barrier. The permeability of this new volume needed to be low and was set to 0.2 md. Both the horizontal and vertical permeability of this layer and the vertical permeability of the Sand #8 below it were also set to this low value. There was no need to invoke any nonlinear mechanisms for the model, such as irreversible pore volume compaction. If there were any nonlinear effects they would probably occur close to the wellbore and be masked by the skin factor such that their effects would be difficult to determine from either the experimental data or reservoir modeling.

The build-up pressure data following the long term production is plotted on a Horner plot in Exhibit 3-12. On the Horner plot the final pressure to which the reservoir will recover after production is found where the extrapolation of the build-up curve intersects the $(T+dt)/dt=1$ axis. From this projected pressure and the material balance equation the reservoir fluid volume can be estimated.

The Horner plot for the McCall pressure build-up data curve is not a straight line and does not extrapolate as a straight line to the $(T+dt)/dt=1$ axis. The point marked P_f is the end point that should be reached for the 1990 S-Cubed model with 7.8 billion barrels in the reservoir. Whether the build up will continue to the value used by S-Cubed in their 1990 computer model is uncertain since the extrapolation requires a curved line of unknown shape.

A possible conclusion from the Horner plot combined with the S-Cubed model is that there is a part of the reservoir intersected by the wellbore and Sand #8 containing 430,000-550,000 barrels of brine with high flow capacity (39,000-44,000 md-ft) and that this high flow capacity part of the reservoir is in contact with a huge volume (at least as large as the S-Cubed model) which has a very low effective flow capacity. The S-Cubed rectangular model takes all of the known geology into account. The exact shape and orientation of the reservoir is only poorly known due to the lack of other wells in the area which can be used to establish the geology and formation properties at the distances indicated by its size. It must also be remembered that when a numerical model matched the measured pressure data the reservoir description is not unique, but only one of many possible geological configurations. The fact that the S-Cubed model matches the data quite well is an indication that the volumes are at least as large as used in the model, even if the exact shape of the reservoir is not known.

3.1.2.9 Calcium Carbonate Scale Inhibition

From previous tests of geopressured-geothermal wells it was known prior to beginning the testing at McCall that calcium carbonate scale formation in the

Gladys McCall Sand 8 Build-up Test

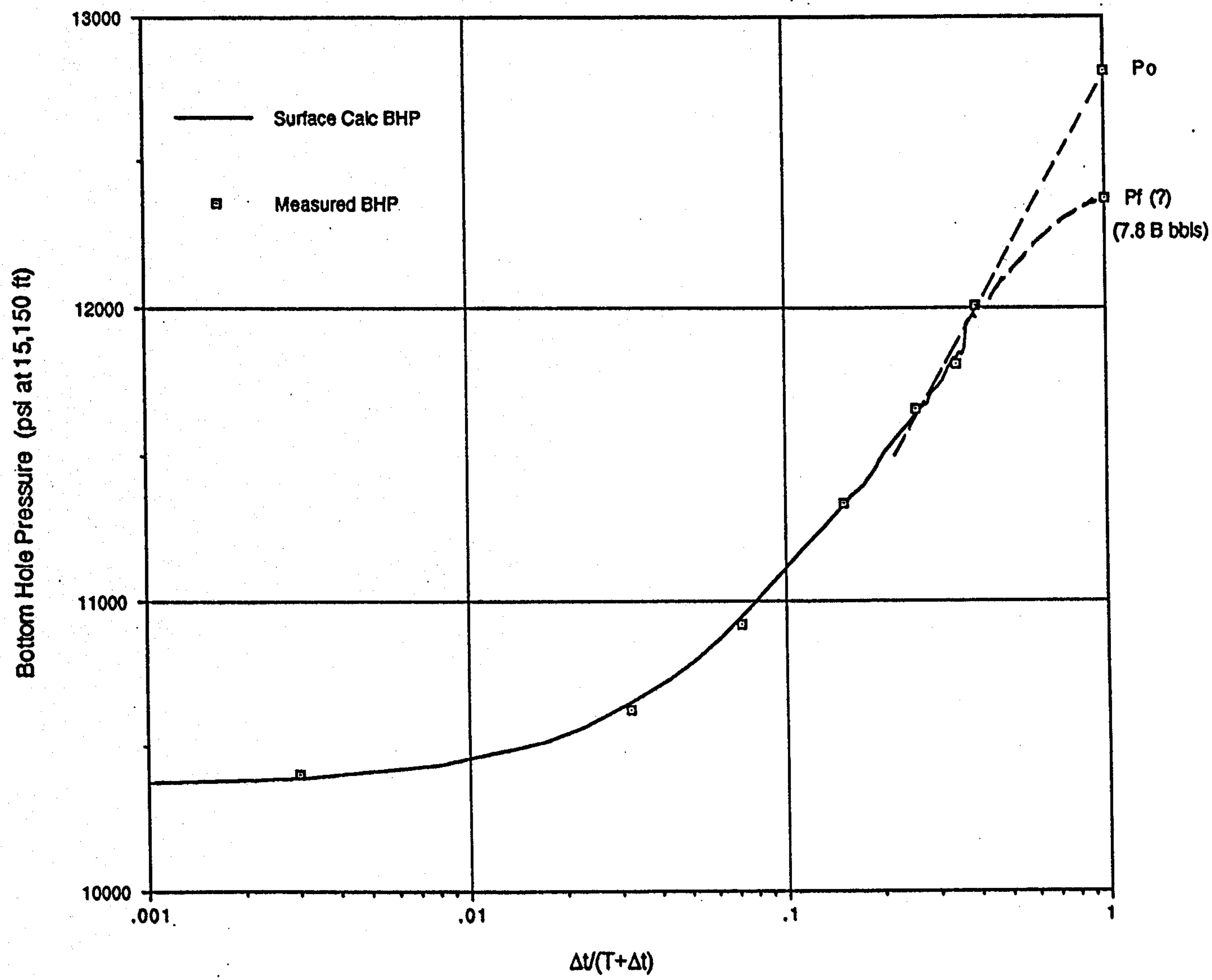


Figure 1

EXHIBIT 3-12

brine flow lines would be a problem unless measures were taken to combat it. Therefore, scale inhibitor was injected into the surface flow lines from the beginning of the flow tests. The inhibitor used was a polyphosphonate (Dequest 2000) manufactured by Monsanto Chemical Company. The pure chemical was diluted with water to an active strength of about 2-3% and then injected with a chemical pump into the brine flow line upstream of the choke so the concentration in the brine was about 0.5 ppm (by volume). Initially, the acid form of the polyphosphonate was used. This proved to be excessively corrosive on the injection piping and equipment so a switch was made to the neutralized form of the chemical.

While the injection of scale inhibitor upstream of the choke protected the surface piping and equipment from scale formation (but not corrosion), it did not protect the tubing in the well or the wellhead upstream of the injection point. Formation of scale in the production well tubing soon became apparent from degraded well performance. Inspection of the wellhead and flow lines revealed the scale. Acid was used to remove the scale. During March 7-14, 1984 the first of several series of acid treatments and intervening evaluations was performed. While this treatment removed the scale, it was only a temporary measure.

With resumption of brine production after each acid treatment, scale immediately began reforming. To monitor the scale buildup the flow line between the wellhead and the surface inhibitor injection point would be periodically inspected. The increased friction pressure in the flowing well was also monitored. When the scale buildup became a problem with its weight on the tubing, too much pressure drop, or problems with the equipment, such as seizing of the valves, another acid treatment was performed.

A typical acid treatment consisted of about 150 barrels of 15% HCl pumped into the well with spacer pads of brine in order to spot the acid at the desired points in the tubing. Each treatment was allowed to soak for about an hour before back flowing it out of the well. Exhibit 3-13 tabulates the total amount of acid used for each treatment series and the estimated amount of calcium carbonate scale removed.

Exhibit 3-13
Acid Treatments to Remove Wellbore Scale

Dates	Acid (15%HCl) (bbls)	Scale Removed (pounds)
March 7-14, 1984	360	33,700
July 10-12, 1984	410	24,800
November 12-16,1984	754	49,900
May 16, 1985	150	3,000

The rate of calcium carbonate scale buildup is calculated by plotting the cumulative amount of scale removed by the acid treatments as a function of the cumulative amount of brine produced. This is shown in Exhibit 3-14 for the treatments up through November 1984 where each treatment series removed all of the wellbore scale. The rate of buildup (slope of the line) is 19.4 pounds of scale formation per 1,000 barrels of brine produced.

To prevent scale formation in the wellbore, inhibitor "squeeze" treatments were performed with consultation from Dr. Mason Tomson of Rice University (Matty, Rogers, Tomson, Varughese, Waggett, 1985) (Greenberg, Matty, O'Day, Sethurman, Sundareswaren, Tomson, Varughese, Waggett, 1986). The treatments consisted of first mixing a "pill" of a few percent phosphonate in brine. The pill was then pumped into the well and forced out into the reservoir formation. In the reservoir, the inhibitor chemical either adsorbs onto the surfaces of the rock or reacts chemically to form a phosphonate precipitate. When brine production is resumed after the treatment the inhibitor slowly redissolves into the brine that passes through the treated zone, thus inhibiting scale formation in the brine before it enters the wellbore.

The first inhibitor squeeze treatment for the McCall well was attempted on November 28, 1984. This attempt was not successful. The pill consisted of 23 drums of Champion Chemical T-120 (Equivalent to Monsanto Dequest 2000) and 20 barrels of 15% HCl mixed with 450 barrels of hot brine produced from the well. When this was pumped into the well the pumping pressure abruptly increased when the pill reached the bottom of the well and was starting to go out into the reservoir. Plugging of the perforations was occurring so the job was aborted. Backflushing the pill revealed a large amount of calcium and iron phosphonate solids. It was subsequently concluded that the acid in the pill had reacted with calcium carbonate scale that remained on the tubing from previous production, and the tubing itself. The dissolved calcium and iron then reacted with the phosphonate to precipitate insoluble calcium and iron phosphonate solids. Production was resumed without the benefit of the inhibitor while the treatment was redesigned to use a neutralized form of the chemical.

The squeeze was again attempted on May 28, 1985. This treatment was also not successful. After injecting an initial 27 barrel slug of 3% neutralized phosphonate inhibitor (Champion Chemical T-132) diluted in 15% synthetic sodium chloride brine, the resistance to pumping suddenly increased, similar to the first squeeze attempt, which again stopped further injection. Backflushing of the pill (still in the wellbore) produced a large amount of solids consisting of calcium-inhibitor salts and/or iron oxides. The solids had also formed in the wellbore and had plugged the formation similar to the first squeeze attempt. The source of the problem was traced to part of the sodium chloride salt used to make the synthetic brine. Although a sample of the solid salt used to make the synthetic brine was analyzed and found free of calcium it turned out that the supplier had provided salt from two different sources and only one of the sources was sampled. The chemists were unaware that two sources had been used. The unsampled salt from

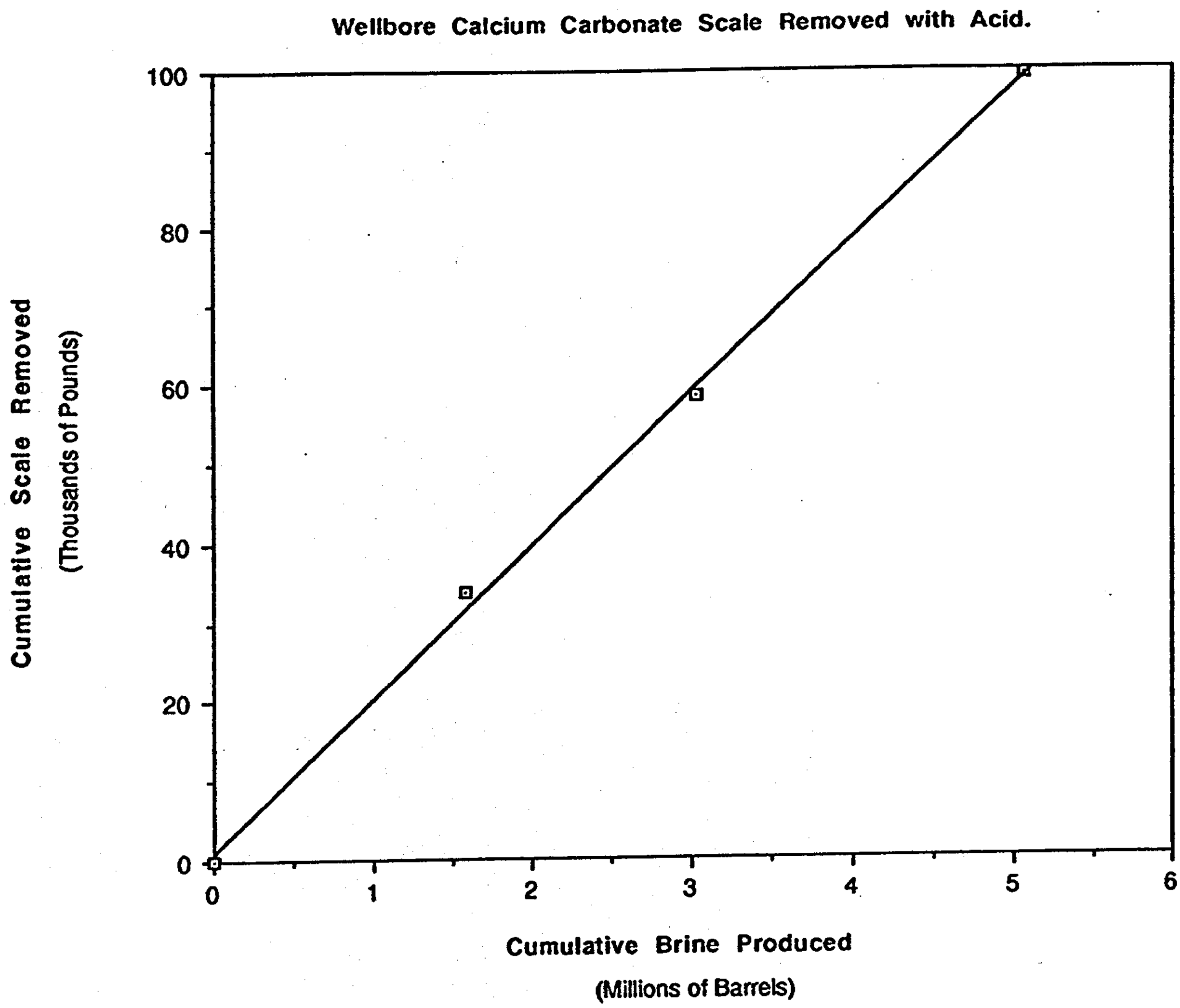

Wellbore Calcium Carbonate Scale Removed with Acid.
Cumulative Scale Removed
(Thousands of Pounds)
100
80
60
40
20
0
0
1
2
3
4
5
6
Cumulative Brine Produced
(Millions of Barrels)

EXHIBIT 3-14

the second source turned out to be contaminated with calcium chloride. The pill and synthetic brine had been mixed and stored in several different tanks on location such that the problem with the calcium contaminated brine was not known until they were mixed during pumping into the well.

Following these two unsuccessful inhibitor squeeze treatment the procedure was replanned and successfully accomplished on June 25, 1985. Stringent quality control was exercised to insure that the fluids were not contaminated and that precipitate would not form in the wellbore. The successful pill consisted of 550 gallons of Champion T-132 dissolved in 87 barrels of 15% sodium chloride brine to give a final volume of 100 barrels. The pill was pumped into the formation with a 300 barrel spearhead of 15% sodium chloride brine ahead of the pill and a 100 barrel overflush of 10 pounds per gallon of calcium chloride brine behind the pill. The purpose of the calcium chloride was to enhance precipitation of the phosphonate inhibitor in the formation. As the calcium chloride solution was being pumped into the formation the injection pressure dramatically increased, indicating that the desired precipitation of the inhibitor in the reservoir was occurring. The well was then shut in for 24 hours to enhance the absorption/precipitation of the inhibitor before resumption of production. Sampling of the initial production (flow back of the injected fluids) revealed that 40% of the inhibitor was retained in the formation rock and 60% of the inhibitor was immediately flushed back out.

When production was resumed the amount of inhibitor released into the produced brine was sufficient to prevent scale formation in the wellbore. The concentration of phosphonate in the produced brine was in the range of about 1 ppm shortly after the inhibitor squeeze, and decreased to levels below the detection limit of the analysis procedure (tenths of a part per million) while effective scale inhibition was continuing to occur. Inhibition was occurring at inhibitor concentration levels lower that were expected to be effective. Periodic analysis of the brine for phosphonate and inspection of the piping was done to determine the time for the next treatment.

The second (and last) inhibitor squeeze was performed on February 5, 1986. For this squeeze the pill consisted of 100 barrels of 3% phosphonate (Champion T-132) in 10% synthetic sodium chloride brine. It was pumped in with a 100 barrel spearhead of plain brine and an overflush of 1200 barrels of brine. This treatment successfully controlled scale formation in the wellbore until the termination of the flow test in October 1987.

The first successful phosphonate scaling inhibitor pill, that was squeezed into the well in 1985, allowed the production of 3,416,359 barrels of brine before indications of scaling were found on the filters in the low pressure portion of the production system. This treatment consisted of 100 barrels of a 6% phosphonate solution. An additional 2,014,051 barrels of brine were produced after the filter-scaling occurred (5,430,410 total) by adding a small amount of scaling inhibitor in the low pressure portion of the system. No scaling deposits were found in the high pressure side of the system during the entire production period.

The second successful phosphonate pill was squeezed on February 4, 1986. 3,261,359 barrels of brine were produced before scaling occurred on the filters, on the low pressure side of the system, on June 2, 1986. This inhibitor treatment used a 3% phosphonate solution. Additional surface inhibition treatment was begun in May 1986. 13,259,353 barrels of brine were produced after the second inhibitor squeeze, until the well was shut in. (Total production after both squeezes - 18,689,763 barrels.)

The well was shut in on October 30, 1987, for pressure buildup. The shut-in bottom hole pressures were recorded for four days. Additional pressures were recorded at 7 days, 10 days, 19 days, 37 days, 54 days, 79 days, 116 days, 172 days, 262 days, 374 days, 500 days, 750 days, and 939 days after shut-in. (Last recording - May 22, 1990; BHP - 12,008 psi; BHT - 299.3°F; @ 15,150'.) The pressure buildup data is being analyzed as recorded.

3.2 Pleasant Bayou Site (Brazoria County, TX)

3.2.1 Review of Past Production Data

Prior production has been reported in terms of phases of well testing (Rodgers, Fenix & Scisson, 1985). An overview of reported data from each phase is provided in the following table.

Date Span	Hrs of Flow	Cum Brine	Avg Brine Rate	GWR
Phase 0				
07/09/79-07/10/79	8.70	539	1,487	16.68
07/10/79-07/10/79	11.25	1,031	2,200	20.70
11/15/79-11/15/79	3.29	2,356	17,187	19.63
11/15/79-11/18/79	65.60	49,082	17,957	19.63
11/23/79-11/26/79	67.66	45,241	16,048	21.00
12/03/79-12/14/79	252.47	177,149	16,840	20.70
Sub-totals & Avg.	408.97	275,398	16,161	20.54
Phase I				
09/04/80-09/04/80	6.66	2,310	8,324	16.68
09/16/80-10/31/80	1,082.50	537,346	11,913	22.35
Sub-totals & Avg.	1,089.16	539,656	11,891	22.33
Phase IIA				
07/02/81-07/17/81	264.92	230,898	20,918	18.65
Phase IIB				
09/22/82-10/23/82	690.50	539,736	18,760	21.68
Phase IIB Cont.				
10/24/82-04/14/83	3,898.40	2,948,653	18,153	22.02
Grand Totals & Avg.	6,351.95	4,534,339	17,193	21.78

3.2.2 Test Results

The Sub-sections below detail the test results.

3.2.2.1 Production

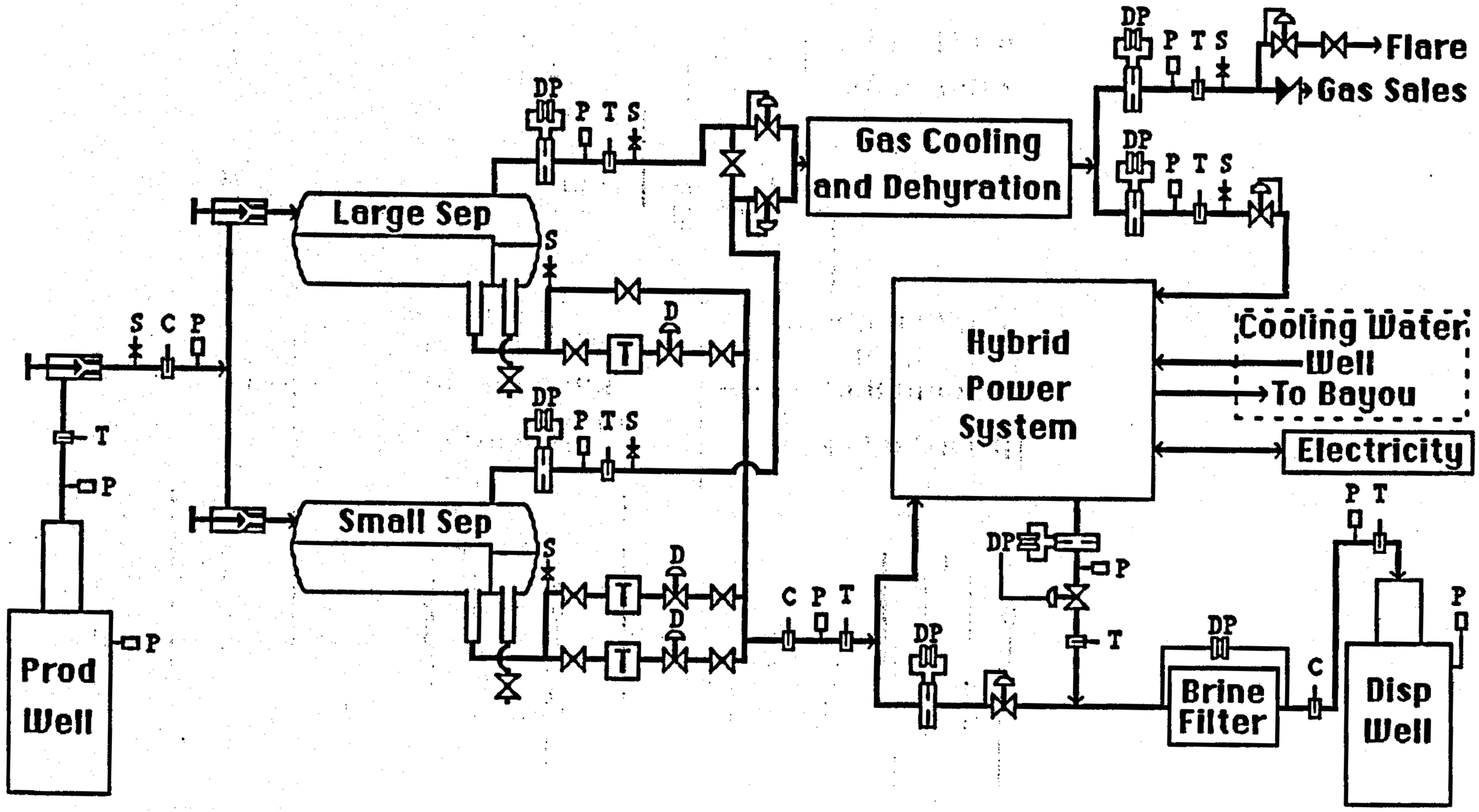
3.2.2.1.1 Surface Facilities

Exhibit 3-15 gives a process flow diagram for the Pleasant Bayou surface facilities.

3.2.2.1.2 Production Data

3.2.2.1.2.1 1986 Well Cleanup & Bottom Hole Pressure Measurement

This section covers details of the well cleanup on March 30-31, 1986 and the bottom hole pressure measurement performed April 1, 1986. During preceding weeks, the packers and fish left in the well in 1983 were removed, and new 5½", 23# tubing was installed to a depth of 13,968' (bottom of the mule shoe on the seal assembly) from the rig Kelly Bushing height, 31' above ground level. The tubing was filled with 16.0 #/gal lignosulphonate mud at this time.



PROCESS FLOW DIAGRAM FOR PLEASANT BAYOU FACILITIES

EXHIBIT 3-15

The clean-out was monitored by IGT to provide data for real-time control of operations, as well as for documentation. Data consisted of tubing and annulus pressures, plus level in the two frac tanks used to collect returned liquids and solids.

Mud Displacement:
The initial step in clean-out was displacement of mud from the well by pumping fresh water down 1¼" continuous tubing to depths that were increased step-wise after bottoms up. For the first eleven hours, liquids and solids entering the tanks were a mixture of mud from the well and the fresh water pumped to displace the mud.

Natural flow from the well did not occur before complete displacement of mud from a depth of 4,500'. However, natural flow began before bottoms up from a tubing depth of 5,500'. The tubing was pulled from the well, and a total of about 50 barrels were produced by natural flow. However, plugging of the two ⅜" holes in the Willis type M3G choke precluded continuous production from the well.

Natural Flow Cleanup:
The annulus pressure increased due to heating by natural flow prior to plugging of the Willis choke. Tubing pressure spikes were observed due to pumping fresh water into the choke in attempts to break loose plugs.

Declining tubing pressures were observed while awaiting delivery and installation of a surface choke manifold. This manifold provided a straight through, 2", heavy wall pipe, plus two positive chokes.

On March 31, flow through the pipe in the choke manifold was started. For about 15 minutes, flow rates were in the range of 1,500 to 4,500 BPD. Then, as flow rate and tubing pressure rapidly increased, flow was switched to a 1" positive choke. The well was shut in at 1:55 AM. Total production during this period was about 500 barrels or slightly more than 1.5 well volumes. The average rate was about 12,000 BPD, and the peak rate observed in a 5 minute interval was 40,000 BPD.

On March 31, the casing pressure was bled off for the first time, and flow from the tubing through a ½" positive choke was started to obtain data for evaluation of the condition of the perforations. Tank strap data verified that the flow rate averaged 7,000 BPD. At bottoms up (300 barrels produced), flow tubing pressure increased from 3,880 psia to 3,970 psia. This was interpreted as meaning that an additional slug of mud had been pushed from the perforations to the surface and that an additional, higher rate flow should be performed to be confident that the well was reasonably well cleaned up. A dip to a tubing pressure of 3,580 psia at the end of the flow was the result of a communication failure which resulted in the service company man switching to a ¾" choke, rather than shutting in the well until brine could be removed from the tanks. Total production during this flow was 450 barrels or 1.5 well volumes.

Also on March 31, and after removing enough brine to provide the required tank capacity, production of 500 barrels through a ¾" positive choke began. The production rate averaged 14,000+ BPD. The drawdown from shut-in pressure was 600 psi at both the beginning and the end of the test. Further, no step in flowing tubing pressure was observed at bottoms up (300 barrels produced). This was interpreted as evidence of adequate cleanup of the well.

Bottom Hole Pressure Measurement:
The heights of the wellhead and the wireline mast were such that the desired number of sinker bars could not be used. Tubing pressure was reduced shortly after 1.5 days by blowing brine through the needle valve on the lubricator in an attempt to get the wireline to go downhole. This was unsuccessful.

After obtaining heavier sinker bars, a sinker bar trip into the well was successfully made. The tool tagged up hard at a wireline depth of 14,042′ below a reference depth of 31′ above ground level (original rig KB). After clean-out, drill pipe rotation at 14,028′ was required to achieve greater penetration, and this is believed to be the depth actually reached with the wireline.

The downhole Panex instrument run was made on April 1. The weight of the downhole tools was so low that several hundred feet of wire was in the well before tension lifted the ground level sheave off the ground. This was apparently accompanied by slippage of wire through the odometer (depth-measuring device). The trip out of the hole revealed a depth discrepancy of 109′. Because tension was adequate for proper odometer operation on the trip out, a 109′ depth correction is made as discussed below.

During the trip into the well, 10 minute stops were made at indicated depths of 12,000′ and 13,000′ to establish a pressure gradient for extrapolation to the depth of perforations. The tool tagged up hard at an indicated depth of 13,887′ for the Panex sensor. The sensor was 25′ above the bottom of the sinker bars. Including this 25′ and the 109′ correction, the tool appears to have tagged up at a depth of 14,021′ below the original rig KB of 31′ above ground level. This is very close to the driller's depth of 14,028′ where drill pipe rotation was required to achieve greater penetration after clean-out. Accepting this depth as a downhole depth reference and recognizing that the Panex sensor was 25′ above the bottom of the wireline hardware, the deepest pressure was recorded at a depth of 14,003′. Indicated wireline depth to the sensor from 33′ above ground level was 13,887′. Thus, the correction from observed wireline depth to actual depth, referenced to the top of the liner, is 118′. Note that this value differs from the depth correction of 109′ that was incorporated in the data report by Milton M. Cooke Petroleum Engineers (see Appendix B-2 for details) by 9′. The reason is that Cooke reported from an assumed original rig Kelly bushing height of 33′ and corrected only for the differences between odometer readings before and after the trip downhole.

A correction to reported pressures is also required before drawing conclusions about bottom hole pressure. When the downhole Panex instrument was in the lubricator, it indicated a pressure of 4,230 psia. At the same time, a deadweight tester indicated a pressure of 4,241 psig (4,256 psia) at the bottom of the lubricator. Assuming that the lubricator was filled with brine with a pressure gradient of 0.46 psi/ft and that the Panex sensor was 32′ above the deadweight tester, the deadweight tester value corresponds to 4,241 psia at the Panex. Thus, the Panex reading in the lubricator was low by 11 psi. When open to the atmosphere, the Panex read 18 psia or a value that is high by 3 psi. The functional relationship between the discrepancies and pressure is not known. It will be assumed that reported downhole pressures in the vicinity of 10,000 to 11,000 psia have a range of uncertainty from being correct on the one hand, to being low by an amount calculated from linear extrapolation of the discrepancies noted above on the other hand. This results in the following equation for an upper limit of true downhole pressure:

$$P_{max} = -3.06 + 1.003324 * P_{indicated}$$

With the 118′ correction to depth, the probable range of actual bottom hole pressures is as shown in Exhibit 3-16. The table also shows calculated values (assuming 0.454 and 0.455 psi per foot pressure gradients) at the mid-point of the perforated interval (14,674′ Induction Log depth).

Reservoir Drawdown:

An IGT Technical Report (see Appendix D of Appendix B-2) included a careful examination of prior bottom hole pressure data and extrapolation of reported pressures to the mid-point of perforations. The search of raw data at that time did not reveal the information required to consider corrections to the data such as applied above.

Another discrepancy was noted in comparing the new measurement to "original reservoir pressure." The first measurement of bottom hole pressure was on November 15, 1979 (11,275.4 psia at 14,750′), using an assumed pressure gradient of 0.44 psi/ft gave a value of 11,241 psia at 14,674′. But for another measurement on September 16, 1980, extrapolation of reported pressures at 14,000′ and 14,500′ to a depth of 14,674′ gave a value of only 11,166 psia. The net result is a difference of 75 psi in measurements. It should have differed only by the drawdown caused by producing about 275,000 Bbls. With this uncertainty in the original reservoir pressure and the estimated uncertainty in the data for April 1, 1986, the range of values for actual reservoir drawdown is 130 psi to 238 psi.

Exhibit 3-16 - DOWNHOLE PRESSURES AND TEMPERATURES

Depth (Corrected) (feet)	Depth Reported (psia)	Pressure Maximum (psia)	Pressure Gradient (psi/ft)	Temperature Reported (Deg. F)
12,118	9,843.3	9,873.0	0.4524-0.4538	267.1
13,118	10,295.7	10,326.9	0.4539-0.4553	277.9
14,003	10,698.3	10,730.8		293.5
Calculated Pressures at the mid-point of perforations:				
	14,674.0	11,002.9	11,036.1	

3.2.2.1.2.2 Production Starting in 1988

The production data from the first instrumented flow on March 7, 1988, through the cutoff date for this report, are presented in tabular form in Appendix A of Appendix B-2 of this report, and in graphical form as discussed in the paragraphs below. The detailed log of significant events in Appendix B of Appendix B-2 provides a detailed summary of significant events, including the reasons for the variations in producing conditions.

Brine flow rate for the three years of production is shown as a function of time in Exhibit 3-17. The values used and tabulated for brine rate in Appendix A of Appendix B-2 are the sum of brine rates for the orifice meters at the HPS. The result is slightly smaller than the sum of values for the turbine meters on the two separators, but is believed to be more accurate.

The reason for the overall decline with time was maintaining disposal well injection pressure low enough for operation of the Hybrid Power System (HPS) without exceeding the working pressure rating of 600 psi for the brine side of the heat exchangers in that system.

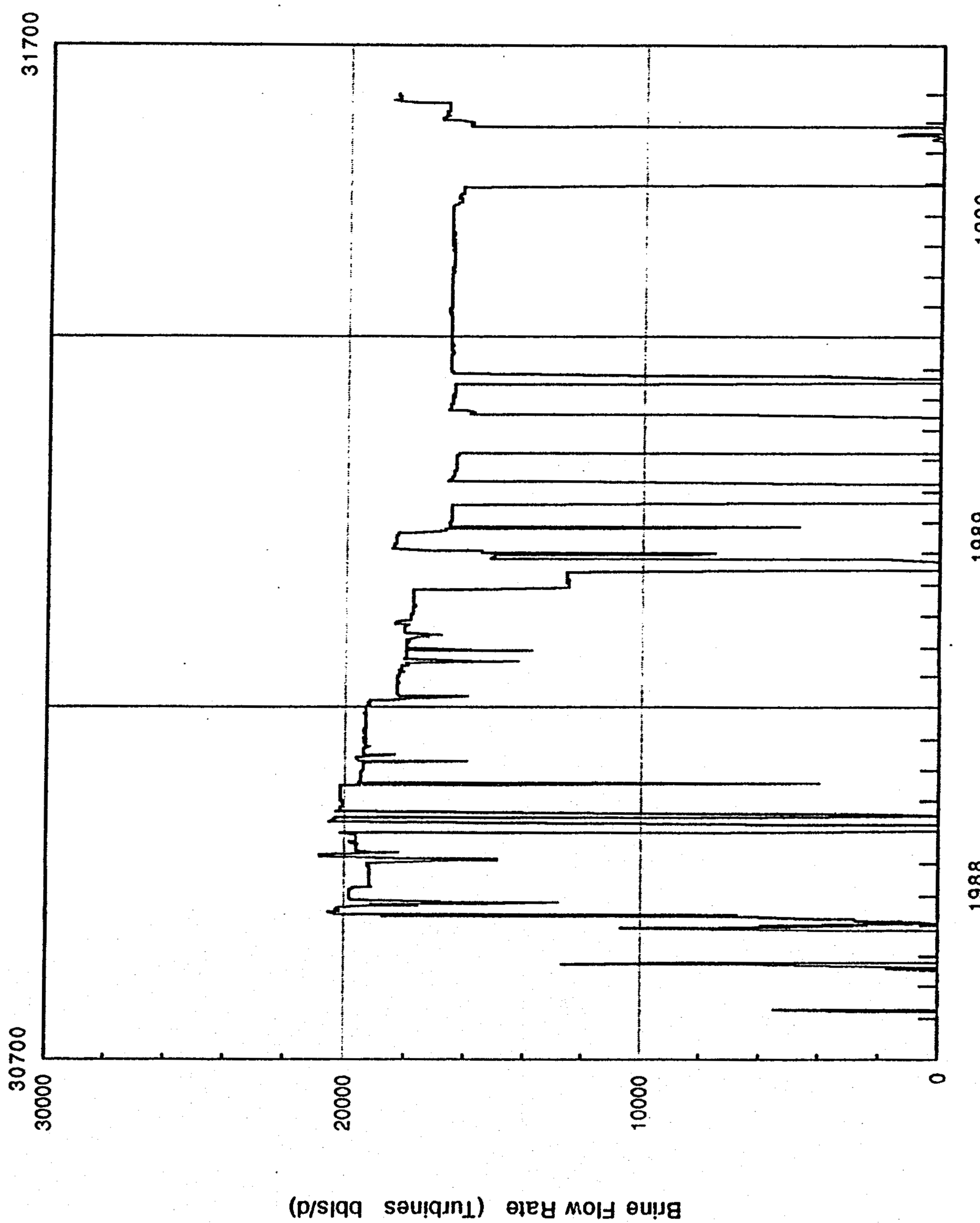
Production wellhead pressure for the past three years is shown as a function of time in Exhibit 3-18. The values plotted are 24-hour averages. With one exception, all values below 2,800 psi are the result of the pressure transmitter being isolated from the actual pressure in the wellhead below the master valve. The exception is a couple of hours on the evening of June 20, 1988, when the brine rate was 25,000 STB/D and the tubing pressure dropped to 2,550 psia. The next highest rate, 22,500 STB/D overnight on June 21-22, 1988, was accompanied by a minimum flowing tubing pressure of 2,875 psia.

Production wellhead temperatures are shown as a function of time in Exhibit 3-19. The values in the range of 50°F to 100°F are ambient temperature at times when brine was not flowing. The zero values are times when actual temperature data was not being recorded. Note that the flowing brine temperature at the HPS went down from 291°F to 286°F in only four (4) hours after the brine rate was decreased from 17,100 STB/D to 12,200 STB/D on April 27, 1989.

The perforation gas rate is shown as a function of time in Exhibit 3-20. This gas rate is the sum of the measured gas rates from the two separators, plus the result of calculating the amount of gas remaining in solution in brine leaving the separators.

The gas/brine ratio is shown as a function of time in Exhibit 3-21. This ratio is calculated by dividing the perforation gas rate by the brine rate measured at the orifice meters at the HPS. A gas/brine ratio of zero is reported for those times when there is no production. The small variations from the overall average of near 24 SCF/STB are believed to reflect measurement uncertainty or error.

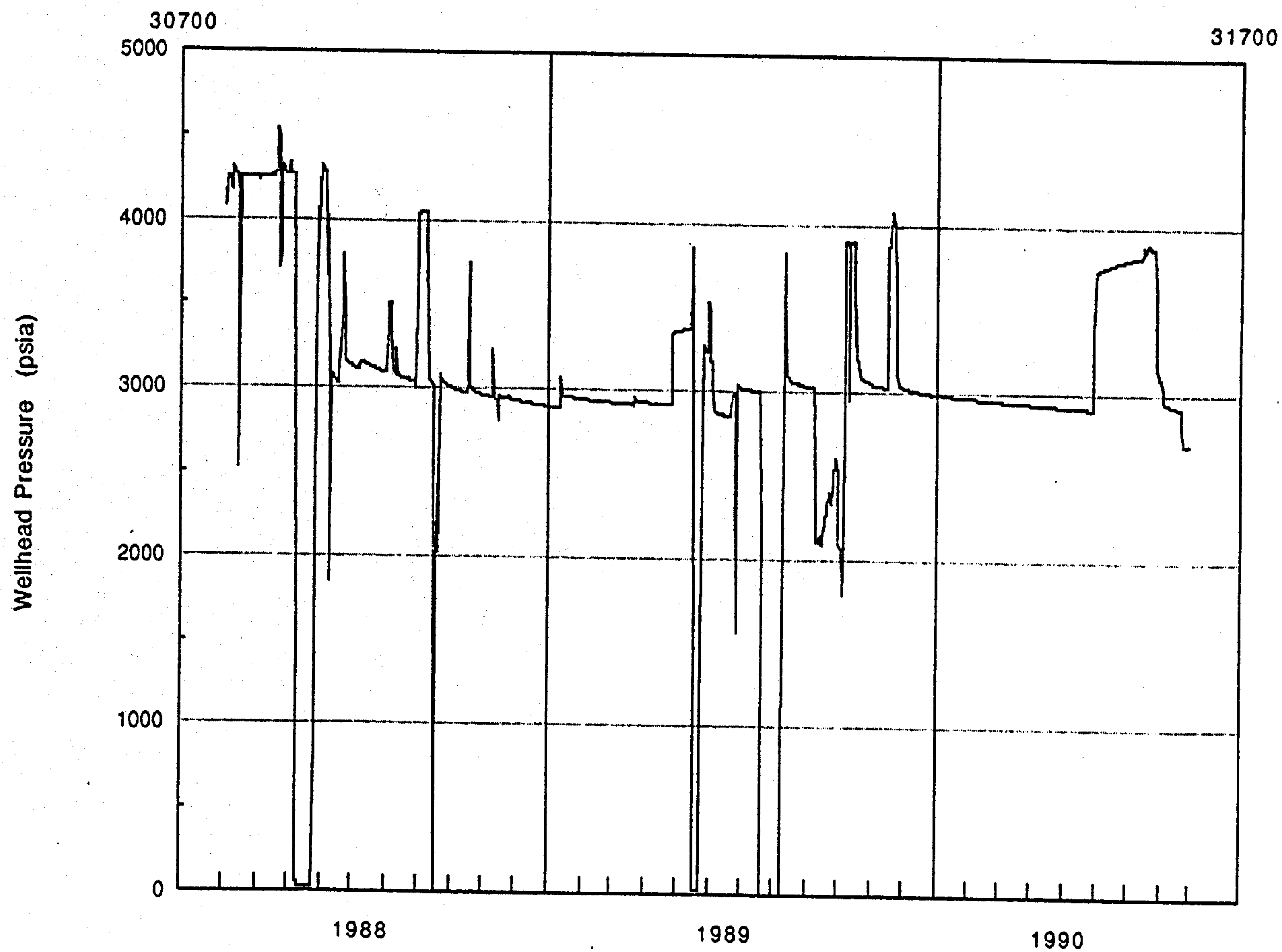
The range of flowing bottom hole pressures was very small for the entire two years of flow. The highest flowing bottom hole pressure was about 10,100 psia in June



BRINE FLOW RATE MEASURED BY ORIFICE METERS

EXHIBIT 3-17

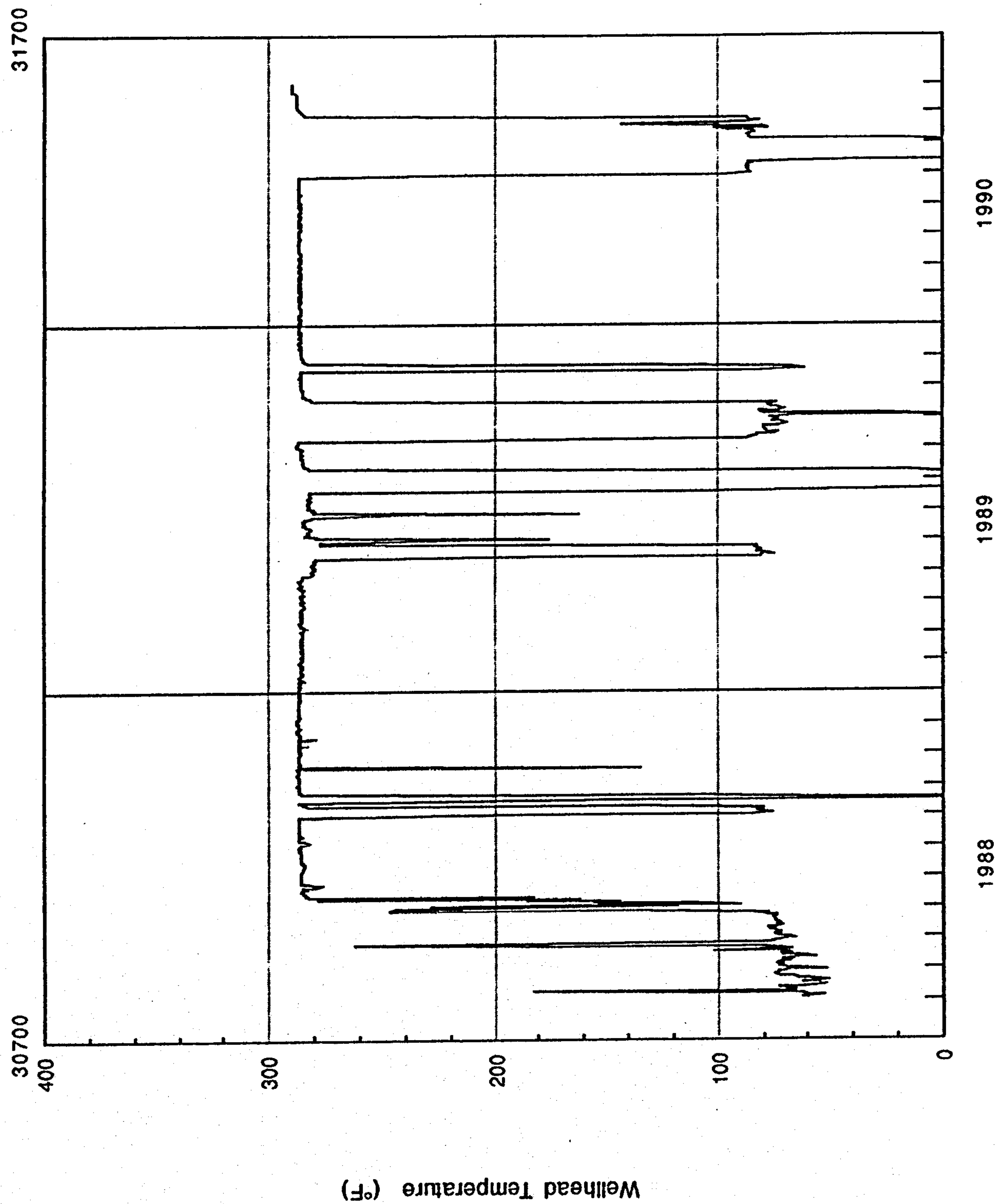
PRODUCTION WELLHEAD PRESSURE



10/1/90

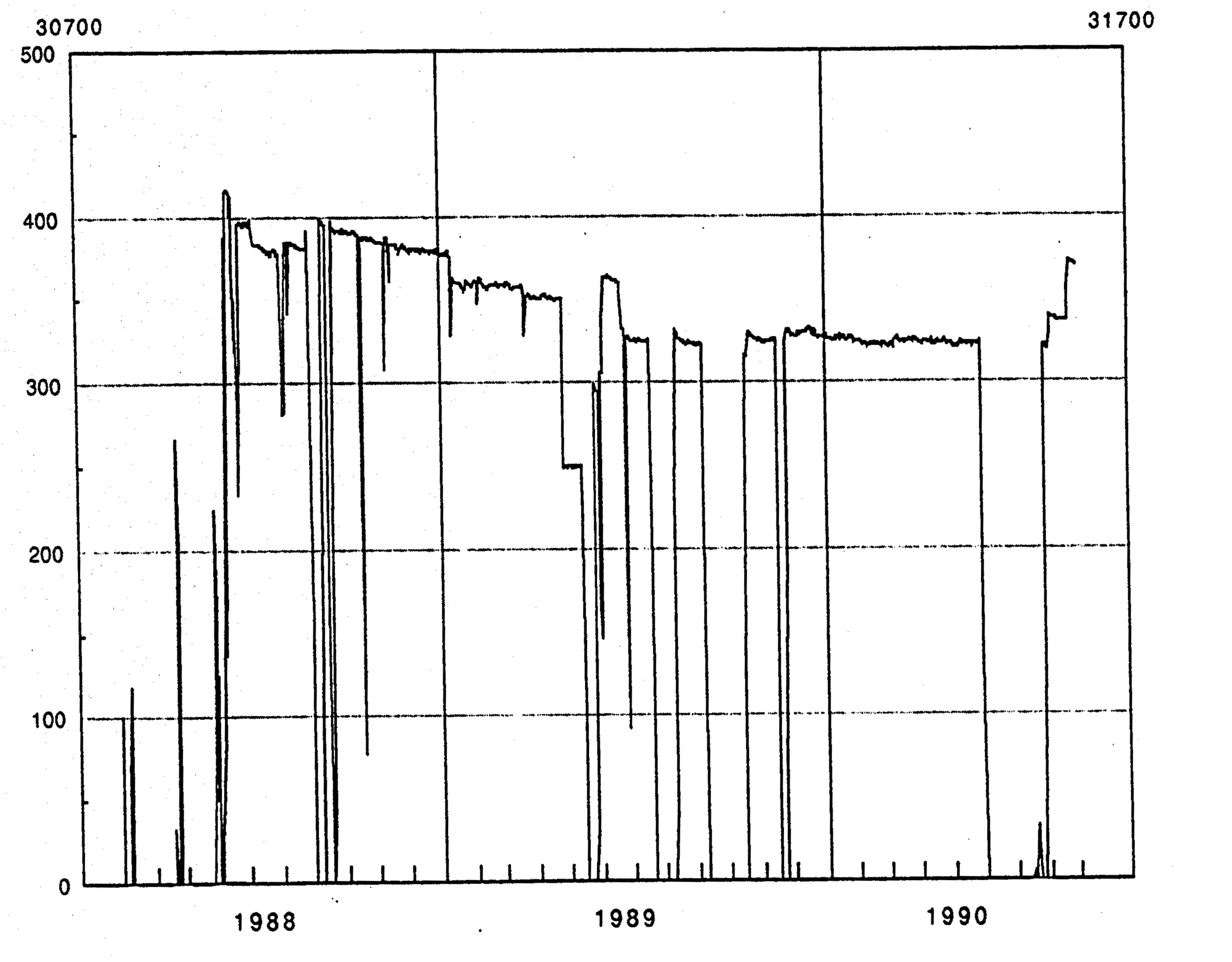
EXHIBIT 3-18

10/1/90



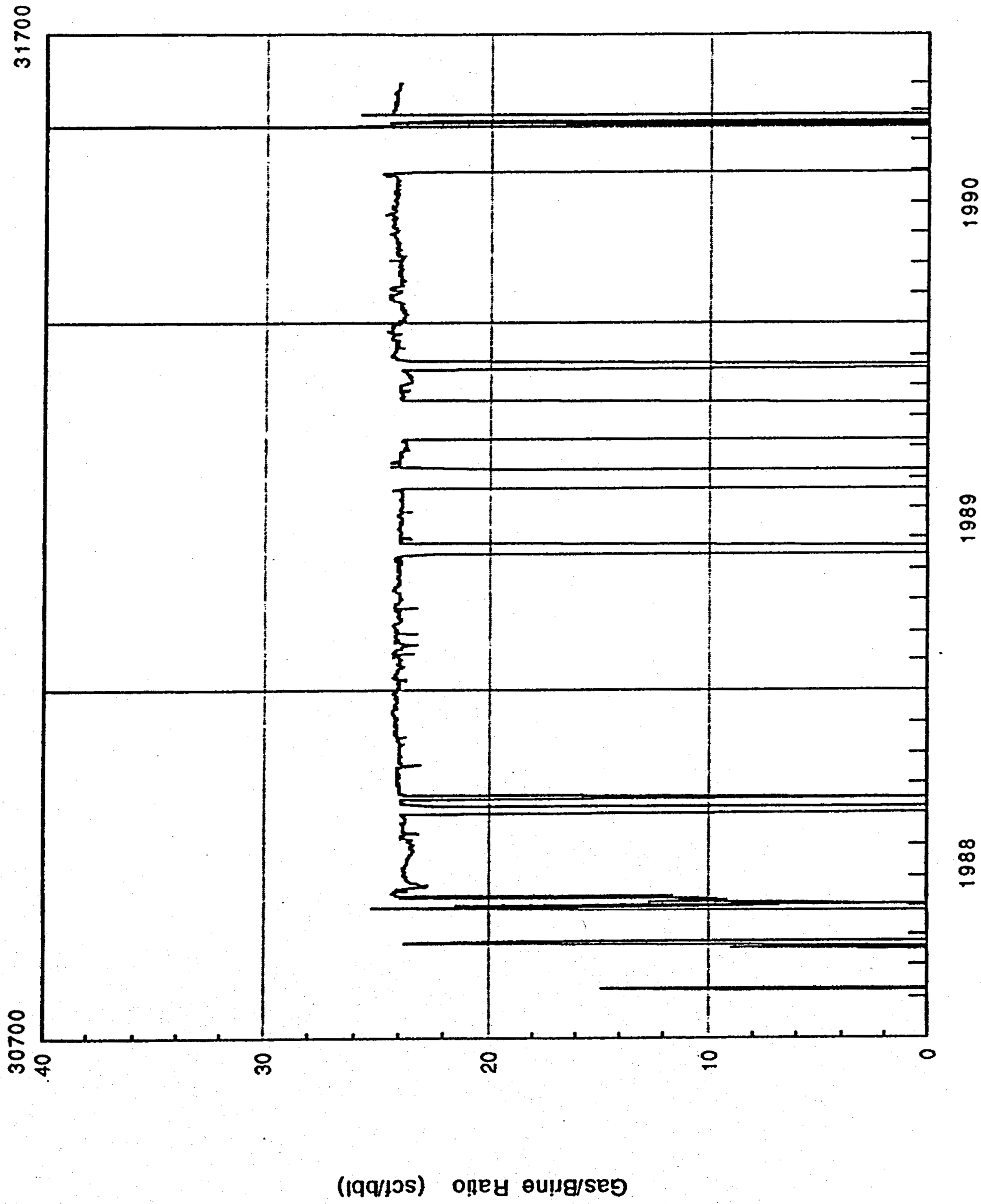
PRODUCTION WELLHEAD TEMPERATURE

EXHIBIT 3-19



GAS RATE AS PRODUCED THROUGH THE PERFORATIONS INTO THE WELL FROM THE RESERVOIR

EXHIBIT 3-20



GAS/BRINE RATIO. PERFORATION GAS IN EXHIBIT 3-20 DIVIDED BY BRINE RATE IN EXHIBIT 3-17

EXHIBIT 3-21

and July of 1988, plus during the May 1989 production with brine rate reduced to 12,200 STB/D. With the exception of the few hours of flow at rates above 20,000 STB in June 1988, the minimum value of calculated flowing bottom hole pressure was 9,760 psia at 14,644 feet at the end of May 1990. This value is only 340 psi less than the highest flowing bottom hole pressure. The difference in calculated solubilities for methane in Pleasant Bayou brine is only 0.3 SCF/STB for these two pressures and a temperature of 308°F. This difference is comparable to the observed variations from the overall average of 24 SCF/STB.

Disposal well tubing pressure is shown as a function of time in Exhibit 3-22. The early June 1988 clean-out made possible injection of about 20,000 STB/D at a pressure a little below 600 psia. By February 1989, the injectivity had deteriorated to where a pressure of about 618 psia was required to dispose of 17,500 STB/D. Then, the addition of only 10 barrels of concentrated hydrochloric acid to the flowing stream such that the acid concentration was 1.6% in the brine reduced the injection pressure to 501 psia. This was low enough for the planned operation of the HPS to take place with only a modest reduction in brine rate.

The minimum brine rate during the test of the HPS was about 15,600 STB/D, a value comfortably above the HPS design brine rate of 10,000 STB/D. The step-wise variations in injection pressure within the range of 400 to 550 psia, in the time interval of September 1989 through May 1990, are due to changes in density of injected brine due to cooling of brine by the HPS or to the stopping thereof.

Total cumulative production of brine through October 31, 1990, and total cumulative production of separated gas is shown in Exhibit 3-23.

3.2.2.1.3 Brine Sampling

Following is a discussion of the sampling methodology and analysis results of brines, as conducted at the sites.

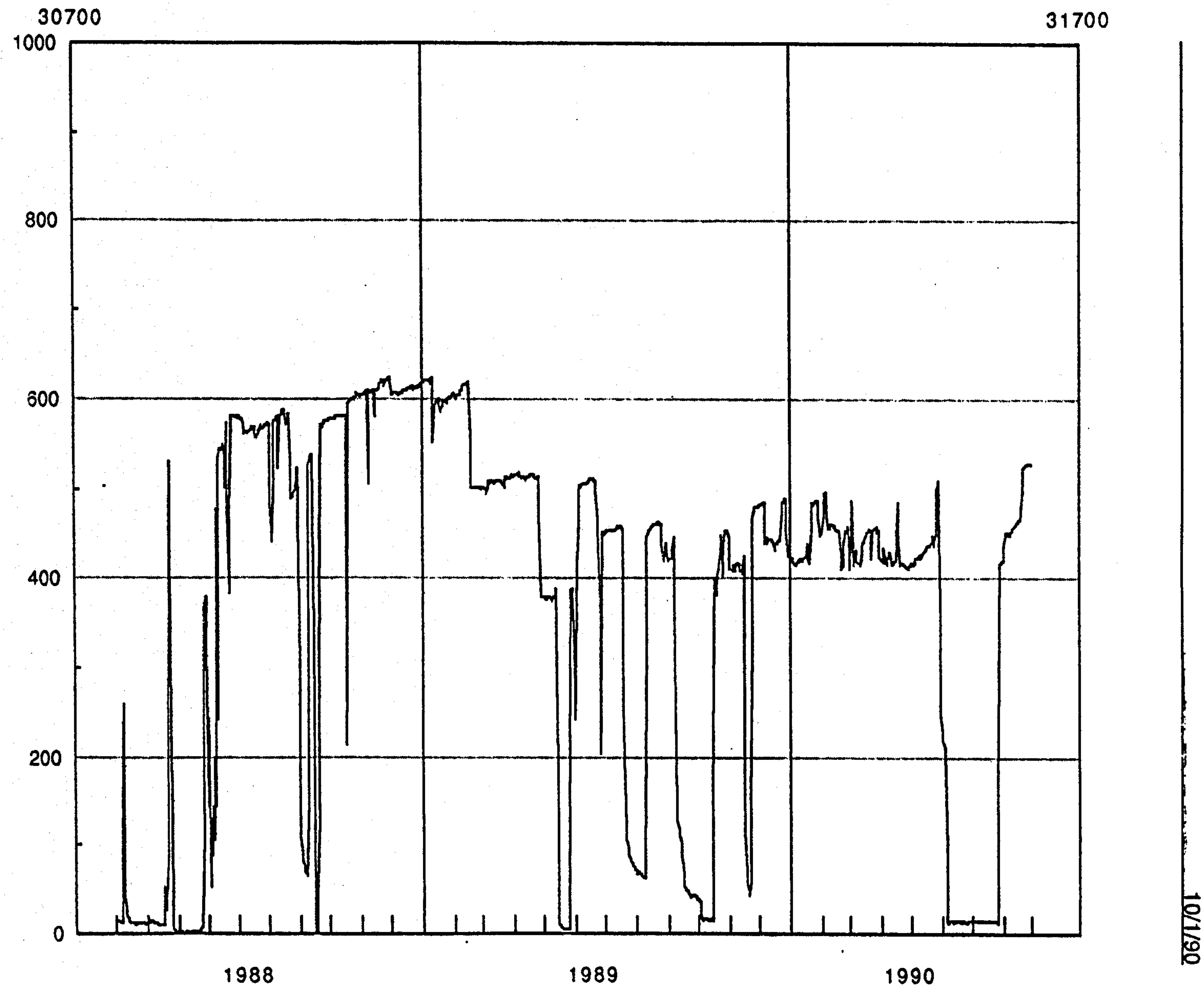
3.2.2.1.3.1 Analytical Methodology

IGT used the Texas Bureau of Economic Geology's Mineral Studies Laboratory for the bulk of the brine analyses. This same laboratory had analyzed Gladys McCall and Hulin brines, as well as numerous brine samples from co-production fields, for IGT. The analytical techniques used are listed in Exhibit 3-24; detailed laboratory procedures are included in the Pleasant Bayou SAR. In addition to running the samples, there was a duplicate analysis performed for each suite of samples as a check on reproducibility and an analysis of appropriate standards. This information is provided in the laboratory reports which are appended to this report.

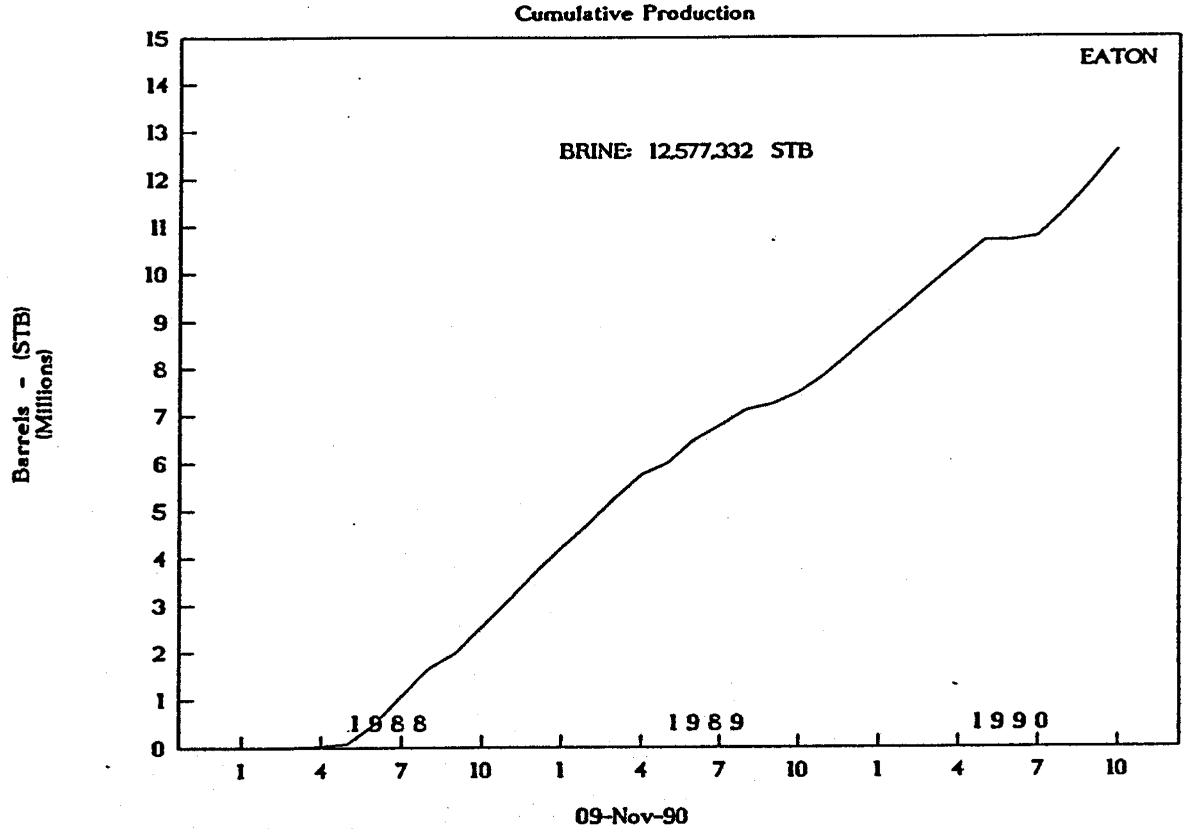
Two brine analyses, alkalinity and iron, were performed on location because the time needed to transport the samples to a laboratory may have seriously affected the accuracy of the analyses. The procedures and chemicals used are described in the Hach Water and Wastewater Analysis Handbook. These tests were also subsequently run in the laboratory, but the field data is believed to be the most reliable. Sulfide was also looked for in the brine on an occasional basis, but

EXHIBIT 3-22

DISPOSAL WELL TUBING PRESSURE



EOC/DOE 2-Pleasant Bayou



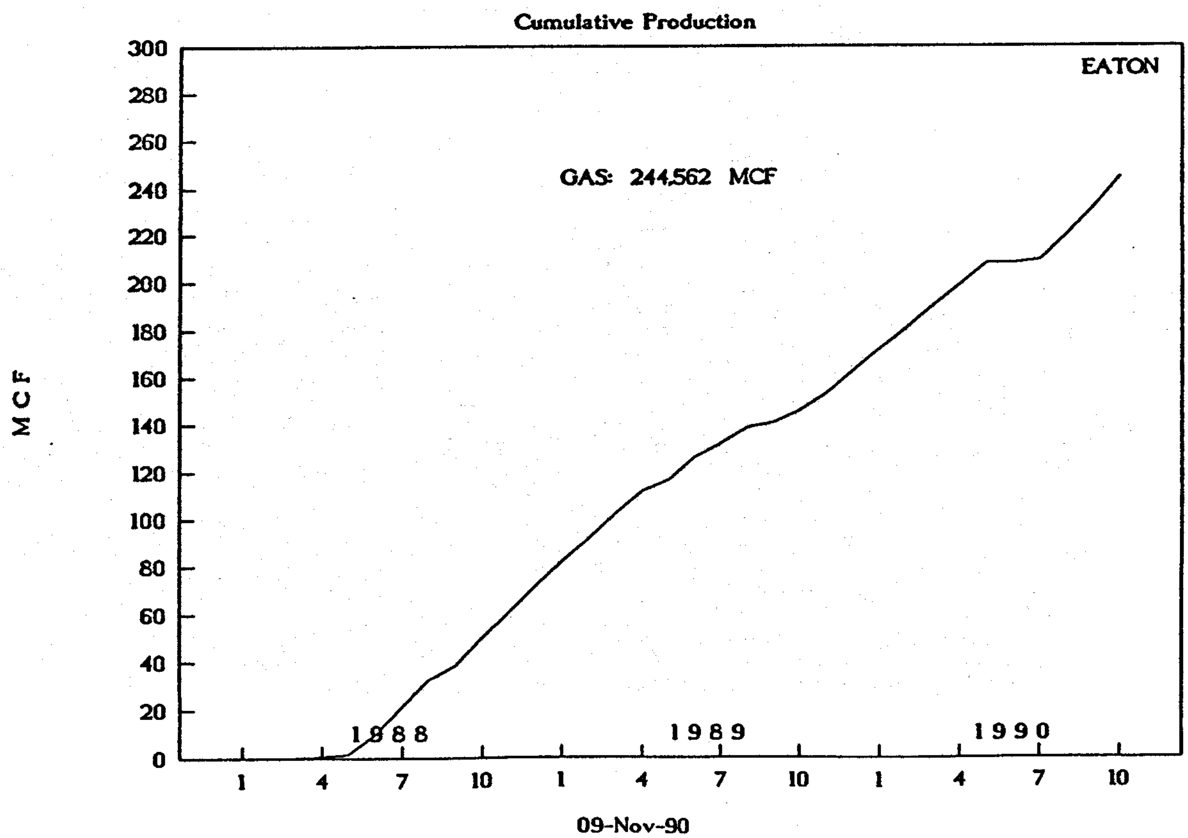


EXHIBIT 3-23

sulfide had not been present at concentrations above the lower limit of detection of about 0.5 mg/L.

Exhibit 3-24 - ANALYTICAL METHODS USED

Element	Method
Sodium, Potassium, Magnesium, Iron Manganese, Strontium, Calcium, Chromium, Barium, Zinc, Lithium, Silica, Copper, Nickel, Arsenic, Cadmium, Lead, Tin, Boron	Inductively Coupled Plasma-Optical Emission Spectroscopy
Mercury	Cold-Vapor Atomic Absorption
Ammonia	Distillation-Titration
Chloride	Titration
Sulfate	Turbidimetric
Bromide, Iodide	Spectrophotometric
Fluoride	Ion Electrode
Alkalinity*	pH Titration
Density, TDS	Gravimetric
Sulfide*, Iron*	Colorimetric
Radium	Radon Generation

* Sample is also analyzed for this element on site. The sulfide measurements have not revealed detectable levels of sulfide in the brine.

Total carbon dioxide measurements were made following procedures described in Parametric Study of Separator Performance (Hayden and Randolph, 1981). This includes collecting brine samples under pressure, cooling the samples, quantitatively flashing off and measuring dissolved gas, and finally using an acid liberation/nitrogen purge gravimetric technique to recover any remaining carbon dioxide.

Brine samples were also collected and sent to other parties. Dr. T. Kraemer of U.S.G.S. was sent filtered, acidified, diluted brine samples for radium-226 and radium-228 analyses. His results are included in this report (Appendix B-2).

Finally, IGT used the in-house analytical laboratory to perform per million quantification of organic acids in the brine, as well as subpart per million analyses for phosphonate. The organic acids were determined by Gas Chromatography/Mass Spectroscopy. The phosphonate concentration was determined using a butyl alcohol extraction/colorimetric analysis as described in the Pleasant Bayou SAR.

3.2.2.1.3.2 Brine Analysis Results

The results of the analyses performed on site are presented in Exhibit 3-25. These include samples collected from just after the primary choke and from just before the disposal well. Exhibit 3-26 presents average results of brine analyses since 1986, along with an "average" of result of analyses (ANACON) performed for 1980 Phase-1 Test, as reported by Rodgers in the Gruy Final Report. (A detailed discussion of these analyses is given in Section 4 of Appendix B-2.) The differences between the compositions reported in 1980 and for the recent samples appear to be due to evaporation from the 1980 samples. The recent samples were cooled before pressure reduction.

Exhibit 3-25
RESULTS OF ON-SITE ALKALINITY ANALYSES
PLEASANT BAYOU

Date	Cum Brine Millions of STB	Alkalinity, as mg $CaCO_3$/L At Chokes	Alkalinity, as mg $CaCO_3$/L At Disp. Well
06/20/88	0.319	311	
07/01/88	0.519	309	310
07/12/88	0.731	315	315
07/21/88	0.902	309	310
07/25/88	0.977	310	312
08/18/88	1.416	313	323
08/24/88	1.529	309	316
10/03/88	2.021	322	319
10/17/88	2.283	314	319
10/31/88	2.533	316	314
11/30/88	3.089	309	304
12/20/88	3.458	310	304
01/10/89	3.845	304	304
01/20/89	4.019	325	315
02/09/89	4.370	314	334
02/28/89	4.702	325	325
03/20/89	5.050	305	315
04/04/89	5.308	325	315
04/27/89	5.701	325	315
06/06/89	6.067	306	314
07/07/89	6.574	304	306
08/23/89	6.975	304	304
11/07/89	7.584	305	305
12/19/89	8.136	305	
02/06/90	8.913	315	315
03/22/90	9.608	304	314
04/19/90	10.048	315	315
08/06/90	10.848	315	310
09/04/90	11.347	320	314
09/19/90	11.644	312	314
10/08/90	12.068	315	305

Exhibit 3-26
AVERAGE BRINE COMPOSITION
PLEASANT BAYOU

Date	1980	1988-1990	1988-1990
Number of Samples Averaged		32	4
Location	Unknown	Choke	Disp. Well
Laboratory	Anacon	BEG	BEG
Brine Temp, °F	268-284	289	
Specific Gravity @ 60°F	1.0907	1.0835	1.080
Total Dissolved Solids, mg/L	137,008	134,119	128,900
Alkalinity, as mg $CaCO_3$/L	272	277	275
Ammonia	92	83.6	-
Barium	764	783	784
Boron	31	25.2	24
Bromide	-	75	74
Calcium	9,360	7,971	7,760
Chloride	78,363	71,777	71,000
Fluoride	1.2	1.52	1.7
Iodide	-	20.6	22
Iron	56	47.8	45
Lithium	-	29.4	30
Manganese	23	16.7	15
Magnesium	658	593	578
Potassium	-	581	542
Silica, as SiO_2	114	101	104
Sodium	37,767	36,207	35,700
Strontium	1,053	905	847
Sulfate	0	1	4
Zinc	1.6	0.48	0.6

3.2.2.1.4 Hydrocarbon Sampling and Analysis

Gas samples were routinely collected at the large separator, small separator, and sales/flare meter runs. The location of these meter runs in the gas processing equipment are shown by the three "S"s in Exhibit 3-15. The separator meter runs contain hot, wet gas and a small quantity of condensed water. The sales/flare gas has been cooled and dehydrated.

Gas samples destined for laboratory analyses were collected in evacuated, teflon-lined, 304 stainless steel cylinders rated at 1,800 psi working pressure. The sample lines were purged, and then the cylinder was connected and filled one time. There was no sequential filling and purging process. The samples were sealed and sent to the laboratory, either IGT or Core Laboratories Chromaspec, for analysis. At the laboratory, the sample cylinders are preheated to line temperature prior to withdrawing an aliquot for analysis. This prevented liquid condensation from interfering with the analysis. The samples were analyzed by gas chromatography.

On site analyses for carbon dioxide and hydrogen sulfide were performed using Draeger tubes following the Gas Processors Association "Tentative Method of Test for Hydrogen Sulfide in Natural Gas Using Stain Tubes" (1977). Tests are also occasionally run for mercury and ammonia.

3.2.2.1.4.1 Results of Gas Analysis

The results of the gas analyses are presented in the following exhibit: Exhibit 3-27, containing the results of IGT analyses performed on sales/flare gas and large and small separator gases. The IGT analyses are very detailed, reporting concentrations of hydrocarbons through decanes plus, the concentration of ringed hydrocarbons through the C3 naphthalenes, and the concentration of helium and molecular hydrogen.

Exhibit 3-27
AVERAGE GAS COMPOSITION
MEASURED AT IGT BY GAS CHROMATOGRAPHY

	Large Separator Gas, mole %	Small Separator Gas, mole %	Sales/Flare Gas, mole %
Number of Analyses	14	11	21
Helium	0.009	0.009	0.009
Hydrogen	0.016	0.016	0.020
Nitrogen	0.52	0.54	0.54
Carbon Dioxide	10.26	10.42	10.35
Methane	84.72	84.68	84.73
Ethane	2.93	2.90	2.92
Propane	0.94	0.91	0.94
Iso-Butane	0.147	0.143	0.147
N-Butane	0.134	0.130	0.133
Iso-Pentane	0.039	0.037	0.040
N-Pentane	0.019	0.018	0.020
Neo-Pentane	0.001	0.001	0.001
Hexanes	0.016	0.015	0.015
Heptanes	0.020	0.017	0.020
Octanes	0.012	0.009	0.010
Nonanes	0.003	0.001	0.002
Decanes	0.001	0.001	0.001
Undecanes	0.002	0.001	0.001
Dodecanes	0.002	0.001	0.001
Tridecanes	0.001	0.000	0.001
Tetradecanes +	0.002	0.001	0.001
Benzene	0.079	0.069	0.054
Toluene	0.053	0.038	0.027
C2 Benzenes	0.027	0.016	0.010
C3 Benzenes	0.010	0.005	0.003
Naphthalene	0.003	0.001	0.001
C1 Naphthalenes	0.003	0.002	0.001
C2 Naphthalenes +	0.002	0.002	0.001
Heating Value, Btu/SCF Dry, 14.65 psia, 60°F	953	948	949
Gravity (air = 1.000)	0.69	0.69	0.69

3.2.2.1.4.2 Comparison Between Laboratories

Duplicate gas samples were obtained from the sales/flare meter run at 13:00 on May 30, 1988. The samples were sent to IGT-Chicago and to Core Labs-Houston for analysis. Core Labs reports benzene with heptanes, toluene with octanes, C2 benzenes with nonanes. The analyses, taking into account the peculiarities of Core Labs' reporting procedures, agree very well for all components except carbon dioxide and methane. The reason for this discrepancy is not understood. The gas, which had been cooled and dehydrated, should not be reactive in the cylinder. No mechanism was found to lose carbon dioxide or methane from the cylinder. The differences are minor with respect to gas gravity and the heating value of the gas.

Exhibit 3-28 presents the results of Core Laboratories Chromaspec analyses on large and small separator gases and the sales/flare gas, respectively. These analyses are through decanes plus, though ringed hydrocarbons are not differentiated from the saturated hydrocarbons.

Exhibit 3-28
AVERAGE GAS COMPOSITION
MEASURED AT CORE LABORATORIES BY GAS CHROMATOGRAPHY

	Small Separator Gas, mole %	Large Separator Gas, mole %	Sales/Flare Gas, mole %
Number of Analyses	7	7	5
Nitrogen	0.49	0.51	0.51
Carbon Dioxide	11.71	11.22	11.70
Methane	83.51	83.84	83.25
Ethane	2.86	2.93	2.86
Propane	0.88	0.94	0.92
Iso-Butane	0.14	0.15	0.14
N-Butane	0.13	0.13	0.13
Iso-Pentane	0.04	0.04	0.03
N-Pentane	0.02	0.02	0.02
Hexanes	0.03	0.03	0.03
Heptanes	0.08	0.07	0.10
Octanes	0.06	0.05	0.06
Nonanes	0.02	0.02	0.03
Decanes +	0.04	0.04	0.02
Heating Value, Btu/SCF Dry, 14.65 psia, 60°F	941	947	940
Gravity (air = 1.000)	0.704	0.700	0.703

3.2.2.1.4.3 Comparison Between Other Geopressured-Geothermal Wells

Gas compositions are similar to the limited sales contract analyses reported in the period from October 1982 to April 1983. During this time, the carbon dioxide averaged 12.3%, nitrogen averaged 0.52%, specific gravity averaged 0.703, and heating value (unspecified as to wet or dry and to the pressure base) averaged 929 BTU/SCF.

The Pleasant Bayou gas contains more heavier hydrocarbons, from propane through decane, than were found in all geopressured-geothermal well tests except the Koelemay. The Koelemay well coned in a gas condensate cap and became a commercial oil and gas producer. The differences in the concentrations of heavy hydrocarbons are evident in Exhibit 3-29, Typical Geopressured-Geothermal Well Gas Analyses. At the same time, the evidence is strong that the Pleasant Bayou brine is undersaturated with gas at reservoir conditions.

Exhibit 3-29
TYPICAL GAS COMPOSITIONS FROM GEOPRESSURED-GEOTHERMAL WELLS[(a)]

Well	Hulin	Girouard	Koelemay	Saldana	Prairie Canal	Crown Zellerbach	Amoco Fee	Sweezy	Gladys McCall	Pleasant Bayou
Date	1/7/90	7/80	9/80	11/80	2/81	6/81	8/81	9/82	6/87	2/90
Pressure, psia	295	277	260	218	272	283	236	NR	1,015	693
Gas Temp, °F	185	189	165	179	160	110	-	NR	300	292
Brine Temp, °F	221	215	201	216	229	197	160	NR	294	271
Mole Percent of:										
Helium	0.01	0.01	0.01	<0.01	<0.01	0.03	<0.01	NA	<0.01	0.01
Hydrogen	0.05	NA[(c)]	NA	NA	NA	NA	0.01	NA	<0.01	0.02
Nitrogen	0.11	0.20	0.27	0.10	0.11	0.44	0.20	0.12	0.28	0.52
Carbon Dioxide	16.70	6.00	7.50	17.18	10.06	25.00	8.13	1.08	8.47	10.40
Methane	81.20	91.50	83.87	78.75	86.94	69.10	89.28	95.61	88.04	84.70
Ethane	1.68	1.80	4.67	2.97	2.29	4.03	1.74	1.95	2.41	2.88
Propane	0.16	0.29	2.19	0.66	0.30	0.76	0.39	0.32	0.52	0.97
Iso-Butane	0.01	0.12	0.38	0.07	0.03	0.10	0.02	0.06	0.08	0.15
N-Butane	0.01	0.08	0.58	0.10	0.02	0.10	0.05	0.11	0.07	0.14
Pentanes	<0.01	<0.01	0.24	0.07	<0.01	0.04	0.01	NR	0.03	0.06
Hexanes +	0.02	<0.01	0.25	0.06	<0.01	0.03	<0.01	NR	0.03	0.06
Benzene	0.03	0.01	0.02	0.07	0.02	0.18	0.10	0.02	0.05	0.07
Toluene	0.01	<0.01	0.02	0.06	0.01	0.18	0.07	0.01	0.01	0.04
C2 Benzenes	<0.01	<0.01	<0.01	0.01	<0.01	0.01	<0.01	<0.01	<0.01	0.02
Heating Value[(b)]	860	970	1,040	892	928	815	NR	NR[(d)]	960	951
Gravity (air = 1)	0.728	0.631	0.698	0.766	0.667	0.838	NR	NR	0.660	0.691

(a) Analyses performed at IGT by mass spectrometry or gas chromatography
(b) Heating value in Btu/SCF, Dry, 14.7 psia, 60°F
(c) NA = Not Analyzed
(d) NR = Not Recorded

3.2.2.1.5 Scaling and Corrosion

The need for scale control was well known to all parties. The end of earlier Phase-2 testing in April 1983 was due to parting of the tubing in the production well. When the tubing was removed from the well, it was found that it was scaled to a thickness of almost ½" thick at the top of the tubing, and scale was continuous to below 12,000'. Scaling had been a serious problem prior to the parting of the tubing.

The production and disposal wells were worked over in 1986 and shut in. After reinstalling the production equipment, the brine well was placed on production in March 1988. A total of 8,579 barrels of brine were produced before a scale inhibitor pill was injected into the producing formation (see Appendix B-2 for details). Some scaling was detected in the low pressure portion of the production system (none in high pressure portion) after 4,950,000 barrels of brine had been produced after the scale inhibitor squeeze. A scale inhibitor was then injected into the surface well stream, as it came out of the well. The well was produced for a total of 7,720,000 barrels of brine after the initial inhibitor squeeze. In November 1989, a second scale inhibitor squeeze was performed. A total of 2,750,000 barrels of brine was produced after the second squeeze before surface inhibition was started again on May 16, 1990. A total of 2,098,753 more barrels of brine have been produced (as of October 31, 1990) (grand total production after the two scale inhibitor squeezes is 12,568,753 barrels).

Coupons were installed at three locations for scale and corrosion monitoring. These were:

1) Between the chokes at a location upstream of the choke at the entrance to the large separator.

2) A short distance downstream of the point where the brine streams from the two separators commingle.

3) Between the brine filter skid and the disposal well.

No significant scaling was observed, but measurable corrosion rates were, and the use of corrosion inhibitors was essential (see Appendix B-2).

The production equipment had been redesigned before reinstallation under this contract. The experience gained at the Gladys McCall site was utilized, some of the new features were:

1) Use of larger piping to maintain flow velocity rates below 15 feet/second, ideally below 10 feet/second.

2) Use of stainless steel sections at critical areas to replace conventional piping.

3) Elimination of as many turns as possible.

These design features plus the use of corrosion chemicals injected into the surface stream have been effective in controlling corrosion rates.

3.2.2.2 Hybrid Power System (HPS)
(See The Ben Holt Co. Final Report (Appendix B-1) and IGT Final Report (Appendix B-2) for more details.)

Geopressured-geothermal resources contain a tremendous amount of energy. These resources can contribute significantly to the national electricity supply once technical and economic obstacles are overcome. From an economic standpoint, the cost of building and operating power plants, along with the cost of wells and the productive life of the reservoirs, are primary concerns. From a technical standpoint, operation of a power plant with the corrosive, highly saline brine and impure wellhead gas presents special problems.

Power plant performance under the harsh conditions of a geopressured resource was unproven, so a demonstration power plant was built and operated on the Pleasant Bayou geopressured resource in Texas. This one megawatt facility provided valuable data over a range of operating conditions. In addition, an extended run at maximum power production demonstrated that power can be produced reliably with no serious operating problems.

This power plant was a first-of-a-kind demonstration of the hybrid cycle concept. A hybrid cycle was used to take advantage of the fact that geopressured resources contain energy in more than one form -- hot water and natural gas. Studies have shown that hybrid cycles can yield thirty percent more power than stand-alone geothermal and fossil fuel power plants operating on the same resource. In the hybrid cycle at Pleasant Bayou, gas was burned in engines to generate electricity directly. Exhaust heat from the engines was then combined with heat from the brine to generate additional electricity in a binary cycle. Heat from the gas engine was available at high temperature, thus improving the efficiency of the binary portion of the hybrid cycle.

The hybrid cycle experiment at Pleasant Bayou was not meant to be an optimized hybrid cycle experiment. Isobutane is not the optimum working fluid for a standard binary cycle on a resource with a temperature as low as that of Pleasant Bayou. For example, propane could be used instead of isobutane to generate more power. However, propane has a higher vapor pressure than isobutane, so it could not be used with the existing equipment available to the project. An optimized cycle would include a pressure reduction turbine to recover the energy from the high pressure brine. An ebullient-cooled engine could also be used to recover the jacket heat from the engines.

A major portion of the equipment used in the hybrid cycle experiment was used in the Direct Contact Heat Exchange Experiment (DCHX) facility at East Mesa, California. This equipment is owned by DOE and was made available for this experiment. The primary goal of this test was to demonstrate the hybrid cycle on a geopressured resource and to gain operating data over an extended time period.

These goals were met by employing used equipment even if design power production was less than optimum.

The turbine, condensers, isobutane circulating pump, and accumulator were used first at the DCHX facility and then at Pleasant Bayou. Modifications to the turbine rotor and the nozzles were made due to the lower inlet pressure and higher isobutane flow at Pleasant Bayou. The four Baltimore Aircoil evaporative condensers showed evidence of substantial corrosion in the tube bundles. Several tubes failed the hydrotest and were subsequently plugged. The isobutane pump required the removal of several stages in order to satisfy the flow and pressure requirements of this test.

New heat exchangers were designed and purchased for this test (see Exhibit 3-30). E-1-N, the brine-to-isobutane heater, is a shell-and-tube exchanger with single tube and shell passes with true countercurrent flow. E-2-N, the brine-to-isobutane boiler, was designed to vaporize 86% of the isobutane. Brine on the tube side makes eight passes through the U-tube bundle. E-3-N, the exhaust gas-to-isobutane boiler, was designed to vaporize the remainder of the isobutane. Exhaust gas entered the exchanger at 1130°F and cooled to 300°F while isobutane vaporized at a constant 210°F. This large temperature difference was a primary design concern. Several different design alternatives were considered before a final design selection was made. A horizontal reboiler type exchanger, with a U-tube bundle with separate inlet and outlet channels, was selected. Both brine exchangers were made of carbon steel; the exhaust gas exchanger was stainless steel.

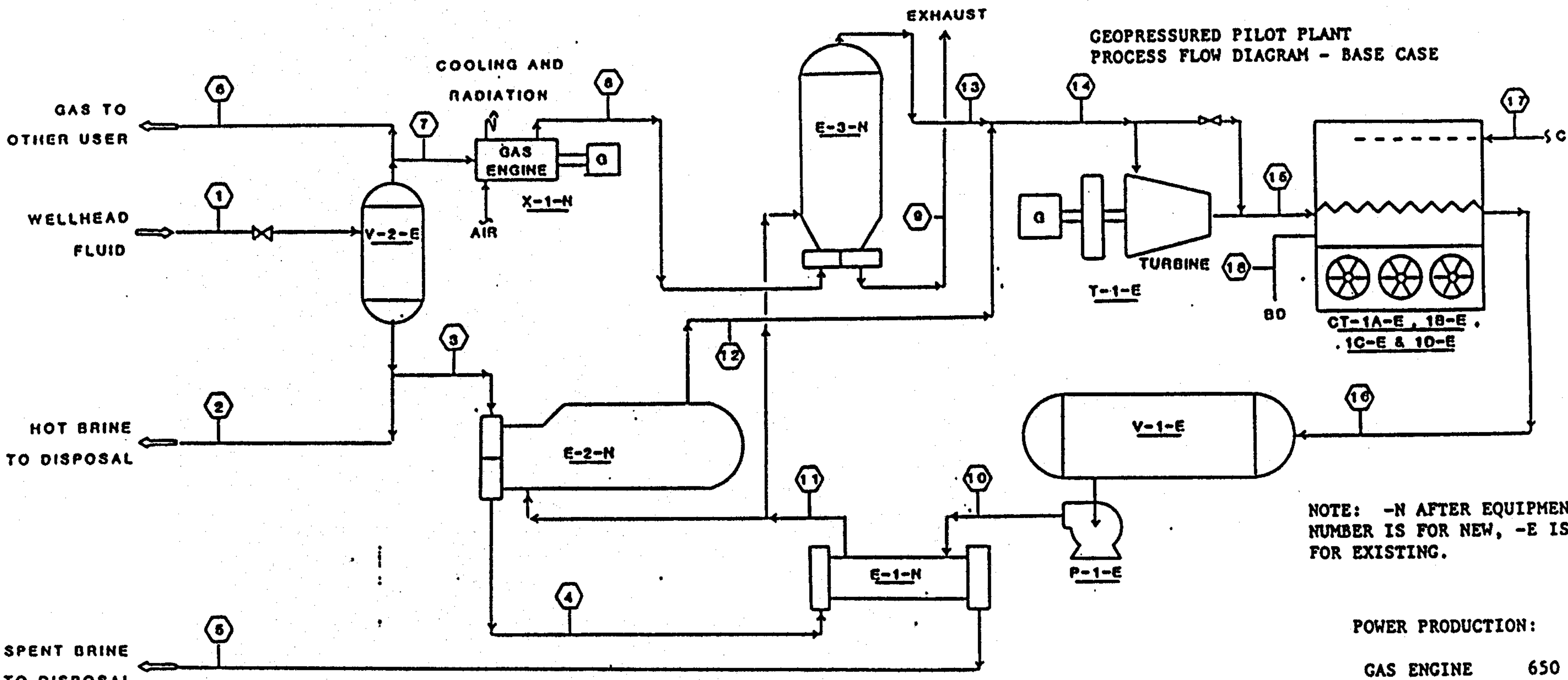
The largest fraction of the hybrid cycle power output was from burning wellhead natural gas in the gas engines. Two Caterpillar 398 engines were used in this project. Their design power production was 650 kW.

Construction began early in 1989. Brine and isobutane circulation began on September 3, 1989. The turbine and gas engines were started for the first time on October 19, 1989. Tests were conducted primarily in November and December of 1989. The well was shut in for maintenance from November 17 through November 24, 1989. From this time until the well was shut in on May 30, 1990, the plant ran at or near design output except for an occasional outage. The plant was shut down a month earlier than scheduled when it became apparent that the injection well required rework.

Tests were conducted that characterized system performance at design isobutane flow, at maximum isobutane flow, and at lower exhaust gas flows. It was determined that maximum power output was achieved at maximum isobutane flow.

The brine inlet to the binary cycle was 18 to 20 Fahrenheit degrees higher than design. This reduced the amount of brine required to heat and vaporize the isobutane from 170,000 to 145,000 lbs/hr. The turbine and gas engines achieved their design power output at design conditions. The actual parasitic load ranged from 260 to 306 kW instead of the design value of 209 kW. The power drawn by the circulating pump was higher than design since the pump output was higher than

SCHEMATIC - HYBRID POWER SYSTEM (HPS)
PLEASANT BAYOU



STREAM NO.	1	2	3	4	5	6	7	8	9
FLUID	BRINE & GAS	BRINE	BRINE	BRINE	BRINE	GAS	GAS	EXHAUST	EXHAUST
FLOW, MLBS/HR	341	170	170	170	170	.47	.47	6.6	6.6
BPD OR (SCFM)	-	10,000	10,000	10,000	10,000	(153)	(153)	-	-
TEMP °F	295	278	278	220	164	278	278	1,130	300
PRESS., PSIA	1,500	595	595	570	528	595	595	16	15
DENSITY, #/CF	-	64.4	64.4	66.5	68.5	1.50	1.50	.024	.054

STREAM NO.	10	11	12	13	14	15	16	17	18
FLUID	ISOBUTANE	ISOBUTANE	ISOBUTANE	ISOBUTANE	ISOBUTANE	ISOBUTANE	ISOBUTANE	CW MAKEUP	BLOW DOWN
FLOW, MLBS/HR	107	107	92	15	107	107	107	30	10
BPD OR (SCFM)	-	-	-	-	-	-	-	-	-
TEMP., °F	96	210	210	210	210	128	94	64	80
PRESS., PSIA	330	300	280	280	280	70	68	30	15
DENSITY, #/CF	34	26.7	3.3	3.3	3.3	.7	33.8	62.4	62.4

POWER PRODUCTION:

GAS ENGINE	650 KW
BINARY CYCLE	541 KW
TOTAL	1,191 KW

PARASITIC LOADS:

CONDENSORS	75 KW
CIRCULATING PUMP	74 KW
MISCELLANEOUS	60 KW
TOTAL	209 KW
NET POWER	982 KW

EXHIBIT 3-30

design. Over the course of the test, 1,443,250 STB of brine and 39,250 MCF of gas flowed through the geopressured hybrid power system.

The gas rates to the HPS were independently measured by IGT and The Ben Holt Company. Brine rates were also independently measured, with the exception that differential pressures were measured across the same orifice plate. Reporting of measured values by The Ben Holt Company began with the first generation of electricity from the turbine driven by iso-butane on October 27, 1989. Cumulative measured values from this date until the completion of electricity generation by the HPS on May 29, 1990, are shown in Exhibit 3-31.

Exhibit 3-31
CUMULATIVE VOLUMES AND ENERGY FOR THE HPS

	Measured By	
	IGT	BHC
Gas, 10^6 SCF	40.4	39.25
Brine, 10^6 STB	1.301	1.443
Gas Energy, 10^9 Btu	37.9	
Actual Thermal Energy, 10^9 Btu	67.8	
Theoretical Thermal Energy, 10^9 Btu	109.9	
Electricity to Market, 10^6 kW-h		3.42
Electricity to Market, 10^9 Btu		11.66

It is not appropriate to use the data tabulated in Exhibit 3-31 to calculate the value of 11% as the overall energy conversion efficiency of the Hybrid Power System. One reason is that a substantial fraction of the thermal energy was taken with the iso-butane bypassing the tubine, so that all of the thermal energy went out of the cooling towers. The iso-butane turbine generator operated about 60% of the total time available for electricity generation. However, during April and May 1990, the iso-butane turbine generator was operating over 85% of the time. A second reason is that the portion of the generated electricity used to drive parasitic loads was higher than would be expected for a commercial power plant.

The design power production was 650 kW from the gas engines and 541 kW from the binary cycle turbine, for a total of 1,191 kW. Design parasitic loads consisted of 75 kW for the pumps and fans on the condenser, 74 kW for the iso-butane circulating pump, and 60 kW for miscellaneous loads -- for a total of 209 kW. Thus, design net power generation was 982 kW. The portion of parasitic load that was higher than would be expected for a commerical power plant was a portion of the miscellaneous load. That load included the utility cooler, lube oil pumps, air conditioning, pressurizing air for the trailers, instrument air, control power, and lighting.

Heat transfer performance of both of the brine exchangers was better than design. No trend towards increased fouling was apparent over the course of the extended test run. These heat exchangers were inspected at the conclusion of the test. Very little scale was apparent on the heat exchanger tubes contacting brine. However, fouling in the exhaust gas exchanger was significant. Carbon deposits from the gas engine exhaust caused fouling of the heat exchange surface, thus degrading performance. Fouling increased uniformly while the engines were running. Each time flow through this exchanger was shut down and restarted, soot blew out of the exchanger and heat transfer improved dramatically.

The turbine operated for 2902 hours at Pleasant Bayou. Some problems with high vibration occurred early in the test. After these problems were solved in March, the turbine ran without any turbine-related outages until the test was completed. Turbine efficiency was approximately 70%, and output ranged from 580 kW to 470 kW.

Turbine output varies with wet bulb temperature. At higher wet bulb temperature, the turbine back pressure is higher, and less power is produced. The design power output of 541 kW was produced at the design turbine back pressure of 70 psi. However, at the design wet bulb temperature of 64°F, the turbine output was approximately 20 kW lower than design due to high back pressure. One cause of this was reduced capacity in the condenser due to tubes being plugged. Additionally, the accumulator pressure was higher than design, since the vapor pressure of the isobutane used at Pleasant Bayou had a higher vapor pressure than isobutane with the design composition. Noncondensables, such as air in the lines, may also have contributed to higher turbine back pressure.

Both gas engines operated consistently and reliably. GE-1-N ran 4585 hours, and GE-2-N ran 4832 hours. Few operational difficulties, associated with operating with impure wellhead gas, were experienced.

The hybrid power system demonstration at Pleasant Bayou was successful in all respects. Design power output was achieved, and 3,445 MWh of power were sold to the local utility over the course of the test. Plant availability was 97.5%, and the capacity factor was over 80% for the extended run at maximum power production.

Furthermore, several concerns about operating a commercial power plant on the Pleasant Bayou resource were favorably resolved. Scale and corrosion inhibitors were shown to be effective throughout the operating range of brine temperatures. Heat exchanger fouling, due to scale deposition from the high salinity brine, was not a problem. Although uninhibited brine is highly corrosive, inhibitors reduced corrosion to such low levels that carbon steel can be used for brine piping and heat exchangers. By using carbon steel as the primary material of construction, the cost of the power plant can be kept in line with other binary cycle power plants which are commercially competitive. (Refer to The Ben Holt Co. (Appendix B-1) and IGT (Appendix B-2) Final Reports for more details.)

The only significant problem encountered during the test was excessive fouling in the exhaust gas exchanger. However, this is a relatively minor problem which can probably be solved at low cost.

Successful operation of the hybrid cycle power plant demonstrated that there are no technical obstacles to electricity generation at Pleasant Bayou. In addition, a power plant can be built and operated with no economic obstacles when compared to commercial facilities at other geothermal resources.

The U.S. Department of Energy (DOE) and Electric Power Research Institute (EPRI) co-funded this hybrid cycle demonstration power plant on a geopressured resource. The Ben Holt Co., under contract to EPRI, designed the facility and procured new and refurbished equipment. Construction and operation were under a separate contract funded by DOE. For this work, Holt teamed with Eaton Operating Company, Inc., the prime contractor (Houston, Texas), as the subcontractor for the Hybrid Power System, and with the Institute of Gas Technology (Chicago, Illinois), the subcontractor for operation and data collection for the production system.

3.3 Willis Hulin Site (Vermilion Parish, LA)
(See IGT Final Report (Appendix C) for details.)

3.3.1 Test Results

The Willis Hulin well is the deepest, hottest, and highest-pressured well to be tested in the DOE's Geopressured-Geothermal Program. The interval of interest for testing in the Hulin well is the massive aquifer sand between 20,100 and 20,700 feet. This geologic section is comprised mostly of layers of brine-saturated clean sand, but with occasional intervening layers or lenses of shale. The objective of the test was to determine the characteristics of the brine and gas in this interval and make an initial determination of the reservoir properties.

The lowermost twenty feet, of the lowest sand member, in the interval of interest (20,670 to 20,690 feet) was perforated first, and given a clean-up flow in February 1989. Instrumented short-term draw-down and buildup tests using rental equipment were delayed because of budget constraints until December 1989 and January 1990.

The first instrumented test was a 1-day flow test to obtain brine and gas samples and to obtain a first indication of the reservoir properties. A bottom hole pressure gauge was in the hole for 5 days to record both the pressure draw-down and following buildup. The remaining part of the lowest sand member (20,622 to 20,666 feet) was then perforated, and the entire 80 foot interval was tested with a 4 day flow and 12 day buildup test. The bottom hole pressure was also recorded for this test. The static bottom hole pressure (at 20,600 feet) was 17,308 psia prior to the 1 day flow test and 17,283 psi prior to the 4 day flow test. The bottom hole temperature was 339°F, and the initial wellhead pressure was 7,460 psi. The produced brine had a total dissolved solids content (mostly sodium chloride) of 207,000 mg/l and was at or near saturation with gas at 31-32 SCF/STB. The gas was leaner in the heavy hydrocarbons than the gas from other geopressured-geothermal wells, and was about one-sixth carbon dioxide. No free gas was detected in the reservoir. The amounts, if any, of produced condensate or oil was small compared to the amount of diesel pumped into the wellhead to prevent hydrates after shut-ins.

Analysis of bottom hole pressure data for the lowermost sand member by S-Cubed gave a transmissivity of about 1,050 md-ft (millidarcy-feet). From this, a permeability of 13 md was calculated for the reservoir. The lateral extent of the reservoir was not determined, although the analysis of the data indicated a fault at a distance of 100 to 200 feet from the well. A skin factor of 15 was found with the entire 80 foot interval perforated. That indicated low flow efficiency for the perforations. The decreasing initial static bottom hole pressure prior to each test suggests that this sand member is not large.

In January 1990, the uppermost sand member in the zone of interest (20,220 to 20,260 feet) was perforated and tested in a 7 day flow test during which the brine produced from this interval was commingled with that from the lower sand. No free gas was found. The brine and gas compositions of the commingled flow changed slightly compared to the lower zone alone, which indicated that the brine in the upper zone was also saturated with gas but isolated from the lower zone. Bottom hole pressures were not measured, and the reservoir characteristics of the upper zone were not determined. But, substantially lower drawdown for the commingled zones suggests either higher permeability or lower skin for the shallower perforated interval.

Although production of free gas from the reservoir was not observed for either the upper or the lower sand members, this does not preclude the possibility of free gas production after additional flow.

Hydrate formation in the wellhead and near surface tubing was a problem. To circumvent this problem, about 10 barrels of diesel were pumped into the well after each flow period to displace the brine in the wellbore down to a point where the temperature was sufficient to prevent hydrate formation. Calcium carbonate scale formation in the brine lines was a potential problem, but was avoided by conducting the flow tests only in pressure and flow rate ranges where scale would not form in the well. The surface equipment was protected from scaling by injecting scale inhibitor into the surface flow lines.

Total production for the December 1989 through January 1990 testing of the well was 16,805 barrels of brine and 536,700 SCF of gas.

4.0 ENVIRONMENTAL, SAFETY & HEALTH (E.S.& H.) AND QUALITY ASSURANCE/QUALITY CONTROL (QA/QC)

4.1 General

All phases of activities undertaken at each of the research sites were conducted in accordance with, or beyond, the requirements of the Occupational Safety and Health Act's (OSHA) Safety and Health Standards, OSHA (1983), and in accordance with Eaton's QA/QC, Environmental, and Safety Manuals, which were developed for this program and approved by DOE. These are updated as new requirements and self-assessments indicate.

EXAMPLES OF
EATON ENVIRONMENTAL SAFETY AND HEALTH PLANS AND REPORTS
GENERAL

1. Pollution Control and Removal - DOE Field Sites (November 15, 1985)
2. Blowout Prevention Equipment and Procedures (November 15, 1985)
3. Eaton Operating Company Safety Manual (1985) (with revisions through 1991)
4. Quality Assurance/Control Plan (1985) (Revision III - December 4, 1986)
5. Yearly Management and Operations Plans
6. Implementing Directives for DOE Orders and Procedures (Yearly)
7. Summary of Ground/Surface Water Sampling Conducted at Willis Hulin, Gladys McCall, and Pleasant Bayou Sites, January 30 and 31, 1991 (April 17, 1991)

GLADYS McCALL SITE PLANS

1. Operational Readiness Plan (October 10, 1985)
2. Gladys McCall Operations Manual (November 15, 1985)
3. Gladys McCall Surface Equipment Maintenance Procedure (November 15, 1985)
4. Composite Research Test Program Recommendations Gladys McCall Site (February 12, 1987)
5. Final Report on Disposal of Hazardous Materials from the Gladys McCall Site (July 23, 1990)

PLEASANT BAYOU SITE PLANS

1. (Revised) Test Program Recommendations Pleasant Bayou Site (March 5, 1987)
2. Environmental Audit (Dr. Jack Matson) (April 20, 1988)
3. Safety Analysis Report (SAR) (1989) (Revision II - September 29, 1989)
4. Pleasant Bayou Data Book (May 1990)
   a. Process Description
   b. Design Data
   c. Drawings
   d. Operating Procedures
   e. Civil, Foundations, Steel Work
   f. Equipment
   g. Instrumentation
   h. Piping

i. Electrical
j. Trailers
k. Painting
l. Computers
m. Safety Analysis Review

WILLIS HULIN SITE PLANS

1. Test Program Recommendation (March 5, 1987)
2. Short Term Flow Test - Safety Analysis Report (SAR) (November 1989) (Revision I - December 1, 1989).

4.2 Compliance

Maintaining compliance with all applicable federal and/or state regulations is one of Eaton's top priorities throughout this program. This effort included securing and working within the parameters of all required regulatory permitting, and permit reporting requirements and conducting periodic self-assessments using Eaton personnel and consultants.

To assist Eaton in maintaining compliance and conducting self-assessments, Eaton utilized Lamar University's Fire and Safety Institute as a QA/QC and Safety subcontractor, Jack V. Matson, Ph.D., P.E. for environmental matters, and the International Technology Corporation for construction and operating permits. This effort parallels Eaton's ongoing compliance with each new E.S.& H. or QA/QC procedure Eaton is directed by DOE-ID to develop and employ.

4.3 QA/QC, Environmental, and Safety Officers

Eaton's QA/QC, Environmental, and Safety Officer, C.R. Featherston, and Field QA/QC, Environmental, and Safety Officer, Tom Meahl, shared the responsibility of identifying and implementing practices and/or procedures needed to maintain a safe facility. They were assisted by D. B. Graham, Assistant QA/QC, Environmental, and Safety Officer, in maintaining proper records and documents for all of these areas.

4.4 QA/QC, Environmental, and Safety Manuals

Eaton's and Eaton's subcontractors, IGT, BHC, and Lamar, activities are governed by the guidelines and procedures contained in Eaton's DOE-ID approved QA/QC, Environmental, and Safety Manuals.

All third party organizations entering a research facility are responsible for the health and safety of their own personnel, and for conducting their activities in a manner deemed consistent with Eaton's Manuals.

4.5 Safety Analysis Report (SAR)

As each site is being constructed, Eaton and its subcontractors, IGT and BHC, compile the documents necessary to develop a Safety Analysis Report (SAR). In part, these documents consist of construction and operating permits, code certificates, i.e., ASME, for all coded pressure vessels, mill certifications for process piping, investigative x-raying to confirm the integrity of, and establishing a baseline for, all critical welds, collecting baseline data on process/flow piping by conducting ultrasonic testing (U.T.), risk assessment, operating procedures, etc.

Once all such documentation has been collected and confirmed, a completed Safety Analysis Report (SAR) is submitted to DOE-ID for review and approval.

Eaton will not begin operation at any of the DOE sites without first obtaining a DOE-ID approved SAR.

4.6 Ground/Surface Water Sampling

Quarterly ground and surface water samplings and analyses are being conducted at all three DOE sites. The methods for analysis of water samples were specified by the DOE-ID ES&H representative, and are tabulated in Exhibit 4-1. The locations for sampling were similarly specified, and had been sampled by prior contractors. (Reference site maps and individual sampling site data, Exhibits 4-2 through 4-7). All samples are then analyzed by a lab which is an active participant in the EPA's Contract Laboratory Program. These results are then reviewed by Dr. Jack V. Matson to provide two points of information. The first is to compare our results against the U.S. Interim Primary Drinking Water Standards, a higher standard than is required for our operations. This provides the most rigid review possible and alerts us to any area that may need further review, or remedial action, long before it can become an actual problem.

The second point is a comparison of the newest results against prior results which would also alert Eaton to any undesired trends.

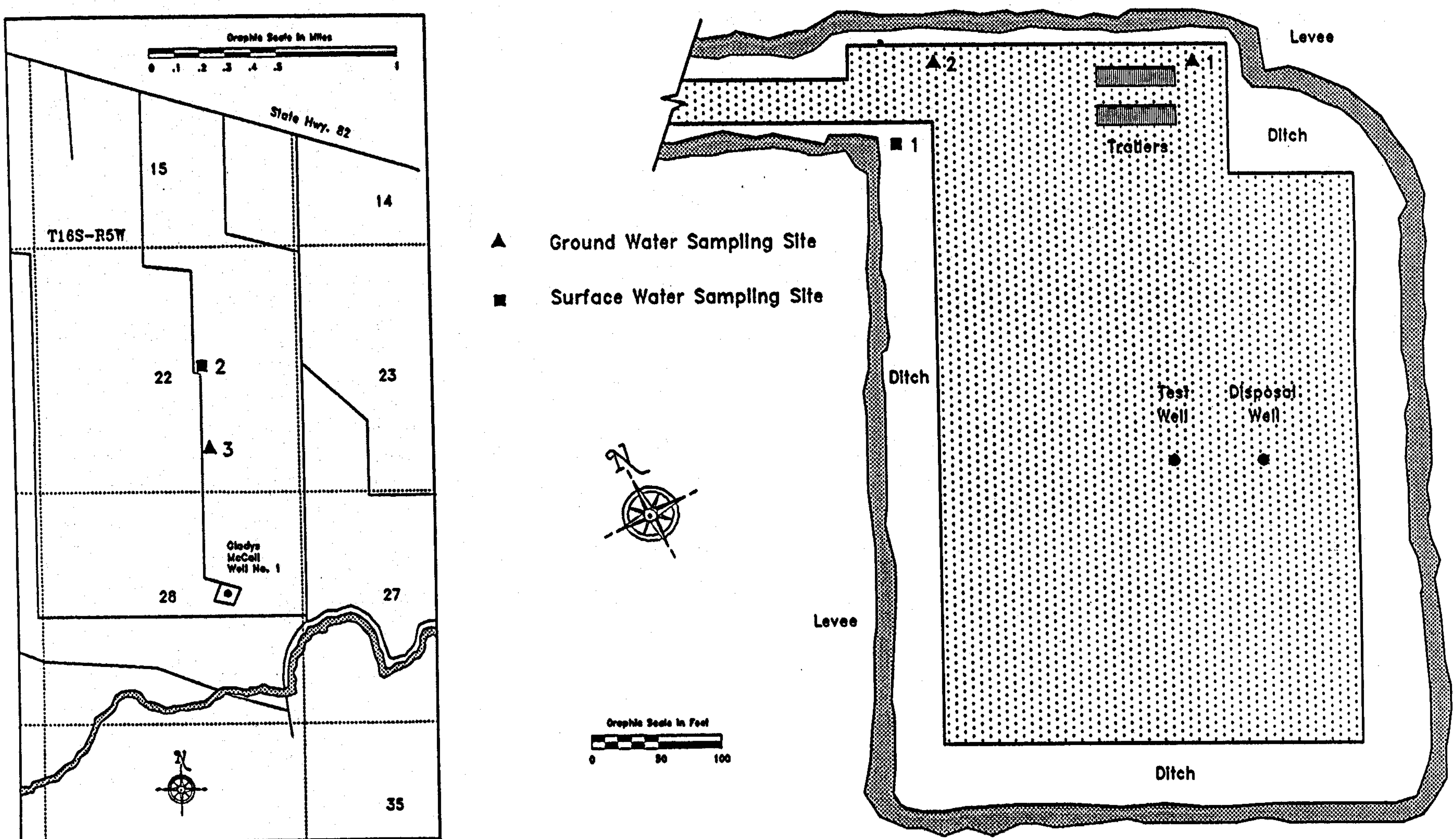
For all samples collected to date, Dr. Matson's independent reviews include written reports which state that "the water samples from the sites were very clean".

The following water samplings were conducted by EOC and IGT, and the types of analyses performed are detailed below.

TYPES OF ANALYSES AND ANALYTICAL METHODS
USED FOR GROUND/SURFACE WATER SAMPLES
COLLECTED FROM ALL THREE DOE SITES

METALS	METHOD
Arsenic	3010/7060 GFAA
Barium	3010/6010 ICP
Boron	3010/6010 ICP
Cadmium	3010/6010 ICP
Calcium	3010/6010 ICP
Chromium	3010/6010 ICP
Copper	3010/6010 ICP
Iron	3010/6010 ICP
Lead	3010/7421 GFAA
Magnesium	3010/6010 ICP
Manganese	3010/6010 ICP
Mercury	7471/7471 CVAA
Selenium	3010/7740 GFAA
Silver	3010/7060 ICP
Zinc	3010/6010 ICP
ANIONS	**METHOD**
Sulfate	9035, 9036, 9038
Phosphate	
Nitrate (as N)	9200
Ammonia	
Chloride	9250, 9251, 9252
Fluoride	Standard Methods 340.3
ORGANIC COMPOUNDS	**METHOD**
Volatiles	8240, including tentatively identified compounds and trihalo-methanes; or proposed 8260 (if promulgated)
Semivolatiles	8270
Endrin, Lindane	8080
Methoxychlor	8080
Toxaphene	8080
2,4-D and 2,4,5-TP Silvex	8150
COLIFORM BACTERIA	9132

E[illegible]C/DOE
Gladys McCall, Well No. 1
Cameron Parish, Louisiana



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EATON

Well Location Map

EXHIBIT 4-2

117

GROUND/SURFACE WATER SAMPLING - GLADYS McCALL WELLSITE

GMGW NO. 1

LOCATION:	Crew well at wellsite
DEPTH:	185′
CASING DESIGN:	Approximately 20 of 4″ Steel casing on top, followed by PVC casing to the screen
SCREEN DEPTH:	175′ to 185′
PRODUCTION:	Groundwater sample via submersible pump set on 1″ tubing set at approximately 90′
PRODUCTION RATE:	Approximately 55 GPM

GMGW NO. 2

LOCATION:	At wellsite
DEPTH:	660′
CASING DESIGN:	2″ PVC casing to the screen
SCREEN DEPTH:	650′ to 660′ (screen likely but presence unconfirmed)
PRODUCTION:	Groundwater sample via surface pump with 3/4″ tubing at approximately 90′
PRODUCTION RATE:	Approximately 30 GPM

GMGW NO. 3

LOCATION:	Approximately 1/2 mile north of wellsite on access road
DEPTH:	310′
CASING DESIGN:	2″ PVC casing to the screen (originally completed with 1″ PVC tubing from screen to surface - 1″ PVC tubing was pulled with bottom joint, approximately 20′ being left in the well - access to screen likely obstructed)
SCREEN DEPTH:	300′ - 310′
PRODUCTION:	Groundwater sample drawn by 2″ pump or bailing 90′
PRODUCTION RATE:	Approximately 5 - 10 GPM

GMSW NO. 1

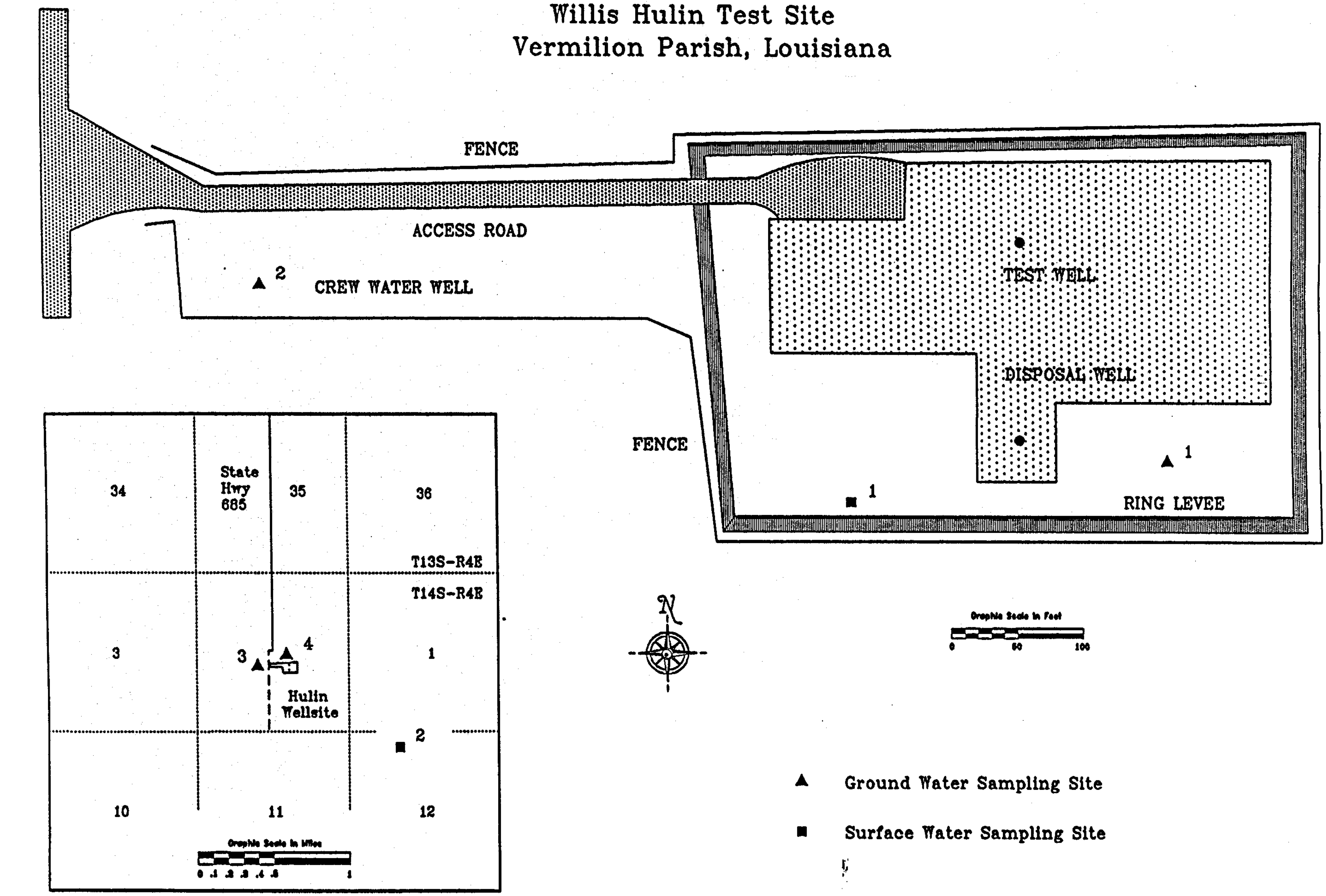
LOCATION:	At wellsite
DEPTH:	Surface sample
PRODUCTION:	Sample obtained by grab method

GMSW NO. 2

LOCATION:	Approximately 3/4 mile north of wellsite, on access road
DEPTH:	Surface sample
PRODUCTION:	Sample obtained by grab method

EXHIBIT 4-3

EOC/DOE
Willis Hulin Test Site
Vermilion Parish, Louisiana



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Well Location Map

EXHIBIT 4-4

GROUND/SURFACE WATER SAMPLING - WILLIS HULIN WELLSITE

HUGW NO. 1

LOCATION:	At wellsite
DEPTH:	358′
CASING DESIGN:	4″ PVC casing to 120′, then 2″ PVC tubing to the screen
SCREEN DEPTH:	338′ to 358′
PRODUCTION:	Groundwater sample via submersible pump set on 1″ tubing at approximately 90′
PRODUCTION RATE:	Approximately 35 GPM

HUGW NO. 2

LOCATION:	Crew well at wellsite
DEPTH:	285′
CASING DESIGN:	4″ PVC casing to the screen
SCREEN DEPTH:	260′ to 275′
PRODUCTION:	Groundwater sample via submersible pump set on 1″ tubing at approximately 90′
PRODUCTION RATE:	Approximately 38 GPM

HUGW NO. 3

LOCATION:	Approximately 300′ WNW of wellsite access road
DEPTH:	250′ to 300′ (well not registered - depth based on water quality)
CASING DESIGN:	Unknown - 2″ Steel casing at surface
SCREEN DEPTH:	Estimated between 250′ - 300′
PRODUCTION:	Groundwater sample via submersible pump set on 1″ tubing at to approximately 90′
PRODUCTION RATE:	Approximately 20 GPM

HUGW NO. 4

LOCATION:	Approximately 700′ NE of HUGW NO. 3
DEPTH:	250′ to 300′ (well not registered - depth based on water quality)
CASING DESIGN:	Unknown - 2″ Steel casing at surface
SCREEN DEPTH:	Estimated between 250′ - 300′
PRODUCTION:	Groundwater sample via surface pump with 1″ tubing at approximately 90′
PRODUCTION RATE:	Approximately 20 GPM

WILLIS HULIN WATER SAMPLING - CONTINUED

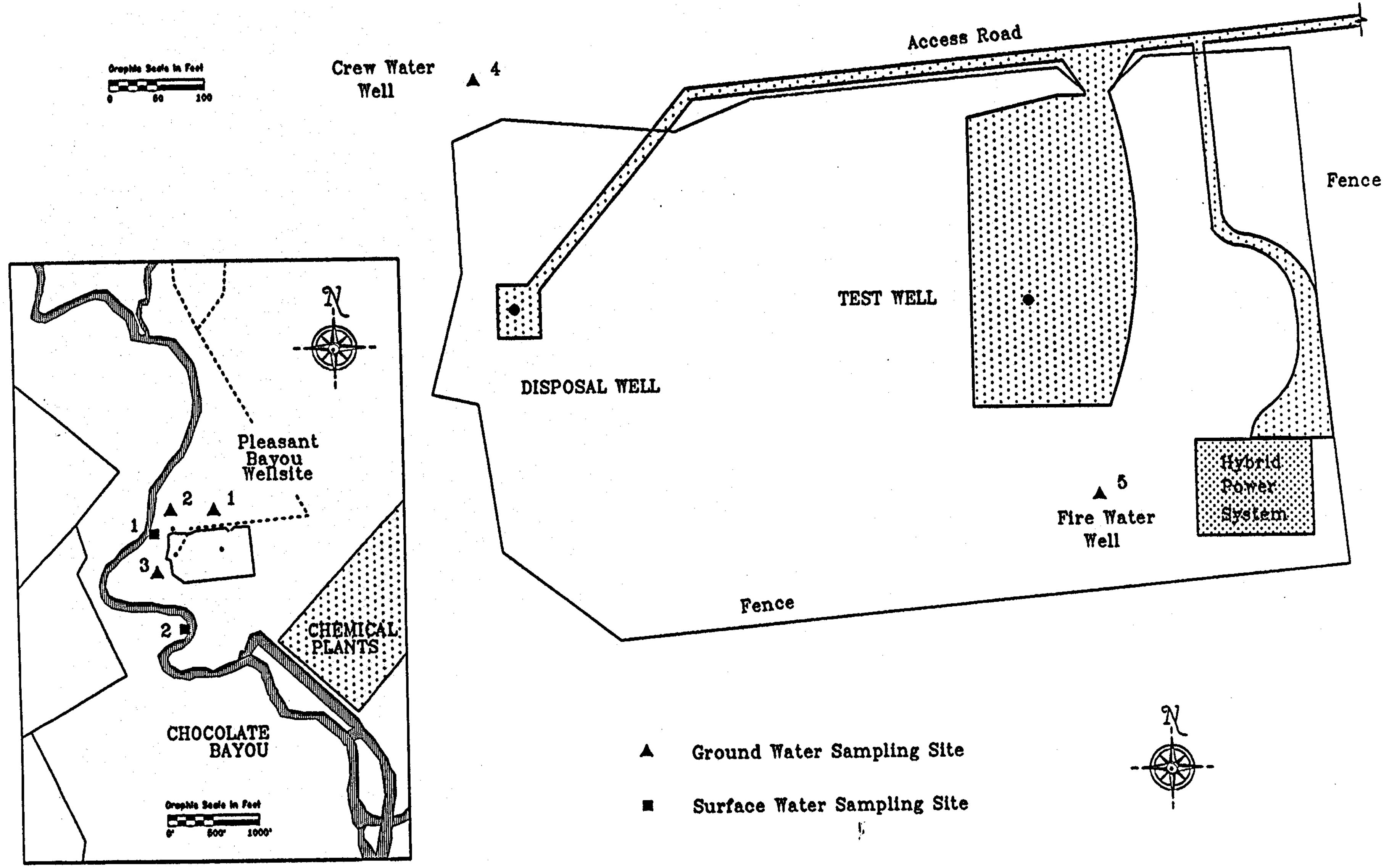
HUSW NO. 1

LOCATION:	At wellsite (obtained from ring levee ditch)
DEPTH:	Surface water sample
PRODUCTION:	Sample obtained by grab method

HUSW NO. 2

LOCATION:	Approximately 3/4 mile SE of wellsite
DEPTH:	Surface water sample
PRODUCTION:	Sample obtained by grab method

EOC/DOE
Pleasant Bayou Test Site
Brazoria County, Texas



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EATON

Well Location Map

EXHIBIT 4-6

GROUND/SURFACE WATER SAMPLING - PLEASANT BAYOU WELLSITE

(Well histories for wells no. 1, 2 & 3 obtained by the Louisiana Geological Survey from the Texas Department of Water Resources)

PBGW NO. 1

LOCATION:	At wellsite, NE corner
DEPTH:	47′
CASING DESIGN:	4″ PVC casing to the screen
SCREEN DEPTH:	37′ to 47′
PRODUCTION:	Groundwater sample via surface pump or by jetting through 1″ tubing at approximately 20′
PRODUCTION RATE:	Approximately 20 GPM

PBGW NO. 2

LOCATION:	At wellsite, NW corner
DEPTH:	37′
CASING DESIGN:	4″ PVC casing to the screen
SCREEN DEPTH:	27′ to 37′
PRODUCTION:	Groundwater sample via surface pump or by jetting through 1″ tubing at approximately 20′
PRODUCTION RATE:	Approximately 20 GPM

PBGW NO. 3

LOCATION:	At wellsite, SW corner
DEPTH:	38′
CASING DESIGN:	4″ PVC casing to the screen
SCREEN DEPTH:	28′ - 38′
PRODUCTION:	Groundwater sample via surface pump or by jetting through 1″ tubing at approximately 20′
PRODUCTION RATE:	Approximately 20 GPM

PBGW NO. 4

LOCATION:	Crew well at wellsite
DEPTH:	108′
CASING DESIGN:	4″ PVC casing to the screen
SCREEN DEPTH:	98′ to 108′
PRODUCTION:	Groundwater sample via surface pump set on 1-1/4″ tubing at approximately 63′
PRODUCTION RATE:	Approximately 35 GPM

EXHIBIT 4-7

PBGW NO. 5

LOCATION:	Hybrid Power System (HPS) firewater well at wellsite
DEPTH:	160′
CASING DESIGN:	5″ PVC casing to the screen
SCREEN DEPTH:	140′ to 160′
PRODUCTION:	Groundwater sample via submersible pump set on 2-1/2″ tubing at approximately 105′
PRODUCTION RATE:	Approximately 70 GPM

PBSW NO. 1

LOCATION:	Chocolate Bayou - approximately 500′ NE of PBGW NO. 4
DEPTH:	Surface water sample
PRODUCTION:	Sample obtained by grab method

PBSW NO. 2

LOCATION:	Chocolate Bayou - Approximately 1 mile downstream from PBSW NO. 1, at the HL&P crossing of Chocolate Bayou
DEPTH:	Surface water sample
PRODUCTION:	Sample obtained by grab method

EXHIBIT 4-7

TYPES OF ANALYSES AND ANALYTICAL METHODS
USED FOR GROUND/SURFACE WATER SAMPLES
COLLECTED FROM ALL THREE DOE SITES

METALS	METHOD
Arsenic	3010/7060 GFAA
Barium	3010/6010 ICP
Boron	3010/6010 ICP
Cadmium	3010/6010 ICP
Calcium	3010/6010 ICP
Chromium	3010/6010 ICP
Copper	3010/6010 ICP
Iron	3010/6010 ICP
Lead	3010/7421 GFAA
Magnesium	3010/6010 ICP
Manganese	3010/6010 ICP
Mercury	7471/7471 CVAA
Selenium	3010/7740 GFAA
Silver	3010/7060 ICP
Zinc	3010/6010 ICP

ANIONS	METHOD
Sulfate	9035, 9036, 9038
Phosphate	
Nitrate (as N)	9200
Ammonia	
Chloride	9250, 9251, 9252
Fluoride	Standard Methods 340.3

ORGANIC COMPOUNDS	METHOD
Volatiles	8240, including tentatively identified compounds and trihalomethanes; or proposed 8260 (if promulgated)
Semivolatiles	8270
Endrin, Lindane	8080
Methoxychlor	8080
Toxaphene	8080
2,4-D and 2,4,5-TP Silvex	8150
COLIFORM BACTERIA	9132

July 29, 1989	Samples from Pleasant Bayou only were analyzed for some Inorganics, Volatiles, Acid and Base/Neutrals, and Pesticides/ PCB's.
October 25-27, 1989	Samples from all three locations were analyzed for Inorganics, Volatiles, Acid and Base/Neutrals, and Pesticdes/PCB's.
January 30 - February 1, 1990	Samples from all three locations were analyzed for Inorganics only.
July 12-13, 1990	Same as January 30 - February 1, 1990.
October 10-12, 1990	Same as January 30 - February 1, 1990.

4.7 Lamar University's Fire & Safety Institute

Lamar's Fire & Safety Institute, serving as a prime subcontractor to Eaton, provides QA/QC, environmental, safety and health services which deal with:

4.7.1 Reviewing EOC's QA/QC, Environmental, and Safety Manuals to update, revise, and supplement, on an as needed basis to assure they are current.

4.7.2 Employee training
a. Fire protection training
b. Industrial hygiene
c. Industrial safety
d. Drilling safety
e. Emergency planning
f. Industrial medicine

4.7.3 Quarterly site QA/QC, Environmental, and Safety inspection audits utilizing standards that meet or exceed the Occupational Safety and Health Administration (OSHA) and Department of Energy (DOE) requirements.

4.7.4 Conducting safety/quality assurance/quality control audits prior to start-up of any site's operation or drilling activity.

5.0 SIGNIFICANT FINDINGS AND CONCLUSIONS

5.1 General and Miscellaneous

Overall, the Test Program has been an unqualified success. Significant improvements in production equipment design have been made, such as:

1) Use of larger piping to reduce flow velocities to 10 feet/second or less, to minimize erosion/corrosion by the fluids.

2) Use of stainless steel piping in critical areas of turbulent flow to minimize erosion/corrosion.

3) Better design and utilization of data control sensors and equipment for data collection.

Scaling and corrosion, very serious problems in earlier experiments, have been brought under chemical control by injection of scale inhibitors into the producing formations and by the use of surface treatment with scale and corrosion inhibitors.

For the first time, a hybrid electrical power plant has been successfully installed and operated, utilizing the geothermal energy resources of heat and gas.

The problems of high volume salt water disposal, well workover (sand removal), and operations have been successfully overcome.

Changes in elastomers and lubricants have increased the life, and significantly reduced maintenance time and costs, of valves and wellhead seals.

Changes made in the seals for the wellhead chokes have resulted in a dramatic reduction in maintenance requirements and costs.

Eaton completed the major yearly tasks of the program, in spite of underfunding of requirements, and maintained strict financial controls to finish the job under yearly budgets.

Eaton successfully planned and executed much more stringent Environmental Safety and Quality Control Programs than had ever existed in the prior programs.

In spite of complicated workover and production operations, involving rigs, cranes, etc. an excellent safety record was maintained (no lost time accidents).

Eaton successfully executed the assigned task of collecting and analyzing ground/surface water samples on a quarterly basis from each site, establishing a bench mark, as well as confirming that the quality of these waters had not been compromised.

5.2 Gladys McCall Site (Cameron Parish, LA) (Significant Findings and Conclusions) (See IGT Final Report (Appendix A) for more details.)

The Gladys McCall well was a successful test as part of the DOE Geopressured-Geothermal Energy Program. The well produced geopressured brine containing dissolved natural gas from the Lower Miocene sands at a depth of 15,150 to 16,650 feet. More than 25 million STB barrels of brine were produced in a series of flow tests between December 1982 and October 1987 at various flow rates up to more than 35,000 barrels per day. The well is now (1990) in a multi-year, long-term, pressure buildup test. Initial short-term flow tests for the Number 9 Sand found the permeability to be 67 to 85 md for a brine volume of 85 to 170 million barrels. Initial short-term flow tests for the Number 8 Sand found a permeability of 113 to 132 md for a reservoir volume of 430 to 550 million barrels of brine. The long-term flow and buildup test of the Number 8 Sand found that the volume of the reservoir, as measured by the short-term flow test, was connected to a much larger, low permeability reservoir. Numerical simulation of the tests required this large, connected reservoir, to have a volume of about 8 billion barrels (two cubic miles of reservoir rock) with an effective permeability in the range of 0.2 to 20 md. Detailed chemical analysis of the brine and gas found the brine to be slightly undersaturated with gas at about 29 SCF/STB. The produced gas/brine ratio was invariant with production time and flow rate. Calcium carbonate scale formation in the well tubing and separator equipment was a problem at first, but was later controlled by the injection of a scale inhibitor into the flow line and by successfully injecting phosphonate inhibitor "pills" (two times) directly into the reservoir formation. The disposal well, which had "sanded up", was successfully cleaned out and restored to operation. Corrosion and/or erosion of piping and equipment was also significant, but was corrected by use of larger diameter sections of piping and stainless steel sections. This experience was applied to the redesign of the Pleasant Bayou production facilities.

5.3 Pleasant Bayou Site (Brazoria County, TX) (Significant Findings and Conclusions) This report is a final report in the context of reaching the final calendar date covered by a specific contract. It is not a final report in the context of completion of testing of the Pleasant Bayou well and evaluation of the reservoir. On the other hand, over two years of production are covered by this report. During that time, 12.58 million STB of brine and 301.3 million SCF of gas were produced. The portion of the gas removed from the brine by the separators was 244.5 million SCF, or 81% of the gas produced. The rest of the gas remained in solution in brine leaving the separators, and most of it was injected into the disposal well with the brine.

The volume produced, starting in 1988, is almost three times as great as the total production of 4.53 STB of brine for all of the prior tests since the well was completed in 1979. The greatest prior amount of brine production between unanticipated major problems was 3.49 million STB.

5.3.1 <u>Production Operations</u> (See IGT Final Report (Appendix 2) for more details.)

Eaton assumed custody of the production well, which had experienced many months of fishing and had been temporarily abandoned for over three years. The well was successfully cleaned out and restored to production.

The disposal well, which had sanded up, was successfully cleaned out, and high volume disposal was maintained for a year of production.

A surface production facility, utilizing old equipment which had been out of service for several years, was successfully assembled, installed and operated.

The redesign of the existing Pleasant Bayou production facilities, prior to the start of the present long-term flow test, resulted in a significantly improved system. Problems to be overcome were corrosion and scaling, as at the Gladys McCall well, and sand production at rates higher than 24,000 BPD. With the redesign, maintenance of piping, instruments and equipment is significantly less than it was for the Gladys McCall well.

These observations clearly support the conclusion that solutions have been found to the major problems that terminated prior production testing. These solutions include --

- Use of MP35N nickel alloy wireline to avoid corrosion and failure of the wireline.
- No flowing at brine rates high enough for production of slugs of sand (i.e., <24,000 BPD).
- Not flowing at brine rates high enough to cause problems with a wireline in the hole (i.e., <10,000 BPD).
- Injection of inhibitor pills to prevent scaling in the production wellbore.
- Maintaining total scale inhibitor concentrations low enough to prevent precipitation of "pseudoscale".
- Sizing piping such that brine flow velocity is less than 10 feet per second.
- Lining piping in turbulent areas with stainless steel to prevent corrosion.
- Routing gas piping, and equipping the gas piping with liquid knockouts, such that condensed liquids do not collect at the separator level-control valve or orifice meter locations.
- Using an external displacer chamber that is connected to the separator vessel with a "bridle" having taps above and below the desired fluid level,

with controllers having reset capability, to provide much more stable separator operation than that achieved with an internal displacer during operations by prior operators.

In addition, several operating procedures have been developed that minimize cost of operation. These include --

- Using tarpaulin enclosures to retain the heat from the high temperature brine in winter. (This provides an effective means of avoiding freezing of instrumentation, such as level controllers, pressure transmitters, differential-pressure transmitters, and pressure-control valves, when ambient temperature is as low as 20°F.)

- Using pressure drop across filters as an indicator of production of slugs of sand.

- Using a computer data system that provides real-time calculation of rates and provides an early signal of departures from normal operating conditions.

- Augmenting the inhibitor pill with surface-injected scale inhibitor when the need is indicated by scale formation in turbine meter bearings.

- Adjusting corrosion inhibitor amount and type on the basis of the monitoring of corrosion coupons.

- Using commercially available controllers to permit changes in rate to a user of produced brine (the Hybrid Power System) with no effect upon production rate.

- Using elastomers and lubricants that are now commercially available and provide significant life extensions and reduced maintenance of valves, wellhead seals, and chokes, in comparison to prior tests of geopressured-geothermal wells.

Conclusions most relevant to the engineering aspects of the production reservoir being tested and to brine disposal are provided under headings below.

Conclusions Relevant to the Reservoir being Tested

- The reservoir is larger and more productive than was indicated by the Phase IIB testing in 1982 and 1983. The reason is that the interpretation of the Phase IIB test assumed that the scale in the wellbore formed near the end of the test. In fact, it is now apparent that the scale began providing a substantial additional drop in wellhead pressure very early in the test. If the scale had not formed, the Phase IIB test interpretation would have been based on much higher flowing wellhead pressure and would have indicated greater potential for the reservoir.

- The reservoir brine was not saturated with natural gas at discovery pressure and temperature. Indeed, it is doubtful whether the bottom hole pressure was drawn down to the bubble point at any time during the testing of the well through the end date of October 1990, for this report.

- Sand production from the reservoir appears to have a trigger level in terms of brine production rate. On June 20, 1988, a slug of sand was apparent in the form of rapid buildup of pressure drop across the filters only 2 hours after the rate was increased to 25,000 STB/D. On October 28, 1990, a slug of sand was again produced. This time, the brine rate had been at 24,000 STB/D for 12 days when the sand hit. Between these two occurrences of sand production, more than 12 million barrels of brine had been produced at lower rates and without detectable (estimated to be less than a pound of sand in a day) sand production. It is noted that undetected production of slugs of sand may well have been the reason for the wireline system failures at a reported brine rate of 29,000 barrels per day during Phase IIA.

- The hydrocarbon liquid that condenses from the separated gas is not "condensate" in the context of the alkane hydrocarbons that are normally found in conventional gas production. Rather, the liquid is predominantly aromatic hydrocarbons and has a specific gravity only slightly below that of water.

Conclusions Regarding Brine Disposal

- Disposal zone pressure buildup, if any, from injection of more than 12.5 million barrels of brine is less than 10 psi.

- The change in brine density with temperature is a significant factor in relation to the pressure required for injection into perforations in the range of 6,000 to 6,500 feet. Cooling of brine by operation of the Hybrid Power System reduced injection pressure by about 0.7 psi per degree Fahrenheit of cooling.

- Prevention of backflow is essential to long-term operation of a deep Miocene disposal well. The unconsolidated sands backflow into the wellbore and become a fluidized bed therein during the backflow. But when injection is resumed, the solids compact to form a plug. If multiple disposal sands are perforated, crossflow between sands at shut-in may well result in loss of injectivity to the deepest sands.

- A slow loss of injectivity over a time of weeks to months of continuous injection can sometimes be reversed by injecting a modest amount (hundreds of gallons) of hydrochloric acid into the flowing brine stream.

- Techniques for washing out the disposal well, by the use of nitrogen foam to remove sand, proved successful in maintaining reliable disposal capabilities.

5.3.2 Hybrid Power System (HPS) (Significant Findings and Conclusions) (See The Ben Holt Co. Final Report (Appendix B-1) for details.)

The Geopressured Hybrid Power System (HPS) at Pleasant Bayou was installed and operated by The Ben Holt Company under subcontract to Eaton. It successfully demonstrated, for the first time, the generation of electricity from a geopressured-geothermal resource. It also demonstrated that the hybrid cycle is an efficient means to recover this energy. Valuable operating data and experience were gained over the nine month demonstration period.

Test results indicate that a commercial hybrid cycle power plant on the Pleasant Bayou geopressured-geothermal resource is technically feasible. Historically, there have been several concerns about operation on a geopressured well. Excessive scaling could have rendered heat exchangers ineffective, severe corrosion could have required the use of expensive, exotic materials, and impure wellhead gas could have caused severe problems with operating gas engines.

The test of the Geopressured Hybrid Power System at Pleasant Bayou showed that these problems have been overcome. The plant achieved an availability of 97.5% and a capacity factor of 80.2% for the five month continuous operation test. These are excellent numbers even for a commercial power plant. 3,445 MWh of power were exported to the local utility.

Both brine heat exchangers exceeded design specifications. No significant fouling, over an extended operating period, was detected on either exchanger. In addition, minimal scale was found when the heat exchangers were inspected at the conclusion of the test. Scale and corrosion inhibitors were effective throughout the range of brine temperatures. Corrosion was minimal in carbon steel piping and heat exchanger tubes.

Fouling in the exhaust gas exchanger was a problem. This issue needs to be addressed in the design of a commercial power plant.

Gas engines ran well on the impure wellhead gas. The only recommended modification is to change the diaphragm material on the gas inlet pressure regulator.

Advantages of the Hybrid Cycle (As quoted from The Ben Holt Co. Final Report) The hybrid concept can be used to improve the utilization efficiency of energy resources. More electricity can be generated from two energy sources in a hybrid cycle than by using each separately to generate electricity. This occurs because heat, which would be wasted from one energy source, is utilized in combination with heat from the other source.

Under EPRI Contract RP1673-4, The Ben Holt Co. evaluated methane/hot water hybrid cycles for hydrothermal and geopressured-geothermal applications. Hybrid cycles were calculated to generate as much as thirty percent more electricity than if the methane was used in a fossil fuel power plant and the hot water in a binary cycle power plant. Results from that evaluation are summarized in Table 5-1.

This table is based on optimized hybrid cycles where enough methane is combusted so that exhaust heat provides all necessary energy to vaporize the working fluid. This requires a methane to hot water ratio higher than is found in a geopressured resource. For example, with a brine temperature of 280°F and a gas turbine heat rate of 14.166 Btu/kwh, 7,100 lb/hr of fuel gas were used with 500,000 lb/hr of brine. At Pleasant Bayou, 470 lb/hr of fuel gas were used with 170,000 lb/hr of brine. The fuel gas to brine ratio is about 5 times greater in this optimized case than at Pleasant Bayou.

TABLE 5-1
SUMMARY OF HYBRID CYCLES POWER PRODUCTION

Gas Turbine Heat Rate = 9.850 BTU/KWH

Brine Temp. Difference (°F)	Hybrid (MW Net)	Binary + Fossil (MW Net)	Difference (MW)	(%)
280	24.11	20.09	4.02	20.0
330	20.58	17.49	3.09	17.7
360	18.37	15.93	2.44	15.3

Gas Turbine Heat Rate = 11.350 BTU/KWH

Brine Temp. Difference (°F)	Hybrid (MW Net)	Binary + Fossil (MW Net)	Difference (MW)	(%)
280	19.42	15.40	4.02	26.1
330	16.48	13.39	3.09	23.1
360	14.77	12.33	2.44	19.8

Gas Turbine Heat Rate = 14.166 BTU/KWH

Brine Temp. Difference (°F)	Hybrid (MW Net)	Binary + Fossil (MW Net)	Difference (MW)	(%)
280	17.07	13.05	4.02	30.8
330	15.05	11.96	3.09	25.8
360	13.81	11.38	2.44	21.4

NOTE: Brine Flow Rate = 500,000 lb/hr for all cases.

Hybrid cycles have another important benefit in that they can be used to provide a base load of power in case of an interruption in supply of one of the energy sources. For instance, the binary cycle portion of a geothermal hybrid plant could continue to operate even if the fossil fuel portion of the hybrid plant was shut down due to lack of fuel. The efficiency of the binary cycle would drop if this occurred, but electricity generation could continue.

Development of a resource in stages is another potential benefit of hybrid cycles. A developer could install a binary cycle on a geothermal resource with the potential for adding a gas engine or gas turbine and utilizing the waste heat. Cash flow from the binary cycle electricity sales could contribute to the financing of the conversion to hybrid.

Converting a binary cycle to hybrid also has an important advantage if the geothermal resource is unknown. A binary cycle could be installed first, and if the geothermal resource has limited production or lower than design temperature, the fossil fuel portion of the plant could be designed to compensate. In any case, where a binary cycle is to be converted to hybrid, it is important to select the binary cycle turbine, circulating pump, and other equipment such that they will be adequate for the hybrid service.

The hybrid cycle experiment at Pleasant Bayou was not meant to be an optimized hybrid cycle experiment. Iso-butane is not the optimum working fluid for a standard binary cycle on a resource with a temperature as low as that at Pleasant Bayou. For example, propane could be used instead of iso-butane to generate more power. However, propane has a higher vapor pressure than iso-butane, so it could not be used with the existing equipment available to the project. An optimized cycle would include a pressure reduction turbine to recover the energy from the high pressure brine. An ebullient-cooled engine could also be used to recover the jacket heat from the engines.

This successful demonstration of electricity generation using the hybrid concept has shown that there are no technical obstacles to commercial utilization of the Pleasant Bayou geopressured-geothermal resource.

5.4 Willis Hulin Site (Vermilion Parish, LA) (Significant Findings and Conclusions)
Eaton assumed custody of the production well after it had been damaged from excess pressure used to attempt to reactivate the well after it ceased production in 1983. The well was shut in. Funds were not available for rework until 1989 (6 year shut-in). In spite of mud dehydration, from years of exposure to extremely high pressures and temperatures, design limitation of tools and logging equipment, and small annular clearances, the well was successfully cleaned out and recompleted for production.

The initial flow test of the Hulin well was done to obtain brine and gas samples and to get a first measure of the reservoir properties. The 20,602′ to 20,690′ interval was perforated and tested in two short-term drawdown and buildup tests. This zone had an initial pressure of 17,308 psia and temperature of 339°F. The total dissolved solids of 207,000 mg/L (mostly sodium chloride) is higher than for previously tested Gulf Coast geopressured-geothermal wells. The gas content in the brine of 31-32 SCF/STB indicates that the brine is at or near saturation with natural gas. The permeability, as deduced from the drawdown and buildup tests, is 13 md for the lower 80′ thick sand member. The duration of the tests was too short to determine the lateral extent of the reservoir; but declining measured values for static bottom hole pressure prior to each flow test was suggestive of a relatively small reservoir.

When the uppermost interval in the zone of interest (20,220′ to 20,260′) was perforated such that flow from this zone would commingle with flow from the lower zone, no free gas was observed. It had been speculated before the test that there might be free gas in this upper zone. It is now apparent that the amount of free gas, if any, is too small to make a significant contribution to production in a short-term test. This does not preclude the possibility of mobilization of gas by higher drawdown or coning down from an offsetting gas cap in one or more of the sand members. No measurements of the reservoir parameters, such as permeability, were made for the shallowest interval tested. But, substantially lower drawdown for the commingled zones suggests either higher permeability or lower skin for the shallower perforated interval.

Hydrate formation in the upper part of the wellbore was a problem. To circumvent this problem, about 10 barrels of diesel was pumped into the top of the well after each flow to displace the brine down to a level in the well where the temperature was too high for hydrates to form. Calculations of saturation index indicated that calcium carbonate scale would also form in the well if the pressure was drawn down too far. Thus, all the flow tests were performed at low flow rates to preclude formation of scale in the wellbore. Scale inhibitor was injected into the surface flow lines to control possible scale formation in the surface equipment.

6.0 RECOMMENDATIONS (FUTURE NEEDS AND PRIORITIES)

6.1 General and Miscellaneous

Much valuable information has been accumulated in this project to date, especially during this five year period. Reservoir testing, in particular, is a very long-term project. It is very important that this program continue to receive strong DOE support in order to obtain the final, end point results. It should not be stopped when only partially completed. It is imperative that the technological improvements implemented during this contract be transferred to industry by means of technical papers, etc.

6.2 Gladys McCall Site (Cameron Parish, LA) (See IGT Final Report (Appendix A) for more details.)

The following recommendations have been made to DOE for the testing of this well.

The well will remain shut-in until FY 1991, then rental equipment will be set up and a 4 - 5 day flow test will be made. This will be to evaluate changes in permeability (Kh), skin effects, and pressure drawdown properties of the reservoir that may have occurred during the three year shut-in pressure buildup test on the well. This will be followed by a three week pressure and buildup test, then clean-out and testing of three shallower sands. This plan was developed using recommendations from Eaton and its subcontractor, Institute of Gas Technology (IGT), the University contractors, and a DOE panel of external and industry reviewers:

a. University of Texas - Austin (UTA)
b. Bureau of Economic Geology (BEG)
c. Lawrence Berkeley Laboratory/S-Cubed
d. Louisiana State University (LSU)
e. University of Southwestern Louisiana (USL)
f. DOE Review Panel, headed by H. Coffer, C K Geo Energy Corp. (H. Ramey, R. Wallace, F. Goldsberry, and C. Querio)

(Their recommendations were incorporated for proposed additional testing at Pleasant Bayou and Hulin also.) (See Eaton Site Test Plans for further details.)

This plan (as detailed in the March 1987 Test Plan) calls for a wireline spinner survey (or equivalent) with a flow test tool during the flow test to determine, if possible, from which zones in the perforations production is coming and whether there is any communication between zones below around the retainer or behind the casing. While the well is shut in, a caliper survey of the tubing will be taken for evidence of any corrosion and/or scaling.

After the packer is removed (has restriction limiting size of logging tools), the following logs should be run (Dunlap, 1987):

a. Spectral Gamma Log
b. Pulsed Neutron Log
c. Neutron Density Log

These logs should be over the following intervals:

a. Plug-back depth (PBD) - 15,850′ up to 14,410′
b. 14,058′ - 14,076′
c. 13,840′ - 13,900′
d. 13,300′ - 13,350′
e. 10,700′ - 10,800′
f. 5,000′ - 5,300′

(Also, CBL/CET Cement Bond Logs should be run over prospective intervals.)

These will be used to evaluate the sands for hydrocarbons, especially gas. These will be compared to the original logs for changes.

Two zones immediately above the present perforations should be tested with a wireline Repeat Formation Tester (RFT) (4 tests) for fluid and gas samples and formation pressures for evidence of possible shale dewatering and/or pressure communication. All perforations will be squeezed with cement.

Analysis of the original logs identified possible hydrocarbon productive zones at (Dunlap, 1987):

a. 9,974-79′
b. 10,286-93′
c. 11,195-200′

These zones should be individually tested and then squeezed with cement. If any one of these zones is commercially productive, the well might be sold, saving DOE the final abandonment plus site clean-up and restoration costs.

Due to lack of funds, the previously recommended additional research testing, including possible coring and logging of additional intervals, will not be done.

The well will be plugged and abandoned and the site restored upon completion of the testing above. Usable production equipment will be moved to the Hulin site for use if the future long-term test is done there. If not, it will be sold or otherwise disposed of.

6.3 Pleasant Bayou Site (Brazoria County, TX)

6.3.1 Production Operations (See IGT Final Report (Appendix B-2) for more details.)

Production, in support of testing, of the Hybrid Power System (HPS) has been the primary objective for most of the time since the rehabilitation of surface facilities was completed in the Spring of 1988. The design brine rate for the HPS was 10,000 barrels per day. While the HPS was in operation, brine was produced at about 15,000 barrels per day. This rate was high enough for the HPS to be put on-line or taken off-line without deviating from the steady rate of brine production from the reservoir that was important to interpretation of reservoir test data. With this production rate, the drawdown of flowing bottom hole pressure was only a few hundred psi, over a period of 2 years.

During the last 3 months, production rate was increased stepwise to a maximum of a little over 24,000 STB/D. After 12 days at that rate, a slug of a few cubic feet of sand was produced, and the brine rate was decreased. At the maximum rate, the flowing bottom hole pressure was drawn to almost 9,000 psia, or a little more than 2,000 psia below the original reservoir pressure. Flowing wellhead pressure was still above 1,800 psia.

It is recommended that the well be produced at the maximum practical rate for at least a year. Specific recommendations for actions during that testing are as follows:

- Periodically check whether the maximum practicable rate is defined by the bursts of sand production that have been experienced after 2 hours at 25,000 STB/D and after 12 days at 24,000 STB/D. Install a sand detector system.

- Carefully monitor both the produced gas/brine ratio and the composition of produced gas with samples taken at least once per month, to determine whether the continuing high-rate production reduces flowing bottom hole pressure to a value below the bubble point of gas in solution in the reservoir brine.

- Continue to inject polymaleic anhydride scale inhibitor at the surface so that the concentration of phosphonate returns from the inhibitor pills can be determined. Analyze brine samples to determine the returned phosphonate concentration at least as often as once per month.

- Continue injection of quaternary alkyl pyridine corrosion inhibitor with the concentration at the minimum for effectiveness, as judged from periodic change-outs of corrosion coupons.

- Document produced solids, observed corrosion, changes in the produced fluids, and well productivity.

This test should be evaluated at the end of the year. If conclusive reservoir results are obtained, the wells will be plugged and abandoned, and the site cleared. If conclusive results are not obtained, a recommendation will be made at the end of the year to extend the long-term flow test. Consideration should also be given at that time to the previously recommended coring program of the production sand and adjacent formations for comparison with the original well cores to determine the changes in rock structure from long-term production. Additional zones are also recommended to be logged and tested.

6.3.2 Hybrid Power System

(See The Ben Holt Co. Final Report (Appendix B-1) for more details.)

6.3.2.1 Equipment Modification and Improvement

A commercial hybrid cycle power plant should use state-of-the-art binary cycle technology. The test of the geopressured hybrid power system at Pleasant Bayou proved the reliability of this concept. An availability of 97.5% and a capacity factor of 80.2% are remarkable for a test facility which was constructed primarily with used equipment. Even better and more economic results can be expected with current technology and new equipment (Economic Study, Plum, et al, 1989).

Equipment and piping did not corrode during the nine month test, so carbon steel is recommended for use throughout a commercial plant. This minimizes the first cost of equipment.

During the design phase, there were many mechanical design concerns about E-3-N. These concerns were due to high temperature operation and to the large temperature difference between the inlet exhaust gas and the outlet isobutane temperature. The unique exchanger design which was explained in detail in Section 6.7 of Appendix B-1 successfully solved the thermal stress problem. This exchanger was built of 304 stainless steel and showed no sign of corrosion. Also, there was no sign of wear between the tubes and the tubesheet support due to vibration. However, fouling in this exchanger was higher than design.

The problem of excessive fouling in the exhaust gas exchanger has several possible solutions. A gas turbine might be installed instead of a gas engine to cut down particulate emissions. In a larger plant, a larger gas engine, which more efficiently completes combustion, could be employed. As another alternative, a blower which periodically removes the soot could be provided. A low pressure drop filter may be all that is required. Although this question must be addressed, it is an engineering design and economic issue rather than a technology development issue. An economic analysis, based on the relative price of electricity and natural gas, would determine whether a hybrid power cycle or a binary power cycle, in which gas is sold to a distributor, should be used. An economic analysis would assess if a pressure reduction turbine should be used to recover hydraulic energy. A commercial power plant would have a negotiated power sales contract, so that power plant would be paid a higher price for power than was received at Pleasant Bayou.

An economic analysis, which uses data from the test facility to estimate the cost of both construction and operation of a commercial power plant, would be a valuable next step. Development of an invaluable energy resource, from which power can be produced safely and with minimal environmental impact, should proceed.

6.3.2.2 Future Geopressured Work

The test at Pleasant Bayou showed the technical feasibility of a commercial power plant on this site. Results prove that the hybrid cycle can efficiently generate power from a geopressured-geothermal resource. Development of an invaluable domestic energy resource from which power can be produced safely and with minimal environmental impact should proceed.

6.4 Willis Hulin Site (Vermilion Parish, LA)

(See IGT Final Report (Appendix C) for more details.)

6.4.1 Production System

Due to budget limitations, this well will remain shut-in through Fiscal Year 1991.

Though not included in the FY 1991 Management Plan, there is another option which would reduce future costs for the Hulin testing. The cost for a new tree for this well is $435,000. There is presently a used tree available. If this tree could be purchased now, it would not only be a considerable savings for the Government, but would also significantly improve the safety of the well. The present tree has a top valve ID of 1-13/16"; the tubing below it has an ID of approximately 3". If the tree should develop a leak, there is no way to put a plug in the tubing below it to seal off the 7,600+ psig pressure in the well. With a new tree, this could be done.

The short-term test on this well showed sharp drawdown. This may have been caused by lack of, or at least limited, perforations due to the very small thru-tubing perforating gun (1-11/16") that can be run through the restricted inner diameter (ID) of the existing tree. It is recommended that the tree be changed as above and the entire sand interval be perforated with a larger, more powerful perforating gun prior to any additional testing.

It is recommended that an initial test be made, to determine possible deliverability, with existing equipment from the Gladys McCall site, supplemented with rental equipment, before permanent production facilities are installed. This would have to be at least four to six months in length.

Initial calculations of total dissolved solids indicate that scaling may be severe in this well at higher flow rates because the temperature is very high (i.e., pressure drop into production equipment at high temperature may result in scale deposition). For this reason, this first flow test may be limited to flow rates of ±4-6,000 BPD. Engineering studies of this problem and possible solutions, such as cooling equipment for the production stream, must be done prior to installation of permanent production facilities.

If the reservoir is capable of high rate, long-term flow, the old tubing string must be exchanged, as well as installing new production facilities, before long-term testing can begin. This requires reworking the well with a rig.

This well, being the deepest, hottest, and hopefully the highest gas/brine ratio of any well tested to date, has the most potential for proving that geopressured-geothermal energy resources can be economic. It is very important that a full, complete test be conducted on all aspects of this well (i.e., production rate, reservoir, and hopefully an electrical generation system).

Since the short-term flow tests only provided initial chemistry and reservoir properties and did not determine the potential of the Hulin well for long-term energy production, further flow testing is needed. It is recommended that the next test of the Hulin well be a sequence of medium-rate flow and pressure buildup tests of at least 6 months' duration, as follows:

- The entire interval, from 20,200 to 20,690 feet, should be perforated and tested as a single unit. This recommendation is based on the fact that both the bottom and top of this interval were previously perforated for the short-term flow test, and flow communication has now been established across the zone. It is now impractical to attempt flow tests on the individual sand members in between the existing perforations. Furthermore, the program objective of determining the potential of the Hulin well for long-term energy production can best be achieved by opening and testing the entire zone.

- The flow test should be done at low-to-moderate flow rates, not the high flow rates anticipated for subsequent energy production. Flow rates in the range of 5,000 to 10,000 barrels per day are anticipated to be sufficient to provide the pressure drawdown and buildup data needed for reservoir engineering evaluations. Furthermore, these flow rates are within the capability of the existing tubing in the well. If a good set of perforations is achieved, such that the skin factor is low, the pressure drop across the perforations and up the well should be low enough to preclude scale formation in the wellbore. Saturation index calculations indicate that calcium carbonate scale may begin to form in the tubing when the wellhead pressure gets into the range of 4,000 to 6,000 psi, depending on the temperature. It will not be possible to flow at high rates through restricted perforations and the existing tubing without forming scale, unless an inhibitor squeeze into the reservoir formation is performed first.

- The surface facilities for processing the brine and gas can be assembled mostly from the equipment previously used for the McCall well test, provided that the vessels still pass the DOE quality control and certification requirements. If this equipment can be used, there will be a significant cost savings over the use of rental equipment. The piping and valves will need to be replaced, however, and can be either purchased or rented, depending on which is less expensive. By limiting the flow rate to a maximum of 10,000 barrels per day, the required piping and valve sizes are in the range of 3 to 4 inches in diameter, which are relatively easy to obtain at modest cost, compared to the 6 to 8 inch pipe and valves needed for higher flow rates. Some new computer-based data acquisition equipment and sensors will also be needed to partially replace the old, and antiquated, system used for the previous McCall and Hulin tests.

- Close coordination with all parties doing reservoir evaluation during the test period will be a must. Although a tentative schedule of times for drawdown and buildup periods will need to be made prior to the beginning of the test, the schedule may need to be altered as the tests proceed. By testing the entire zone -- which is comprised of many sand layers -- at once, it will probably be necessary to evaluate the reservoir as a complex, multi-layered system. Data analysis and numerical reservoir simulation should be initiated while the test is still in progress and field test parameters can be altered, if necessary, to evaluate possible alternate scenarios.

Whether a long-term, and high rate, test of the Hulin well is warranted will depend upon the results of the medium-rate test. To accomplish a high-rate flow test, it will be necessary to replace the current 3-1/2 inch tubing in the well. It is possible that a new well will be needed so that the tubing can be large enough to safely handle the flow rate needed for utilization of the resource.

A basic problem is that the Hulin well casing is longer and smaller in diameter than the two design wells. The Gladys McCall well has 5 inch tubing inside 7 inch casing, and the Pleasant Bayou well has 5-1/2 inch tubing inside 9-5/8 inch casing. In contrast, the deeper 4,700 feet of casing in the Hulin well has the same inside diameter as the Gladys McCall tubing (4.276 inches), and the shallower 15,970 feet of 6.05 inch casing has an inside diameter of only 5.000 inches. Production without tubing would be the only way that the Hulin well could achieve the flow rates experienced at the Gladys McCall and Pleasant Bayou wells with comparable flow velocities.

Engineering evaluation of alternatives is a prerequisite to defining the maximum long-term flow rate that can be safely achieved through the existing wellbore. The possibilities to be considered should include annular flow, the use of a "liquid" packer, and conventional completion with tubing and a packer. The surface piping and valving may need to be rebuilt with larger diameter piping and valves, depending on the maximum flow rate.

6.4.2 Electrical Conversion System

It is recommended that a demonstration power plant be built on the Hulin resource. The salinity of the Hulin brine is higher than that at Pleasant Bayou. This proposed test would prove the binary cycle technology under perhaps the most severe geopressured resource condition in which it may be employed. Combining these results with those from the Pleasant Bayou test would provide potential investors with a high degree of confidence of the viability of this technology.

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8.0 GLOSSARY OF TERMS

Annular Space (Annulus) - 1. The space surrounding a cylindrical object within a cylinder. 2. The space around a pipe (i.e., tubing) in a wellbore, sometimes termed the annulus, the outer wall of which may be the inside wall of either the bore hole or the casing or another tubing string.

Back Off - To unscrew one threaded piece (as a section of pipe) from another.

Blind Back Off - Applying reverse torque in pipe without knowing where it will unscrew.

Blowout Preventer (BOP) - Equipment installed at the wellhead to prevent the escape of pressure either in the annular space between the casing and drill pipe/tubing or open casing during drilling or workover/completion.

Bumper Jars - A percussion tool operated mechanically or hydraulically to deliver a heavy hammer blow to objects in the bore hole. Jars are used to free objects stuck in the hole or loosen tubing or drill pipe that is hung up. Blows may be delivered downward or upward, the jar being controlled at the surface. To apply a heavy blow to the drill stem by use of a jar.

Casing - Steel pipe, usually at least partially cemented, placed in a well as drilling progresses to prevent the wall of the hole from caving during drilling or production, and to provide a means of extracting fluids if the well is productive.

Cement Retainer - A blocking tool set in the casing to prevent the passage of cement above it. Cement can be pumped below it by use of a "stinger" on the bottom of drill pipe or tubing that goes through the retainer. A one way check valve closes to prevent flow through the retainer when the stinger is withdrawn.

Circulate - To pass fluid from one point throughout a system and back to the starting point. Drilling fluid is circulated from the suction pit through the drill pipe (or tubing) to the bottom of the well and returns to the surface through the annulus, back to the suction pit.

Directional Drilling - Intentional deviation of a wellbore from the vertical. Although wellbores are normally drilled vertically, it is sometimes necessary or advantageous to drill at an angle from the vertical. The direction of the new hole may or may not be controlled from the surface.

Drill Collar - A heavy, thick-walled tube, usually steel, used between the drill pipe and the bit (or other tools) in the drill string to add weight in order to improve the performance of the bit or other bottom hole tools.

Drill String (Stem) - The entire length of tubular pipes, composed of the Kelly, the drill pipe, and drill collars that make up the drilling assembly from the surface to the bottom of the hole.

Electric Well Log - A record of certain electrical characteristics of formations traversed by the bore hole, made to identify the formations, determine the nature and amount of fluids they contain, and estimate their depth.

Fish - An object left in the hole during workover or completion operations that must be recovered before work can proceed. 1. To recover from a well any equipment left there during drilling/workover operations such as a lost bit or part of the drill string. 2. To remove from an older well certain pieces of equipment, such as packers, pipe, etc., to allow reconditioning of the well.

Free Gas - Gas in the free state in the reservoir, i.e., excess gas above that which is dissolved in solution in the brine.

Free-point Indicator - A tool designed to measure the amount of stretch in a string of stuck pipe and to indicate the deepest point at which the pipe is free. The free-point indicator is lowered into the well on a conducting cable. Each end of a strain-gauge element is anchored to the pipe wall by friction springs or magnets, and, as increasing vertical strain is put on the pipe, an accurate measurement of its stretch is transmitted to the surface. The stretch measurements indicate the depth at which the pipe is stuck.

Gas/Water Ratio - A measure of the volume of gas produced with brine, expressed in cubic feet per barrel or cubic meters per cubic meter of water produced. (In this report, the volumes are corrected to stock tank volumes.)

Impression Block - A block with lead or another relatively soft material on the bottom of it, which is made up on wireline, drill pipe or tubing at the surface, run into the well, and allowed to rest on a tool or other object lost in the hole or restricting the hole. When the block is retrieved, the size, shape and position of the fish or restriction are obtained from the examination of the impression left in the lead, and an appropriate fishing or other tool may be selected.

Kill String - A small tubing run inside the production tubing through which heavy drilling mud can be pumped into the well to control (kill) the pressures of a threatened blowout.

Liner - Any string of casing whose top is located below the surface. The top of the liner extends into and is hung in the bottom of the casing above it. A "tieback sleeve" may be run on top of the liner hanger so that the casing may later be extended to the surface ("tieback casing").

Make Up - 1. To assemble and joint parts to form a complete unit (as to make up a string of tubing). 2. To screw together two threaded pieces (connection). 3. To mix or prepare (as to make up a tank of mud).

Mill - A downhole tool with rough, sharp, extremely hard cutting surfaces for removing metal by grinding or cutting. Mills are run on drill pipe or tubing to grind up debris in the hole, remove stuck portions of drill stem or sections of casing for sidetracking, and to ream out tight spots in the casing.

<u>Overshot</u> - A fishing tool that is attached to tubing or drill pipe and lowered over the outside wall of pipe lost or stuck in the wellbore. A friction device in the overshot, usually either a basket or a spiral grapple, firmly grips the pipe, allowing the lost fish to be pulled from the hole.

<u>Packer</u> - A piece of downhole equipment, consisting of a sealing device, a holding or setting device, and an inside passage for fluids, used to block the flow of fluids through the annular space between the tubing and the wall of the wellbore (casing) by sealing off the space between them. It is set above the producing zone. A sealing element expands to prevent fluid flow except through the inside bore of the packer and into the tubing.

<u>Perforate</u> - To pierce the casing wall and cement to provide holes through which formation fluids may enter the wellbore. Perforating is accomplished by lowering a perforating gun, or perforator, that fires electrically detonated bullets or shaped charges (jets), operated from the surface.

<u>Plug Back</u> - To place cement or a mechanical plug in a well to isolate the lower portion of the well from the zones of interest above.

<u>Polished Bore Receptacle</u> (PBR) - A metal assembly (receptacle) of which the inside has been honed (polished) to a very smooth, mirrorlike finish so that seals run on tubing can slide in and seal effectively. It is usually run on top of a liner or packer to provide a larger internal diameter than seals that would have to be smaller if they had to go inside and seal in the liner or packer.

<u>Recompletion</u> - To restore or make a new well completion.

<u>Sidetrack</u> - To drill around broken drill pipe, casing or other obstruction that has been lost permanently in the hole. To directionally drill from an existing wellbore (i.e., to go around an obstruction).

<u>Sinker Bar</u> - A heavy weight or bar placed on or near a lightweight wireline tool. It provides weight so that the tool can be lowered into the well properly, to overcome the buoyancy effects of the fluid it is being lowered into.

<u>Snubbing Unit</u> - Equipment used to put pipe or tools into a high pressure well that has not been killed (i.e., to run pipe or tools into the well against pressure). Hydraulic units use fluid pressure operated controls and holding devices to force the pipe or tools into the well through a stripper head or blowout preventers until the weight of the string is sufficient to overcome the lifting effect of the well pressure on the pipe in the stripper.

<u>Stock Tank Volume</u> - Volume as it exists at atmospheric conditions in a stock tank (i.e., corrected to a standard atmospheric pressure and temperature).

<u>String</u> - The entire length of casing, tubing or drill pipe run into a hole; the casing string. Compare with drill string (stem).

String Shot - An explosive device that uses Primacord, a textile-covered fuse with a core of very high explosive, to create an explosive jar inside stuck pipe or tubing to back off the pipe at the joint (connection) immediately above the stuck point.

Thread Dope - A lubricant for the threads of oil field tubular goods.

Tieback Stem - A tapered connection which seals run on casing (tieback) to connect the casing to the top of a liner. The tieback stem goes inside a larger diameter "tieback sleeve" connected on top of the liner when it was run.

Torque - The turning force that is applied to a pipe to cause it to rotate or tend to do so. Torque is measured in foot-pounds, joules, meter-kilograms, and so forth.

Tubing - Small diameter pipe that is run into a well to serve as a conduit for the passage of fluid from the reservoir to the surface.

Washover Pipe (Wash Pipe) - An accessory used in fishing operations to go over the outside of tubing or drill pipe that is stuck in the hole because of cuttings, mud, and so forth, that have collected in the annulus. The wash pipe cleans the annular space (by circulation of fluids and rotation) and permits recovery of the pipe.

Well Completion - The activities and methods necessary to prepare a well for the production of oil and/or gas; the method by which a flowline for formation fluids is established between the reservoir and the surface. The method of well completion used by the operator depends on the individual characteristics of the producing formation(s). These techniques include open-hole completions, conventional perforated completions, multiple completions, etc.

Wireline Bailer - A long, cylindrical container, fitted with a valve at its lower end, used to remove water, sand, mud or oil from a well. It is run into the well on a wireline.

Workover - To perform one or more of a variety of remedial operations to increase or restore production. Examples of workover operations are deepening, plugging back, pulling/fishing of the well setting, and so on.

(DETACHED - UNDER SEPARATE COVER)

APPENDIX A

GLADYS McCALL SITE (CAMERON PARISH, LA)

IGT REVIEW OF PAST PRODUCTION DATA

AND

FINAL SITE REPORT

(DETACHED - UNDER SEPARATE COVER)

RESEARCH AND DEVELOPMENT FOR THE GEOPRESSURED-GEOTHERMAL ENERGY PROGRAM

VOLUME I. FLOW TESTS OF THE GLADYS McCALL WELL

IGT Final Report for the Period October 1985—October 1990

Prepared By:

P. L. Randolph

C. G. Hayden

L. A. Rogers

INSTITUTE OF GAS TECHNOLOGY

3424 South State Street

Chicago, Illinois 60616

IGT Project No. 65071

for

EATON OPERATING COMPANY, INC.

1240 Blalock, Suite 100

Houston, Texas 77055

IGT/EOC Subcontract
IGT/EOC-85-4

DOE Prime Contract
DE-AC07-85ID12578

April 1992

(DETACHED - UNDER SEPARATE COVER)

APPENDIX B
PLEASANT BAYOU SITE (BRAZORIA COUNTY, TEXAS)

B-1 The Ben Holt Co. Final Report
of Hybrid Power System (HPS)
Volumes I & II (Previously Furnished)

B-2 IGT Final Site Report

(DETACHED - UNDER SEPARATE COVER)

APPENDIX B-1

PLEASANT BAYOU SITE

THE BEN HOLT CO.

FINAL REPORT

OF

THE HYBRID POWER SYSTEM (HPS)

(DETACHED - UNDER SEPARATE COVER)

DESIGN AND OPERATION OF A GEOPRESSURED-GEOTHERMAL HYBRID CYCLE POWER PLANT

FINAL REPORT

VOLUME I

February 1991

by

Richard G. Campbell

and

Mai M. Hattar

for

EATON OPERATING COMPANY, INC.

AND

UNITED STATES DEPARTMENT OF ENERGY

The Ben Holt Co.

Pasadena, CA

DOE Contract No. DE-AC07-85ID12578

Holt Project No. 30008

(DETACHED - UNDER SEPARATE COVER)

DESIGN AND OPERATION OF A GEOPRESSURED-GEOTHERMAL HYBRID CYCLE POWER PLANT

FINAL REPORT

VOLUME II

February 1991

by

Richard G. Campbell

and

Mai M. Hattar

for

EATON OPERATING COMPANY, INC.

AND

UNITED STATES DEPARTMENT OF ENERGY

The Ben Holt Co.

Pasadena, CA

DOE Contract No. DE-AC07-85ID12578

Holt Project No. 30008

(DETACHED - UNDER SEPARATE COVER)

APPENDIX B-2

PLEASANT BAYOU SITE

INSTITUTE OF GAS TECHNOLOGY (IGT)

FINAL REPORT

(DETACHED - UNDER SEPARATE COVER)

RESEARCH AND DEVELOPMENT FOR THE GEOPRESSURED-GEOTHERMAL ENERGY PROGRAM

VOLUME II. TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

IGT Final Report for the Period October 1985—October 1990

Prepared By:

P. L. Randolph

C. G. Hayden

V. L. Mosca

J. L. Anhaiser

INSTITUTE OF GAS TECHNOLOGY
3424 South State Street
Chicago, Illinois 60616

IGT Project No. 65071

for

EATON OPERATING COMPANY, INC.
1240 Blalock, Suite 100
Houston, Texas 77055

IGT/EOC Subcontract
IGT/EOC-85-4

DOE Prime Contract
DE-AC07-85ID12578

August 1992

(DETACHED - UNDER SEPARATE COVER)

APPENDIX C

WILLIS HULIN SITE

INSTITUTE OF GAS TECHNOLOGY (IGT)

FINAL SITE REPORT

(DETACHED - UNDER SEPARATE COVER)

RESEARCH AND DEVELOPMENT FOR THE GEOPRESSURED-GEOTHERMAL ENERGY PROGRAM

VOLUME III. FLOW TESTS OF THE WILLIS HULIN WELL

IGT Final Report for the Period October 1985—October 1990

Prepared By:

P. L. Randolph

C. G. Hayden

L. A. Rogers

INSTITUTE OF GAS TECHNOLOGY

3424 South State Street

Chicago, Illinois 60616

IGT Project No. 65071

for

EATON OPERATING COMPANY, INC.

1240 Blalock, Suite 100

Houston, Texas 77055

IGT/EOC Subcontract
IGT/EOC-85-4

DOE Prime Contract
DE-AC07-85ID12578

February 1992

APPENDIX D

GENERAL & MISCELLANEOUS

D-1 ENVIRONMENTAL WATER SAMPLING RESULTS (1989—1990)

D-2 WELLHEAD SCHEMATICS

APPENDIX D-1

ENVIRONMENTAL WATER SAMPLING RESULTS (1989—1990)

Following are environmental water and soil sampling results for samples collected from the Pleasant Bayou, Gladys McCall, and Willis Hulin sites. Samples were collected at each site, as detailed below, through October 1990:

August 7, 1989 - Water, Pleasant Bayou
October 25, 26, 27, 1989 - Water, All Three Sites
January 30, 31, February 1, 1990 - Water, All Three Sites
July 19, 20, 21, 1990 - Water, All Three Sites
October 10, 12, 1990 - Water, All Three Sites

JACK V. MATSON Ph.D., P.E.
CONSULTING ENGINEER
10919 BRAES FOREST
HOUSTON, TEXAS 77071
713-776-8617

August 10, 1989

Mr. Doug Graham
Eaton Industries of Houston, Inc.
1980 Post Oak Blvd. Suite 2000
Houston, Texas 77056

RECEIVED
AUG 11 1989
PROCUREMENT DIV.

DG 8/11/89

Re: Analysis of Sample Test Results

Dear Mr. Graham

My scope of work was to analyze the analytical results from samples taken at the Pleasant Bayou Geopressured Energy Site, compare the results to applicable standards, and draw conclusions as the water quality. The samples were collected by Eaton Operating Company from three shallow wells on the site. Bioaquatic Laboratory of Carrollton, Texas, performed quantitative analyses of the heavy metals, organics, and other pertinent parameters, and reported the results in a FACS dated 8/7/89. These results were compared to the US Environmental Protection Agency National Interim Primary Drinking Water Standards currently in force.

The constituent concentrations in all three samples were within the Drinking Water Standards. All heavy metals were below the detectable limits with the exception of barium which was at twenty three percent of the Standard. The organics were all below detectable limits. My conclusion is that these samples were very clean and met US Drinking Water Standards.

Sincerely,

Jack Matson

Jack V. Matson PhD, PE

CC: KEN TAYLOR
AS ATTACHMENT TO
BIO-AQUATIC'S WATER
ANALYSIS.

CC: P.B. GROUND WATER ANALYSES
FILE

DG 8/11/89

JACK V. MATSON, Ph.D., P.E.
CONSULTING ENGINEER
10919 BRAES FOREST
HOUSTON, TEXAS 77071
PHONE
713 776-8617

RECEIVED
NOV 27 1989
PROCUREMENT DIV.

November 25, 1989

Mr. Doug Graham
Eaton Industries of Houston, Inc.
1900 Post Oak Blvd., Suite 2000
Houston, Texas 77056

Re: Evaluation of Water Analyses

Dear Mr. Graham:

I evaluated the analytical results of water samples taken at the Gladys McCall, Pleasant Bayou, and Willis Hulin sites, and compared the results to the U.S. Environmental Protection Agency National Interim Primary Drinking Water Standards. The samples were from surface water and shallow ground water collected at the sites in the last week of October, 1989. SPC, Inc. analyzed these samples in five categories:

1. Inorganic chemicals
2. Biological - coliform
3. Volatile organics
4. Pesticides
5. Synthetic organics

I also checked the sample results against the proposed USEPA Drinking Water Regulations (see attachment).

The results of my evaluation are as follows:

<u>Pleasant Bayou:</u> All samples were below existing and proposed standards.

JACK V. MATSON, Ph.D., P.E.
CONSULTING ENGINEER
10919 BRAES FOREST
HOUSTON, TEXAS 77071
PHONE
713 776-8617

Willis Hulin: All sample results were below existing and proposed standards with the exception of Barium in sample E910366-05A. It was 2.7 mg/l as compared to the existing standard of 1.0 mg/l, but it meets the proposed standard of 5 mg/l.

Gladys McCall: All sample results were below existing and proposed standards with the exception of Barium in sample E910364-01B. It was 1.5 mg/l which exceeded slightly the existing standard of 1.0 mg/l but meets the proposed standard of 5 mg/l.

Do not be concerned about the Barium results. As mentioned the USEPA is in the process of revising the Barium standard upward from one to five mg/l. The overall results indicate the waters sampled and analyzed meet the high drinking water standards and are very clean.

Sincerely,

Jack Matson

Jack V. Matson, Ph.D., P.E.
[redacted]

IGT

3424 South State St., Chicago, IL 60616
P.O. Box 632, Hitchcock, TX 77563

RECEIVED
MAR 06 1990
PROCUREMENT DIV.

Memorandum

March 2, 1990

To: Doug Graham
From: Chris Hayden CH

Subject: Results of Analyses of Surface and Ground Water Samples Collected at Hulin, Gladys McCall, and Pleasant Bayou

Please find enclosed the analytical reports on the environmental samples collected by myself and EOC personnel on 3 locations between January 30 and February 1, 1990. Chain of custody records are provided on the back of these reports. These reports are the originals, and I am keeping copies of each in my files.

Also please find enclosed the Sample Log Sheets for each sample collected. These sheets contain the records of purge volumes, physical and analytical measurements made on-site, and other pertinent information.

As we discussed over the phone, the two samples Matson had flagged for barium in the October 1989 sample group had the barium concentration go down. The GMSW1 barium concentration dropped from 1.7 to 0.77 mg/l and the HUSW1 barium concentration dropped from 2.7 to 1.7 mg/l. On the other hand, the PBGW3 barium concentration increased slightly from 1.0 to 1.1 mg/l. Drinking water regulations permit 1 mg/l, but in the October 1989 report Matson said don't be concerned...

The only Pleasant Bayou sample with arsenic is PBGW5, which contains 0.007 mg/l. This sample was the only Pleasant Bayou sample to contain arsenic in the October 1989 sampling - the recorded value in October 1989 was 0.009 mg/l. This was not mentioned in Matson's report because the level for drinking water is 0.05 mg/l.

GMC, P.B, Hulin Ground/Surface analyses file

JACK V. MATSON Ph.D., P.E.
CONSULTING ENGINEER
10919 BRAES FOREST
HOUSTON, TEXAS 77071
713-776-8617

SAMPLING CONDUCTED
JANUARY 30, 31 & FEB. 1,
1990.

March 20, 1990

Mr. Doug Graham
Eaton Industries of Houston, Inc.
1240 Blalock, Suite 100
Houston, Texas 77055

RECEIVED
MAR 23 1990
PROCUREMENT DIV.

Dear Mr. Graham:

I reviewed the analyses of water samples taken at the Gladys McCall, Pleasant Bayou, and Willis Hulin sites during the month of February, 1990, and compared them to the U.S. Environmental Protection Agency National Interim Primary Drinking Water Standards.

The analyses meet the Standards with the exception of HUSW1 on February 19,1990, which had a barium reading of 1.7 mg/l. That reading is slightly above the Standard of 1.0 mg/l but far below the proposed Standard of 5.0 mg/l. These results indicate the water samples from the sites were very clean.

Sincerely,

Jack Matson

Jack V. Matson, Ph.D., P.E.

[redacted]

ORIGINAL: JACK MATSON'S VENDOR FILE.
CC: P.B. GROUND H_2O FILE
CC: W.H. GROUND H_2O FILE
CC: G.M^C. GROUND H_2O FILE
CC: KEN TAYLOR - DOE-ID

IGT

3424 South State St., Chicago, IL 60616
P.O. Box 632, Hitchcock, TX 77563

Memorandum
To: Tom Meahl
From: C. G. Hayden / P. L. Randolph

August 13, 1990

Subject: Results of Analyses of Surface and Ground Water Samples Collected at Hulin, Gladys McCall, and Pleasant Bayou

The final results of the environmental sampling exercise performed on the three design well locations are enclosed. Also included are the originals of the data sheets filled out on location and the chain of custody records.

The higher than expected pH values recorded on the Gladys McCall surface samples were discussed in two memos sent to you dated July 23 and July 30, 1990, respectively. The higher than expected lead concentration measured in GMGW3 was discussed in a memo sent to you dated August 10, 1990.

In addition to those memos, we note the barium levels are near or above the U.S. E.P.A. Interim Primary Drinking Water Standard specified maximum of 1.0 mg/l for the following samples: GMSW1, GMGW3, and HUSW1. All of these samples had exceeded this 1.0 mg/l limit on previous analyses, as shown in the Table below, and are within the expected range based on those previous analyses. However, it is suggested that these values for the surface water samples, both obtained from within the dike surrounding the location, be considered in the context that the combination of taste, odor, and appearance of this water make contemplation of drinking it repugnant at best.

BARIUM CONCENTRATION	Sample	10/89	1-2/90	7/90
	GMSW1	1.5 mg/l	0.77 mg/l	0.98 mg/l
	GMGW3	1.0 mg/l	1.1 mg/l	1.11 mg/l
	HUSW1	2.7 mg/l	1.7 mg/l	1.77 mg/l

There were changes, both up and down, in the sulfate and chloride concentrations of many of the surface water samples (See the accompanying Table). Whether the variations in sulfate concentration correlate with off site use of fertilizer, dissolving of calcium sulfate from the purchased limestone road and pad, or some other source, is speculative. The changes in chloride may be due to the local weather conditions, since at each location there exists some degree of seawater intrusion into the freshwater. We do not have sufficient backround data to guess whether these changes can be considered normal. There were no significant changes in the sulfate or chloride concentrations of the groundwater well samples.

Please call if you have any questions.

All Concentrations Are In mg/l

Sample	10/89	1-2/90	7/90
GMSW1			
Chloride	2940	1190	920
Sulfate	108	160	116
GMSW2			
Chloride	4210	1570	1680
Sulfate	260	87	41
HUSW1			
Chloride	66	200	144
Sulfate	25	111	260
HUSW2			
Chloride	1390	353	535
Sulfate	133	46	49
PBSW1			
Chloride	6120	4340	2590
Sulfate	900	610	390
PBSW2			
Chloride	7060	4990	3400
Sulfate	880	690	500

Jack V. Matson, Ph.D., P.E.
Consulting Engineer
P.O. Box 710497
Houston, Texas 77271-0497

September 27, 1990

Mr. Doug Graham
Manager - Contracts & Procurement
Eaton Operating Co., Inc.
1240 Blalock, Suite 100
Houston, Texas 77056

Re: Evaluation of Water Analyses

Dear Mr. Graham:

I evaluated the analytical results of water samples taken at the Gladys McCall, Pleasant Bayou, and Willis Hulin sites, and compared the results to the U.S. Environmental Protection Agency National Interim Primary Drinking Water Standards. The samples were from surface water and shallow ground water collected at the sites in July and August, 1990. Southern Petroleum Laboratory analyzed them for a variety of inorganic materials.

The results of my evaluation are that all samples met the standards with the exception of Willis Hulin, HUSW #1, 7/13/90, barium at 1.77 mg/l; and Gladys McCall, GMGW#3, 7/13/90, barium at 1.11 mg/l, which were slightly above the standard of 1.0 mg/l. The Barium Standard is being revised to 5.0 by EPA. The overall results indicate the waters sampled are clean as per the Drinking Water Standards.

I also analyzed the individual test results over the past year at these sites for undesirable trends worthy of investigation. My findings were that no trends were indicated, and there were no problem areas. The three DOE test site water samples were very clean as per the EPA Primary Drinking Water Standards (enclosed).

Sincerely,

Jack V. Matson

Jack V. Matson, Ph.D., P.E.
[redacted]

ORIGINAL: JACK MATSON'S VENDOR FILE
cc: P.B. GROUND H_2O FILE
cc: W.H. GROUND H_2O FILE
cc: G.M. GROUND H_2O FILE
cc: KEN TAYLOR-DOE-ID

IGT

3424 South State St., Chicago, IL 60616
P.O. Box 1775, Alvin, TX 77512

Memorandum
To: Tom Meahl
From: C. G. Hayden CGH

December 14, 1990

Subject: Results of analyses of environmental samples collected from Hulin and Gladys McCall on October 10 and from Pleasant Bayou on October 12, 1990

Please find enclosed the analytical reports from Southern Petroleum Laboratories, the field analysis sheets, and the custody records for the above referenced samples. Significant results and investigations are discussed below.

- There were no anomalous pH values recorded during this trip.

- A duplicate sample was obtained from GMGW3. During the July sampling water from this well contained 0.045 mg/l of lead. Prior analyses of this water had not shown any trace of lead to the detection threshold of 0.005 mg/l. The two GMGW3 samples obtained on October 10 again showed no trace of lead. The composition of the regular and duplicate samples were consistent with each other and with historical data.

- There were problems with the results of the magnesium analysis for HUGW1. The original HUGW1 (358 foot well near the southeast corner of the location) sample results showed more than an order of magnitude increase in magnesium, from 15 to 220 mg/l. The concentrations of the other elements in this sample were essentially unchanged. This indicated the magnesium data was suspect. I asked SPL to re-check the calculations for these samples, and they verbally reported the data was correct as reported.

I asked that they run carbonate and bicarbonate, in an attempt to find enough anions to get a charge balance with the magnesium. There was no carbonate and an insufficient quantity of bicarbonate to give a charge balance, shedding further doubt on the validity of the first analysis. Finally, we paid to have the same sample rerun for calcium and magnesium. The calcium remained unchanged, while the magnesium concentration on the rerun was only 15.4 mg/l. Finally, SPL called and verbally reported that a 'computer error' had been found in the original report, and the true magnesium concentration in the original analysis was 18 mg/l. A corrected page was sent for insertion into the regular report.

I believe the lower, corrected value is representative of what was in the brine. This lower value is consistent with historical values, and is provides a reasonable charge balance. The corrected sheet was inserted in the report sent to you. The sheet containing the erroneous magnesium concentration, which in all other respects is identical to the replacement page, is not enclosed but will be retained in my files.

- There was no water at the normal HUSW1 sample point at the south side of the ring levee. This has happened on previous sampling trips - for instance, the July 13, 1990 sample was obtained from the ditch 100 feet east of the staked location. That July 13 sample composition was similar to the composition of earlier samples collected at the staked location.

On October 10, 1990, however, the only standing water found in the ring levee was in a small puddle located at the north west corner of the location. A sample was obtained from that point. This HUSW1 sample had roughly an order of magnitude more barium, chromium, iron, and lead compared to the July 13, 1990 analysis.

The October 10, 1990 values for barium, chromium, and lead were above the maximum level in the primary drinking water regulation. The data was confirmed in a rerun of the sample. High concentrations due to evaporation is not suspected because the chloride content of the sample was on the low side of prior scatter for the normal sample point.

- Compositional changes, compared to previous samples, at the GMSW1, GMSW2, HUSW2, PBSW1, and PBSW2 reflect differing quantities of sea water mixed with fresh water. Most of these sample points have some degree of contact with the gulf, and variations in the relative amount of fresh water and sea water over time are expected. Sea water contains sodium (10,600 mg/l), chloride (19,000 mg/l), magnesium (1,272 mg/l), sulfate (2,600 mg/l), calcium (400 mg/l), and boron (4.6 mg/l). The relative changes in the concentration of these species, when mixing fresh water with sea water, are predictable from the composition of sea water. There is no reason to be concerned over these minor changes.

This concludes the analyses that will be performed on those samples collected on October 10 and 12, 1990.

Because of the discrepancies observed on the HUGW1 and HUSW1 sample analyses, these locations were re-sampled on November 29, 1990. This data has not yet been received from the laboratory.

6.84

Department of Energy

Idaho Operations Office
785 DOE Place
Idaho Falls, Idaho 83402

November 27, 1990

Dr. Ben Eaton
Eaton Operating Company, Inc.
1240 Blalock, Suite 100
Houston, Texas 77055

SUBJECT: Contract No. DE-AC07-85ID12578 - Water Quality Monitoring

Dear Dr. Eaton:

As a result of positive indications of trace metals found in the water samples taken from the Hulin site in October 1990, you are hereby authorized to perform additional sampling and analysis at the Hulin site. This sampling and analysis falls within the existing scope of work and shall be done as follows:

1. Sample the HUGW1 groundwater well. The sample should be analyzed for metals, specifically looking for magnesium.

2. Take three composited soil samples utilizing approved U. S. EPA methodologies from various locations within the dike surrounding the Hulin site. One of the samples shall be taken from the location where the surface water sample is normally taken. These samples shall be analyzed for metals, paying particular attention to Ba, Pb, and Cr.

I. Aoki, DOE-ID shall be monitoring the sediment/soil sampling. The cost of this activity shall be no greater than what remains to be spent in the Water Quality Monitoring Program. If there are any questions concerning this direction, please contact Trudy Thorne, 208-526-9519 or Ken Taylor, 208-526-9063.

Sincerely,

J P Anderson

J. P. Anderson
Contracting Officer
Chief, Acquisition Branch
Contracts Management Division

cc: T. A. Thorne
K. J. Taylor

CC: DOE CONTRACT FILE
GROUND H_2O SAMPLING FILE (W. HULIN)
SPL VENDOR FILE

U.S. Department of Energy
Idaho Operations Office

INTEROFFICE MEMORANDUM

Date:	16-Nov-1990 10:48am MST
From:	ISAMU AOKI
	IAOKI
Dept:	DOE-ID
Tel No:	6-0583

TO: THOMAS WILLIAMS (TEWILLIAMS)

CC: PEGGY BROOKSHIER (PBROOKSHIER)
CC: KENNETH TAYLOR (KTAYLOR)
CC: W.H. THIELBAHR (WTHIELBAHR)

Subject: RECOMMENDED SEDIMENT SAMPLING PROTOCOL AT THE HULIN WELL SITE

SURFACE SOIL/SEDIMENT SAMPLING WITHIN THE PERIMETER LEVEE AT THE HULIN WELL SITE

The recommended sampling techniques at the Hulin Site perimeter levee will utilize techniques which are standardized to United States Environmental Protection Agency (USEPA) methodologies. Samples will be collected in a manner to best characterize or be representative of the entire levee.

Sample results from the Hulin well site surface water samples from the perimeter levee for the 3rd quarter 1990 showed positive indications for the following trace metals:

Barium	15.00mg/l
Chromium	0.28mg/l
Lead	0.07mg/l

The Maximum contaminant levels (MCL) for the above trace metals as listed in the USEPA Interim Primary Drinking Water Standards are:

Barium	1.0mg/l
Chromium	0.05mg/l
Lead	0.002mg/l

The above reported results exceed the standards, with lead being 35 times higher than acceptable. The results as reported are from our quarterly water samples. Water samples would only show the soluble components of the trace metals and therefore the source of the soluble portion would have to be from soils, sediments or sludges. Because of the potentially high degree of heterogeneity found in soils, sediments and sludges, the collection oif representative samples requires careful planning and considerable technical judgement.

Generally, the preferred sampling strategy is to collect at least several aliquots from either randomly selected points or systematic grids at a sampling location and composite aliquots by homogenizing in the field before transferring to the laboratory. Homogenization consists of thoroughly mixing the aliquot using stainless steel screens. At a minimum, three such composited samples from a sample location is necessary to give analytical results which can then be used as an estimate of the mean and variance of concentrations of trace metals or other pollutants at any given sampling point.

The most direct method of collectiing soil, sediment or sludge samples for subsequent analyses is to use stainless steel spoons to collect the sample. The procedure is generally used to sample the top 3 inches of surface material.

The systematic procedure for collecting of nonvolatiles is as follows:

1. Collect and composite at least 10 grab samples, approximately 400g each, from the top 3 inches of soil. Collect using disposable stainless steel spoons and screen if possible in the field through a pre-cleaned 0-mesh (no. 10, 2mm) disposable stainless steel screen. Mix the sample in disposable aluminum trays, and place in the appropriate labeled container.

2. For trenches and ditches, subsamples will be spaced equidistant along along the centerline of the trench. For spill areas, as the condensate collection area at Pleasant Bayou, the subsamples should be collected from heavily stained areas. Collect at least three composited samples at each sampling site.

3. Wipe sample containers clean of surface contamination.

4. Place in individual plastic bags with freezer packs in an insulated ice chest.

5. Place disposable sampling equipment and other materials in plastic bags seal, and properly dispose of by the appropriate personnel.

6. Complete all chain-of-custody documents and field logbooks.

The following are necessary equipment and supplies:

Rubber gloves
Stainless steel spoons
No. 10 mesh stainless steel screen
Aluminum pans
Appropriate sample containers
Preprinted labels
Field logbook
Chain-of-custody materials
Map of locations
Plastic bags for waste & used rubber gloves
Plastic bags for sample containers
Ice or Freeezer packs
Ice chests

The referenced sources for the above information came from the following:

DeVera, E. R., Simmons, B. P., Stephens, R. D., and Strom, D. L., SAMPLERS AND SAMPLING PROCEDURES FOR HAZARDOUS WASTE STREAMS, EPA-600/2-80-018, January 1980.

U. S. Environmental Protection Agency, CHARACTERIZATION OF HAZARDOUS WASTE SITES--A METHODS MANUAL: Vol. II, Available Sampling Methods, 2nd Ed., EPA-600/4-84-076, December 1984.

Jack V. Matson, Ph.D., P.E.
Consulting Engineer
P.O. Box 710497
Houston, Texas 77271-0497

January 4, 1991

Mr. Doug Graham
Eaton Operating Company
1240 Blalock - Suite 100
Houston, Texas 77055

Re: Test Results of environmental samples for the Hulin, McCall, and Pleasant Bayou Sites for Fourth Quarter, 1990.

Dear Mr. Graham:

I reviewed the test results reported by Southern Petroleum Laboratory on water samples collected from Hulin and McCall on October 10, 1990, and from Pleasant Bayou on October 12, 1990, and compared the results to the EPA Drinking Water Standards. With the exception of sample HUSWI, all other samples meet EPA Standards.

Sample HUSW1 has been the subject of research as to why the values for Ba, Cr, and Pb are above the Standards. C. G. Hayden in a memo to Tom Meahl dated December 14, 1990, indicated HUSW1 was taken at a location different from where it is normally taken. This location is near the drilling mud tanks. The soil was tested and found to be within the normal range for these heavy metals. The quantitative results show none of the metals to be an order of magnitude or more greater than the Standard (Ba = 15. mg/l, compared to a current Standard of 1.0 and proposed Standard of 5.0; Cr = .28, compared to a Standard of 0.05; and Pb = 0.067, compared to a Standard of 0.05).

My conclusion is since the soil was not contaminated the high readings were to do with some spillage of mud and was temporary in nature;; and this presented no threat to the environment.

Sincerely,

Jack Matson

Jack V. Matson, Ph.D., P.E.

APPENDIX D-2

WELLHEAD SCHEMATICS

(With Descriptions)

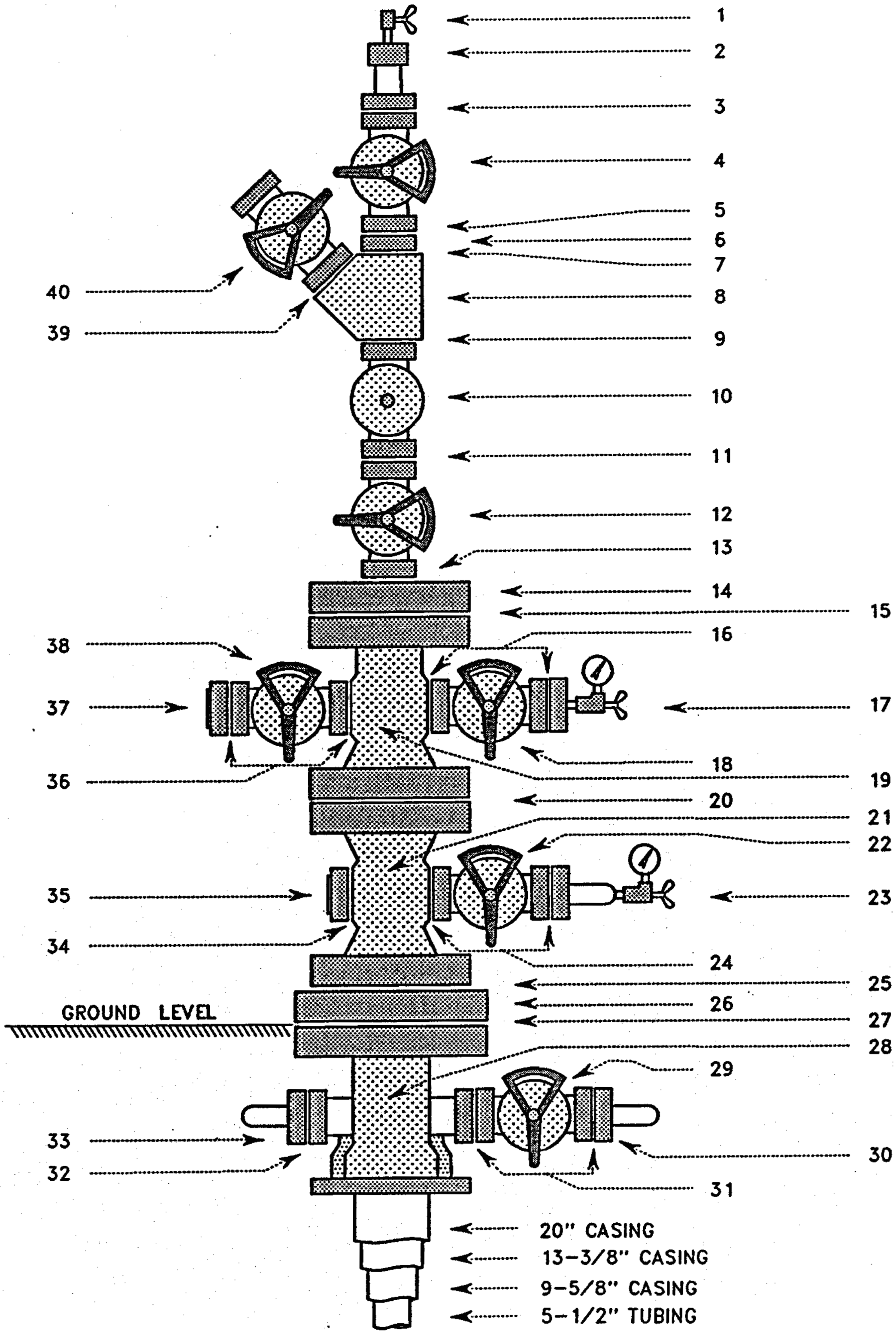
1. EOC/DOE Pleasant Bayou Well No. 2 (Production Well)
2. EOC/DOE Pleasant Bayou SWDW No. 1 (Disposal Well)
3. EOC/DOE Gladys McCall Well No. 1 (Production Well)
4. EOC/DOE Gladys McCall SWDW No. 1 (Disposal Well)
5. EOC/DOE Willis Hulin Well No. 1 (Production Well)
6. EOC/DOE Willis Hulin CVW No. 1 (Disposal Well - Class V)

WELLHEAD SCHEMATIC

(With Description)

1. EOC/DOE Pleasant Bayou Well No. 2 (Production Well)

EOC/DOE PLEASANT BAYOU No. 2
Brazoria County, Texas



EATON

Production Wellhead Description Schematic As Of 5/90.

PLEASANT BAYOU NO. 2 PRODUCTION WELLHEAD

1. 30m# W.P. psig autoclave valve w/o a gauge
2. 7-1/16" 15m# blanking plug tapped w/1/2" 15,000# NPT
3. BX-156, API 316 S.S. ring gasket
4. 7-1/16" 15m# WKM "m-1" FE x FE gate valve 1/T-26 trim (5-1/16" drift)
5. BX-156, API 316 S.S. ring gasket
6. 7-1/16" 15m# x 7-1/16" 15m# spacer flange w/2 1/2" NPT tapes
7. BX-156, API 316 S.S. ring gasket
8. 7-1/16" 15m# WKM Y-block (5-1/16" drift)
9. BX-156, API 316 S.S. ring gasket
10. 7-1/16" 15m# WKM "m-1" FE x FE manumatic mastergate valve w/T-26 trim (5-1/16" drift)
11. BX-156, API 316 S.S. ring gasket
12. 7-1/16" 15m# WKM "m-1" FE x FE lower master gate valve w/T-26 trim (5-1/16" drift)
13. BX-156, API 316 S.S. ring gasket
14. 7-1/16" x 11" API 15m# tubing spool
15. BX-158, API 316 S.S. ring gasket
16. BX-151, API 316 S.S. ring gaskets
17. 1-13/16" 15m# blind flange tapped w/1/2" 10,000# NPT & 0-10,000# W.P. gauge

<u>PLEASANT BAYOU NO. 2 PRODUCTION WELLHEAD</u>

18. 1-13/16" WKM "m-1" FE x FE gate valve

19. 11" 15m# x 13-5/8" 10m# tubing head

20. BX-159, API 316 S.S. ring gasket

21. 13-5/8" 10m# x 13-5/8" 5m# casing head

22. 1-13/16" 10m# WKM "m-1" FE x FE gate valve

23. 1-13/16" 10m# blind flange tapped w/bull plug, 1/2" 6000# NPT & 0-1500# W.P. gauge

24. BX-151, API 316 S.S. ring gaskets

25. BX-160, API 316 S.S. ring gasket

26. 13-5/8" 5m# x 21-1/4" 5m# D.S.A.

27. BX-165, API 316 S.S. ring gasket

28. 21-1/4" 5m# x 20" SOW casing head

29. 2-1/16" 5m# WKM "m" FE x FE gate valve

30. 2-1/16" 5m# blind flange tapped w/bull plug

31. RX-24, API ring gasket

32. RX-24, API ring gasket

33. 2-1/16" 5m# blind flange tapped w/bull plug

34. BX-151, API 316 S.S. ring gasket

35. 1-13/16" 10m# blind flange

36. BX-151, API 316 S.S. ring gaskets

PLEASANT BAYOU NO. 2 PRODUCTION WELLHEAD

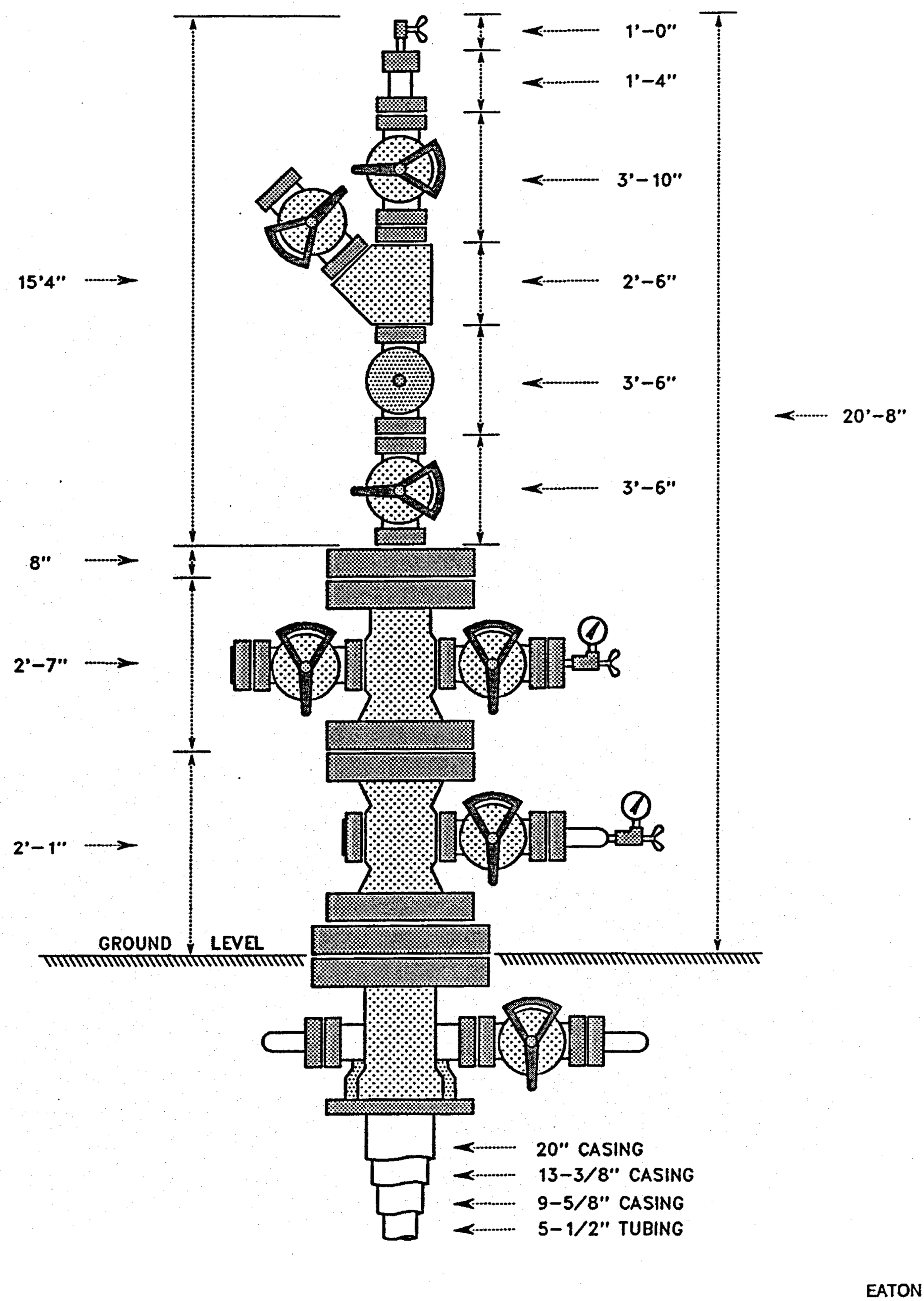
37. 1-13/16" 15m# blind flange

38. 1-13/16" 15m# WKM "m-1" FE x FE gate valve

39. BX-156, API 316 S.S. ring gasket

40. 7-1/16" 15m# WKM "m-1" FE x FE gate valve w/T-26 trim
    (5-1/16" drift)

EOC/DOE PLEASANT BAYOU No. 2
Brazoria County, Texas



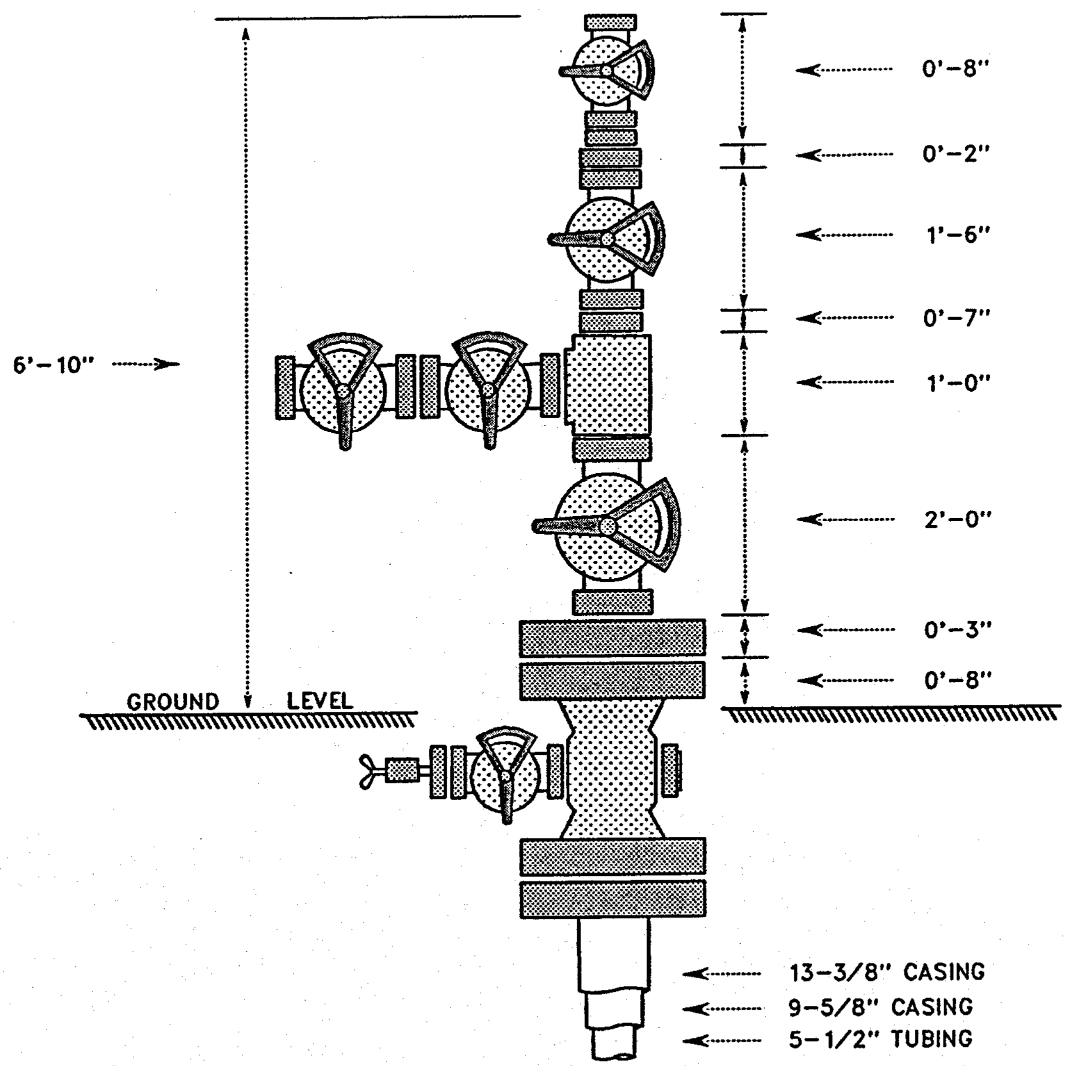
Production Wellhead Dimensions Schematic As Of 5/90.

WELLHEAD SCHEMATIC

(With Description)

2. EOC/DOE Pleasant Bayou SWDW No. 1 (Disposal Well)

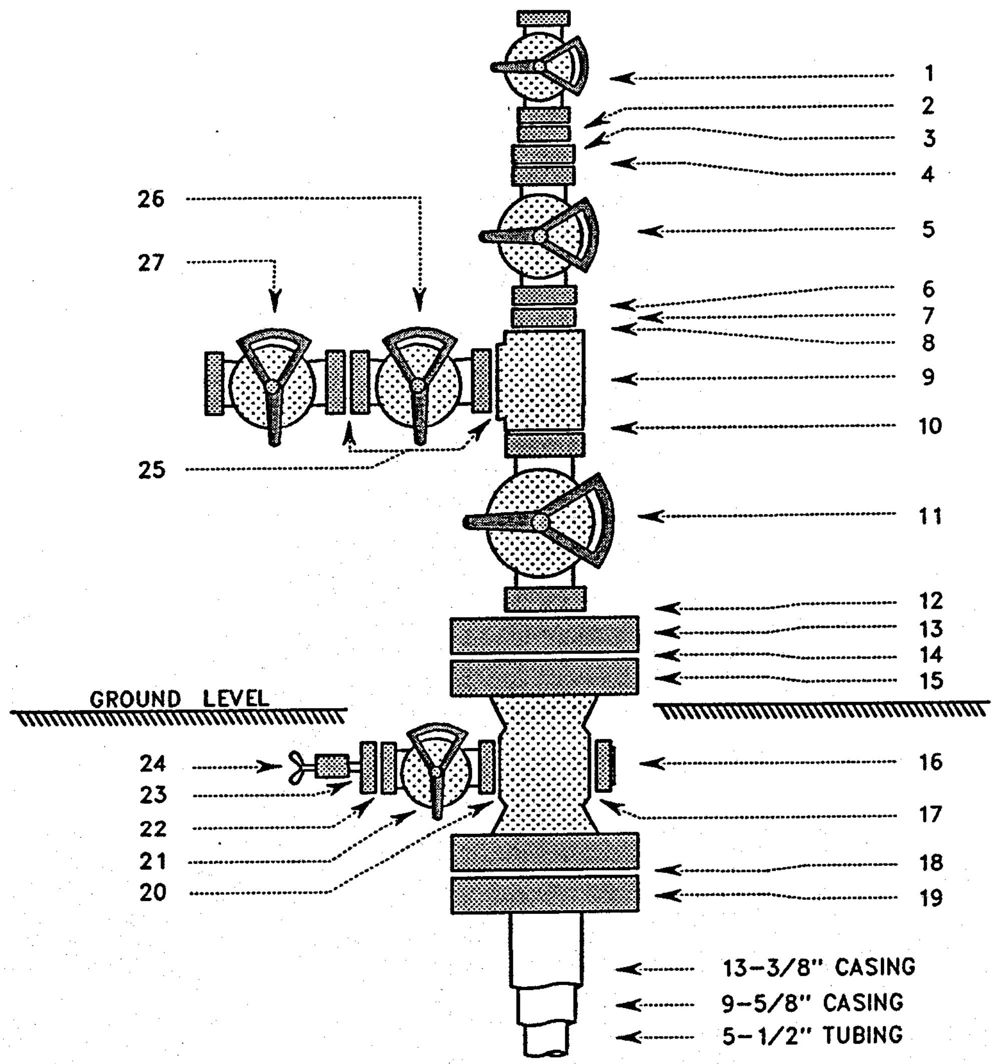
EOC/DOE PLEASANT BAYOU SWDW No. 1
Brazoria County, Texas



EATON

Disposal Wellhead Dimensions Schematic As Of 8/90.

EOC/DOE PLEASANT BAYOU SWDW No. 1
Brazoria County, Texas



EATON

Disposal Wellhead Description Schematic As Of 8/90.

PLEASANT BAYOU SWDW NO. 1
WELLHEAD DESCRIPTION

1. 2" 2000# W.P./WOG ball valve
2. 2" Sch 160 threaded nipple
3. 4-1/16" 3000# W.P. flange w/2" NPT tap
4. R-37, API 316 S.S. ring gasket
5. 4" 3000# W.P. full opening ball valve w/316 S.S. trim; ball, stem and body internally plastic coated
6. R-37, API 316 S.S. ring gasket
7. 4-1/16" 3000# W.P. x 7-1/16" 3000# W.P. spacer flange
8. R-45, API 316 S.S. ring gasket
9. 7-1/16" x 4-1/16" x 7-1/16" WKM studded T-block
10. R-45, API 316 S.S. ring gasket
11. 7-1/16" 3000# W.P. WKM "m" FE x FE gate valve w/T-24 trim
12. R-45, API 316 S.S. ring gasket
13. 7-1/16" 3000# W.P. x 9" 3000# W.P. D.S.A.
14. R-49, API 316 S.S. ring gasket
15. 9" 3000# W.P. x 13-5/8" 3000# W.P. tubing hanger

    Note: Tubing hanger is a modified 5-1/2" WKM type U-EN Mandrel hanger with an extended neck; P/N 882975.

    Upper seal (S-seal) nominal 7" for high temp. P/N 44799; body seal, nominal 9" for high temp. P/N 448000.

16. 2-1/16" 3000# W.P. blind flange
17. R-24, API ring gasket
18. R-57, API ring gasket

19. 13-5/8" 3m# x 13-3/8" SOW casing head

20. R-24, API ring gasket

21. 2-1/16" 3000# W.P. FE x FE gate valve

22. R-24, API ring gasket

23. 2-1/16" 3000# W.P. flange w/2" NPT tap

24. 1/2" 3000# W.P. NPT valve

25. R-37, API 316 S.S. ring gaskets

26. 4-1/16" 3000# W.P. WKM "m" FE x FE gate valve w/T-24 trim

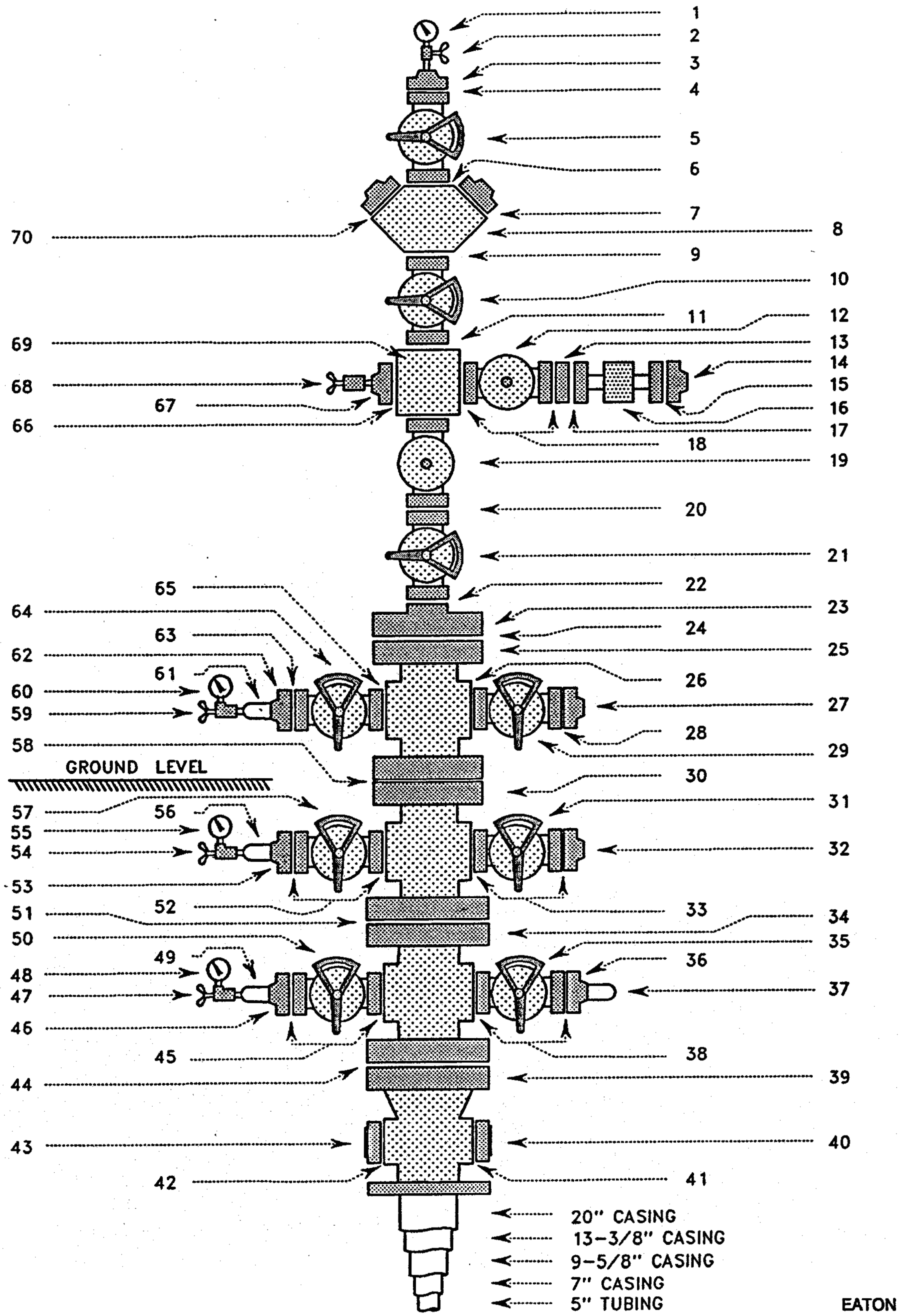
27. 4-1/16" 3000# W.P. Arrow FE x FE check valve

WELLHEAD SCHEMATIC

(With Description)

3. EOC/DOE Gladys McCall Well No. 1 (Production Well)

EOC/DOE GLADYS McCALL No. 1
Cameron Parish, Louisiana



Production Wellhead Description Schematic As Of 6/90.

GLADYS McCALL NO. 1 PRODUCTION WELLHEAD

1. 1-1/2" 10,000# W.P. 316 S.S. Marsh pressure gauge

2. 1/2" LP 10,000 W.P. S.S. NACE straight gauge cock

3. 5-1/8" 10,000# W.P. 6 BX w/1/2" LP tap, type III LA, blind flange

4. BX-169, API 316 S.S. ring gasket

5. 5-1/8" 10,000# W.P. 6 BX FE x FE, E trim for 450°F Gray gate valve w/bevel gear operator

6. BX-169, API 316 S.S. ring gasket

7. BX-155, API S.S. ring gasket

8. 5-1/8" 10,000# W.P. 6 BX x 4-1/16" 10,000# W.P. 6 BX on 45 degree, type II LA NACE dual studded Y block

9. BX-169, API 316 S.S. ring gasket

10. 5-1/8" 10,000# W.P., 6 BX FE x FE, E trim for 450°F Gray gate valve w/bevel gear operator

11. BX-169, API 316 S.S. ring gasket

12. 4-1/16" 10,000# W.P., C, x 4-1/16" 10,000# W.P. 6 BX FE x FE, E-trim w/Graysafe operator HA-7 for 450°F and below

13. 4-1/16" 10,000# W.P. 6 BX x 4-1/16" 10,000# W.P. 6 BX spacer flange

14. 2-1/16" 10,000# W.P. 6 BX w/2" tap flange

15. BX-152, API 316 S.S. ring gasket

16. 4-1/16" 10,000# W.P. x 2-1/16" 10,000# W.P. Gray hydraulic accumulator

17. BX-155, API 316 S.S. ring gasket

18. BX-155, API 316 S.S. ring gaskets

19. 5-1/8" 10,000# W.P. "C" x 5-1/8" 10,000# W.P. 6 BX FE x FE, E-trim for 450°F w/Graysafe HA-10 operator w/manual override

GLADYS McCALL NO. 1 PRODUCTION WELLHEAD

20. BX-169, API 316 S.S. ring gasket

21. 5-1/8" 10,000# W.P. 6 BX x FE, E-trim for 450°F, Gray gate valve w/bevel gear operator

22. BX-169, API 316 S.S. ring gasket

23. 5-1/8" 10,000# W.P. 6 BX x 9" 10,000# W.P. 6 BX, type III 410 S.S. NACE, tubing bonnet, K

24. BX-157, API 316 S.S. ring gasket

25. 9" 10,000# W.P. MSP x 11" 10,000# W.P. MSP x 2-1/16" 10,000# W.P. 6 BX outlets, LA NACE CWCT-D15 tubing head

26. BX-152, API 316 S.S. ring gasket

27. 2-1/16" 10,000# W.P., 6 BX, Type II LA NACE blind flange

28. BX-152, API 316 S.S. ring gasket

29. 2-1/16" 10,000# W.P., "C", x 2-1/16" 10,000# W.P. 6 BX FE x FE, E-trim pkg for 350°F service, Gray gate valve

30. 13-5/8" 5,000# W.P. 6 BX x 11" 10,000# W.P. 6 BX, CWCT, 9-5/8" casing spool

31. 1-13/16" 10,000# W.P. "C" x 1-13/16" 10,000# W.P. 6 BX FE x FE w/D-trim Gray gate valve

32. 1-13/16" 10,000# W.P. 6 BX, blind flange

33. BX-151, API CAD PLT ring gaskets

34. 20" 2,000# W.P. x 13-5/8" 5,000# W.P. 6 BX, CWCT, 13-3/8" casing spool

35. 2-1/16" 5,000# W.P. "D" x 2-1/16" 5,000# W.P. FE x FE w/A-trim Gray gate valve

36. 2-1/16" 5,000# W.P. tapped w/2" NPT, flange

37. 2" w/1/2" LP tap bull plug

38. R-24, API, CAD PLT, ring gaskets

39. 20" SOW 2,000# W.P. CWCT Gray casing head w/two 2" 5,000# W.P. std outlets and 32" base plate

40. 2-1/16" 5,000# W.P. blind flange

41. R-24, API ring gasket

42. R-24, API ring gasket

43. 2-1/16" 5,000# W.P. blind flange

44. R-73, API, CAD PLT, ring gasket

45. R-24, API, CAD PLT, ring gaskets

46. 2-1/16", 5000# W.P. tapped w/2" NPT, flange

47. 1/2" LP 5,000# W.P. S.S. NACE straight gauge cock

48. 1/2" x 4-1/2" 5,000# W.P. 316 S.S. Marsh pressure gauge

49. 2" w/1/2" LP tap bull plug

50. 2-1/16" 5,000# W.P. "D" x 2-1/16" 5,000# W.P. FE x FE w/A-trim Gray gate valve

51. BX-160, API CAD PLT, ring gasket

52. BX-151, API, CAD PLT, ring gaskets

53. 1-13/16" 10,000# W.P. 6 BX, Thd w/2" L.P. for 5,000# W.P., Type II LA NACE flange

54. 1/2" L.P. 5,000# W.P. S.S. NACE straight gauge cock

55. 1/2" x 4-1/2" 10,000# W.P. 316 S.S. Marsh pressure gauge

56. 2" CS NACE, 4" LGW w/1/2" LP tap bull plug

57. 1-13/16" 10,000# W.P. "C" x 1-13/16" 10,000# W.P. 6 BX FE x FE w/D-trim Gray gate valve

58. BX-158, API 316 S.S. ring gasket

59. 1/2" LP 10,000# W.P. S.S. NACE straight gauge cock

GLADYS McCALL NO. 1 PRODUCTION WELLHEAD

60. 1/2" x 4-1/2" 10,000# W.P., 100-3-SS-MS, 315 S.S. Marsh pressure gauge

61. 2" CS NACE x 4" LG w/1/2" LP tap bull plug

62. 2-1/16" 10,000# W.P. 6 BX, type II, LA NACE w/2" tap, flange

63. BX-152, API 316 S.S. ring gasket

64. 2-1/16" 10,000# W.P. "C", x 2-1/16" 10,000# W.P. 6 BX FE x FE E-trim pkg for 350°F service, Gray gate valve

65. BX-152, API 316 S.S. ring gasket

66. BX-155, API 316 S.S. ring gasket

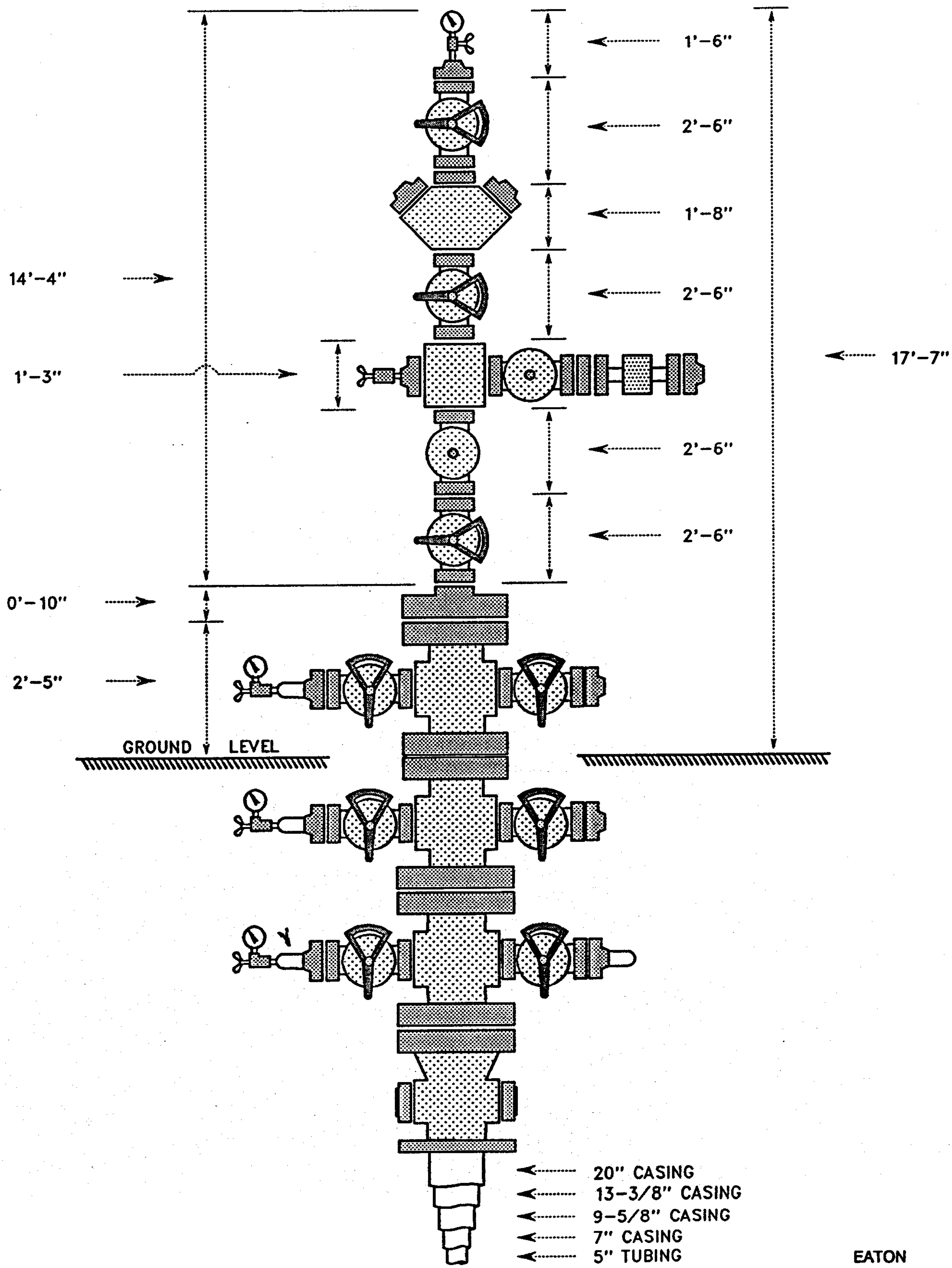
67. 4-1/16" 10,000# W.P. 6 BX, 4135 w/1/2" tap, flange

68. 1/2" 10,000# W.P. Weld-O-Let needle valve

69. 5-1/8" 10,000# W.P. 6 BX x 4-1/16" 10,000# W.P. 6 BX x 4-1/16" 10,000# W.P. 6 BX, type II LA NACE, w/A206 bolting studded cross

70. BX-155, API 316 S.S. ring gasket

EOC/DOE GLADYS McCALL No. 1
Cameron Parish, Louisiana



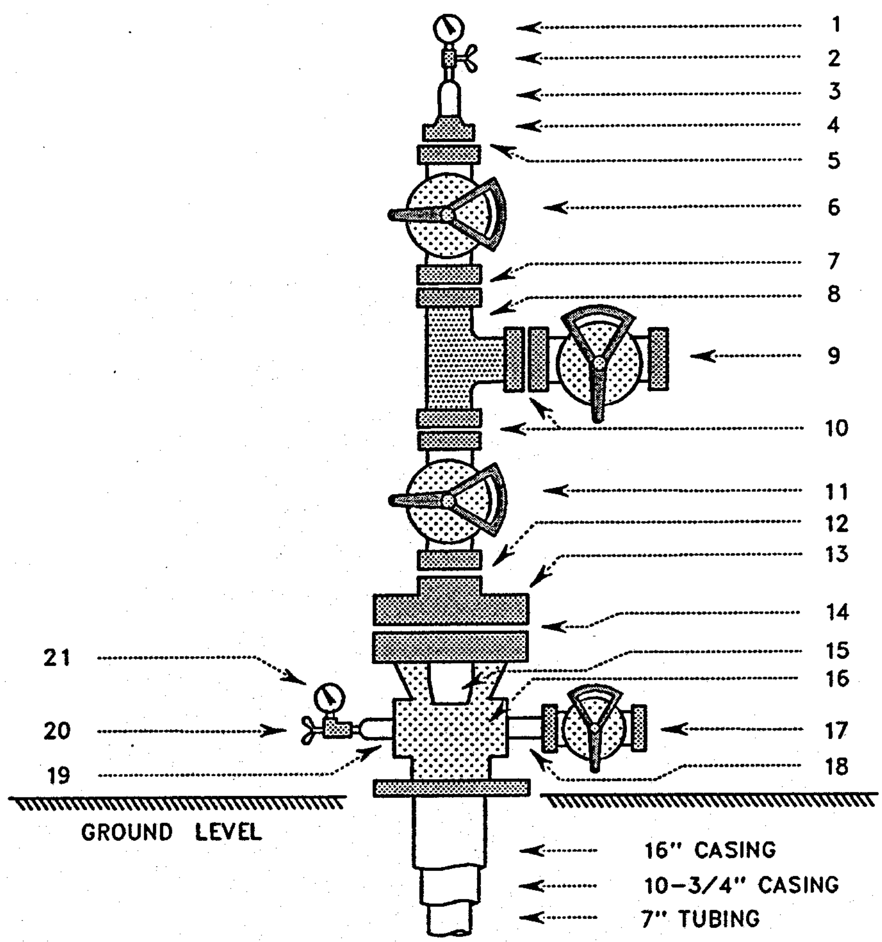
Production Wellhead Description Schematic As Of 6/90.

WELLHEAD SCHEMATIC

(With Description)

4. EOC/DOE Gladys McCall SWDW No. 1 (Disposal Well)

EOC/DOE GLADYS McCALL SWDW No. 1
Cameron Parish, Louisiana



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Disposal Wellhead Description Schematic As Of 10/90.

GLADYS McCALL SWDW NO. 1

1. 0-3000# W.P. pressure gauge
2. 1/2" 3000# W.P. NPT valve
3. 2-3/8" EUE 8 Rd bull plug tapped w/1/2" NPT
4. 7-1/16" 2000# FE x 2-3/8" EUE 8 Rd adapter flange
5. R-45, API 316 S.S. ring gasket
6. 7-1/16" FE x 6" S/600, 1440# W.P. Demco "V" ball valve
7. R-45, API 316 S.S. ring gasket
8. 7-1/16" FE x 7-1/16" FE x 7-1/16" FE 2000# W.P. studded tee
9. 7-1/16" FE x 6" S/600, 1440# W.P. Demco "V" ball valve
10. R-45, API 316 S.S. ring gaskets
11. 7-1/16" FE x 6" S/600, 1440# W.P. Demco "V" ball valve
12. R-45, API 316 S.S. ring gasket
13. 11" 2000# W.P. double studded pack-off x 7-1/16" 2000# W.P. w/7 "00" pack-off
14. R-53, API 316 S.S. ring gasket
15. ERC "AW" 11" x 7" O.D. casing hanger
16. ERC "C-80" 11" 2000# W.P. FE x 10-3/4" S/O W/T w/2-2" LPO casing head
17. 2" LP SE 2000# W.P. ball balve
18. 2" x 6" XXH nipple
19. 2" XXH bull plug tapped w/1/2" NPT
20. 1/2" 3000# W.P. NPT valve
21. 0-3000# W.P. pressure gauge

38. R-24, API, CAD PLT, ring gaskets

39. 20" SOW 2,000# W.P. CWCT Gray casing head w/two 2" 5,000# W.P. std outlets and 32" base plate

40. 2-1/16" 5,000# W.P. blind flange

41. R-24, API ring gasket

42. R-24, API ring gasket

43. 2-1/16" 5,000# W.P. blind flange

44. R-73, API, CAD PLT, ring gasket

45. R-24, API, CAD PLT, ring gaskets

46. 2-1/16", 5000# W.P. tapped w/2" NPT, flange

47. 1/2" LP 5,000# W.P. S.S. NACE straight gauge cock

48. 1/2" x 4-1/2" 5,000# W.P. 316 S.S. Marsh pressure gauge

49. 2" w/1/2" LP tap bull plug

50. 2-1/16" 5,000# W.P. "D" x 2-1/16" 5,000# W.P. FE x FE w/A-trim Gray gate valve

51. BX-160, API CAD PLT, ring gasket

52. BX-151, API, CAD PLT, ring gaskets

53. 2" w/1/2" LP tap bull plug

54. 1/2" x 4-1/2" 10,000# W.P. 316 S.S. Marsh pressure gauge

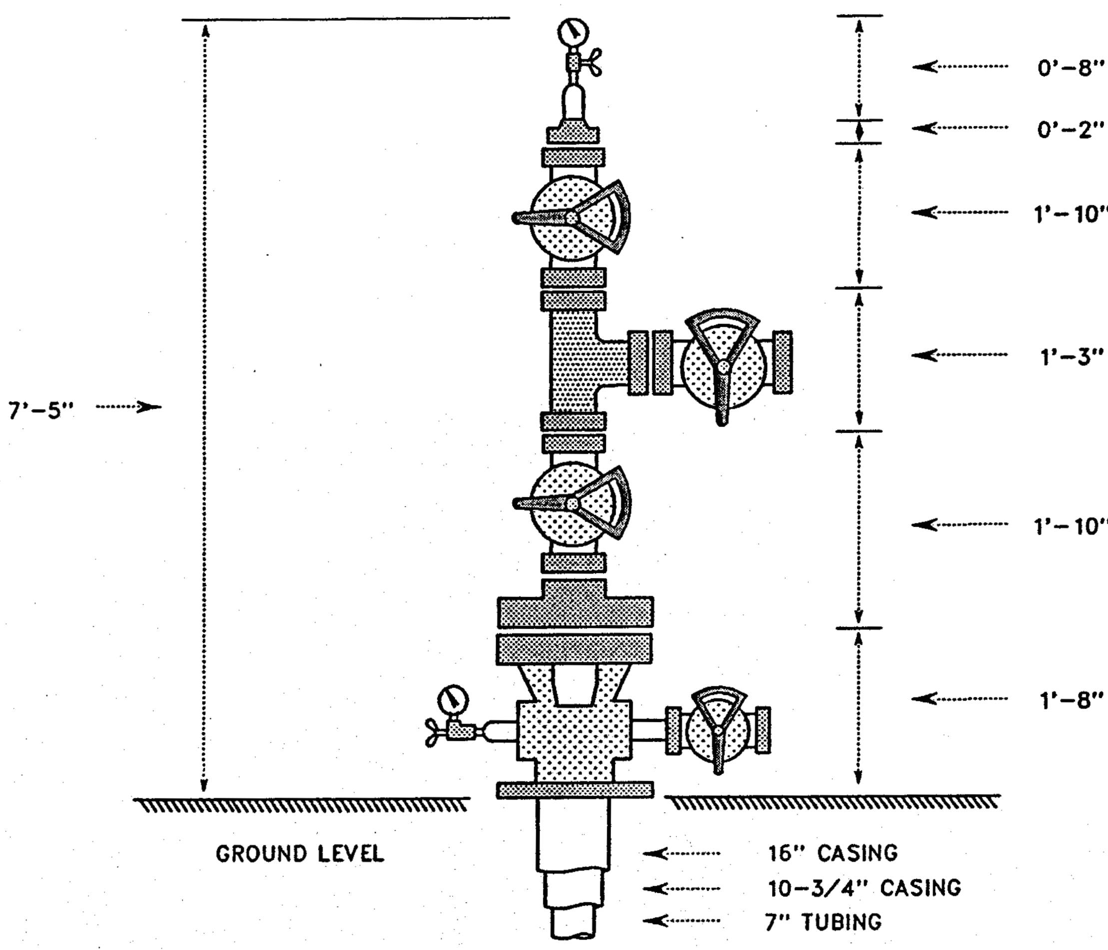
55. 2" CS NACE, 4" LGW w/1/2" LP tap bull plug

56. 1-13/16" 10,000# W.P. "C" x 1-13/16" 10,000# W.P. 6 BX FE x FE w/D-trim Gray gate valve

57. BX-158, API 316 S.S. ring gasket

58. 1/2" LP 10,000# W.P. S.S. NACE straight gauge cock

EOC/DOE GLADYS McCALL SWDW No. 1
Cameron Parish, Louisiana



EATON

Disposal Wellhead Dimension Schematic As Of 10/90.

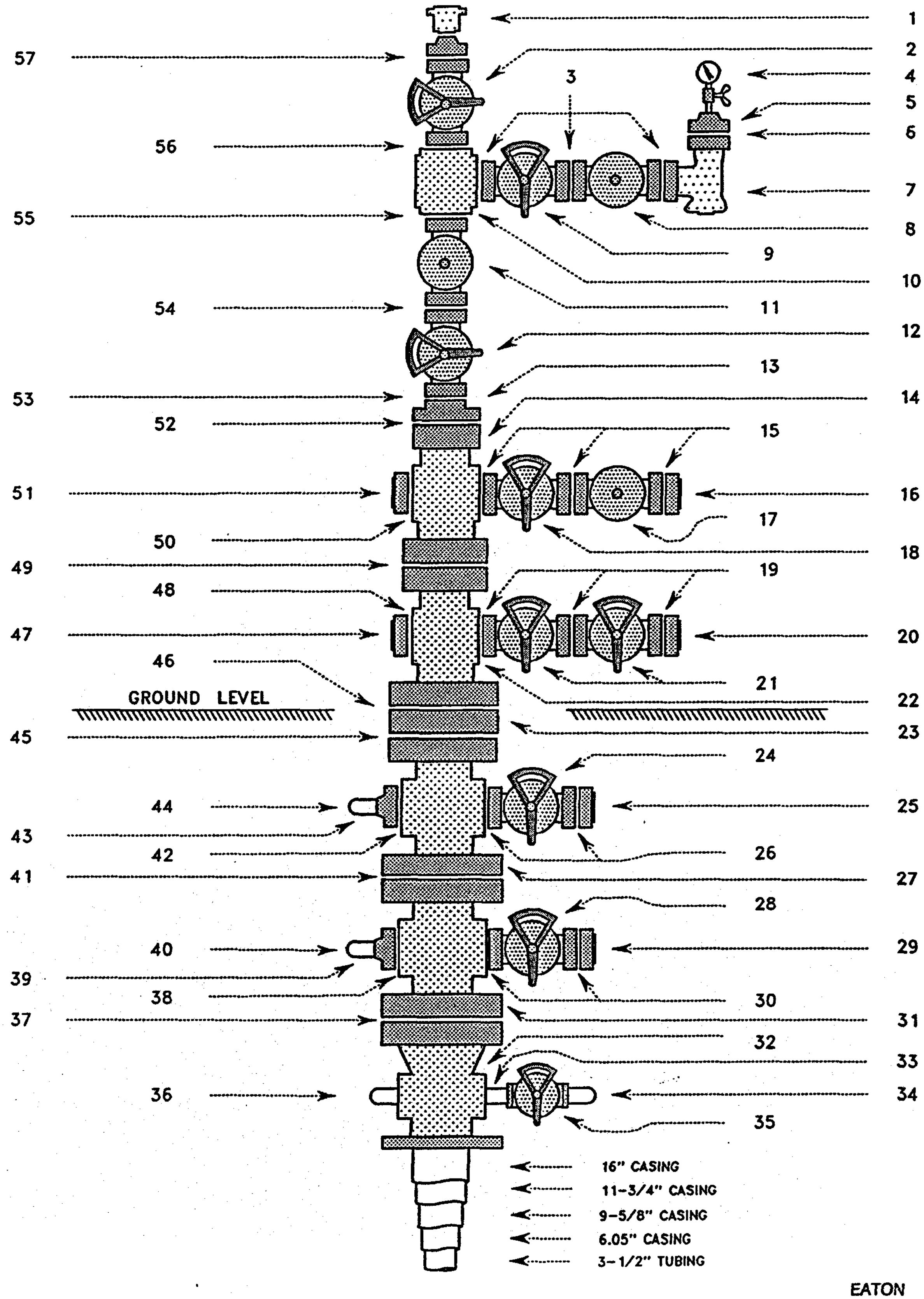
WELLHEAD SCHEMATIC

(With Description)

5. EOC/DOE Willis Hulin Well No. 1 (Production Well)

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
1240 Blalock, Suite 100
Houston, Texas 77055

EOC/DOE Willis Hulin No. 1
Vermilion Parish, Louisiana



Production Wellhead Description Schematic As Of 10/90.

<u>WILLIS HULIN NO. 1 PRODUCTION WELLHEAD</u>

1. 1-13/16" B-11-A-0 20,000# W.P. (special O-ring seal) treecap

2. 1-13/16" 20,000# W.P. WKM "m-1" FE x FE gate valve w/T-26 hi-temp trim (S/N 584198-1)

3. BX-151 API 304 S.S. ring gaskets

4. 1-3/8" S.S. straight gauge cock w/0-10,000# W.P. S.S. pressure gauge w/4-1/2" face

5. 1-13/16" 20,000# W.P. flange tapped w/1-3/8" autoclave, 12's UNC

6. BX-151 API 304 S.S. ring gasket

7. 1-13/16" 20,000# W.P. OCT, "PC" FE x FE positive choke

8. 1-13/16" 20,000# W.P. WKM "m-1" FE x FE gate valve w/Otis type "u" hydraulic operator w/T-26 hi-temp trim (S/N 581833-4)

9. 1-13/16" 20,000# W.P. WKM "m-1" FE x FE gate valve w/T-26 hi-temp trim (S/N 536612-3)

10. 1-13/16" x 1-13/16" x 1-13/16" 20,000# W.P. studded T-608 flow tee

11. 1-13/16" 20,000# W.P. WKM "m-1" FE x FE gate valve w/Otis type "u" hydraulic operator w/T-26 hi-temp trim (S/N Z-584563-1)

12. 1-13/16" 20,000# W.P. WKM "m-1" FE x FE gate valve w/T-26 hi-temp trim (S/N 538396-4)

13. 7-1/16" 20,000# W.P. open face bottom x 1-13/16" 20,000# W.P. studded top OCT "A-5-P" S.S. tubing head bonnet adaptor w/test port and w/bottom bored for hi-pressure extended neck tubing hanger

14. 7-1/16" 20,000# W.P. x 7-1/16" 20,000# W.P. OCT type "TCM-BG" tubing head w/two (2) 1-13/16" 20,000# W.P. F.P.O.'s and w/bottom bored for hi-pressure extended neck tubing hanger

WILLIS HULIN NO. 1 PRODUCTION WELLHEAD

15. BX-151 API 304 S.S. ring gaskets

16. 1-13/16" 20,000# W.P. blind flange tapped w/1-1/8" N.F.T.

17. 1-13/16" 20,000# W.P. WKM "m-1" FE x FE gate valve w/Otis type "u" hydraulic operator w/T-26 hi-temp trim (S/N Z-580038-3)

18. 1-13/16" 20,000# W.P. WKM "m-1" FE x FE gate valve w/T-26 hi-temp trim (S/N 575456-1)

19. BX-151 API 304 S.S. ring gaskets

20. 1-13/16" 20,000# W.P. blind flange tapped w/1-1/8" N.F.T.

21. 1-13/16" 20,000# W.P. WKM "m-1" FE x FE gate valves w/T-26 hi-temp trim (S/N's 575778-1 & 575822-4)

22. 7-1/16" 20,000# W.P. x 11" 15,000# W.P. FE x FE, 6.05" OCT type "TCM-00" tubing head w/two (2) 1-13/16" 20,000# W.P. F.P.O.'s (S/N - none)

    Note: includes 6" x 3-1/2" Armco Nu-Lock type "TC-1A-EN" tubing hanger, grooved for an OCT 3" type "IS" back pressure valve w/6.05" casing pack-off at the bottom of the 7-1/16" x 11" tubing head

23. 11" 15,000# W.P. x 11" 10,000# W.P. DSA w/internal 6.05" casing pack-off

24. 1-13/16" 10,000# W.P. WKM "m-1" FE x FE gate valve w/T-22 trim (S/N 535178-4)

25. 1-13/16" 10,000# W.P. blind flange tapped w/1-1/8" N.F.T.

26. BX-151 API 304 S.S. ring gaskets

27. 11" 10,000# W.P. x 13-5/8" 5,000# W.P. FE x FE, 9-5/8" OCT type "C-29-L-00" casing spool (S/N 54290)

    Note: includes - 10" x 6-1/16" OCT type "C-29" casing hanger at the top of the csg spool and a 9-5/8" csg pack-off at the bottom

WILLIS HULIN NO. 1 PRODUCTION WELLHEAD

28. 2-1/16" 5,000# W.P. WKM FE x FE gate valve w/T-22 trim (S/N 33969)

29. 2-1/16" 5,000# W.P. blind flange tapped w/1-1/8" N.F.T.

30. R-24 API ring gaskets

31. 13-5/8" 5,000# W.P. x 16-3/4" 3,000# W.P. FE x FE, 11-3/4" OCT type "C-29-L-00" casing spool (S/N 24884)

    Note: includes 12" x 9-5/8" OCT type "C-29" csg hanger at the top of the csg spool and a 11-3/4" csg pack-off at the bottom

32. 16-3/4" 3,000# W.P. OCT type "C-22" SOW casing head w/2" thick x 34" O.D. base plate and eight (8) 2" thick gussets (S/N none)

    Note: includes 16-3/4" x 11-3/4" OCT type "C-22" casing hanger at the top of the csg head

33. 2" x 6" XXH nipple

34. 2" XXH bull plug

35. 2-1/16" 3,000# W.P. WKM thread x thread S.S. gate valve w/T-21 trim (S/N 555530-1)

36. 2" XXH bull plug

37. R-66 API ring gasket

38. R-24 API ring gasket

39. 2-1/16" 5,000# W.P. companion flange w/2" N.F.T.

WILLIS HULIN NO. 1 PRODUCTION WELLHEAD

40. 2″ XXH bull plug
41. BX-160 API ring gasket
42. BX-151 API ring gasket
43. 1-13/16″ 10,000# W.P. companion flange w/2″ N.F.T.
44. 2″ XXH bull plug
45. BX-158 API ring gasket
46. BX-158 API ring gasket
47. 1-13/16″ 20,000# W.P. blind flange
48. BX-151 API 304 S.S. ring gasket
49. BX-156 API 304 S.S. ring gasket
50. BX-151 API 304 S.S. ring gasket
51. 1-13/16″ 20,000# W.P. blind flange
52. BX-156 API 304 S.S. ring gasket
53. BX-151 API 304 S.S. ring gasket
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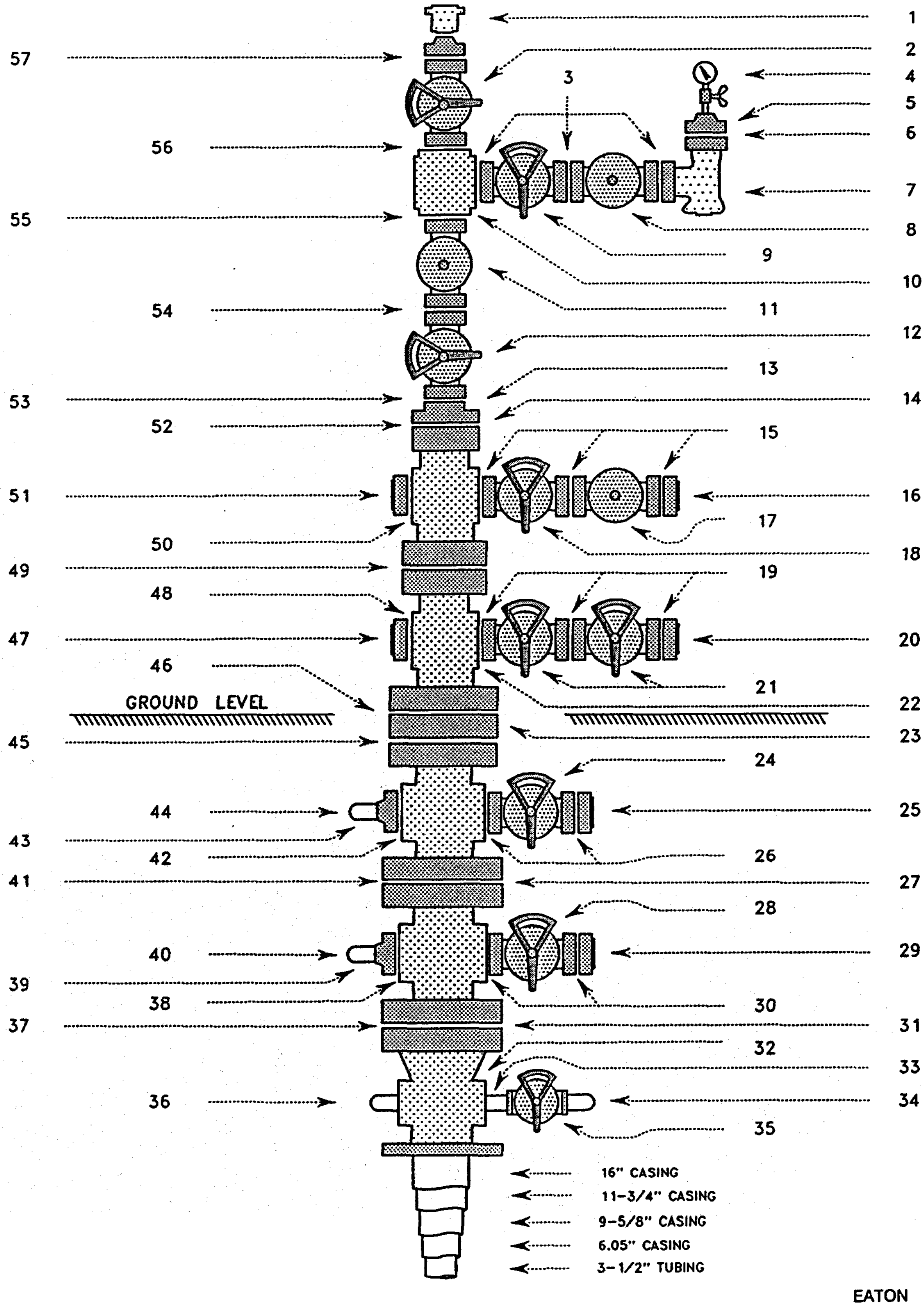
EOC/DOE Willis Hulin No. 1
Vermilion Parish, Louisiana



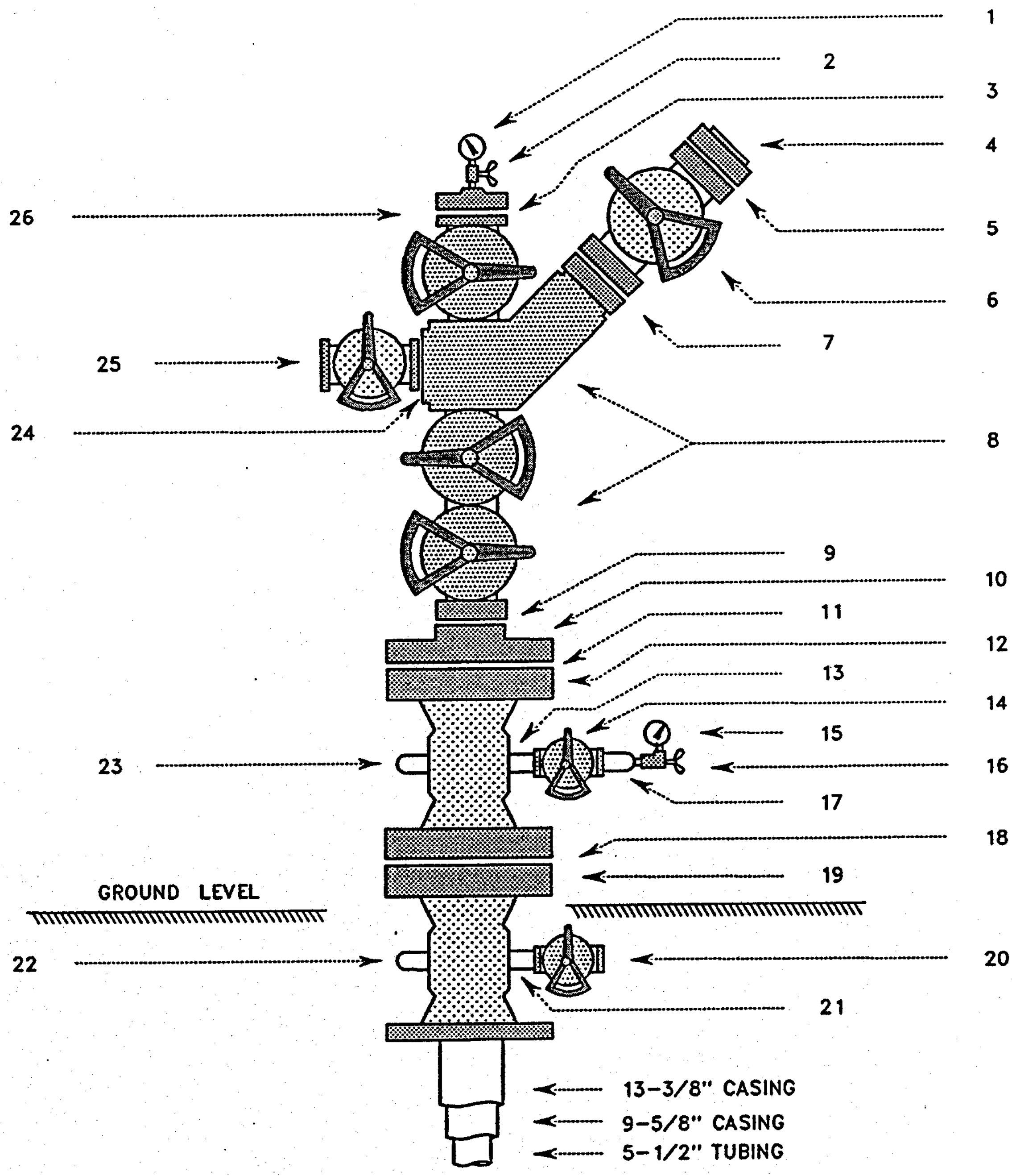
Production Wellhead Description Schematic As Of 10/90.

WELLHEAD SCHEMATIC

(With Description)

6. EOC/DOE Willis Hulin CVW No. 1 (Disposal Well - Class V)

EOC/DOE WILLIS HULIN CVW No. 1
Vermilion Parish, Louisiana



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Disposal Wellhead Description Schematic As Completed by EOC 2/89.

WILLIS HULIN C V W NO. 1 DISPOSAL WELLHEAD

1. 1/2" N.P.T. x 4-1/2" face, 0-5,000 PSI W.P. pressure gauge
2. 1/2" N.P.T. 5,000# W.P. needle valve
3. 2-7/8" 8 Rd nipple w/1/2" N.P.T. tap
4. 7-1/16" 5,000# W.P. flange w/2-7/8" 8 Rd R.F.
5. 7-1/16" 5,000# W.P. flange x 6" weld neck
6. R-46 API 316 S.S. ring gasket
7. 7-1/16" 5,000# "OCT", Model 20, balanced stem FE x FE gate valve (7-1/8" drift)
8. R-46 API 316 S.S. ring gasket
9. Composite tree consisting of: two (2) master valves and one (1) swab valve, each being 7-1/16" 5,000# "OCT", Model 20, balanced stem gate valves (7-1/8" drift); one (1) 7-1/16" 5,000# studded wing angled at 45 degrees from tree body,, and one (1) 4-1/16" 5,000# flanged wing at 90 degrees to body
10. R-50 API 316 S.S. ring gasket
11. 11" 5,000# W.P. x 9" 5,000# W.P. DSA
12. R-54 API 316 S. S. ring gasket
13. 13-3/8" 3,000# W.P. x 11" 5,000# W.P. w/two (2) 2" L.P.S.O.'s, tubing spool
14. 2" L.P. x 6" long, XXHVY nipple
15. 2" L.P. API 3,000# W.P. gate valve
16. 1/2" N.P.T. x 4-1/2" face, 0-5,000# pressure gauge
17. 1/2" N.P.T. needle valve
18. 2" L.P., tapped w/1/2" N.P.T., XXHVY bull plug
19. R-57 API 316 S.S. ring gasket

WILLIS HULIN C V W NO. 1 DISPOSAL WELLHEAD

20. 13-3/8" S.O.W. x 13-5/8" API 3,000# W.P. w/two (2) 2" L.P.S.O.'s and base plate for 20", casinghead

21. 2" L.P. 3,000# W.P. ball valve

22. 2" L.P. x 6" long, XXHVY nipple

23. 2" L.P. solid, SSHVY bull plug

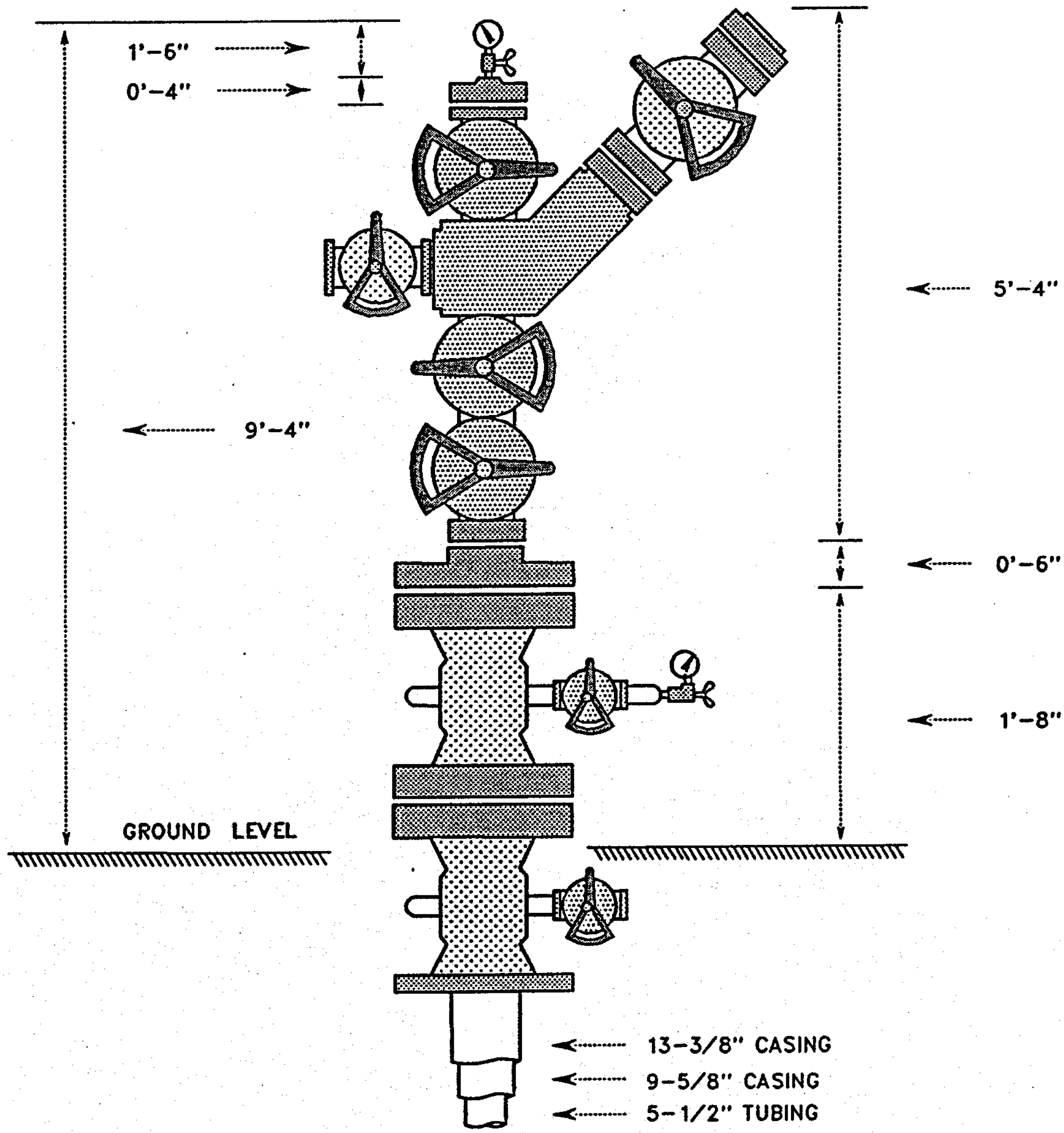
24. 2" L.P. solid, XXHVY bull plug

25. R-39 API 316 S.S. ring gasket

26. 4-1/16" 5,000# "OCT" Model 20, balanced stem FE x FE gate valve

27. R-46 API 316 S.S. gasket

EOC/DOE WILLIS HULIN CVW No. 1
Vermilion Parish, Louisiana



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Disposal Wellhead Dimensions Schematic As Completed by EOC 2/89.

CONTRACTOR FOR GEOPRESSURED-GEOTHERMAL SITES

EATON OPERATING COMPANY

FINAL CONTRACT REPORT

FISCAL YEARS 1986-1990 (5 YEARS)

1.0 EXECUTIVE SUMMARY

Eaton Operating Company (EOC) (Houston, TX) and its two prime subcontractors, the Institute of Gas Technology (IGT) (Chicago, IL) and The Ben Holt Co. (BHC) (Pasadena, CA) assumed operation of the Department of Energy's (DOE) three Gulf Coast Geopressured-Geothermal Field Sites in September 1985 for five years (fiscal years 1986-1990). This Final Report covers the activities completed during this period. (Other reports (shown in References) were made of operations by other contractors prior to this contract period.)

The Gulf of Mexico sedimentary basin contains large reservoirs of abnormally high pressured (geopressured), hot (geothermal) brines. These reservoirs contain gas, primarily methane, dissolved in the brine, with the amount in solution dependent on brine salinity, pressure, temperature and source of the methane. The reservoirs may also contain free gas (see Glossary). The free gas is usually accumulated at the geologic structural top of the reservoir. The free gas has been commercially exploited for years by the petroleum industry, but the geopressured-geothermal brines containing dissolved gas have not been commercially utilized.

Geopressured-geothermal reservoirs have been tested along the Louisiana-Texas Gulf Coasts under two prior DOE programs (see Exhibits 1-1 and 1-2):

- o In the "Wells of Opportunity Program" (1977-1982), twelve wells were taken over by DOE from industry, before being abandoned as not being commercial for initial or continued hydrocarbon production. Nine of these wells were tested for short terms of less than a month. Another well, the Willis Hulin well in Vermilion Parish, LA, was acquired in 1984, but was not tested until done under this contract.

- o The original "Design Well Program" (1979-1985) in which four wells were drilled and completed for long-term testing. Tests were completed on two wells and were continued on the other two under this contract (FY 1986-1990). The two design wells currently testing are: the Gladys McCall Well No. 1 in Cameron Parish, LA; and the Pleasant Bayou Well No. 2 in Brazoria County, TX.

The five technical goals of DOE for development of the brines under the geopressured-geothermal research program have been to:

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