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INSTITUTE OF GAS TECHNOLOGY (IGT)
FINAL REPORT

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**RESEARCH AND DEVELOPMENT FOR THE
GEOPRESSURED-GEOTHERMAL ENERGY PROGRAM**

**TESTING OF THE PLEASANT BAYOU WELL
THROUGH OCTOBER 1990**

Final Report for the Period October 1985-October 1990

Prepared by

INSTITUTE OF GAS TECHNOLOGY

for

EATON OPERATING COMPANY

**IGT/EOC Subcontract
IGT/EOC-85-4**

**DOE Prime Contract
DE-AC07-85ID12578**

August 1992

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EXECUTIVE SUMMARY

The Pleasant Bayou No. 2 well was the first Design Well drilled and completed in the U.S. Department of Energy (DOE) Geopressured-Geothermal Energy Program. It was drilled in 1979 after mechanical problems precluded completion of the Pleasant Bayou No. 1 well, which was subsequently used as the brine disposal well.

The location was selected in a multiyear, multi-department research program at the University of Texas in Austin that was coordinated by the Center for Energy Studies at the university. The contractor to DOE for the drilling and initial testing was General Crude Oil Company. Initial testing (Phase 0) of the 60-foot-thick sandstone reservoir in 1979 revealed permeability in excess of 100 millidarcies (md) and validated the reservoir as being adequate for construction of surface facilities for long-term, high-rate testing.

Surface facilities designed for long-term, high-rate testing were operated, with Fenix & Scisson as the prime contractor, for about 6 weeks at an average brine rate slightly below 12,000 barrels per day in 1980. Production rate was limited because pseudoscale caused high injection pressure on the disposal well. The test provided the most extensive set of bottomhole pressure measurements that have been obtained from the well.

A few days of attempts to flow at a brine rate of 29,000 barrels per day in 1981 ended with the need to pull the tubing to remove over 14,000 feet of wireline.

During the period from September 1982 through April 1983, almost 3.5 million barrels of brine were produced at an average brine rate of about 18,200 stock tank barrels per day (STB/d). Scale buildup in the production tubing and wellhead interfered with the planned deduction of bottomhole pressure from wellhead pressure. The 5-1/2 inch tubing contained 1/4 to 3/8 inch of scale in almost 12,000 feet of its length, and the tubing parted at a depth of 5225 feet about 3 weeks after the well was shut in.

The Pleasant Bayou location was inactive from 1983 until the cleanout of the production and disposal wells by Eaton Operating Company in 1986. The surface facilities were rehabilitated in 1987 and 1988. After shakedown of the system, additional repair of wellhead valves, and injection of an inhibitor pill, continuous long-term production was started in June 1988.

After a few months of production provided confidence that the well would provide a viable source of fluids to drive a Hybrid Power System (HPS) designed by the Electric Power Research Institute (EPRI), the HPS was assembled. A flow splitter was designed and installed to allow HPS operation independent of reservoir testing, as long as the brine rate for reservoir testing was greater than the 10,000 barrel per day design rate for the HPS.

During the period from August 1989 through May 1990, a total of 41.5 million standard cubic feet (SCF) of produced natural gas and 1.40 million STB of brine were delivered to the HPS. Total production from the reservoir during that time was 94.1 million SCF of natural gas and 3.91 million STB of brine. Taking into account the heating value of the gas and the actual brine temperature drop in the HPS, the energy delivered to the HPS was 39.7×10^9 Btu of gas energy and 67.8×10^9 Btu of thermal energy in the brine. It is noted that the thermal energy content of this brine was 109.9×10^9 Btu when calculated against the temperature base of 60°F that is normally used in the context of geothermal resources.

During the 2 years of production through the completion of the HPS operation at the end of May, 1990, 256.1 million SCF of natural gas and 10.68 million STB of brine were produced with brine rates at the lower end of the range of 15,000 to 20,000 STB/d for most of the time. After completion of the HPS work and comprehensive reviews of safety and QA/QC, the production rate was increased in a stepwise fashion seeking understanding of the phenomenon that would set the upper limit on the maximum rate.

After 12 days at a brine rate of 24,100 STB/d, production of roughly a cubic foot of sand was indicated by a sudden increase in pressure drop across the filters on October 28, 1990. A slightly larger "slug" of sand had been produced only 2 hours after brine rate was increased to 25,000 STB/d 2 years earlier on June 20, 1988. It thus appears that the maximum practical rate without sand production will be in the vicinity of 24,000 STB/d. Total production from recompletion of the wells in 1986 through October 1990 was 301.3 million SCF of natural gas and 12.58 million STB of brine.

The produced brine contains about 134,000 mg/L of dissolved solids. There was no change in the composition of produced brine during the time covered by this report. The salinity is about 8% lower than reported from the earlier testing. This is assumed to be because the early samples were collected hot and that percent of the water evaporated before the laboratory analysis.

The gas to the sales line contains about 10% carbon dioxide, about 0.1% aromatic hydrocarbons, and about 1.2 gallons of NGL per 1000 SCF. It has a gravity of 0.69 and a heating value of about 950 Btu/SCF. Neither gas composition nor the produced gas/brine ratio changed through the completion of testing of the HPS. As brine rate was increased stepwise to more than 20,000 STB/d, measured gas/brine ratio declined by a few percent. But additional work needs to be done before concluding that the calculated flowing pressure of 9020 psia at the top perforation (14,644 feet) was below the bubble point of the reservoir brine. This lowest calculated flowing pressure at the top perforation was only 2000 psi less than the static pressure measured at that depth in 1986 and 1988.

The gas leaves the separators at a temperature in excess of 250°F. It also contains both water vapor and aromatic hydrocarbons that condense as the gas is cooled. The quantity of condensed liquid hydrocarbons has averaged about 2 parts per million in the produced brine. This gallon or two of daily production is not the alkane "condensate" normally associated with natural gas. The mixture includes benzene, toluene, xylenes, and naphthalenes. It has a specific gravity in excess of 0.95.

Scale formation in the wellbore has been prevented by phosphonate inhibitor "pills" that were pumped into the producing formation in April 1988 and November 1989. Supplemental injection of scale inhibitor at the surface was started in March 1989, after production of 4.95 million barrels of brine following injection of the first pill. Supplemental surface injection was again started in May 1990, after production of 2.75 million barrels of brine following injection of the second pill. Seizing of the bearings in brine turbine meters was found to provide early warning of the start of scaling in surface facilities.

Polymaleic anhydride has been found to be ideally suited for supplemental injection while monitoring the concentration of phosphonate inhibitor from the pills. It is effective at concentrations in the range of 0.20 to 0.30 mg of polymaleic anhydride per liter of brine. Measured concentrations of phosphonate in brine produced since the second inhibitor pill have spanned almost an order of magnitude and have averaged 0.18 mg of phosphonate per liter of brine.

On the basis of experience at the Gladys McCall well, the highly turbulent areas immediately downstream of chokes and level-control valves were either fabricated from stainless steel or internally clad with stainless steel to reduce corrosion. Corrosion inhibitor had not been used during years of production at the Gladys McCall well and was not injected during the first million barrels of Pleasant Bayou production in 1988. Metal-loss rates as high as an inch per year were observed on some coupons, and corrosion pits penetrated old 4-inch Schedule 80 piping at two locations within a 20-foot span upstream of the large separator. Internal inspection of piping revealed widespread onset of erosion/corrosion at locations where irregularities on internal surfaces induced local turbulence. Water-soluble quaternary alkyl pyridine inhibitor has been found to be very effective in stopping this corrosion at a concentration as low as 7 parts per million by volume (ppmv) of commercial product (Champion Technologies, Inc., Corton RN-97) in the brine.

Long-term production testing of the reservoir at brine rates in excess of 20,000 STB/d is expected to continue for at least another year.

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

1.0. INTRODUCTION

The Pleasant Bayou No. 2 well was the first Design Well drilled in the Department of Energy (DOE) Geopressured-Geothermal Energy Program. The objective of the program is to evaluate the geopressured-geothermal resource as a possible source of energy for the nation. The Gulf Coast geopressured-geothermal wells, such as the Pleasant Bayou well, produce hot brine and the hydrocarbons dissolved in the brine. The possible energy sources from these wells consist of the heat, pressure, and recoverable hydrocarbons. The Pleasant Bayou test focused on evaluating the reservoir response to production, mitigating operating problems such as corrosion and scale formation, determining the quantity and characteristics of the recoverable hydrocarbons, and utilizing the natural gas and thermal energy to generate electricity.

This report focuses on the data obtained from the well-test program subsequent to rework of the production well by Eaton Operating Company in 1986. The intent is to provide detailed data on the physical and chemical processes involved in producing energy from the Pleasant Bayou well and to provide information that may be useful for future production from wells with a high water cut, including other geopressured-geothermal wells.

1.1. Project Location

Exhibits 1.1-1 and 1.1-2 show the Pleasant Bayou project location on a USGS geodetic map and on a road map of the area, respectively. The site is in Brazoria County, Texas, at a location about 40 miles south of Houston, Texas. The location is adjacent to Chocolate Bayou and is on well-drained solid ground. Access to the location is via 3.5 miles of high-quality gravel road that intersects Farm Road 2917 about halfway between State Highway 35 and Farm Road 2004. The nearest neighbors on the same side of Chocolate Bayou are chemical plants operated by Amoco, Monsanto, and Oxy Chem. The main entrance to the Amoco Plant is on Highway 2004. The entrances to the Monsanto and Oxy Chem plants are on Farm Road 2917 between Farm Road 2004 and the gravel road to the Pleasant Bayou project location.

1.2. Summary of Geology

The location of the Pleasant Bayou project was selected on the basis of extensive studies at the University of Texas in the mid-1970s. These studies involved efforts by personnel in several departments at the University that were coordinated by the Center for Energy Studies. In addition to geological assessments by the Bureau of Economic Geology, the studies included baseline environmental monitoring, evaluation of the legal issues relevant to production of geopressured-geothermal energy, and projections of the economics of energy production from the resource.

Exhibit 1.1-1. PLEASANT BAYOU PROJECT LOCATION ON A USGS MAP

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.1-2. PLEASANT BAYOU PROJECT LOCATION ON A ROAD MAP

Selection of the Pleasant Bayou location started with a regional geologic investigation based on a grid of Frio formation correlation sections.¹ The well log control and cross sections constructed over the entire onshore portion of the Texas Gulf Coast are shown in Exhibit 1.2-1. The objective of the regional studies was to outline geothermal fairways containing thick sandstone bodies having fluid temperatures higher than 300°F. One of these was the Brazoria Fairway that parallels the Gulf Coast in Brazoria and Galveston Counties.

The fairways then became the targets of additional work to determine reservoir size, the relationship to major and minor growth faults, porosity and permeability, and the nature of the porosity (diagenetic fabric). In addition to the 300°F temperature specification, the objective was to locate reservoirs having a volume greater than 3 cubic miles and a minimum permeability of 20 millidarcies (md). It was expected that water salinity would be in the range of 20,000 to 80,000 ppm total dissolved solids (TDS) and that the water would be saturated with methane [40 to 50 SCF/STB (standard cubic feet per stock tank barrel)]. Initial bottomhole pressure was expected to be in excess of 10,000 psi.

The Austin Bayou prospect in the Brazoria Fairway was found to a prime candidate to meet these criteria, and the Pleasant Bayou wells were drilled in that prospect area. Exhibit 1.2-2 shows the location of the Pleasant Bayou project on a structure map on the top of the T5 marker in the Frio sequence. The site is in a synclinal area characterized by loading with large quantities of shale and sandstone. Salt withdrawal from the synclinal area, as a result of this loading, supplied salt for the growth of Danbury dome and other salt anticlines on the northwest side of the fairway. The Pleasant Bayou location is a compromise in the context that temperature and sandstone thickness increase to the southwest whereas permeability was believed to increase to the northeast.

Sand deposition in the Austin Bayou prospect prior to penetration of the Frio by salt structures is believed to have consisted of multiple depositional sequences of high-constructive lobate deltas as illustrated in Exhibit 1.2-3. A net sand thickness of 800 to 900 feet, of which 30% to 35% would have adequate permeability, was expected in the depth interval from 13,500 to 16,500 feet.

The pores in the target sandstone are not simply the result of preservation of primary porosity. They dominantly consist of secondary leached-grain porosity. Most stages of consolidation of the sandstone at shallow-to-moderate depths resulted in destruction of the porosity through compaction and precipitation of calcite and quartz cements. At depths of about 9000 to 11,000 feet, a major stage involving leaching of feldspar, volcanic and carbonate rock fragments, and calcite cement occurs. Below about 11,000 feet, leached porosity is reduced by precipitation of kaolinite and iron-rich carbonate cement. One important result of this geologic history is a strong rock matrix and minimal sand production with the brine.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.2-1. CROSS SECTIONS FOR THE FRIO FORMATION REGIONAL STUDY

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.2-2. STRUCTURE MAP ON THE TOP OF THE T5 MARKER

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.2-3. PROGRADATIONAL LIMITS OF DEPOSITIONAL SEQUENCES

1.3. Summary of Drilling of the Disposal and Production Wells

A contract was executed between DOE and the General Crude Oil Company, which owned a large block of land that included the desired location for the design well test. The contract provided for drilling of the wells and conduct of production testing by General Crude Oil Company. Sub-contractors under the General Crude contract included 1) Welsh Drilling and Service Company, to provide the rig and crew to drill the test well; 2) Hudson Engineering, to design the surface facilities; and 3) S & B Contractors, to install the surface facilities.

General Crude Oil Company was acquired by Mobil Oil during 1979, and the prime contractor was changed to Fenix & Scisson during 1980. A report on the details of the drilling, completion, and initial testing of the two wells was assembled by J. A. Rogers of Gruy Federal, Inc., and published in November 1980.¹⁸ Gruy Federal was a subcontractor to Fenix & Scisson. Much of the material in the report was provided by Fenix & Scisson from records of General Crude Oil Company and General Crude's subcontractors. A second report by the same author covers operations until October 23, 1982.¹⁷

1.3.1. Disposal Well

The Pleasant Bayou No. 1 well was spudded July 1, 1978, and drilled to a depth of 15,676 feet, where a core barrel became stuck while preparing to cut core No. 10. After fishing for 56 days, the operator temporarily abandoned the hole. A workover rig was later used to convert the Pleasant Bayou No. 1 well to a brine disposal well.

At the time that the well was temporarily abandoned, it contained --

1. Conductor casing (26-inch, 1/2-inch wall) that had been driven to 97 feet below the rotary table or 67 feet below ground level
2. Surface casing (20-inch, 900 feet of H-40, 94.01-pound-per-foot and 419 feet of K-55, 106.5-pound-per-foot) that had been cemented to 1319 feet with good cement returns to the surface
3. Intermediate casing (13-3/8 inch, 3900 feet of S-95, 72.0-pound-per-foot and 4601 feet of L-80, 72.0-pound-per-foot) that had been cemented to 8501 feet with good cement returns
4. A fish consisting of 4-1/2 inch drill pipe, drill collars, and a core barrel in the depth interval between 10,475 and 15,646 feet
5. A fish consisting of 4-1/2 inch drill pipe in the depth interval between 8619 and 10,051 feet that had been used to displace seven cement plugs (2400 sacks total) to 10,051 feet and then not recovered
6. Cement plugs consisting of a 233-sack cement plug that had been spotted with drill pipe at 8580 feet and a second plug (80 sacks) that was spotted with drill pipe at 1250 feet.

Two 125-sack cement squeezes of the 13-3/8 inch casing had been performed due to leaks within the interval of 4250 to 4340 feet.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.3.1-1 is a list of wireline operations during drilling. Exhibit 1.3.1-2 is a list of the depths at which radioactive markers were placed. Exhibit 1.3.1-3 is a core record for the well. Results of conventional core analyses by Core Laboratories, Inc., are provided in Appendix A.

Exhibit 1.3.1-1. PLEASANT BAYOU NO. 1 WIRELINE OPERATIONS IN 1978-1979

7/7/78	Dresser Atlas attempted to log surface; stopped at 98, 406, and 360 ft.
7/8/78	RA bullets spotted, ran IES log.
7/29/78	Dresser Atlas ran DIFL, BHC sonic, caliper, CNL, CDL, GR, and 50-shot SWC gun. TD = 8478 ft.
8/9/78	RA bullets spotted.
8/22/78	Ran Dialog caliper from 8425 to 0 ft.
9/17/78	Ran Dialog and 13-3/8 inch caliper log, lost tool at 8192 ft.
9/28/78	Ran induction log. Located top of fish at 10,742 ft with WL log.
10/9/78	Dresser Atlas obtained IES log 12,308 to 8478 ft.
11/5/78	Ran DILL and acoustic log.
11/11/78	Running caliper survey in 13-3/8 inch casing.
12/27/78	Ran McCullough noise log, temperature survey, and free point. Tool stopped at 9997 ft.
12/28/78	Ran McCullough temperature log from surface to 10,003 ft.
12/29/78	Ran McCullough noise log to 10,003 ft.
12/30/78	Ran McCullough noise log to 9800 ft.
12/31/78	Ran McCullough noise log.
1/1/79	Ran McCullough noise log.
1/2/79	Ran free-point indicator.
10/23/79	Ran CCL-GR from 7200 ft to surface. Perforated 7125 to 7127 ft (DFFL).
10/24/79	Perforated 6010 to 6012 ft.
10/26/79	Dresser Atlas perforated 6012 to 6026 ft (DIF log).
10/31/79	Dresser Atlas ran GR collar from 7000 ft to surface.
11/2/79	Perforated with 4-inch jumbo jet gun from 6518 to 6538, 6494 to 6514, and 6460 to 6480 ft.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.3.1-2. DEPTHS OF RADIOACTIVE MARKERS IN PLEASANT BAYOU NO. 1

<u>Depth, ft</u>	<u>Depth, ft</u>	<u>Depth, ft</u>
110	2900	5600
200	3000	5700
300	3100	5800
400	3200	5900
500	3400	6000
600	3500	6100
700	3600	6200
800	3700	6300
900	3800	6400
1000	3900	6500
1100	4000	6700
1200	4100	6800
1300	4200	6900
1500	4300	7000
1600	4400	7100
1700	4500	7200
1800	4600	7300
1900	4700	7400
2000	4800	7600
2100	4900	7700
2200	5000	7900
2300	5100	8000
2400	5200	8100
2500	5300	8200
2600	5400	8400
2800	5500	

Completion of the Pleasant Bayou No. 1 well for brine disposal started with drilling out the cement plug that had been spotted at 1250 feet. Then an attempt was made to squeeze cement through perforations in the depth interval from 7125 to 7127 feet, below the planned disposal injection interval. When 2100 psi of surface pressure through an EZ-SV tool at 7000 feet could not break down the perforations, a 35-sack cement plug was placed on top of the tool, leaving the top of the cement at 6950 feet.

The annulus outside the 13-3/8 inch casing above the planned disposal interval was squeezed with 35 sacks of cement through perforations in the depth interval of 6010 to 6016 feet.

Exhibit 1.3.1-3. PLEASANT BAYOU NO. 1 CORE RECORD

<u>No.</u>	<u>----- Depth, ft -----</u>		<u>Feet</u>	<u>Feet</u>	<u>Description</u>
	<u>From</u>	<u>To</u>	<u>Cut</u>	<u>Recovered</u>	
1	4,300	4,350	50	10	2-1/2 ft ringtailed shale, 3 ft soft consolidated sand, 4-1/2 ft unconsolidated sand
2	6,700	6,750	50	8	8 ft sand and shale
3	10,215	10,270	55	52.5	33.5 ft sand, 19 ft ringtail shale
4	11,732	11,792	60	54	32 ft sand, 22 ft shale
5	12,580	12,634	54	51	4 ft siltstone, 47 ft ringtail shale
6	14,053	14,104	51	51	33 ft sand, 18 ft ringtail shale
7	14,745	14,771	36	19	8 ft medium-grained sand, 2 ft black silty shale, 9 ft med-to-coarse grained sand
8	15,147	15,202	55	40	40 ft sand with shale streaks
9	15,543	15,593	50	36	36 ft shale and sand
			461	321.5	

A string of 9-5/8 inch, 40.0-pound-per-foot, N-80 buttress thread casing was cemented to the surface from a depth of 5990 feet to ensure integrity of the casing. After running a bit to the top of the cement plug at 6950 feet and circulating the mud from the hole with fresh water, a 9-5/8 X 5-1/2 inch packer was set at 5865 feet by wireline. Then, injection tubing (5-1/2 inch, 14.0-pound-per-foot K-55 LT&C ABC modified, internally coated with TD2) was run with the bottom of seals at 5873 feet. Three depth intervals (6538 to 6518, 6514 to 6494, and 6480 to 6460 feet) were perforated with four shots per foot using 4-inch jumbo jet guns. After firing, the wireline pulled from the rope socket on the first gun. It was pushed to the bottom and left in the well. Exhibit 1.3.1-4 is a schematic diagram of the well as configured in 1979 for its first use as an injection well. Additional perforations were added in 1981 and 1990.

Preparation for Phase II testing in 1981 included perforating three more intervals (6426 to 6390, 6380 to 6362, and 6262 to 6226 feet) with four shots per foot. These increased the total perforated footage between 6226 and 6538 feet to 150 feet. Exhibit 1.3.1-5 is an electric log with the perforated intervals shown.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.3.1-4. PLEASANT BAYOU NO. 1 AS PREPARED FOR INJECTION IN 1979

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.3.1-5. ELECTRIC LOG OF PLEASANT BAYOU NO. 1 SHOWING INTERVALS PERFORATED IN 1979 AND 1981

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

1.3.2. Production Well

After temporarily abandoning the Pleasant Bayou No. 1 well, the drilling rig was moved to an offset location on the other side of the mud pit, and drilling of the Pleasant Bayou No. 2 well was started on January 25, 1979. This hole was drilled to a total depth of 16,500 feet and was completed as a geopressured-geothermal well on July 11, 1979.

Exhibit 1.3.2-1 is a listing of wireline operations during the drilling of the well. Exhibit 1.3.2-2 is a list of the depths at which radioactive markers were placed. Exhibit 1.3.2-3 is a directional survey of the well. Exhibits 1.3.2-4 and 1.3.2-5 are schematic diagrams of the tubulars that were cemented into the Pleasant Bayou No. 2 well and a tabulation of the properties of those tubulars, respectively. Exhibit 1.3.2-6 is a core record for the well. Results of conventional core analysis by Core Laboratories, Inc., are provided at the end of Appendix A.

Exhibit 1.3.2-1, Part 1. PLEASANT BAYOU NO. 2 WIRELINE OPERATIONS IN 1978-1979

1/31/79	Dresser Atlas attempted IES log, failed to get below 285 ft.
2/1/79	Ran Dresser Atlas IES log and hit bridge at 287 ft; three RA bullets at 354, 254, and 106.5 ft.
2/21/79	Ran Dresser Atlas dual induction focused DHC acoustic log from 8517 to 1395 ft. Ran caliper from 8517 to 1395 ft. Obtained long-spaced sonic log 8516 to 1395 ft.
3/2/79	Ran CBL from 8479 ft to surface.
3/6/79	Ran gyro survey to 8400 ft, tool failure. Made 2nd run to 8450 ft with no results.
3/7/79	Ran casing caliper profile log, tool stopped at 6033 ft. Caliper survey of 13-3/8 inch tool failed. Pulled out of rope socket -- fished.
3/8/79	Ran Sperry-Sun gyro survey from 8400 ft to surface. Ran casing caliper from 7840 ft to surface.
4/17/79	Ran casing caliper from 8488 ft to surface.
4/19/79	Bit at 14,310 ft worked free. Free point at 10,751 ft.
4/23/79	Ran long-spaced sonic 14,340 to 8488 ft.
4/24/79	Dresser Atlas DILL focused with GR and Caliper from 14,342 to 8488 ft. Twelve RA bullets.
5/5/79	Ran Dresser Atlas CBL tool to 9100 ft and failed.
5/6/79	Ran CBL-VDL GR with Dresser. Ran Dialog casing profile caliper.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.3.2-1, Part 2. PLEASANT BAYOU NO. 2 WIRELINE OPERATIONS IN 1978-1979

5/29/79	Schlumberger attempted to run long-spaced sonic -- failed due to temperature. Dresser Atlas ran DILL with caliper -- caliper tool failed. Ran GR/sonic -- sonic tool failed.
5/30/79	Ran GR sonic caliper -- no log.
5/31/79	Dresser Atlas attempted to run GR density with caliper tool -- failed at 11,300 ft. Ran compensated sonic with GR neutron; ran long-spaced sonic.
6/1/79	Ran FDC-CNL and GR-HRD logs.
6/7/79	Attempted to run Sperry-Sun gyro, tool failed at 12,500 ft. Ran CBL, tool stopped at 10,808 ft.
6/8/89	Ran gyro from 8400 to 14,000 ft. Ran GRN-CBL with VDC and CCL, tool stopped at 14,800 ft.
6/9/79	Ran CBL from 16,421 to 13,576 ft. Ran GRN from 16,420 to 13,490 ft.
6/10/79	Schlumberger ran high-resolution temperature log from TD to surface. Birdwell ran VSP log.
6/12/89	Schlumberger GRN in 9-5/8 inch casing.
6/13/89	Dresser Atlas ran CBL on 7-inch liner with 1500 psi on casing.
6/14/79	Ran Spectro log from 16,417 to 13,700 ft; neutron lifetime log from 16,417 to 8906 ft.
6/15/79	Ran 9-5/8 inch Dialog casing profile caliper log.
6/16/79	Perforated from 15,988 to 16,006 ft and 16,038 to 16,046 ft.
6/20/79	Perforated from 15,576 to 15,586 ft GRN.
7/5/79	Ran 2-7/8 inch gauge and collar locator from 13,800 to 14,600 ft.
7/9/79	Perforated from 14,647 to 14,707 ft GRN-PDC.

Exhibit 1.3.2-2. DEPTHS OF RADIOACTIVE MARKERS IN PLEASANT BAYOU NO. 2

<u>Depth. ft</u>	<u>Depth. ft</u>	<u>Depth. ft</u>	<u>Depth. ft</u>
160.5	4,500.0	10,300.0	14,300.0
254.0	5,500.0	10,800.0	14,471.0
354.0	6,500.0	11,300.0	14,975.0
1,500.0	7,000.0	11,800.0	15,471.0
2,000.0	8,000.0	12,300.0	15,971.0
2,500.0	8,800.0	12,800.0	16,471.0
3,500.0	9,300.0	13,000.0	
4,000.0	9,800.0	13,800.0	

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.3.2-3. DIRECTIONAL SURVEY OF PLEASANT BAYOU NO. 2 WELL

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.3.2-4. SCHEMATIC DIAGRAM OF PLEASANT BAYOU WELL NO. 2 AS DRILLED

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.3.2-5. PLEASANT BAYOU NO. 2 TUBULARS CEMENTED INTO PLACE

<u>Tubular</u>	<u>Size, in.</u>	<u>---- Depth, ft ----</u> <u>From</u>	<u>To</u>	<u>Wt, lb/ft</u>	<u>Drift, in.</u>	<u>Casing Grade</u>	<u>Casing Thread</u>
Conductor Pipe	26	Surface	126	136.17			PEB
Surface Casing	20	Surface	944	94.00	18.936	H-40	ST&C
	20	944	1,395	106.50	18.812	K-55	ST&C
Intermediate Casing	13-3/8	Surface	3,947	72.00	12.191	S-95	ST&C
	13-3/8	3947	8,392	72.00	12.191	L-80	ST&C
	13-3/8	8393	8,487	72.00	12.191	N-80	ST&C
Intermediate Casing	9-5/8	Surface	202	53.50	8.379	S-105	Butt
	9-5/8	202	2,070	53.50	8.379	S-95	Butt
	9-5/8	2070	5,942	47.00	8.525	S-95	Butt
	9-5/8	5942	10,643	53.50	8.379	S-95	Butt
	9-5/8	10643	14,285	53.50	8.379	S-105	Butt
Production Liner	7	14015	16,465	38.00	5.920	P-110	SHFJ

Exhibit 1.3.2-6. PLEASANT BAYOU NO. 2 CORE RECORD

<u>No.</u>	<u>---- Depth, ft ----</u> <u>From</u>	<u>To</u>	<u>Feet Cut</u>	<u>Feet Recovered</u>	<u>Description</u>
1	14,666	14,716	41	31	10 ft lost core, 31 ft sand with a few shale laminations
2	15,615	15,644	50	49	49 ft silty sand
3	15,644	15,675	11	11	6 ft silty sand, 5 ft shaly sand and shale

1.4. Drill-Stem Testing and Perforation for Production Testing

The deepest potentially productive sandstones were evaluated with drill-stem tests as follows: The intervals from 15,988 to 16,006 and 16,038 to 16,048 feet were perforated with four shots per foot and did not flow to the surface during testing through a packer set at 15,943 feet. After pulling the test tool, a 50-foot plug of cement was placed on top of a bridge plug that was set at 15,950 feet.

The interval from 15,580 to 15,590 feet was then perforated with four shots per foot and tested through a packer set at 15,512 feet. Rates were 336 barrels per day (BPD) of brine containing 87,000 ppm chlorides and 2200 SCF/d of gas with a final flowing pressure of 180 psi.

A 7-inch cement retainer was then set at 15,535 feet and a 25-sack plug was spotted on top of the retainer when 4000 psi failed to break down the formation below the retainer.

Before perforating for production, 1) cement squeezes were performed through four shots per foot in the depth intervals from 14,714 to 14,716 and 14,600 to 14,602 feet, 2) the 15.7-pound-per-gallon mud was displaced from the casing with 10.0-pound-per-gallon brine to a depth of 15,475 feet, 3) two packers were set with their tops at depths of 13,962 and 13,967 feet, and 4) 5-1/2 inch, 23-pound-per-foot tubing was run to a polished-bore receptacle in the shallower of the two packers. The annulus outside the tubing was filled with calcium bromide brine.

The 7-inch liner was perforated from 14,644 to 14,704 feet with a 2-7/8 inch Hyper Dome gun loaded with four shots per foot with 180-degree phasing. The tubing pressure increased to 3750 psi immediately after the first perforations were made.

Exhibits 1.4-1 and 1.4-2 show the induction log and the borehole compensated sonic log across the interval selected for testing, respectively.

Comparison of prominent wireline log "events" between the No. 1 and No. 2 wells in the interval from 2000 to 14,700 feet in Exhibit 1.4-3 shows 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. As shown in Exhibit 1.4-4, it is about 88 feet in the perforated interval. This may indicate differential subsidence or a growth fault that was active only during the time of the "events" below 10,240 feet.

1.5. Prior Production From the Pleasant Bayou No. 2 Well

Prior production has been reported in terms of phases of well testing. An overview of reported data from each phase is provided in Exhibit 1.5-1. Gruy reports^{17,18} provide comprehensive reporting of production data through the first month of Phase IIB (until October 23, 1982). The test program from October 23, 1982, through July 1985, including the production data from the Phase IIB Continuation through April 14, 1983, is covered in the Final Report by Fenix & Scisson, Inc.³

It is not clear whether the brine rates tabulated above have been corrected to stock tank conditions. However, onsite work sheets for the Phase IIB Continuation do indicate that correction for temperature was made prior to offsite reporting of brine production rate. Similarly, gas rates calculated on location during Phase IIB were corrected for both temperature and gravity of the gas.

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Company	GENERAL CRUDE OIL CO.	Drillers T.D.	16,500'
Well	DEPT. OF ENERGY	Log F.R.	16,474.5'
Field	GCO-DOE PLEASANT BAYOU #2	Log T.D.	16,476'
County	WILDCAT (CHOCOLATE BAYOU AREA)	Elevations:	
State	BRAZORIA	K.B. 43.3'	D.F. 42.3' O.L. 12.0'
	TEXAS

Exhibit 1.4-1. INDUCTION LOG ACROSS THE TESTED DEPTH INTERVAL FROM 14,644' TO 14,704 FEET

Exhibit 1.4-2. BOREHOLE COMPENSATED SONIC LOG ACROSS THE TESTED DEPTH INTERVAL FROM 14,644 TO 14,704 FEET

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 1.4-3. DEPTHS OF CORRELATING WIRELINE LOG "EVENTS"

Pleasant Bayou No. 1 42.30 KB (GL 11.0 ft)		Pleasant Bayou No. 2 43.50 KB (GL 12.0 ft)		Vertical Displacement Pleasant Bayou No. 1 Relative to Pleasant Bayou No. 2,
<u>Depth, ft</u>	<u>Interval, ft</u>	<u>Depth, ft</u>	<u>Interval, ft</u>	<u>ft</u>
2,038	1,704	2,040	1,699	-2
2,009	1,733	2,110	1,629	0
3,742	608	3,739	611	3
4,350	854	4,350	847	0
5,204	417	5,197	420	7
5,621	272	5,617	265	4
5,893	407	5,882	405	11
6,300	560	6,287	563	13
6,860	174	6,850	171	10
7,034	118	7,021	120	13
7,152	271	7,141	273	11
7,423	286	7,414	288	9
7,709	137	7,702	138	7
7,846	48	7,840	48	6
7,894	99	7,888	102	6
7,993	339	7,990	341	3
8,332	724	8,331	726	1
9,058	102	9,056	102	2
9,160	1,028	9,158	1,025	2
10,188a	56	10,183a	60	5
10,244	1,160	10,243	1,137	1
11,404	348	11,380	331	24
11,752	216	11,711	215	41
11,968	676	11,926	681	42
12,644	12	12,607	11	37
12,656	610	12,618	600	38
13,266	338	13,218	332	48
13,604	42	13,550	42	54
13,646	404	13,592	388	54
14,050	431	13,980	429	70
14,481	188	14,409	172	72
14,669	61	14,581b	62	88
14,730		14,643c		87

a Top of Frio Formation sandstone.

b 300°F isotherm intercepted at about 14,500 feet.

c Top of geopressured test zone (14,644 to 14,704 feet).

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Exhibit 1.5-1. PRIOR PLEASANT BAYOU PRODUCTION

<u>Date Span</u>	<u>Flow Time, Hours</u>	<u>Cum Brine, STB</u>	<u>Avg Brn Rate, STB/d</u>	<u>GWR, SCF/STB</u>
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	<u>252.47</u>	<u>177,149</u>	<u>16,840</u>	<u>20.70</u>
Subtotals & Averages	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	<u>1,082.50</u>	<u>537,346</u>	<u>11,913</u>	<u>22.35</u>
Subtotals & Averages	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 Continuation				
10/24/82-04/14/83	3,898.40	2,948,653	18,153	22.02
Grand Totals & Averages	6,351.95	4,534,339	17,193	21.78

The values for gas/brine ratio tabulated above do not take into account the gas that remains in solution in the brine leaving the separator. This is clearly reported in the context of the value of 22.35 SCF/STB for the portion of the Phase I flow during the period September 16, 1980, to October 31, 1980. The report on PVT analyses of samples collected on October 8, 1980,²³ (Appendix B) gives 22.35 SCF/STB as the ratio of gas leaving the separator to brine leaving the separator, with both volumes corrected to 60°F. That report indicates that an additional 8.11 SCF/STB of dry gas was liberated by flashing the 850-psi separator brine to atmospheric pressure after cooling the brine to 72°F.

On the same date, October 8, 1980, samples of separator gas and brine were collected by IGT for analysis directed toward determining whether the reservoir brine was saturated with natural gas. The report covering that work (Appendix D) concluded that the gas content of reservoir brine was in the range of 27 to 28 SCF/STB and was below saturation.¹⁶ The IGT flashing of gas from cooled 850-psi separator brine liberated 5.4 SCF/STB of dry gas. This is

substantially below the value of 8.11 SCF/STB reported by Weatherly Laboratories, Inc., but is much closer to the value expected on the basis of prior field tests and the results of published laboratory studies.

A second round of sampling for PVT studies was performed on October 14, 1982. The reported gas/brine ratio was 21.23 SCF of separator gas per STB of separator brine (both volumes corrected to 1 atmosphere and 60°F) (Appendix C).²² This is close to the 21.68 SCF/STB reported for the Phase IIB test. Flashing of gas from the cooled separator brine liberated an additional 3.22 SCF/STB. This is about the amount expected for the separator pressure of 560 psig.

The reported bubble-point pressures for the two recombinations of gas and brine were 9670 and 7460 psia. Both reports concluded that the brine was not saturated with natural gas at reservoir conditions. The lower of the two bubble points is probably closer to the actual value because the amount of gas reported to have been flashed from separator brine for the other sample was too high to be credible.

Summaries of the prior tests are under subheadings below:

Phase 0: After multiple attempts over a 5-month span, interpretable production data were obtained from rental equipment. The interpretation indicated permeability and gas content sufficient for construction of facilities for long-term testing to be warranted. The major problems that had to be overcome in Phase 0 were scaling of turbine meters, separator level control at the low gas/brine ratio, and failures of the pressure seal in the electrical connection between the wireline and the bottomhole pressure sensor.

Phase I: The surface facilities used were designed by Hudson Engineering Corporation and modified on the basis of recommendations by engineers from Gruy Petroleum Technology, Inc. Before starting the test, the disposal well was acidized to improve injectivity enough to allow disposal of 20,000 barrels per day with a maximum separator pressure of 1000 psi.

The planned initial brine rates of roughly 5000 and 10,000 barrels per day were achieved as planned. But 3 days after the brine rate was increased to 19,200 barrels per day on the 15th day of the test, disposal well injection pressure became so high that the brine rate had to be reduced to 15,500 barrels per day. Then, 3 days later, the brine rate dropped to 13,248 barrels per day with no change in choke setting. Disposal well injection pressure continued to increase and the well was shut in for pressure buildup after 45 days of flow.

Sample collection and analysis by Lawrence Livermore Laboratory indicated that the disposal well problem was due to plugging with pseudoscale caused by the use of too much scale inhibitor (50 ppm of phosphonate-polyacrylate threshold-type carbonate scale inhibitor).¹⁴ Other major

problems experienced during the test were the unexplained drop in brine rate, losing the float off the torque tube on the separator level controller, and trouble keeping the flare lit due to oscillations in gas rate out of the separator.

Phase IIA: The testing was preceded by changes in the facilities that were intended to make possible brine rates of up to 40,000 barrels per day. The largest of these changes were 1) adding a second separator in parallel, 2) increasing the pipe to the disposal well from 4 to 6 inches, 3) perforating additional sands in the disposal well, and 4) adding hardware to cool, dehydrate, and meter the gas to be sold.

The duration of the Phase IIA test was only 15 days. The well had to be shut in four times during those 15 days to remove and repair the bottomhole pressure gauge. After the gauge failed for the fifth time, only a small amount of wadded up line was recovered. Most of the gauge failures had been at brine rates in excess of 29,000 barrels per day.

Removing the wireline from the well and resuming production involved the use of three different drill rigs. The crown failed on the first rig. The seal assembly had become stuck in the production packer and would not pull free with maximum tension placed on the tubing. The tubing was backed off and the portion of the 5-1/2 inch tubing shallower than 12,287 feet was pulled with the second rig. A gauge run then indicated that the wellbore was clear to below the perforations. The upper 12,287 feet of 5-1/2 inch tubing was then run and screwed back into the unrecovered tubing. The third rig was used to repair a leak at the tubing hanger near the end of July 1982.

Phase IIB and Phase IIB Continuation: During the first 31 days of Phase IIB, Weatherly Engineering Data Systems provided an computerized data gathering system and Gruy Petroleum Technology, Inc., had a major role in the field operation. For the Phase IIB Continuation from October 24, 1982, through April 14, 1983, more conventional manually read gauges, circular charts, and turbine meter instrumentation was operated by Fenix & Scisson, Inc.

This phase of testing was terminated on April 13, 1983, after the well was shut in by the emergency shutdown system (ESD), apparently due to a low-pressure indication from the wellhead pressure sensor. The low pressure was falsely sensed because access to the flow stream had been plugged with an accumulation of carbonate scale. A three-arm caliper, being run to determine the extent of scale in the tubing on May 5, 1983, indicated the 5-1/2 inch production tubing was parted at 5225 feet. The tubing is reported to have parted sometime between the evening of May 4 and the morning of May 5, because there was no pressure on the annulus the afternoon of May 4. This was approximately 3 weeks after the well was shut in.

Bottomhole pressure was not measured during the Phase IIB test. The intent was to deduce bottomhole pressure by using the relationship between surface and bottomhole pressure from

earlier testing. However, this could not be done because the unknown time dependence of scale buildup had caused much greater friction pressure drop than previously determined for scale-free tubing. An additional complication was caused by a piece of wireline that had become entangled around a 1/2-inch pipe nipple that was protruding inside the flow stream in the flow loop. Scale had accumulated on and around the snarled wireline, nearly plugging the inside of the flow loop. The pressure gauge was downstream from this obstruction.

Interpretation of Well Test Data Through the Phase IIB Continuation: Appendix F of the Fenix & Scisson, Inc., Final Report dated July 1985³ contains an interpretation of the data through Phase IIB in the context of a reservoir simulation study. Although several different geometries and properties computed adequate history matches for Phase I, no single set of data could be found that adequately matched the pressure data through Phase IIB. The model selected for description of the aquifer is shown in Exhibit 1.5-2. Long-term production was supported by a large, high-permeability reservoir volume beyond a restriction with low permeability and a thickness of only 5 feet. Matching the short-term behavior in Phase IIB was accomplished by including the "skin effect" as a function of time that is shown in Exhibit 1.5-3. The resultant match of measured and calculated pressure as a function of time is shown in Exhibit 1.5-4. Exhibit 1.5-5 shows the Phase IIB data and the 1988-1989 data on the same scales. Note that the brine rates were similar for both tests. The Fenix & Scisson, Inc., report interprets the increases in drawdown slope at the end of the Phase IIB Continuation, as shown by the three dashed lines in Exhibit 1.5-4, as indicating that scale buildup in the production tubing and wellhead began influencing the wellhead pressures between March 1 and March 15, 1983. In contrast, the Exhibit 1.5-5 comparison of the Phase IIB production rates and pressures with those from the 8 months of testing in 1988 clearly indicated that scaling had started early in Phase IIB and was the primary reason for the rapid decrease in wellhead pressure during the first 3 months of production.

1.6. Pleasant Bayou Activities Prior to the Beginning of the Present Work in 1986

After the well was shut in on April 14, 1983, the annulus pressure went to vacuum. About 3 weeks later, a positive annulus pressure was observed. A caliper survey run on May 5, 1983, indicated that the 5-1/2 inch production tubing had parted at 5225 feet.

The production well was killed by injecting 250 barrels of 16.5-pound-per-gallon XC-polymer mud down the tubing and circulating the annulus from 5225 feet to surface with 272 barrels of the same mud. An additional 354 barrels of 16.4-pound-per-gallon mud was circulated after a differential pressure developed between the annulus and tubing due to migration of the lighter bromide fluid up the annulus. A wireline-set bridge plug was set inside the 5-1/2 inch tubing 19 feet below the top of the bottom section.

Exhibit 1.5-2. 1983 AQUIFER MODEL FOR PLEASANT BAYOU PRODUCTION

Exhibit 1.5-3. SKIN EFFECT VERSUS TIME FOR 1983 SIMULATION OF PRODUCTION

Exhibit 1.5-4. MEASURED AND CALCULATED PHASE IIB SURFACE PRESSURE

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Exhibit 1.5-5. COMPARISON OF 1982-1983 AND 1988-1989 PRODUCTION

Almost 2 months later, in the latter half of July 1983, annulus pressure was again eliminated by circulating mud before starting to pull the tubing. As a result of the hard scale in the tubing, torques in excess of 30,000 foot-pounds were required to break connections that would normally break between 10,000 and 12,000 foot-pounds. The tubing was found to have parted due to a failed API LT&C (8rd.) coupling that split longitudinally over its entire length.

Tubing recovery operations ended with five joints (13,750 to 13,964 feet) of tubing remaining in the hole. A retrievable bridge plug was set inside the 9-5/8 inch casing with the top of the plug at 13,725 feet.

Measured values of scale thickness inside the tubing as a function of depth are presented in Exhibit 1.6-1.

Exhibit 1.6-1. SCALE THICKNESS VERSUS DEPTH IN THE PRODUCTION TUBING

<u>Depth, ft</u>	<u>Thickness, in.</u>
5	0.400
5,215	0.310
11,770	0.183
12,100	0.147
12,360	0.126
12,930	0.007

2.0. REHABILITATION OF THE PLEASANT BAYOU WELL AND FACILITIES STARTING IN 1986

The production and disposal wells were rehabilitated by Eaton Operating Company in 1986. After the wells were successfully restored to operating condition, the surface facilities were rehabilitated by the Institute of Gas Technology starting in 1987.

2.1. Rehabilitation of the Disposal and Production Wells

The remaining tubing and packers were removed from the production well (Pleasant Bayou No. 2) and the well was cleaned out to the bottom of the perforated interval at 14,704 feet below the Rotating Kelly Bushing (RKB) elevation of 31 feet above ground level. New 5-1/2 inch, 23-pound-per-foot, P-110 tubing with new VAM MS/ATAC connections was run to a seal assembly in a Brown 2-B Permanent Packer. The top of the packer was at 13,952 feet and the bottom of the seal assembly was at 13,967.6 feet. Exhibit 2.1-1 is a schematic diagram of the production well on April 3, 1986.

The connections in the 5-1/2 inch tubing were increasingly difficult to break during cleanout of the disposal well (Pleasant Bayou No. 1). Cutting of each joint with a torch was required for

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Exhibit 2.1-1. SCHEMATIC DIAGRAM OF THE PRODUCTION WELL
AFTER REWORK IN 1986

the deeper joints. But the seal assembly was successfully pulled from the packer. After burning over the top 3 feet of the packer, the remains of the packer assembly and seal bore extension were pulled from the well. After washing through bridges, an 8-1/2 inch bit was run to a depth of 6636 feet, almost 100 feet below the deepest perforation. The well was then treated with 10,000 gallons of 15% HCl and 11.5-pound-per-barrel rock salt to establish an adequate injection rate. After washing additional bridges from the well to a depth of 6568 feet, 5-1/2 inch, 15.5-pound-per-foot K-55, ABM tubing was stabbed into a packer that had been set at a depth of 5855.5 feet on October 17, 1986. No new perforations were made and the previously perforated intervals were --

6538 to 6518 feet
6514 to 6494 feet
6480 to 6460 feet

6426 to 6390 feet
6380 to 6362 feet
6262 to 6226 feet.

Subsequent down-hole operations on the disposal well were as follows:

1. June 1988: The well was circulated to 6510 feet and then a fish consisting of a 2-3/8 inch mule shoe, a 2-3/8 inch tubing joint, and 3 feet of tubing was left in the well with the top at 6476 feet.
2. May 19, 1989: A bailer sample of sand was caught from 6345 feet in conjunction with repair of the tree. Three and a half sets of perforations were covered with sand.
3. May 26, 1989: Additional perforations were shot at four shots per foot in the depth intervals 6216 to 6198, 6190 to 6100, and 6092 to 6060 feet.
4. July 1990: The well was cleaned out to 6444 feet but then filled back to 6408 feet before replacing the 5-1/2 inch tubing.

Exhibit 2.1-2 is a schematic diagram of the disposal well on July 22, 1990.

2.2. Rehabilitation of Surface Facilities

The surface hardware within about 100 feet of the production well had been removed to provide working space for the drill rig and associated equipment. This included 1) production piping through the wellhead, flow loop, and main choke up to the expansion loop on the way to the separators, 2) about 100 yards of 6-inch brine line that passed near the production well on the way to the disposal well, and 3) the structure that housed the air compressors and the majority of data recording hardware. The rest of the hardware had been left charged with nitrogen in 1983. But in the 4 years the nitrogen supply ran out, there was some internal corrosion, and substantial amounts of external corrosion had occurred. The external corrosion was particularly striking where use of a wrench had chipped paint from pipe or tubing fittings. Multiple layers of rust had swollen the outside dimensions of fittings, such as those on the glycol unit, to twice their normal values. It was no longer possible to use the wrench flats on such fittings. Metal loss had made replacement of these fittings essential.

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Exhibit 2.1-2. SCHEMATIC DIAGRAM OF THE DISPOSAL WELL AFTER REWORK IN 1990

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Rehabilitation of surface facilities included a number of changes from the previous configuration. The most significant of these included --

1. Eliminating the two-phase turbine meter upstream of the main choke
2. Placing the main choke on the outlet side, rather than upstream of, the "target block" (This cube of steel provides a 90-degree change in flow direction with a lead impact face downstream of the fluid entry.)
3. Installing a 10-foot-long spool of 316 stainless steel downstream of the main choke to reduce erosion/corrosion. Interior wetted portions of the chokes were either fabricated from or clad with 316 stainless steel.
4. Equipping the separators with bridles to external float chambers for level-control sensing
5. Routing the gas piping leaving the separators such that liquids condensing before rate measurement flow back into the separator and those condensing downstream of the orifice plate move away from the plate, plus installing liquid knockouts at each low point in the gas piping where liquids could accumulate due to condensation and gravity
6. Filling the earthen pit near the separators and arranging piping such that all liquids from the gas stream were collected in steel tanks, with the hydrocarbon fraction being measured and analyzed
7. Replacing the outlet piping on the separators to minimize corrosion by reducing the number of elbows to a minimum, and keeping pipe diameters large enough for the flow velocity to be less than 10 feet per second
8. Equipping the separators with 316 stainless steel dump valves having 10-foot spools of the same material downstream
9. Routing the brine disposal line by the area selected for installation of the Hybrid Power System (HPS) and installing the additional expansion loop appropriate to such routing
10. Providing "flow splitters" such that the test of the reservoir could proceed independent of operation of the Hybrid Power System
11. Installing a filter skid near the disposal well
12. Replacing the former pneumatic and manual data logging with electronic sensors plus on-line calculation of rates and bottomhole pressure
13. Providing redundancy of data recording such that the accuracy, or validity, would be apparent.

Exhibit 2.2-1 is a flow diagram for the Pleasant Bayou surface facilities. Major hardware items and the primary instrumentation are shown thereon. The system is discussed below with separate headings for major portions of the system.

2.2.1. Two-Phase Flow Portion of the System

The main choke and the hardware upstream thereof has working-pressure ratings of 10,000 psi or higher. The pressure rating of the wellhead is 15,000 psi. This was selected due to the remote possibility that dry gas production might be encountered and that the shut-in wellhead pressure on a gas column might exceed 10,000 psi. The low-pressure-rated piping between the main choke and the separator chokes is protected with a relief valve having a set pressure of

Exhibit 2.2-1. PROCESS FLOW DIAGRAM FOR PLEASANT BAYOU FACILITIES

1935 psi. The purpose of the chokes just upstream of the two separators is adjustment of the portion of the stream that flows to each. This function is readily accomplished with a pressure drop of as little as 100 psi.

The piping at the tee where the brine stream is split to the two separators is symmetrical, with identical lengths and diameters of pipe to both separator chokes. However, the relative amounts of gas and brine that flow to each separator vary with choke settings. There is a factor of 2 difference in liquid volume of the two separators. Thus, identical residence times for gas/brine separation would occur if two-thirds of the brine went to the larger separator. But, in practice, such splitting of the brine flow is accompanied by nearly all of the gas going to the large separator. Typical operating conditions are 9500 STB/d and 105,000 SCF/d through the small separator while 14,000 STB/d and 320,000 SCF/d flow through the large separator.

As indicated in the schematic diagram, the separators are designed for three-phase operation. However, free oil has not yet been found in either separator. The procedure for checking to see if oil is being produced is to drain the water from the oil leg of the separator and then manually override the brine-level controller such that the surface liquid flows over the weir into the oil leg. This liquid is then blown from the oil leg into a 55-gallon drum whose surface is visually monitored for oil sheen. Effectiveness of this monitoring method has been demonstrated by collection of gallons of the "honey oil" that enters the stream from the lubricator on the wellhead during wireline operations.

2.2.2. Gas-Handling Facilities

The natural gas leaving the top of each of the separators passes through an orifice meter at the highest elevation in the gas line. Thus, any liquid that condenses upstream of the orifice plate drains back to the separator and liquid condensing downstream of the plate flows away from the plate. The importance of this step to keep liquid water away from the gas metering becomes apparent when one recognizes that the gas stream is saturated with water vapor at a temperature in the range of 250° to 280°F.

Water accumulation in the piping to the back-pressure control valve is minimized by installing the valve in a pipe run that slopes downward to a water knockout. As indicated in the schematic diagram, capability for operating the separators at different pressures was provided. But, in practice, the system has run well with the two separators in parallel and all of the gas passing through a single control valve. A very small valve is used in order to achieve smooth control of separator pressure -- a 1/2-inch Badger Research Control valve with a "D" trim.

Gas cooling and dehydration are accomplished using conventional fin fan cooling and glycol dehydration units that are appropriately sized for a gas rate of up to 500,000 SCF/d. Collection of

liquids condensing from the hot gas stream is provided by knockouts (two-phase separators) upstream of the gas cooler, between the cooler and dehydrator, in the base of the dehydrator tower, in the base of the flare stack, and, as backup, just upstream of the gas sales meter that is operated by the gas buyer. The liquids dumped from all of these collect in a single tank that operates as a "gunbarrel separator." The hydrocarbons from the top are measured daily and poured into the storage tank. The water phase from the "gunbarrel" flows to a sump whose pump is manually operated as required to move the water to the storage tanks.

After dehydration, the gas splits into two separately metered streams. One is gas supplied to the Hybrid Power System. The other stream is gas that is either sold or flared. During normal operation, this gas flows through the buyer's meter run and then into a 400-psi pipeline. When the gas contains too much water vapor to meet the sales specification, such as during startup, a manual valve to the sales line is closed. After pressure builds up to 550 psi, the control valve allows gas to flow to the flare stack. The flare is manually ignited.

Comparison of the amount of gas measured from the separators with the amount of gas leaving the dehydrator is one of the important data quality control functions built into the system. All gas rates are calculated in real time from 10-second readings that are properly averaged over operator-selectable time intervals of up to 15 minutes. At each of these times, the sum of gas rates from the separators and the sum of gas rates from downstream of the dehydrator are printed side by side. Each weekly report explicitly reports the percent difference in these values. Agreement is a clear indication of proper calibration and operation of all of the pressure transmitters, differential-pressure transmitters, and temperature transmitters that provide inputs to the gas-rate calculations.

2.2.3. Brine-Handling Facilities

Brine level in each separator is sensed by a displacer in an external chamber that is connected to the separator by a bridle having connections to the main vessel both above and below the desired fluid level. The pneumatic output of the Fisher level controllers drive 316 stainless steel dump valves that are downstream of turbine meters. Turbine installation upstream of the dump valves is essential to avoid errors due to gas exsolving from the brine and resulting in two-phase flow through the turbine.

The piping, turbine meter, and dump valve in the normal flow path leaving the large separator have a 4-inch diameter. They are bypassed by a 2-inch line with a globe valve that can be used for manual throttling if needed for servicing the 4-inch hardware without a shutdown. For the small separator, the normal path is 3-inch diameter. There is an optional 2-inch path, including a turbine

meter and a dump valve, in parallel. This smaller path is for times when a measured small flow rate is needed. An example is while flowing at about 2000 STB/d with frequent sample collection during cleanup of an inhibitor pill.

Brine flow from the two separators is commingled into a 6-inch line that contains a back-pressure valve adjacent to the Hybrid Power System. That valve maintained 550 psig at the inlet to the HPS. Downstream from that valve, the back pressure on the HPS was determined by the sum of friction drop in about 600 feet of 6-inch pipe, pressure drop across the filters, and disposal well injection pressure. The pressure drop across the HPS was in excess of 100 psi and flow rate through the HPS was controlled by a valve at the outlet from the HPS to the line to the filters and the disposal well. Details of the piping associated with this brine stream "flow splitter" were arranged to minimize accumulation of gas exsolved from the brine stream in HPS facilities.

The filter skid has five filter pots, each of which holds eleven elements that are 2 inches in diameter by 40 inches long. In normal operation, four of the filter pots were on-line and the fifth was kept in reserve to be put on-line when another pot was blocked in to change elements. During operation of the HPS, elements with a nominal rating of 10 microns were used. But when brine rate was increased from 16,000 to 24,000 STB/d, elements with a nominal rating of 50 microns were used. Installation of stainless steel baffle plates to distribute inlet flow vertically throughout the filter pots was essential to avoid erosion of the elements adjacent to the inlets on a time scale of only a few days. The upper limit on element life in the hot brine is about 3 weeks before disaggregation of the elements releases cotton to the disposal well.

Comparison of the amount of brine passing through the turbine meters at the separators with the amount of brine passing through the orifice meters at the HPS is one of the important data quality control functions that is built into the system. All brine rates are calculated in real time and averaged over operator-selectable time intervals of up to 15 minutes. At each of these times, the sum of brine rates from the separator turbines and the sum of brine rates from downstream orifice meters are printed side by side. Each weekly report explicitly reports the percent difference in these values. Agreement is a clear indication of proper calibration and operation of all of the turbines, differential-pressure transmitters, and temperature transmitters that provide inputs to the brine-rate calculations.

2.3. Piping and Instrumentation Diagram

Exhibit 2.3-1, Parts 1 and 2, is the Piping and Instrumentation Diagram (P&ID) for the Pleasant Bayou Facilities. In contrast to the previously discussed schematic diagram, the P&ID

Exhibit 2.3-1, Part 1. PIPING AND INSTRUMENTATION DIAGRAM

Exhibit 2.3-1, Part 2. PIPING AND INSTRUMENTATION DIAGRAM

shows piping specification breaks and all vessels, valves, and instrumentation. Important features that have not been previously discussed include --

ESD System: The emergency shutdown system uses hydraulic pressure to hold open a normally closed valve in the wellhead. Activation of any of several sensors will trigger release of the hydraulic pressure and closure of the valve. The sensors and triggering conditions are --

<u>Sensor</u>	<u>Triggers if --</u>
Production Well Tubing Pressure	Less Than 1000 psig
Pressure Between Chokes	Above 1700 psig
Large Separator	Above High-Level Switch
Small Separator	Above High-Level Switch
Large Separator Pressure	Above 1100 psig
Small Separator Pressure	Above 1100 psig
Pressure in Piping to the Filter Skid	Less Than 50 psig
Production Wellhead Fire Sensor	Break in Plastic Tubing
Large Separator Fire Sensor	Break in Plastic Tubing
Small Separator Fire Sensor	Break in Plastic Tubing

Relief Valves: All portions of the facilities that can be isolated and pressurized are protected by relief valves having settings and seat sizes that ensure that the working-pressure rating cannot be exceeded for any portion of the system. Large-capacity relief-valve outputs are manifolded to the open blowdown tank.

Separator Sand Checkpoints: Both separators are equipped with ball valves that are opened to quickly charge about 15 feet of 2-inch pipe from the bottom of the separator. After the pipe is charged, it is isolated from the separator and then bled off to check for solids accumulation in the bottom of the vessel. This check is made weekly when brine is being produced.

Kill Line: This is a 10,000-psi working-pressure line from the separator area to the flow loop coming down from the wellhead. It is equipped with a hydraulically actuated valve that can be opened from the separator area. This line would be used to kill the well by pumping in heavy mud in the event of an emergency such as failure of the packing on the stem of a wellhead valve. It was used for injection of the scale-inhibitor pills.

2.4. Data Acquisition and Analysis System

A block diagram of the desktop computer-based data acquisition and analysis system is shown in Exhibit 2.4-1. As programmed for Pleasant Bayou, this digital system handles 64 channels of data. A total of 33 of the 38 raw data inputs from 4 to 20-milliamp analog transmitters (pressure, differential pressure, and temperature) were used while the HPS was in operation. Those channels and the digital data from the Panex were scanned every 10 seconds and then averaged over operator-selectable time intervals for recording of permanent records on disk and in printed form. These data channels and calculated outputs from the on-line computer system are tabulated in Exhibit 2.4-2. Channels 1 and 3 through 39 are analog data from 4 to 20-milliamp transmitters. Channels 40 through 44 are cumulative output of pulse counts out of the turbine meters. Channels 45 through 62 are the results of real-time interpretation of raw data.

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Exhibit 2.4-1. COMPUTER-BASED DATA ACQUISITION AND ANALYSIS SYSTEM

Exhibit 2.4-2. CONTENT OF EACH PERMANENT DISK DATA RECORD

<u>Channel</u>	<u>Channel Identification</u>	<u>Channel</u>	<u>Channel Identification</u>
0	Time/date	32	HPS Brine Orifice Diff. Pressure
1	Ambient Temperature	33	Brine Pressure to HPS
2	Tubing Pressure (From Panex)	34	Brine Temperature to HPS
3	Tubing Pressure	35	Brine Filter Diff. Pressure
4	Casing Pressure	36	Disposal Well Casing Pressure
5	Second Casing Pressure	37	Disposal Well Tubing Pressure
6	Wellhead Brine Temperature	38	Disposal Well Brine Temperature
7	Inhibitor Supply Level	39	Unassigned
8	Pressure Between Chokes	40	Small Separator 3-inch Turbine
9	Large Separator Level	41	Small Separator 2-inch Turbine
10	Large Separator Meter	42	Small Separator Oil Turbine
11	Large Separator Meter Pressure	43	Large Separator 4-inch Turbine
12	Large Separator Meter Temperature	44	Large Separator Oil Turbine
13	Small Separator Meter Diff. Pressure	45	Large Separator Gas Rate
14	Small Separator Meter Pressure	46	Small Separator Gas Rate
15	Small Separator Meter Temperature	47	45 + 46 (Σ Sep Gas Rates)
16	Small Separator Liquid Level	48	Sales/Flare Gas Rate
17	Tank #1 Differential Pressure	49	HPS Gas Rate
18	Tank #2 Differential Pressure	50	Sales Gas Rate
19	Unassigned	51	48 + 49
20	Sales/Flare Meter Diff. Pressure	52	Oil Rate From Turbines
21	Sales/Flare Meter Pressure	53	Oil Rate From Tank Levels
22	Sales/Flare Meter Temperature	54	Small Separator Brine Rate
23	HPS Meter Diff. Pressure	55	Large Separator Brine Rate
24	HPS Meter Pressure	56	54 + 55 (Σ Sep Brine Rates)
25	HPS Meter Temperature	57	HPS Bypass Brine Rate
26	Sales Meter Diff. Pressure	58	HPS Brine Rate
27	Sales Meter Pressure	59	57 + 58 (Σ Brine Orif. Rates)
28	Sales Meter Temperature	60	Inhibitor Flow Rate (Gal/Day)
29	Control Air Pressure	61	Separator Gas/Brine Ratio
30	Temp of Brine From the HPS	62	Calculated BHP
31	Bypass Brine Orifice Diff. Pressure	63	Sequential File Number

The reason for 10-second averaging is that pressure and level controllers tend to oscillate with a period of a few minutes. This in turn causes oscillations in gas and brine rates that can result in large errors if rates are calculated on the basis of instantaneous readings taken minutes apart. This problem existed with the data system fielded by Weatherly for the Phase II testing in 1982 and resulted in the necessity for recalculating all rates from the backup circular chart data. The calculation of flow rates from orifice-meter data involves the square root of the differential pressure, and for gas, the square root of the pressure. In order to maximize the accuracy of flow-rate calculations, the square roots of these values are taken before 10-second readings are averaged.

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Flow-rate calculations were performed at the operator-selected time intervals for printing of permanent records on disk and on paper. Those intervals are increments of 10 seconds and are as short as 10 seconds during transients such as the start of draw-down or buildup tests. During steady production, the time interval between records is normally 15 minutes. The rate calculations at each print interval were fully corrected for properties of the fluids, temperature, and pressure. Later manipulation of the values was needed only if the inputs to the calculation were not valid for reasons such as a defective sensor or a meaningless reading that resulted from a sensor being isolated by a valve.

In addition, flowing bottomhole pressure was calculated from the surface data each hour. This calculation consumes about a minute of computer time. More frequent calculation would sometimes interfere with collection of accurate data.

Additional features of the computer data system include --

- The most recent 1000 of the permanent records are stored in the computer and can be used to draw screen plots of any of the recorded or calculated data. The time span of the plots is selectable and overlay plots are an option. These capabilities are of high value as inputs to real-time operational decisions.
- Intrinsically safe barriers are included in the circuits to areas where appropriate to be in compliance with the National Electric Code.
- High and low alarm values can be set on up to 16 data channels. In addition to the audible alarm in the control room, relay closures are available for activation of other alarm devices such as flashing lights or an automatic telephone-dialing system.
- A summary of production each day, by hour, is automatically printed at 6:00 a.m. An example is provided in Exhibit 2.4-3.

The calculations of gas/brine ratio and of flowing bottomhole pressure have an important quality control function. For a large geopressured-geothermal reservoir, the values of these parameters should change very slowly, if at all, under constant producing conditions. More rapid change alerts the operator to look for problems.

3.0. PRODUCTION DATA

This section presents a discussion of the production data. This includes the well cleanup and bottomhole pressure (BHP) measurement performed in 1986 plus the long-term production starting in 1988 and continuing through the end of the reporting period in October 1990.

3.1. Overview

During March and April of 1986, the Pleasant Bayou No. 2 production well was cleaned of residual mud and a bottomhole pressure measurement was made. The next activity on the

IGT Daily Report for the Pleasant Bayou No. 2 Well for the Period Starting 06:00:00 25 May 1990

Daily Production:

Gas
Sep Gas: 323.1
Total Dry Gas: 305.9
Gas To HPS: 230.8
Perf Gas: 378.3

Brine
Sep Turbs: 16229.4
Orif Mtrs: 15644.2
Brine To HPS: 9439.4
Gas/Brine Ratio: 23.31

Time [h:m]	-----Pressure-----						-----Temp-----		-----Gas Rate-----		---Brine Rate---		Perf Gas/Brn [SCF/STB]	Calc BHP [psia]
	Casing [psia]	Tubing [psia]	Sml Sep [psia]	Lrg Sep [psia]	Brine [psia]	Disp [psia]	Brine [F]	Ambient [F]	Sep Sum [MCFD]	Dry Sum [MCFD]	Sep Turbs [STBD]	Orifs [STBD]		
07:00	3101	2914	704.4	703.9	521.3	442.7	290.9	74.5	320.9	306.1	16222.8	15615.9	23.22	9762
08:00	3101	2913	704.4	703.7	522.3	442.9	290.9	75.3	322.7	307.5	16218.7	15602.2	23.34	9761
09:00	3101	2913	692.6	691.7	520.3	443.0	290.6	78.9	323.1	306.3	16237.8	15630.4	23.28	9762
10:00	3101	2913	692.4	691.6	517.9	442.6	290.4	80.6	324.3	306.9	16239.4	15649.2	23.35	9762
11:00	3101	2913	696.9	696.3	517.3	442.6	290.3	81.3	323.2	305.5	16233.8	15652.1	23.31	9762
12:00	3101	2913	696.3	695.9	517.3	442.9	290.3	81.7	323.4	305.6	16235.6	15653.1	23.31	9762
13:00	3100	2913	696.6	696.3	517.5	443.1	290.2	83.0	322.7	305.2	16239.4	15656.5	23.27	9762
14:00	3100	2914	697.6	697.2	517.2	443.4	290.2	83.7	322.4	304.9	16232.3	15666.0	23.26	9762
15:00	3101	2913	695.4	695.1	516.9	443.5	290.2	84.4	323.4	305.4	16234.0	15669.4	23.31	9762
16:00	3101	2914	694.9	694.6	515.7	443.8	290.2	84.8	323.2	304.9	16234.1	15680.8	23.30	9762
17:00	3101	2913	694.6	694.2	516.0	443.8	290.3	83.9	323.4	305.1	16237.5	15672.1	23.31	9762
18:00	3101	2914	695.6	695.0	516.6	443.5	290.3	82.9	323.2	305.3	16231.8	15665.5	23.31	9762
19:00	3101	2913	695.9	695.3	519.6	443.1	290.4	81.4	323.6	305.3	16230.9	15663.3	23.33	9761
20:00	3101	2914	696.1	695.5	519.8	442.8	290.5	80.0	323.4	306.0	16235.3	15660.0	23.32	9763
21:00	3101	2914	698.0	697.6	520.4	442.6	290.7	78.0	322.8	306.1	16230.6	15649.3	23.30	9763
22:00	3101	2914	699.5	699.2	521.6	442.8	290.7	77.4	322.8	306.3	16221.9	15640.4	23.32	9762
23:00	3101	2914	698.7	698.4	521.9	443.0	290.7	77.3	323.6	306.7	16225.6	15641.0	23.36	9762
00:00	3101	2914	698.3	698.1	521.8	442.8	290.7	76.6	323.5	306.3	16227.7	15638.1	23.35	9762
01:00	3101	2914	699.2	699.0	521.7	442.7	290.7	76.0	323.1	306.2	16224.7	15628.6	23.33	9762
02:00	3101	2914	698.0	697.8	522.2	442.5	290.7	75.9	323.8	306.7	16223.4	15631.1	23.37	9762
03:00	3101	2914	697.4	697.3	522.2	442.2	290.6	75.6	323.9	306.4	16228.3	15625.6	23.37	9762
04:00	3101	2913	697.5	697.4	522.2	442.2	290.7	75.3	323.5	306.3	16226.2	15630.6	23.35	9762
05:00	3101	2914	702.9	702.6	522.7	442.7	290.8	74.1	321.0	305.2	16218.0	15617.7	23.23	9762
06:00	3101	2914	704.2	703.8	523.3	443.3	290.9	73.7	322.3	305.7	16215.7	15622.4	23.32	9762

All flow rates are reported at 14.65 psia, 60 deg F. ---BHP is calculated (not measured)

Parameters used in rate calculations are:

Gas Meter Run	Gravity	CO2 %	Pipe Size	Orif Size
Large Sep	0.7005	10.0	2.123	.625
Small Sep	0.7006	10.0	2.067	.375
Sal/Fir	0.7006	10.0	1.939	.500

Brine Metering: Small Sep 2 Inch Brine Turbine Count Rate = 2280 Pulses per Barrel
Small Sep 3 Inch Brine Turbine Count Rate = 2350 Pulses per Barrel
Large Sep 4 Inch Brine Turbine Count Rate = 1249 Pulses per Barrel

Brine Salinity = 133000 mg/l Produced Brine Orif = 4.000 inches

Exhibit 2.4-3. EXAMPLE OF COMPUTER-GENERATED MORNING REPORT

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production well was after rehabilitation of the surface facilities and started with a caliper log and a measurement of down-hole pressure at the end of February 1988. A plug in the wellbore limited wireline data to depths shallower than about 14,000 feet.

A day of production to check out operation of the surface facilities was performed on March 6-7, 1988. In April 1988, a gamma-ray log was run, attempts to dissolve the aluminum plug from the wellbore with caustic were unsuccessful, and the well was produced for 6-1/2 hours during April 18 to displace the caustic from the wellbore. An inhibitor pill was then pumped into the formation. The first day of inhibitor pill cleanup flow was at a rate of only 2000 BPD so that samples could be collected with good resolution. Then 2 days of production were at a higher rate of about 13,000 STB/d.

After a month for repair of wellhead and flow loop components, a multi-rate draw-down test was performed at the end of May 1988 with a bottomhole pressure sensor at a depth of 13,950 feet.

During the week of June 2 through June 8, 1988, the well was periodically produced to provide brine in support of disposal well cleanout operations. Long-term, high-rate production testing commenced on June 8, 1988, and included the three main flow periods listed below:

1. Long-term flow, prior to HPS operation, from June 1988 through July 1989. Brine flow rate started at approximately 20,000 BPD and gradually decreased to approximately 16,000 BPD at the end of this period. Two important objectives were accomplished during this period. First, June 1988 flow excursions to above 25,000 BPD established an approximate limit of brine production that could not be exceeded without the danger of sand production. Further work to refine this limit was put off until the last flow period. Second, production and disposal well operational procedures required to achieve steady-state operation to support the HPS experiment were defined.
2. Flow during HPS operation occurred between August 1989 and May 1990. Brine flow rate was maintained relatively constant at about 15,600 BPD -- well above the design HPS brine capacity of 10,000 BPD.
3. Flow after the HPS was shut down occurred between July and October 1990. During this period, brine flow was raised in increments from 15,600 to almost 24,000 BPD to determine the maximum flow possible without sand production. The maximum rate appears to be 24,000 BPD. Sand, when produced, seems to come in discrete slugs that may not occur until days after a rate change.

There were a number of production shut-ins of various durations. For the most part, the shut-ins were initiated in accordance with preconceived plans to shut the well in for wellbore or surface repairs and modifications. When piping was removed during shut-ins, it was inspected on a regular basis for any evidence of scale formation or corrosion. Discussions of corrosion and scale are presented in full detail in Sections 7.0 and 8.0. Reasons for the major shut-ins are provided in Exhibit 3.1-1.

Exhibit 3.1-1. SUMMARY OF PRODUCTION SHUT-INS

<u>Period</u>	<u>Reason</u>
4/19/88-4/20/88	Pump Inhibitor Pill
4/24/88-5/25/88	Repair Wellhead Swab Valve and Flow Loop Flange
6/2/88-6/8/88	Clean Out Disposal Well
8/31/88-9/9/88	Choke Replacement, Piping Leak, and Valve Repair
9/15/88-9/18/88	Threat of Hurricane Gilbert
10/17/88-10/18/88	Choke Replacement (Reinstalled Original, Repaired Choke)
5/15/89-5/26/89	Buildup Test, Install Flow Splitter for HPS
6/26/89-6/27/89	Rising Water From Tropical Storm Allison
7/20/89-8/10/89	ESD Valve Repair and Threat of Hurricane Chantel
9/8/89-10/16/89	Testing, Final Safety Inspection Before HPS Operation
11/16/89-11/22/89	Pump Inhibitor Pill
5/30/90-7/27/90	Disposal Well Rework, Safety and QA/QC Reviews

Cumulative brine production during the reporting period is shown in Exhibit 3.1-2. A total of 12.58 million STB were produced. The brine produced at Pleasant Bayou contains both natural gas and a trace of liquid hydrocarbons. Exhibits 3.1-3 and 3.1-4 show cumulative gas and condensate production. Cumulative gas produced through the perforations was 301 million SCF, and cumulative liquid hydrocarbons were 26.3 STB. Based on gas solubility at reservoir temperature and pressure, the brine is not saturated with natural gas. The relatively stable ratios of produced gas to produced brine over the life of the production test provides additional evidence for gas content less than saturation in the reservoir.

Exhibit 3.1-2. CUMULATIVE BRINE PRODUCTION VERSUS TIME

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Exhibit 3.1-3. CUMULATIVE PERFORATION GAS VERSUS TIME

Exhibit 3.1-4. CUMULATIVE LIQUID HYDROCARBONS VERSUS TIME

The production data from the first instrumented flow on March 7, 1988, through the October 1990 cutoff date for this report are summarized in tabular form in Appendix E. These data are in the form of daily averages and are presented as 1 month per page.

3.2. Cleanup

This section covers details of the well cleanup on March 30-31, 1986, and the bottomhole pressure measurement performed April 1, 1986. During preceding weeks, the packers and fish left in the well in 1983 were removed and new 5-1/2 inch, 23-pound-per-foot tubing was installed to a depth of 13,968 feet (bottom of the mule shoe on the seal assembly) from the Kelly bushing height of 31 feet above ground level. The tubing contained 16.0-pound-per-gallon lignosulphonate mud at this time.

The cleanout 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 and the levels in the two frac tanks used to collect returned liquids and solids. Flow rates were calculated from the tank levels at 5-minute intervals.

3.2.1. Mud Displacement

The initial step in the cleanout was displacement of mud from the well by pumping fresh water down 1-1/4 inch continuous tubing to depths that were increased stepwise after bottoms up. For the first 11 hours, liquids and solids entering the tanks were a mixture of mud from the well and the fresh water pumped to displace the mud. The average rate during this time corresponded to a pump rate of about 2/3 barrel per minute for displacing fresh water. Variations from this were the result of removing liquid from the tanks with a vacuum truck or periodic stopping of pumping to observe whether the well would flow.

Natural flow from the well did not occur before complete displacement of mud from a depth of 4500 feet. However, natural flow began before bottoms up from a tubing depth of 5500 feet. Between 5:00 and 6:15 p.m. the tubing was pulled from the well and a total of about 50 barrels were produced by natural flow. However, plugging of the two 3/8-inch holes in the Willis Type M3G choke precluded continuous production from the well.

3.2.2. Natural Flow Cleanup

The annulus pressure increased starting at 6:00 p.m. due to heating by natural flow prior to plugging of the Willis choke. Tubing pressure spikes were observed between 7:00 and 7:30 p.m. due to pumping fresh water into the choke in attempts to break loose plugs.

Between 7:30 p.m. on March 30 and 1:00 a.m. on March 31, the tubing pressure declined before delivery and installation of a surface choke manifold. This manifold provided a straight-through, 2-inch, heavy-wall pipe and two positive chokes.

At 1:25 a.m. 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 to 3 barrels per minute (1500 to 4500 BPD). Then, as flow rate and tubing pressure rapidly increased, flow was switched to a 1-inch positive choke. The well was shut in at 1:55 a.m. Total production during the 1/2 hour 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.

At 3:30 a.m. on March 31, the casing pressure was bled off for the first time, and flow from the tubing through a 1/2-inch positive choke was started to obtain data for evaluation of the condition of the perforations. Tank strap data verified that the flow rate averaged 7000 BPD. At bottoms up (300 barrels produced), flowing tubing pressure increased from 3880 to 3970 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 3580 psia at the end of the flow was the result of a communication failure that resulted in the service company hand switching to a 3/4-inch 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.

At 9:15 a.m. on March 31, after trucking away enough brine to provide the required tank capacity, production of 500 barrels through a 3/4-inch positive choke began. The production rate averaged just over 14,000 BPD. The drawdown from shut-in pressure was 600 psi at both the beginning and the end of the test. Furthermore, 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.

3.2.3. Bottomhole Pressure Measurement

The height of the wellhead and the wireline mast were such that the desired number of sinker bars could not be used. Tubing pressure was reduced at 6:20 p.m. on March 31, 1986, by blowing brine through the needle valve on the lubricator in an attempt to get the wireline to go down-hole. This was unsuccessful.

After obtaining heavier sinker bars, a sinker bar trip into the well was successfully made between 8:45 p.m. on March 31 and 4:00 a.m. on April 1. The tool tagged up hard at a wireline depth of 14,042 feet below a reference depth of 31 feet above ground level [original Rig Kelly

Bushing (RKB)]. Drill-pipe rotation at 14,028 feet had previously been required to achieve greater penetration. This is believed to be the depth actually reached with the wireline.

The down-hole Panex instrument run was made between 5:30 a.m. and 1:00 p.m. on April 1, 1986. The weight of the down-hole tools was so low that several hundred feet of wire were 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 feet. Because tension was adequate for proper odometer operation on the trip out, a 109-foot depth correction was made as discussed below.

During the trip into the well, 10-minute stops were made at indicated depths of 12,000 and 13,000 feet to establish a pressure gradient for extrapolation to the depth of perforations. The tool tagged up hard at an indicated depth of 13,887 feet for the Panex sensor. The sensor was 25 feet above the bottom of the sinker bars. Including this 25 feet and the 109-foot correction, the tool appeared to have tagged up at a depth of 14,021 feet below the original RKB of 31 feet above ground level. This was very close to the driller depth of 14,028 feet where drill-pipe rotation was required to achieve greater penetration after cleanout. Accepting this depth as a down-hole depth reference and recognizing that the Panex sensor was 25 feet above the bottom of the wireline hardware, the deepest pressure was recorded at a depth of 14,003 feet ($14,028 - 25$) below an RKB 31 feet above ground level. Indicated wireline depth to the sensor from 33 feet above ground level was 13,887 feet. Thus, the correction from observed wireline depth to actual depth, referenced to the top of the liner, is 118 feet ($14,003 + 2 - 13,887$). Note that this value differs from the depth correction of 109 feet that was incorporated in the data report by Milton M. Cooke Petroleum Engineers by 9 feet.¹⁵ The reason was that Cooke reported from an assumed original rig Kelly bushing height of 33 feet and corrected only for the differences between odometer readings before and after the trip down-hole.

A correction of reported pressures was also required before drawing conclusions about bottomhole pressure. When the down-hole Panex instrument was in the lubricator, it indicated a pressure of 4230 psia. At the same time, a deadweight tester indicated a pressure of 4241 psig (4256 psia) at the bottom of the lubricator. Assuming that the lubricator was filled with brine with a pressure gradient of 0.46 psi/foot and that the Panex sensor was 32 feet above the deadweight tester, the deadweight tester value corresponds to 4241 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 is assumed that reported down-hole 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

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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 down-hole pressure:

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

With the 118-foot correction to depth, the probable range of actual bottomhole pressures is as shown in the Exhibit 3.2.3-1. The exhibit also shows calculated values (assuming 0.454 and 0.455-psi/foot pressure gradients) at the midpoint of the perforated interval (14,674-foot Induction Log depth).

Exhibit 3.2.3-1. DOWN-HOLE PRESSURES AND TEMPERATURES

Depth (Corrected), ft	----- Reported, psia	----- Maximum, psia	----- Gradient, psi/ft	Temperature (Reported), °F
12,118	9,843.3	9,873.0		267.1
13,118	10,295.7	10,326.9	0.4524-0.4538	277.9
14,003	10,698.3	10,730.8	0.4539-0.4553	293.5

Calculated Pressures at the Midpoint of Perforations:

14,674.0	11,002.9	11,036.1
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A May 1981 IGT Technical Report entitled "Do We Know Whether Pleasant Bayou No. 2 is Saturated with Methane?" by P. L. Randolph and E. Rockar¹⁶ (Appendix D) included a careful examination of prior bottomhole pressure data and extrapolation of reported pressures to the midpoint of perforations. The search of raw data at the time did not reveal the information required to consider corrections to the data such as applied above. Furthermore, a discrepancy was noted that was troublesome in comparing the new measurement to "original reservoir pressure." The first measurement of bottomhole pressure, on November 15, 1979, (11275.4 psia at 14,750 feet.) and an assumed pressure gradient of 0.44 psi/foot gave a value of 11,241 psia at 14,674 feet. But for another measurement on September 16, 1980, extrapolation of reported pressures at 14,000 and 14,500 feet to a depth of 14,674 feet gave a value of only 11,166 psia. The net result is a difference of 75 psi in measurements that should have differed only by the drawdown from producing about 275,000 barrels. With this uncertainty in original reservoir pressure and the estimated uncertainty in the data for April 1, 1986, the range of values for actual reservoir drawdown is 130 to 238 psi.

3.3. Start-Up of Testing in 1988 Production

The activities that preceded the start of continuous production in June 1988 are discussed under subheadings below. They consisted of 1) running caliper and bottomhole pressure logs that tagged up hard slightly below 14,000 feet in February 1988; 2) a day of production to check out surface facilities in March; 3) attempts to remove the plug from the wellbore and pumping of an inhibitor pill, both of which involved producing brine from the well, in April; and 4) performing a multi-rate draw-down test with bottomhole pressure measurement at the end of May.

3.3.1. Wireline Logging in February 1988

This first planned action was measurement of bottomhole pressure. This was preceded by running a 4-inch-diameter gauge ring. It tagged up hard at 14,024 feet, the same depth that had been reached after well cleanout in 1986. A second wireline run was made with a 4-inch-diameter weight that was tapered on both ends. Hammering with this weight was believed to have pushed the obstruction down the hole about 10 feet. But when the wireline was pulled from the hole, only the rope socket and collar locator were recovered. A 37.6-foot-long fish consisting of the tapered gauge ring, jars, and sinker bars had been left in the well.

While waiting for fishing tools, a caliper log was run from a depth of 13,925 feet to the surface. There was no indication of scale or corrosion inside the tubing. Then, on the 4th day of wireline activity, the 37.6-foot-long fish was successfully recovered from the well with a single run of an overshot and grapple.

Review of the history of the well and the observation of small amounts of solids that were found to be primarily aluminum on the bottom of hardware that had impacted at the depth of 14,024 feet in the well resulted in the belief that the obstruction was a pump-out plug that had been run with the tubing in 1986. The plug that was supposed to have fallen to the bottom of the well had an outside diameter of 4-15/16 inches and was 4-1/8 inches long. It apparently lodged on a ridge in the 7-inch liner at the depth where rotation had been required for deeper drill-pipe penetration before the tubing was run in 1986.

On February 29, 1988, a Panex bottomhole pressure sensor was run to a depth of 14,000 feet. Stops were made to obtain stabilized pressures and temperatures on the trip out of the well. The resultant data and calculated gradients are tabulated in Exhibit 3.3.1-1.

Assuming a pressure gradient of 0.450 psi/foot below 14,000 feet, a pressure of 11,002 psia is calculated for the midpoint of the perforations at 14,674 feet. This is the same as the value that was reported for the measurement on March 31, 1986.

Exhibit 3.3.1-1. STATIC PRESSURE AND TEMPERATURE GRADIENTS
ON FEBRUARY 29, 1988

Depth, <u>ft</u>	Pressure, <u>psia</u>	Press. Grad., <u>psi/ft</u>	Temperature, <u>°F</u>	Temp Grad. <u>°F/ft</u>
14,000	10,699	0.461	295.1	0.021
13,000	10,260	0.439	279.3	0.016
12,000	9,815	0.445	264.7	0.015
11,000	9,368	0.447	248.1	0.017
10,000	8,917	0.451	230.0	0.018
9,000	8,461	0.446	206.6	0.0234
8,000	7,997	0.464	183.2	0.0214
7,000	7,530	0.467	164.8	0.0184
6,000	7,063	0.467	152.4	0.0124
5,000	6,595	0.468	136.1	0.0163
4,000	6,125	0.470	121.2	0.0149
3,000 ^a	5,654	0.471	107.5	0.0137
2,000 ^a	5,183	0.471	94.6	0.0129
1,000 ^a	4,700	0.483	87.0	0.0126

^a The tool was intermittently shorting out between depths of 4000 and 3000 feet.
The data from shallower than 4000 feet may not be accurate.

It is interesting to note that the temperature gradient showed a minimum in the depth interval between 6000 and 7000 feet where produced brine was injected in the disposal well. The highest measured temperature gradients were in the 3000 feet below 7000 feet.

3.3.2. Start-Up Production in March 1988

Brine was produced for 24 hours starting at 13:15 on March 7, 1988, for initial start-up and checkout of the rehabilitated surface facilities. That morning, the surface facilities had been charged with nitrogen and a couple small leaks had been repaired. Start-up was with all of the flow through the small separator and was in increments as follows:

<u>Time</u>	<u>Brine Rate, STB/d</u>
13:15	2000
13:30	3000
14:00	4200
14:14	4800
15:40	7500

The large separator was put on-line at 16:00 and the brine rate was increased to 9200 STB/d at 17:00. Brine rate was left at this value until the well was shut in at 13:15 on March 8, 1988.

Scale-inhibitor injection was started at 15:00 at a concentration of 0.5 ppm. The injection rate was increased to provide a concentration of 1.0 ppm after the surface brine temperature increased to 200°F at 19:00.

During the flow, controllers were tuned for proper damped operation and proper operation of the computer data system and on-line calculations were verified. Total production was 8579 STB of brine and 202,000 SCF of gas through the perforations. The portion of the gas separated from the brine was 170,000 SCF. Gas/brine ratios were 23.55 SCF/STB for total gas through the perforations and 19.77 SCF/STB for the portion of the gas that was removed from the brine by the separators.

3.3.3. Caustic Treatment and Inhibitor-Pill Treatment in March and April 1988

On March 30, 1988, 30 gallons of a solution of 10% sodium hydroxide and 5% sodium nitrate was spotted on the obstruction at a depth of 14,024 feet in the wellbore in multiple trips with a wireline dump bailer. Previous analysis of solids taken off the tip of hardware that had impacted the obstruction confirmed the obstruction was primarily aluminum. Aluminum is soluble in this solution. Unfortunately, the sodium hydroxide also reacts almost instantly with the brine to form calcium hydroxide precipitate, so the effect of this treatment was uncertain.

On April 6, 1988, the obstruction was found to still be at the same depth when a gamma-ray correlation log was run.

On April 18, 1988, the well was flowed to clean caustic residue from the well before pumping a scale-inhibitor "pill." A total of 1308 STB of brine was produced with the brine rate being in the range of 4000 to 7500 STB/d for most of the time. After "bottoms up" (production of a volume of brine equal to the volume of the wellbore), flow rate did not correlate with choke opening in a normal manner. Also, noise due to solid material moving through the flow loop was heard. These characteristics were later found to be due to production of chunks of aluminum, with the largest having a volume of about a cubic inch. Most of the area of one of the two holes in the disk of the Willis choke was blocked by one of the pieces of produced aluminum. These observations removed any doubt as to whether the obstruction at 14,024 feet was the aluminum pump-out plug and suggested the plug was disaggregating.

On April 20, a scale-inhibitor pill was injected into the producing formation. The pill consisted of 273 gallons of Champion's Gypton T-132, a concentrated, neutral pH, phosphonate-based scale inhibitor, and 10 gallons each of an oxygen scavenger and an iron-sequestering agent. The pill components were mixed with a calcium-free 5% synthetic sodium chloride brine to obtain

100 barrels total. The intent was to displace the 100-barrel pill into the formation and then chase it with 50+ barrels of a calcium-free brine flush. In practice, the flush was not achieved due to high injection pressure.

The well was shut in for 24 hours after pumping the pill. Then a production at a rate of about 2000 STB/d was started at 17:00 on April 21, 1988. The low rate was used to permit accurate correlation of sample collection with the volume of liquid recovered. Flow rate was subsequently increased in steps up to 13,000 STB/d. The pill cleanup flow ended at 19:00 on April 24 after approximately 30,000 barrels of brine were produced.

The inhibitor-pill treatment is discussed in more detail in Section 7.5 of this report.

3.3.4. Multi-Rate Draw-Down Test in the Last Week of May 1988

After the well had been shut-in for a month following the 3-day inhibitor-pill cleanup flow, a Panex bottomhole pressure sensor was run to a depth of 13,950 feet on May 26, 1988. This depth was selected after a gauge-ring run showed that the obstruction was still at 14,024 feet. During that month, the wellhead swab valve and the flange connection in the middle of the flow loop were rebuilt to eliminate leaks.

Stops were made every 1000 feet for determination of pressure and temperature gradients on the trip into the well. The measured values are tabulated in Exhibit 3.3.4-1.

Exhibit 3.3.4-1. STATIC PRESSURE AND TEMPERATURE GRADIENTS
ON MAY 26, 1988

<u>Depth,</u> <u>ft</u>	<u>Pressure,</u> <u>psia</u>	<u>Press. Grad.,</u> <u>psi/ft</u>	<u>Temperature,</u> <u>°F</u>	<u>Temp Grad.</u> <u>°F/ft</u>
20	4,244	--	79.6	--
1,000	4,699	0.464	88.5	0.009
2,000	5,174	0.475	100.3	0.0118
3,000	5,644	0.470	113.4	0.0131
4,000	6,115	0.471	126.2	0.0118
5,000	6,579	0.464	140.8	0.0146
6,000	7,051	0.472	155.2	0.0144
7,000	7,514	0.463	167.9	0.0127
8,000	7,977	0.463	186.4	0.0185
9,000	8,443	0.466	208.9	0.0215
10,000	8,896	0.453	231.3	0.0224
11,000	9,352	0.456	248.9	0.0176
12,000	9,810	0.458	266.0	0.0171
13,000	10,256	0.446	279.2	0.0132
13,950	10,685	0.452	293.8	0.0154

Assuming a pressure gradient of 0.45 psi/foot, the reported shut-in bottomhole pressure of 10,685 psia at 13,950 feet translates to a pressure of 11,011 psia at the midpoint of the perforations (14,674 feet). This value is 9 psi greater than the previous two measurements. This difference is well within the magnitude of probable error of values reported by this wireline contractor for measurements on DOE geopressured-geothermal wells.

The temperature gradient showed variations with depth similar to those observed on February 29 -- namely, a minimum temperature gradient in the depth interval between 6000 and 7000 feet in which produced brine was injected in the disposal well and the highest temperature gradients in the 3000 feet of depth below 7000 feet. The February measurements were made on the way out of the well, whereas the May measurements were made on the way into the well. This provides important validation of the data.

The draw-down test was started at 07:34 on May 27 by opening the choke 20/64" in a time of about 20 seconds to achieve a brine production rate of about 5000 STB/d. Subsequent rate changes were also made by changing the choke setting in a time of about 20 seconds. The sequence of steps was as follows:

1. Flow at about 5000 BPD.
2. Increase rate to about 7500 BPD.
3. Increase rate to about 11,500 BPD.
4. Reduce rate to below 10,000 BPD to change out down-hole sensors.
5. Shut in for a 1-day buildup test.
6. Stabilize flow at 8750 BPD and measure the flowing pressure gradient.
7. Shut in the well after the down-hole sensor reached the surface.

Additional information on the timing of rate changes and the resultant values of brine rate and flowing pressures are summarized in Exhibit 3.3.4-2. The flowing gradient data obtained on June 1, 1988, are tabulated in Exhibit 3.3.4-3.

The flowing gradient data had been requested in order to compare calculated and measured friction pressure drops in the wellbore. But the management restriction of flowing at a rate below 10,000 STB/d resulted in the friction component of the pressure drop being too small for a meaningful comparison. In fact, the flowing pressure gradients at all depths were less than the previously measured static gradients. This is primarily due to the lower density of the higher temperature brine.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 3.3.4-2. STEPS IN THE MAY 1988 MULTI-RATE TEST

<u>Date</u>	<u>Time</u>	<u>Choke Setting</u>	<u>Brine Rate, STB/d</u>	<u>BHP @ 13,950 feet. psi</u>
5/27/88	07:00	Closed	0	10,685
5/27/88	07:34	Inc. to 20/64"	Transient	Transient
5/27/88	19:00	20/64"	4,870	10,535
5/27/88	19:03	Increased	Transient	Transient
5/28/88	07:00	Not Touched	7,450	10,427
5/28/88	07:03	Inc. to 34/64"	Transient	Transient
5/29/88	11:20	34/64"	11,480	10,197
5/29/88	13:50	Red. to 30/64"	Transient	Dead Gauge
5/29/88	16:00	30/64"	9,600	Replacing Gauge
5/29/88	20:30	30/64"	9,650	10,284
5/30/88	18:00	30/64"	9,650	10,281
5/30/88	18:08	Closed	Transient	Transient
5/31/88	16:00	Closed	Zero	10,641
5/31/88	16:34	Open to 28/64"	Transient	Transient
6/01/88	06:30	28/64"	8,750	10,334
6/01/88	14:00	Closed	Transient	Gauge Out

Exhibit 3.3.4-3. FLOWING PRESSURE AND TEMPERATURE GRADIENTS ON JUNE 1, 1988

<u>Depth, ft</u>	<u>Pressure, psia</u>	<u>Gradient, psi/ft</u>	<u>Temperature, °F</u>	<u>Gradient, °F/ft</u>
13,950	10,335	--	299.3	--
12,000	9,448	0.455	297.4	0.0010
10,000	8,544	0.452	294.3	0.0016
8,000	7,639	0.453	389.9	0.0022
6,000	6,731	0.454	284.1	0.0029
4,000	5,831	0.450	277.7	0.0032
2,000	4,934	0.449	268.9	0.0044
20	4,036	0.449	259.3	0.0048

3.4. Long-Term Brine Production

The discussion below provides an overall summary of brine produced from the well, surface and reservoir bottomhole pressure response, and surface temperature response with emphasis on the long-term flows between June 1988 and October 1990.

3.4.1. Overall Summary

This section deals only with brine production data. Details of brine chemistry are provided in Section 4.0. Section 7.0 deals with inhibition of scale formation, including both surface and subsurface (inhibitor-pill) actions. Section 8.0 discusses corrosion inhibition.

Total flow from the well was regulated by the main choke. A brine rate of 18,000 BPD results from a choke setting of 56/64". Brine flow rate is shown as a function of time in Exhibit 3.4.1-1. The values used in the exhibit and tabulated in Appendix E 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 it is believed to be more accurate. The data plotted in Exhibit 3.4.1-1 are daily averages. As such, short-term fluctuations are somewhat smoothed.

Exhibit 3.4.1-1. PRODUCED BRINE RATE VERSUS TIME

3.4.2. Wellhead and Bottomhole Pressure Responses

The flowing wellhead production pressure is shown as a function of time in Exhibit 3.4.2-1. The values plotted are 24-hour averages. Pressures that were not stable for an entire 24-hour day have been clipped by the averaging process. Also, with one exception, all values below 2800 psi prior to mid-1990 are the result of the pressure transmitter being isolated from the actual pressure in the wellhead below the master valve. The exception was a few hours on the evening of June 20, 1988, when the brine rate was 25,000 STB/d and the tubing pressure got down to 2550 psia. The next highest rate, 22,500 STB/d overnight on June 21-22, 1988, was accompanied by a minimum flowing tubing pressure of 2875 psia. The stepwise increase in rate to 24,000 STB/d in October 1990 reduced the flowing tubing pressure to 1813 psia.

Exhibit 3.4.2-1. FLOWING PRODUCTION TUBING PRESSURE VERSUS TIME

Flowing bottomhole pressure is related to flowing wellhead pressure, but not in a linear manner. IGT calculates flowing BHP from variables (pressure, temperature, and flow rate) measured on the surface. Exhibit 3.4.2-2 provides calculated BHP values at the depth of the top perforation (14,644 feet) as a function of time.

The range of flowing bottomhole pressures was very small for the entire 2 years of flow before mid-1990. The highest flowing bottomhole pressure was about 10,100 psia in June and July of 1988 and 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 bottomhole pressure was 9760 psia at 14,644 feet at the end of May 1990, when HPS operations ceased. This value is only 340 psi less than the highest flowing bottomhole pressure. As brine flow rates were increased in stages from 16,000 to 24,000 BPD during the months of July to October of 1990, a new low calculated BHP of just over 9000 psia was reached on October 28. At this time, the brine flow rate was just over 24,000 BPD. This BHP minimum was still about 1000 psi above the estimated bubble point of the reservoir (Section 5.2), even though it represents a total drawdown (at the wellbore) of approximately 2000 psi.

Exhibit 3.4.2-2. CALCULATED BHP AT 14,644 FEET VERSUS TIME

On May 14, 1989, a down-hole pressure survey was run while maintaining a brine production rate of about 12,600 BPD. This measurement provided an opportunity to cross-check the calculated BHP values. At the last stop at 14,000 feet RKB, the Panex gauge in the wellbore registered 10,085 psia and 307.7°F. Correction of this value to the depth datum used in IGT's BHP calculations (14,644 feet) yields a corrected value of 10,104 psia. One further correction is needed. At the same elevation as IGT's wellhead sensors (15 feet RKB), the IGT deadweight tester read 3364 psia while the service company tool read 3358 psia. Applying this surface difference directly to the down-hole readings yields a final corrected value of 10,112 psia at 14,644 feet.

Although BHPs were calculated on May 14 at the time of the down-hole measurements, some interference was expected from the presence of the wireline. Therefore, a comparison was made with the last measurements before wireline operations started on May 13. At that time, calculated BHPs averaged 10,116 psia, only 4 psi more than the corrected measured value. The agreement between measured and calculated BHP values is quite good.

3.4.3. Surface Temperature Responses

Production wellhead temperature is shown as a function of time in Exhibit 3.4.3-1. The values in the range of 50° to 100°F were ambient temperature at times when brine was not flowing.

Exhibit 3.4.3-1. FLOWING WELLHEAD TEMPERATURE VERSUS TIME

The zero values are times when actual temperature data were not being recorded. During periods of relatively steady flow between 15,000 and 20,000 BPD, flowing wellhead temperatures were stable in the range of $290^{\circ} \pm 2^{\circ}\text{F}$. A discussion of brine temperatures through the rest of the system follows.

One of the things that was surprising when the production tests were started in 1988 at Pleasant Bayou was that the measured temperature in the brine-flow line downstream from the choke and separator was higher than the wellhead temperature upstream from the choke. At first it was thought that the temperature transmitters were incorrect, but careful calibration revealed that the increased downstream temperature was real. It had been assumed, without doing the engineering calculations, that the wellhead temperature would be the highest and that cooling of the brine and gas as it flowed through the pipes and vessels would cause all of the downstream temperatures to be lower than the wellhead temperature. This elevated downstream temperature had not been noted or looked for in previous geopressedured-geothermal well tests.

The reason for the elevated downstream temperature is clear when the thermodynamics of the system are considered. The heat generated by the turbulent release of energy as the brine passes through the choke exceeds the expansion cooling of the gas as it passes through the choke.

Whether the net effect will be heating or cooling of the line downstream of the choke depends on

the ratio of the gas and brine as they pass through the choke together. For the geopressured-geothermal aquifer wells, the volume of brine is so much larger than the volume of the gas that the heating effect dominates.

After passing through the choke, the brine will continue to cool by transfer of heat to the atmosphere from the pipes and vessels. This cooling depends on the heat-transfer coefficient, which is a strong function of the wind velocity across the equipment and precipitation. It is constantly changing with the changing weather conditions. The only weather parameter routinely measured at the Pleasant Bayou location is the ambient temperature. The wind, rain, and humidity are not recorded. Therefore, quantitative calculations of the expected temperature change are difficult to make. Appendix F provides a more detailed discussion of this topic and some calculations indicating a temperature rise across the choke of about 6.4°F for a flowing pressure drop of 2393 psi. To a first approximation, the heating due to passage through the choke is a linear function of pressure drop and is about 2.7°F per 1000 psi of pressure drop.

Exhibit 3.4.3-2 is a summary of production wellhead, HPS, and disposal wellhead temperatures and pressures at times when operation had been relatively stable. Exhibit 3.4.3-3 is a plot of flowing wellhead, HPS, and disposal wellhead brine temperatures (on an expanded temperature scale) versus time. These exhibits indicate that the roughly 4°F temperature rise that occurs at the chokes is almost exactly compensated for by cooling through the rest of the system such that the temperature at the production well is almost exactly equal to the temperature at the disposal wellhead.

Exhibit 3.4.3-2. SELECTED TEMPERATURE CHANGE DATA

<u>Date</u>	<u>Brine Rate, STB/d</u>	<u>WHP, psia</u>	<u>WHT, °F</u>	<u>HPS Pressure, psia</u>	<u>HPS Temp, °F</u>	<u>Disposal Pressure, psia</u>	<u>Disposal Temp, °F</u>
21 May 90	15,600	2915	287.4	522	291.2	441	209.5 ^a
22 Aug 90	18,000	2716	289.6	548	292.5	527	290.7
6 Sept 90	19,800	2471	291.2	615	293.2	585	291.3
25 Sept 90	21,700	2121	292.8	721	294.3	448	292.6
28 Oct 90	25,760	1800	294.1	748	295.0	705	293.1
5 Dec 90	12,200	3207	284.9	411	289	408	281.4

^a Disposal temperature depressed due to cooling of brine by the HPS.

Exhibit 3.4.3-3. BRINE TEMPERATURES AT THE PRODUCTION WELLHEAD, HPS, AND DISPOSAL WELLHEAD VERSUS TIME

3.5. Long-Term Gas Production

The rate of production of gas is shown as a function of time in Exhibit 3.5-1. The separated gas rate is the sum of the measured gas rates from the two separators. The perforation gas rate is the separated gas rate plus the result of calculating the amount of gas remaining in solution in the brine leaving the separators. It represents the total amount of gas in solution in the brine entering the perforations. Note that the gas/brine ratio reported by prior operators (Exhibit 1.5-1) corresponds to the separated gas in Exhibit 3.5-1. It is less than the actual amount of gas leaving the reservoir by an amount that is dependent upon the separator operating pressure.

The gas/brine ratio is shown as a function of time in Exhibit 3.5-2. 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 was reported for those times when there was no production. Gas/brine ratios showed only small variations from the overall average of about 24 SCF/STB. The difference in calculated solubilities for methane in Pleasant Bayou brine was only 1 SCF/STB for the range of bottomhole pressures encountered over the production test and a temperature of 308°F. This difference was comparable to the observed variations from the overall average of 24 SCF/STB.

Exhibit 3.5-1. RATE OF GAS PRODUCTION VERSUS TIME

Exhibit 3.5-2. PRODUCED GAS/BRINE RATIO VERSUS TIME

3.6. Liquid Hydrocarbon Production

As gas exits the separators, it is cooled and liquids are condensed. Those liquids are primarily condensed water vapor, but they also contain some hydrocarbons. Condensed liquids are collected from the cooling gas stream in knockouts 1) upstream of the gas cooler, 2) between the gas cooler and the glycol dehydrator, 3) in the base of the dehydrator tower, 4) at the inlet to the sales meter skid, and 5) in the base of the flare stack. Liquids from these knockouts flow into a gunbarrel separator, where gravity separates the water and hydrocarbon fractions. Once each day, the operators drain and measure the volume of liquid hydrocarbons. Both water and hydrocarbon fractions are stored temporarily in an onsite tank before being hauled off by private contractors to permitted disposal facilities.

Exhibit 3.6-1 shows the rate of liquid hydrocarbon recovery versus time. Although there is some scatter in the individual daily measurements, that rate averages about 2 gallons per day. The volume of hydrocarbons recovered is too small to justify a sales contract and has only amounted to a total of 26.3 STB through October 31, 1990. Unlike condensates produced by typical oil and gas operations, the hydrocarbons produced at Pleasant Bayou have high concentrations of aromatics. Approximately two-thirds of the hydrocarbons recovered consist of derivatives of benzene and naphthalenes. Section 5.3 provides a more detailed discussion of this aspect of these hydrocarbons.

Exhibit 3.6-1. RATE OF LIQUID HYDROCARBON PRODUCTION VERSUS TIME

3.7. Production to HPS

The Hybrid Power System was designed by the Ben Holt Company, under contract to the Electric Power Research Institute (EPRI), to generate electricity from both the natural gas and the thermal energy in produced brine from a brine rate of 10,000 barrels per day. Thermal energy utilization was through a binary cycle wherein iso-butane was boiled by the hot brine and was the working fluid to drive a turbine that was coupled to a generator through an appropriate gear box. Two reciprocating engines fueled by the natural gas each drove an electrical generator for utilization of the natural gas energy. The exhaust from the reciprocating engines passed through a heat exchanger where it was used to boil additional iso-butane.

In conjunction with construction of the HPS by the Ben Holt Company under subcontract to Eaton Operating Company, IGT modified the Pleasant Bayou production facilities during July and August 1989 to provide flow splitters in the gas and brine piping such that the Hybrid Power System could operate independently of the production for testing of the reservoir. The split of the gas production consisted only of providing a tee in the piping after the glycol dehydrator and metering of gas flow through that tee to the HPS. Any gas used by the lower pressure of the carburetors on the natural gas-fired engines was simply a reduction in gas flow to the 400-psi gas sales line.

Key constraints on the brine flow splitter were that 1) pressure at the inlet to the HPS had to be below the 600-psig working-pressure rating of the heat exchangers and 2) pressure in the piping leaving the HPS for the brine disposal well had to be at least 50 psi below the inlet pressure to the HPS so that flow rate through the HPS could be controlled. This was accomplished by installing a back-pressure controller in the brine line that bypassed the HPS. Brine take by the HPS was from upstream of the controller, and brine for disposal was returned downstream of the pressure controller. The controller was set to hold about 540 psia, and an upstream relief valve was set at 550 psig. These values ensured that the 600-psig working pressure would not be exceeded, even during the inevitable pressure transients at times of large changes in brine take by the HPS. Including the flowing pressure drop through the pipe to the disposal well and through the filters, these constraints translated to an upper limit on the disposal well injection pressure of roughly 450 psia.

In addition, prior to the HPS operation, some parties were concerned about scale formation and corrosion of piping within the HPS due to the chemistry of the geothermal brine. In practice, the brine treatment adopted before installation of the HPS removed any problem. The Ben Holt Company final report stated "Historically, there have been several concerns about operation on a geopressured well. Excessive scaling may have rendered heat exchangers ineffective; corrosion may have required the use of expensive, exotic materials and impure well head gas may 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." Indeed, there was no additional scale or corrosion prevention program in place to protect the HPS exclusively. Scaling and corrosion problems associated with carbon steel piping were not a problem in the operation of the HPS or the rest of the facility. The scale- and corrosion-inhibitor programs on the Pleasant Bayou system are discussed in detail in Sections 7.0 and 8.0.

The piping changes necessary to supply natural gas and geothermal brine to the HPS were completed in early August 1989. Gas and brine were taken by the HPS, at less than half of the design rate, for operational testing of HPS components starting in August 1989. On September 8, 1989, the well was shut in for recertification of relief valves, recalibration of instruments, preparation of a Safety Analysis Report (SAR), and comprehensive safety and QA/QC reviews by DOE. On October 16, 1989, production resumed. Production was again shut in for 9 days in November 1989 for injection of a scale-inhibitor pill into the producing formation. Thereafter, production was continuous until the completion of the operational testing of the Hybrid Power System at the end of May 1990. Brine rate slowly declined from 16,000 to 15,300 STB/d while flowing wellhead pressure declined from 3065 to 2911 psia.

Exhibit 3.7-1 provides a summary of gas and brine rates to the HPS versus time. Gas flow rates to the HPS with both engines running averaged about 220,000 SCF/d. Only one of the engines was running at those times when gas rate to the HPS was about one-half of this value. Brine flow rates to the HPS were in the range of 6000 to 10,000 STB/d. The vast majority of operation was at a brine rate less than the design rate of 10,000 STB/d. This is because the brine temperature at the HPS was higher than anticipated in the design.

Appendix G is a summary of the daily takes of gas and brine by the HPS. It includes tabulation of the energy delivered to the HPS in terms of combustion energy for the natural gas and thermal energy removed from the brine. In assessing geothermal resources, the USGS reports thermal energy content relative to a base temperature of 60°F. The energy that would have been removed from the brine if it had exited the HPS at the temperature of 60°F is shown in Appendix G as the Theoretical Energy content of the brine.

Exhibit 3.7-2 is a plot of the temperature of brine entering and leaving the HPS. The exiting values above 275°F are erroneous because there was no flow at the location of the downstream temperature sensor at times when the HPS was not taking brine. When brine was being taken, the temperature of exiting brine averaged roughly 155°F, rather than the 60°F used by the USGS in evaluating geothermal resources.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 3.7-1. RATES OF GAS AND BRINE TO THE HPS VERSUS TIME

Exhibit 3.7-2. TEMPERATURE OF BRINE IN AND OUT OF THE HPS VERSUS TIME

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 3.7-3.

Exhibit 3.7-3. CUMULATIVE VOLUMES AND ENERGY FOR THE HPS

	----- Measured by -----	
	<u>IGT</u>	<u>Ben Holt Co.</u>
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 3.7-3 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 turbine 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 1191 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, which was higher than would be expected for a commercial 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.

3.8. Brine Disposal

Injectivity of a disposal well is primarily a function of the disposal formation and its associated aquifer. All things remaining constant, a certain driving force (equilibrium reservoir

pressure minus flowing bottomhole sandface pressure) should be required to support a given injection rate. Our measurements to monitor disposal well performance were strictly surface measurements of pressure and temperature at the disposal wellhead. Ideally, surface pressure should be directly related to bottomhole pressure -- differing only by the static head of fluid in the wellbore and the friction losses of flowing brine. Reasons for fluctuations include fluid property changes, wellbore changes, and damage to the formation. Pressuring up of the disposal aquifer in response to injected brine has not been observed.

Brine properties affect measured pressure primarily due to changes in the static head if brine density changes. In this case, periodic cooling of the brine by either ambient conditions or HPS operation lowered the temperature of injected brine, causing the density to rise. A higher brine density results in a lower surface pressure even if bottomhole pressure does not change.

Changes in the wellbore affect flowing friction losses and therefore the relation between surface and bottomhole pressures. Any buildup of scale or corrosion will affect friction losses by decreasing the area available for flow and/or changing the pipe wall roughness. We are not able to directly monitor such changes, but we believe them to be small.

Damage to or isolation from disposal formations is a major factor with respect to well injectivity. There are several disposal sands perforated, and they may or may not be interconnected at some distance from the wellbore. The disposal formation sand is unconsolidated. Sand-particle sloughing and buildup in the wellbore (if there is any flow-back from the formation to the wellbore or crossflow between perforated intervals) is a possibility. As sand builds up and covers the perforation intervals, these zones are isolated and the injection pressure increases. This problem was addressed by cleaning sand from the wellbore on occasion and by carefully attending to shut-in procedures when flow was stopped. Specifically, disposal wellhead valves were shut to minimize the flow-back volume.

Formation damage can result from injection of solids or liquids that plug the sandface. These effects are best quantified by running pressure-transient tests but can be inferred by monitoring gross changes in disposal well performance. The polishing filters were installed to mitigate such effects. During most of the time that the HPS was in operation, filter elements with a nominal rating of 10 microns were used. For perspective, the mean pore throat size in the disposal sand is estimated to be about 15 microns and spherical particles with density equal to sand (2.6 g/cc) and diameter greater than about 25 microns are expected to settle out in the separators.

As brine rate was increased above 20,000 STB/d, it became necessary to increase the nominal rating of the filter elements to 50 microns. Although particles this large are expected to settle out in the separators, rapid increases in pressure drop across the filters has been

observed to be the most sensitive indicator of production of slugs of a roughly a cubic foot of sand at brine rates in excess of 24,000 STB/d.

Sections below provide detailed discussions of the effects of HPS operation on disposal well performance, acid treatments to remove formation damage, and well rework operations.

3.8.1. Summary

Exhibits 3.8.1-1 and 3.8.1-2 summarize daily average disposal wellhead pressure and temperature. The disposal well tubing pressure shows a range of values as a function of injection rate, as shown in Exhibit 3.8.1-3. The slope of a linear regression through the data indicates a rise in injection pressure of approximately 28 psi per 1000 BPD of brine injection.

3.8.2. HPS Effects

The return brine from the HPS at about 150°F (Exhibit 3.7-1) was recombined with the 290°F produced brine stream and injected into the salt water disposal well. The result was a lower brine disposal temperature of about 204°F (Exhibit 3.8.1-2). The lower brine disposal temperature resulted in a higher density fluid with an average decrease in the disposal injection pressure of about 45 to 50 psi. These decreases are apparent in the first half of 1990 in Exhibit 3.8.1-1.

The disposal well injection pressure varied with the amount of cooling of brine by the HPS due to the temperature dependence of brine density. Consider the week of October 26, 1989, through November 1, 1989. At the beginning of the week, while the brine rate through the HPS was 8000+ STB/d, the brine temperature at the disposal well was 219°F, and the injection pressure was 402 psia. In contrast, for 4 full days with all brine bypassing the HPS, the brine temperature at the disposal well was 289°F, and the daily average injection pressure was 452 psia.

During the week of December 21-27, 1989, the produced brine rate was about 16,000 STB/d. The injection pressure was essentially constant at slightly above 445 psia during the first part of the week when brine was being cooled by the HPS. After 4 days without brine cooling by the HPS, the injection pressure was up to 490 psia. The pressures with and without cooling were about 10 psi greater than was being experienced a month earlier.

After the HPS stopped taking brine on May 26, 1990, the injection pressure jumped from 445 to 500 psia due to an increase in brine disposal temperature from 208° to 289°F at a brine disposal rate of 15,600 STB/d. The HPS brine take had been about 9500 STB/d with a reject temperature of 156°F.

The injection pressure reduction is about 0.7 psi/°F of reduction in temperature of the injected brine. Extraction of thermal energy will lower the pressure needed to dispose of brine.

Exhibit 3.8.1-1. DISPOSAL WELL TUBING PRESSURE VERSUS TIME

Exhibit 3.8.1-2. DISPOSAL WELL BRINE TEMPERATURE VERSUS TIME

Exhibit 3.8.1-3. PRODUCED BRINE RATE VERSUS DISPOSAL TUBING PRESSURE

3.8.3. Acid Treatments

In 1988, it was noticed that recovery of injection pressure was delayed by hours, to days, after it decreased due to cooling of the injected brine by rain. It was as if the cooler brine had dissolved material that was blocking entry into the disposal sandface. It was hypothesized that the effect was due to the dissolving of a very small amount of calcite. Calcite, unlike most salts, has an inverse relationship between solubility and temperature. Calcite is more soluble at 200°F than at 300°F. This hypothesis was tested by conducting several small acid treatments on the Pleasant Bayou No. 2 salt water disposal well. Either hydrochloric acid or citric acid was injected into the flowing brine stream. The treatments generally reduced the skin on the disposal sandface and restored injectivity by reducing the wellhead injection pressure. Exhibit 3.8.3-1 summarizes the amount and type of acid used and gives flowing disposal injection pressures before the treatment, 1 day after the treatment, and 1 week after the treatment.

Immediately after the disposal well was cleaned out in June 1988, the injection pressure (surface) required for a flow rate of 20,000 BPD was less than 600 psia. During August 1988, disposal well injection pressure was increasing a few psi per week. At a lower brine injection rate of 19,000 STB/d, it was 590 psia. Two experiments with small quantities of acid were performed.

Exhibit 3.8.3-1. ACID TREATMENT SUMMARY

<u>Date</u>	<u>Treatment</u>	-----Disposal Pressure, psia-----		
		<u>Before</u>	<u>1 Day After</u>	<u>1 Week After</u>
8/18/88	4 gals 15% HCl	584	560	580 ^a
8/23/88	90 lbs Citric Acid	580	478	523
12/1/88	90 lbs Citric Acid	622	603	605
2/17/89	10 bbls 28% HCl	619	501	501
3/6/89	40 bbls 28% HCl	495	508	507
2/14/90	15 lbs Citric Acid	462	453	454 ^a
10/4/90	25 bbls 28% HCl	667	617	620

^a Pressure indicated is only 5 days after the treatment, rate was changed after that.

The first experiment used 4 gallons of inhibited 15% hydrochloric acid and the second used 90 pounds of anhydrous granular citric acid. In the first experiment, performed on August 18, 1988, 4 gallons of inhibited 15% hydrochloric acid (equivalent to 77 moles hydronium ions) were poured into an isolated filter pot. Then the filter pot was put on-line. The acid was diluted by the brine and carried down-hole, with a portion immediately neutralized by the alkalinity in the brine. If all the acid was swept from the pot within 1 minute of opening the valves, the acid treatment at the disposal wellhead would have consisted of 550 gallons of 0.1% HCl. After the 12-minute transit time for the brine to move from the filters to the disposal well perforations, the injection pressure dropped from 584 to 560 psia in the following 8 minutes. Within 4 to 5 days, the wellhead injection pressure had recovered to the injection pressure prior to the acid treatment on August 18. This was about the same pressure drop and recovery as previously experienced from the brine-cooling effect of a few inches of rain. This supported the hypothesis that small calcite particles were responsible for plugging the sandface.

The citric acid injection on August 23, 1988, was accomplished in the same manner. Ninety pounds was the maximum amount that could be poured in the filter pot upstream of the filter elements. The citric acid molecule contains three acid groups, so 90 pounds of citric acid is equivalent to 640 moles of hydronium ions if it is completely dissociated. This would be equivalent to eight times as much available acid as the previous hydrochloric acid treatment on August 18, 1988. The citric acid reached the perforations in 12 minutes followed by declining wellhead injection pressure until a minimum was reached 8 minutes later. The injection pressure drop was more than 100 psi, with the minimum injection pressure being 478 psia. At the end of August 24, the injection pressure had recovered to only 491 psia, and it was 523 psia 1 week after the treatment.

The ability of citrate ions to complex calcium ions is not significant. The stoichiometric ratio of the calcium citrate complex is one or two, so the citrate in 90 pounds of acid could, at most, complex the calcium contained in 5 to 10 barrels of brine. Citric acid was reported by Matty *et al.*¹³ to be an effective scale inhibitor at concentrations above 20 ppm. Whether the injected citric acid prevents reprecipitation of calcite in the reservoir, thereby increasing the effectiveness of citric acid over other acids, is not known. Citric acid is a relatively expensive acid, however, and is not generally used in large acid treatments.

On December 1, 1988, the disposal well was again treated with 90 pounds of anhydrous granular citric acid. The acid was injected by filling the space outside the elements in a filter pot and then putting the pot on-line. Average daily disposal well tubing pressure decreased from 622 psia on November 30 to 603 psia on December 1. The average daily tubing pressure was 605 psia at the end of 1 week on December 8.

The 10-barrel treatment with concentrated acid (28% HCl) on February 17, 1989, was responsible for the reduction in the average daily disposal well tubing pressure from 619 psia on February 16 to 501 psia on February 18, 1989. One week later, injection pressure was still at 501 psia. The amount of acid used was greater than on prior treatments of the disposal well during this test but was still much smaller than is considered normal in the industry. Injection of the acid into the flowing brine stream also dilutes the acid to a low concentration prior to the acid reaching the perforations. The reason for the small, dilute treatments was to avoid dissolving the calcite that provides what little cementation there is in the weak formation. This in turn would minimize the amount of sand that flowed into the disposal wellbore when injection ceased.

The 10 barrels of inhibited 28% hydrochloric acid and 3 barrels of chase water, to flush acid from piping, were pumped into the bottom of a filter pot at a rate of about 0.75 barrels per minute. Adding this to the produced brine rate of 17,450 STB/d gives about 18,700 barrels per day or 13.0 barrels per minute at disposal wellhead pressure and temperature. Thus, the concentration of acid reaching the perforations was about 1.6%. The tubing pressure increased due to the increased rate when the pumping started. It then dropped in steps when acid reached the perforations and when the pump was turned off. Injection pressure then continued to drop until all of the acid had been displaced to the depth of perforations. This suggested that still more pressure reduction could be achieved prior to the start-up of the HPS by the pumping of additional acid. The reduction achieved was from 618 to 501 psia.

On March 6, 1989, 40 barrels of the same concentrated acid were pumped at the same rate as the February 17, 1989, treatment. The expected decrease in injection pressure was not experienced. There was no drop in pressure when the acid hit the perforations 12 minutes (0.2 hour) after the start of pumping. Indeed, injection pressure increased from 495 psia the day before

treatment to 508 psia the day after. One week later, the injection pressure was 507 psia. The anticipated additional decrease in injection pressure from this second treatment did not materialize.

On February 14, 1990, 15 pounds of granular citric acid was flushed into the disposal well. Eighteen minutes after injecting the citric acid, the injection pressure decreased stepwise from 462 to 453 psia. At 16,000 BPD, 200 barrels of brine were injected in the 18 minutes. This volume is the capacity of the well to a depth below the shallowest perforated sand but shallower than the other five sets of perforations. Five days later, just before a change in injection rate, the injection pressure was 454 psia.

On October 4, 1990, 25 barrels of inhibited 28% hydrochloric acid were pumped into the swab valve on the disposal wellhead at a rate of 1 barrel per minute. The brine rate of 22,240 STB/d immediately provided a 16:1 dilution so that the concentration of acid going down-hole was about 1.8%. The acid was chased with 10 barrels of brine from the holding tank at the disposal well to which 1.3 gallons of RN-97 at purchased concentration was added. This was to expedite replacement of the protective layer that was removed from the disposal tubing by the acid. The daily average injection pressure was 667 psia on October 3, 1990, the day before the acid treatment. The day after the acid treatment, October 5, the injection pressure averaged 617 psia. It averaged 620 psia at the end of the week, on October 10, 1990.

3.8.4. Well Rework

At the end of the HPS flow test, the disposal well was reworked to increase injectivity. This decision resulted from the fact that, during the final month of the HPS flow test, injection pressures had risen from just over 400 to over 440 psia at the injection rate of approximately 15,600 BPD. Given that an extra 40 to 50 psi of injection pressure was likely without the cooling effect of the HPS, rework was necessary to allow for the increased brine flow rates planned for after the shut-in (between 20,000 and 30,000 BPD to determine the limit imposed by the onset of sand production) without requiring excessive separator pressure. Also, tracking of the tubing and casing pressures suggested loss of tubing integrity.

On May 30, 1990, production was shut in for mechanical integrity evaluation of the disposal well casing and tubing. Isolation of the HPS from its gas and brine supply was performed. The Production Test System (PTS) surface facilities were shut in containing produced fluids under positive pressure to prevent air from entering the facilities and accelerating oxidation of the steel.

The disposal well failed the integrity test and, during June 1, the disposal line and filter skid were bled down to atmospheric pressure so that the configuration of the filter skid could be changed to enable filtering of the brine to be used to kill the disposal well. The produced brine was not drained from the line or the first three filter pots.

On July 13, 1990, a workover rig was set up and started work on the disposal well. Brine was produced to fill the rig tanks and Production Test System (PTS) tanks at four different times during the week. In addition, brine was pumped through the orifice meter while being transferred from the PTS tanks to the rig tanks between the times of production. The 2-inch turbine on the small separator provided a reasonably accurate measure of the low brine production rate. Some of the movement through the orifice meter to the rig tanks was not recorded because the line pressure was too low for the orifice meter to function properly.

After the old packer was removed from the well on June 17, 1990, the top of fill was tagged at 6334 feet. This depth is 72 feet below the shallowest set of perforations and 28 feet above the shallowest perforation in the second set. The perforations in the disposal well were in the depth intervals of 6226 to 6262, 6362 to 6380, 6390 to 6426, 6460 to 6480, 6494 to 6514, and 6518 to 6538 feet. A fish consisting of a joint of 2-3/8 inch tubing had been left with its top at 6476 feet when the disposal well was cleaned out in June 1988.

During July 18, nitrogen foam was circulated down the 3-1/2 inch drill pipe and up the annulus to remove a few tens of barrels of sand in 5-3/4 hours. A total of 625,000 SCF of nitrogen was circulated through the well. Rates into the foam generator were about 1.5 BPM of brine and 1800 SCF/minute of nitrogen. A choke on the return annulus was used to maintain the back pressure of 1200 psi calculated to be required to balance the disposal zone reservoir pressure.

The maximum depth reached was 6444 feet. This is midway between the third and fourth perforated intervals and about 30 feet above the top of the 2-3/8 inch tubing fish. The capacity of the 110 feet of 13-3/8 inch casing that was cleaned out is about 16 barrels. This volume is a substantial fraction of the sand washed from the well. The amount of sand that entered the well through perforations during the cleanout process was much less than is typically removed to form the stable cavity outside the casing in packerless-completion disposal wells.

Attempts to kill the well with 10-pound-per-gallon brine after the cleanout were unsuccessful. Apparently some of the nitrogen gas had entered disposal sands, and was bleeding back into the wellbore. This problem was accompanied by some influx of sand. During July 19, 1990, fill was tagged with the drill pipe at a depth of 6408 feet. This depth is midway through the third set of perforations in the well and 36 feet shallower than the maximum depth cleaned out.

During the night of July 19-20, the production well was produced to supply brine to the disposal well for several hours at a rate of about 8000 BPD. The reason was to displace nitrogen gas back into the formation. The well was then successfully killed with heavy brine. After laying down the drill pipe, the 3-foot-long TIW SS-BB permanent packer carrying a 20-foot-long seal

bore extension was run on a wireline. The 15-foot-long seal nipple assembly on the 5-1/2 inch tubing had three units of Viton packing in the bottom 3.4 feet and a fourth Viton seal unit with its center 13.6 feet above the half mule shoe.

The manifold on the filter skid had been reconfigured so that the first three pots could be used to filter produced brine and the other two could be used to filter heavy brine from trucks. After the disposal well work was finished, the normal configuration was restored, and all five pots were loaded with new 50-micron cotton filter elements. The elements in one of the pots were found to have been so heavily loaded that they had collapsed and were no longer effective.

After production resumed in August 1990, results from the first flow rate increase (from about 15,500 to 16,500 BPD) were used to assess the effectiveness of the workover and the ability to conduct further high-rate flow testing. The average daily injection pressure increased by about 30 psi (from 420 to 450 psia) due to the 1000-BPD increase in brine rate on August 2, 1990. This estimate was then refined to include flowing friction, and the result is shown in Exhibit 3.8.4-1.

The portion of the pressure drop due to friction is calculated to be 81 psi at 15,000 BPD and 309 psi at 30,000 BPD. Assuming no deterioration of the disposal well, the injection pressure at 30,000 BPD would be about 835 psi, within separator operating limits.

On August 20, 1990, the brine rate was increased from 16,000+ to 18,000+ BPD by changing the choke opening from 52/64" to 56/64". The average daily injection pressure increased by about 58 psi (from 466 to 524 psia) due to the 2000-BPD increase in brine rate.

On September 12, 1990, the separator pressure was increased from 700 to 850 psia, and the separator chokes were adjusted to maintain 930 psia between the main choke and the separator chokes. Before the changes, the pressures in the separators and in the brine line at the HPS were about 700 and 615 psia, respectively. The pressure drop across the separator dump valves was less than 85 psi. Each of the two previous rate increases had been accompanied by an increase of 55 to 60 psi in disposal well injection pressure. Therefore, this increase in separator pressure was essential to maintain proper separator control at the higher disposal pressures after the planned rate increased from about 20,000 to about 22,000 STB/d. Two or three more incremental 2000-STB/d rate increases were then possible before still higher separator pressures would be required.

The brine rate was increased from 19,750 to about 22,200 STB/d on September 19, 1990, by changing the choke opening from 60/64" to 66/64". The flowing wellhead pressure dropped by 316 psi, from 2449 to 2133 psia, in response to the rate increase to 22,200 STB/d. The disposal well injection pressure increased by about 55 psi (from 527 to 582 psia) due to the 2000-BPD increase in brine rate. This change is consistent earlier rate-change responses.

Exhibit 3.8.4-1. SALT WATER DISPOSAL WELL
INJECTION RATE VERSUS PRESSURE

On October 16, 1990, the choke opening was again increased to provide a brine rate of 24,100 STB/d. Production well tubing pressure went down to 1820 psia, and disposal well injection pressure went up to 715 psia. Twelve days later, on October 28, a slug of a roughly a cubic foot of sand was produced. Brine rate was reduced to about 18,000 STB/d with the expectation that sand entry through the perforations would stop but the rate would still be high enough to flush the sand from the production wellbore. Sand production did stop. The next day, October, 29, 1990, a previously used choke opening was duplicated to determine whether there had been any erosion of the choke by the sand. The prior brine rate was observed, indicating that erosion had not taken place. Brine rate was then reduced to 12,500 STB/d so that the large separator could be taken off-line to clean out the sand that had collected therein.

The disposal well is capable of accepting more than 24,000 STB/d of brine at pressures that are within the operating range of the production test system. The production well is apparently not capable of supplying brine at rates above 24,000 STB/d for extended periods of time without sand production. Calcite seems to be forming on or collecting on the disposal sandface, resulting in increased skin and an increased injection pressure. This is despite the presence of scale inhibitors. The calcite seems controllable with small, infrequent acid treatments.

4.0. BRINE SAMPLING AND ANALYSIS

Brine samples were collected and analyzed on a routine basis. Most brine samples were collected from a port just after the primary choke. In 1988, samples were also collected from a port just before the disposal well. There was no significant change in brine chemistry over the 12.6 million barrels of brine produced between May 1988 and October 1990. Sampling methodology, analytical procedures, analytical results, discussion of the significance of the results relative to well performance, and quality control information are discussed in subsections below.

4.1. Brine Sampling Methodology

Brine sampling procedures are different from the procedures presumed to have been followed during the Phase I testing, and these differences affect the reported compositions. IGT used a sampling methodology where primary emphasis is placed on cooling the brine sample before flashing it to atmospheric pressure and preventing air from contacting the sample. We assume that samples collected during the Phase I testing were separator samples collected without prior cooling, possibly with acid stabilization of some samples. Flashing water vapor from the 290°F brine as it is exposed to atmospheric pressure would concentrate the brine by between 4% and 8%.

The majority of brine samples were collected from a port just downstream of the outlet end of the primary choke but well upstream of the separator chokes and separators. The pressure in the pipe at this point was generally close to 1000 psia, and the temperature was approximately 290°F. The brine sample passed through a stainless steel cooling coil that is immersed in a water bath, reaching ambient temperature prior to experiencing the pressure drop to atmospheric conditions. Sampling lines were well purged and the samples were normally not filtered. The samples were collected in narrow-mouth, high-density polyethylene bottles under a carbon dioxide head to minimize exposure to atmospheric oxygen. These precautions minimized precipitation of solids prior to analysis. If precipitates were present, the sample was homogenized prior to withdrawing an aliquot for analysis.

Experience has shown that the accuracy and reproducibility of the alkalinity tests, and to a lesser extent the iron tests, degrade as the sample ages and starts to drop out precipitates. These analyses were performed onsite on refrigerated samples within a few days of sample collection.

Several consecutive samples were collected for each sample suite. The primary sample was collected, using the procedures described above, and was sent to BEG for analysis. Samples collected for special analyses had different collection and preservation techniques. Such samples include the following:

1. Samples collected for onsite analysis of alkalinity and iron were refrigerated until analyses were performed

2. Samples for radioactivity analyses were filtered, diluted, and acidified
3. Samples for trace phosphonate analyses that had been collected following the same procedures as the regular samples except that bottles were double rinsed with dilute hydrochloric acid and distilled water
4. Samples collected for carboxylic acid analyses that had been precooled, collected in glass bottles, and preserved with mercuric chloride or nitric acid
5. Samples collected from other points in the system, such as at the outlet of the Hybrid Power System and at the disposal well, using normal sample collection procedures
6. Samples of brine collected under pressure at a point after the separator to determine the quantity and composition of dissolved gases.

4.2. Analytical Methodology

IGT used the Texas Bureau of Economic Geology's (BEG) 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 Appendix I; 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 to check for analytical bias. This information is provided in the laboratory reports, an example of which is at the end of Appendix I.

The alkalinity analyses were performed on location because the time needed to transport the samples to a laboratory might have seriously affected the accuracy of the analyses. These tests were also subsequently run in the laboratory, but the field data is believed to be the most reliable. Other analyses were occasionally performed onsite when timely data were needed. These include analyses for chloride, iron, and sulfate. The procedures and chemicals used are described in the Hach Company's *Procedures for Water and Wastewater Analysis*.⁵ Sulfide was also looked for in the brine on an occasional basis, but sulfide had not been detected with the lower limit of detection of about 0.5 mg/L.

Total carbon dioxide measurements and the quantity of gas remaining in the brine after the separator were made following procedures described in "Parametric Study of Separator Performance", which is included in Appendix I.⁶ This includes collecting brine samples under pressure, cooling the samples, quantitatively flashing off and measuring dissolved gas, and 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 the United States Geological Survey (USGS) was regularly sent filtered, acidified, diluted brine samples for radium 226 and radium 228 analyses. His results are included in this report.

Finally, the IGT in-house analytical laboratory performed parts per million quantification of organic acids in the brine, as well as subpart per million analyses for phosphonate scale inhibitor. The phosphonate concentration was determined using a butyl alcohol extraction/colorimetric analysis techniques described in Appendix I.

4.3. Brine Analysis Results

The tables presenting the results of each analysis are contained in Appendix I. Exhibit 4.3-1 presents the arithmetic average of thirty-two comprehensive brine analyses performed on samples collected from just after the primary choke. There is also an average of four samples collected from a point after the filters but before the disposal wellhead. Also included in Exhibit 4.3-1 is an "average" of analyses performed from 1980 Phase I test as reported by Rodgers in the Gruy Final Report.¹⁷ This average was obtained after discarding data that were apparently bad and then taking an arithmetic average of the remaining data.

The average of the Phase I analyses shows that brine was about 9% more concentrated than samples collected from 1988 to 1990. This is presumed to be due to sampling methodology.

The major difference between the current brine sampling procedures versus those previously used by IGT and many other parties is that the brine is cooled prior to reducing the pressure to atmospheric. It has been observed that when geopressured-geothermal brines are collected without prior cooling, the brine flashes upon exposure to atmospheric pressure. The quantity of brine lost due to vaporization has been estimated below. There are several assumptions in this work, listed in decreasing order of importance.

- The person taking the sample realized that problems exist and closed the sample jar as soon as possible. This study assumes the bottle was closed, and therefore vaporization ceased, while the brine was still at 203°F.
- There was no heat lost to conduction. This was obviously not the case, as those who have held these hot sample lines and sample bottles know, but the amount of heat lost to conduction was small relative to the heat capacity of water. In addition, most people sampling the brine purge the lines and valves with large quantities of brine to remove impurities and ensure a fresh sample, thereby preheating the system.
- Sodium chloride brines have lower thermal capacity than water. Specifically, a 10% NaCl brine has roughly 8% less thermal capacity than an equal volume of water. This was a risky extrapolation of data measured at 25°F, but the effect is minor.
- There was no recondensation in the sample jar.
- Escaping steam was at the same temperature as the brine.
- Escaping gas carried away no heat.
- Heat of water at vaporization was taken as 540 cal/g. Thermal capacity of water at various temperatures was obtained from the *CRC Handbook of Chemistry and Physics*.²¹

Exhibit 4.3-1. AVERAGE BRINE COMPOSITION

Date	<u>1980</u>	<u>1988-1990</u>	<u>1988-1990</u>
Number of Samples Averaged		32	4
Location	Unknown	Choke	Disposal 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

The quantity of water lost as steam was the calculated for a 10% salinity brine. The results, parametric with temperature, are shown in Exhibit 4.3-2. Extrapolating the data to 290°F shows the old sampling technique should result in brine samples that are about 8% more concentrated than samples collected with precooling. This is close to the discrepancy between the Phase I samples analyzed by Anacon and the thirty-two brine analyses performed by BEG.

Exhibit 4.3-2. WATER LOSS FROM SUPERHEATED SAMPLES
FLASHING TO ATMOSPHERIC PRESSURE

<u>Temperature at Sample Point</u>	<u>% Water Vaporized</u>
284°F	7.2%
266°F	5.6%
248°F	4.1%
230°F	2.5%
212°F	0.8%

The calcium, magnesium, and strontium concentrations are about 18% lower than reported in 1980. This is more than could be expected because of brine concentration from sample flashing. Calcium, magnesium, and strontium have similar chemical behaviors -- all form relatively insoluble carbonate salts. The difference between the 1980 and 1988-to-1990 analyses, however, could not all be caused by scale formation. There simply was not enough carbonate present in the brine to precipitate such a large quantity of calcite. The reason for the difference is not understood.

4.3.1. Alkalinity Measurements

Samples from just after the primary choke and from just before the disposal well were routinely analyzed for alkalinity to identify when scale deposition began. The factors controlling scale deposition are such that scale will first form at the lowest pressure points in the system and will then slowly work its way into higher pressure regimes. The lowest pressure experienced by most of the produced brine occurs in the surface facilities after the filter skid. The two alkalinity values should therefore begin to diverge when surface scale deposition begins, with the alkalinity at the disposal well falling to values lower than those measured after the chokes.

The purpose of measuring alkalinity is to monitor scale formation. At a flow rate of 20,000 STB/d of brine, an alkalinity decline of 10 mg/L as calcium carbonate would correspond to depositing 70 pounds of scale per day. The alkalinity data suggest the scale-inhibitor pills injected into the reservoir, along with the scale inhibitor injected on the surface, are effectively preventing scale. During Phase II testing in 1982 and 1983, scale was accumulating in the wellhead and wellbore. Alkalinity values measured by Rice University²⁰ were depressed by as much as 20%.

The results of the alkalinity analyses performed onsite since 1987 are presented in Exhibit 4.3.1-1. These include both samples collected from just after the primary choke and from just before the disposal well. The occasional high values after July 1988 are possibly due to interferences caused by the corrosion inhibitor.

The alkalinity values measured onsite between 1988 and 1990 are above 300 mg/L as CaCO_3 (365 mg/L as HCO_3). The alkalinity values measured in the laboratory, included in Exhibit 4.3-1, have been notoriously unreliable. The Phase I values and the current laboratory alkalinity values are essentially equal. The Phase I alkalinity values, however, are believed to have also been measured on location. The alkalinities of samples collected in 1980 should have been low because a portion of the bicarbonate was deposited as calcite in the production well. The maximum Phase I alkalinity reported was 330 mg/L CaCO_3 . This is higher than the 310 mg/L CaCO_3 average for onsite measurements performed from 1988 to 1990 by about the amount due to sample concentration caused by the high-temperature flashing described above.

Exhibit 4.3.1-1. ALKALINITY CONCENTRATION MEASURED ONSITE

<u>Date</u>	<u>Cum Brine, STB</u>	<u>Alkalinity at Chokes, mg CaCO₃/L</u>	<u>Alkalinity at Disp Well, mg CaCO₃/L</u>
6/20/88	319,000	311	
7/1/88	519,000	309	310
7/12/88	731,000	315	315
7/21/88	902,000	309	310
7/25/88	977,000	310	312
8/18/88	1,416,000	313	323
8/24/88	1,529,000	309	316
10/3/88	2,021,000	322	319
10/17/88	2,283,000	314	319
10/31/88	2,533,000	316	314
11/30/88	3,089,000	309	304
12/20/88	3,458,000	310	304
1/10/89	3,845,000	304	304
1/20/89	4,019,000	325	315
2/9/89	4,370,000	314	334
2/28/89	4,702,000	325	325
3/20/89	5,050,000	305	315
4/4/89	5,308,000	325	315
4/27/89	5,701,000	325	315
6/6/89	6,067,000	306	314
7/7/89	6,574,000	304	306
8/23/89	6,975,000	304	304
11/7/89	7,584,000	305	305
12/19/89	8,136,000	305	
2/6/90	8,913,000	315	315
3/22/90	9,608,000	304	314
4/19/90	10,048,000	315	315
8/6/90	10,848,000	315	310
9/4/90	11,347,000	320	314
9/19/90	11,644,000	312	314
10/8/90	12,069,000	315	305

Scale deposition would make alkalinity values decline. One milligram CaCO₃ per liter is equivalent to 3.5 pounds of calcite scale per 10,000 STB of brine. Before corrosion-inhibitor injection commenced, the alkalinity analysis had an accuracy of about ± 4 mg/L. An alkalinity difference of 5 mg/L at a 20,000 STB/d flow rate corresponds to the deposition of 35 pounds of calcite per day. From early alkalinity titrations it was concluded that scale was probably not being deposited in the surface facilities.

After August 25, 1988, however, alkalinity titrations lost a large portion of the sensitivity and began giving variable data. This was not due to changes in the produced fluids or scaling, but was due to interference caused by the corrosion inhibitor. The corrosion inhibitor, a quaternary alkyl pyridiene, is basic (pH $\approx$ 10), has a very large alkalinity component, and tends to coat and adhere

to pH probes. After injection of corrosion inhibitor, it was found that alkalinities at the disposal well were often higher than alkalinities after the choke. This was presumably due to partial decomposition of the corrosion inhibitor and a subsequent increase in its alkalinity component.

With the addition of corrosion inhibitor, the accuracy and reproducibility of alkalinity titrations are uncertain to ± 10 mg/L CaCO_3 , or about 70 pounds of calcite per 20,000 STB. During periods when scale was forming in the wellbore in Phase I testing, however, the alkalinity decrease caused by scale deposition in this well exceeded 50 mg/L CaCO_3 . However, the usefulness of the alkalinity titration as an early indicator of scaling was compromised after injection of corrosion inhibitor.

4.3.2. Iron Measurements

Iron concentrations are often useful in monitoring corrosion rates. The measured concentration of iron in the brine samples was found to decline as samples were stored and precipitation developed. For this reason some iron analyses were performed onsite. Early tests, however, showed that iron measurements would be of little value for monitoring corrosion, because of the high concentration of iron in the native formation brine. Iron concentrations were between 40 and 60 mg/L in both the brine after the first choke and the brine at the disposal well. This corresponds to 400 pounds of iron per day for a brine rate of 20,000 BPD. The vast majority of this iron is believed to have been contained in the native formation brine, because the hydrogen content of early gas samples indicated only about 15 pounds of iron per day were dissolving from the tubulars. A statistically significant difference in the iron concentration, about 10 mg/L, corresponds to corrosion rates in excess of 50 pounds of iron per day at a flow rate of about 20,000 STB/d.

The more sensitive indicator, the hydrogen concentration in the gas, is therefore used to monitor corrosion. This is discussed with the gas analyses in Section 5.0.

4.3.3. Sulfide

Sulfide tends to flash out of the brine as hydrogen sulfide gas when the pressure is reduced to atmospheric pressure. For this reason, the concentration of sulfide in the brine is difficult to determine and is usually only a lower limit.

An early brine sample, collected on July 1, 1988, was collected from just downstream of the large separator and analyzed for sulfide. The sample was collected in a Teflon-lined stainless steel cylinder, cooled, and analyzed. The results of the sulfide analyses of the brine ranged from 0.02 to 0.04 mg/L. These values are suspect in that the resolution of the Hach method has not been established for this brine. The hydrogen sulfide concentration of the gas that flashed off the cooled brine when the pressure was reduced was about 40 ppmv, and this hydrogen sulfide would add

about 0.06 mg/L to the total when dissolved in brine. The hydrogen sulfide content of the separator gas, ranging from 22 to 27 ppm by volume, is equivalent to about 0.2 mg/L of sulfide when dissolved in the brine.

The total hydrogen sulfide produced was therefore estimated to be 0.3 mg/L. Any significant change in the sulfide concentration would be quickly spotted in the gas phase, which contains two-thirds of the total sulfide produced. Analysis of sulfide in samples collected the "normal" way always showed no indication of sulfide. Analysis of brine samples for sulfide was then suspended, although the hydrogen sulfide concentration of the gas was routinely monitored.

4.3.4. Carboxylic Acids

The quantity of acetic acid and other carboxylic acids in the Pleasant Bayou brine samples was determined by gas chromatography/mass spectroscopy at IGT. The quantity of carboxylic acids found in the brine are presented in Exhibit 4.3.4-1.

Exhibit 4.3.4-1. CARBOXYLIC ACIDS IN BRINE

	<u>19 Dec 88</u>	<u>10 Jan 89</u>	<u>20 Jan 89</u>	<u>7 Jul 89</u>	<u>7 Nov 89</u>
Acetic Acid	89 mg/L	47 mg/L	68 mg/L	95 mg/L	53 mg/L
Propionic Acid	ND ^a	ND	ND	3 mg/L	6 mg/L
Butyric Acid	ND	ND	ND	ND	2 mg/L

^a ND = Not detected.

Acetic acid is slightly volatile at this concentration, and no special precautions were taken to preserve this compound in samples collected in December 1988 and January 1989. Because there were no preservation procedures, these values should be regarded as lower limits. The detection threshold for these early samples was 20 mg/L.

For the July 7, 1989, and later samples, additional preservation procedures were used along with cooling prior to releasing the pressure. These procedures were 1) carbon dioxide was not bubbled through the brine, 2) the sample container was glass rather than the high-density polyethylene bottles, and 3) the sample was preserved with mercuric chloride or nitric acid. The first two changes were incorporated because the organic acids are volatile and it was desired to minimize losses to atmosphere during sample collection and storage prior to the analysis. The mercuric chloride or nitric acid prevents microorganisms, which may consume organic acids, from living in the brine. Nitric acid, however, reduces the fraction of the carboxylic acids that are dissociated in the brine (H-acetate versus $\text{H}^+ + \text{acetate}^-$), thereby increasing the volatility of the

carboxylic acids. In addition to the better sampling procedures, the analytical procedure at the laboratory was improved to lower the detection threshold to only a few parts per million.

The reported concentration of carboxylic acids varied by as much as a factor of 2. The significance of the changes in the acetic acid concentrations, and whether the changes are real or an artifact of sampling or analysis, is not known. The contribution of carboxylic acids to the total alkalinity is less than 20 mg/L equivalent as CaCO_3 .

4.4. Trends in the Brine Composition

The brine composition showed no significant change over time. There were several occasions when it appeared the brine composition was changing by a few percent. However, in most cases a reanalysis of the samples showed the discrepancy to be due to systematic errors.

Plots of brine composition versus cumulative brine production and date are presented in Exhibits 4.4-1 through 4.4-4. Exhibits 4.4-1 and 4.4-2 present barium, calcium, chloride, magnesium, potassium, sodium, and strontium concentrations versus the cumulative brine production and date, respectively. These components represent more than 99% by weight of all elements detected in the brine. Exhibits 4.4-3 and 4.4-4 present ammonium, boron, bromide, iodide, iron, silica, and lithium concentrations versus the cumulative brine production and date, respectively. These seven elements, along with alkalinity, comprise the bulk of the remaining elements. The concentrations are plotted on a log cycle to allow easy comparison of relative changes in the concentration of each species.

Exhibit 4.4-1. CONCENTRATIONS OF MAJOR IONS
IN BRINE VERSUS BRINE PRODUCTION

Exhibit 4.4-2. CONCENTRATIONS OF MAJOR IONS IN BRINE VERSUS DATE

Exhibit 4.4-3. CONCENTRATIONS OF MINOR IONS IN BRINE VERSUS BRINE PRODUCTION

Exhibit 4.4-4. CONCENTRATIONS OF MINOR IONS IN BRINE VERSUS DATE

It is apparent that compositional changes, if any, were small. Most of the changes that have been observed are less than the accuracy of the analytical techniques employed. The best accuracy and resolution was obtained with the chloride analyses, which is reported to be 5% but for which numerous standard and replicate analyses have been consistent to between 1% and 1.5%. An error of 1.5% is equal to 1100 mg/L. None of the changes in the chloride concentration approached the stated accuracy of 5%, and most changes fell within the 1.5% accuracy that experience has shown to be more realistic.

The first samples collected from the well had low chloride values. The trend of the analyses since mid-1989 indicates the chloride concentrations may soon be significantly below those early values. The April 19, 1990, chloride content (10.5 million barrels on the graph) is the lowest measured. Furthermore, the samples collected on February 6, 1990, (8.9 million barrels) and on March 22, 1990, (9.6 million barrels) are the lowest values recorded since just after start-up.

Nevertheless, the changes are within the analytical accuracy claimed by BEG. The larger variations for other species are discussed in Section 4.7.

4.5. Brine Analyses in Support of the HPS Operation

There were requests that IGT collect and analyze samples from before and after the HPS to determine whether the HPS was having any effect on brine composition. Several limited analyses were performed, although in all cases IGT did not expect to and did not see any significant change in brine composition. There is too high a brine flux to expect to see a significant change in the

brine chemistry. For instance, if the alkalinity value were to change a significant amount, say 10 mg/L, then the amount of scale deposited in the HPS would be 30 pounds per day. If this amount of scale were being deposited by the brine, there would surely have been a disruption of the heat exchangers. Similarly, if the brine were corroding away a significant amount of material to make a significant change in the iron or manganese concentrations, there would have been numerous leaks. No such disruption was noted.

On March 22, 1990, brine samples were collected from just after the primary choke (upstream of the HPS) and from the outlet of the HPS before the brine commingles with hot brine from the bypass. Onsite analyses for iron gave the 56.5 mg/L iron in the brine just after the coke and 57.1 mg/L iron in the brine after the HPS. The results of analyses of these two brine samples performed at IGT-Chicago are presented in Exhibit 4.5-1. There is no significant difference in the results of the two analyses, although again the sample collected after the HPS had a slightly higher iron content.

Exhibit 4.5-1. BRINE ANALYSES BEFORE AND AFTER HPS,
ANALYSES PERFORMED AT IGT

	Sp Gravity	----- mg/L ----- Chloride	Iron	Phosphonate
After Primary Choke	1.090	72,300	47.9	0.15
After HPS	1.090	72,200	48.5	0.18

Brine samples collected at the same time on March 22, 1990, were also sent to BEG for a comprehensive analysis. The results of the BEG analyses are presented in Exhibit 4.5-2. The only significant difference is in the zinc value. The zinc content of the produced brine has historically ranged from 0.2 to 0.7 mg/L. The zinc content of the HPS brine was measured three times, and the recorded values were 1.35 ± 0.03 mg/L, while zinc concentrations in the brine just after the primary choke were only about 0.5 mg/L. The quantity of zinc needed to cause this 0.8 mg/L excess is 2.4 pounds per day in 8600 STB/d of brine. It is not known whether the operators of the HPS had zinc-cathode corrosion protection in the system.

4.6. Radioactivity

Exhibit 4.6-1 presents radium and radon activities from samples analyzed by Dr. Tom Kraemer of the United States Geological Survey. It includes Pleasant Bayou samples dating from 1979 to the most recent samples collected in December 1989. The radium activity has declined by 17% since 1979, although most of this decline apparently occurred between 1979 and 1982. Regarding the decrease in the radium content, Dr. Kraemer observed "I have seen this same effect

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 4.5-2. BRINE ANALYSES BEFORE AND AFTER HPS, ANALYSES PERFORMED AT BEG

Date	<u>22-Mar-90</u>	<u>22-Mar-90</u>
Relative to HPS	Before	After
Brine Temp, °F	291	151
Spec Gravity @ 60°F	1.085	1.084
Total Dissolved		
Solids, mg/L	140,480	137,380
Alkalinity, as mg CaCO ₃ /L	316	315
Ammonia	84	85
Arsenic	<0.1	<0.1
Barium	797	784
Boron	27	27
Bromide	88	86
Calcium	7,880	7,810
Chloride	70,500	71,000
Fluoride	1.4	1.4
Iodide	20	19
Iron	42	44
Lithium	28	28
Manganese	16	16
Magnesium	602	603
Potassium	602	611
Silica, as SiO ₂	111	110
Sodium	36,100	36,000
Strontium	904	896
Sulfate	<5	<5
Zinc	0.5	1.4

Exhibit 4.6-1. RADIUM AND RADON ACTIVITY IN THE BRINE

<u>Date</u>	<u>Radium 226, dpm/L Water (# Samples)</u>	<u>Radon 222, dpm/L Gas at STP</u>
1979	1590 ±41 (9)	
1980	1513 ±21 (14)	350.7
1982	1398 ±42 (7)	
1983	1435 ±71 (6)	
July 1988	1360 (1)	
Oct. 1988	1335 (1)	
Nov. 1988	1355 (1)	
Apr. 1989	1358 (1)	
Dec. 1989	1312 (1)	259.1

for radium in the Sweezy well and showed pretty conclusively that it was due to actual precipitation of a radium-barium-strontium sulfate material within the formation itself."⁹

Previous studies have shown that, for Gulf Coast brines, radium activity correlates with the brine salinity.¹¹ The correlation in a paper by Dr. Kraemer suggested that a brine with the salinity of Pleasant Bayou brine should have a radium 226 activity of about 1300 dpm/L. This equals the measured value. The radium 226/radium 228 activity ratio is about 1.3. For the December 19, 1989, sample the radium 226 activity was 1312 dpm/L, while the radium 228 activity was 1029 dpm/L. The radium 226 comes from the uranium 228 decay series, while radium 228 comes from the thorium 232 decay series.

The radon activity is comparable to the radon activity of conventional natural gas produced throughout the United States, although it is higher than the 10 dpm/L gas average for natural gas produced from Gulf Coast reservoirs.¹⁰ The radon generation per cubic foot of reservoir material is relatively constant. The reason the radon concentration in the gas produced from these geopressured-geothermal wells is so much higher than from conventional natural gas reservoirs in the Gulf Coast is that conventional reservoirs contain much more gas per cubic foot of reservoir rock. Low concentrations just reflect greater dilution of the available radon with natural gas.

4.7. Quality Control/Quality Assurance

There were several aspects to the quality control program for brine analyses. First, there were numerous samples collected and analyzed. Apparent changes were rigorously pursued by re-analyzing samples. Second, BEG analyzed both a set of appropriate standards in conjunction with analysis of each suite of samples to determine accuracy, and analyzed at least one sample out of each suite of samples three times to determine reproducibility. The trace phosphonate analyses were performed with standard additions, thereby incorporating an internal standard into the analysis. Several subjects related to the quality control for brine analyses are presented below.

4.7.1. Relation Between Standard Analyses and the Reported Brine Analyses

The Bureau of Economic Geology used inductively coupled plasma (ICP) spectroscopy to measure most cations in the brine. This technique allows the concentration of most elements to be measured simultaneously, using various software programs to eliminate interference between elements. The brines are so concentrated, and contain many elements, so choosing appropriate standards provides extremely important checks on the calculation routines. BEG used Standard Sea Water for major elements and EPA 18 TM#2 for trace heavy metals as standards. Quality control analyses of these standards were included in every report. An example brine analysis report, including the quality control runs, is in Appendix I.

There is almost always some bias apparent in the analyses. The BEG concentrations measured in the standard were 1% low for calcium, 2% high for magnesium, and 11% low for strontium for the two August 1988 analyses. It is not known whether the reported concentrations

in the Pleasant Bayou brine were off by the same amounts, although this is a reasonable assumption. Analyses are not corrected to compensate for biases found in the analyses of standards. Samples of the August 1988 samples that were shipped to IGT for phosphonate analyses were also analyzed for calcium, magnesium, and strontium. IGT's laboratory uses atomic adsorption/atomic emission spectroscopy techniques, with a different set of standards. The IGT analyses' average for these two August 1988 samples was 0.6% less than BEG's for calcium (7880 versus 7925 mg/L), 8% less than BEG's for magnesium (555 versus 604 mg/L), and 19% greater than BEG's for strontium (995 versus 839 mg/L). The differences between these analyses are similar to differences reported in BEG's quality control runs for calcium and strontium.

4.7.2. Batch Effects

To minimize expenses, brine samples were stored until there were enough to run as a batch through the laboratory. Batches were composed of between 2 and 5 samples. This sometimes resulted in samples being stored for 3 to 10 weeks prior to analysis. For certain chemical species, particularly alkalinity, concentration apparently decreases with time. For this reason alkalinity is also measured onsite soon after sample collection. At BEG, the oldest sample in a batch generally has the lowest alkalinity. There is no such systematic variation in the results obtained from onsite analyses. For the vast majority of elements, there was no variation with time.

A more serious problem was that the concentrations of various species seemed to change between batches. The first batches, all in 1988, included May and June samples, the second included July and August samples, while the third included October and November samples. There are small, abrupt changes in the concentration of certain species that correlate with sample batching times. A few species that illustrate this change are presented in Exhibit 4.7.2-1.

The changes are not systematic. Concentrations both increased and decreased. Some small variations may be real. Specifically, the small increase in the calcium concentration between June

Exhibit 4.7.2-1. BATCH EFFECTS ON CHEMICAL COMPOSITION

<u>Element</u>	<u>May 30 to Aug 24, 1988</u>	<u>Oct 3 to Nov 29, 1988</u>
Boron	24 ±1	20 ±1
Chloride ^a	71,300 ±1100	73,600 ±1000
Silica	104 ±4	91 ±3
Strontium	848 ±20	900 ±30
Manganese	15 ±1	19 ±0

^a Chloride concentrations reanalyzed. Reanalysis data replaced original data per instructions from BEG.

and August was confirmed by replicate analyses at IGT. There was evidence that batching effects were also occurring with boron, silica, strontium, and manganese.

The Mineral Studies Laboratory investigated this phenomenon with numerous duplicate analyses and found that batching effects have indeed occurred but that the results were within the established accuracy of an ICP analysis. A few of the reanalyses are presented in Exhibit 4.7.2-2. The ICP analyzed thirty-four elements simultaneously, resulting in very substantial cost savings. But the machine calibration drifts, and repeated standardization is needed. The BEG procedures call for the required accuracy for the analysis of standards to be 5% for major components and 15% for trace components. The BEG procedures state that when no appropriate standard is available and internal spiking is necessary, the accuracy degrades to $\pm 25\%$ for trace elements. A few reanalyses were substituted in the primary data tables when suggested by BEG. For instance, the chloride concentrations over 73,000 mg/L that focused attention on the batching effect were immediately reanalyzed and these values replaced those transmitted to IGT originally. Comprehensive reanalyses to resolve batching effects were performed on thirteen samples from four batches. The data are presented in Exhibit 4.7.2-2.

Exhibit 4.7.2-2. REANALYSES OF BRINE TO RESOLVE BATCHING BIASES

<u>Date</u>	<u>Chloride Original</u>	<u>Chloride Re-Analysis</u>	<u>Sodium Original</u>	<u>Sodium Re-Analysis</u>	<u>Calcium Original</u>	<u>Calcium Re-Analysis</u>	<u>Strontium Original</u>	<u>Strontium Re-Analysis</u>
First Batch								
05/30/88	70,200	70,310	35,000	36,400	7,620	7,380	838	895
06/14/88	70,400	69,590	35,300	37,500	7,700	7,520	855	955
Second Batch								
07/01/88	72,200	71,590	35,900	36,200	7,760	7,570	864	911
07/21/88	71,200	72,340	36,400	36,900	7,940	7,710	866	903
08/05/88	72,400	71,660	36,900	36,900	7,890	7,810	827	985
08/24/88	72,000	72,230	36,700	36,700	7,960	7,690	750	921
Third Batch								
10/03/88	71,700	71,700	37,400	36,000	8,010	7,760	930	877
10/17/88	72,000	72,030	36,800	37,400	7,970	7,720	930	933
10/28/88	71,600	71,560	36,500	37,600	7,890	7,740	900	955
11/29/88	72,600	72,640	35,700	38,700	7,900	8,010	870	959
Fourth Batch								
12/19/88	71,600	71,590	37,000	38,100	7,940	7,940	950	952
01/10/89	71,700	71,650	36,700	37,700	7,860	7,860	880	882
01/20/89	72,300	72,270	36,500	37,600	7,890	7,890	910	915

4.7.3. Sampling Personnel Changes

Two people collected the brine samples during the period covered by this report. Although written sampling techniques were followed, minor differences between personnel always exist.

Two brine samples were collected on August 23, 1989; one each by the two IGT personnel who routinely collect brine samples. These samples were analyzed to determine whether potential variations in sample collection techniques -- in particular the evaporation of water from the samples prior to analysis -- were responsible for some of the observed brine chemistry changes. These samples were only analyzed for chlorides and total dissolved solids. The averages of six analyses of aliquots from the same samples, and the standard deviations, were --

Sample A	TDS = 135,100 $\pm$ 2400	Cl ⁻ = 71,680 $\pm$ 410
Sample B	TDS = 135,600 $\pm$ 2600	Cl ⁻ = 71,550 $\pm$ 160

These values indicate there is no significant difference in brine composition that can be correlated with the person collecting the samples.

4.7.4. Acidified, Diluted Samples

Normal brine samples were collected on November 7 and December 19, 1989. As a quality control check, additional samples were collected in 1-liter high-density polyethylene bottles prefilled with 0.500 liters of acidified water to give a final dilution of 1:1. The sample was acidified with 1 ml of reagent-grade nitric acid, and the resulting pH was less than 1.5. The dilution and acidification prevent visible precipitation for many weeks, whether or not air contacts the samples. These samples were analyzed using the same procedures that were used on the normal samples.

The analytical results are presented in Exhibit 4.7.4-1. This preservation technique prevents precipitation of all metals, including calcium and iron, and prevents precipitation of silica. This preservation treatment precludes analyzing the samples for alkalinity. Also, there is significant error, estimated at between 1% and 3%, introduced as a result of performing the field dilution.

It is difficult to determine whether the dilution and acidification had any significant effect on the analyses. One analysis that was expected to be particularly sensitive was the silica. Silica solubility is temperature sensitive, and lowering the brine temperature from 290° to 40°F is expected to result in precipitation of silica. Silica can either precipitate on sand crystals, co-precipitate with other compounds, or form an amorphous precipitation. There was no significant difference between the silica content of the normal samples and the diluted, acidified samples.

Exhibit 4.7.4-1. COMPARISON BETWEEN SAMPLES DILUTED
AND ACIDIFIED VERSUS REGULAR SAMPLES^a

<u>Date</u>	<u>7 Nov 89</u>	<u>7 Nov 89</u>	<u>19 Dec 89</u>	<u>19 Dec 89</u>
Brine Type	Regular	1-L Dilution	Regular	1-L Dilution
Specific Gravity @ 60°F	1.084	1.042	1.079	1.050
Total Dissolved Solids, mg/L	134,360	133,620	136,880	129,280
Alkalinity, as mg CaCO ₃	265	NA ^b	299	NA
Ammonia	86	NA	85	NA
Barium	826	835	762	795
Boron	26	26	25	25
Bromide	83	NA	81	NA
Calcium	8,220	8,270	8,230	8,500
Chloride	71,650	71,520	71,550	71,180
Chromium	0.16	0.15	<0.1	<0.1
Copper	0.22	0.19	<0.1	<0.1
Fluoride	1.6	NA	1.6	NA
Iodide	22	NA	22	NA
Iron	38	39	39	39
Lithium	27	27	28	27
Manganese	14	15	15	15
Magnesium	621	621	595	616
Nickel	0.35	0.32	<0.25	<0.25
Potassium	639	621	606	631
Silica, as SiO ₂	101	104	100	99
Sodium	37,000	37,100	37,400	38,400
Strontium	992	985	981	1030
Sulfate	<5	NA	<5	NA
Zinc	0.5	0.6	0.6	0.7

^a All results in milligrams per liter unless otherwise specified.

^b NA = Not analyzed.

These samples were reanalyzed in May 1989. The low sodium values in the original data for Batch 1 samples were not in the reanalyses. Much of the stepwise changes apparent in Exhibit 4.4-3 are not observed in the reanalyses. The data suggest the very early samples contained lower concentrations of calcium and chloride than the subsequent samples. The concentrations of other species showed no discernible trend. The range of values encountered for each species in the reanalysis are easily within the required accuracy for calibrating the ICP. The percent variation of minor species (those that are present in concentrations below 500 mg/L) are similar to the percent variation of those species shown in Exhibit 4.7.2-2

5.0. HYDROCARBON SAMPLING AND ANALYSIS

There were two categories of hydrocarbons collected and analyzed. The primary hydrocarbon production from this well was the produced gas. This gas is dissolved in the brine at reservoir pressure, but it exsolves from the brine as the brine travels up the wellbore, through the chokes, and into the separator. The gas is gravimetrically separated from the brine in the separators. The separators operate at a pressure high enough to drive brine through the surface facilities and down the disposal well. The degree of hydrocarbon recovery is dependent on the separator pressure, because a significant portion of the gas remains dissolved in the brine at separator conditions.

There was also a trace quantity of liquid hydrocarbons that condensed from the gas stream as the gas was cooled from 290°F separator temperature to the ambient temperature prior to gas sales. The liquid hydrocarbon accumulation was only a very heavy fraction of the produced gas. The quantity (less than a few gallons per day) and the composition (very highly aromatic) made these liquid hydrocarbons more a liability than a benefit to geopressured-geothermal aquifer production.

Gas sampling and analysis is discussed in Section 5.1. The question of whether the gas saturation pressure is below the reservoir pressure is discussed in Section 5.2. Liquid hydrocarbon sampling and analysis is presented in Sections 5.3.

5.1. Gas Sampling and Analysis

This section, along with Appendix J, presents sample collection and analyses, the results of over sixty gas analyses, and a discussion of the significance of the results with respect to recovery and sale of hydrocarbons as well as operational problems such as corrosion monitoring and keeping filters operational.

5.1.1. Gas Sampling and Analysis Techniques

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 5.1.1-1. The large and small separator meter runs contain hot, wet gas and a small quantity of condensed water. There are both steam and hydrocarbon liquids that eventually fall out of the gas in the separator meter run. The gas at the sales/flare meter, on the other hand, has been cooled to near-ambient temperature and dehydrated with a glycol countercurrent extractor.

Gas samples destined for laboratory analyses were collected in evacuated, Teflon-lined, 304 stainless steel cylinders rated at 1800-psi working pressure. Valve bodies and seats were 304 or 316 stainless steel. The sample lines were purged by blowing gas to the atmosphere, and then the evacuated cylinder was connected and filled one time. There was no sequential filling and purging

Schematic of Pleasant Bayou Gas Separation and Processing Equipment

Exhibit 5.1.1-1. SCHEMATIC DIAGRAM OF THE GAS PROCESSING EQUIPMENT

process. The samples were sealed with end caps and sent to either IGT or Core Laboratories for analysis. At the laboratory, the sample cylinders were preheated to approximately the meter run temperature prior to withdrawing an aliquot for analysis. This helps prevent liquid condensation from interfering with the analysis. There would still be interference from liquid accumulations if there were two phases at the sample port when the sample was collected. The samples were analyzed by gas chromatography. The IGT analysis requires three separate tests -- one for light hydrocarbons and fixed gases, one for heavier hydrocarbons, and one for hydrogen and helium. Typical chromatograms of heavier hydrocarbon analyses are shown in Exhibit 5.1.1-2. The analytical procedure followed at IGT is summarized in Appendix J.

Onsite 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).⁴ This procedure is also included in Appendix J. Draeger tests were also occasionally run for mercury, ammonia, and water.

5.1.2. Results of Gas Analyses

The results of the sixty-nine gas analyses performed between 1988 and October 1990 are presented in the Appendix J. Exhibit 5.1.2-1 contains the average of results of IGT analyses performed on sales/flare gas and the large and small separator gases. The IGT analyses report concentrations of hydrocarbons through tetradecanes (C14) or higher, the concentration of ringed hydrocarbons through the C3 naphthalenes, and the concentration of helium and molecular hydrogen. Minimum detection thresholds are 0.001 mole percent for hydrocarbons and 0.0005 mole percent for hydrogen and helium.

Exhibit 5.1.2-2 presents the average results of Core Laboratories' analyses on small and large separator gases and the sales/flare gas. These analyses are through decanes plus, although ringed hydrocarbons are not differentiated from the saturated hydrocarbons.

Gas compositions are similar to the Pleasant Bayou 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 as to the pressure base) averaged 929 Btu/SCF.

5.1.3. Onsite Analyses

Certain components in the gas phase are measured onsite with Draeger "length-of-stain" tubes. These components are generally of such a reactive nature and are present in very small concentrations and therefore are usually not detectable in samples stored for more than a few hours. These compounds include hydrogen sulfide, ammonia, water, and mercury. Carbon

Exhibit 5.1.1-2. TYPICAL CHROMATOGRAMS OF HYDROCARBON ANALYSES

Exhibit 5.1.2-1. AVERAGE GAS COMPOSITION, MEASURED
AT IGT BY GAS CHROMATOGRAPHY

	Large Separator <u>Gas, mole %</u>	Small Separator <u>Gas, mole %</u>	Sales/Flare <u>Gas, mole %</u>
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

dioxide is also occasionally measured onsite for operational purposes. This compound is reactive, but it is present in such a large concentration that the laboratory data is believed to be accurate.

The hydrogen sulfide concentration in the gas started low, at 16 ppmv on May 30, 1988. The initial low concentrations are believed to be due to loss of hydrogen sulfide due to reactions with the tubulars. The concentration increased steadily and reached 27 ppmv by November 2, 1988. The concentration has remained near that level with variations that correlate with

Exhibit 5.1.2-2. AVERAGE GAS COMPOSITION, MEASURED AT CORE LABORATORIES
BY GAS CHROMATOGRAPHY

	Small Separator <u>Gas, mole %</u>	Large Separator <u>Gas, mole %</u>	Sales/Flare <u>Gas, mole %</u>
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
<i>n</i> -Butane	0.13	0.13	0.13
iso-Pentane	0.04	0.04	0.03
<i>n</i> -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

separator pressure. The gas from the small separator has, in general, about 1 ppmv more hydrogen sulfide than does the large separator gas and the sales/flare gas. The estimated error for these types of measurements is about 10%, so this difference is not significant. The difference is believed to be the result of the unequal distribution of gas and brine between the separators. The hydrogen sulfide concentration dropped to 24 ppm for both the September 19, 1990, and October 8, 1990, samples. This was the result of increasing the separator pressure from 710 to 830 psia in September 1990.

The length-of-stain water-vapor analysis was performed only on the sales/flare gas to check the operation of the dehydrator. The normal gas contract specification for water is 7 pounds per million standard cubic feet of gas. The water-vapor content of the separator gas was very much higher than this due to the separator temperature of about 280°F. As the gas cools, condensing water and hydrocarbons were removed from the gas stream by a succession of liquid knockouts. The final water removal to meet the gas sales specification was then performed in the counter-current glycol dehydrator. The water removed by the glycol dehydrator was vaporized and then vented to the atmosphere.

Ammonia has not been detected in the gas phase, although it is present in the brine at concentrations in excess of 80 mg/L. The lower limit of detection on the various tests, all performed with Draeger tubes, has ranged from 0.2 to 1 ppmv.

Mercury analyses have been inconclusive. There have been two tentatively positive results, both at the detection threshold of 0.01 mg/cubic meter of gas, on July 7 and August 29, 1989. The only other test for mercury in the gas, performed soon after the well was put into production in 1987, showed no discoloration -- which is interpreted to be less than 0.01 mg/cubic meter. This measurement is performed on sales/flare gas only. This amount of mercury, if it is actually present, was equivalent to less than 0.001 mg mercury per liter of brine produced. This is 50 times less mercury than can be detected in the brine using ICP analyses; the detection limit for brine analyses is 0.05 mg/L.

Tubes to test for acetic acid and for hydrochloric acid in the gas were also tested. These tubes measure between 5 and 240 ppm acetic acid in gas and between 50 and 5000 ppm hydrochloric acid, but cross sensitivity to other acids is a problem. The response on the acetic acid tubes is distinguishable by a yellow color for weak acids such as acetic acid and by a red color for strong acids such as hydrochloric acid. Tests on the separator gases have revealed the presence of a "strong acid" that turned the entire tube red before the prescribed volume had passed through the tube, but then quickly faded. The hydrochloric acid tube did not have any discoloration, indicating less than 50 ppm hydrochloric acid. We do not know what is causing the discoloration in the acetic acid tubes, but we assume it is carbonic acid from the carbon dioxide.

5.1.4. Comparison Between Laboratories

IGT had observed in previous Wells of Opportunity tests that the carbon dioxide contained in the wet separator gas could react with the steel walls of the sample cylinder and with the condensed water to form solid precipitates. Carbon dioxide concentrations in sample vessels would decrease with time. The quicker an analysis is performed, the more accurately the data represent the true gas composition in the pipe.

IGT-Chicago has historically performed many of the gas analyses for the Wells of Opportunity and for other Design Wells in the Geopressured-Geothermal Program. IGT provides the gas industry with National Bureau of Standards traceable chromatographic standards. IGT also developed the capability to routinely quantify hydrogen and helium concentrations to ppm levels necessary to monitor corrosion rates. For these reasons, and the responsiveness of an internal laboratory, we wanted to continue using IGT for gas analyses. At the same time, it was felt that a local laboratory could analyze samples faster, thereby limiting carbon dioxide losses from the sample prior to analysis. We chose Core Laboratories for the local laboratory.

In practice, samples have been delivered to Core Laboratories during the evening, after working hours, and have been sent to IGT via overnight express services. There has been little difference in the amount of time samples wait prior to analysis. Use of Core Laboratories for routine gas analyses was phased out after the first year of flow. The importance of appropriate analytical standards cannot be overstated.

The gas from geopressured-geothermal wells is not similar to most gas sold in the Gulf Coast area. There are normally strict limits placed on the carbon dioxide concentration of gas sold, and this limit is often 2 mole percent or less. For this reason, natural gas standards often contain only 1% or less carbon dioxide. Minor discrepancies in the standard composition and the analytical machine response are magnified for samples with high carbon dioxide concentrations.

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 Laboratories in Houston for analysis. The analytical technique used by Core Laboratories combines benzene with heptanes, toluene with octanes, and C2 benzenes with nonanes. The analyses, taking into account the peculiarities of Core Laboratories' reporting procedure, agree very well for all components except carbon dioxide and, by difference, methane. These carbon dioxide values were 11.95% in the Core Laboratories' report and 10.9% in the IGT report. The same problem was found for duplicate samples collected on September 25, 1988, with Core Laboratories reporting 12.03% carbon dioxide and IGT reporting 10.3% carbon dioxide. The reason for this discrepancy is not understood, but may reflect the calibration problem noted above. The carbon dioxide in the sales/flare gas, which for the September 25, 1988, sample had been cooled and dehydrated, should not be very reactive in the cylinder.

5.1.5. Comparison Among Other Geopressured-Geothermal Wells

Exhibit 5.1.5-1 presents gas compositions, analyzed by IGT, from ten geopressured-geothermal wells. The Pleasant Bayou gas contains more heavier hydrocarbons, from propane through decane, than were found in all geopressured-geothermal well tests except the Koelema well. The Koelema well coned in a gas condensate cap and became a commercial oil and gas producer. The presence of high concentrations of propane-plus hydrocarbons in the produced gas may suggest the brine is in contact with an oil or wet gas deposit.

At the same time, the PVT tests provide evidence that shows that the Pleasant Bayou brine is undersaturated with gas at reservoir conditions. There is geologic evidence that the aquifer is in direct contact with producing hydrocarbon wells located within 15 miles of the well. These producing zones, however, are several thousand feet updip of the sand at the Pleasant Bayou well. This may explain both the presence of heavy hydrocarbons and the undersaturated gas content.

Exhibit 5.1.5-1. 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	1015	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
<u>Mole Percent of:</u>										
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	1040	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.

5.1.6. Hydrogen as a Corrosion Monitor

Chemical erosion is a primary cause of iron loss in these wells. The overall reaction is --

The metallic iron (Fe^0) is provided by the well tubulars. The hydronium ion (H^+1) is supplied by the dissociation of carbonic acid as follows:

The reaction does not necessarily have to go to completion. Two carbonic acid molecules can each contribute one hydronium ion and thereby become two bicarbonate ions. There is a complex and shifting equilibrium between gaseous and dissolved carbon dioxide and the carbonate and bicarbonate ions.

The products of these reactions are carbonate ions (CO_3^{-2}), the ferrous iron (Fe^{+2}), and hydrogen gas. The ferrous ions and the carbonate ions have a strong tendency to form siderite, or iron carbonate. This scale then protects the steel from further corrosion until it is worn or dissolved away. There is already a large quantity of both ferrous ions and bicarbonate ions in the native brine, and both calcite and siderite scale formation can shift the concentrations of those two ions. This makes it difficult to measure corrosion via iron or bicarbonate (alkalinity) concentrations.

The hydrogen gas is not native to the formation brine. Each molecule of hydrogen gas produced corresponds to the loss of one molecule from the production tubulars. This makes hydrogen gas a sensitive and specific indicator of corrosion. Most of this corrosion takes place at the casing near the perforations and in the tubing. For a gas/brine ratio of 28 SCF/STB, a hydrogen concentration of 50 ppmv (0.005 mole percent) corresponds to an iron loss of 2 pounds for every 10,000 barrels of brine produced. The sample dates, hydrogen concentrations, and corrosion rates are shown in Exhibit 5.1.6-1. It can be seen that the corrosion rate has been declining with time.

5.1.7. Separator Study

It is possible to change the hydrocarbon recovery and even the gas composition by small but measurable amounts by changing the separator pressure. The changes are easily predicted using straightforward thermodynamic principals, as shown in the paper "Parametric Study of Separator Performance" in Appendix I.⁶

A considerable quantity of the produced gas, possibly as high as 20%, remains dissolved in the brine at separator conditions. Each gaseous species, be it carbon dioxide, methane, or pentane,

Exhibit 5.1.6-1. CORROSION RATES DEDUCED FROM HYDROGEN CONCENTRATIONS

<u>Date</u>	<u>Hydrogen, mole %</u>	<u>Brine rate, STB/d</u>	<u>Gas Rate, 1000 SCF/d</u>	<u>Corrosion Rate, lb/d</u>	<u>Corrosion Rate, lb/10⁵ barrels</u>
30-May-88	0.055	7,699	186.4	15	20
17-Jun-88	0.026	19,905	479.9	18	9
22-Jul-88	0.023	18,947	443.6	15	8
29-Aug-88	0.026	18,918	450	17	9
25-Sep-88	0.02	19,138	458.5	14	7
2-Nov-88	0.018	18,787	451.2	12	6
20-Jan-89	0.02	15,936	382.9	11	7
27-Apr-89	0.019	15,545	373.2	10	7
12-May-89	0.027	12,167	293.9	12	10
7-Jul-89	0.018	15,952	380.6	10	6
23-Aug-89	0.017	15,860	379.8	10	6
7-Nov-89	0.016	16,236	381.3	9	6
19-Dec-89	0.017	16,004	388.9	10	6
6-Feb-90	0.018	15,710	379.2	10	6
22-Mar-90	0.02	15,817	381.7	11	7
19-Apr-90	0.02	15,615	381.2	11	7
6-Aug-90	0.013	16,323	395.7	8	5
4-Sep-90	0.012	17,999	434.3	8	4
19-Sep-90	0.012	21,074	501.7	9	4
8-Oct-90	0.012	22,450	528.5	9	4

has its own solubility characteristics. For the hydrocarbon gases and the nitrogen, the solubility relationship is best expressed by a linear Henry's Law relationship, where the amount dissolved is directly proportional to the partial pressure of that species. The Henry's Law constants are similar but are not the same for all the hydrocarbon gases, however, and the relative amounts of methane, ethane, propane, etc., in the brine will change with changes in pressure.

The relationship between carbon dioxide concentration in the gas and carbon dioxide solubility is more complex because of bicarbonate ion equilibria. The Henry's Law constant for carbon dioxide is considerably different from those of the hydrocarbon gases. The end effect is that, as the separator pressure is elevated, the fraction of carbon dioxide remaining in the separated gas decreases. With increasing separator pressure, there is a trade-off between enriching the gas, by increasing the fraction of heavier hydrocarbons and decreasing the fraction of carbon dioxide on the one hand, and decreasing the total recovery of hydrocarbons on the other hand.

A "Separator Study" was performed on July 7, 1989, to determine the quantity of gas leaving the separator in the brine stream. Samples of brine were collected under pressure in 316 stainless steel cylinders from the outlets of both the large and small separators. The cylinders were allowed to cool and solution gas was flashed to atmospheric pressure using an apparatus appropriate for

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measuring the gas/brine ratio. The flashed gas was analyzed onsite using the Carle gas chromatograph.

A portion of the brine was then placed in a "carbonate train" wherein the sample was acidified and purged with nitrogen to remove all of the remaining carbon dioxide, including that normally existing as carbonate and bicarbonate. This liberated and purged carbon dioxide was then trapped and measured gravimetrically. The data are presented in Exhibit 5.1.7-1. The gas flashed from the brine is about one-third CO₂. In other words, about 1.9 SCF of CO₂ flash from a barrel of brine when the pressure is dropped from 707 psia to atmospheric after cooling. An additional 1.8 SCF/STB is liberated from the brine when it is treated with acid to break down the carbonates and bicarbonates and then purged with nitrogen.

Exhibit 5.1.7-1. SEPARATOR STUDY PERFORMED ON JULY 7, 1989

Gas Content of Brine Leaving the Separators

Date	<u>7 July 1989</u>	<u>7 July 1989</u>
Separator	Large	Small
Pressure, psia	707	707
Brine Temp, °F	290	290
Measured GBR, SCF/STB	5.33	5.36
Calculated GBR, SCF/STB	3.44	3.44

Analysis of Gas Flashed From the Brine

<u>Component</u>	<u>Mole %</u>	<u>Mole %</u>
Methane	63.0	59.3
Ethane	1.63	1.55
Propane	0.38	0.33
Butanes	0.08	0.06
Pentanes	0.01	0.01
C6 ⁺	0.7	0.8
Carbon Dioxide	33.0	34.2
Nitrogen (includes air contamination)	1.2	3.8

Additional Carbon Dioxide Liberated by Acid and Purged From the Brine

1.75 SCF/STB

1.90 SCF/STB

The calculated GBR value of 3.44 SCF/STB in Exhibit 5.1.7-1 is the value from the algorithm used in the data collection program. The algorithm is used to calculate the amount of gas in brine leaving the separators for use in reporting the total gas production through the perforations and the produced gas/brine ratio. The gas analysis data in Exhibit 5.1.7-1 reveals that an average of about 64% of the flashed gas, or 3.4 SCF/STB of the gas from the brine, is combustible

hydrocarbons. This hydrocarbon content is in excellent agreement with the calculated value. It is therefore apparent that for a separator pressure of 707 psi, the reported gas production through the perforations does not include either the 1.9 SCF/STB of carbon dioxide that flashes from separator brine or the 1.8 SCF/STB of carbon dioxide that remains in the brine at atmospheric pressure in the form of carbonate and bicarbonate ions.

5.1.8. The Effect of Separator Pressure on Gas Composition

The recovered gas composition is a function of the separator pressure. Indeed, separator pressure was varied at the Gladys McCall well to tailor the gas composition to meet the gas composition specifications in the gas sales contract. The principles behind the relationship are discussed in the separator study in Section 5.1.7. The largest effect of separator pressure changes is to change the quantity of carbon dioxide in the recovered gas. There are other minor effects, such as the change in relative amounts of hydrocarbon gases and the hydrogen sulfide concentration (discussed in Section 5.1.3).

There has been little variation in separator pressure to date to quantify the effect of separator pressure on the concentration of carbon dioxide. The majority of the samples were collected while the separator was operating between 690 and 730 psia. The four samples at 830 psia are the only samples collected when the separator pressure was outside that narrow band. The effect of separator pressure on the carbon dioxide content of the gas is presented in Exhibit 5.1.8-1.

Exhibit 5.1.8-1. CARBON DIOXIDE CONCENTRATION IN THE SEPARATOR GAS

5.1.9. Gas Vented From the Filter Pots

There is a pressure drop of 100 to 400 psi from the separators to the filters, and gas is exsolved as a result. The filter-pot gas was vented. Roughly a cubic foot of this gas flashed out of solution per barrel of produced brine. If a filter pot gas vent was not continued, this gas accumulated in the filter pots, degraded the performance of the filters, and moved on to the disposal well. It is known that gas exsolving from brine at low pressure has higher carbon dioxide content and lower natural gas liquid content than gas previously exsolved from the same brine at higher pressure. The composition of filter-pot gas is presented in Exhibit 5.1.9-1 along with the compositions of the separator and sales gases.

Exhibit 5.1.9-1. COMPOSITION OF GAS VENTED FROM THE FILTER POTS

Date	<u>5 Jul 88</u>	<u>5 Jul 88</u>	<u>5 Jul 88</u>	<u>5 Jul 88</u>
Time	17:50	17:40	17:30	16:00
Location	Lrg Sep	Sm Sep	Sls/Flare	Filter Pot
Brine Temp, °F	291	291	291	288
Pressure, psia	719	718	433	579
Nitrogen	0.53	0.49	0.50	0.44
Carbon Dioxide	10.99	11.63	11.06	13.26
Methane	84.14	83.75	84.12	82.59
Ethane	2.91	2.83	2.89	2.60
Propane	0.95	0.89	0.94	0.71
iso-Butane	0.15	0.14	0.15	0.09
n-Butane	0.14	0.12	0.13	0.08
iso-Pentane	0.04	0.04	0.04	0.02
n-Pentane	0.02	0.01	0.04	0.01
Hexanes	0.02	0.01	0.02	0.01
Heptanes	0.07	0.05	0.06	0.10
Octanes	0.03	0.03	0.03	0.06
Nonanes	0.01	0.01	0.01	0.02
Decanes+	0.00	0.00	0.01	0.01
Gravity (air=1.000)	0.6959	0.6984	0.6967	0.7127
Heating Value, Btu/SCF Dry at 60°F and 14.65 psia	942	931	943	913

The gas vented from the filter pots is of lower quality than the sales gas, and there is not enough gas to justify the separator and several hundred yards of pipe needed to put this gas into the sales gas cooling and dehydration system.

5.1.10. The Effect of the Disproportionate Split in Gas Between Separators on Gas Composition

Although the "Y" splitting the flow between separators is mechanically symmetrical, a disproportionately large quantity of the gas goes to the large separator. The "Y" is after the primary choke but before the separator chokes. A small amount of gas is exsolved from the brine in conjunction with the pressure drop across the separator chokes. This gas has a different composition than the gas phase in the pipe just prior to the choke. The newly flashed gas would contain a little more carbon dioxide and a slightly leaner hydrocarbon fraction of the gas, following the principles presented in Section 5.1.7. The amount of this gas is proportional to the pressure drop across the separator chokes. However, the small separator will always receive a disproportionately higher fraction of this lean gas relative to the large separator.

The different gas/brine ratios into the two separators result in slightly different gas compositions out of each separator. The effect could be seen in Exhibit 5.1.8-1, where for a given separator pressure there was usually a higher carbon dioxide concentration in gas from the small separator compared to gas from the large separator. Normally the pressure drop across the separator chokes is kept below 200 psia. Before collecting the July 22, 1988, samples, the pressure after the primary choke was raised to 1150 psia to amplify the effect of gas/water ratios on gas properties. The pressure drop across the separator chokes was almost 450 psi. In addition, separator chokes were set to deliver twice the amount of brine to the large separator as to the small separator. The gas/brine ratio, excluding gas still dissolved in the brine at separator conditions, out of the small separator was 4.8 SCF/STB, and the ratio out the large separator was 29.8 SCF/STB.

The large separator gas sample, with the largest gas/brine ratio, contained a gas richer in heavy hydrocarbons and lower in carbon dioxide. The differences are modest, with the carbon dioxide concentrations equal to 9.75% from the large separator and 11.23% from the small separator. The details of composition of the separator gases are included in Appendix I. The analyses of these two samples of separator gases illustrate the range of gas chemistry alterations achievable due to the partitioning of phases in the piping for the parallel separators in these surface separation facilities.

5.1.11. Analytical Problems

The gas analyses have been fairly consistent, and fair agreement between the laboratories has been demonstrated. A small problem had surfaced with the reported propane concentrations. Spurious values have been recorded that are certainly erroneous. The true propane concentration has remained at near 0.93 mole percent since production was resumed in 1988. Since November 1989 the propane concentrations have ranged from 0.87% to 1.04%. These apparent variations are

not real. Separator gas samples collected at the same time as the problematic sales/flare analyses have shown that the propane concentrations have not changed. We have not determined the cause of the problem. These modest differences from prior results have little impact on the heating value and gravity of the gas.

5.2. Gas Saturation of Reservoir Brine Relative to the Bubble Point

The Pleasant Bayou No. 2 well gas/brine ratio for the period between March 1, 1988, and October 31, 1990, was 23.96 SCF/STB. As discussed in the Separator Study in Section 5.1.7, this value is low by about 1 cubic foot. The 1 cubic foot of gas that is under-reported is essentially all carbon dioxide. The brine was initially undersaturated with natural gas at a reservoir pressure of 11,003 psia on April 1986. During the long-term production phase, the flowing bottomhole pressure has not been drawn down below the 8000 psia believed to be the reservoir bubble-point pressure. Evidence -- including the stable produced gas/brine ratio, the lack of changes in the produced gas composition, and special short-term transient tests developed by IGT -- suggests the reservoir pressure has not been drawn down below the bubble-point pressure.

The laboratory data on bubble-point pressure for the reservoir brine is discussed below in Section 5.2.1. Changes in the produced gas/brine ratio and gas composition that determine whether the reservoir has been drawn down to below the bubble-point pressure are discussed in Sections 5.2.2 and 5.2.3.

5.2.1. Laboratory Recombination Studies

On October 8, 1980, separator gas and brine samples were collected at a pressure of 850 psig by an Anacon, Inc., representative for laboratory PVT analyses. The samples were given to Weatherly Laboratories, Inc., for analysis. IGT obtained samples the same day. This 1980 PVT study (Appendix B) was performed by the same personnel and laboratory facility as similar prior studies of samples from the Wells of Opportunity Program.²³ Their results from this prior work were in good agreement with other laboratories studying the solubility of natural gas in brine.

The sample appeared to be flawed, however. A flash of the separator brine to atmospheric pressure revealed a gas/brine ratio of 8.11 SCF/STB. This is outside the range of other tests performed on other wells at similar pressures and was outside the range anticipated based on laboratory studies of the solubility of methane in brine. The IGT sample collected the same day, on the other hand, had a gas/brine ratio of 5.4 SCF/STB. This is about equal to the value expected based on the separator pressure and temperature. The subsequent laboratory studies probably did not contain this excess gas, and may be valid. IGT believes, however, that the correction for gas remaining in the separator brine should be 5.4 SCF/STB rather than the 8.11 SCF/STB used in the Weatherly report. This value is used herein.

A second suite of separator gas and brine samples were collected at a pressure of 560 psig by a Weatherly Laboratories, Inc., representative for laboratory PVT analyses on October 14, 1982. Their report is included in Appendix C.²² The gas/brine ratio in this separator brine sample was 3.22 SCF/STB, which is within the range of expected values and is consistent with the 5.4 SCF/STB found by IGT at the higher separator pressure.

The laboratory recombined the separator gas and separator brine at various ratios and determined the bubble-point pressure of each recombination to obtain curves of the bubble-point pressure versus the gas/brine ratio. The data from the two studies are presented in Exhibit 5.2.1-1 and plotted in Exhibit 5.2.1-2. In addition to these recombinations, there was a study of methane solubility in Pleasant Bayou brine performed by Blount for IGT in 1981. The report is appended to the IGT Technical Report "Do We Know Whether the Pleasant Bayou #2 is Saturated With Methane" in Appendix D.¹⁶ Exhibit 5.2.1-2 includes points for methane solubility that were calculated from the equation for Pleasant Bayou brine that is on page D-8 in the report in Appendix D using a temperature of 305°F.

Exhibit 5.2.1-1. LABORATORY RECOMBINATIONS OF GAS AND BRINE

<u>Date</u>	<u>Gas/Brine Ratio, SCF/STB</u>	<u>Bubble-Point Pressure, psia</u>
October 8, 1980 ^a	13.43	3,445
	18.46	5,775
	22.47	7,450
	25.49	8,650
	27.75 ^b	9,670
October 14, 1982	13.78	3,000
	19.06	5,050
	24.44 ^b	7,460
	29.62	9,950
	32.16	11,275 ^c

^a IGT separator flash gas/brine ratio of 5.4 SCF/STB used instead of the Weatherly data.

^b Produced gas/brine ratio measured on the day samples were collected.

^c Gas/brine ratio extrapolated from lower pressure data to the reservoir pressure.

There is no clear basis for resolving the differences between the two PVT studies and the results of the studies of methane solubility in Pleasant Bayou brine. We have therefore used the points in Exhibit 5.2.1-2 to develop the following least-squares polynomial fit for the pressure dependence of the solubility of natural gas in the brine in the Pleasant Bayou reservoir:

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$$\text{Gas/Brine Ratio} = 3.37 + (3.70 \times 10^{-3} \cdot P) - (1.289 \times 10^{-7} \cdot P^2)$$

$$\text{Correlation Coefficient } R^2 = 0.96$$

The extrapolated point at 11,275 psi in Exhibit 5.2.1-1 was not used in derivation of the equation because it resulted from linear extrapolation when the curve should have been concave downward. The equation indicates that the gas solubility would be 28.5 SCF/STB at the pressure of 11,003 psia measured before start of production in 1988. The bubble-point pressure of the brine at the produced gas/brine ratio of 24 SCF/STB, plus 1 SCF/STB of carbon dioxide, is 8170 psia. In contrast, the lowest bottomhole pressure achieved during this flow test was 9020 psia.

Exhibit 5.2.1-2. BUBBLE-POINT PRESSURE VERSUS GAS/BRINE RATIO

5.2.2. Changes in Composition of the Produced Gas

The natural gas in this reservoir is a mixture containing methane, ethane, propane, butanes, carbon dioxide, and other gases. Because the individual components have different solubilities, a gas phase in equilibrium with brine will have a different composition than the gas in solution in the brine. The heavier hydrocarbon/methane ratios are higher in the free gas than in the dissolved gas. The effect becomes more pronounced as still heavier hydrocarbons are examined. For instance, the propane/methane ratio contrast is greater than the ethane/methane ratio contrast.

This effect is demonstrated in Exhibits 5.2.2-1 and 5.2.2-2, which present data from differential liberation studies performed by Weatherly Laboratories as a part of the PVT studies of samples (Appendixes B and C). The pressure on the brine was reduced until a bubble large enough to sample had exsolved from the brine. This bubble was then removed for analysis in a gas chromatograph and the pressure was lowered further until another bubble could be sampled. Each column of the table gives the composition of gas liberated by the pressure step at the top of the column.

Exhibit 5.2.2-1. OCTOBER 8, 1980, GAS DIFFERENTIAL LIBERATION DATA

Pressure, psia	9670- <u>5000</u>	5000- <u>3000</u>	3000- <u>1000</u>	1000- <u>15</u>
<u>Mole Percent of:</u>				
Carbon Dioxide	3.55	4.52	9.88	49.4
Methane	90.21	91.28	87.73	49.6
Ethane	3.52	2.53	1.66	0.75
Propane	1.75	0.88	0.39	0.10
Butanes	0.60	0.21	0.06	0.01
Pentanes	0.21	0.15	0.06	0.02
C6+	0.16	0.43	0.22	0.12

Exhibit 5.2.2-2. OCTOBER 14, 1982, GAS DIFFERENTIAL LIBERATION DATA

Pressure, psia	7460- <u>5000</u>	5000- <u>3000</u>	3000- <u>1000</u>	1000- <u>15</u>
<u>Mole Percent of:</u>				
Carbon Dioxide	5.19	2.75	7.17	33.43
Methane	88.13	91.86	89.54	64.15
Ethane	4.11	3.55	2.51	2.00
Propane	1.82	1.35	0.62	0.30
Butanes	0.61	0.43	0.13	0.09
Pentanes	0.14	0.06	0.03	0.03
C6+	0.00	0.00	0.00	0.00

Both of the differential liberation studies show the normal lower concentration of heavier hydrocarbons with successive pressure drops. It is clear from these tables that, if bubbles of gas formed in the reservoir as the pressure was drawn down below the bubble-point pressure, these gas bubbles would be richer in the heavy hydrocarbons than the original solution gas. Most gas that exsolved from the brine in the reservoir will remain trapped in the reservoir. At the same time, the gas remaining in solution in the brine and produced up the wellbore would become slightly depleted in ethane and heavier hydrocarbons. The numerous gas analyses, presented in Appendix J, did not show evidence of declining ethane or propane values.

5.2.3. Variation in the Produced Gas/Brine Ratio Due to Bottomhole Pressure

The decline in the gas/brine ratio in 1990, apparent in Exhibit 3.5-2, suggests the reservoir pressure may have been drawn down below the bubble point. These data are not supported by any other data and are therefore suspect.

The reported gas/brine ratio dropped from 24.22 SCF/STB in May 1990 to 23.49 SCF/STB in October 1990. This is a decline of about 0.7 SCF/STB.

If the cause of the apparent decline was that gas was exsolving from the brine in the reservoir, the equation relating the gas/brine ratio to the pressure presented in Section 5.2.1 should approximate the pressure drop. The flowing bottomhole pressure in May 1990 was 9770 psia, whereas the flowing bottomhole pressure in October 1990 was 9020 psia. This pressure drop, if the brine was saturated at both pressures, would cause the produced gas/brine ratio to fall by about 1 SCF/STB. This is close to the 0.7 SCF/STB drop that was observed. However, the preponderance of data suggests the brine was not saturated. The reason for the decline in the gas/brine ratio has not been identified.

5.2.4. "Bubble Test" for Free Gas Adjacent to the Wellbore

IGT developed a "bubble test" to determine whether there was free gas at critical saturation in the formation near the wellbore. As the flowing bottomhole pressure falls below the bubble-point pressure of the brine, gas is exsolved. This gas remains trapped in the reservoir until the gas saturation reaches the critical gas saturation. A small amount of the free gas then flows into the wellbore and the gas saturation near the wellbore is maintained at the critical gas saturation. The "bubble test" involves increasing the rate in a stepwise manner. This stepwise increase in flow rate creates an instantaneous drop in the bottomhole pressure, which in turn causes gas caught in the reservoir to expand slightly. As the gas expands, the gas saturation exceeds the critical gas saturation, so the free gas flows. The amount of gas produced is dependent on the pressure decline, which is small for these high-permeability reservoirs. The excess gas is produced for a short period, and then the produced gas/brine ratio should drop to a level slightly lower than its level before the rate increase because more gas exsolves from the brine further out in the reservoir.

IGT monitored gas rates and composition following a step increase in drawdown on October 16, 1990, as a "bubble test" to determine whether the flowing bottomhole pressure was below the bubble-point pressure of reservoir brine -- or, in other words, to determine whether free gas was in pores of the reservoir rock near the wellbore. Excess gas production is generally hard to spot because of transients in the surface facilities caused by the flow rate change. Changes in gas composition, caused by the addition of a small amount of rich gas in equilibrium with the brine at reservoir conditions, are generally easier to determine.

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Gas samples were collected in conjunction with the stepwise brine rate increase from 22,400 to 24,100 STB/d on October 16, 1990.

The analyses presented in Exhibit 5.2.4-1 are for samples that were obtained before, at, and after the time the "bubble" would have reached the separators. The lack of a significant change in the gas chemistry indicates that little, if any, free gas was produced. The negative results of this test suggested that the bottomhole pressure was still above the bubble-point pressure.

Exhibit 5.2.4-1. PLEASANT BAYOU SALES/FLARE GAS BUBBLE TEST

Date	<u>10/16/90</u>	<u>10/16/90</u>	<u>10/16/90</u>
Time	14:30	14:43	15:11
Pressure, psia	472	471	472
Gas Temp, °F	91	91	93
Brine Temp, °F	294	294	294
<u>Mole Percent of:</u>			
Helium	0.009	0.009	0.009
Hydrogen	0.010	0.011	0.010
Nitrogen	BDL ^a	BDL	BDL
Carbon Dioxide	9.55	9.57	9.51
Methane	86.4	86.4	85.9
Ethane	2.93	2.93	2.91
Propane	0.85	0.85	0.85
iso-Butane	0.13	0.13	0.13
n-Butane	0.12	0.12	0.12
iso-Pentane	0.03	0.03	0.03
n-Pentane	0.01	0.01	0.02
neo-Pentane	BDL	BDL	BDL
C-6 & Heavier	0.10	0.09	0.70

^a BDL = Below detection limits.

5.3. Liquid Hydrocarbon Sampling and Analysis

A small quantity of liquid hydrocarbons condensed from the Pleasant Bayou gas stream as the gas was cooled to ambient temperature and dehydrated. The quantity of hydrocarbons recovered averaged less than 2 gallons per day. This condensed hydrocarbon liquid was highly aromatic, with more than two-thirds of the liquid composed of benzene, toluene, xylenes, ethylbenzene, and naphthalenes. This section, along with Appendix K, presents sample collection and analyses, the results of over twenty condensate analyses, and a discussion of the significance of the results with respect to recovery of liquid hydrocarbons as well as operational problems such as control-valve fouling.

5.3.1. Condensate Sampling and Analytical Technique

The gas stream must be dehydrated prior to sale to pipeline companies to minimize corrosion and prevent hydrate formation in the pipelines. The equipment commonly used for dehydrating gas is a countercurrent glycol absorber and a reboiler for regenerating the glycol. The water-vapor content of the gas leaving the unit depends on both the gas pressure and temperature. For proper dehydration, most glycol dehydrators are operated at pressures above 400 psig at ambient temperature. A small quantity of hydrocarbon liquids and a considerably larger quantity of condensed water vapor are deposited by the separator gas stream as the gas is cooled and processed. The production facility routes the majority of this liquid into a gunbarrel separator. The water is separated from the hydrocarbon liquid gravimetrically. The water is then routed to tanks, whereas the condensate is measured and dumped into the tanks manually each day.

The gunbarrel separator had to be modified before proper operation was achieved. The gunbarrel separator operates by gravity and siphoning action rather than pressure. The gunbarrel separator is vented to atmosphere. An important variable in the design of the gunbarrel separator is the difference in the density of the two phases. Condensate traditionally recovered from gas wells is almost exclusively alkanes, such as pentane and hexane. The density of these alkane hydrocarbons is about 0.70 g/cc, whereas the density of water is 1.00 g/cc. The gunbarrel separator was designed with these parameters, and the water underflow piping was about 3 inches below the hydrocarbon outlet pipe.

A sample of the condensate from the gas knockout pots was collected on June 21, 1988. The sample was a clear, dark straw-colored liquid that had the appearance of traditional condensate, but with a surprising API gravity of 19. This corresponds to a density of 0.94 g/cc. Such high densities are normally associated with heavy asphaltic oils. The gas analyses suggested why the sample has such a high density. There were 0.098 gallons of C6+ hydrocarbons per 1000 SCF in the gas stream after the cooler, dehydrator, and knockout pots. This is over twenty times more liquid than the 0.005 gallons of condensate per 1000 SCF condensed out of the gas stream. The majority of these hydrocarbons were benzene, toluene, xylenes, and naphthalenes.

The density of benzene and its derivatives is around 0.88 g/cc, and the density of naphthalene and its derivatives is around 1.0 g/cc. Subsequent analyses showed the condensate contains about two-thirds aromatic compounds (benzene, naphthalenes, and their derivatives) and one-third alkanes. With this density difference, the gunbarrel separator as originally designed would eventually have completely filled with hydrocarbons. The height of the water underflow piping was adjusted from 3 inches to about 1/2 inch lower than the hydrocarbon outlet. The height of the hydrocarbon layer in the redesigned gunbarrel separator is only a few inches.

The gunbarrel separator used to separate and collect liquid hydrocarbons from the gas stream also dumps about 200 gallons per day of nearly fresh water to the sump. The amount varies daily, but the average for 1988 is about 250 ppmv as a fraction of the produced brine. This water is milky white, indicating that an emulsion exists. A sample was collected on October 13, 1988, extracted, and analyzed. The analysis found 1800 mg/L, or about 0.20% by volume, of this "water" was in fact hydrocarbons. The composition of this entrained hydrocarbon liquid, presented in Exhibit 5.3.1-1, is similar to the composition of the condensate recovered. The daily quantity of emulsified and/or dissolved liquid hydrocarbons carried with the water to the tanks averages 0.40 gallons per day, which is about one-fifth the average amount of liquid hydrocarbons recovered from the gunbarrel separator.

Exhibit 5.3.1-1. COMPOSITION OF THE 0.2% BY VOLUME HYDROCARBONS FOUND IN WATER LEAVING THE GUNBARREL SEPARATOR

<u>Carbon Number</u>	<u>Weight Percent Distribution by Carbon Number</u>	<u>Cumulative Distribution by Carbon Number</u>
<7	0.20	0.20
Benzene	9.08	9.28
7	1.80	11.08
Toluene	14.44	25.52
8	1.79	27.31
Ethylbenzene	2.79	30.10
<i>m,p</i> -Xylene	9.14	39.24
<i>o</i> -Xylene	5.89	45.13
9	0.75	45.88
C3-Benzenes	12.23	58.11
10	1.02	59.13
11	5.82	64.95
12	4.11	69.06
Naphthalene	6.29	75.35
13	1.38	76.73
C1-Naphthalene	9.26	85.99
14	1.89	87.88
C2-Naphthalenes	5.95	93.83
15	0.78	94.61
C3-Naphthalenes	2.13	96.74
16	0.97	97.71
17+	2.29	100.00

Most of the condensate from the gunbarrel falls out of the gas stream between the separator and the knockout just after the gas cooler. The driving force is the reduction of the gas temperature from 290°F in the separator to less than 100°F by the time it leaves the knockout after the cooler. During normal operation, the gas does not cool appreciably after this point, so liquid condensation is not expected after this point. These knockout pots are all plumbed in to the gunbarrel separator.

In addition to this condensate, there is a small quantity of water and liquid hydrocarbons recovered from a condenser on the glycol reboiler located after the knockouts. These hydrocarbons were in the gas phase in the countercurrent extractor but dissolved in the liquid glycol. Liquids recovered at the glycol dehydration unit are primarily a function of the solubility of the various hydrocarbons in triethylene glycol at a gas pressure of 400 psia.

The light hydrocarbons and water are then driven out of the glycol in the reboiler and are collected in an open container. The compositions of a gunbarrel separator liquid hydrocarbon sample and a dehydrator liquid hydrocarbon sample are presented in Exhibit 5.3.1-2. The condensate caught at the dehydrator is 88.5% aromatic and is composed primarily of benzene derivatives and naphthalene derivatives. The benzene fraction of the glycol dehydrator hydrocarbons is believed to be low due to volatilization. Benzene is the primary constituent of the hydrocarbons in the gas that are heavier than pentanes. Benzene is also more soluble in water than are other hydrocarbons. Therefore, the majority of the liquids caught from the dehydrator should be benzene. Much of the benzene probably evaporates from the open 5-gallon bucket used for sample collection. This hydrocarbon liquid is combined with the hydrocarbon liquid recovered from the gunbarrel separator, and the total is summed to get the daily condensate production.

Exhibit 5.3.1-2. COMPOSITIONS OF LIQUID HYDROCARBONS FROM THE GUNBARREL SEPARATOR AND THE GLYCOL DEHYDRATOR

	29 Aug 88 <u>Gunbarrel</u>	29 Aug 88 <u>Dehydrator</u>
Benzene	1.47	0.50
C7	0.30	0.02
Toluene	5.62	15.39
C8	0.82	0.16
Ethylbenzene	1.63	6.53
<i>m,p</i> -Xylenes	5.43	20.99
<i>o</i> -Xylene	3.49	13.28
C9	0.26	0.22
C3-Benzenes	9.08	18.94
C10	0.35	0.35
C11	5.26	5.65
C12	4.31	2.82
Naphthalene	9.37	4.89
C13	3.52	1.16
C1-Naphthalenes	17.44	5.58
C14	3.81	0.73
C2-Naphthalenes	12.71	2.05
C15	2.60	0.19
C3-Naphthalenes	4.26	0.36
C16	2.87	0.17
C17+	5.37	0.02

The vast majority of liquid hydrocarbon samples collected and analyzed by IGT came from the gunbarrel separator. In addition to the one glycol dehydrator condenser sample, there were occasionally samples from other points in the gas processing stream. Sample locations are shown in the accompanying schematic diagram in Section 5.3.3. Condensate samples were obtained from several locations in the gas flow path, both prior to gas cooling, after gas cooling, and after gas dehydration. Numerous samples of triethylene glycol were obtained from the dehydrator unit to determine whether hydrocarbons were contaminating the glycol. Finally, several liquid hydrocarbon samples were obtained from various points in the Hybrid Power System to determine whether this condensate was finding its way into the HPS. These additional samples included engine lubricating oil from the Mustang generators, lubricating oil from the turbine, and a liquid hydrocarbon accumulation found in a heat exchanger.

The liquid hydrocarbon samples were analyzed by gas chromatography, using a capillary gas chromatography column in a temperature-programmed oven with a flame ionization detector. This detector burns the components in a hydrogen flame and determines the number of carbon (and a few other) atoms ionized in the flame. The number of carbon atoms is related to weight percent based on average values for a carbon number.

Compound identification is based on the time required for the compound to pass through the column. Natural oil deposits normally contain an enormous number of compounds, and analysts do not attempt to identify all of them. Typical analyses are by carbon number. But reporting of results from Pleasant Bayou is complicated by the fact that the composition of recovered liquid hydrocarbons differs greatly from that for the oil or NGL normally produced by the petroleum industry. The aromatic hydrocarbons do not tend to be eluted from the column at the same time as alkanes of comparable molecular weight. For this reason the aromatics, through C2-naphthalenes, are individually quantified. The remaining hydrocarbons are grouped by carbon number. The analytical procedure is described in Appendix K. The analysis is terminated after C30 hydrocarbons are eluted.

5.3.2. Results of Condensate Analyses

Chromatographic analysis of natural oil or NGL usually shows a "backbone" of normal paraffinic hydrocarbons (alkanes) that provide a useful "fingerprint" of a sample, as is illustrated in the first chromatograph in Exhibit 5.3.2-1. This chromatogram is an analysis of a "normal" condensate from a co-production well located 20 miles from Pleasant Bayou. A standard practice for tabular reporting of this data is to group the components by carbon number. For instance, all unidentified components falling after the normal C8 peak, up to and including the normal C9 peak, are reported as weight percent C9.

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PRETS190

PLBAY290

Exhibit 5.3.2-1. CHROMATOGRAMS OF NORMAL ALIPHATIC CONDENSATE
AND PLEASANT BAYOU CONDENSATE

The second chromatograph in Exhibit 5.3.2-1 is of a gunbarrel condensate sample. It is very different from normal oil or NGL in that the peaks for normal paraffinic hydrocarbons (alkanes) are minor features rather than the "backbone" of the spectrum. The major peaks are benzene and derivatives plus naphthalene and derivatives. Aromatic compounds are much more soluble in water than alkanes of a similar molecular weight. The hydrocarbons making up the condensed liquid hydrocarbons collected at Pleasant Bayou are dissolved in the brine at reservoir conditions.

We have elected to reflect this difference in tabular reporting of compositions by reporting the weight percents for selected components separate from the carbon number grouping. The selected components are benzene and derivatives up to and including C3 benzenes and naphthalene and derivatives up to and including C3 naphthalenes. There are a total of eight C3 benzene isomers that are identified and summed in the C3 benzene entry. There are about twenty C4 benzene isomers, each containing ten carbon atoms, that are eluted from the chromatograph after the normal C10 peak and before the normal C12 peak. In the interest of minimizing costs, these C4 benzenes remain unidentified and are reported in the C11 and C12 totals. Similarly, the C4 naphthalenes are included in C16 and C17+ entries. A typical chromatogram, expanded to show more detail, is provided in Exhibit 5.3.2-2.

The sample analysis is carried out to C28 hydrocarbons, although the heavier hydrocarbons are grouped as C17+ for reporting purposes. The average of nineteen analyses of gunbarrel condensate samples is provided in Exhibit 5.3.2-3. The individual analyses are presented in Appendix K.

The composition of the condensate varied with time, although the changes often did not seem to correlate with well operations. Exhibit 5.3.2-4 presents a few sequential chromatograms for five Pleasant Bayou gunbarrel condensate samples collected in 1989. The compositions are similar to one another, with the most noticeable difference being a larger naphthalene fraction in the later samples. Cold ambient temperatures, ranging from 40° to 60°F, often result in analyses with higher fractions of light hydrocarbons. Because the driving force for condensing out hydrocarbons is the temperature drop, and the gas-cooling apparatus is not adjustable, it is believed that changes in the ambient temperature should affect the condensate quantity and composition. In addition, both the gunbarrel separator and the reboiler collection container are vented to the atmosphere. Volatilization and subsequent loss of hydrocarbons from these vessels are temperature dependent. This may account for some of the compositional changes, although there are several other factors that can affect the composition of the accumulated liquid hydrocarbons.

Exhibit 5.3.2-2. GUNBARREL CONDENSATE CHROMATOGRAMS
EXPANDED TO SHOW MORE DETAIL

Exhibit 5.3.2-3. AVERAGE COMPOSITION OF NINETEEN SAMPLES
OF GUNBARREL CONDENSATE

<u>Compound</u>	<u>Weight Percent</u>	<u>Compound</u>	<u>Weight Percent</u>
Benzene	2.18	C1-Naphthalenes	15.83
C7-	0.79	C14	3.13
Toluene	6.47	C2-Naphthalenes	12.23
C8	0.84	C15	2.95
Ethylbenzene	1.75	C3-Naphthalenes	3.72
<i>m,p</i> -Xylenes	5.77	C16	2.48
<i>o</i> -Xylene	3.68	C17	2.96
C9	0.48	C18	1.32
C3-Benzenes	8.80	C19	0.85
C10	0.80	C20	0.63
C11	4.96	C21	0.38
Naphthalene	8.52	C22	0.24
C12	5.02	C23	0.19
C13	2.76	C24	0.13
		C25+	0.25

There was some concern that the condensate composition or quantity was being affected by the corrosion inhibitor. The RN-97 corrosion inhibitor is injected into the brine at a concentration near 10 ppm by volume. The condensate recovery averages 2 ppm by volume relative to brine production. The corrosion inhibitor was analyzed at IGT for compounds in the condensate. In addition, the corrosion inhibitor was vaporized at a temperature of about 500°F at the inlet to the chromatograph in case thermal decomposition was a factor. Although traces of benzene derivatives and other compounds were found in the RN-97, the concentrations were far too low to have any affect on the volume or the chemical composition of the condensate.

5.3.3. Operational Problems Caused by Condensate

Condensed liquid hydrocarbons have been deleterious to normal operation, although in all cases the problems were resolved without difficulty once the causes were identified.

The glycol dehydrator operates by injecting clean, dehydrated glycol in the top of a counter-current absorption tower. As gas travels up the tower to the outlet, it contacts the glycol traveling down, and water vapor is absorbed from the gas. The glycol then leaves the bottom of the tower and enters a reboiler. This reboiler is maintained at 350°F and is vented to atmosphere. Water vapor and some light hydrocarbons that dissolve in the glycol are driven off by the heat. The glycol is then cooled and recycled to the top of the tower. A schematic diagram of a gas processing unit and the glycol dehydrator is shown in Exhibit 5.3.3-1.

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Exhibit 5.3.2-4. CHROMATOGRAMS OF GUNBARREL CONDENSATE SAMPLES

Schematic of Pleasant Bayou Gas Separation and Processing Equipment

Exhibit 5.3.3-1. SCHEMATIC DIAGRAM OF A GAS PROCESSING UNIT AND GLYCOL DEHYDRATOR

There were two condensate-related problems with the glycol dehydrator. Both were caused by the hydrocarbon solubility in the triethylene glycol. The first was that the elastomers in the pumps were not compatible with the condensate. This problem was solved by replacing the pump packing with Teflon packing. The second was that condensate seemed to be accumulating in the glycol, and there was concern that the efficiency of the glycol unit would be impaired.

Samples of triethylene glycol were obtained from several sample points in the glycol dehydrator. The sample locations are C, D, E, and F in Exhibit 5.3.3-1. These samples were analyzed for total hydrocarbon content, and two of the samples were given detailed analyses to determine what this hydrocarbon contamination is. The analytical data is presented in Exhibit 5.3.3-2.

There is a valve on the bottom of the glycol reboiler. When this valve was cracked open, dark liquid and some solids were recovered. This liquid, labeled Sample C, contained 22% by weight hydrocarbons. This sample was from the valve body -- there was no purging of the sample port prior to sampling C. The valve was then opened and allowed to purge several valve volumes, and a second sample, Sample D, was collected. This sample contained only 4.7% by weight liquid hydrocarbons. The liquid hydrocarbon contamination had a composition similar to the heavy fraction of a normal gunbarrel condensate sample, with little material lighter than C1 naphthalenes.

A liquid sample was obtained from the sightglass of the glycol reboiler. This liquid was found to be a light condensate. Some of the condensate vapor driven from the glycol in the reboiler must have entered the cool sightglass and condensed. This process would continue until the condensate accumulation eventually completely displaced the glycol from the sightglass.

A sample of dehydrated triethylene glycol was obtained from the line leading back to the tower. This sample also contained hydrocarbon contamination (4.3% by weight) that appeared to be a very heavy fraction of the gunbarrel condensate. Finally, a sample of fresh triethylene glycol was analyzed to confirm that these contaminants were from the gas stream.

The 4.3% hydrocarbons are contaminants that dissolve from the gas into the glycol in the absorbing tower but are too heavy to be driven off in the reboiler. It is not known whether the quantity of these hydrocarbons in the glycol has reached a steady state. These aromatic hydrocarbons attack elastomers that were chosen to be compatible with the more benign triethylene glycol, thereby causing the pump problems. There are, however, other elastomers readily available from the pump manufacturer that have excellent resistance to these hydrocarbons.

There were also minor condensed hydrocarbon liquid-related problems with the Hybrid Power System. This was somewhat surprising because the gas is cooled to ambient temperature, with liquid knockouts in place, before the HPS inlet. Nevertheless, liquid hydrocarbon

Exhibit 5.3.3-2. TRIETHYLENE GLYCOL ANALYSES

C	Bottom of glycol reboiler.
D	Bottom of glycol reboiler after more purging (liquid got lighter in color).
E	"Clean" glycol to the absorber tower.
F	Sight glass in glycol reboiler.
New	New triethylene glycol from the drum kept on location.

Sample Location	C	D	E	F	New
Date	5/24/90	5/24/90	5/24/90	5/24/90	5/24/90
Triethylene Glycol	78.09	5.3	95.7	0.1	99.63
Hydrocarbons	NA ^a			NA ^c	NA
Benzene		0.002	0.004		
C7-		0.001	0.002		
Toluene		0.005	0.008		
C8		0.006	0.006		
Ethylbenzene		0.001	0.002		
<i>m,p</i> -Xylenes		0.003	0.005		
<i>o</i> -Xylene		0.002	0.004		
C9		<0.001	<0.001		
C3-Benzenes		0.003	0.006		
C10		b	b		
C11		0.007	0.005		
Naphthalene		0.015	0.016		
C12		0.002	0.004		
C13		b	b		
C1-Naphthalenes		0.062	0.065		
C14		0.019	0.028		
C2-Naphthalenes		0.47	0.49		
C15		0.10	0.09		
C3-Naphthalenes		0.27	0.25		
C16		0.19	0.20		
C17		0.42	0.41		
C18		0.27	0.26		
C19		0.24	0.23		
C20		0.26	0.24		
C21		0.21	0.20		
C22		0.21	0.20		
C23		0.28	0.25		
C24		0.25	0.22		
C25		0.27	0.24		
C26+		1.07	0.86		

^a NA = Not analyzed.

^b An impurity in the glycol obscures the C10 region, while the triethylene glycol itself obscures the C13 region. Therefore, quantitation of peaks is not possible in those regions.

^c This liquid is very much like a light condensate fraction, and there is little or no triethylene glycol present in this sample.

deposition, although slight, was enough to attack a nitrile diaphragm and eventually disrupt operations. The presence of condensate at the HPS was a surprise, so liquid hydrocarbon samples were looked for and collected from other points in the system. Sample locations were labeled A, B, G, H, and I in Exhibit 5.3.3-1. Samples of lubricating oil from the Mustang generators and lubricating oil from the iso-butane turbine were also collected. The samples were analyzed at IGT following the same procedures as for the gunbarrel liquid analyses.

The composition of the hydrocarbon liquid samples are presented in the Exhibit 5.3.3-3, and are presented graphically in the five chromatograms in Exhibit 5.3.3-4. There was less than a cup of liquid hydrocarbons at sample point A, before the gas entered the gas cooler. This liquid was almost totally devoid of hydrocarbons lighter than naphthalenes and had the interesting characteristic that it sank in water. This is expected when one realizes the density of C1 to C3 naphthalenes average 1.01 g/cc, whereas water has a density of 1 g/cc.

There were plenty of liquid hydrocarbons from Sample Location B, the filter located just after the gas cooler. The composition of this liquid is indistinguishable from the composition of the gunbarrel liquid hydrocarbon samples (Sample Location J). These compositions provide conclusive, and not surprising, evidence that the majority of the gunbarrel liquid hydrocarbons comes from this liquid knockout.

There were only traces of liquid hydrocarbons from sample points G, H, and I, which are located after the dehydrator. The hydrocarbon liquid total recovered from these points was under 1 cup. This is the liquid, however, that was suspected of swelling the elastomers in pressure regulators upstream of carburetors at the HPS, resulting in the control problems. All of these samples had compositions similar to the normal Pleasant Bayou gunbarrel condensate but were enriched in the heavy ends. Sample I was collected from a point after a pressure regulator, where the gas was cooled by adiabatic expansion. These samples are highly aromatic in nature, with more than half of these samples composed of C1 to C4 naphthalenes. It should be noted that there was not a detectable level (less than 0.01% by weight) of triethylene glycol in these samples.

This heavy hydrocarbon liquid built up on the nitrile rubber diaphragms used in pressure regulators on the generators. Over a period of a few months, the diaphragms would fail. Because these components were easy to replace, the HPS operator elected to schedule routine diaphragm replacements rather than find a more resistant material.

The other concern of the HPS operator was whether liquids that fall out of the gas stream were contaminating the generator oil or the iso-butane turbine oil. Chromatographic analyses showed there was no measurable contamination.

Exhibit 5.3.3-3. PLEASANT BAYOU NO. 2 WELL CONDENSATE ANALYSES

- A Gas line out of the separators, before the back pressure-control valve.
- B Coalescing filter after the gas cooler.
- G Valve just upstream of Enron sales meter run.
- H Valve in HPS gas meter run.
- I Liquid knockout pot on Mustang generator skid.
- J Normal gunbarrel condensate.

Sample Location Date	A 5/24/90	B 5/24/90	G 5/24/90	H 5/24/90	I 5/24/90	J 5/24/90
Benzene	0.18	4.12	0.70	1.71	0.27	2.45
C7-	0.08	1.15	0.09	0.34	0.07	0.41
Toluene	0.42	8.05	1.65	3.06	0.62	7.29
C8	0.06	1.14	0.19	0.51	0.10	0.86
Ethylbenzene	0.10	1.88	0.37	0.53	0.12	1.92
<i>m,p</i> -Xylenes	0.37	6.02	1.22	1.69	0.42	6.25
<i>o</i> -Xylene	0.25	3.87	0.65	0.83	0.22	3.99
C9	0.03	0.52	0.12	0.23	0.04	0.49
C3-Benzenes	0.86	9.15	1.19	1.35	0.37	8.56
C10	0.13	0.51	0.12	0.16	0.01	1.55
C11	0.48	3.89	0.48	0.50	0.09	3.96
Naphthalene	2.90	8.59	0.53	0.32	0.11	8.88
C12	1.21	5.61	0.43	0.35	0.06	5.48
C13	0.97	2.51	0.40	0.24	0.21	2.18
C1-Naphthalenes	11.16	14.92	3.26	2.84	2.87	10.53
C14	1.49	3.41	0.51	0.49	0.69	7.30
C2-Naphthalenes	17.60	11.48	a	a	a	12.33
C15	1.72	1.69	23.39	22.91	23.46	2.10
C3-Naphthalenes	9.85	3.83	a	a	a	4.04
C16	3.09	1.37	19.50	19.22	23.28	1.85
C17	10.01	2.44	13.47	13.35	14.32	2.50
C18	9.16	1.31	8.80	8.79	8.44	1.69
C19	6.38	0.84	6.62	6.46	6.07	0.99
C20	6.77	0.59	4.81	4.28	4.42	0.83
C21	4.26	0.34	2.78	2.24	2.77	0.45
C22	2.40	0.19	1.66	1.30	1.78	0.26
C23	3.42	0.21	1.81	1.34	2.03	0.35
C24	1.55	0.11	1.07	0.89	1.30	0.17
C25	1.05	0.09	0.95	0.89	1.22	0.13
C26+	3.05	0.17	3.23	3.19	4.66	0.21

^a Due to the nature of these samples, the C2 and C3 naphthalenes could not be accurately resolved and quantified from the smaller neighboring hydrocarbons. While the bulk of the material is naphthalenes, they have been included in the generic C15 and C16 data. Similarly, C4 naphthalenes are included with the C17 and C18 data.

Exhibit 5.3.3-4. CHROMATOGRAMS OF CONDENSED LIQUID HYDROCARBON SAMPLES

5.3.4. Cryocondensate

Cryocondensate sampling and analyses were performed by Drs. Keeley and Meriwether of The University of Southwestern Louisiana (USL). Cryocondensate samples are those hydrocarbons that can be condensed by passing produced gas through a dry ice-acetone bath held at -78°C and that can be extracted from cooled brine with hexane. The concentrations are then related to the brine production. The cryocondensate concentration versus brine production, presented in Exhibit 5.3.4-1, is reproduced from a USL quarterly report to DOE.⁷ The concentration averages about 34 μl per liter (ppmv) of brine.

The USL research is investigating whether changes in cryocondensate production can be related to production-induced stress on shales and accompanying migration of hydrocarbons. To date the concentration of cryocondensates at Pleasant Bayou have been relatively unchanging.

The composition of the cryocondensate should reflect the composition of the heavier hydrocarbons in the gas analysis. That is, the cryocondensate should consist primarily of benzene, with rapidly decreasing quantities of toluene, C2-benzenes, and naphthalenes. This was found to hold true -- more than half of the cryocondensate is benzene and toluene.

The hydrocarbon liquid collected in the gunbarrel is only a small, heavy fraction of the hydrocarbons that make up the cryocondensate. The condensate recovery averages 0.005 gallons per 1000 SCF of gas, or less than one-twentieth of the C6+ fraction of the separator gas. This equates to between 2 and 3 ppmv of condensate in brine. This is, not surprisingly, less than 10% of the volume fraction of liquid hydrocarbons extracted from the gas and brine streams with the cryogenic methods used by Drs. Keeley and Meriwether. The composition of the gunbarrel hydrocarbon phase is different from the composition of the cryocondensate. Much of the benzene tends to remain in the gas phase at ambient temperature. A portion of the lighter benzene and toluene that is collected by the gunbarrel separator is no doubt lost to the atmosphere via volatilization.

6.0. SOLIDS SAMPLING AND ANALYSIS

The following sections present the results of sample collection and analyses performed on samples of solids. Section 6.1 details the two occurrences when small slugs of sand were produced. The total volume of sand produced during these two occasions was less than 6 cubic feet. Section 6.2 describes analyses performed at the onset of lead sulfide production. Section 6.3 describes solids recovered from the disposal well.

Exhibit 5.3.4-1. CRYOCONDENSATE CONCENTRATION VERSUS
BRINE PRODUCTION

6.1. Solids Production and Monitoring

During the course of this reporting period, the solids production was monitored by separator sand checks and by observing the filter pressure buildup. The pressure drop across the cotton filter elements located just upstream of the disposal well was monitored continuously.

The separator sand checks were a weekly inspection of solids removed from the sand blowdown valves located near the inlet of the large separator and at the outlet of the small separator. These samples are not a quantitative measure of solids production. At most, a few percent of the solids that settle in the separator are eventually sampled via the sand blowdown valve. The normal amount of solids observed was 1 teaspoon or less from the checkpoints for each separator. During periods of high solids production, however, the quantity of sand recovered could increase by an order of magnitude or more.

During June 20, 1988, brine rate was increased stepwise to 20,000, then 22,000, and finally 25,000 STB/d in a few hours. High solids production was indicated by rapidly increasing differential pressure across filter elements and increasing disposal well injection pressure. After 2 hours at the 25,000 STB/d rate, the rate was reduced to 17,000 STB/d due to suspected sand production. Overnight flow at 17,000 STB/d indicated cessation of sand production, and the rate was increased in two steps to 22,500 STB/d during June 21. The rate of buildup of filter pressure drop and increases in disposal well injection pressure mandated rate reduction to stop sand production the next morning. The flow was reduced to 11,000 STB/d so that the full flow could be switched to the small separator and the large separator could be opened to determine total sand production.

About 4 cubic feet of sand was carried to the surface by the brine rates in excess of 20,000 STB/d on June 20, 1988. This was somewhat surprising because brine rates as high as 30,000 STB/d were reported during the Phase IIA testing in July 1981, and it was generally perceived that sand was not produced. With this in mind, it was thought as early as July 1988 that there was a reasonable chance that the brine production rate could be held well over 20,000 STB/d without excessive sand production. However, the following observations are relevant:

- Filters were not in use during the July 1981 production, and therefore the current most sensitive sand detection capability was not active in 1981.
- The solids produced did not cause variations in disposal well injection pressure larger than those reflected in the Phase IIA report.

Samples of solids from filter elements and samples of sand from the large separator were collected on June 20 and 24, 1988, respectively. Most of the solids found in the surface facilities are believed to have been produced during the 25,000 STB/d flow between 17:00 and 20:00 hours

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on June 20. A total of about 400 pounds of sand settled out in the separator. An estimated 10 to 20 pounds of the solids that carried through the separator were caught by, and plugged, the filters.

Grain-size distributions of the solids are presented in Exhibit 6.1-1. The particle-size distribution of the pan fraction of the filter solids is presented in Exhibit 6.1-2. The pan fraction of the solids is the portion responsible for disposal well plugging. The filters, nominally rated at 50 microns, clearly caught much smaller particles. The large separator was expected to retain sand grains with diameters greater than about 60 microns at a brine rate of 25,000 STB/d, based on the Stokes Law settling velocity. Sixty-micron-diameter particles should just pass through a 325-mesh screen.

Exhibit 6.1-1. GRAIN-SIZE DISTRIBUTION OF JUNE 1988 SAND SAMPLES

<u>Mesh</u>	----- Separator Sand, wt % -----			<u>Filter Solids, wt %</u>
	<u>Inlet</u>	<u>Middle</u>	<u>Outlet</u>	
20	4.5	5.1	5.0	7.3
40	12.9	1.3	1.1	6.9
60	42.0	18.8	13.6	4.2
80	16.7	24.9	24.5	2.2
120	9.1	22.3	26.4	2.4
170	3.4	13.9	18.3	5.1
230	1.0	2.1	1.4	9.8
270	0	0	0	6.9
325	0	0	0	7.5
Pan	10.4	11.6	9.7	47.7

Exhibit 6.1-2. PARTICLE-SIZE DISTRIBUTION OF FILTER SOLIDS PAN FRACTION
(Normalized to 47.7%)

<u>Microns</u>	<u>wt %</u>	<u>Microns</u>	<u>wt %</u>
51	0	13	5.97
40	0.05	10	6.40
32	1.86	8	6.69
25	3.10	6	6.11
20	4.82	5	4.15
16	5.68	4	2.91

The compositions of the sand and filter solids are given in Exhibit 6.1-3. The composition of the separator and filter solids was similar to the original Pleasant Bayou core description. The reservoir was composed primarily of quartz, with kaolinite and albite common, carbonates and mixed-layer illite/smectite only in minor quantities, and trace chlorite flakes associated with quartz.¹²

Exhibit 6.1-3. COMPOSITION OF JUNE 1988 SAND AND FILTER SOLIDS SAMPLES

<u>Mineral</u>	----- Separator Sand, wt % -----			<u>Filter Solids, wt %</u>
	<u>Inlet</u>	<u>Middle</u>	<u>Outlet</u>	
Quartz	89	87	85	61
Plagioclase (Albite)	7	7	9	11
K-Feldspar (Microcline)	0	0	0	0
Calcite				1
Barite	tr ^a	tr	tr	
Magnesite				7
Magnetite (Fe ₃ O ₄)				8
Iron Sulfide				6
Clays	4	6	6	6
Kaolinite, % of clays	35	32	19	76
Chlorite, % of clays	29	42	40	
Illite ^b , % of clays	36 (tr)	26 (tr)	41(tr)	24 (18)

^a tr = trace.

^b Mixed-layer illite/smectite in parentheses.

The next instance of noticeable sand production occurred in October 1988. Production during this period was only 19,000 STB/d. The first indication of sand production was on October 10, 1988, when approximately 1/4 cup of sand was recovered from the separator sand checks. The filter differential pressure had peaked earlier in the day, and this may well have been due to production of a small slug of sand. A total of 2 cups of sand was recovered from the sand checkpoint on the large separator on October 20, 1988. This was significantly more than the "less than a teaspoon" of sand normally recovered. The small separator sample had only a trace of sand.

At the brine rates in the range of 18,000 to 15,000 STB/d associated with the test of the HPS, the produced brine was remarkably free of entrained sand and suspended solids. There were occasional increases in weekly recovery from separator separator check points up to a cup. But these were not accompanied by evidence of new sand production from the reservoir rather than redistribution of the small amount of sand already in the surface piping and vessels.

In the fall of 1990, after completion of the HPS experiment, brine rate was increased stepwise to look for the onset of sand production. After a month with no sand production at a brine rate of 22,400 STB/d, the brine rate was increased to 24,100 STB/d during October 16, 1990. Ten days later, variation in the gas split between the separators and an increase of 9 psi in pressure drop across the filters was noted overnight. Production then remained steady with no sign of sand for a day. A few hours after new filter elements were installed October 28, the filters fully loaded in half an hour. The brine rate was reduced to 18,000 STB/d to stop the production of sand. About 2 cubic feet of sand were removed from the separators when they were cleaned out.

6.2. Lead Sulfide

Suspended-solids samples were collected on 0.45-micron filters at points downstream of the first choke and at the disposal well on September 4, 1990. The quantity of solids collected was 0.07 pounds/1000 barrels at the choke and 0.09 pounds/1000 barrels at the disposal well. These solids were found to be primarily lead sulfide. Because the presence of lead was so surprising, the solids were reanalyzed by X-ray diffraction, analyzed by X-ray fluorescence, and then dissolved and analyzed by ICP. These additional tests all confirmed the first results. Calcium and iron were present in minor quantities, whereas mercury, zinc, copper, nickel, and chloride were present in trace quantities. But the majority of the solids were lead sulfide.

Two weeks after these suspended-solids samples were obtained, a dark tar-like substance was observed in the solids collected from the sand checkpoints in the large separator. Extensive laboratory analyses were performed on this dark material obtained from the sand blowdown checks collected on October 2, 1990. The sample volume was about 1/4 cup of solids.

The first analysis consisted of extracting hydrocarbons with methylene chloride and then performing liquid chromatography analysis. The hydrocarbons were found to constitute 6.1 weight percent of the sample. They contained naphthalene and its derivatives, phenanthrene and its derivatives, biphenyl, and a large unresolved continuum of hydrocarbon-like material extending well beyond C32. The material had the appearance of a very thick oil and some heavy ends of the aromatic condensate recovered in the gunbarrel separator. The results of X-ray diffraction analysis of the sample are presented in Exhibit 6.2-1.

Exhibit 6.2-1. X-RAY DIFFRACTION ANALYSES OF SEPARATOR SOLIDS
COLLECTED ON OCTOBER 2, 1990

<u>Quantity</u>	<u>Mineral</u>
Major (>10%)	Galena Quartz
Major-Minor (1%-10%)	Calcite Siderite
Minor (0.1%-1%)	Albite Microcline

Albite and microcline are naturally occurring feldspars. These and quartz are major components of the producing formation. The siderite (iron carbonate) found in the blowdown solids was probably formed during corrosion of the well tubulars.

The presence of galena (lead sulfide) was a surprise. This mineral was not a major component of Frio sand. The only identified significant amount of lead in the system was sinker bars that were lost in the well years ago, plus an impact plate on a flange just upstream of the primary choke. The sinker bars are believed to be below the perforations, covered with Frio sand, and not contacted by the flowing brine.

A confirming analysis consisted of determining the fractions of solids (after extracting hydrocarbons) that were soluble in, or converted to carbon dioxide by treatment with, 6N HCl. Expressed as weight percent of solids after hydrocarbon extraction, the results of these analyses are presented in Exhibit 6.2-2.

Exhibit 6.2-2. ACID-SOLUBLE MATERIAL IN THE OCTOBER 2, 1990, SEPARATOR SOLIDS

<u>Element</u>	<u>wt %</u>	<u>Element</u>	<u>wt %</u>
Carbonate, as CO ₃	17.9	Barium	0.4
Calcium	5.5	Chromium	0.1
Iron	8.2	Potassium	<0.05
Magnesium	0.2	Manganese	0.2
Sodium	0.4	Lead	12.9
Strontium	0.1	Zinc	0.1
Unidentified	4.8	Acid Insoluble	49.1

From these results and the X-ray diffraction data, we concluded that the October 2, 1990, sample contained 15% by weight lead sulfide, 14% by weight calcite, and 17% by weight siderite. The acid-insoluble fraction of the sample was 49% by weight, and 5% by weight was soluble but was not identified.

Lead sulfide, also called galena, is a principal ore of lead. This mineral had not been previously identified in solids analyses, and its sudden appearance in the separator solids was clearly noteworthy. The source of this lead sulfide is not known. The two major hypotheses, however, are that the lead sulfide is the result of metallic lead in the surface facilities reacting with the sulfide in the brine or that the lead is the result of the radioactive decay of radon. Lead 210 is a daughter product of radon gas, which is present in the produced gas at an activity level of about 300 disintegrations per minute per liter at standard conditions. This lead isotope is radioactive.

The presence of lead 210 in the galena was first indicated by above-background radiation readings with a thin-window Geiger Mueller counter. Subsequently, analysis of a concentrated galena sample found the lead 210 activity to be 2166 disintegrations per minute per gram or 976 picoCuries per gram (personal communication, Dr. T Kraemer, 1991).⁸

6.3. Disposal Well Sand Analysis

A bailer sample was obtained from the Pleasant Bayou No. 1 SWD well at a depth of 6348 feet on March 30, 1988. The X-ray diffraction results and grain-size analysis are summarized in Exhibit 6.3-1. The laboratory also reported that 7.5% of the sample was soluble in 18% hydrochloric acid. Much of the dissolved material was iron.

Exhibit 6.3-1. CHARACTERISTICS OF DISPOSAL WELL BAILER SAMPLE

Particle-Size Distribution		Composition by X-ray Diffraction	
Mesh	wt %	Mineral	wt %
20	0.73	Calcite	1
40	0.85	Albite	2
60	1.83	Microcline	8
80	10.98	Quartz	88
120	51.71	Kaolinite	0.4
170	21.59	Illite/Smectite	0.2
230	4.51	Smectite	0.4
270	2.20		
325	1.71		
Pan	3.90	Solid density = 2.68 g/cc	

The well was cleaned out to 6476 feet on June 8, 1988. A bailer sample was obtained from the Pleasant Bayou No. 1 SWD well at a depth of 6348 feet 11 months later on May 18, 1989. The sample appeared to be unconsolidated sand and clay. The sample contained about 0.9% by weight "honey oil" introduced by the wireline lubricators used during logging of the production well. When cleaned of oil, the sample had a grain density of 2.66 g/cc, which was normal for sand. A portion of the bailer sample was immersed in acid. Only 1.4 % by weight of the sample was dissolved by the acid. The dissolved material contained, by weight, 1.2% iron, 0.14% calcium, and 1.03% magnesium. No carbonate was detected.

The particle-size distribution and composition of the May 18, 1989, sample is presented in Exhibit 6.3-2. There is more clay than in the March 30, 1988 sample. Coulter Counter analysis revealed that two-thirds by weight of the pan fraction were particles between 13 and 40 microns in diameter (larger than the pore throats in the disposal sand) and only 6% had a grain size less than 6 microns. In contrast, X-ray diffraction indicated that 10% of the total sample was clay.

7.0. SCALE CONTROL

Long-term production from geopressed-geothermal aquifers is not practicable unless a low-cost, effective scale-prevention program is in place. As a rule, calcium carbonate (calcite) scale is

Exhibit 6.3-2. COMPOSITION OF SOLIDS FROM
THE SWD WELL, 6348-FOOT DEPTH

Particle-Size Distribution		Composition by X-ray Diffraction	
<u>Mesh</u>	<u>wt %</u>	<u>Mineral</u>	<u>wt %</u>
20	5.39	Calcite	0
40	4.28	Albite	4
60	2.06	Microcline	9
80	3.80	Quartz	72
120	37.90	Kaolinite	3.3
170	26.90	Illite/Smectite	6.7
230	4.44	Pyrite	2
270	1.74	Fluorite	3
325	1.27		
Pan	12.20		

Solid density = 2.66 g/cc

the major problem. Sulfate scales have not been observed in large quantities. Major inroads with respect to scale prevention were made during the Gladys McCall test, and these new scale-prevention techniques were implemented at Pleasant Bayou at the onset of production in 1988. These include scale-inhibitor pills injected into the producing formation, supplemental scale inhibitor injected at the surface, and routine scale-detection protocols. Production of well over 12.5 million barrels of brine has taken place without scale-related problems.

During Phase I and Phase II testing in the early 1980s, scale deposition resulted in shut-ins of the flow test. The need for scale control after the choke was recognized early in the flow test, but the operator had difficulty implementing a system that would work. The Phase I testing, in October 1982, resulted in scale deposition on the choke plates and subsequently resulted in the well being shut-in. The Phase II test in 1983 ended when the tubing in the production well parted due in part to the weight of attached scale. The scale was almost 1/2 inch thick at the top of the tubing and was continuous to below 12,000 feet. Additional testing in 1988 had to be preceded by removal and replacement of the tubing.

Calcite deposition on the walls of piping increases pressure losses due to friction, thereby causing more carbon dioxide to flash from the brine and still more calcite to form. This effect can be large. Pressure drop due to friction is inversely proportional to the interior diameter of the tubing to the fifth power. For a given flow rate, a 13% reduction in the interior diameter will result in doubling the pressure drop due to friction. Much of the wellhead pressure data from the testing in the early 1980s was compromised by the unknown and changing pressure drop due to friction caused by scale and debris in the well and wellhead.

The Pleasant Bayou production facilities were modified during July and August 1989 to accommodate the addition of the Hybrid Power System (HPS) to the producing system. A primary goal of IGT was to provide a steady flow of geothermal brine at a rate of 10,000 STB/d at about 520 psia to the HPS built and operated by the Ben Holt Company. There were initial concerns about scale formation and corrosion of piping within the HPS due to the chemistry of the geothermal brine. According to the Ben Holt Company Final Report, "Historically, there have been several concerns about operation on a geopressured well. Excessive scaling may have rendered heat exchangers ineffective; corrosion may have required the use of expensive, exotic materials and impure wellhead gas may 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...Scale and corrosion inhibitors were effective throughout the range of brine temperatures. Corrosion was minimal in carbon steel piping and heat exchanger tubes."² Indeed, scaling and corrosion problems associated with carbon steel piping were not a problem in the operation of the HPS.

Section 7.1 presents the causes of scale formation and methods used for scale detection. Sections 7.2 and 7.3 present the results of the two pills injected into the formation in 1988 and 1989. Section 7.4 covers the scale inhibitors evaluated for supplemental surface injection.

7.1. Cause of Scale Deposition

The reservoir material contains a small amount of calcite cement. As a result, the brine in the reservoir is saturated with calcium carbonate. The absolute amounts of calcium, carbonate, and bicarbonate ions vary with temperature, pH, and other constituents in the brine, but the brine is still saturated with calcium carbonate. The Pleasant Bayou brine, at equilibrium with calcite in the reservoir, has very little carbonate, a small quantity of bicarbonate and carbon dioxide, and a large excess of calcium. The scale-forming reactions are represented by the following equations:

The driving force behind calcite formation is pressure reduction during production. As the brine flows up the well, the hydrostatic pressure exerted by the water column above is reduced. After the pressure falls below the bubble-point pressure, gas is exsolved and a separate gas phase forms. As carbon dioxide leaves the solution the equilibrium between carbon dioxide, bicarbonate, and carbonate ions shifts. To compensate for the lost carbon dioxide, two bicarbonate ions can become a carbonate ion and a carbon dioxide molecule. Removing carbon dioxide from the brine drives the equilibrium to the right in the equations above. The generated carbonate ion upsets the equilibrium between calcium and carbonate ions, resulting in a tendency to form calcite scale.

Sulfate scales, on the other hand, have not been much of a problem during the tests of these wells. Sulfate scales form as a result of temperature reduction during production, rather than as a result of gas exsolution, as is the case for carbonate scales. Because the temperature reduction of the brine from the producing formation to the disposal wellhead is only about 10°F during normal high-volume production, there is little driving force to deposit sulfate scales. Sulfate scale deposition may become problematical when heat is extracted from the brine, such as when the HPS was operational. In any case, the same inhibitors that we use for calcite scale inhibition work for sulfate scale inhibition, although more inhibitor is often needed for sulfate scale inhibition.

7.2. Calculation of Scaling Tendency at Different Points in the Production Stream

There is a tendency for brine to precipitate scale after carbonate in excess of the calcium carbonate equilibrium becomes available. The degree of supersaturation can be estimated from any of the several thermodynamic equilibrium correlations that have been published. We have had excellent agreements between field data and the calculated scaling tendency using Oddo and Tomson's Saturation Index.¹³ The 1985 version of the equation is --

$$SI = \log[(Ca)(Alk^2)/P * X_{CO_2}] + 5.89 + (T * 1.549 * 10^{-2}) - (T^2 * 4.26 * 10^{-6}) \\ - (P * 7.44 * 10^{-5}) + (0.92 * IS) - (2.526 * IS^{-0.5})$$

where --

Ca = (mg Ca/L)/40,000
 Alk = (mg HCO₃/L)/61,000
 X_{CO₂} = fraction of carbon dioxide in the gas phase
 IS = (mg TDS/L)/58,500
 P = pressure, psia
 T = Temperature, °F.

The brine at the bottom of the well, just as it enters the wellbore, should be very close to being in equilibrium with the calcite in the reservoir. Tomson suggested a method to eliminate systematic errors, such as acetate accounting for some of the alkalinity, would be to calculate a ΔSI. This value is calculated by applying an additive factor to the calculated SI at the bottom of the well to set that value to 0.0. The same factor is applied to the other SI values calculated for other points in the system, and the resulting value is called the ΔSI. The SI and ΔSI values for the bottom of the well, the wellhead before the choke, the separators, and the disposal wellhead were calculated using the following typical values for input:

Ca = 7900/40,000 = 0.1975
 Alk = 378/61,000 = 0.0062
 IS = 120,000/58,500 = 2.05
 X_{CO₂} = 0.1 at the bottom of the well, the wellhead, and the separators
 0.133 at the disposal wellhead

For the four locations, approximate values for the temperature and pressure, plus calculated values for SI and ΔSI are shown in Exhibit 7.2-1.

Exhibit 7.2-1. SUMMARY OF SATURATION INDEX VALUES

<u>Location</u>	<u>Temp. °F</u>	<u>Pressure. psia</u>	<u>Sat. Index</u>	<u>ΔSI</u>
Perforations	296	9000	-.4	0.0
Prod. Wellhead	290	2000	0.7	1.1
Separators	292	800	1.2	1.6
Disp. Wellhead	291	400	1.4	1.8

This Saturation Index is an equilibrium calculation, where an SI of 0 means the fluid is at equilibrium. ΔSI values above 1 generally result in scale deposition in the absence of inhibitors. It can be seen from the calculated results above that scale will form in all areas from the wellhead to the disposal well in the absence of inhibitors. ΔSI values above 2.4 will generally result in scale deposition whether or not scale inhibitors are present. This value is not reached at Pleasant Bayou unless the brine is exposed to atmospheric pressure.

7.3. Scale Detection Methods Utilized at Pleasant Bayou

Formation of scale from this brine results from the consumption of one calcium atom and two bicarbonate molecules to form one molecule of scale, one molecule of water, and one molecule of carbon dioxide. The produced fluids contain huge excesses of calcium, carbon dioxide, and water. Scale detection via analyzing for these constituents is therefore not a viable procedure. The two compounds that are not present in great concentrations are the calcite scale itself and the bicarbonate ion. Examination of the surface facilities for changes in these two components are therefore used to detect the onset of scale formation.

Bicarbonate Ion -- The primary source of alkalinity in this brine is from the bicarbonate ion. The produced brine contains roughly 310 mg/L of alkalinity as calcium carbonate. Production of a scale will cause this concentration to decrease. During the Phase I and Phase II testing of this well, decreases of as much as 50 mg/L of alkalinity as bicarbonate were reported during periods where it was later found that scale was forming. Unfortunately, soon after the problem was recognized, the production well was shut in and the tubing parted.

The current practice is to collect samples of brine at the production and disposal wellheads. The samples are analyzed for alkalinity by titration with sulfuric acid, with a pH meter used to detect the point of inflection of the titration curve. This provides a fairly accurate value for alkalinity. Surprisingly, with the corrosion inhibitor, the alkalinity at the disposal well tends to be higher than the alkalinity at the production well. The addition of the quaternary ammonium

corrosion inhibitor caused a degradation of accuracy, but the accuracy is still within ± 10 mg/L. At a brine rate of 20,000 barrels per day, the deposition of 70 pounds of scale per day would result in a change of 10 mg/L alkalinity as calcium carbonate.

This illustrates the problem of monitoring scale deposition by monitoring alkalinity. Small but significant quantities of scale can be forming without a significant change in the alkalinity. The alkalinity values are presented in Exhibit 7.3-1. The point where alkalinity values in brine collected at the disposal wellhead started varying by more than 3 mg/L from the alkalinity values in brine collected at the production wellhead corresponds to the start of injection of corrosion inhibitor. These data suggest scale deposition was not occurring in the surface facilities or the wellbore.

Exhibit 7.3-1. ALKALINITY VALUES AT PRODUCTION AND DISPOSAL WELLHEADS

Another method that can be used to detect the onset of scaling is by a change in pH. Making accurate and repeatable pH measurements on the hot, degassing brine is difficult. The pH of this brine is approximately 5.6. At a brine rate of 20,000 barrels per day, the deposition of 35 pounds of scale per day would change the pH by less than 0.03 pH units. This change in the pH is less than can be reliably measured. This procedure was not used at Pleasant Bayou.

Calcite -- It would be very difficult and expensive to examine most of the wellbore and surface facilities for scale deposits. The easiest ways to look for calcite were to examine the interior of the filter pots when filters were changed and to look for the effects of calcite deposits on

other operational parameters. The methods used include both monitoring the pressure drop across sections of pipe for increased friction loss and monitoring the brine turbines for evidence of scale deposition.

Without supplemental inhibitor injection at the wellhead, scale should first form after the separators, where the pressure on the brine is lowest. There was evidence by January 1989, that the first inhibitor pill had become only marginally effective at preventing scale deposition at separator conditions. The first evidence was that small quantities of dilute acid were effective at reducing the disposal well injection pressure. The 10 barrels of 28% HCl injected into the disposal well on February 17, 1989, were responsible for the reduction in the average daily disposal well tubing pressure from 619 psia on February 15 to 501 psia on February 22, 1989.

More surprising was the fact that the injection pressure would temporarily decline by tens of psi after treatment with a few gallons of acid or even after a rainstorm. The effect of rainstorms is to temporarily cool the brine. Cooling the injected brine increases the solubility of calcite, redissolving the calcite deposits. For such a large effect with small temperature changes or acid treatments, the calcite crystals would need to have a very high surface area-to-volume ratio. This suggests the calcite precipitation in the brine is small particles or even a web-like structure rather than growth of crystals adhering to pipe walls.

The second indication that the concentration of inhibitor pill returns was becoming ineffective at separator pressure was that the turbine bearings were seizing with scale. The brine turbines turn on shafts that are lubricated with the working fluid, in this case brine. The friction of the shaft generates a small quantity of heat, which is subsequently dissipated in the brine stream. Brine flow through the bearings is somewhat restricted. Scale solubility is strongly dependent on temperature, with lower solubility at higher temperature. It is believed that the small quantity of excess heat raised the brine temperature a small amount, thereby lowering the calcite solubility enough that scale deposition began. After scale deposition began, the extra friction caused by the calcite resulted in even more heat generation and more calcite formation. In short order, the turbines would be outputting erratic values that could be low by as much as 10%.

Scale accumulation in the large separator meter turbine was discovered on January 12, 1989. The 4-inch turbine meter output became erratic. The turbine meter was found to have scale on the thrust bearings at both ends of the propeller shaft. The 3-inch brine turbine on the small separator began erratically reading lower by up to a few percent on February 11, 1989, and then stopped completely on February 15, 1989. The next day, it was removed from service and was also found to have scale in the thrust bearing. The amount of scale was estimated to be considerably less than 1 gram. The scale was dissolved in hydrochloric acid, and the turbine was put back in service. The 3-inch brine turbine on the small separator stopped again on February 26, 1989, and was

repaired the next day. It was found to have a scale-like white solid in the thrust bearing and was repaired by dissolving the deposit in hydrochloric acid. On March 14, 1989, scale-inhibitor injection was begun between separator chokes and the main choke with Champion's T-132 to resolve this problem.

Scale accumulations were observed after the second inhibitor pill returns fell below 0.2 ppm, although not to the degree that turbine meter accuracy was impaired. During May 14, 1990, the small separator brine was switched from the 3-inch turbine to the 2-inch turbine, and the 3-inch turbine was removed for inspection. A small amount of scale was found in the bearing recess, and all wetted parts of the turbine had a heavy coating of corrosion inhibitor. The turbine was cleaned and put back into service. Brine rates from the 2-inch turbine and 3-inch turbine both before and after cleaning were the same to within 0.3%.

Another mechanism used for detecting scale deposition was observing the pressure drop across a long section of pipe. The 2000 feet between the HPS takeoff point and the disposal wellhead was chosen. Friction drop for this pipe run varies with the second power of flow rate and with the fifth power of diameter. A 2% decrease in diameter, at a given flow rate, would result in a 10% increase in the pressure drop. Examination of the data showed little or no increase in friction over this section of pipe, suggesting significant scale deposition was not occurring.

The coupons and filters were also carefully monitored for evidence of scale formation. These checks were found to be less sensitive than other methods. The sensitivity of most of these monitors was impaired by the eventual injection of a corrosion inhibitor injected before the primary choke. It turned out that the brine turbines and the plugging of the disposal well by small quantities of easily dissolved calcite were the earliest reliable indicators of scale formation in the surface facilities.

7.4. Supplemental Surface Injection

The primary mechanism for controlling scale deposition at Pleasant Bayou is with inhibitor pills. These pills are expensive and are somewhat difficult to inject, however, and one objective of the flow test was to determine the potential life of the inhibitor pills. The minimum amount of inhibitor needed to protect the production well from scale deposition will be insufficient to protect the surface facilities because the carbonate concentration continues to increase as pressure is lowered. As the inhibitor residuals from the inhibitor pills fell below 0.1 mg/L and evidence of scale formation was noted, supplemental inhibitor injection at the wellhead was added to prevent scale formation in the surface facilities.

The quantity of inhibitor needed for effective scale inhibition is largely dependent on the quantity of the least available component in the brine, either calcium or carbonate. For brine in equilibrium with calcite in the formation, the calcium and carbonate values are related through the solubility product constant as shown below.

$$K_{sp} = (Ca^{+2}) \times (CO_3^{-2})$$

The Pleasant Bayou brine contains a large quantity, about 8000 mg/L, of calcium in solution. It therefore contains very little, less than 1 mg/L, of carbonate. The inhibitor concentration needed to prevent scale deposition should therefore be relatively low.

7.4.1. Laboratory Tests to Determine Minimum Effective Inhibitor Concentration

A laboratory test was devised at Rice University to test various inhibitors under more controlled conditions than is possible in the field. Several inhibitors were tested in a brine with a composition similar to Pleasant Bayou brine. The approximate compositions of both the synthetic brine and the Pleasant Bayou brine are in Exhibit 7.4.1-1.

Exhibit 7.4.1-1. COMPOSITIONS OF SYNTHETIC AND PLEASANT BAYOU BRINES

	<u>Pleasant Bayou Brine</u>	<u>Synthetic Brine</u>
CaCl ₂	0.20 Molar	0.25 Molar
NaCl	1.6 Molar	2.0 Molar
HCO ₃ ⁻	0.006 Molar	0.00125 Molar
Ionic Strength	2.3 Molar	2.5 Molar
pH	5.5 (estimated)	7.0
CO ₃ =(calculated)	1.8 X 10 ⁻⁷	0.4 X 10 ⁻⁷

The concentration of bicarbonate and the pH interact and result in similar concentrations of carbonate ions (CO₃⁼) between the two brines. This synthetic brine, with a pH of 7, was easier to prepare and use in the laboratory than actual Pleasant Bayou brine. The scaling tendencies of the two brines, as calculated using the Saturation Index, are similar. Tomson *et al.*²⁰ used this laboratory apparatus to find the lowest inhibitor concentrations where calcium carbonate scale deposition was inhibited. The minimum concentrations of a few inhibitors tested are reproduced in Exhibit 7.4.1-2.

These minimum effective concentrations were used as guidelines both for inhibitor selection and for determining the amount of inhibitor injected at the surface. As a general rule, the amount of inhibitor for supplemental surface injection was set at twice the minimum effective concentration. The amount of inhibitor injected, and therefore to a first approximation the cost, therefore depends on the inhibitor chosen. The other factors that must be considered when

Exhibit 7.4.1-2. MINIMUM EFFECTIVE CONCENTRATION OF
VARIOUS INHIBITORS

<u>Generic Chemical Name</u>	<u>Brand Name</u>	<u>ppm^c</u>
Aminotri(methylenephosphonic acid)	Dequest 2000	0.10
also known as ATMP ^a	Aqua Process AMP-20	0.15
Anionic Polyacrylate ^a	ARCO Chemical	0.35
	Aqua Process P-42	0.60
	Champion Gypton T96	0.45
	CIBA-GEIGY Belclene 260	0.60
1-Hydroxyethylidene, 1,1 Diphosphonic Acid, also known as HEDP	Dequest 2010	0.20
Citric Acid	-	20
Polymaleic Anhydride ^{a,b}	CIBA-GEIGY Belclene 200	0.14

^a This inhibitor was tested at Pleasant Bayou between 1988 and 1990.

^b This value was obtained from Matty *et al.*¹³

^c ppm = parts per million by weight. This is equivalent to mg/L divided by the brine density in g/cc.

selecting an inhibitor are the corrosiveness of the inhibitor and the compatibility of the inhibitor with the produced brine (formation of pseudoscale).

Three scale inhibitors have been tested for supplemental surface injection at Pleasant Bayou. A phosphonate scale inhibitor was used for both an inhibitor pill and for supplemental surface inhibitor injection. A polymaleic anhydride scale inhibitor and a polyacrylate scale inhibitor were tested for supplemental surface injection only. These three inhibitors are discussed in subsections below.

7.4.2. Aminotri(methylenephosphonic acid), or ATMP

The inhibitor ATMP is phosphonate-based. Laboratory tests suggest that concentrations as low as 0.1 mg/L can effectively prevent scale in a brine similar to that produced at Pleasant Bayou. This inhibitor was used for both scale-inhibitor pills injected at Pleasant Bayou, and traces of this inhibitor have therefore been present in almost all brine produced between 1988 and 1990.

The Phase II testing in 1983 included field testing by Rice University personnel on scale inhibition. The testing included lowering the concentration of ATMP while monitoring the alkalinity of the system at several points after the choke. Testing was compromised to some degree by scaling before the choke upstream of the scale-inhibitor injection point and in the production well. Concentrations tested ranged from 8 to 0.5 ppm. Pseudoscale, a calcium-iron-inhibitor deposit, was observed after inhibitor injection of 1 ppm. This suggested the amount of inhibitor

injected at that time, 1 ppm, was too high. The lowest concentration tested was 0.5 ppm ATMP, and this concentration was apparently controlling scale in the surface facilities.²⁰

This same inhibitor was then used for both unsuccessful and successful inhibitor pills injected at the DOE Gladys McCall geopressured-geothermal well. It was also used as the supplemental surface inhibitor injected at Gladys McCall. This inhibitor has also been used in several Gas Research Institute-sponsored field tests where large volumes of brine were produced, notably the N.E. Hitchcock Field and the Port Arthur Code 1-6 well co-production projects. These tests showed the inhibitor to be very effective in preventing scale deposition at low concentrations, although some pseudoscale was observed on almost all tests. Pseudoscale did in fact plug the end of the injector nozzles at Pleasant Bayou. The ATMP inhibitor has been tested on numerous wells, both for inhibitor pills and for continuous injection, and results have generally been successful once proper concentrations were achieved.

The work at Pleasant Bayou has supported the laboratory minimum concentration level for ATMP of 0.1 mg/L for prevention of scale in the surface facilities. Trouble-free operation of surface facilities was observed with inhibitor concentrations of 0.05 mg/L or below, although there is evidence of scale accumulation in portions of the surface facilities over a period of weeks to months. Very low ATMP concentrations, averaging 0.02 mg/L have been shown to be effective at preventing scale deposition in the production well but not effective once the brine passes through the choke. The ATMP inhibitor was chosen for the inhibitor pills injected at Pleasant Bayou. The reasons for this selection were the effectiveness of this inhibitor at very low concentrations, the reported thermal stability of this inhibitor at reservoir temperatures, and most importantly the success of the Gladys McCall inhibitor pills using this same chemical. The ATMP is slowly leached from the reservoir by the brine flux, providing long-lived and automatic scale protection in the producing wellbore.

The ATMP was the first inhibitor chosen for supplemental surface injection, simply because of availability. Excess inhibitor from the inhibitor pills was used for supplemental inhibitor injection after evidence showed that scale deposition in the surface facilities was occurring. This inhibitor had three drawbacks, however, that led to a search for an alternate inhibitor for surface injection. These drawbacks are accelerated corrosion, pseudoscale deposition, and the difficulty in assessing inhibitor pill performance while injecting the same inhibitor near the wellhead.

The primary drawback was that concentrated solutions of ATMP are extremely corrosive to 4130-grade steel. This steel is a common constituent of wellhead and high-pressure piping components, including the high-pressure flow loop from the top of the wellhead to ground level at Pleasant Bayou. The supplemental scale-inhibitor injection point is located in the high-pressure

flow loop just after the wellhead. Precautions were taken to keep concentrated inhibitor away from the 4130-steel pipe walls. These included 1) injecting through a 316 stainless steel tube to the center of the pipe, 2) turning off the inhibitor pumps minutes before shutting in the well, and 3) using a dilute mixture of the inhibitor.

The results of laboratory corrosion tests are shown in Exhibit 7.4.2-1. Corrosion rates of 11,000 mils per year (almost 1 inch per month) were documented in the lab tests. The ATMP inhibitor used at Pleasant Bayou was also used at N.E. Hitchcock, a gas and brine co-production project 20 miles from Pleasant Bayou. At N.E. Hitchcock, extended (between 2 and 4 months) contact of neutralized 10% by weight ATMP solution resulted in holes 1 inch in diameter through portions of the wellhead made from 4130 steel. The ATMP seems to have no measurable effect on corrosiveness of brine once it is diluted to 1 ppm. However, the possibility of the scale-inhibitor pump not being shut down in a timely manner during an unplanned shut-in, with associated accelerated corrosion of portions of the high-pressure piping, was a concern.

Exhibit 7.4.2-1. CORROSION RATES OF 4130-GRADE STEEL IN CONCENTRATED SCALE INHIBITORS

Type	Concentration, % by weight	Time of Test, Hours	Temperature, °F	Corrosion Rate, mils/year
ATMP	32	4.5	190	11,000
ATMP/Polyacrylate	12/5	4.5	190	490
Polyacrylate	20	4.5	190	2
Tap Water	--	4.5	190	31

The second problem with ATMP was its demonstrated ability to form pseudoscale, a calcium-iron-inhibitor salt, at concentrations as low as 1 ppm. Pseudoscale was observed at Pleasant Bayou in 1983, at Gladys McCall, and at the GRI Port Arthur Code 1-6 Well test. Pseudoscale is a calcium-iron-inhibitor salt that precipitates in the production piping as a consequence of too high an inhibitor concentration. The concentration of inhibitor that resulted in pseudoscale deposition at Pleasant Bayou was shown to be 1 ppm. The combination of surface-injected inhibitor and inhibitor from the pill was expected to be 1/4 ppm. This does not mean that pseudoscale could not form.

The inhibitor used for surface injection varied in concentration from about 100,000 to about 500,000 ppm. It could easily be envisioned that over a range of the mixing zone, conditions would be favorable for pseudoscale deposition. The injection port was designed to put the inhibitor into the middle of the flowing brine stream, so that crystals that may form would not readily attach themselves to pipe walls. The injection port was made of 316 stainless steel to prevent corrosion.

A small quantity of pseudoscale formed in the injection tube. Inhibitor injection occurs in a series of pulses from a positive-displacement pump, rather than in a continuous stream. During the lag time, brine and inhibitor near the end of the injection tube mix, and conditions are favorable for pseudoscale production. The injection tubes plugged off in November 1989. The material was scraped out of the tube; however, this involved shutting in the well. Analysis of the material at Nutro Inc. showed there was only a trace of iron, and the deposits were predominately calcium phosphonate.

The third problem with use of ATMP, or any other phosphonate- or phosphate-based inhibitor, for supplemental surface injection was that the analytical techniques used to measure the amount of phosphonate in the brine could not distinguish between returns from the inhibitor pill and the supplemental inhibitor injection. Surface scale inhibitor is injected at a point upstream of the primary choke. Brine samples are collected from a point after the choke. The laboratory techniques used to measure the extremely low phosphonate concentration in the brine are complex and tedious, and at very low levels (less than 0.05 mg/L) the laboratory error can be 50% of the measured value. There was no way to measure the concentration of ATMP being bled back from the inhibitor pills when ATMP was being injected at the surface at concentrations near 0.2 mg/L.

To get around these problems, alternate scale inhibitors that contained no phosphorus were required. Based on the results of laboratory corrosion tests and the Rice University list of minimum effective concentrations, polyacrylate scale inhibitor was the first choice for supplemental scale-inhibitor injection.

7.4.3. Polyacrylate Scale Inhibitor

Polyacrylate inhibitor was chosen 1) to minimize the possibility of phosphonate pseudoscale formation due to mixing with returns from the phosphonate inhibitor pill, 2) because the polyacrylate inhibitor is much less corrosive to 4130-grade steel than phosphonate inhibitor, and 3) the absence of phosphorus in the formulation allows accurate monitoring of inhibitor pill performance. The minimum effective concentrations of polyacrylate inhibitors, from Exhibit 7.4.1-2, was 0.4 to 0.7 ppm, depending on the brand tested.

Surface injection of a polyacrylate scale inhibitor, Nutro SI-56, was started the evening of May 8, 1989. It contained about 157 grams of partially neutralized polyacrylate-type inhibitor per liter of delivered SI-56 solution. After overnight injection of a mixture of phosphonate and polyacrylate inhibitors, injection of straight undiluted SI-56 began May 9, 1989. A total of 9 quarts of SI-56 were injected into the brine by midday May 10, providing 4.4 ppmv of undiluted SI-56 in the brine or 0.7 ppm of active inhibitor. The differential pressure across the filter skid increased from 1.5 to 3.0 psia, indicating loading of the 10-micron filter elements. The amount of

SI-56 injected was reduced from 9 quarts per day to 3 quarts per day on May 10, lowering the SI-56 concentration to 1.5 ppmv, or 0.23 ppm of active inhibitor. The pressure across the filter skid continued to climb, reaching 9.5 psia by the evening of May 13. The 9.5 psia included loading of a pot of new 50-micron filters that was put on-line during May 11.

The material plugging the 10-micron filters was found to be a calcium polyacrylate pseudoscale. This pseudoscale formed despite injecting less than the minimum effective concentration. With precipitation at this low concentration, and with the reported minimum effective concentration of 0.4 to 0.7 ppm, it was doubtful whether effective scale inhibiting in Pleasant Bayou brine is practicable with polyacrylate-type inhibitors.

Use of the polyacrylate-based scale inhibitor was stopped shortly thereafter, and the inhibitor type was switched back to ATMP while searching for a suitable substitute.

7.4.4. Polymaleic Anhydride Scale Inhibitor

The next inhibitor chosen was polymaleic anhydride. The minimum concentration, deduced from the Rice University work, was 0.14 mg/L. Nutro Inc., a chemical company that supplied the surface-injected phosphonate and polyacrylate inhibitors, ran filter and corrosion tests on Belcene 200, a brand of polymaleic anhydride scale inhibitor. The results of the filtration tests are presented in Exhibit 7.4.4-1. These tests involved mixing 100 ppmv of inhibitor concentrates with Pleasant Bayou brine, and then filtering the sample through 0.45 and 1.2 μ paper filters. Solids that had precipitated in the Pleasant Bayou brine were not removed prior to the test. The time required to filter 100 ml of solution and the quantity of solids remaining on the filter are reported. The results of the filter tests, performed in Pleasant Bayou brine, indicate that polymaleic anhydride forms no precipitate up to 20 ppm by weight of active inhibitor. This is two orders of magnitude more inhibitor than would be injected into the brine and suggests pseudoscale deposition will not be a problem even in the injection tubes.

IGT provided Nutro with the 4130-grade steel coupons to be used in corrosion evaluations. The coupons were immersed in concentrated, neutralized inhibitor at 150°F for 24 hours. The data are presented in Exhibit 7.4.4-2. The corrosion rate for concentrated ATMP, 7000 mils per year, is close to the 11,000 mils per year for a 4.5-hour test at 200°F reported for this same inhibitor by Nutro in 1988. The concentrated polymaleic anhydride, Belcene 200, had a corrosion rate two orders of magnitude lower.

Another advantage of Belcene 200 is that it contains no phosphate. Polymaleic anhydride molecules contain only carbon, oxygen, and hydrogen atoms and have an average molecular weight of 500. This allowed resumption of the monitoring of inhibitor pill returns that was not possible when ATMP was being injected. The inhibitor pill contained Dequest 2000, and because

Exhibit 7.4.4-1. FILTER TESTS, SCALE INHIBITORS IN PLEASANT BAYOU BRINE

<u>Inhibitor Type</u>	<u>Concentration, mg/L</u>	<u>pH</u>	<u>Filter size, μ</u>	<u>Filter Time, s</u>	<u>Residue, mg/L</u>
Brine	--	5.5	0.45	30	40
Brine	--	5.5	1.2	--	26
Terpolymer	20	1.1	0.45	60	42
Terpolymer	20	1.1	1.2	--	27
Polymaleic	22	1.8	0.45	30	41
Polymaleic	22	1.8	1.2	--	15
Polyacrylate	16	5.5	0.45	47	41
Polyacrylate	16	5.5	1.2	--	32
Brine	--	5.5	0.45	29	37
Brine	--	5.5	1.2	7.5	29
ATMP	12	5.5	0.45	28	36
ATMP	12	5.5	1.2	10	29
Polymaleic	22	5.5	0.45	33	34
Polymaleic	22	5.5	1.2	7	22
Terpolymer	20	5.5	0.45	>300	>10000

Exhibit 7.4.4-2. CORROSION TESTS, 4130-GRADE STEEL IN SCALE INHIBITORS

<u>Product</u>	<u>Product Description</u>	<u>Corrosion Rate</u>
Water	--	0 mils/year
SI-35	Concentrated Neutralized Phosphonate	7000 mils/year
Belcene 200	Concentrated Neutralized Polymaleic Anhydride	50 mils/year

the surface inhibitor-injection point is upstream of the sample collection point, it had not been possible to measure inhibitor pill returns for several months.

These tests indicated that polymaleic anhydride was more compatible with the produced brine than the other inhibitors tested. This inhibitor also showed little tendency to accelerate corrosion. This inhibitor is effective at low concentrations, although it requires roughly 1-1/2 times as much chemical as Dequest 2000. Finally, this inhibitor contains no phosphorus. The only disadvantage of polymaleic anhydride is that there is no reliable laboratory procedure to measure the inhibitor concentration in the brine at the low concentrations injected. Belcene 200 was chosen as the long-term supplemental scale inhibitor. Use of the polymaleic anhydride inhibitor, was started in mid-September 1989.

7.4.5. Summary of Supplemental Surface-Injected Scale Inhibitor

Supplemental inhibitor injection commenced in March 1989. Surface injection of supplemental scale inhibitor, upstream of the choke, was started after production of 4.95 million barrels

of brine after the first inhibitor pill. Field experience after this first pill suggested that minor scale deposition occurred in the surface facilities and disposal well when the inhibitor concentration fell below 0.05 mg/L. These deposits were easily cleaned out with small quantities of acid, and further deposition was effectively inhibited by the surface injection.

The two questions regarding surface inhibitor injection were 1) "what inhibitor should be used?" and 2) "what minimum concentration is effective?" Reasoning behind the selection of inhibitor was presented in previous sections. The quantity of supplemental scale inhibitor injected has generally been either the minimum effective concentration or twice the minimum effective concentration, as reported by Rice University.

The inhibitor first chosen was Champion Technologies Inc. T-132 that was left over from the inhibitor pill in April 1988. The purpose behind this choice was to utilize available stock, thereby minimizing waste. The liquid in the drum had been diluted a little by rain and was further diluted with two equal volumes of water prior to injection. The pump was set for an injection rate of 3 quarts per day. This gave a concentration of undiluted T-132 in the brine of about 0.2 to 0.3 ppmv. This was continued until the supply was exhausted.

Surface injection of a polyacrylate scale inhibitor, Nutro SI-56, was started the evening of May 8, 1989. The inhibitor contained about 157 grams of partially neutralized polyacrylate-type inhibitor per liter of delivered solution. As discussed in Section 7.4.3, accelerated loading of 10-micron filter elements was found to be due to calcium polyacrylate pseudoscale. Injection was stopped.

As a result of short lead-time availability, the injected scale inhibitor was changed to Nutro SGR-12, a ~12% mixture of ATMP, the evening of May 13, 1989. The solution actually delivered contained 110,000 mg of ATMP per liter of delivered SGR-12. On location, each volume of SGR-12 was further diluted with three volumes of water so the concentration of phosphonate in the pumped solution is 27,500 mg/L. The initial selected pump rate of 2 gallons per day would provide an SGR-12 concentration in the brine of 1.0 ppmv and a phosphonate concentration of 0.11 mg of ATMP per liter of brine. This quantity was eventually raised so that 0.2 mg of ATMP per liter of brine was maintained.

A second inhibitor pill was injected into the producing formation in November 1989. Supplemental scale-inhibitor injection was suspended because the high inhibitor returns from the second pill were sufficient to protect both the producing well and the surface facilities. Surface injection of scale inhibitor was resumed on May 16, 1990, after production of 2.75 million barrels of brine since the last pill. The supplemental injection program was initiated despite the fact that

there was no evidence of scale deposition. This cautious policy was to ensure that scale deposition would in no way affect the test of the HPS. Even a slight buildup of scale in the heat exchangers would seriously degrade their performance.

The inhibitor chosen for supplemental surface injection was a polymaleic anhydride provided by Nutro Inc. The minimum effective concentration for polymaleic anhydride (Belclene 200) reported by Rice University from laboratory studies is between 0.10 and 0.14 mg polymaleic anhydride per liter of brine. In practice, the inhibitor was injected at a concentration of 0.21 mg/L. No scale-related problems were reported for the remainder of the test. The final report on the HPS stated there was no evidence of scale buildup. In addition, the polymaleic acid does not promote corrosion in 4130-grade steel and allows continued monitoring of the inhibitor pill performance.

7.5. The Scale-Inhibitor Pills

The Phase I and Phase II flow tests performed in the early 1980s had clearly demonstrated that scale will form both in the producing well and in the surface facilities in the absence of inhibitors. The Gladys McCall test had shown that inhibitor pills could be effective at protecting the production wellbore from scale deposition over production of many millions of barrels of brine. Injecting the first inhibitor pill into the reservoir was an early priority during the resumption of production at Pleasant Bayou during 1988.

Inhibitor pills are solutions of inhibitor that are injected into the producing zone and allowed to react in the formation. Both precipitation of pseudoscale and adsorption of inhibitor on the solid reservoir matrix trap a portion of the inhibitor. After production is resumed, brine flux through the sand containing the trapped inhibitor slowly leaches inhibitor out of the formation. The amount of inhibitor leached out is quite small, but seems to be of sufficient quantity to prevent scale formation in the wellbore during production of millions of barrels of brine. Inhibitor pill technology has been very effective at preventing the scaling problems that plagued the early tests of the Gladys McCall well and the Pleasant Bayou well. The following sections describe the injection and flow-back of the two inhibitor pills injected.

7.5.1. The April 20, 1988, Scale-Inhibitor Pill

Prior production, in the early 1980s, had resulted in scale deposition in the tubing and the eventual failure of that tubing. The tubing was fished from the well and replaced, and surface facilities were made operational during 1987 and 1988. The first inhibitor pill was injected into the Pleasant Bayou well before there was significant production from the well. The primary goal of the inhibitor pill was preventing scale formation in the producing wellbore and wellhead. The inhibitor from the pill was supplemented by surface injection if needed to protect the surface

facilities. The following subsections describe the composition of the pill, the mechanics of injecting the pill, and the effectiveness of the pill in preventing scale.

7.5.1.1. The April 20, 1988, Scale-Inhibitor Pill Composition

On April 20, 1988, the first scale-inhibitor pill was injected into the Pleasant Bayou No. 2 producing formation. The inhibitor chosen was a neutralized form of Dequest 2000, a Monsanto formulation of aminotri(methylenephosphonic), or ATMP. This is the same inhibitor used for the successful Gladys McCall inhibitor pills. The Dequest 2000 had also shown evidence of scale inhibition in surface facilities at concentrations as low as 0.5 mg/L during Pleasant Bayou field tests in 1982 and 1983. The inhibitor pill contained 514 kilograms of ATMP. The pill consisted of 273 gallons of Champion's Gypton T-132, a concentrated, neutral pH, phosphonate-based scale inhibitor, and 10 gallons each of an oxygen scavenger and an iron-sequestering agent. The pill components were mixed with a 5% synthetic sodium chloride brine to obtain 100 barrels total volume. A dye, Fluorescein, was added to the pill as a tracer. There was a 100-barrel preflush and a 500-barrel increment of the 5% synthetic brine behind the pill to isolate the pill from reservoir brine until the inhibitor reached the formation and to allow the pill to be displaced out of the tubing. The oxygen scavenger and the iron-sequestering agents were mixed to achieve equal concentrations in the preflush, pill, and postflush.

Pleasant Bayou brine contains high calcium and iron concentrations that would cause the inhibitor to precipitate before the pill reached the formation. This precipitation had resulted in early failures at injecting pills into the Gladys McCall well. Industrial grades of NaCl brines also contained concentrations of iron and calcium that were too high. A reagent-quality NaCl brine was therefore specified in the bid. The brine was mixed using reagent-quality sodium chloride (Morton's Purex Salt) and distilled-quality water to minimize the divalent cations such as calcium and iron present. The quantity of iron-scavenging reagent mixed with the fluids could only chelate a few ppm of iron or calcium from solution. A 10% solution of sodium chloride would have been closer to the salinity of the Pleasant Bayou brine, but a 5% solution was chosen for economy. The 5% solution would have few deleterious effects on clays in the producing formation. The density difference between a 5% salt solution and a 10% salt solution resulted in injection pressures 200 psi above that which would be seen using a 10% salt solution.

7.5.1.2. The April 20, 1988, Scale-Inhibitor Pill Injection

Prior to injecting the inhibitor pill, the well was cleaned out by producing from the reservoir. There were residual workover fluids left in the well from an attempt to dissolve an aluminum plug that had stuck in the wellbore.

This plug, which was run with the tubing, was initially held in place by shear pins. These pins sheared off when pressure was applied, as designed, but the plug did not fall to the bottom of the well as anticipated. It lodged at a depth of 14,024 feet. Wireline tools could not get past the obstruction. Thirty gallons of caustic were spotted on the plug, but the caustic reacted with the calcium in the brine to form calcium hydroxide before the caustic could react with the aluminum plug. The well was flowed to clean the calcium hydroxide solids from the wellbore so they would not interfere with the inhibitor pill injection. A total of five well volumes (1740 barrels) of brine were produced.

The plan was to consecutively inject a 100-barrel preflush of 5% sodium chloride brine, 100 barrels of 5% sodium chloride brine with 3% active inhibitor, and 500 barrels of 5% sodium chloride brine. Additional produced brine from tanks on location would then be pumped into the well to displace the 500 barrels of 5% brine into the formation. The wellbore volume is 320 barrels. The injection pressure limit was 6000 psi. In practice, the highest pressure reached was a few hundred psi below that figure. The operational guideline was to keep the casing pressure below 1500 psi, although the published pressure rating of the casing was considerably above that conservative value. After the pill was pumped into the formation, the well was to be shut-in for 24 hours. Then flow-back was begun at the reduced rate of 2000 STB/d to facilitate sample collection.

Injection of this inhibitor pill did not follow the plan but nevertheless was a partial success. A plot of the casing and tubing pressures is presented in Exhibit 7.5.1.2-1. The casing had been charged with brine from the tubing to a pressure of about 1050 psi prior to injecting the pill.

Pumping of the pill proceeded smoothly at rates between 4 and 5 barrels per minute until about 300 barrels had been injected, at which time the first of the synthetic brine preflush fluid was near the perforations.

At that time, the tubing pressure suddenly dropped about 150 psi and the casing pressure suddenly increased by about 300 psi. During the 1-1/2 hours following the pressure break, an additional 105 barrels of synthetic brine was injected. This resulted in the majority of the 100 barrel preflush being injected into the formation and the active pill material being displaced down-hole to very near the perforations. Pumping was slowed or stopped multiple times to bleed fluid from the casing to maintain the pressure between 1000 and 1500 psi. The need for bleeding multiple barrels of fluid from the casing suggested the tubing had partially retracted from the polished bore receptacle on the packer. The casing pressure limit was changed to 2500 psi to minimize the amount of the pill that would enter the annulus between the tubing and casing.

Exhibit 7.5.1.2-1. CASING AND TUBING PRESSURE DURING THE APRIL 1988 INHIBITOR PILL

Over the next 3 hours, the active portion of the inhibitor pill was displaced into the formation, with injection rates often below 1 barrel per minute and injection pressures limited to less than 6000 psi. The 100-barrel pill was displaced into the formation over a period of about 2.5 hours of pumping. The casing pressure was not bled off during this period, to minimize the amount of the inhibitor that was presumed to be entering the annulus instead of the formation. About 50 barrels of the postflush brine was displaced into the formation. The remaining synthetic brine was injected into the disposal well.

The difficulty in injecting the inhibitor pill into the formation is presumed to be due to the formation of pseudoscale with calcium and iron available from the fluid initially in the annulus. Injecting ambient-temperature fluid cooled the average wellbore temperature. Pressuring up on the tubing to maintain injection rates while maintaining a low pressure in the annulus caused the tubing to expand laterally (balloon out) a small amount. Both of these actions result in shortening of the tubing in the well. The tubing retracted from a polished bore receptacle in the packer, allowing mixing of the calcium chloride-based fluid from the annulus with the inhibitor pill.

After the well had been shut-in for the planned 24 hours, production at a rate of about 2000 BPD was started at 17:00 on April 21, 1988. This low rate facilitated accurate correlation of sample collection with volume of liquid recovered. The flow rate was subsequently increased in steps to 13,000 BPD. The cleanup flow ended at 19:00 on April 24 after approximately 30,000 barrels of brine were produced.

7.5.1.3. The April 20, 1988, Scale-Inhibitor Pill Cleanup Flow

About 220 kilograms of ATMP was estimated to have flowed back during the subsequent cleanup flow, leaving 290 kilograms of ATMP in the reservoir. Samples were caught by IGT and UURI at appropriately spaced intervals during the inhibitor pill flow-back. A cursory examination of the color intensity of the returning fluid confirmed the injection volumes measured the previous day. There were large quantities of a precipitate, varying from less than 1% to as much as 20% of the sample by volume. Early IGT samples were provided to Champion Technologies, Inc., the service company supplying the chemicals, for analysis. Because the concentration dropped below a few parts per million, the Champion Technologies, Inc., laboratory was not able to accurately measure the returns. At that point samples were shipped to IGT's analytical laboratory where measurements of concentrations less than 0.1 ppm were possible.

Champion attempted to put all the precipitate back into solution to facilitate the analysis. Surprisingly, large quantities of the precipitate would not readily dissolve in an acidic/EDTA solution, necessitating analysis of both solid and liquid phases. The composition of the precipitate that would not go into solution are presented as a fraction of produced volume in Exhibit 7.5.1.3-1.

Exhibit 7.5.1.3-1. QUANTITY AND COMPOSITION OF
SOLIDS IN PILL RETURNS^a

<u>Sample</u>	<u>Cum. Volume, Barrels</u>	<u>Concentration, mg/L</u>	<u>Sample Composition</u>
A	210	187	Insufficient Sample
B	255	144	Insufficient Sample
C	300	154	Insufficient Sample
D	320	197	Fe-phosphonate
E	342	777	Fe-Ca-phosphonate
F	355	1446	Fe-Ca-phosphonate
G	363	2913	Fe-Ca-phosphonate
H	390	5431	Fe-Ca-phosphonate
I	405	4482	Fe-Ca-phosphonate
J	415	4336	Fe-Ca-phosphonate
K	426	4748	Fe-Ca-phosphonate
L	447	4189	Fe-Ca-phosphonate, trace of BaSO ₄
M	490	2017	Insufficient Sample
N	515	1355	Fe-Ca-phosphonate, BaSO ₄
O	553	894	Fe-Ca-phosphonate, BaSO ₄ , SrSO ₄
P	600	428	Fe-Ca-phosphonate
Q	674	289	Insufficient Sample
R	755	290	Insufficient Sample
S	916	280	Fe ₂ O ₃
T	1,078	297	Insufficient Sample
U	1,240	300	Insufficient Sample
V	6,100	315	Insufficient Sample
W	11,730	307	Insufficient Sample
X	23,430	292	Insufficient Sample

^a Compounds listed in order of decreasing concentration. Analysis reports only major compounds (those greater than about 5% of the total).

Samples with small amounts of precipitate had almost no calcium; the bulk of these precipitates were made up of iron phosphonate. Samples with large amounts of precipitate had calcium-iron phosphonate complexes, not simple iron or calcium compounds exclusively. The molar ratio of calcium to iron was 1:1 in these precipitates. After about 700 barrels of flow, the insoluble phosphonate complexes tapered off. The solids then consisted of iron compounds and barite, and sample analyses became suspect due to the small sample quantity.

The results of the phosphonate analyses performed by Champion Technologies, Inc., are presented as a fraction of produced volume in Exhibit 7.5.1.3-2. The phosphonate concentrations include that portion of the phosphonate that was originally contained in precipitates that were put back into solution with acid and EDTA.

Exhibit 7.5.1.3-2. INHIBITOR CONCENTRATION IN PILL RETURNS
DURING CLEANUP FLOW

(Values Reported by Champion Technologies, Inc.)

<u>Date</u>	<u>Time</u>	<u>Cum. Flow, STB</u>	<u>T-132 Concentration, ppm</u>
4/21/88	1930 hours	210	46
4/21/88	2000 hours	255	68
4/21/88	2030 hours	300	102
4/21/88	2045 hours	320	132
4/21/88	2100 hours	342	173
4/21/88	2110 hours	355	1,551
4/21/88	2115 hours	363	2,792
4/21/88	2135 hours	390	5,005
4/21/88	2145 hours	405	6,462
4/21/88	2152 hours	415	17,836
4/21/88	2200 hours	426	10,340
4/21/88	2215 hours	447	16,053
4/21/88	2245 hours	490	3,924
4/21/88	2300 hours	515	1,795
4/21/88	2330 hours	553	685
4/22/88	0005 hours	600	128
4/22/88	0100 hours	674	68
4/22/88	0200 hours	755	43
4/22/88	0400 hours	916	30
4/22/88	0600 hours	1,078	24
4/22/88	0800 hours	1,240	20
4/22/88	2140 hours	6,100	6
4/23/88	0800 hours	11,730	6
4/24/88	0600 hours	23,4304	

The inhibitor pill injected on April 20, 1988, contained 514 kilograms of ATMP. Given the uncertainties in the solids analyses, an estimated 220 kilograms of ATMP flowed back in one form or another during the 30,000-barrel cleanup flow. This left about 294 kilograms of active inhibitor in the reservoir. The solids analyses indicated that about 15 pounds of barite and more than 30 pounds of iron were also produced during the cleanup flow. The source of the iron is presumed to be corrosion of the well tubulars. Iron concentrations in the solids can be estimated, but iron concentrations in the brine, after dissolving much of the precipitate, were not measured.

7.5.1.4. The April 20, 1988, Scale-Inhibitor Pill Long-Term Performance

Monitoring long-term inhibitor pill performance is difficult because the inhibitor returns are an extremely small fraction of the total dissolved solids in the brine. Conventional wet chemical methods, such as those marketed by Hach, are useful in this brine only at inhibitor concentrations above a few mg/L. Tomson and others developed a sensitive yet tedious analytical technique employing butyl alcohol extractions and numerous standard additions to analyze trace levels of

Exhibit 7.5.1.4-1. PHOSPHONATE RETURNS FROM THE
APRIL 1988 INHIBITOR PILL

<u>Date</u>	<u>Cum. Flow, STB</u>	<u>Concn ATMP, mg/L</u>
5/30/88	60,326	0.49
6/14/88	192,221	0.04
7/1/88	508,361	0.43
7/12/88	720,700	0.08
7/21/88	891,270	0.15
8/5/88	1,162,500	0.03
8/18/88	1,405,200	0.08
8/24/88	1,518,300	0.02
9/3/88	1,639,300	0.03
9/17/88	1,749,900	0.02
9/28/88	1,915,500	0.01
11/11/88	2,725,300	0.01
11/29/88	3,059,800	0.06
12/19/88	3,429,000	0.01
1/10/89	3,834,000	0.03
1/20/89	4,009,000	0.03
2/9/89	4,359,700	0.04
2/28/89	4,691,600	0.05
3/20/89	5,039,900	0.09
3/20/89a	5,039,900	0.35
4/4/89	5,383,500	0.13
5/12/89	5,847,600	0.10
6/6/89b	6,047,900	0.30
7/7/89b	6,531,000	0.39

- a This sample was collected at the disposal well and contains inhibitor from both the inhibitor pill and the supplemental surface injection. The weekly average for supplemental surface inhibitor injected for the week of March 16 to 22, 1989, was between 0.16 and 0.21 mg/L.
- b These samples were collected after the supplemental surface inhibitor-injection point was moved upstream of the brine sample collection point. The weekly average for surface inhibitor injected for the week ending June 7, 1989, was 0.21 mg/L. The weekly average for surface inhibitor injected for the week ending July 12, 1989, was 0.25 mg/L.

During a shut-in in May 1989, the surface scale inhibitor-injection point was moved to the flow loop, upstream of the brine sample-collection point. Then, brine samples contained both pill returns and supplemental surface-injected inhibitor. On occasion the supplemental inhibitor injection was turned off for a few minutes to try to collect a sample representative of the brine in the wellbore. The phosphonate concentration in the brine had averaged more than 0.10 mg/L above the weekly average concentration of surface-injected inhibitor. There was no scale buildup in well-head plumbing before the main choke by May 1989, after about 5.8 million barrels of brine had been produced. This was verified by examining the interior of pipes while the well was shut-in.

phosphonate in brine. Because the concentration was lower than 1 mg/L immediately after the cleanup flow, IGT adopted the method provided by Tomson to analyze trace quantities of phosphonate in brine. IGT further increased sensitivity by using a longer optical path for the colorimetric portions of the analysis. At inhibitor concentrations of less than 0.1 milligrams per liter, the analytical accuracy falls to about $\pm 50\%$ or ± 0.01 mg/L, whichever is larger.

The accuracy of the sample-collection, storage, and analytical procedures was tested before the inhibitor pill was injected by analyzing a sample of brine that contained only inhibitor injected at the wellhead. A brine sample was collected on March 8, 1988, during a short flow test performed before injecting the inhibitor pill. A phosphonate inhibitor was being injected at the wellhead at a calculated rate of 0.95 mg/L. A sample collected just after the primary choke was found to contain 0.86 mg/L. The close agreement provided confidence in the analytical accuracy.

The results of the IGT phosphonate analyses are presented in Exhibit 7.5.1.4-1. The data, plus those data from the cleanup flow, are plotted on a log-log scale and a semilog scale in Exhibit 7.5.1.4-2. The log-log scale allows examination of the cleanup flow, while the semilog scale is better for examining long-term behavior of the pill.

The high spike of ATMP, reaching 17,800 mg/L during the early cleanup flow, suggests less than half of the phosphonate was left in the reservoir that for a portion of the pill. The inhibitor pill contained roughly 32,000 mg/L ATMP of fluid. This may have been the result of failing to inject a sufficient quantity of chaser brine to displace the pill fluid away from the wellbore. About 57% of the inhibitor pill is calculated to have remained in the reservoir after the cleanup flow.

Inhibitor concentrations as low as 0.02 mg/L still appear to effectively inhibit scale deposition in the producing well. The primary purpose of the inhibitor pill was to prevent scale in the producing well. The tendency to precipitate calcium carbonate scale increases as the pressure on the brine drops. At the same time, the concentration of inhibitor returns from the inhibitor pill was expected to decline over time. Eventually the inhibitor concentration falls below the effective threshold, and scale develops. The down-hole scale inhibitor was eventually supplemented by injection of additional inhibitor into the flow line before the choke. As the quantity of inhibitor declines to a point where it is only marginally effective, scale should begin to form at the lowest pressure point in the system. The low-pressure point in this system is after the separators. Analyses from August 1988 to December 1988 (1.0 to 3.5 million STB produced), when there was no supplemental surface injection and all inhibitor was being supplied by the pill, averaged 0.03 mg/L ATMP. Between January 1989 and May 1989 (3.8 to 5.8 million STB produced), the pill returns inexplicably climbed to about 0.10 mg/L ATMP. There was supplemental surface injection of inhibitor during this time, but at a point many tens of feet downstream of the brine sampling point.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit 7.5.1.4-2. PHOSPHONATE RETURNS FROM THE APRIL 1988 INHIBITOR PILL

The decision was made to inject a second pill in November 1989 to make sure that scale deposition would not interfere with the Hybrid Power System test. The first pill protected the surface facilities until problems with scaling turbines were noted in January 1989, after production of 4.2 million barrels of brine. The pill protected the wellbore for a total of 7.7 million barrels of brine. A total of about 60 ± 30 kilograms of ATMP was produced during the production of the 7.7 million barrels of brine. This is in addition to the 214 kilograms produced during the cleanup flow. The mass balance suggests there were approximately 230 kilograms of phosphonate remaining in the reservoir when the second inhibitor pill was injected.

7.5.2. The November 19, 1989, Scale-Inhibitor Pill

On November 19, 1989, a second inhibitor pill was injected. The second inhibitor pill was pumped after production of 7.72 million barrels of brine since the initial inhibitor pill. Before injection, about 2 to 4 barrels of brine were produced through the kill line through which the pill was to be pumped. This flushed out a few pounds of black material that looked like a mixture of fine-grained solids, rust, and oil or grease. Procedural changes and compositional changes were made that allowed the injection to proceed smoothly without a large increase in injection pressure. These included maintaining pressure in excess of 3000 psi on the annulus outside the tubing plus use of additional oxygen scavenger and iron-sequestering agents in the injected fluids. Injection of all fluids including 1200 barrels of chaser fluid was accomplished without a significant buildup in injection pressure. A total of only 45 kilograms of ATMP came back during the cleanup flow of 91,000 barrels, compared to 214 kilograms for the cleanup flow of only 30,000 barrels following the April 1988 inhibitor pill. A remarkably high 91% of the injected inhibitor was left in the reservoir, compared to only 57% for the April 1988 inhibitor pill.

7.5.2.1. The November 19, 1989, Scale-Inhibitor Pill Composition

The inhibitor pill consisted of 100 barrels of 3% active Dequest 2000 (ATMP) phosphonate inhibitor in a 10% sodium chloride brine. This is the same quantity of ATMP as was included in the April 1988 inhibitor pill. Utilizing 10% synthetic brine rather than the 5% synthetic brine used in the April 1988 inhibitor pill gave an additional 200 psi of pressure at the perforations due to the greater density of the liquid columns. The pill was preceded by a 100-barrel preflush of 10% sodium chloride brine to isolate the pill from the Pleasant Bayou brine. Then the 100 barrels of inhibitor pill was injected, followed by 900 barrels of 10% sodium chloride brine chaser to displace the pill into the formation. The chaser was displaced to the perforations using 300 barrels of previously produced brine and fresh water from the tanks.

The pH was controlled to make sure the pill would not dissolve iron or traces of calcium carbonate or iron carbonate during transit down the wellbore. The plan called for addition of

1 gallon of oxygen scavenger (Cortron 142, containing 780 g/L of ammonium bisulfite) and 1 quart of iron-sequestering agent (Chelant 100, containing approximately 500 g/L EDTA) per 100 barrels of synthetic brine. The Cortron 142 was to provide 185 mg/L ammonium bisulfite, capable of removing about 30 mg/L of dissolved oxygen. The Chelant 100 was to provide 30 mg/L EDTA in the brine, capable of complexing about 4 mg/L of calcium or 5.5 mg/L of iron from the brine.

The premixed fluids were stored in batch tanks at the location. Onsite analysis of the fluids, presented in Exhibit 7.5.2.1-1, found that they did not meet the planned specifications for iron and oxygen. In addition, the quantity of inhibitor present was only 2.3% rather than the planned 3%. We could not determine whether this was the result of insufficient chemical delivered or insufficient mixing prior to sampling. For material-balance purposes the pill was assumed to contain the full 3% of ATMP specified in the bid.

Exhibit 7.5.2.1-1. INHIBITOR PILL SPECIFICATIONS AND ACTUAL COMPOSITION

	<u>Specification</u>	-----Concentration Found in the-----			
		<u>Preflush</u>	<u>Pill</u>	<u>Chaser</u>	<u>Tanks</u>
pH	5-6 in brine 6-7 in pill	5.9	6.4	5.5	5.7
Iron, mg/L	< 0.1	0.6	8.0	1.3	0.7
Sulfate, mg/L	< 100	44	8	45	39
Calcium, mg/L	< 40	< 2	< 2	< 2	5
Oxygen, mg/L	< 0.1	> 1	> 1	> 1	> 1
Turbidity, (FTU) ^a	< 2	2	6	2	2
NaCl, %	10 ± 0.5	10.23	10.22	10.08	10.04
ATMP, mg/L	30,000		22,640		

^a Formazin Turbidity Unit.

When pumped, each tank of fluid was transferred from the batch tank to a surge tank through a 2-micron filter using a centrifugal pump. The Cortron 142 and Chelant 100 were poured into the surge tank as it was being filled. Liquid was then moved from the surge tank to the pump truck with a second centrifugal pump. Aeration was noted during the mixing process. After the pill was found to be about an order of magnitude over the range for iron and oxygen, the concentrations of the Cortron 142 and Chelant 100 were changed from the plan. The first 100-barrel preflush was mixed with 2.5 gallons of Cortron 142 and 1 gallon of Chelant 100, providing a concentration of 464 mg/L ammonium bisulfite and 118 mg/L EDTA. The 100-barrel pill was treated to get a concentration of 464 mg/L ammonium bisulfite and 236 mg/L EDTA. The next 200 barrels of sodium chloride brine were treated only with 464 mg/L ammonium bisulfite, and the last

700 barrels of sodium chloride water were not treated. These changes were made to lessen the chance of precipitation of calcium or iron phosphonates until after the pill had passed through the perforations. It was believed that there would not be a significant amount of phosphonate available to form precipitates when the last 700 barrels of synthetic brine were injected.

The lack of appreciable buildup of injection pressure while pumping the inhibitor pill into the reservoir suggests the treatment was successful at preventing precipitation in the wellbore.

7.5.2.2. The November 19, 1989, Scale-Inhibitor Pill Injection

The inhibitor pill consisted of 100 barrels of 3% active Dequest 2000 (ATMP) phosphonate inhibitor in a 10% sodium chloride brine. The pill was preceded by a 100-barrel preflush of 10% sodium chloride brine to isolate the pill from the Pleasant Bayou brine. Then the 100 barrels of inhibitor pill were injected, followed by 900 barrels of 10% sodium chloride brine chaser to displace the pill into the formation. The chaser was displaced to the perforations using 300 barrels of previously produced brine and fresh water from the tanks. The premixed fluids to be injected were stored in batch tanks at the location. When pumped, each tank of fluid was moved from the batch tank to a surge tank through a 2-micron filter using a centrifugal pump. Exhibit 7.5.2.2-1 presents the tubing and casing pressure versus time while the pill was injected.

The treatment began with a pressure test to 6000 psi at 10:30 (1-1/2 hours on the plot). The entire pill was injected at a rate of 5 barrels per minute, with occasional downtime to switch between tanks. The pressure drop just before 11:00 was for switching from the tank containing 100 barrels of preflush to the tank containing the 100 barrels of premixed pill, and the longer pressure drop at 2.3 to 2.5 hours on the plot was for switching fluid supply from that tank to the first of two frac tanks containing 10% chaser brine. The pressure drop during the first hour of pumping was due to cooling of the wellbore and the higher specific gravity of the pill fluid.

The April 1988 Pleasant Bayou inhibitor pill injection ran into problems when the combination of low annulus pressure and cooling resulted in communication between the annulus and wellbore at the packer. Calcium and iron in the annular fluid is believed to have reacted with the pill. The resultant precipitation of calcium phosphonate greatly restricted flow through the perforations. This was avoided during the second inhibitor pill injection by pumping brine into the annulus to maintain pressure high enough to minimize ballooning and associated shortening of the tubing. In addition, the 10% brine had a higher specific gravity than the 5% brine used in the April 1988 pill, which also minimized injection pressures.

The pump on the annulus fell behind as the wellbore cooled, and several hours were required to restore the 4000 psia on the casing. Nevertheless, it succeeded in preventing communication

Exhibit 7.5.2.2-1. TUBING AND CASING PRESSURE VERSUS TIME

between the annulus and the wellbore. After injection ceased, the wellbore began heating up and fluid was then bled from the casing to keep the annulus pressure close to the tubing pressure.

The 100 barrels of pill fluid went from the wellbore into the formation between noon and 13:00 (3 and 4 hours on the plot). In contrast to prior inhibitor pills on the DOE wells, there was only a small pressure increase when the pill fluid entered the perforations. Injection pressure at 5 barrels per minute also remained constant while the 900 barrels of chaser fluid were pumped into the wellbore. The 20 minutes of downtime at 5.5 hours was for switching to tanks of a lower density mixture of produced brine and water. The pressure increase during the next hour was due to displacing the reagent-grade synthetic brine from the 300-barrel volume of the wellbore into the formation with the lower density produced brine/water mixture. The increase in the shut-in tubing pressure between November 19 and the beginning of flow on November 22 reflects heating and resultant lowering of density of the fluid in the wellbore.

7.5.2.3. The November 19, 1989, Scale-Inhibitor Pill Cleanup Flow

The plan originally called for the well to be shut-in for 24 hours prior to the cleanup flow. Research by Dr. Tomson at Rice University suggested that longer shut-ins may be beneficial, so this period was extended. After being shut-in for 66 hours after the end of pumping, flow-back of the pill was started at 10:00 on November 22, 1989.

The rate was 2400 STB/d and samples were collected every 10 barrels (6 minutes) starting after two-thirds of the 300-barrel wellbore capacity had been produced. This sampling frequency was maintained until a total of 1460 barrels had been produced. (A total of 1400 barrels were injected during the pill.) The 2400-STB/d rate was maintained with samples being collected every 20 barrels (12 minutes) until the total flow-back was 1700 barrels and then every 50 barrels (30 minutes) until 2200 barrels had been recovered.

Shortly after 08:00 on November 23, the brine rate was doubled with the samples still being collected every half hour (100 barrels between samples). The sampling interval was increased to hourly (every 200 barrels) after recovery of 3700 barrels and to every 2 hours (400 barrels) after 7200 barrels. Increases in the interval continued and had reached 2 days at the end of the week when the well was shut-in.

A total of 184 samples were collected after production was resumed on November 22, 1989. The pH of each sample was measured immediately after collection. Very little precipitate was observed in the samples, in sharp contrast to the 10% to 25% solids content observed in samples of fluid returned from the April 1988 pill. All samples were clear with little, if any, turbidity. A few days later, a small amount of precipitate was noticeable in nearly all of the sample bottles.

The samples were sent to IGT's Chicago laboratory for analysis to determine phosphonate and calcium content. Measured concentrations of ATMP in brine produced after this second inhibitor pill are shown in Exhibit 7.5.2.3-1.

The very low concentrations of ATMP in the cleanup flow, peaking at only 283 mg/L, mean that a large fraction of the injected inhibitor adsorbed into the reservoir. During the April 1988 inhibitor pill, inhibitor concentrations in the cleanup flow reached 17,800 mg/L, and only 57% of the inhibitor remained in the reservoir after the cleanup flow. About 91% of the injected inhibitor remained in the reservoir following this cleanup flow. The second pill should have a greatly extended lifetime compared to the April 1988 inhibitor pill.

Prior to starting flow-back, all but two of the filter pots that had previously seen 2 weeks of production were blocked in. These filters had more than half of there useful life remaining. At the rate of 2400 barrels per day, the pressure drop across these 10-micron cotton filter elements was up to 2 psi and increasing rapidly after production of 1100 barrels. A third filter pot, containing new 10-micron cotton elements, was put on-line in parallel 100 barrels before the brine that had carried the phosphonate pill reached the surface.

Pressure drop across the filters doubled when the brine rate was doubled during the morning of November 23 and, after a total of 4500 barrels had been produced, pressure drop across the three filter pots was up to 10 psi. At that time, a fourth pot, which contained elements that had been previously used for 2 weeks, was put on-line. The pot with the new elements was blocked in after collecting pill-related solids for a total of 21 hours. This data suggested that while there were no visible solids in the samples, a small quantity of solids were being produced. Depending on the properties of the solids, the filters may be plugged after collecting only a few pounds of solids.

7.5.2.4. The November 19, 1989, Scale-Inhibitor Pill Long-Term Performance

Results of analyses for phosphonate concentration during the flow after the November 1989 inhibitor pill are reported in Exhibit 7.5.2.4-1. The data are plotted on log-log and semilog scales in Exhibit 7.5.2.4-2. The concentration of ATMP has averaged 0.2 mg/L over the 4.5 million barrels of brine produced.

The early samples, for flow-back of less than 10,000 barrels, were analyzed by ICP. This method is quick and easy to run but is not accurate at low levels of phosphonate. The other technique -- involving butyl alcohol extractions, internal standards, and a very sensitive calorimetric analysis -- is very sensitive but is difficult and time-consuming to run. This technique was used exclusively on samples collected after 10,000 barrels. There was an apparent discrepancy, a drop in the plot, at the point where the analytical methods were changed.

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Exhibit 7.5.2.3-1. PHOSPHONATE RETURNS DURING THE CLEANUP FLOW, NOVEMBER 22-29, 1989

<u>Date</u>	<u>Cum. Brine, STB</u>	<u>Concn. ATMP, mg/L</u>
11/22/89	214	3
11/22/89	270	3
11/22/89	321	3
11/22/89	373	3
11/22/89	424	10
11/22/89	475	20
11/22/89	527	27
11/22/89	578	39
11/22/89	631	64
11/22/89	682	100
11/22/89	734	116
11/22/89	785	116
11/22/89	836	142
11/22/89	887	177
11/22/89	939	206
11/22/89	990	264
11/22/89	1041	283
11/22/89	1091	264
11/22/89	1141	193
11/22/89	1191	164
11/22/89	1241	206
11/22/89	1290	225
11/22/89	1340	196
11/22/89	1390	148
11/23/89	1442	122
11/23/89	1544	87
11/23/89	1646	68
11/23/89	1808	55
11/23/89	2061	42
11/23/89	2399	29
11/23/89	2938	19.3
11/23/89	3476	17.7
11/23/89	4340	11.9
11/23/89	5422	6.0
11/24/89	6509	7.1
11/24/89	8930	3.9
11/24/89	12761	1.00
11/25/89	16699	0.64
11/25/89	20633	0.32
11/25/89	24620	0.58
11/25/89	28766	1.22
11/26/89	32899	0.32
11/27/89	55991	0.32
11/29/89	90805	0.05

Exhibit 7.5.2.4-1. PHOSPHONATE RETURNS AFTER THE
NOVEMBER 1989 INHIBITOR PILL

<u>Date</u>	<u>Cum. Brine, STB</u>	<u>Concn Phosphonate, mg/L</u>
12/1/89	122,913	0.16
12/19/89	409,663	0.09
2/6/90	1,186,563	0.10
3/22/90	1,880,563	0.15
3/22/90	1,882,163	0.18
4/20/90	2,337,000	0.29
8/6/90	3,123,775	0.303
9/4/90	3,587,258	0.142
9/19/90	3,919,736	0.035
10/8/90	4,343,771	0.235

Three of the samples previously run by ICP were rerun using the colorimetric technique. In all cases the reported phosphonate concentrations dropped. We conclude the apparent bump in the data reflected the loss of accuracy of the ICP analyses at low concentrations of phosphonate, and there was not a stepwise change in the phosphonate levels.

7.6. Documentation of Scale Accumulations

Scale was found in the filter pots when the elements were changed on March 22, 1989. This was the first clear indication of scale since the inhibitor pill was injected at the beginning of production in 1988. The scale is presumed to have formed prior to start of scale-inhibitor injection on March 14, 1989.

During the week from June 21, 1990, to June 27, 1990, the 6-inch Rockwell plug valve at the inlet to the HPS was removed during a shut-in because it had a small leak through the seat. The leakage resulted in the development of a layer of scale about 1/16 inch thick on the downstream side of the valve. This scale is not surprising because the calculated value of the Oddo-Tomson scale index for hot Pleasant Bayou brine is such that inhibitors are not expected to be effective for pressure below 200 psi.

Coupons were not in use when production was started in March 1988. Corrosion-coupon fittings and hardware for insertion and extraction of coupons had been used previously, and all components appeared to be in good condition. When coupon installation was attempted, however, the piston of the installation tool would not move in its cylinder. A representative of the manufacturer concluded that the cylinder had been bent and could not be repaired. The most rapid and cost-effective means of repair was replacement with more modern hardware of a different

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Exhibit 7.5.2.4-2. PHOSPHONATE CONCENTRATION VERSUS TIME

design. The net result was delay of corrosion-coupon installation until July 20, 1988, by which time 1.09 million barrels of brine had already been produced.

Coupon fittings were installed at three locations. 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, and 3) between the filter skid and the disposal well. There has been no detectable buildup of calcite on the coupons.

8.0. CORROSION MONITORING AND CONTROL

Cost-effective corrosion control is essential for long-term production from geopressured-geothermal aquifers. The vast majority of the production facilities are made from mild steel. The produced brine contains several agents that promote corrosion, including carbon dioxide, hydrogen sulfide, chlorides, and entrained solids.

During the 2 months of Phase I testing in the fall of 1980, corrosion coupons had metal-loss rates in the range of 180 to 680 mils per year. During Phase II, corrosion inhibitor (Champion Technologies, Inc., Cortron RN-97, a water-soluble quaternary ammonium salt) was injected upstream of the choke and was found to reduce coupon metal-loss rates to below 10 mils per year. But severe pitting was still reported on the downstream side of flanges in high-pressure piping. The worst pitting appeared at the internal flange face just inside the ring seal. Regular carbon steel rings were also severely pitted in a number of flanges.

The Phase II corrosion problem was most severe at the locations where the full produced two-phase stream was passing through piping with an inside diameter of less than 4.0 inches. At 18,000 barrels per day, the flow velocity in such piping exceeded 13 feet per second. IGT examination of Gladys McCall piping had revealed that this velocity is in the range where the rate of pitting-type corrosion was increasing rapidly. The McCall observation was based on tens of leaks wherein the pit had corroded all the way through the piping.

Rehabilitation of the surface facilities in 1987 and 1988 included a number of actions to minimize problems due to corrosion. These included --

- Eliminating the 4-inch carbon steel piping and turbine flow meter upstream of the choke because the flow velocity through this piping was the highest of any pipe run in the system
- Using level-control valves with stainless steel bodies for the separators because of the high turbulence of fluids exiting the trim
- Placing stainless steel pipe spools in the highly turbulent flow areas downstream of the main choke and the separator level-control valves
- Minimizing the number of changes of direction in brine piping and using large-radius elbows whenever possible to minimize turbulence associated with the change in flow direction

- Using stainless steel gaskets
- Using Schedule 160 carbon steel piping to provide a corrosion allowance at locations where Schedule 80 brine piping would otherwise have an adequate pressure rating.

Production was started in 1988 without injection of corrosion inhibitor and without corrosion coupons installed in the system. The lack of corrosion inhibitor reflected the assumption that the piping changes above had adequately reduced the corrosion problems that had been observed in earlier testing at Pleasant Bayou and at the Gladys McCall well (corrosion inhibitor was never injected during the test of that well). Lack of corrosion coupons was due to learning that the previously used installation tool had been damaged and was an obsolete design for which parts were not available.

New coupon-mounting and installation hardware was procured, and the first C-1018 coupons were installed on July 20, 1988. Metal-loss rates for the coupons were found to be in excess of an inch per year upstream of the separators, about 3/16 inch per year downstream of the separators, and about 1/8 inch per year near the disposal well. The high apparent corrosion rate upstream of the separators was alarming and triggered prompt action to start inhibitor injection similar to that used during Phase IIB. Additional impetus to inject inhibitor was provided by a brine leak due to corrosion pit penetration of the inlet piping to the large separator on the morning of August 2, 1988.

In parallel with the prompt start of inhibitor injection, a metallurgical approach to fighting corrosion was initiated. It consisted of documentation of observed corrosion and limited evaluation of possibilities for reducing corrosion by use of different metallurgy or fabrication techniques. This work is presented in a section that follows sections on the corrosion inhibitor and corrosion coupon data. The final section documents observations on corrosion of the tubing in the brine disposal well.

8.1. Corrosion Inhibitor

There was no injection of corrosion inhibitor into the brine stream during production of the first 1.1 million barrels of brine. The high metal-loss rate on the first C-1018 coupons and the leak through a corrosion pit a couple weeks later resulted in a quick start of injection using the chemical that had shown effectiveness on coupons during the Phase II testing.

Injection of Cortron RN-97 at a concentration of 20 ppmv was started on August 5, 1988. The supplier, Champion Technologies, Inc., described the RN-97 as a quaternary alkyl pyridine, with added surfactants and a few percent methanol as an antifreeze. The material is water-soluble. This provides two advantages. First, a water-soluble inhibitor is more likely to reach areas that are

isolated from the main flow path. Most classes of corrosion inhibitors, such as imidazolines and amido amines, are soluble in oil rather than water.

The second advantage is related to the inhibitor pumps that were available at no cost to the project. The inhibitor-pump skid from Gladys McCall was brought to the location. The pumps on the skid are Milton Roy Milroyal Size C Metering Pumps, which are rugged and dependable but run on electricity and are oversized for the application. The lowest level the pumps could reliably be turned down to is about 15 gallons per day. At a brine flow rate of 15,000 STB/d, this rate would provide 24 ppmv of chemical to the brine stream. We hoped, after sufficient testing, to be able to use a considerably lower corrosion-inhibitor concentration.

The corrosion inhibitor, RN-97, is soluble in water. Champion Technologies, Inc., provided a free-standing 750-gallon tank. The procedure developed includes mixing the delivered RN-97, usually 3 drums, or 165 gallons, with two equal volumes of tap water. The pump then injects this diluted mixture into the well stream at the desired concentration.

Champion Technologies, Inc., ran some batch tests with other inhibitors in samples of Pleasant Bayou brine. Their report, dated August 22, 1988, evaluated three proprietary inhibitor blends. These were RN-97, RU-163A, and RN-178. The tests were performed at 300°F temperature and 3000 psi pressure, with inhibitor concentrations of 100 and 200 ppmv. Test duration was 48 hours. Summaries of the tests are shown in Exhibit 8.1-1.

Exhibit 8.1-1. SUMMARY OF INHIBITOR TEST DATA

<u>Inhibitor</u>	<u>Concentration</u>	<u>Corrosion Rate</u>
RN-97	100 ppmv	64 mils/year
RN-97	200 ppmv	41 mils/year
RN-163A	100 ppmv	32 mils/year
RN-163A	200 ppmv	20 mils/year
RN-178	100 ppmv	34 mils/year
RN-178	200 ppmv	34 mils/year
Blank	--	107 mils/year

These data suggest the RN-97 was little better than no inhibitor at all, and the other inhibitors performed better. However, field tests suggested RN-97 concentrations of less than 20 ppmv reduced corrosion rates from over 100-200 mils per year to under 20 mils per year. Because the batch tests did not come close to imitating the field data, there may have been some problem or bias in the analysis. The product information on the other inhibitors showed that they were oil-soluble and could only be diluted with light hydrocarbon oils. A concern was that an oil-soluble inhibitor would have a difficult time reaching areas of the system that were isolated from the main flow path, compared to a more soluble inhibitor. We opted to continue with the RN-97 rather than deal with

the expense that would be incurred to purchase pumps to inject the oil-based inhibitor and the uncertainties in the corrosion protection for the entire system.

8.2. Corrosion Coupon Data

There are four locations where corrosion coupons were used. The first is in the flow loop piping leading from the wellhead to the primary choke. The pressure and temperature conditions at the wellhead are too extreme to be able to remove the coupon while the well is flowing. Flow loop coupons can only be removed when the well is shut-in. In practice, some coupons were severely corroded or even lost from the mount before they were retrieved. The other three locations are 1) in the piping between the primary choke and the separator chokes, 2) in the piping downstream of the separators, and 3) in the piping between the filters and the disposal well. A Rohrbach Cosasco coupon-removing tool was obtained to allow coupons to be installed and removed from these three locations without interrupting flow. Coupon data are in Appendix L.

Coupons made of C-1018 steel were first installed in the three locations on July 20, 1988. The first coupon examined was removed after 43 hours in the piping downstream of the separators. There was no scale, and the weight loss calculated to a uniform metal-loss rate of 0.155 inches (155 mils) per year. A new coupon was installed at that location and was pulled 4 days later, at the same time that coupons were pulled from upstream and downstream of the separators. Calculated metal-loss rates, with the assumption of uniform metal loss, were --

<u>Coupon Location</u>	<u>Mils-Per-Year Loss Rate</u>
Upstream of the Separator Chokes	1274
Downstream of the Separators	190
Near Disposal Well	110

The corrosion rate upstream of the separator chokes was in excess of 1 inch per year. At that rate the piping would have a service life of well under a year. These very high corrosion rates resulted in extreme haste to obtain and start injecting corrosion inhibitor. Because Champion Technologies', Inc., Cortron RN-97 was successfully used during the Phase II testing in 1982 and 1983 without any reported adverse affects, that material was obtained. Subsequent tests revealed this is an excellent choice of inhibitor for this system. Injection at a concentration of 20 ppmv was started on August 5, 1988, and after production of 1.1 million STB of brine.

The metal-loss rates for the three removable coupons, and the average concentration of inhibitor, are tabulated in Exhibit 8.2-1. These data leave no doubt as to whether the corrosion inhibitor has been effective at the locations of the coupon holders. Metal-loss rates were in the range of 0.1 to 1+ inches per year before the start of inhibitor injection on August 5, 1988. Since

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Exhibit 8.2-1. CORROSION COUPON DATA

<u>Date In</u>	<u>Date Out</u>	<u>Flowing Time, # days</u>	<u>Inhibitor Concentration, ppmv</u>	<u>-----Metal-Loss Rate for Coupon From-----</u>		
				<u>Before Sep, mils/yr</u>	<u>After Sep, mils/yr</u>	<u>Before SWD mils/yr</u>
7/20/88	7/22/88	2	0.0	.-	154.9	.-
7/22/88	7/26/88	4	0.0	.-	189.6	.-
7/20/88	7/26/88	6	0.0	1274.0	.-	110.3
7/26/88	8/2/88	7	0.0	222.0	177.8	111.0
8/2/88	8/9/88	7	13.8*	1028.2 ^a	66.0 ^a	53.3 ^a
8/9/88	8/16/88	7	21.6	1.1	-3.9	14.0
8/16/88	8/23/88	7	14.9	0.7	14.0	4.9
8/23/88	8/30/88	7	14.0	1.4	.-	.-
9/10/88	9/22/88	12	10.0	5.4	4.8	6.4
9/22/88	9/29/88	7	8.8	4.6	6.0	4.9
9/29/88	10/12/88	13	9.7	4.7	1.8	1.9
10/12/88	10/25/88	13	8.5	7.1	39.1	2.3
10/25/88	11/8/88	14	7.9	7.3	1.7	2.6
11/8/88	11/22/88	14	8.3	13.3	1.4	3.6
11/22/88	12/6/88	14	7.5	12.1	5.7	7.3
12/6/88	12/20/88	14	6.7	4.4	7.1	5.7
12/20/88	1/3/89	14	7.9	5.7	2.0	5.0
1/3/89	1/17/89	14	8.6	4.3	10.5	4.3
1/17/89	1/31/89	14	5.3	5.4	8.4	6.4
1/31/89	2/14/89	14	4.2	5.4	14.2	6.1
2/14/89	3/17/89	31	5.4	4.0	4.9	11.3
3/17/89	4/18/89	32	6.2	4.6	6.1	4.5
4/18/89	5/17/89	29	6.0	2.9	5.6	3.5
5/17/89	6/28/89	31	6.2	5.0	28.1	.-
6/28/89	8/25/89	37	5.8	23.7	23.3	10.9
8/25/89	10/19/89	17	9.7	18.0	16.3	5.1
10/19/89	12/20/89	56	8.7	4.1	12.4	5.0
12/20/89	3/19/90	89	8.6	4.6	3.2	2.8
3/19/90	5/8/90	50	5.3	4.7	1.1	1.3
5/8/90	6/7/90	22	4.3	6.6	5.1	1.4
7/27/90	10/2/90	67	7.0	18.4	23.0	9.7

^a Corrosion-inhibitor injection was started at a concentration of 20 ppmv on August 5, 1988. This is 3 days after the coupons were installed

that time, a concentration of delivered Cortron RN-97 of less than 10 ppmv in the brine has resulted in metal-loss rates of less than 0.01 inches per year for the C-1018 coupons.

8.3. Direct Observations of Corrosion in the Surface Facilities

After visual inspection at several locations, a large portion of the original brine piping was retained during the rehabilitation of the surface facilities during 1987 and 1988. This included all of the piping components from the wellhead through the main choke, for the last 100+ feet upstream of the separators, and several hundred feet of the 6-inch line from the separators to the

disposal well. New piping was installed to decrease turbulence and velocity in the vicinity of the turbine meters and level-control valves on the separators, to permit installation of the filter skid near the disposal well, and to accomplish the re-routing of brine to the location for the Hybrid Power System.

Corrosion inhibitor was not injected into the first 1.1 million barrels of produced brine. Then, in August and September 1988, two leaks developed due to pinhole corrosion through the old piping upstream of the large separator. Inspections at other locations while the leaks were being repaired revealed that significant corrosion was widespread. Details of the observed corrosion and the understanding thereof that was developed in 1988 are discussed in the first subsection below. Then, two subsections provide details of data on the arresting of corrosion by the inhibitor that was developed in 1989 and 1990.

8.3.1. Surface Piping Corrosion Observed During 1988

Several corrosion problems were noted during the first few months of production in 1988. These included extensive corrosion of certain choke components, leaks in old piping at the inlet to the large separator, and corrosion at welds. As a result of these observations, some old piping was replaced, chokes were clad with stainless steel, and corrosion-inhibitor injection was initiated. The individual observations are discussed in chronological order in the paragraphs below. Additional details are provided in the reports from Corrmnet Engineering Services that are in Appendix M.

Inspection of the upstream end of the main choke while it was disassembled on June 10, 1988, revealed metal missing due to erosion/corrosion between "O"-ring grooves outboard of the stainless cladding on the bonnet. Total production at that time was only 123,000 barrels of brine. Also, a small amount of erosion of the trim (disks) was observed. A solid stainless bonnet and replacement tungsten carbide trim were ordered.

A brine leak developed in the vertical 4-inch supply pipe at the inlet to the large separator during the morning of August 3, 1988. The leak was about four pipe diameters downstream from an elbow that changed flow direction by 90 degrees after the outlet of the separator choke. It was in a straight run of Schedule 80 pipe that had been used during the majority of prior production. The total brine produced through this pipe had been in the range of 4 to 5 million barrels. The portion of this production during Phase II (one-half to two-thirds) had contained corrosion inhibitor. The leak was large enough to make appropriate diversion of flow from that pipe on a time scale of hours necessary, but it did not constitute an emergency situation. The brine flow was reduced from about 19,000 to about 14,000 STB/d and then the flow stream was diverted to the small separator. The large separator was isolated so that the leaking pipe could be removed and replaced.

The removed spool was cut in half lengthwise for examination of the internal corrosion.

Significant observations are --

- In the direction of flow, the pipe spool consisted of 1) a 4-inch, 900# ANSI flange, 2) a Schedule 160, 90-degree ell, 3) 3-1/2 feet of Schedule 80 4-inch pipe, 4) a second Schedule 160 ell, 5) a 4 to 8-inch Schedule 80 concentric reducer, and 6) an 8-inch 600# flange. The replacement spool differed in that the pipe between the ells and the concentric reducer was also Schedule 160.
- Pitting-type corrosion with internal footprints about 1/16 to 1/8 inch wide and 3/8 to 1/2 inch long in the direction of flow were common in the 4-inch pipe for the first foot of its length in the direction of flow. These were mostly on the outside of the turn. But the pit that actually penetrated the pipe to make the leak was one of a small number on the inside and was almost a foot above the weld.
- The top half of the 4-inch pipe was protected by about 1/8 inch of scale from production in prior years. The scale appeared to have been eroded off the lower (upstream) part of the pipe where the pitting had taken place.
- Metal loss from the ells and welds was much less severe than 1) in the straight part of the 4-inch pipe, 2) on the inside of the concentric reducer (flow was from the small to the large diameter), or 3) on the flange faces (with the exception of no corrosion on the flange that is welded to the separator vessel).
- The geometry of the corrosion/erosion of the flange faces indicates that it is associated with turbulence at the gap between the faces.

When the 3-inch turbine on the small separator was removed for cleaning on August 12, iron loss in the downstream flange and pipe was observed. This pipe spool had been fabricated from new material in 1988. The depth of pits was less than 1/16 inch.

During the evening of August 28, 1988, a small brine leak was noticed in old 4-inch piping between the tee in the brine line and the large separator choke. The leak rate was almost unmeasurable at first, but grew progressively worse. The well was shut in the morning of August 31, 1988. The exit point of the leak was about 3/8 inch downstream from a weld that joined concentric pieces of 4-inch Schedule 80 piping. It was only about 10 feet upstream of the leak in 4-inch Schedule 80 pipe that was repaired the first week in August. But the new leak was upstream of the separator choke and block valve so that shut-in of production was required for repair.

In view of the two leaks in the old pipe in less than a month and discovery that the 4-inch portions were Schedule 80 rather than the Schedule 160 that were called for in IGT's specifications, it was decided that the entire tee section of piping that split flow from 8-inch pipe to 4-inch pipes to each separator would be replaced. This consisted of about 6 feet of 8-inch pipe, including an ell and a tee, reducers to 4-inch pipe, and about 20 feet of 4-inch pipe. The replacement pipe was all Schedule 160.

The removed pipe was cut in half lengthwise for internal inspection. The leak was found to be through a pit inside an annular ring of lost metal on the downstream side of a weld. In addition, significant pitting was found on the inside of the small radius in the 8-inch tee and at locations where Thredolets had been welded into the pipe. Deep pitting existed in the reducers from 8 to 4-inch pipe and at the flanged ends of the 4-inch pipe.

While the new piping was being fabricated at the end of August 1988, the chokes were opened and inspected. The main choke had visible, but not serious, erosion of the disks. The stainless steel-clad choke body and tail piece were in good shape. Iron loss from the bonnet was still limited to the area of the internal "O"-ring grooves for the "tuning fork" where it had been noticed when the choke was inspected in June 1988. New trim and the newly purchased stainless steel bonnet were installed when the choke was reassembled. The removed bonnet was sent out for stainless cladding and re-machining of the "O"-ring grooves.

Severe corrosion was apparent in the body and tail piece of the choke leading to the large separator. Iron loss averaged 1/4 inch over areas of multiple square inches, and pits as deep as 3/8-inch were observed. During the rehabilitation of the choke prior to starting flow in June 1988, the lining had been built up using 8018B2L welding rod rather than 316 stainless steel. The rod used is a 2% chrome, low-carbon alloy. The bonnet on the large separator choke showed little evidence of iron loss. Nevertheless, it was replaced with the recently purchased stainless steel bonnet so that the bonnet removed could be used in the other separator choke. The trim had minimal erosion and a small buildup of scale.

The body, tail piece, and trim from the secondary choke leading to the small separator were in good condition. But the bonnet had lost up to 1/4 inch of steel. Because the bonnet in one separator choke was badly corroded, and the body of the other separator choke was badly corroded, we suspect that the bonnets had previously been switched between the chokes during rehabilitation. The steel that makes up the small separator choke seems to be more resistant to corrosion than the steel in the large separator choke. The small separator choke was reassembled with the good bonnet that was previously in the large separator choke. The corroded bonnet was sent out to be built up with stainless steel.

While the system was down at the end of August 1988, two new 4-inch Rockwell valves were installed to replace old valves that had unacceptably high leakage while closed. One was the block valve downstream of the large separator dump valve and the other was the block valve upstream of the large separator choke. None of the flanges on the removed valves had pitting, but all of the mating carbon steel flanges were pitted. The metallurgy of the valve bodies is obviously superior to that of the weld neck flanges in the system.

There was no evidence of corrosion of the outlet end of the 4-inch, 316 stainless steel spool after the dump valve of the large separator. However, corrosion had completely removed the stringer pass of the first two welds in 4-inch Schedule 160 pipe downstream of the block valve. These welds were made as a part of system rehabilitation in 1987. They constituted the only observed significant corrosion of items that were newly fabricated during rehabilitation of the system. All other observed corrosion was on items that had been in service during production by prior contractors. Penetration by corrosion was less than the corrosion allowance provided by use of Schedule 160 pipe. Therefore, these corroded welds were not repaired. Rather, they were documented with X-rays as a step toward determining whether the corrosion inhibitor stopped the metal loss.

Six of the items removed in August and September 1988 were provided to Corrmec Engineering Services for analysis. The resulting March 8, 1989, report in Appendix M provides details leading to the following conclusions:

1. "Both the microstructures and hardness values of the varied piping components examined and compared indicated or showed only slight variances from section to section."
2. "The internal erosion-corrosion attack that was experienced within these critical piping components of the brine piping system appears to be independent of the carbon steel material's metallurgy and mechanical properties."
3. "The combined action of erosion (due mainly to fluid flow variances and inadequate piping design and fit-up) coupled with corrosion contributed greatly to the localized corrosion pitting attack experienced in the piping components examined since all of these components were constructed of a wear susceptible material such as low carbon steel."
4. "The overall or major cause of the severe localized pitting corrosion experienced within this brine piping components examined appears to be primarily related to the following:
 - (a) Improper Piping Design Practices/Fluid Flow Variables
 - (b) A Wear susceptible piping material (low carbon steel)
 - (c) Inadequate pipe joint fit-up for joining by butt-welding
 - (d) Built-in welding defects due to poor welding practices, welding procedures and improper joint design (i.e., fabrication deficiencies)."

Ultrasonic inspection of the flow loop on November 7, 1988, revealed little, if any, uniform metal loss due to corrosion of the 4130 steel. This is very important because C-1018 corrosion coupons have shown metal-loss rates of an inch per year or higher upstream of the inhibitor-injection point in the flow loop. On the other hand, the ultrasonic inspection technique used would probably not detect corrosion pitting of the type that has been observed in flanges and piping associated with the separators.

8.3.2. Surface Piping Corrosion Observed During 1989

On May 15, 1989, the well was shut in for buildup testing and flow-splitter installation. The 4130-steel wellhead loop was removed for changing wing valves, and localized but extensive pitting was observed on the ring-gasket groove in the lowest flange face of the wellhead loop. The location and appearance of the corrosion appeared similar to phosphonate-induced corrosion of tubing hangers at the N.E. Hitchcock co-production project. There remains a possibility that this corrosion was the result of phosphonate trapped in the flange during the injection of the inhibitor pill. The lower portion of the wellhead loop was sent to a shop to be refaced.

The installation of the flow splitter for the HPS was completed, and all the new welds, plus selected old welds, were X-rayed. All the new welds passed inspection. An old 6 X 4-inch reducer located just upstream of the check valve at the disposal well had lost so much metal adjacent to welds that it was replaced. Repetition of the X-rays at the locations of two corroded welds downstream of the brine block valve after the level-control valves on the large separator revealed little change from the corrosion previously observed at the end of August 1988.

The reducer was cut in half and sent to Corrmec for analysis. Also, a 6-inch tee that was removed from the brine line to install the flow splitter had similar corrosion and was also sent to Corrmec. All welds sent to Corrmec had been made in new material as a part of rehabilitating the surface hardware in 1987 and 1988. The observations detailed in the resulting June 15, 1989, report in Appendix M revealed that the ring-like (weld-line) corrosion attack experienced was limited to or confined within the weld Heat Affected Zone (HAZ) of the welded joints. The report offered the following to try to explain the mechanism responsible for the weld-line corrosion attack that had been experienced within the sections examined:

1. "Initially, all corrosion attack was located and limited to the fitting's end sections. The fittings involved herein were manufactured by a forging process which involves a forming process whereby the material is in a highly stressed condition. Also, its grain structure is somewhat different than for "as-rolled" or "hot-rolled" materials."
2. "The heat generated by the welding process caused the fitting material, in the vicinity of the weld seam, to give a different grain structure than that of the rest of the forged fitting."
3. "Due to differences in grain structure adjacent to the weldment (HAZ) and the fitting parent metal, these two areas have different tendencies to preferentially corrode. This is providing the environment media is also corrosive. As a result, "weld-line" corrosion at the HAZ can occur."
4. "Sometimes a similar problem can result from an improper choice of welding electrodes. This problem is avoided by proper welding practices. In this case, this condition can be overcome by fully normalizing the finished weld seam and surrounding area. Normalizing is a heat treatment process that gives uniformity to grain structure."

These studies of corroded system components suffer from the problem that it is impossible to deduce whether corrosion was occurring while corrosion inhibitor was present or whether it all occurred during the production of a little over a million barrels of brine at the start of production in 1988. But the lack of change in the corroded welds downstream of the brine block valve after the level-control valves on the large separator indicated that the inhibitor had greatly reduced the rate of metal loss.

Searching for and documentation of corrosion was a part of the safety and QA/QC investigations before starting operation of the iso-butane turbine system in September and October 1989. More than 6 million barrels of brine had been produced without apparent corrosion problems since the start of corrosion-inhibitor injection in August 1988. No corrosion requiring repair was found. Documentation of lost metal at a weld on the 6-inch pipe flange just downstream of the stainless steel spool after the main choke included pressing clay into a finger-size corroded groove and then making a plaster cast from the clay. The metal loss at this point is much like that observed at several welds. Some of the weld metal is still in place on the upstream side of the weld. But on the downstream side, roughly equal amounts of weld and pipe metal are missing. In the case of the leak in old piping at the end of August 1988, the corrosion-pit leak path started in this groove and then penetrated the pipe about 1/2 inch downstream from the weld.

8.3.3. Surface Piping Corrosion Observed During 1990

On November 25, 1989, the corrosion/erosion of the flange downstream of the 3-inch turbine was noticeably worse than observed the last time the turbine was taken out on August 10, 1989. This point was visually checked again on May 14, 1990. The difference is both at the flange face and in pits downstream of the face as illustrated below. The flanges upstream and downstream of the 3-inch turbine were inspected for corrosion while the turbine was being cleaned. All surfaces had a heavy uniform coating of corrosion inhibitor. There was no detectable metal loss upstream of the turbine and only a small additional loss downstream as indicated in Exhibit 8.3.3-1.

The metal loss at the face of the flange is all the way around and is becoming more uniform with time. There are still only two small pits a couple of inches inside the flange and on the bottom side. They do not appear to have grown since November 1989.

During June 1990, production was shut in for work on the disposal well in an attempt to decrease the injection pressure. This provided the opportunity to obtain additional data relevant to corrosion. Brine production was up to a total of 10.7 million barrels, of which 3.5 million barrels had been produced subsequent to the safety and QA/QC review that preceded operation of the iso-

Exhibit 8.3.3-1. CORROSION FROM FLANGE DOWNSTREAM OF THE 3-INCH TURBINE

butane turbine. The inspections during the week of June 21 to June 27, 1990, strongly indicated that the inhibitor had been very effective. Visual inspection after removal of the disposal wellhead did not reveal significant metal loss from either well hardware or from the carbon steel piping upstream of the check valve on the disposal well. The lack of metal loss in piping immediately upstream of the disposal well is particularly significant because the welds and interior of the 6 to 4-inch reducer had lost so much metal that replacement was necessary in May 1989. At that time, there was no way to deduce what portion of the heavy metal loss had occurred before the start of inhibitor injection. This data suggested the RN-97 has been very effective. Since the reducer was replaced, a total of 4.76 million barrels of brine have passed through it without significant metal loss.

During the week of June 7 to June 10, 1990, a section of 6-inch pipe about 40 feet long with flanges on both ends between the filter skid and the disposal well was removed and set aside to make room for the rig that was used to work on the disposal well. Subsequent inspection of the 8 to 6-inch reducer at the filter skid end revealed both pitting of the reducer and loss of metal at the 8-inch weld. Both were limited to the lower half of the pipe. Metal loss, if any, was too small to be visually or manually detected at the 6-inch, 90-degree, long-sweep elbow a couple feet downstream from the reducer.

During the week of June 21 to June 27, 1990, the HPS brine bypass orifice meter was taken apart in search of understanding the reason for the 3% to 5% discrepancy in brine rates from the separator turbine meters and the downstream orifice meters. The upstream orifice flange was found to have lost about 1/8 inch of metal between the tap and the plate. Up to 1/8 inch of metal had corroded away from several patches downstream of the plate. New orifice flanges were ordered due to the possibility that meter accuracy was degraded by the corrosion.

Metal loss downstream of the first weld after the stainless steel spool after the main choke was documented with a plaster cast when found on October 3, 1989. A second cast made during the week of June 21 to June 27, 1990, was identical. Additional metal loss, if any, was at most a few percent.

Metal loss at four points in the 4-inch piping downstream of the dump valve on the large separator had been previously documented with X-rays in September 1988 and May 1989. Repeat X-rays of the same spots during the week of June 21 to June 27, 1990, did not reveal detectable change in the metal loss.

A total of 21 welds at locations where corrosion was most likely were examined with X-rays. Only two of these would have passed inspection as new welds. Fortunately, the examined weld in the flow loop upstream of the choke was one of the fully acceptable welds. The other was in 8-inch pipe at the brine outlet of the large separator. On the other hand, none of the metal loss appears to exceed the corrosion allowance that was built into the piping specifications in the form of Schedule 160 pipe where Schedule 80 pipe would normally have been used.

8.4. Production Well Tubing

The production tubing was not removed from the well during this report period. Production well tubing corrosion can only be monitored by remote means, such as a caliper log, and by chemical means such as monitoring iron in the brine or hydrogen in the gas.

Monitoring of corrosion by iron concentration in the brine was not practicable because the iron concentration in brine in the formation is not known. Monitoring corrosion rates through the hydrogen concentration in the gas showed the corrosion rate was relatively constant at between 6 and 8 pounds of iron per day, independent of flow rate. This same independence of corrosion rate from the brine rate was also observed at the Gladys McCall well. A baseline caliper survey was run, but there has not been a survey since 1988.

The fraction of this iron loss that is coming from tubing versus the fraction from casing near the perforations is not known. The total tubing weight is approximately 320,000 pounds (13,968 feet of 23-pound-per-foot tubing). If all 8 pounds per day (2820 pounds per year) of iron were corroding uniformly from the tubing, more than 10 years would pass before 10% of the

tubing was corroded away. In actuality, corrosion is more likely to be localized pitting, and the tubing may spring a leak before the 10 years have passed. Conversely, there could have been as much as 3 or 4 tons of metal corroded from the tubing and casing between June 1988 and October 1990. If this metal loss was uniform from the tubing, the wall thickness would have decreased by only about 5 mils. This is too low a level to accurately measure.

8.5. Disposal Well Tubing

A workover rig was set up and work was started on the disposal well on July 13, 1990. During the workover, the tubing was pulled from the well. The tubing was 5-1/2 inch OD, 15.5-pound-per-foot, J-55 grade. A total of 141 joints of tubing were inspected by Tuboscope Inc. Tuboscope Inc. divided the joints into those with pits that exceeded 15% of the wall thickness (scrap) and those where no pits exceeded 15% of the wall thickness (reused). A total of 82 joints was able to be reused, but 59 joints, or 42% of the joints, were scrapped. Reasons for rejecting joints included bad pins (4), bad box ends (22), bad pins and box ends (22), bad pins due to internal corrosion (13), and bad tube bodies due to internal corrosion (7). The pin is the male threaded end, and the box end is the female threaded connector. Internal corrosion was a predominant factor in scrapping on 20 of the joints.

About a dozen holes were found to have corroded through Joint 134, counting down the well. This joint apparently had different metallurgical characteristics from the other 140 joints. No other holes were found.

A layer of scale about 1/16 inch thick was on the outside of the seven joints between the holes and the bottom of the tubing string. This implies some low-rate brine circulation in that portion of the annulus. No scale accumulation was found inside the tubing.

9.0. 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 2 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 much 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.

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
- Not flowing at brine rates high enough for production of slugs of sand while a wireline is in the well
- 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.

9.1. Conclusions Relevant to the Reservoir Being Tested

1. 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.

2. The reservoir brine was not saturated with natural gas at discovery pressure and temperature. Indeed, it is doubtful whether the bottomhole 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.
3. 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.
4. 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.

9.2. Conclusions Regarding Brine Disposal

1. Disposal zone pressure buildup, if any, from injection of more than 12.5 million barrels of brine is less than 10 psi.
2. 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 6000 to 6500 feet. Cooling of brine by operation of the Hybrid Power System reduced injection pressure by about 0.7 psi per degree Fahrenheit of cooling.
3. 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.
4. 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.

10.0. RECOMMENDATIONS

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 to 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 bottomhole 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 bottomhole pressure was drawn to almost 9000 psia, or a little more than 2000 psia below the original reservoir pressure. Flowing wellhead pressure was still above 1800 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.
- 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 bottomhole 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.

11.0. ACKNOWLEDGMENTS

The Pleasant Bayou work by IGT in the period from 1986 through 1990 and the preparation of this report were performed under DOE Contract DE-AC07- 85ID12578 with Eaton Operating Company and Subcontract IGT/EOC 85-4 with the Institute of Gas Technology.

Significant contributions to the successful conduct of the work reported herein have been made by numerous peers. Technical roles that were particularly important include:

- Dr. Leo Rogers did the initial programming for the digital data collection system during the geopressed-geothermal well-of-opportunity tests in 1979 and 1980, and made major improvements in the real-time data interpretation and output aspects of the program during the current testing at Pleasant Bayou.
- Mr. Bob Rose developed the portions of the computer program that provides capability for screen plotting of data as it is collected and that automatically outputs daily reports each morning.

- Ms. Mary Newberg augmented published procedures for calculation of flowing bottomhole pressure to include algorithms for calculating 1) solubility of gas in brine, 2) use of a fit to formation volume factors measured by IGT for brine saturated with natural gas in calculation of brine density, and 3) bubble rise velocity proportional to the density difference between the high-pressure gas and the brine. The calculation was incorporated into the digital data system so that flowing bottomhole pressure was calculated each hour.
- Ms. Karen Crippen refined procedures to improve quality of results and performed the majority of solids and phosphonate analyses reported herein.
- Mr. Gerald Koncar refined laboratory procedures and performed the majority of hydrocarbon analyses reported herein. His role has been particularly significant in relation to the aromatic compounds.

Mr. Steve Foh has made noteworthy contributions to management of the IGT work. In addition, extraordinary effort by him and by Mr. Michael Mathius have been critically important to the reporting of results.

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APPENDIX A

Analysis of Core by Core Laboratories, Inc.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

CORE ANALYSIS REPORT

FOR

GENERAL CRUDE-DEPT. OF ENERGY

PLEASANT BAYOU NO. 1
WILDCAT
BRAZORIA COUNTY, TEXAS

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

CORE LABORATORIES, INC.

January 8, 1979

General Crude Oil Company
2700 One Allen Center
Houston, Texas 77001
Attn: Mr. Charles Jones

Subject: Core Analysis
Pleasant Bayou #1
Wildcat
Brazoria County, Texas
CLI File #2202-10173

Gentlemen:

Diamond coring equipment and water base mud were utilized to core the subject well. The cores were picked up at the well site by a representative of Core Laboratories, Inc. and transported to the Houston Laboratory for conventional plug analysis. The results of this analysis may be found in tabular form on the accompanying pages of this report.

Cores number one through nine were sampled every other foot in the sand sections as requested by a representative of the client. Grain density measurements were made on each sample and are reported with the tabular data.

A Core-Gamma correlation was run and the log is inserted in the pocket of this final report folder.

Polaroid photos were made of each recovered foot and have been delivered to the client.

Selected sidewall cores were taken and the results are enclosed following the diamond core data.

Core remnants and plugs have been shipped to Balcones Research Center at the University of Texas at Austin.

Thank you for the opportunity to be of service.

Very truly Yours,

C. E. Kuhlman
C. E. Kuhlman
Laboratory Manager
Core Laboratories, Inc.

CEK/kw

Enclosure

GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1
WILDCAT
BRAZORIA COUNTY, TEXAS

DATE: 7-17-78
FORMATION:
DRLG. FLUID: WATER BASE MJD
LOCATION:

FILE NO: 2202-10173-3
LABORATORY: HOUSTON, TEX.,
ANALYSTS: BRAXTON
ELEVATION:

CONVENTIONAL CORE ANALYSIS

SMP NO	DEPTH	PERM HORZ(KA)	MD %	POR %	OIL% PORE	WTR% PORE	PROB PROD	GAS% BJLK	GRN. DEN.	DESCRIPTION
	4300.0-50.0	CORE NO. 1 CUT 50 FT. REC. 12 FT.								
	4300.0-38.0	LOST CORE								
	4338.0-39.0	SD F-MG CLN W/SH STKS & VSHY INCLS FOSS LMY N FLU								
1	4339.0-40.0	456	36.6	0.0	93.0		2.6	2.59		SD F-VFG CLN W/SHY INCLS TOP 1/4' VSLTY SHY LMY N FLU
	4340.0-41.0	SD F-VFG SSLTY FOSS W/A THIN SH STK LMY N FLU								
2	4341.0-42.0	305	36.5	0.0	93.2		2.5	2.66		SD F-VFG SALTLY FOSS VLMY N FLU
	4342.0-43.0	SD F-VFG SALTLY FOSS VLMY N FLU								
3	4343.0-44.0	315	37.8	0.0	92.7		2.8	2.64		SD F-VFG SALTLY FOSS VLMY N FLU
	4344.0-44.9	SD VFG VSHY VCARB VLMY N FLU								
4	4344.9-46.2	<0.1	5.3	0.0	37.7		3.3	2.62		SD VFG DNS VLMY FOSS N FLU
	4346.2-47.0	RETAINED BY CLIENT								
	4347.0-48.0	SHALE SSDY VLMY SFOSS								
	4348.0-49.4	RETAINED BY CLIENT								
5	4349.4-49.8	0.3	25.0	0.0	83.8		4.0	2.60		SD VFG VSLTY VLMY FOSS N FLU
	4349.8-50.0	SHALE RINGTAIL SLTY VLMY								
	6700.0-50.0	CORE NO. 2 CUT 50 FT. REC. 9 FT.								
	6700.0-01.5	CRUSHED SHALE & FG SD MUDSHOT II FLU								
	6701.5-03.0	SHALE GREY VLMY RINGTAIL W/DNS VFG SD STK N FLU								
	6703.0-04.0	CRUSHED SHALE & MUDSHOT SD N FLU								
	6704.0-05.0	BROKEN SHALE & DNS FG SD VLMY II FLU								

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GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1DATE: 7-17-78
FORMATION:FILE NO: 2202-10173-3
LABORATORY: HOUSTON, TEX.

SMP NO	DEPTH	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	PROD PROD	GAS% BULK	GRN. DEN.	DESCRIPTION
6	6705.0-06.0	<0.1	6.6	0.0	69.7		2.0	2.66	SD VFG DNS VLMY N FLU
	6706.0-07.0								SHALE W/HD DNS VFG SD INCLS VLMY N FLU
7	6707.0-08.0	31	20.0	0.0	82.6		3.5	2.62	SD F-VFG SLTY W/HD DNS KNOTS POSS VLMY N FLU
	6708.0-09.0								SHALE W/HD DNS F-VFG SD INCLS POSS VLMY N FLU
	6709.0-50.0								LOST CORE
	10215.0-70.0	CORE NO. 3 CUT 55 FT. REC. 53 FT.							
	10215.0-16.0								SD VFG VSLTY LMY N FLU
8	10216.0-16.6	<0.1	9.3	0.0	87.5		1.2	2.65	SD VFG VSLTY LMY N FLU
	10216.6-17.7								SHALE RINGTAIL
	10217.7-19.0								SD VFG SSHY LMY N FLU
9	10219.0-20.0	<0.1	15.4	0.0	83.8		2.5	2.70	SD VFG VSLTY LMY N FLU
	10220.0-21.0								SD VFG VSLTY SLMY N FLU
10	10221.0-22.0	0.4	18.8	0.0	71.8		5.3	2.69	SD VFG VSLTY W/SML SH INCLS SLMY N FLU
	10222.0-23.0								SD VFG VSLTY SLMY N FLU
11	10223.0-24.0	0.3	15.4	0.0	71.4		4.4	2.69	SD VFG VSLTY LMY N FLU
	10224.0-25.0								SD VFG VSLTY LMY N FLU
12	10225.0-26.0	6.1	18.8	0.0	70.2		5.6	2.67	SD VFG VSLTY LMY N FLU
	10226.0-27.0								SD VFG VSLTY BOT 1/4' SH LMY N FLU
13	10227.0-28.0	<0.1	10.0	0.0	94.0		0.6	2.65	SD VFG-SILT W/SH STKS SLMY N FLU
	10228.0-29.0								SD VFG-SILT W/SH STKS BOT 1/4' SH SLMY N FLU
	10229.0-30.0								SHALE RINGTAIL TOP 1/2' VSLTY
	10230.0-48.0								SHALE RINGTAIL OCCASIONAL SILT STKS
	10248.0-49.0								SD VFG VSLTY W/SH STKS SLMY N FLU
14	10249.0-50.0	<0.1	12.7	0.0	92.0		1.0	2.69	SD VFG VSLTY W/SH STKS BOT 1/4' VSHY N FLU
	10250.0-51.0								SD VFG VSLTY W/LG SH STKS SLMY N FLU
15	10251.0-52.0	0.1	12.1	0.0	88.6		1.4	2.70	SD VFG VSLTY BOT 1/2' VSHY SLMY N FLU

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1DATE: 7-17-78
FORMATION:FILE NO: 2202-10 73-3
LABORATORY: HOUSTON, TEX.

SMP NO	DEPTH	PERM HORZ (KA)	MD %	POR %	OIL% PORE	WTR% PORE	PROD	GAS% BULK	GRN. DEN.	DESCRIPTION
16	10252.0-53.0									SD VFG VSLTY VSHY SLMY N FLU
	10253.0-54.0	0.1	13.1	0.0	81.8			2.4	2.69	SD VFG VSLTY W/SML SH LAMS SLMY N FLU
	10254.0-55.0									SD VFG VSLTY BOT 1/2' SHY SLMY N FLU
17	10255.0-56.0	0.1	9.8	0.0	91.0			0.9	2.71	SD VFG VSLTY SHY SLMY N FLU
	10256.0-57.0									SD VFG VSLTY W/SH STKS SLMY N FLU
18	10257.0-58.0	0.2	20.7	0.0	75.4			5.1	2.67	SD VFG VSLTY SLMY N FLU
	10258.0-59.0									SD VFG VSLTY SLMY N FLU
19	10259.0-60.0	0.4	15.3	0.0	62.2			5.8	2.68	SD VFG VSLTY BOT 1/2' VSHY LMY N FLU
	10260.0-61.0									SD VFG VSLTY VSHY LMY N FLU
20	10261.0-62.0	0.1	17.4	0.0	68.9			5.4	2.68	SD VFG VSLTY SLMY N FLU
	10262.0-63.0									SD VFG VSLTY BOT 1/3' SH SLMY N FLU
21	10263.0-64.0	0.1	17.0	0.0	83.2			2.9	2.70	SD VFG VSLTY SSHY STKS SLMY N FLU
	10264.0-65.0									SD VFG VSLTY SLMY N FLU
22	10265.0-66.0	0.1	11.0	0.0	91.3			1.0	2.71	SD VFG VSLTY W/SML SH STKS SLMY N FLU
	10266.0-67.0									SD VFG VSLTY W/SML SH STKS SLMY N FLU
23	10267.0-68.0	<0.1	6.3	0.0	74.5			1.6	2.71	SD VFG VSLTY VLMY N FLU
	10268.0-70.0									LOST CORE
	11732.0-86.0	CORE NO. 4 CUT 54 FT. REC. 54 FT.								
24	11732.0-33.0									SD VFG CLN N FLU
	11733.0-34.0	<0.1	7.3	0.0	47.9			3.8	2.68	SD VFG CLN BOT 1/4' VSLTY VLMY N FLU
	11734.0-35.0									SD VFG VSLTY VLMY N FLU
25	11735.0-36.0	31	21.5	0.0	84.2			3.4	2.66	SD F-VFG CLN N FLU
	11736.0-37.0									SD VFG CLN N FLU
26	11737.0-38.0	1.1	18.3	0.0	85.2			2.7	2.67	SD VFG CLN H FLU
	11738.0-39.0									SD VFG CLN N FLU
27	11739.0-40.0	36	23.9	0.0	88.7			2.4	2.66	SD VFG CLN H FLU
	11740.0-41.0									SD F-VFG CLN N FLU
28	11741.0-42.0	83	23.9	0.0	77.8			5.3	2.65	SD F-VFG CLN N FLU
	11742.0-43.0									SD F-VFG CLN H FLU
29	11743.0-44.0	19	21.8	0.0	81.7			4.0	2.66	SD F-VFG CLN H FLU

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GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1DATE: 7-17-78
FORMATION:FILE NO: 2202-10173-3
LABORATORY: HOUSTON, TEX.

SMP NO	DEPTH	PERM HORZ (KA)	MD	POR %	OIL% PORE	WTR% PORE	PROB PROD	GAS% BULK	GRN. DEN.	DESCRIPTION
30	11744.0-45.0 11745.0-46.0 11746.0-47.0	2.7		20.1	0.0	76.6		4.7	2.67	SD F-VFG CLN W/SLTY STKS N FLU SD F-VFG CLN W/SLTY STKS N FLU SD F-VFG CLN N FLU
31	11747.0-48.0 11748.0-49.0	7.7		21.2	0.0	79.7		4.3	2.66	SD F-VFG CLN N FLU SD F-VFG CLN N FLU
32	11749.0-50.0 11750.0-51.0	20		17.4	0.0	83.9		2.8	2.65	SD F-VFG CLN N FLU SD F-VFG CLN N FLU
33	11751.0-52.0 11752.0-53.0	17		20.9	0.0	89.5		2.2	2.65	SD F-VFG CLN N FLU RINGTAIL SH W/VSLTY STK @ BOT & CLN S @ TOP N FLU
34	11753.0-54.0 11754.0-55.0	40		23.6	0.0	84.7		3.6	2.66	SD VFG VSLTY VLMY W/SH STKS N FLU SD F-VFG CLN W/SLTY STKS & INCLS SLMY N FLU
35	11755.0-56.0 11756.0-57.0	0.1		12.9	0.0	83.7		2.1	2.66	SD F-VFG CLN SLMY N FLU SD F-VFG CLN SLMY N FLU
36	11757.0-58.0 11758.0-59.0	40		19.0	0.0	84.2		3.0	2.64	SD F-VFG CLN N FLU SD F-VFG CLN N FLU
37	11759.0-60.0 11760.0-61.0	36		18.9	0.0	87.3		2.4	2.67	SD F-VFG CLN N FLU SD F-VFG CLN 2/3' SH N FLU
38	11761.0-62.0 11762.0-63.0	17		14.4	0.0	73.6		3.8	2.65	SD F-VFG CLN W/FOS @ BOT SHY LMY STKS N FLU SD F-VFG CLN FOS LMY N FLU
39	11763.0-64.0 11764.0-65.0	12		14.9	0.0	86.6		2.0	2.66	SD FG SGLTY VFOS N FLU SD FG SSLTY W/SLTY STKS VSHY @ TOP H FLU
40	11765.0-66.0 11766.0-67.0	0.3		13.4	0.0	83.6		2.2	2.70	SD VFG VSLTY VSHY STKD N FLU SD VFG VSLTY VSHY STKD 1/6' FG CLN SD N FLU
41	11767.0-68.0 11768.0-69.0	60		19.4	0.0	86.1		2.7	2.65	SD FG CLN N FLU SD MG CLN VFOS N FLU
42	11769.0-70.0 11770.0-71.0	110		20.1	0.0	89.1		2.2	2.64	SD FG CLN SFOS N FLU SD FG CLN N FLU

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1DATE: 7-17-78
FORMATION:FILE NO: 2202-10173-3
LABORATORY: HOUSTON, TEX.

SMP NO	DEPTH	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	PROD PROD	GAS% BULK	GRN. DEN.	DESCRIPTION
43	11771.0-72.0	179	20.6	0.0	87.9		2.5	2.65	SD FG CLN N FLU
	11772.0-73.0								SD FG CLN N FLU
44	11773.0-74.0	0.1	8.1	0.0	66.7		2.7	2.67	SD FG W/SH STKS VLMY TOP 1/4' CLN N FL
	11774.0-75.0								SD FG W/SH STKS VLMY BOT 1/3' CLN N FL
45	11775.0-76.0	22	16.8	0.0	86.9		2.2	2.64	SD F-VFG CLN N FLU
	11776.0-77.0								SD F-VFG CLN BOT 1/2' FG VLMY N FLU
46	11777.0-78.0	0.7	17.4	0.0	73.0		4.7	2.66	SD F-VFG CLN N FLU
	11778.0-79.0								SD VFG SSLTY LMY N FLU
47	11779.0-80.0	0.1	14.9	0.0	62.4		5.6	2.68	SD VFG SSLTY LMY N FLU
	11780.0-81.0								SD VFG SLTY SHY N FLU
48	11781.0-82.0	<0.1	13.0	0.0	84.6		2.0	2.71	SD VFG SLTY SHY INCLS N FLU
	11782.0-83.0								SD VFG SLTY N FLU
49	11783.0-84.0	<0.1	12.7	0.0	85.0		1.9	2.68	SD VFG SLTY SHY STKS N FLU
	11784.0-85.0								SD F-VFG CLN N FLU
50	11785.0-86.0	0.3	15.9	0.0	84.9		2.4	2.67	SD F-VFG SLTY VSHY STKS N FLU
12580.0-12634.0 CORE NO. 5 CUT 54 FT. REC. 52 FT.									
12580.0-83.5									
12583.5-32.0									
12632.0-34.0									
SHALE W/LG VSLTY STKS									
SHALE RINGTAIL W/OCCASIONAL VSLTY STKS									
LOST CORE									
14053.0-14106.0 CORE NO. 6 CUT 53 FT. REC. 53 FT.									
51	14053.0-54.0	0.3	18.2	0.0	85.7		2.6	2.68	SD VFG VSLTY W/SH STKS N FLU
	14054.0-55.0								SD VFG VSLTY N FLU
52	14055.0-56.0	0.4	19.0	0.0	61.6		7.3	2.68	SD VFG VSLTY W/SH STKS N FLU
	14056.0-57.0								SD VFG VSLTY N FLU
53	14057.0-58.0	13	23.3	0.0	83.7		3.8	2.66	SD VFG VSLTY N FLU
	14058.0-59.0								SD VFG VSLTY N FLU
54	14059.0-60.0	6.0	20.9	0.0	75.6		5.1	2.66	SD VFG VSLTY N FLU
	14060.0-61.0								SD VFG VSLTY N FLU

GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1

DATE: 7-17-78
FORMATION:

FILE NO: 2202-10173-3
LABORATORY: HOUSTON, TEX.

SMP NO	DEPTH	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	PROD PROD	GAS% BULK	GRN. DEN.	DESCRIPTION
55	14061.0-62.0	17	20.3	0.0	91.6		1.7	2.66	SD VFG VSLTY N FLU
	14062.0-63.5								SHALE SLTY W/SDY STKS N FLU
	14063.5-80.5								SHALE RINGTAIL
56	14080.5-81.0	0.3	8.1	0.0	76.5		1.9	2.65	SD VFG DNS N FLU
	14081.0-82.0								SD VFG DNS N FLU
57	14082.0-83.0	5.4	15.7	0.0	63.7		5.7	2.65	SD VFG DNS W/SH STKS N FLU
	14083.0-84.0								SD VFG CARB INCL VSLTY N FLU
58	14084.0-85.0	<0.1	11.7	0.0	88.0		1.4	2.70	SD VFG CARB INCL VSLTY N FLU
	14085.0-86.0								SD VFG CARB INCL VSLTY N FLU
59	14086.0-87.0	<0.1	10.3	0.0	72.8		2.8	2.70	SD VFG CARB INCL VSLTY N FLU
	14087.0-88.0								SD VFG SML CARB INCL VSLTY N FLU
60	14088.0-89.0	0.1	13.8	0.0	89.8		1.4	2.68	SD VFG SML CARB INCL VSLTY N FLU
	14089.0-90.0								SD VFG SSLTY (SWIRLS) VSLTY N FLU
61	14090.0-91.0	0.1	17.7	0.0	86.4		2.4	2.69	SD VFG SSLTY (SWIRLS) VSLTY N FLU
	14091.0-92.0								SD VFG SSLTY STKS VSLTY N FLU
62	14092.0-93.0	0.1	14.6	0.0	85.6		2.1	2.69	SD VFG SHY STKS VSLTY N FLU
	14093.0-94.0								SD VFG SHY STKS VSLTY N FLU
63	14094.0-95.0	0.1	13.0	0.0	80.4		2.6	2.68	SD VFG SHY STKD VSLTY N FLU
	14095.0-96.0								SD VFG VSLTY N FLU
64	14096.0-97.0	0.1	18.0	0.0	92.2		1.4	2.69	SD VFG VSLTY N FLU
	14097.0-98.0								SD VFG VSLTY N FLU
65	14098.0-99.0	<0.1	17.6	0.0	89.8		1.8	2.69	SD VFG VSLTY N FLU
	14099.0-00.0								SD VFG VSLTY N FLU
66	14100.0-01.0	<0.1	17.7	0.0	87.6		2.2	2.69	SD VFG SSHY STKS VSLTY N FLU
	14101.0-02.0								SD VFG SSHY STKS VSLTY N FLU
67	14102.0-03.0	0.1	15.2	0.0	88.2		1.8	2.69	SD VFG SSHY STKS VSLTY N FLU
	14103.0-04.0								SD VFG SSHY STK VSLTY BOT 1/2' SH H FL
68	14104.0-05.0	1.2	15.3	0.0	68.6		4.8	2.65	SD VFG VSLTY N FLU
	14105.0-06.0								SD VFG VSLTY N FLU
	14747.0-83.0	CORE NO. 7 CUT 36 FT. REC. 20.5							

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GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1DATE: 7-17-78
FORMATION:FILE NO: 2202-10173-3
LABORATORY: HOUSTON, TEX.

SMP NO	DEPTH	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	PROB PROD	GAS% BJLK	GRN. DEN.	DESCRIPTION
69	14747.0-48.0	96	16.5	0.0	46.7		8.4	2.67	SD F-MG SSLTY N FLU
	14748.0-49.0								SD F-MG SSLTY N FLU
70	14749.0-50.0	114	19.1	0.0	50.8		9.4	2.66	SD F-MG SHY STKS N FLU
	14750.0-51.0								SD F-MG SHY STKS N FLU
71	14751.0-52.0	107	17.9	0.0	52.5		8.5	2.66	SD FG SSLTY N FLU
	14752.0-53.0								SD FG SSLTY N FLU
72	14753.0-54.0	332	20.3	0.0	45.8		11.0	2.66	SD FG SSLTY N FLU
	14754.0-55.0								SD F-MG SSLTY SH INCLS N FLU
73	14755.0-56.0	0.8	11.6	0.0	75.0		2.9	2.70	SD VFG VSLTY W/LG SH STKS & INCLS II FL
	14756.0-57.0								SD VFG VSLTY W/MNY SH STKS SLICKENSIDE N FLU
74	14757.0-58.0	8.2	17.8	0.0	53.4		8.3	2.69	SD FG VSLTY W/SML SH INCLS LMY N FLU
	14758.0-59.0								SD F-MG SSLTY N FLU
75	14759.0-60.0	1041	21.6	0.0	54.2		9.9	2.65	SD F-MG SSHY STK N FLU
	14760.0-61.0								SD F-MG SSLTY N FLU
76	14761.0-62.0	701	20.7	0.0	38.6		12.7	2.66	SD MG SSLTY N FLU
	14762.0-63.0								SD FG SSLTY N FLU
77	14763.0-64.0	134	17.0	0.0	42.9		9.7	2.67	SD F-MG SSHY STKS N FLU
	14764.0-65.0								SD F-MG SSLTY N FLU
78	14765.0-66.0	129	18.3	0.0	48.6		9.4	2.67	SD F-MG SSHY STKS BOT 1/4' F-VFG VSHY STKS N FLU
	14766.0-67.0								SD F-MG SSLTY N FLU
79	14767.0-67.5	266	18.9	0.0	63.5		6.9	2.66	SD F-MG SSHY STKS N FLU
	14767.5-83.0								LOST CORE
	15147.0-87.0	CORE NO. 8 CUT 40 FT. REC. 40 FT.							
80	15147.0-48.0	<0.1	0.8	0.0	25.0		0.6	2.60	SD VFG DNS 1/2' VSHY N FLU
	15148.0-49.0								SD VFG SHY LAM N FLU
81	15149.0-49.5	0.4	7.8	0.0	89.7		0.8	2.65	SD VFG SHY LAM SLTY N FLU
	15149.5-51.0								SHALE N FLU
	15151.0-54.0								SHALE W/SD STKS N FLU

GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1

DATE: 7-17-78
FORMATION:

FILE NO: 2202-10173-3
LABORATORY: HOUSTON, TEX.

SMP NO	DEPTH'	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	PROB PROD	GAS% BULK	GRN. DEN.	DESCRIPTION
82	15154.0-55.0	<0.1	5.4	0.0	87.0		0.7	2.67	SD FG VSHY STKD SLFY N FLU
	15155.0-58.0								SHALE W/SD STKS N FLU
83	15158.0-58.5	0.1	6.6	0.0	89.4		0.7	2.70	SD FG SHY STKD N FLU
	15158.5-59.0								SHALE N FLU
	15159.0-60.0								SD FG VSHY STKD N FLU
84	15160.0-61.0	<0.1	3.0	0.0	63.3		1.1	2.66	SD FG SHY STKD SLMY N FLU
	15161.0-62.0								SD FG SSHY STKD SLMY N FLU
85	15162.0-62.5	<0.1	2.6	0.0	73.1		0.7	2.65	SD FG SSHY STKS SLMY N FLU
	15162.5-65.0								SHALE W/SD STKS N FLU
86	15165.0-65.5	<0.1	2.3	0.0	65.2		0.8	2.60	SD FG SSHY STKS SLMY N FLU
	15165.5-67.0								SHALE W/SD STKS N FLU
87	15167.0-68.0	0.4	7.8	0.0	87.2		1.0	2.69	SD FG VSHY STKD SLMY N FLU
	15168.0-69.0								SD FG VSHY STKD SLMY N FLU
88	15169.0-69.5	<0.1	7.5	0.0	73.3		2.0	2.69	SD FG SSHY N FLU
	15169.5-71.0								SD FG VSHY STKD N FLU
89	15171.0-72.0	0.1	5.8	0.0	58.6		2.4	2.65	SD FG LMY N FLU
	15172.0-73.0								SD FG SSHY STKD LMY N FLU
90	15173.0-74.0	0.1	8.0	0.0	40.0		4.8	2.66	SD FG LMY N FLU
	15174.0-75.0								SD FG LMY LG SH STK N FLU
91	15175.0-76.0	0.3	9.9	0.0	51.0		4.8	2.67	SD FG LMY LG SH STK N FLU
	15176.0-77.0								SD FG LMY N FLU
92	15177.0-78.0	0.4	13.1	0.0	48.1		6.8	2.68	SD FG SML SH INCLS N FLU
	15178.0-79.0								SD FG SML SH INCLS SLMY N FLU
93	15179.0-80.0	0.2	13.7	0.0	45.3		7.5	2.68	SD FG SLMY N FLU
	15180.0-81.0								SD FG SLMY N FLU
94	15181.0-82.0	0.1	8.3	0.0	31.3		5.7	2.67	SD FG SLMY N FLU
	15182.0-83.0								SD FG SLMY N FLU
95	15183.0-84.0	0.4	17.5	0.0	44.6		9.7	2.69	SD FG SLMY N FLU
	15184.0-85.0								SD FG SLMY N FLU
96	15185.0-86.0	0.4	15.8	0.0	46.8		8.4	2.67	SD FG SLMY N FLU
	15186.0-87.0								SD FG SLMY N FLU
	15543.0-93.5	CORE NO. 9 CUT 50 FT. REC. 37.5							

GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1

DATE: 7-17-78
FORMATION:

FILE NO: 2202-10173-3
LABORATORY: HOUSTON, TEX.

SMP NO	DEPTH	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	PROD PROD	GAS% BULK	GRN. DEN.	DESCRIPTION
97	15543.0-44.0	<0.1	7.7	0.0	77.9		1.7	2.66	SD FG SSLTY DNS BOT 1/2' SH LAMS N FLU
	15544.0-45.0								SD VFG DNS VSHY LAMS N FLU
98	15545.0-46.0	<0.1	7.1	0.0	84.5		1.1	2.65	SD VFG DNS VSHY W/SH INCLS N FLU
	15546.0-47.0								SD VFG DNS VSHY W/SH INCLS N FLU
99	15547.0-48.0	<0.1	8.9	0.0	73.0		2.4	2.65	SD VFG DNS SLTY W/SH LAMS N FLU
	15548.0-49.0								SD VFG SLTY DNS N FLU
100	15549.0-50.0	<0.1	6.5	0.0	69.2		2.0	2.67	SD VFG SLTY DNS N FLU
	15550.0-51.0								SD VFG SLTY DNS W/SHY STKS N FLU
101	15551.0-52.0	<0.1	6.9	0.0	81.2		1.3	2.68	SD VFG DNS SHY W/SH LAMS N FLU
	15552.0-53.0								SD VFG DNS SHY W/SH LAMS N FLU
102	15553.0-54.0	<0.1	6.6	0.0	63.6		2.4	2.63	SD VFG DNS SLTY N FLU
	15554.0-55.0								SD VFG DNS SLTY N FLU
103	15555.0-56.0	<0.1	6.5	0.0	76.9		1.5	2.63	SD VFG DNS SLTY N FLU
	15556.0-57.0								SD VFG DNS VSHY W/SH LAMS N FLU
	15557.0-58.5								SHALE
	15558.5-62.5								SHALE VSLTY
104	15562.5-63.0	<0.1	8.7	0.0	81.6		1.8	2.66	SD VFG VSLTY DNS N FLU
	15563.0-76.0								LOST CORE
105	15576.0-77.0	0.1	17.0	0.0	21.2		13.4	2.67	SD VFG SLTY N FLU
	15577.0-78.0								SD VFG SLTY N FLU
106	15578.0-79.0	0.4	17.9	0.0	24.0		13.6	2.65	SD VFG SLTY N FLU
	15579.0-80.0								SD VFG SLTY N FLU
107	15580.0-81.0	<0.1	12.4	0.0	25.8		9.2	2.66	SD VFG SLTY N FLU
	15581.0-82.0								SD VFG SLTY BOT 2/3' SH N FLU
108	15582.0-83.0	<0.1	14.0	0.0	84.3		2.2	2.66	SD VFG SLTY N FLU
	15583.0-84.0								SHALE
109	15584.0-85.0	<0.1	6.1	0.0	70.5		1.8	2.73	SD VFG VSHY N FLU
	15585.0-86.0								SD VFG SLTY N FLU
110	15586.0-87.0	<0.1	12.5	0.0	84.8		1.9	2.67	SD VFG SLTY N FLU
	15587.0-88.0								SD VFG SLTY N FLU
111	15588.0-89.0	0.4	16.8	0.0	24.4		12.7	2.67	SD VFG SLTY N FLU
	15589.0-90.0								SD VFG SLTY N FLU

GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1

DATE: 7-17-78
FORMATION:

FILE NO: 2202-10173-3
LABORATORY: HOUSTON, TEX.

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SMP NO	DEPTH	PERM MD HORZ (KA)	POR %	OIL% PORE	WTR% PORE	PROB PROD	GAS% BULK	GRN. DEN.	DESCRIPTION
112	15590.0-91.0 15591.0-92.0	<0.1	2.6	0.0	53.8		1.2	2.63	SD VFG SLTY DNS N FLU SD VFG VSHY W/SLTY INCLS N FLU
113	15592.0-93.0 15593.0-93.5	<0.1	5.2	0.0	71.2		1.5	2.66	SD VFG VSLTY W/SH INCLS N FLU SD VFG SLTY TOP SH N FLU

GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1
WILDCAT
BRAZORIA COUNTY, TEXAS

DATE: 7-29-78
FORMATION:
DRLG. FLUID: WATER BASE MUD

FILE NO: 2202-10173-3
ANALYSTS: WELLS
LABORATORY: HOUSTON
CORES:

SIDE WALL CORE ANALYSIS

REC IN	DEPTH FEET	PERM MD(*)	POR %	OIL% PORE	WTR% PORE	PROB PROD	OIL% BULK	GAS% BULK	GAS DET	CRIT WTR%	DESCRIPTION
1.1	2045.0	1950	33.3	0.0	81.3	WTR	0.0	6.2	TR	37	SD FG SSLTY VLMY N FLU
	2185.0										SHALE VLMY N FLU
0.7	2280.0	300	36.0	0.0	89.3	WTR	0.0	3.8	TR	47	SD FG SLTY VLMY N FLU
	2335.0										SHALE VLMY
0.8	2435.0	235	35.8	0.0	84.1	WTR	0.0	5.7	0	49	SD FG SLTY VLMY N FLU
1.5	2795.0	245	34.7	0.0	79.8	WTR	0.0	7.1	0	49	SD FG SLTY VLMY N FLU
	2820.0					(3)					MUDCAKE W/TR FG SLTY SD
0.9	2875.0	5.0	24.5	0.0	87.2	(6)	0.0	3.2	0	75	SD FG VSLTY VLMY N FLU
	2915.0										MUDCAKE
1.1	3066.0	4.8	20.0	0.0	81.1	(6)	0.0	3.8	0	71	SD FG VSLTY VLMY N FLU
	3159.0										MUDCAKE
0.8	3160.0	5.6	22.7	0.0	82.2	(6)	0.0	4.0	0	73	SD FG VSHY VLMY N FLU
0.7	3173.0	335	36.5	0.0	83.2	WTR	0.0	5.1	0	46	SD FG SHY VLMY N FLU
1.1	3318.0	1250	32.1	0.0	80.8	WTR	0.0	4.9	0	37	SD FG SSHY VLMY N FLU
1.5	3770.0	135	30.8	0.0	87.0	WTR	0.0	4.0	0	53	SD F-VFG SHY VLMY N FLU

GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1

DATE: 7-29-78
FORMATION:

FILE NO: 2202-10173-3
ANALYSTS: WELLS

REC IN	DEPTH FEET	PERM MD(*)	POR %	OIL% PORE	WTR% PORE	PROB PROD	OIL% BULK	GAS% BULK	GAS DET	CRIT WTR%	DESCRIPTION
1.3	3860.0								0		SHALE VLMY
	4232.0										NO RECOVERY
1.2	4325.0	185	31.0	0.0	88.9	WTR	0.0	3.4	0	49	SD F-VFG SLTY W/LG VFOS SHY STKS N FLU
0.8	4340.0	33	30.4	0.0	88.4	WTR	0.0	3.5	TR	67	SD VFG VSLTY VLMY N FLU
1.2	4568.0	19	28.3	0.0	82.3	WTR	0.0	5.0	0	70	SD VFG VSLTY VLMY N FLU
1.5	4571.0	5.1	25.2	0.0	79.8	(6)	0.0	5.1	0	75	SD VFG VSHY VLMY N FLU
0.4	4574.0	30	28.4	0.0	84.8	WTR	0.0	4.3	0	66	SD VFG VSHY VLMY N FLU
1.0	4582.0	185	31.2	0.0	84.2	WTR	0.0	4.9	0	49	SD F-VFG SLTY VLMY N FLU
0.6	4697.0								0		MUDCAKE
1.0	4708.0					(1)	0.0		0		SD FG CLN CARB N FLU
1.5	5410.0	145	32.0	0.0	89.8	WTR	0.0	3.3	0	53	SD FG SHY SLMY N FLU
0.7	5825.0								0		MUDCAKE
1.6	5985.0	9.8	21.5	0.0	75.8	(6)	0.0	5.2	0	69	SD MG VSHY STKD FOS VLMY N FLU
0.4	6100.0	4.4	23.8	0.0	87.8	(6)	0.0	2.9	0	74	SD VFG VSHY VLMY N FLU
0.6	6513.0	28	25.6	0.0	79.6	WTR	0.0	5.2	0	65	SD VFG SLTY LMY N FLU
1.5	7800.0								1		SHALE VLMY
1.4	8100.0								0		SHALE VLMY

GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1

DATE: 7-29-78
FORMATION:

FILE NO: 2202-10173-3
ANALYSTS: WELLS

REC IN	DEPTH FEET	PERM MD(*)	POR %	OIL% PORE	WTR% PORE	PROD PROD	OIL% BULK	GAS% BULK	GAS DET	CRIT WTR%	DESCRIPTION
1.1	8400.0								0		SHALE VLMY

- (1) ALTERED CORE
(3) INSUFFICIENT SAMPLE
(6) LOW PERMEABILITY
CRIT WTR% ■ CRITICAL WATER SATURATION
(SEE ATTACHED EXPLANATION)
(*) PERMEABILITY VALUES FOR PERCUSSION TYPE SIDEWALL
CORES DETERMINED EMPIRICALLY.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering

CRITICAL WATER SATURATION

Critical water is the maximum water saturation permissible in the reservoir for each sample if the formation is hydrocarbon productive. The value is an estimate obtained using core analysis permeability and porosity values and average critical water correlations.*

This interpretive method requires a comparison of critical water saturation obtained from core data with the formation water saturation calculated from the resistivity log. Hydrocarbon production is indicated if the actual formation water saturation in

the reservoir is less than the critical value.

The core analysis critical value represents a specific depth. The log calculated value is affected by resistivity averaging over an interval of more than four feet. Consequently, the comparison of the two water values may yield a pessimistic interpretation in thin bedded hydrocarbon productive zones. It is essential that sufficient samples be analyzed to assure representative core data and that allowance be made for thin bed resistivity averaging effect.

*Granberry, Raymond J., and Keelan, Dare K., 1977.
Critical Water Estimates for Gulf Coast Sands:
Gulf Coast Assoc. Geol. Soc. Trans., XXVII, p. 41-43.

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DISTRIBUTION OF FINAL REPORTS

GENERAL CRUDE-DEPT. OF ENERGY
PLEASANT BAYOU NO. 1

WILDCAT
BRAZORIA COUNTY, TEXAS

FILE NO: 2202-10173-3
DATE: 7-29-78

LETTER ADDRESSED TO:

2CC GENERAL CRUDE OIL COMPANY
2700 ONE ALLEN CENTER
HOUSTON, TEXAS 77001

ATTN: MR. CHARLES JONES

COPIES TO:

2CC DR. DONALD G. BEBOUT
BUREAU OF ECONOMIC GEOLOGY
P. O. BOX X
UNIVERSITY OF TEX. AT AUSTIN
AUSTIN, TEXAS 78712

2CC GENERAL CRUDE OIL COMPANY
2700 ONE ALLEN CENTER
HOUSTON, TEXAS 77001

ATTN: MR. CLIFF DYE

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

CORE ANALYSIS REPORT

FOR

GENERAL CRUDE OIL CO. - D.O.E.

PLEASANT BAYOU NO. 2
WILDCAT
BRAZORIA COUNTY, TEXAS

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

CORE LABORATORIES, INC.

June 4, 1979

General Crude Oil Company
2700 One Allen Center
Houston, Texas 77001

Attention: Mr. Charles Jones

Subject: Core Analysis
Pleasant Bayou #2
Wildcat
Brazoria County, Texas
CLI File #2202-10763

Gentlemen:

Diamond coring equipment and water base mud were utilized to core the subject well. The cores were picked up at the well site by a representative of Core Laboratories, Inc. and transported to the Houston Laboratory for conventional plug analysis. The results of this analysis may be found in tabular form on the accompanying pages of this report.

Cores number one through three were sampled every other foot in the sand sections as requested by a representative of the client. Grain density measurements were made on each sample and are reported with the tabular data.

A Core-Gamma correlation was run and the log is inserted in the pocket of this final report folder.

Polaroid photos were made of each recovered foot and have been delivered to the client.

Core remnants and plugs have been shipped to Balcones Research Center at the University of Texas at Austin.

Thank you for the opportunity to be of service.

Very truly yours,

CORE LABORATORIES, INC.

A handwritten signature in dark ink, appearing to read "C.E. Kuhlman".
C.E. Kuhlman
Laboratory Manager

CEK:ss
Enclosure

GENERAL CRUDE OIL CO. - D.O.E.
PLEASANT BAYOU NO. 2
WILDCAT
BRAZORIA COUNTY, TEXAS

DATE : 10-MAY-79
FORMATION : FRIO
DRLG. FLUID: WATER BASE MUD
LOCATION :

FILE NO : 2202-10763
LABORATORY: HOUSTON
ANALYSTS : MEHALL
ELEVATION :

CONVENTIONAL CORE ANALYSIS

SMP NO	DEPTH	PERM MD HORZ(KA)	POR %	OILZ PORE	WTRZ PORE	PROB PROD	GASZ BULK	GRAIN DEN(M)	DESCRIPTION
CORE NO. 1 14666.0-14716.0 CUT 50 FT REC. 32 FT									
	14666.0-84.0								LOST CORE
	14684.0-85.0								SD VF-CG W/PEBS VLMY MIN FLU
1	14685.0-86.0	0.07	2.5	0.0	56.0		1.1	2.66	SD VF-CG W/PEBS VLMY MIN FLU
	14686.0-87.0								SD VF-CG W/PEBS VLMY MIN FLU
2	14687.0-88.0	19.	14.7	0.0	61.9		5.6	2.65	SD VF-MG W/SM MICA SH LAM LMY SPTY MIN FLU
	14688.0-89.0								SD VF-MG SLMY N FLU
3	14689.0-90.0	105.	20.6	0.0	84.0		3.3	2.64	SD VF-MG SLMY N FLU
	14690.0-91.0								SD VF-MG SLMY N FLU
4	14691.0-92.0	124.	18.1	0.0	76.8		4.2	2.64	SD VF-MG SM SLTY SH LAM SLMY N FLU
	14692.0-93.0								SD VF-MG SLTY SH LAM N FLU
5	14693.0-94.0	15.	14.7	0.0	68.7		4.6	2.64	SD VF-MG SM SLTY SH LAM N FLU
	14694.0-95.0								SD VF-MG N FLU
6	14695.0-96.0	38.	15.5	0.0	71.6		4.4	2.65	SD VF-MG FEW SM SH INCLS SLMY N FLU
	14696.0-97.0								SD VF-MG N FLU
7	14697.0-98.0	120.	16.2	0.0	77.2		3.7	2.64	SD VF-MG N FLU
	14698.0-99.0								SD VF-MG N FLU
8	14699.0-00.0	397.	17.6	0.0	72.7		4.8	2.64	SD VF-MG N FLU
	14700.0-01.0								SD VF-MG N FLU
9	14701.0-02.0	230.	19.6	0.0	85.2		3.1	2.64	SD VF-MG N FLU
	14702.0-03.0								SD VF-MG N FLU
10	14703.0-04.0	3.29	12.0	0.0	68.3		3.8	2.65	SD VF-MG SM SH LAMS SLTY SLMY N FLU
	14704.0-05.0								SD VF-MG N FLU
11	14705.0-06.0	275.	19.4	0.0	79.4		4.0	2.64	SD VF-MG TOP 6" SLTY W/SM SH LAM N FLU

GENERAL CRUDE OIL CO. - D.O.E.
PLEASANT BAYOU NO. 2

DATE : 10-MAY-79
FORMATION : FRIO

FILE NO : 2202-10763
LABORATORY: HOUSTON

CONVENTIONAL CORE ANALYSIS

SMP NO	DEPTH	PERM MD HORZ(KA)	POR %	OILZ PORE	WTRZ PORE	PROB PROD	GASZ BULK	GRAIN DEN(M)	DESCRIPTION
12	14706.0-07.0								SD VF-MG N FLU
	14707.0-08.0	185.	17.6	0.0	75.6		4.3	2.64	SD VF-MG SM SH LAM N FLU
	14708.0-09.0								SD VF-MG N FLU
13	14709.0-10.0	475.	20.9	0.0	84.7		3.2	2.64	SD VF-MG N FLU
	14710.0-11.0								SD VF-MG N FLU
14	14711.0-12.0	140.	17.5	0.0	95.1		2.6	2.64	SD F-VFG SSHY STKS SLMY N FLU
	14712.0-13.0								SD VF-MG N FLU
15	14713.0-14.0	466.	19.6	0.0	73.5		5.2	2.63	SD VF-MG N FLU
	14714.0-15.0								SD VF-MG N FLU
16	14715.0-16.0	515.	20.5	0.0	81.0		3.9	2.64	SD VF-MG N FLU

(M) = MEASURED

GENERAL CRUDE OIL CO. - D.O.E.
 PLEASANT BAYOU NO. 2
 WILDCAT
 BRAZORIA COUNTY, TEXAS

DATE : 10-MAY-79
 FORMATION : FRIO
 DRLG. FLUID: WATER BASE MUD
 LOCATION :

FILE NO : 2202-10763-4
 LABORATORY: HOUSTON
 ANALYSTS : MEHALL
 ELEVATION :

CONVENTIONAL CORE ANALYSIS

SMP NO	DEPTH	PERM MD HORZ(KA)	POR %	OILZ PORE	WTRZ PORE	PROD PROD	GASZ BULK	GRAIN DEN(M)	DESCRIPTION
CORE NO. 2 15615.0-15664.0 CUT 48 FT REC 49 FT									
17	15615.0-16.0	200.	22.9	0.0	84.7		3.5	2.65	SD VF-CG SLTY W/PEBS MIN FLU
	15616.0-17.0								SD VF-CG SLTY W/PEBS MIN FLU
18	15617.0-18.0	72.	13.6	0.0	50.7		6.7	2.65	SD VF-MG SLTY MIN FLU
	15618.0-19.0								SD VF-MG SLTY MIN FLU
19	15619.0-20.5	14.	21.0	0.0	49.0		10.7	2.64	SD VF-MG SLTY MIN FLU
	15620.5-31.0								SHALE LIG
20	15631.0-32.0	0.02	11.0	0.0	35.5		7.1	2.66	SD F-VFG VSLTY W/CARB STKS MIN FLU
	15632.0-33.0								SD F-VFG VSLTY W/CARB STKS MIN FLU
21	15633.0-34.0	0.05	12.0	0.0	30.0		8.4	2.65	SD VF-MG VSLTY W/CARB STKS MIN FLU
	15634.0-35.0								SD VF-MG VSLTY W/CARB STKS MIN FLU
22	15635.0-36.0	0.02	15.7	0.0	58.6		6.5	2.65	SD VF-MG VSLTY W/CARB STKS MIN FLU
	15636.0-37.0								SD VF-MG VSLTY W/CARB STKS MIN FLU
23	15637.0-38.0	0.44	11.8	0.0	38.1		7.3	2.64	SD VF-MG VSLTY W/CARB STKS MIN FLU
	15638.0-39.0								SD VF-MG VSLTY W/CARB STKS MIN FLU
24	15639.0-40.0	0.56	12.5	0.0	40.8		7.6	2.64	SD VF-MG VSLTY MIN FLU
	15640.0-41.0								SD VF-MG VSLTY MIN FLU
25	15641.0-42.0	0.44	11.8	0.0	38.9		7.2	2.65	SD VF-MG VSLTY MIN FLU
	15642.0-43.0								SD VF-MG VSLTY MIN FLU
26	15643.0-44.0	0.36	11.8	0.0	43.2		6.7	2.65	SD VF-MG VSLTY W/SH LAMS MIN FLU
	15644.0-45.0								SD VF-MG VSLTY W/SH LAMS MIN FLU
27	15645.0-46.0	0.32	9.6	0.0	26.0		7.1	2.64	SD VF-MG VSLTY MIN FLU
	15646.0-47.0								SD VF-MG VSLTY MIN FLU
28	15647.0-48.0	0.49	10.1	0.0	21.8		8.3	2.64	SD VF-MG VSLTY MIN FLU
	15648.0-49.0								SD VF-MG VSLTY MIN FLU
29	15649.0-50.0	0.78	10.4	0.0	41.3		6.7	2.64	SD VF-MG VSLTY MIN FLU

GENERAL CRUDE OIL CO. - D.O.E.
PLEASANT BAYOU NO. 2

DATE : 10-MAY-79
FORMATION : FRIO

FILE NO : 2202-10763-4
LABORATORY: HOUSTON

CONVENTIONAL CORE ANALYSIS

SMP NO	DEPTH	PERM MD HORZ(KA)	POR %	OIL% PORE	WTR% PORE	PROD PROD	GAS% BULK	GRAIN DEN(M)	DESCRIPTION
30	15650.0-51.0 15651.0-52.0 15652.0-53.0	0.16	8.7	0.0	27.6		6.3	2.64	SD VF-MG VSLTY MIN FLU SD F-MG VSLTY SLMY MIN FLU SD F-MG VSLTY MIN FLU
31	15653.0-53.5 15653.5-54.8	0.34	9.8	0.0	26.5		7.2	2.66	SD VF-MG VSLTY MIN FLU SD F-VFG VSHY MIN FLU
32	15654.8-56.0 15656.0-57.0	0.25	11.0	0.0	14.5		9.4	2.64	SD VF-MG SSLTY MIN FLU SD VFG VSHY MIN FLU
33	15657.0-58.0 15658.0-59.0	0.13	8.5	0.0	81.2		1.6	2.69	SD VFG VSLTY VSHY MIN FLU SD VFG VSLTY VSHY MIN FLU
34	15659.0-60.0 15660.0-61.0	0.12	8.7	0.0	81.6		1.6	2.69	SD VFG VSLTY W/SH LAMS MIN FLU SD VFG VSLTY W/SH LAMS MIN FLU
35	15661.0-62.0 15662.0-63.0	0.52	11.6	0.0	44.8		6.4	2.64	SD VF-MG VSLTY VFT FLU SD VF-MG VSLTY MIN FLU
36	15663.0-64.0	43.	10.5	0.0	78.1		2.3	2.64	SD VF-CG SLTY SLMY MIN FLU
CORE NO. 3 15664.0-15675.0 CUT 11 FT REC. 11 FT									
37	15664.0-65.0 15665.0-66.0 15666.0-67.0	169.	19.5	0.0	92.3		1.5	2.64	SD VF-CG SLTY SLMY MIN FLU SD VF-CG SLTY SLMY MIN FLU SD VF-CG SLTY SLMY MIN FLU
38	15667.0-68.0 15668.0-69.0	729.	19.4	0.0	92.3		1.5	2.64	SD VF-CG SLTY SLMY MIN FLU SD VF-CG SLTY SLMY MIN FLU
39	15669.0-70.0 15670.0-71.0 15671.0-75.0	3.87	9.0	0.0	34.4		5.9	2.64	SD F-VFG VSLTY VLMY MIN FLU SD VFG VSHY STKD MIN FLU SHALE

(M) = MEASURED

A-26

GENERAL CRUDE OIL CO. - D.O.E.
PLEASANT BAYOU NO. 2
BRAZORIA COUNTY, TEXAS

DATE : 10-MAY-79
FIELD: WILDCAT

FILE NO: 2202-10763-4
ANALYST: MEHALL

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BUREAU OF ECONOMIC GEOLOGY
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ATTN: DR. D. G. BEBOUT

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

APPENDIX B

PVT Analysis by Weatherly Laboratories, Inc. -- 1981

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

RESERVOIR FLUID ANALYSIS

For

ANACON, INC.

D.O.E. - FENIX & SCISSON, INC.

Pleasant Bayou No. 2
Chocolate Bayou Field
Brazoria County, Texas

WEATHERLY LABORATORIES, INC.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

J. E. Weatherly, Jr.
President

WEATHERLY LABORATORIES, INC.
223 Georgette Lafayette, Louisiana 70506
Phone (318) 232-4877
(318) 232-4604 24 Hours

John D. Neal
Vice President

Petroleum Engineers

April 21, 1981

Anacon, Inc.
2950 S. Shaver, Bldg. #A-14
Pasadena, TX 77502

Attn: Mr. James Lee

Re: Reservoir Fluid Study
D.O.E.-Fenix & Scisson Inc.
Pleasant Bayou Well No. 2
Chocolate Bayou Field
Brazoria County, Texas

Gentlemen:

The following pages present the results of the analysis of the chemical and physical characteristics of a recombined reservoir fluid (water). Separator samples were taken from the subject well on October 8, 1980 by a representative of Anacon, Inc.

Several gas-water ratios were recombined to determine a gas-water ratio -vs- saturation pressure curve. It was determined that the reservoir fluid is undersaturated at reservoir conditions. Pressure-volume relations and a differential liberation was performed on reservoir fluid recombined to the produced gas-water ratio at the time of sampling. There was insufficient sample to attempt viscosity measurements.

We wish to thank you for this opportunity of serving you. Should there be any questions concerning this report, please contact us.

Very truly yours,

John Neal

cc: Mr. H.R. Battin
Proj. Mgr. Pleasant Bayou
Fenix & Scisson Inc.
P.O. Box 36030
Alvin, TX 77511

Lab. No. N-1249

**Pleasant Bayou Well No. 2 Geopressure/Geothermal Project
Sampling and Laboratory Procedures**

- 1) The subject well was sampled on October 8, 1980 by representatives of Anacon, Inc. Two each, 500 ml. samples of separator water (one leaked), and one each 500 ml. sample of separator gas were taken.
- 2) Flash liberation of gas from separator water was accomplished by using a weighed separator flask. This separator flask was connected to the outlet of a separator water cylinder by a short capillary line. Gas from the separator flask passed through a weighed drying tube to a Ruska Gasometer. A vacuum valve and a mercury manometer was connected to the gas manifold between the drying tube and the gasometer. Before commencing the flash, the entire flash gas manifold was evacuated and then filled with Helium to atmospheric pressure. A known volume of separator water was pushed out of the sample cylinder at a pressure slightly above field separator pressure by use of a calibrated mercury pump. The volume of stock tank water produced was determined by its weight and density. The volume of dry gas evolved was determined with the gasometer. The gas was charged to a chromatograph for analysis.
- 3) Physical recombinations of separator effluents:
Separator gas was charged into a temperature controlled cell. The volume of this windowed cell is known for any pressure and temperature. The pressure of the gas in the cell was measured with a mercury manometer and a barometer. A volume of separator water was charged into the windowed cell by use of a calibrated mercury pump. The water was metered and measured at a pressure slightly above field separator pressure. Four recombinations were done in order to produce a saturation pressure-vs-gas-water ratio curve. A fifth recombination was done using the produced gas-water ratio at the time of sampling.
- 4) Pressure-volume relations of recombined reservoir fluid at reservoir temperature:
Each datum of pressure-volume relations was corrected for mercury pump calibration, manifold expansion, cell expansion, mercury compressibility and mercury thermal expansion. Liquid volume percent was determined by calibrated cathetometer.
- 5) Differential Liberation of reservoir fluid at reservoir temperature:
Gas from each pressure decrement of the differential liberation was measured and analyzed in the same manner as described in 2), (flash liberation). Differential liquid volume changes were noted.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Field Data for Weatherly Laboratory Investigation

Well Record

Company	Anacon, Inc. for D.O.E. - Fenix & Scisson, Inc.
Well	Pleasant Bayou No. 2
Field	Chocolate Bayou
County and State	Brazoria, Texas

Field Characteristics

Formation Name
Sand Name or Designation
Date Completed
Original Reservoir Pressure

Well Characteristics

Original Produced Gas-Liquid Ratio

Perforations	14,640 - 14,704	ft.
Elevations		
Total Depth		
Last Reservoir Pressure	11,116.5	psia
Reservoir Temperature	301	°F

Sampling Conditions

Date Sampled	10-8-80	
Tubing Pressure, Flowing		
Primary Separator Temperature	277	°F
Primary Separator Pressure	850	psig
Primary Separator Gas Rate		
Separator Liquid Rate		
Gas-Liquid Ratio (Separator)	21.14	SCF/Bbl. Sep. Liq.
Shrinkage Factor $\left(\frac{\text{vol. S.T. Liq. @ 60°F}}{\text{vol. Sep. Liq. @ Sep. Cond.}} \right)$	0.9459	
Gas-Liquid Ratio (Stock Tank)	22.35	SCF/Bbl. S.T. Liq.
Pressure Base	14.65	psia @ 60°F

Lab. No. N-1249

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Anacon, Inc.
Pleasant Bayou No. 2

Reservoir Fluid Summary

Reservoir Temperature, °F	301
Saturation Pressure at 301 °F, Psia	9670 ± 50
Compressibility of Reservoir Oil at 301 °F	
Vol. per Vol. per Psi x 10 ⁶	
From 9670 Psia to 10000 Psia	2.77
From 10000 Psia to 11116 Psia	2.67
Saturated Oil at 9670 Psia, 301 °F	
Density, Gms. per Ml.	1.0255
Lbs. per Bbl.	359.4
Specific Volume, Cu.Ft. per Lb.	0.01562
Viscosity, Centipoise	insufficient sample
Formation Volume Factor, Bbls. per Bbl.	
"Residual Stock Tank Oil" at 60°F	1.0656
Solution Gas-Oil Ratio, Cu.Ft. per Bbl.	
"Residual Stock Tank Oil" at 60°F	30.46 dry
	33.25 wet
Reservoir Oil at 1116 Psia 301 °F	
Density, Gms. per Ml.	1.0295
Lbs. per Bbl.	360.8
Specific Volume, Cu.Ft. per Lb.	0.01556
Viscosity, Centipoise	
Formation Volume Factor, Bbl. per Bbl.	
"Residual Stock Tank Oil" at 60°F	1.0614
Thermal Expansion at	Psia, % per °F

Lab. No. N-1249

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Anacon - Pleasant Bayou Well No. 2 COMPOSITE LABORATORY DATA AT 301 °F

Recombination(1): 19.00 SCF Sep.Gas @ 14.65 psia & 60°F/Bbl. Sep.Water @ Sep.Cond.

PRESSURE, PSIA	PRESSURE VOLUME RELATIONS			OIL VISCOSITY Centipoises	DIFFERENTIAL LIBERATION			
	RELATIVE VOLUME V/V _{sat} B ₁	SPECIFIC VOLUME cu. ft. Per Pound	Volume Percent Liquid		FORMATION VOLUME FACTOR B _o ★★	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO	
							Per Bbl. Stock Tank Oil at 60°F ★★	Per Bbl. Oil at Reservoir Bubble-Point

WET GAS

11116	Res.	0.9937	0.01556	100.00				
10001		0.9965	0.01561	100.00				
9005		0.9991	0.01565	100.00				
8705		0.9998	0.01566	100.00				
8650	B.P.	1.0000	0.01566	100.00	1.0675		31.29	
8599		1.0001	0.01566	bubble				
8008		1.0018	0.01569	99.98				
7017		1.0049	0.01574	99.91				
6018		1.0084	0.01579	99.79				
5022		1.0126	0.01586	99.60				
4000		1.0177	0.01594	99.31				
3000		1.0252	0.01605	98.76				
2000		1.0421	0.01632	97.47				
1000		1.0957	0.01716	93.02				
143		2.2501	0.03524	46.91				

NOMENCLATURE:

V/V_{sat} is the volume of fluids (oil and gas) at the indicated temperature and pressure relative to the volume of saturated oil at bubble-point pressure and indicated temperature.

B_o is the volume of oil at reservoir temperature and indicated pressure relative to the volume of residual stock tank oil measured at 60°F.

Gas-Oil Ratio, is cubic feet of gas at 14.65 psia at 60°F, per barrel of residual oil at 60°F.

Note: * indicates value measured at 60°F.

★★ based on separator water flash
References to "oil" above should read "water".

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Anacon - Pleasant Bayou Well No. 2 COMPOSITE LABORATORY DATA AT 301 °F

Recombination(2): 16.15 SCF Sep.Gas @ 14.65 psia & 60°F/Bbl. Sep.Water @ Sep.Cond

PRESSURE, PSIA	PRESSURE VOLUME RELATIONS			OIL VISCOSITY Centipoises	DIFFERENTIAL LIBERATION			
	RELATIVE VOLUME V/V _{sat} B1	SPECIFIC VOLUME cu. ft. Per Pound	Volume Percent Liquid		FORMATION VOLUME FACTOR B _o ★★	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO	
							Per Bbl. Stock Tank Oil at 60°F ★★	Per Bbl. Oil at Reservoir Bubble-Point

WET GAS

11116 Res.	0.9900	0.01554	100.00					
9996	0.9929	0.01559	100.00					
9000	0.9955	0.01563	100.00					
8003	0.9983	0.01567	100.00					
7497	0.9999	0.01570	100.00					
7450 B.P.	1.0000	0.01570	100.00		1.0696		28.28	
7397	1.0001	0.01570	bubble					
7012	1.0013	0.01572	99.97					
6000	1.0049	0.01578	99.85					
5003	1.0092	0.01584	99.67					
4002	1.0146	0.01593	99.37					
3000	1.0223	0.01605	98.86					
2002	1.0371	0.01628	97.69					
1000	1.0855	0.01704	93.56					
164	1.9135	0.03004	55.03					

NOMENCLATURE:

V/Vsat. is the volume of fluids (oil and gas) at the indicated temperature and pressure relative to the volume of saturated oil at bubble-point pressure and indicated temperature.

Bo is the volume of oil at reservoir temperature and indicated pressure relative to the volume of residual stock tank oil measured at 60°F.

Gas-Oil Ratio, is cubic feet of gas at 14.65 psia at 60°F, per barrel of residual oil at 60°F.

Note: * indicates value measured at 60°F.

★★ based on separator water flash
References to "oil" above should read "water".

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Anacon - Pleasant Bayou Well No. 2 COMPOSITE LABORATORY DATA AT 301 °F

Recombination(3): 12.35 SCF Sep.Gas @ 14.65 psia & 60°F/Bbl. Sep.Water @ Sep.Cond

PRESSURE, PSIA	PRESSURE VOLUME RELATIONS			OIL VISCOSITY Centipoises	DIFFERENTIAL LIBERATION			
	RELATIVE VOLUME V/V _{sat} Bt	SPECIFIC VOLUME cu. ft. Per Pound	Volume Percent Liquid		FORMATION VOLUME FACTOR B _o ★★	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO	
							Per Bbl. Stock Tank Oil at 60°F ★★	Per Bbl. Oil at Reservoir Bubble-Point

WET GAS

8004	0.9945	0.01568	100.00					
7004	0.9969	0.01572	100.00					
6008	0.9994	0.01576	100.00					
5828	0.9999	0.01577	100.00					
5775 B.P.	1.0000	0.01577	100.00		1.0721		24.26	
5722	1.0002	0.01577	bubble					
5008	1.0033	0.01582	99.88					
4003	1.0086	0.01591	99.60					
3002	1.0156	0.01602	99.15					
2001	1.0278	0.01621	98.22					
1000	1.0663	0.01682	94.91					
222	1.4598	0.02302	70.71					

NOMENCLATURE:

V/V_{sat} . is the volume of fluids (oil and gas) at the indicated temperature and pressure relative to the volume of saturated oil at bubble-point pressure and indicated temperature.

B_o is the volume of oil at reservoir temperature and indicated pressure relative to the volume of residual stock tank oil measured at 60°F.

Gas-Oil Ratio, is cubic feet of gas at 14.65 psia at 60°F, per barrel of residual oil at 60°F.

Note: * indicates value measured at 60°F.

★★ based on separator water flash
References to "oil" above should read "water".

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Anacon - Pleasant Bayou Well No. 2 COMPOSITE LABORATORY DATA AT 301 °F

Recombination(4): 7.60 SCF Sep.Gas @ 14.65 psia & 60°F/Bbl. Sep.Water @ Sep.Cond.

PRESSURE, PSIA	PRESSURE VOLUME RELATIONS			OIL VISCOSITY Centipoises	DIFFERENTIAL LIBERATION			
	RELATIVE VOLUME V/V _{sat} B ₁	SPECIFIC VOLUME cu. ft. Per Pound	Volume Percent Liquid		FORMATION VOLUME FACTOR B ₀ ★★	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO	
							Per Bbl. Stock Tank Oil at 60°F ★★	Per Bbl. Oil at Reservoir Bubble-Point

WET GAS

6009	0.9940	0.01576	100.00
5001	0.9965	0.01580	100.00
4000	0.9991	0.01585	100.00
3696	0.9999	0.01586	100.00
3645 B.P.	1.0000	0.01586	100.00
3591	1.0002	0.01586	bubble
3003	1.0032	0.01591	99.85
2007	1.0119	0.01605	99.23
1000	1.0397	0.01649	96.82
208	1.3757	0.02182	73.32

1.0750

19.24

NOMENCLATURE:

V/V_{sat}. is the volume of fluids (oil and gas) at the indicated temperature and pressure relative to the volume of saturated oil at bubble-point pressure and indicated temperature.

B₀ is the volume of oil at reservoir temperature and indicated pressure relative to the volume of residual stock tank oil measured at 60°F.

Gas-Oil Ratio, is cubic feet of gas at 14.65 psia at 60°F, per barrel of residual oil at 60°F.

Note: * indicates value measured at 60°F.

★★ based on separator water flash
References to "oil" above should read "water".

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Anacon - Pleasant Bayou Well No. 2 COMPOSITE LABORATORY DATA AT 301 °F

Recombination(5): 21.14 SCF Sep. Gas @ 14.65 psia & 60°F/Bbl. Sep.Water @ Sep.Con.

PRESSURE, PSIA	PRESSURE VOLUME RELATIONS			OIL VISCOSITY Centipoises	DIFFERENTIAL LIBERATION		
	RELATIVE VOLUME V/V _{sat} B ₁	SPECIFIC VOLUME cu. ft. Per Pound	Volume Percent Liquid		FORMATION VOLUME FACTOR B _o	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO
							Per Barrel Stock Tank Oil at 60°F
							Dry Incl. H ₂ O

11116 Res.	0.9961	0.01556	100.00		1.0614		30.46 33.25
10000	0.9991	0.01561	100.00		1.0646		30.46 33.25
9670 B.P.	1.0000	0.01562	100.00		1.0656		30.46 33.25
9000	1.0019	0.01565	bubble				
8000	1.0048	0.01569	99.95				
7000	1.0080	0.01574	99.87				
6000	1.0116	0.01580	99.74				
5000	1.0162	0.01587	99.55		1.0773	22.93	25.33
4000	1.0221	0.01597	99.25				
3000	1.0310	0.01610	98.65		1.0811	19.43	21.53
2000	1.0482	0.01637	97.15				
1000	1.1032	0.01723	92.71		1.0848	13.92	15.19
191	1.8051	0.02820	57.19				
112	2.8454	0.04445	35.54				
15						0.00	0.00
15*						0.00	0.00

NOMENCLATURE:

V/V_{sat} is the volume of fluids (oil and gas) at the indicated temperature and pressure relative to the volume of saturated oil at bubble-point pressure and indicated temperature.

B_o is the volume of oil at reservoir temperature and indicated pressure relative to the volume of residual stock tank oil measured at 60°F.

Gas-Oil Ratio, is cubic feet of gas at 14.65 psia at 60°F, per barrel of residual oil at 60°F.

Note: * indicates value measured at 60°F.
References to "oil" above should read "water".

Anacon - Pleasant Bayou #2

Effect of Gas-Water Ratio Upon Bubble Point Pressure @ 301°F

Recombination No.	Gas-Water Ratio		Bubble Point (PSIA)
	(SCF Sep. Gas @ 14.65 psia & 60°F) (Bbl. Sep. H ₂ O @ 850 psig & 277°F)	(SCF Sep. Gas @ 14.65 psia & 60°F) (Bbl. S.T. H ₂ O @ 0 psig & 60°F)	
1	19.00	20.09	8650 ± 50
2	16.15	17.08	7450 ± 50
3	12.35	13.06	5775 ± 50
4	7.60	8.04	3645 ± 50
5	21.14	22.35*	9670 ± 50

* Produced at time of sampling.

Lab. No. N-1249

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WEATHERLY LABORATORIES, INC.

Anacon - Pleasant Bayou #2

Separator Water Flash to 0 psig & 72°F

Solution Gas-Water Ratio, dry = 8.11
 , wet = 11.20

SCF gas @ 14.65 psia & 60°F
 Bbl. water @ 0 psig & 60°F

Shrinkage = 0.9459 $\frac{\text{vol. S.T. water @ 60°F}}{\text{vol. Sep. H}_2\text{O @ 850 psig \& 277°F}}$

S.T. Water Density = 1.0882 Gm./Ml. @ 60°F

Gas Gravity , dry = 0.8568 (see analysis)
 , wet = 0.7920

Total Gas-Water Ratio , wet = 22.35 + 11.20
 = 33.55 $\frac{\text{SCF Total gas @ 14.65 psia \& 60°F}}{\text{Bbl. S.T. water @ 60°F}}$

Produced at time of sampling.

Lab. No. N-1249

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WEATHERLY LABORATORIES, INC.

B-14

Anacon - Pleasant Bayou No. 2

Separator gas sampled:
1800 hrs. 10-8-80
@ 850 psig & 277°F

Chromatographic Analysis

	Dry	Wet
	Mole %	
Water		(none measured on site)
Carbon Dioxide	6.80	
Nitrogen	0.41	
Methane	88.28	
Ethane	3.13	
Propane	0.95	
Iso-Butane	0.15	
N-Butane	0.14	
Iso-Pentane	0.04	
N-Pentane	0.02	
Hexanes	0.01	
Heptanes Plus	0.07	
Total	100.00	

Gravity (Air=1.0) 0.6545

Lab. No. N-1249

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WEATHERLY LABORATORIES, INC.

B-15

Anacon - Pleasant Bayou No. 2

Solution Gas from
Separator Water Flash
@ 0 psig & 72°F
(Calculated Nitrogen Free)

Chromatographic Analysis

	Dry	Wet
	Mole %	
Water		27.60
Carbon Dioxide	30.40	22.01
Nitrogen		
Methane	67.96	49.20
Ethane	1.35	0.98
Propane	0.26	0.19
Iso-Butane	0.03	0.02
N-Butane	0.00	0.00
Iso-Pentane	0.00	0.00
N-Butane	0.00	0.00
Hexanes	0.00	0.00
Heptanes Plus	0.00	0.00
Total	100.00	100.00
Gravity (Air=1.0)	0.8568	0.7920

Lab. No. N-1249

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WEATHERLY LABORATORIES, INC.

B-16

Anacon - Pleasant Bayou No. 2

Solution Gas from 5000 psia
Sample - Differential Liberation
(Calculated Nitrogen Free)

Chromatographic Analysis

	Dry	Wet
	Mole %	
Water		4.91
Carbon Dioxide	3.55	3.38
Nitrogen		
Methane	90.21	85.77
Ethane	3.52	3.35
Propane	1.75	1.66
Iso-Butane	0.29	0.28
N-Butane	0.31	0.29
Iso-Pentane	0.12	0.11
N-Pentane	0.09	0.09
Hexanes	0.06	0.06
Heptanes Plus	0.10	0.10
Total	100.00	100.00
Gravity (Air=1.0)	0.6400	0.6371

Lab. No. N-1249

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WEATHERLY LABORATORIES, INC.

Anacon - Pleasant Bayou No. 2

Solution Gas from 3000 psia
Sample - Differential Liberation
(Calculated Nitrogen Free)

Chromatographic Analysis

	Dry	Wet
	Mole %	
Water		8.02
Carbon Dioxide	4.52	4.16
Nitrogen		
Methane	91.28	83.96
Ethane	2.53	2.33
Propane	0.88	0.81
Iso-Butane	0.13	0.12
N-Butane	0.08	0.07
Iso-Pentane	0.08	0.07
N-Pentane	0.07	0.06
Hexanes	0.16	0.15
Heptanes Plus	0.27	0.25
Total	100.00	100.00
Gravity (Air=1.0)	0.6373	0.6360

Lab. No. N-1249

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WEATHERLY LABORATORIES, INC.

B-18

Anacon - Pleasant Bayou No. 2

Solution Gas from 1000 psia
Sample - Differential Liberation
(Calculated Nitrogen Free)

Chromatographic Analysis

	Dry	Wet
	Mole %	
Water		13.12
Carbon Dioxide	9.88	8.58
Nitrogen		
Methane	87.73	76.21
Ethane	1.66	1.44
Propane	0.39	0.34
Iso-Butane	0.03	0.03
N-Butane	0.03	0.03
Iso-Pentane	0.03	0.03
N-Butane	0.03	0.03
Hexanes	0.05	0.04
Heptanes Plus	0.17	0.15
Total	100.00	100.00
Gravity (Air=1.0)	0.6701	0.6638

Lab. No. N-1249

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WEATHERLY LABORATORIES, INC.

Anacon - Pleasant Bayou No. 2

Solution Gas from 15 psia
Sample - Differential Liberation
(Calculated Nitrogen Free)

Chromatographic Analysis

	Dry	Wet
	Mole %	
Water		8.39
Carbon Dioxide	49.40	45.26
Nitrogen		
Methane	49.60	45.43
Ethane	0.75	0.69
Propane	0.10	0.09
Iso-Butane	0.01	0.01
N-Butane	0.00	0.00
Iso-Pentane	0.02	0.02
N-Pentane	0.00	0.00
Hexanes	0.04	0.04
Heptanes Plus	0.08	0.07
Total	100.00	100.00
Gravity	1.0397	1.0047

Lab. No. N-1249

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WEATHERLY LABORATORIES, INC.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Company Anacon, Inc.
Reservoir _____

Well Pleasant Bayou No. 2
Field Chocolate Bayou

Effect of Gas-Water Ratio Upon Bubble Point Pressure @ 301°F

Lab. No. N-1249

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B-21

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Liquid Volume Percent from P-V Relations
of Reservoir Water Recombined to 21.14 SCF/Bbl. Separator Water
Company Anacon, Inc. Well Pleasant Bayou No. 2
Reservoir _____ Field Chocolate Bayou
@ Reservoir Temperature of 301°F

Lab. No. N-1249

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B-22

Differential Liberation of Reservoir Water
Recombined to 21.14 SCF/Bbl. Separator Water

Company Anacon, Inc. Well Pleasant Bayou No. 2
Reservoir _____ Field Chocolate Bayou

@ Reservoir Temperature of 301°F

Lab. No. N-1249

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APPENDIX C

PVT Analysis by Weatherly Laboratories, Inc. -- 1983

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

RESERVOIR FLUID ANALYSIS

FOR

THE GRUY COMPANIES

PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD
BRAZORIA COUNTY, TEXAS

WEATHERLY LABORATORIES, INC.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

WEATHERLY LABORATORIES, INC.

E. WEATHERLY, JR.
CHAIRMAN

223 GEORGETTE LAFAYETTE, LA 70506
PHONE (318) 232-4877

JOHN D. NEAL
PRESIDENT
BRYAN SONNIER
VICE PRESIDENT

FEBRUARY 11, 1983

THE GRUY COMPANIES
2500 TANGLE WILD, SUITE 150
HOUSTON, TEXAS 77063

ATTENTION: DR. J. HARTSOCK

RE: RESERVOIR FLUID STUDY
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD
BRAZORIA COUNTY, TEXAS

GENTLEMEN:

ATTACHED ARE THE RESULTS OF THE ANALYSES OF THE CHEMICAL AND PHYSICAL CHARACTERISTICS OF A RECOMBINED RESERVOIR FLUID SAMPLE FROM THE SUBJECT WELL. SURFACE SEPARATOR SAMPLES WERE COLLECTED FROM THIS WELL BY A REPRESENTATIVE OF WEATHERLY LABORATORIES, INC. ON OCTOBER 14, 1982. THE GAS-WATER RATIO (GWR) MEASURED ON THIS TEST, 20.11 CUBIC FEET OF SEPARATOR GAS PER BARREL OF SEPARATOR LIQUID, WAS USED AS THE BASIS FOR ONE RECOMBINATION. THE RESULTANT RESERVOIR FLUID EXHIBITED A BUBBLE POINT OF 7460 PSIA AT THE RESERVOIR TEMPERATURE 308 DEGREES FAHRENHEIT.

OTHER RECOMBINATIONS WERE DONE TO DETERMINE A BUBBLE POINT -VS- GWR RELATIONSHIP. A DIFFERENTIAL LIBERATION AND VISCOSITY MEASUREMENTS WERE PERFORMED USING RESERVOIR FLUID RECOMBINED TO THE PRODUCED GWR AT THE TIME OF SAMPLING.

WE WISH TO THANK YOU FOR THIS OPPORTUNITY OF SERVING YOU. SHOULD THERE BE ANY QUESTIONS CONCERNING THIS REPORT, PLEASE CONTACT US.

YOURS VERY TRULY

JOHN NEAL

LAB. NO. N1814-10046

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

GEOPRESSURE/GEOTHERMAL PROJECT SAMPLING AND LABORATORY PROCEDURE

- 1) WATER VAPOR CONTENT OF SEPARATOR GAS WAS DETERMINED BY FLOWING GAS FROM A METERING VALVE ON THE SEPARATOR GAS METER RUN THROUGH A WEIGHING TUBE (INDICATOR DRIERITE (CaSO₄) WEIGHED TO 0.1 MILLIGRAM) TO A G.C.A./PRECISION SCIENTIFIC WET TEST METER. SEPARATOR GAS SAMPLES WERE TAKEN FROM THE SAME PLACE INTO EVACUATED 1 GALLON STAINLESS STEEL (S.S.) CYLINDERS AFTER THOROUGH PURGING OF TRANSFER LINE AT SEPARATOR PRESSURE. SEPARATOR LIQUID SAMPLE CYLINDERS (500 ML. S.S.) WERE FIRST CHARGED WITH SEPARATOR GAS TO FULL SEPARATOR PRESSURE. THE LIQUID CYLINDERS WERE THEN CONNECTED TO THE SEPARATOR WATER SAMPLING POINT BY A S.S. TUBE LONG ENOUGH TO LOOP THROUGH A COOLING BATH. THE WATER TRANSFER LINE WAS THEN SLOWLY AND THOROUGHLY PURGED AT THE CYLINDER. SEPARATOR WATER WAS LET INTO THE CYLINDER BY SLOWLY BLEEDING GAS FROM THE TOP VALVE. AT NO TIME WAS THE WATER CAUGHT IN THE CYLINDER ALLOWED TO DROP BELOW SEPARATOR PRESSURE.
- 2) FLASH LIBERATION OF GAS FROM SEPARATOR WATER WAS ACCOMPLISHED BY USING A WEIGHED SEPARATOR FLASK. THIS SEPARATOR FLASK WAS CONNECTED TO THE OUTLET OF A SEPARATOR WATER CYLINDER BY A SHORT CAPILLARY LINE. GAS FROM THE SEPARATOR FLASK PASSED THROUGH A WEIGHED DRYING TUBE THROUGH A GLASS CYLINDER (~ 300 ML.) TO A RUSKA GASOMETER. A VACUUM VALVE AND A MERCURY MANOMETER WAS CONNECTED TO THE GAS MANIFOLD BETWEEN THE DRYING TUBE AND THE GASOMETER. BEFORE COMMENCING THE FLASH, THE ENTIRE FLASH GAS MANIFOLD WAS EVACUATED AND THEN FILLED WITH HELIUM TO ATMOSPHERIC PRESSURE. A KNOWN VOLUME OF SEPARATOR WATER WAS PUSHED OUT OF THE SAMPLE CYLINDER AT A PRESSURE SLIGHTLY ABOVE FIELD SEPARATOR PRESSURE BY USE OF A CALIBRATED MERCURY PUMP. THE VOLUME OF STOCK TANK WATER PRODUCED WAS DETERMINED BY ITS WEIGHT AND DENSITY. THE VOLUME OF DRY GAS EVOLVED WAS DETERMINED WITH THE GASOMETER. THIS GAS VOLUME WAS SUBJECT TO ± 2 % ERROR DUE TO THE VERY SMALL AMOUNTS MEASURED. THE GAS WAS CHARGED TO A CHROMOTOGRAPH FOR ANALYSIS FROM THE GLASS CYLINDER.
- 3) PHYSICAL RECOMBINATION OF SEPARATOR EFFLUENTS:
DRY SEPARATOR GAS WAS CHARGED INTO A TEMPERATURE CONTROLLED CELL. THE VOLUME OF THIS WINDOWED CELL IS KNOWN FOR ANY PRESSURE AND TEMPERATURE. THE PRESSURE OF THE GAS IN THE CELL WAS MEASURED WITH A MERCURY MANOMETER AND A BAROMETER. THIS CALCULATED GAS VOLUME WAS SUBJECT TO A ± 1 % ERROR DUE TO THE SMALL AMOUNT CHARGED TO THE CELL. A VOLUME OF SEPARATOR WATER WAS CHARGED INTO THE WINDOWED CELL BY USE OF A CALIBRATED MERCURY PUMP. THE WATER WAS METERED AND MEASURED AT A PRESSURE SLIGHTLY ABOVE FIELD SEPARATOR PRESSURE. FOUR RECOMBINATIONS WERE DONE IN ORDER TO PRODUCE A SATURATION PRESSURE-VS-GAS WATER RATIO CURVE. RESERVOIR FLUID RESULTING FROM RECOMBINATION OF THE PRODUCED GWR WAS USED TO PERFORM A DIFFERENTIAL LIBERATION AND VISCOSITY MEASUREMENT.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

- 4) PRESSURE-VOLUME RELATIONS OF RECOMBINED RESERVOIR FLUID AT RESERVOIR TEMPERATURE:
EACH DATUM OF PRESSURE-VOLUME RELATIONS WAS CORRECTED FOR MERCURY PUMP CALIBRATION, MANIFOLD EXPANSION, CELL EXPANSION, MERCURY COMPRESSIBILITY AND MERCURY THERMAL EXPANSION. LIQUID VOLUME PERCENT WAS DETERMINED BY CALIBRATED CATHETOMETER AND BY DATA INTERPRETATION.
- 5) DIFFERENTIAL LIBERATION OF RESERVOIR FLUID AT RESERVOIR TEMPERATURE:
GAS FROM EACH PRESSURE DECREMENT OF THE DIFFERENTIAL LIBERATION WAS ANALYZED IN THE SAME MANNER AS DESCRIBED IN 2), (FLASH LIBERATION). DIFFERENTIAL LIQUID CHANGES WERE NOTED.
- 6) VISCOSITY OF RESERVOIR FLUID WAS MEASURED BY MR. J. R. COMEAU OF WEATHERLY LABORATORIES. A DESCRIPTION OF MR. COMEAU'S EXPERIMENTAL PROCEDURES IS GIVEN BELOW:
GEOTHERMAL WATER VISCOSITIES WERE MEASURED USING AN E.L.I. ROLLING BALL VISCOMETER WITH AN ELECTRONIC DETECTION SYSTEM TO PREVENT ELECTROLYSIS. THE DETECTION SYSTEM CONSISTS OF A SENSITIVE AUDIO AMPLIFIER WITH POSITIVE FEEDBACK ADJUSTED JUST BELOW OSCILLATION. FEEDBACK WAS TURNED ON BY AN AUTOMATIC SWITCH AS THE VISCOMETER WAS INVERTED AT THE BEGINNING OF THE CYCLE AND TURNED OFF WHEN THE BALL MADE CONTACT. PART OF THE SIGNAL WAS USED TO TURN THE DIGITAL TIMER ON AND OFF. TIMES WERE MEASURED TO 1/100TH OF A SECOND AND AVERAGED. THE VISCOMETER WAS CALIBRATED AT EACH OF THREE ANGLES USING SEVERAL KNOWN VISCOSITY STANDARDS WHICH WERE CHECKED AGAINST CANNON-FENSKE VISCOMETERS AND THE RESULTS ($t\Delta p$ vs. μ) PLOTTED. THE VISCOMETER WAS RECALIBRATED USING DISTILLED WATER AT SEVERAL TEMPERATURES. THESE RESULTS WERE USED ALONG WITH PREVIOUS RESULTS TO OBTAIN NEW CALIBRATION CURVES.

t = ROLL TIME, (SECONDS)

Δp = DENSITY DIFFERENCE BETWEEN BALL AND RESERVOIR FLUID, (gm./ml.)

μ = VISCOSITY, (CENTIPOISE)

THE VISCOMETER WAS CHARGED WITH RESERVOIR FLUID AND RUN AT 308°F AT 1000 LB. INTERVALS. THE VISCOSITIES HAD A PROBABLE ERROR OF ± 0.007 CENTIPOISE.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

FIELD DATA FOR WEATHERLY LABORATORY INVESTIGATION

WELL RECORD

COMPANY	THE GRUY COMPANIES
WELL	PLEASANT BAYOU NO. 2
FIELD	PLEASANT BAYOU
COUNTY AND STATE	BRAZORIA, TEXAS

FIELD CHARACTERISTICS

FORMATION NAME		
SAND NAME AND DESIGNATION		
DATE COMPLETED		
ORIGINAL RESERVOIR PRESSURE	(@ 14,750 FT.) 11,275	PSIA

WELL CHARACTERISTICS

ORIGINAL PRODUCED GAS-LIQUID RATIO

PERFORATIONS	14,467-14,707	FT
ELEVATIONS		
TOTAL DEPTH		
LAST RESERVOIR PRESSURE	(@ 14,560 FT.) 11,162	PSIA
RESERVOIR TEMPERATURE	308	DEGREES F

SAMPLING CONDITIONS

DATE SAMPLED	10-14-82	
TUBING PRESSURE, FLOWING	2818	PSIG
PRIMARY SEPARATOR TEMPERATURE (METER RUN)	260	DEGREES F
PRIMARY SEPARATOR PRESSURE	560	PSIG
PRIMARY SEPARATOR GAS RATE (WET GAS)	427.2	MCF/DAY
SEPARATOR LIQUID RATE	21,247	BBL.S./DAY
GAS-LIQUID RATIO (SEPARATOR)	20.11	SCF/DBL.SEP.WATER
SHRINKAGE FACTOR (VOL.S.T.WATER @ 60°F/VOL.SEP.WATER)	0.9468	
GAS-LIQUID RATIO (STOCK TANK)	21.24	SCF/DBL.S.T.WATER
PRESSURE BASE	14.65	PSIA @ 60 DEGREES F

NOTE: FOR DRY GAS, 20.10 SCF/DBL. SEP. WATER @ SEP. CONDITIONS.
21.23 SCF/DBL. S.T. WATER @ 60°F.

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

CALCULATION OF GAS RATE, 10-14-82 TEST

(Factors from GPSA Engineering Data Book)

$\sqrt{H_w P_f} = 149.7498$	$H_w = 39$	"H ₂ O ,	$P_f = 575$	psia
$F_b = 115.6168$	$D = 1.939$	" ,	$d = 0.750$	"
$F_{pB} = 1.0055$		14.65		psia
$F_r = 1.0003$	$b = 0.0485$			
$Y_2 = 1.0004$	$H_w/P_f = 0.068$	,	$d/D = 0.387$	
$F_g = 1.1844$	Gravity = 0.7129	,	$F_g = \sqrt{1 / 0.7129}$	
$F_{tf} = 0.8498$	Temp. = 260 degrees F ,		$F_{tf} = \sqrt{520 / 720}$	
$F_{pv} = 1.0152$	$p_{Tr}' = 1.973$	,	$p_{Pr}' = 0.835$	
	$Z = 0.9702$	,	$F_{pv} = \sqrt{1 / Z}$	

$$Q = \sqrt{H_w P_f} \times F_b \times F_{pB} \times F_r \times Y_2 \times F_g \times F_{tf} \times F_{pv} \times 24$$

$$Q = 427.2 \quad \text{MCF/day @ 14.65 PSIA @ 60 Degrees F}$$

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

RESERVOIR FLUID SUMMARY

Reservoir Temperature, Degrees F	303
Saturation Pressure at 303 Degrees, Psia	7460
Compressibility of Reservoir Oil at 303 Degrees F	
Vol. per Vol. per Psi x 10 ⁶	
From 7460 Psia to 9000 Psia	2.92
From 9000 Psia to 11275 Psia	2.87
	DIFF. LIB.
Saturated Oil at 7460 Psia, 303 Degrees F	
Density, Gms. per Ml.	1.0264
Lbs. per Bbl.	359.8
Specific Volume, Cu.Ft. per Lb.	0.015606
Viscosity, Centipoise	0.363
Formation Volume Factor, Bbls. per Bbl.	
"Equivalent Stock Tank Oil" at 60 Degrees F	1.0603 *
Solution Gas-Oil Ratio, Cu.Ft. per Bbl.	25.03 *
"Equivalent Stock Tank Oil" at 60 Degrees F	24.45 *
	1.0621
	25.78 WET
	24.50 DRY
Reservoir Oil at 11275 Psia 303 Degrees F	
Density, Gms. per Ml.	1.0379
Lbs. per Bbl.	363.8
Specific Volume, Cu.Ft. per Lb.	0.015434
Viscosity, Centipoise	0.379
Formation Volume Factor, Bbl. per Bbl.	
"Equivalent Stock Tank Oil" at 60 Degrees F	1.0504
Thermal Expansion at	Psia, % per Degrees F

NOTE: REFERENCES TO 'OIL' ABOVE SHOULD READ 'WATER'.

* BASED ON SEPARATOR WATER FLASH.

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

COMPOSITE LABORATORY DATA 308 DEGREES F

RECOMBINATION (1) 25.00 SCF SEP. GAS @ 14.65 PSIA & 60°F/BBL. SEP. WATER @ SEP. CONDITIONS.

SSURE	PRESSURE VOLUME RELATIONS				DIFFERENTIAL LIBERATION			
	RELATIVE	SPECIFIC	LIQUID	OIL	FORMATION	RELATIVE	SOLUTION	
	VOLUME	VOLUME			VOLUME		GAS-OIL RATIO	
	V/Vsat	cu. ft.	VOLUME	VISCOSITY	FACTOR	OIL	PER BARREL	
IA	Bt	per	PERCENT	CENTIPOISES	Bo	VOLUME	STOCK TANK OIL	
		Pound			**		AT 60°F	
							DRY **	WET **
5 RES.	0.9962	0.015435	100.00		1.0494		29.62	30.20
0 B.P.	1.0000	0.015493	100.00		1.0534		29.62	30.20
0	1.0028	0.015537	BUBBLE					
0	1.0062	0.015589	99.95					
0	1.0101	0.015650	99.85					
0	1.0141	0.015712	99.74					
0	1.0189	0.015786	99.56					
0	1.0250	0.015881	99.25					
0	1.0341	0.016022	98.66					
0	1.0519	0.016297	97.26					
0	1.1088	0.017179	92.28					
0	1.2306	0.019066	83.73					
1	2.4943	0.038645	43.99					
0	3.9418	0.061071	27.59					
9	5.1137	0.079227	20.41					

NOMENCLATURE:

V/VSAT. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

Bo IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 14.65 PSIA AND 60 DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: ** BASED ON SEPARATOR WATER FLASH.
REF. TO 'OIL' ABOVE SHOULD READ 'WATER'.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

COMPOSITE LABORATORY DATA 308 DEGREES F

COMBINATION (2) PRODUCED 20.10 SCF SEP. GAS @ 14.65 PSIA & 60°F/DBL. SEP. WATER @ SEP. CONDITIONS.

SURE	PRESSURE VOLUME RELATIONS				DIFFERENTIAL LIBERATION			
	RELATIVE	SPECIFIC	LIQUID	OIL	FORMATION	FORMATION	SOLUTION	
	VOLUME	VOLUME			VOLUME	VOLUME	GAS-OIL RATIO	
	V/Vsat	cu. ft.	VOLUME	VISCOSITY	FACTOR	FACTOR	PER BARREL	
A	Bt	per	PERCENT	CENTIPOISES	Bo	Bo	STOCK TANK OIL	
		Pound			**		AT 60°F	
							DRY **	WET **
RES.	0.9890	0.015434	100.00	0.379	1.0486	1.0504	24.50	25.78
	0.9926	0.015491	100.00	0.373	1.0525	1.0542	24.50	25.78
	0.9955	0.015535	100.00	0.369	1.0555	1.0573	24.50	25.78
	0.9984	0.015581	100.00	0.365	1.0586	1.0604	24.50	25.78
B.P.	1.0000	0.015606	100.00	0.363	1.0603	1.0621	24.50	25.78
	1.0002	0.015610	BUBBLE					
	1.0015	0.015630	99.99	0.361				
	1.0054	0.015691	99.90	0.357				
	1.0096	0.015756	99.78	0.354		1.0691	19.77	20.92
	1.0148	0.015837	99.58	0.353				
	1.0224	0.015956	99.13	0.353		1.0737	14.35	15.34
	1.0370	0.016184	98.02	0.356				
	1.0825	0.016894	94.17	0.361		1.0784	6.30	7.04
	1.1907	0.018582	86.45					
	2.0653	0.032231	51.96					
	3.2622	0.050910	31.75					
*						1.0000	0.00	0.00

NOMENCLATURE:

V/VSAT. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

Bo IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 14.65 PSIA AND 60 DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: ** BASED ON SEPARATOR WATER FLASH. ALSO BASED ON SEP. WATER FLASH: SOLUTION GAS IN RESERVOIR FLUID IS 24.45 SCF DRY GAS/DBL. S.T. WATER @ 60°F. REF. TO 'OIL' ABOVE SHOULD READ 'WATER'.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

COMPOSITE LABORATORY DATA 308 DEGREES F

RECOMBINATION (3) 15.00 SCF SEP. GAS @ 14.65 PSIA & 60°F/BBL. SEP. WATER @ SEP. CONDITIONS.

PRESSURE	PRESSURE VOLUME RELATIONS			DIFFERENTIAL LIBERATION			
	RELATIVE	SPECIFIC	LIQUID	OIL	FORMATION:	RELATIVE	SOLUTION
	VOLUME	VOLUME			VOLUME		GAS-OIL RATIO
	V/V _{sat}	cu. ft.	VOLUME	VISCOSITY	FACTOR	OIL	PER BARREL
A	Bt	per	PERCENT	CENTIROISES	Bo	VOLUME	STOCK TANK OIL
		Pound			**		AT 60°F
							DRY ** WET **
RES.	0.9821	0.015436	100.00		1.0480		19.06 19.64
	0.9857	0.015493	100.00		1.0518		19.06 19.64
	0.9914	0.015582	100.00		1.0579		19.06 19.64
	0.9972	0.015673	100.00		1.0641		19.06 19.64
B.P.	1.0000	0.015717	100.00		1.0671		19.06 19.64
	1.0001	0.015719	BUBBLE				
	1.0043	0.015785	99.90				
	1.0099	0.015873	99.66				
	1.0210	0.016047	98.89				
	1.0555	0.016590	95.96				
	1.1459	0.018011	88.52				
	1.5309	0.024062	69.19				

NOMENCLATURE:

V/V_{SAT}. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

Bo IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 14.65 PSIA AND 60 DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: ** BASED ON SEPARATOR WATER FLASH.
REF. TO 'OIL' ABOVE SHOULD READ 'WATER'.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

COMPOSITE LABORATORY DATA 303 DEGREES F

RECOMBINATION (4) 10.00 SCF SEP. GAS @ 14.65 PSIA & 60°F/BBL. SEP. WATER @ SEP. CONDITIONS.

PRESSURE	PRESSURE VOLUME RELATIONS			DIFFERENTIAL LIBERATION				
	RELATIVE VOLUME	SPECIFIC VOLUME	LIQUID VOLUME	OIL VISCOSITY	FORMATION VOLUME FACTOR	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO	
A	V/Vsat Bt	cu. ft. per Pound	PERCENT	CENTIPOISES	Bo **		PER BARREL STOCK TANK OIL AT 60°F	
							DRY **	WET **
RES.	0.9764	0.015437	100.00		1.0473		13.78	14.35
	0.9799	0.015493	100.00		1.0510		13.78	14.35
	0.9855	0.015581	100.00		1.0570		13.78	14.35
	0.9912	0.015671	100.00		1.0632		13.78	14.35
	0.9970	0.015763	100.00		1.0694		13.78	14.35
B.P.	1.0000	0.015810	100.00		1.0726		13.78	14.35
	1.0075	0.015929	99.56					
	1.0162	0.016067	98.88					

NOMENCLATURE:

V/VSAT. IS THE VOLUME OF FLUIDS (OIL AND GAS) AT THE INDICATED TEMPERATURE AND PRESSURE RELATIVE TO THE VOLUME OF SATURATED OIL AT BUBBLE-POINT PRESSURE AND INDICATED TEMPERATURE.

Bo IS THE VOLUME OF OIL AT RESERVOIR TEMPERATURE AND INDICATED PRESSURE RELATIVE TO THE VOLUME OF EQUIVALENT STOCK TANK OIL MEASURED AT 60 DEGREES F.

GAS-OIL RATIO, IS CUBIC FEET OF GAS AT 14.65 PSIA AND 60 DEGREES F, PER BARREL OF STOCK TANK OIL AT 60 DEGREES F.

NOTE: ** BASED ON SEPARATOR WATER FLASH.
REF. TO 'OIL' ABOVE SHOULD READ 'WATER'.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

EFFECT OF GAS-WATER RATIO UPON BUBBLE POINT PRESSURES @ 308°F

GAS-WATER RATIO	BUBBLE POINT
(SCF DRY SEP. GAS @ 14.65 PSIA & 60°F)	

(BBL. SEP. WATER @ 560 PSIG & 287°F)	(PSIA)
-----	-----
-----	-----
27.4 EXTRAPOLATED	~ 11275 RESERVOIR PRESSURE
25.00	9950
20.10	7460
15.00	5050
10.00	3000

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SEPARATOR WATER FLASH TO 0 PSIG & 76°F

SOLUTION GAS-WATER RATIO, DRY = 3.22

, WET = 3.79 SCF GAS @ 14.65 PSIA & 60°F

BBL. WATER @ 0 PSIG & 60°F

SHRINKAGE = 0.9468 VOL. S.T. WATER @ 60°F

VOL. SEP. H2O @ 560 PSIG & 287°F

STOCK TANK WATER DENSITY = 1.0345 Gm/ML. @ 60°F

GAS GRAVITY, DRY = 0.9061 (SEE ANALYSIS)
 , WET = 0.8616

PRODUCED OCTOBER 14, 1982:

GWR = 21.23 + 3.22 = 24.45 SCF TOTAL DRY GAS @ 14.65 PSIA & 60°F

BBL. STOCK TANK WATER @ 60°F

GWR = 21.24 + 3.79 = 25.03 SCF TOTAL WET GAS @ 14.65 PSIA & 60°F

BBL. STOCK TANK WATER @ 60°F

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SEPARATOR GAS SAMPLED:
OCTOBER 14, 1982 @
560 PSIG & 260°F

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	

WATER		0.045 + .004
CARBON DIOXIDE	12.497	12.491
NITROGEN	0.552	0.552
METHANE	82.598	82.560
ETHANE	2.895	2.894
PROPANE	0.923	0.923
ISO-BUTANE	0.141	0.141
N-BUTANE	0.131	0.131
ISO-PENTANE	0.036	0.036
N-PENTANE	0.020	0.020
HEXANES	0.028	0.028
HEPTANES PLUS	0.179	0.179
	-----	-----
TOTAL	100.000	100.000
GRAVITY (AIR = 1.00)	0.7129	0.7129

NOTE: WATER MEASURED ON SITE, AVERAGE 3 RUNS.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SOLUTION GAS FROM
SEPARATOR WATER FLASH
@ 0 PSIG & 76°F
(CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	

WATER		15.04
CARBON DIOXIDE	35.03	29.76
NITROGEN	-----	-----
METHANE	62.95	53.48
ETHANE	1.64	1.39
PROPANE	0.33	0.28
ISO-BUTANE	0.02	0.02
N-BUTANE	0.03	0.03
ISO-PENTANE	0.00	0.00
N-PENTANE	0.00	0.00
HEXANES	0.00	0.00
HEPTANES PLUS	0.00	0.00
	-----	-----
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.9061	0.8616

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SOLUTION GAS FROM
5000 PSIA SAMPLE -
DIFFERENTIAL LIBERATION
(CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	

WATER		2.60
CARBON DIOXIDE	5.19	5.06
NITROGEN	-----	-----
METHANE	88.13	85.84
ETHANE	4.11	4.00
PROPANE	1.82	1.77
ISO-BUTANE	0.31	0.30
N-BUTANE	0.30	0.29
ISO-PENTANE	0.09	0.09
N-PENTANE	0.05	0.05
HEXANES	0.00	0.00
HEPTANES PLUS	0.00	0.00
	-----	-----
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.6545	0.6536
GAS DEVIATION FACTOR (Z) = 1.0434 @ 5000 PSIA & 308°F		
BBLs. GAS IN RES./MMSCF (Bg) = 804 @ 5000 PSIA & 308°F		

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SOLUTION GAS FROM
3000 PSIA SAMPLE -
DIFFERENTIAL LIBERATION
(CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	

WATER		2.82
CARBON DIOXIDE	2.75	2.67
NITROGEN	-----	-----
METHANE	91.86	89.28
ETHANE	3.55	3.45
PROPANE	1.35	1.31
ISO-BUTANE	0.22	0.21
N-BUTANE	0.21	0.20
ISO-PENTANE	0.04	0.04
N-PENTANE	0.02	0.02
HEXANES	0.00	0.00
HEPTANES PLUS	0.00	0.00
	-----	-----
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.6193	0.6182

GAS DEVIATION FACTOR (Z) = 0.9724 @ 3000 PSIA & 308°F

BBLs. GAS IN RES./MMSCF (Bg) = 1,249 @ 3000 PSIA & 308°F

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SOLUTION GAS FROM
1000 PSIA SAMPLE -
DIFFERENTIAL LIBERATION
(CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	

WATER		3.00
CARBON DIOXIDE	7.17	6.95
NITROGEN	----	----
METHANE	89.54	86.86
ETHANE	2.51	2.43
PROPANE	0.62	0.60
ISO-BUTANE	0.07	0.07
N-BUTANE	0.06	0.06
ISO-PENTANE	0.02	0.02
N-PENTANE	0.01	0.01
HEXANES	0.00	0.00
HEPTANES PLUS	0.00	0.00
	-----	-----
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.6449	0.6431
GAS DEVIATION FACTOR (Z) =	0.9682 @ 1000 PSIA & 308°F	
BBLS. GAS IN RES./MMSCF (Bg) = 3732	@ 1000 PSIA & 308°F	

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

THE GRUY COMPANIES
PLEASANT BAYOU WELL NO. 2
PLEASANT BAYOU FIELD

SOLUTION GAS FROM
15 PSIA SAMPLE -
DIFFERENTIAL LIBERATION
(CALCULATED NITROGEN FREE)

CHROMATOGRAPHIC ANALYSIS

	DRY	WET
	MOLE %	
	-----	-----
WATER		10.45
CARBON DIOXIDE	33.43	29.74
NITROGEN	-----	-----
METHANE	64.15	57.44
ETHANE	2.00	1.79
PROPANE	0.30	0.27
ISO-BUTANE	0.05	0.04
N-BUTANE	0.04	0.04
ISO-PENTANE	0.02	0.02
N-PENTANE	0.01	0.01
HEXANES	0.00	0.00
HEPTANES PLUS	0.00	0.00
	-----	-----
TOTAL	100.00	100.00
GRAVITY (AIR = 1.00)	0.8932	0.8630
GAS DEVIATION FACTOR (Z) =	1.000 @ 15 PSIA & 308°F	
BBLS. GAS IN RES./MMSCF (Bg) =	263,081 @ 14.65 PSIA & 308°F	

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Company The Gruy Companies
Reservoir _____

Well Pleasant Bayou No. 2
Field Pleasant Bayou

FIG. 1: Effect of Gas-Water Ratio on Bubble Point Pressure @ 308°F

No. N1814-10046

SCF Sep. Gas @ 14.65 psia & 60°F
Bbl. Sep. Water @ 560 psig & 287°F

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Company The Gruy Companies
Reservoir _____

Well Pleasant Bayou No. 2
Field Pleasant Bayou

FIG. 2: Liq. Vol. % vs. Pressure-Res. Water @ 308°F GWR = 20.10

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Company The Gruy Companies
Reservoir _____

Well Pleasant Bayou No. 2
Field Pleasant Bayou

FIG. 3: Diff. Liberation of Reservoir Water @ 308°F GWR = 20.10

ab. No. N1814-10046

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Company The Gruy Companies

Well Pleasant Bayou No. 2

Reservoir _____

Field Pleasant Bayou

FIG. 4: FVF & Solution GWR of Saturated Water (based on sep. water flash) @308°F

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Company The Gruy Companies
Reservoir _____

Well Pleasant Bayou No. 2
Field Pleasant Bayou

FIG. 5: Specific Volume of Saturated (Bubble Point) Water @ 308°F

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APPENDIX D

"Do We Know Whether the Pleasant Bayou No. 2 is Saturated With Methane?"

IGT TECHNICAL REPORT

"Do We Know Whether the Pleasant
Bayou #2 is Saturated with Methane?"

Philip L. Randolph
Evelyn M. Rockar

Unconventional Natural Gas

Institute of Gas Technology
3424 South State Street
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May 1981

D-3

INTRODUCTION

This report brings together from several DOE and GRI funded programs enough information for us to update our understanding of the degree of saturation of the Pleasant Bayou aquifer. We are able to update at this time for several reasons;

- Professor Blount has corrected a systematic error in his data interpretation procedure which causes his previously reported solubility values to be revised downwards and he has studied methane solubility in actual Pleasant Bayou brine.
- IGT has collected and analysed flare line gas and gas flashed from brine for samples collected at the Pleasant Bayou in early October 1980.
- IGT has developed a procedure for interpreting production data for the Wells of Opportunity that gives corrected values for GWR's.

Professor Blount's work has been sponsored by G.R.I. through a subcontract on IGT's "Gas Saturation in Formation Waters" program and by D.O.E. The gas analysis mentioned above was also carried out under the "Gas Saturation in Formation Waters" program. The procedure for interpreting production data was developed by IGT under a subcontract from Eaton Operating Company for production analysis on D.O.E. "Wells of Opportunity" program. Finally the compilation and interpretation of the data reported here were performed under GRI-IGT's "Gas Saturation in Formation Waters" and DOE-IGT's "Computer Simulation for Production of Geopressured-Geothermal Aquefusus" contracts.

The most interesting result of this update is the convergence on the value 27-28 SCF/STB for both laboratory and field data analyses for the gas to water ratio (GWR). However, a conclusion as to whether the aquifer brine is saturated at this gas content still requires:

- Determining whether the brine leaving the separator contains gas bubbles and, if so, quantifying their gas content in relation to brine volume.
- Laboratory recombination studies using separator gas and brine samples taken at the separator pressure.
- Improved understanding of the extent to which observed CO₂ is actually in carbonate form before the brine is produced from the aquifer.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

The following sections describe how the value of 27-28 SCF/STB was determined from production data, field flashing and laboratory studies. A final section discusses this work in relation to relevant publications on gas solubility in brine.

FIELD DATA INTERPRETATION

The subheadings which follow describe the calculations performed to verify the use of proper meter dimensions and describe details of each of the six steps in the procedure now used by IGT for determining gas to water ratio on "Wells of Opportunity." These calculations were applied to production data obtained by Weatherly Engineering, Inc. for October 8, 1980 at about 2000 hours. This is the time of separator fluid sampling by IGT.

Meter Run Dimensions

The orifice meter is assumed to have an inside diameter of 1.939 inches with a 0.75 inch orifice. This was tested by calculating gas to water ratio with the assumption that:

- Dry Gas Gravity = 0.600 relative to air.
- Supercompressibility = 1.000.

For a pressure base of 14.73 psia and a temperature base of 60°F, the orifice temperature (238°F) static pressure (790 psig) and differential pressure (12 inches water) for 2005 hours on October 8, 1980 give a calculated flare gas production of 303.71 Mcf/d compared to 303.98 reported by Weatherly. Weatherly's reported GWR of 22.95 SCF/separator barrel then results from dividing this by the brine turbine derived rate of 13,248 bpd at separator pressure and temperature.

Flare Line Gas Gravity and Heating Value

On October 8, 1980 flare line gas samples were collected for analysis by both IGT and Anacon. Results of these independent analyses are:

	<u>IGT</u>	<u>Anacon</u>
Dry Gas Gravity	.7006	.6787
Heating Value (BTU/SCF)	949.4	970.7

This modest difference is due to higher CO₂ content in the IGT analysis (11.18 vs. 9.13 mole percent) and higher content of C5 + hydrocarbons in the Anacon analysis (0.16 vs. 0.07 mole percent). The variation in gas analyses is

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

believed by IGT to be due to a difference in sampling procedure. Namely, IGT preheats sample pressure vessels to above brine temperature (277°F on 10/8/80) to minimize condensation of heavy hydrocarbons or water, which subsequently absorb CO₂ from the gas.

Gross Flare Line Gas Flow

All relevant parameters were quite steady between 1915 and 2015 hours on 10/8/80 except differential pressure (ΔP) across the orifice. The average of the square roots of ΔP 's reported every five minutes was squared to yield a value of 11.33 inches of water. Supercompressibility ($F_{pv} = \sqrt{\frac{1}{Z}}$) at orifice meter temperature (238°F) and pressure (790 psig) was 1.0189 and total gas flow through the flare line was 278.9 MCF/d for a pressure base of 14.73 psia.

Reduce Total Gas Flow Due to Steam

At the orifice meter temperature of 238°F, the vapor pressure of water is 24 psia. Thus, dry gas production is estimated to be

$$\frac{(790) + (14.73) - 24}{(790) + (14.73)} (278.9) = 270.6 \text{ McF/d}$$

Metered Brine Rate Corrected to 14.73 psia and 60°F

For the separator pressure of 790 psig, and the brine temperature of 277°F, IGT's correction procedure reduces brine rate from 13,248 separator barrels per day to 12,514 stock tank barrels (STB) per day.

Calculated Flare Line Gas to Brine Ratio

Using the dry gas and corrected brine rates developed above, this ratio is $\frac{270,600}{12,514} = 21.6 \text{ SCF/STB}$.

Add Gas Remaining in Solution in Brine to the Disposal Well

For the low salinity "Wells of Opportunity" IGT has been using the computer algorithm developed by Systems, Science and Software for methane solubility in distilled water. This was selected on the basis of the best fit of published empirical expressions to date from flashing brine during the test of the Wainoco P.R. Girouard No. 1 well. That algorithm gives a value of 5.92 SCF/STB for separator pressure and brine temperature. However, the value of 5.4 SCF/STB measured by flashing a Pleasant Bayou sample collected at 2005 hours on 10/8/80 is more realistic.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Thus, the ratio of produced gas to produced brine at 2000 hrs on 10/8/80 is estimated to be $21.6 + 5.4 = 27.0$ SCF/BBL. The accuracy of methods used to develop this estimate has not been established. A particularly significant question is whether brine to the disposal well contains gas bubbles that would have not been detected with IGT's sampling procedure.

Whether the particular hour examined in detail is representative of the 45 day test has been examined by using one hour average ΔP of 11.33 inches of water in the previously described Weatherly field calculation procedure. The result is 22.30 cubic feet of flared gas per measured barrel of brine. In contrast, dividing the reported cumulative gas production by cumulative brine production for the 45 day test* yields and overall ratio of 20.28 cubic feet of flared gas per barrel of brine at separator pressure and temperature.

* Values used are from the Fennix and Scisson daily report for October 31, 1980.

LABORATORY STUDY OF METHANE SOLUBILITY IN PLEASANT BAYOU BRINE

Dr. Charles Blount has studied methane solubility in a Pleasant Bayou well brine sample collected in December 1979. His work was at temperatures and pressures that bracket actual reservoir conditions. Data from that work was interpreted using his revised procedure giving lower values than his previously published values for methane solubility. Using an equation provided by Dr. Blount specifically for Pleasant Bayou brine yields the estimate of 27.8 to 28.3 SCF/STB for methane solubility in the Pleasant Bayou aquifer. The equation is $\log_e (\text{SCF/BBL}) = -4.40 + 0.77403 \log_e P + .003374T - (4.48 \times 10^{-5})P$ where P is in psia and T is in degrees fahrenheit. Note that this equation does not contain salinity terms and is applicable only to Pleasant Bayou brine from the perforated interval between 14,644 and 14,704 feet. Dr. Blount's report to IGT is appended to this report and contains a revised equation which can be applied from 212°-450° F, 200-22,500 psi and 0.3 to 25 weight percent NaCl. The solubility values obtained on Pleasant Bayou brines are slightly lower than would be predicted by his general equation derived from NaCl solutions.

COMPARISON OF FIELD AND LABORATORY GAS TO BRINE RATIOS

If one considers only overall ratios of dry gas, independent of composition, to produced brine, both the IGT field data analysis and Dr. Blounts laboratory studies appear to be converging to about 27-28 SCF/BBL. However, as with the Wainoco P.R. Girouard test, the field result is below the laboratory result by just enough to be frustrating in relation to identified probable errors.

When gas composition is taken into account, conclusions regarding saturation of in-situ reservoir brine become more elusive as is apparent from Table 1.

Table 1. GAS CONTENT OF BRINE

	Field Data (2000 hrs, 10/8/80)						Blount
	Flare Gas		Gas in Disposal Brine		Produced Gas		SCF/STB
	Mole %	SCF/STB	Mole %	SCF/STB	Mole %	SCF/STB	
All Components	100	21.6	100	5.4	100	27.0	-
CO ₂	11.19	2.41	25.99	1.40	14.15	3.82	-
CH ₄	83.26	17.98	69.57	3.76	80.52	21.74	27.8-28.3
All Hydrocarbons	88.21	19.05	73.46	3.97	85.26	23.02	-

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

The methane content of produced brine is only about 78 percent of the saturation value for pure methane found by Dr. Blount. Thus the aquifer is gas saturated only,

if gases replace one another in solution or;

if field results contain a substantial error due to a phenomenon such as improper separator operation so that gas bubbles are entrained in brine to the disposal well.

One important comparison to make is that of Professor Blount's results with the Haas empiricism. Haas' empiricism is based on the work of several investigators, but primarily those of Culberson and McKetta and Sultanov for gas solubilities in pure water and O'Sullivan and Smith for salting-out coefficients. The more recent work of Price on pure water was unavailable to Haas. Table 2 makes such a comparison for several pressures and temperatures measured during Pleasant Bayou tests.

Except for the values at the separator pressure there is quite good agreement. There is also good agreement between Haas' empiricism and Price's data for pure water. For reasons to be explained below it will be assumed that Blount's value of 5.4 SCF/bbl is correct. It is strikingly identical to the value measured for total gas in the disposal brine. (See Table 1.) The influence on the solubility of one gas by the presence of another in these temperature and pressure regimes needs to be evaluated.

Two pieces of evidence exist which say that the methane solubility is decreased by the presence of other gases. The first is an analysis by Weatherly Laboratories of the bubble point in Wainoco P.R. Girouard fluids. The observed total gas solubility is the same as that predicted by the Haas empiricism for methane alone. Methane comprises about 90% of the gas from the Wainoco. Professor Blount also has some data on the influence of CO₂ on methane solubility. His data indicate that for 5 weight percent NaCl solutions methane solubility is slightly increased for small amounts of CO₂ but is dramatically decreased for amounts of CO₂ in excess of 15 mole percent.

The results of Amirijafari and Campbell on the other hand, show that up to 8,000 psi and 220° F the solubility of mixtures of light hydrocarbons is greater than that of pure components. These are solubilities in pure water. Culberson and McKetta, in discussing the data of Dodson and Standing, note that the natural gas solubilities at higher pressures is between the pure

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Table 2

CALCULATED METHANE SOLUBILITY FOR TEMPERATURE AND PRESSURES MEASURED DURING PLEASANT BAYOU WELL TESTING

<u>Depth ft.</u>	<u>Pressure psia</u>	<u>Temperature Degrees F</u>	<u>Methane Solubility</u>	
			<u>Blount</u>	<u>Haas (6)</u>
14674 (1)	11241 (2)	300 (2)	27.89	29.73
14674 (1)	11166 (3)	308 (3)	28.60	30.75
14674 (1)	10478 (4)	308 (3)	28.08	29.66
Surface	815 (5)	277 (5)	5.40	3.72

±1 SCF/BBL

- (1) The depth of 14,674 feet (reference from KB 33 feet above BHF) for the center of the perforated interval is from the document:

PLEASANT BAYOU GEOPRESSURE GEOTHERMAL PROJECT
ON SITE ENGINEERING REPORT
J. DONALD CLARK
JOHN E. STEVENS

SUMMARY OF TESTING TO NOVEMBER 20, 1979

- (2) Pressure and temperatures at 14,674 feet from interpolation of November 13-15, 1979 gradient data in the above referenced report.
- (3) Pressure and temperature from extrapolation to 14,674 feet from the measurements reported at 14,000 and 14,560 feet in the Reservoir Data, Inc. Field Test Data sheet for September 16, 1980.
- (4) Pressure and temperature at 14,674 feet estimated from the Reservoir Data, Inc. Field Test Data sheet for 2000 hours on October 8, 1980 assuming
- pressure gradient at depth = 0.44 psi/ft.
 - temperature gradient at depth = 15 degrees F/1000 ft.
 - sensor depth = 14,560 ft.
- (5) Separator pressure and temperature values reported by Weatherly Engineering for 2005 hours on October 8, 1980.
- (6) Calculated using a salinity of 130,000 mg/l and brine density of 66.2 lbs/ft.³

methane and pure ethane solubilities. No conclusions can be drawn at this time about formation saturation until the question of the solubility of mixtures is resolved.

The discrepancy in the low pressure comparison between Blount and Haas mentioned above is due primarily to the fact that Haas' low pressure, high temperature values are based on Culberson and McKetta data from 1951. A paper published in 1960 by Davis and McKetta repeated the measurement at low pressures. Figure 3 compares Culberson and McKetta solubility values with Davis and McKetta solubility values along the 220°F isotherm. At 400 psi the difference in solubility is ~0.5 SCF/bbl, at 800 psi the difference is ~1/SCF/bbl. Haas' empiricism is based on the lower solubilities. Therefore, for the conditions in Table 2, Blount's value at 815 psi is presumed more valid than Haas' value.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

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College of Liberal Arts
Department of Geology

Report for Institute of Gas Technology

Purchase Order Number S542544

Solubility of Methane in Waters from Pleasant Bayou Well No. 2.

The solubility of methane gas was determined in a sample of Pleasant Bayou well water supplied by the Institute of Gas Technology. This fluid contained some reddish colored fine grained precipitate resembling ferric hydroxide. This precipitate was removed by filtration before being put into the experimental equipment. The resulting solution had a density of 1.0914 g/ml while the unfiltered solution was 1.09227. The salinity of the solutions is about 130 grams/liter.

The filtered solution was put into a teflon sample container which was then installed in a pressure vessel. The assembled equipment was pressure tested, put into a rocking oven and heated. Methane was then injected into the sample container and pressure vessel. The equipment was then rocked for a period of time, 8 to 24 hours. Methane was reinjected to obtain the desired pressure. Rocking was continued. Samples were then taken at intervals of time and analyzed. Sample weights were determined on an analytical balance. The quantity of methane was determined by pressure measurements using high precision test gauges obtained from Matheson. Pressure was measured to ± 0.04 psi. Methane concentrations in moles per kilogram were calculated using the ideal gas law. The volume of gas was computed from the known volume of the flask, the calculated volume of liquid sample, and the volume of the test gauge. A correction was also made for the compression of air present in the flask before sampling. The injection of a liquid would cause pressure in the flask to increase due to reduced volume alone in addition to any gasses exsolved from the liquid.

In the derived empirical equation, methane concentrations are expressed as the logarithms to the base e of concentration units given in standard cubic feet of gas per petroleum barrel. Examination of all 81 points show that 10 data points had larger than expected standard deviations. Low values could be the result of gas losses from sample vessels before measurement. High values could represent a procedural error. Gasses not completely bled out of vessel prior to next determination or a gas bubble in the system was swept out during sampling. The expected uncertainty in the calculated methane concentration would be about $\pm \frac{1}{2}$ SCF. Solubilities calculated from the equation differ from the measured values by $\frac{1}{2}$ to 1 SCF in most cases. The fit of observed data to the equation line is shown in figure 1. The ten previously mentioned high and low values have been deleted.

The solubilities of methane observed in Pleasant Bayou brines were compared

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to the solubilities obtained in NaCl solutions at a salinity of 135 grams/liter. The values in NaCl solution were obtained from an empirical equation derived from measurements in NaCl solutions. This equation is also given in table 3. The NaCl solution equation has an overall uncertainty of about + 8% of the value. Measurements in NaCl solutions are consistently higher by a slight amount compared to measurements in well solutions. The difference is less than the standard deviations of either equation. These differences are thus probably not really significant.

Concentrations of gasses reported from Pleasant Bayou No. 2 well total 27.0 SCF/Bbl (letter dated Feb. 24, 1981). This estimate includes 21.7 SCF of methane, 1.3 SCF of other hydrocarbon gasses and 3.8 SCF of CO₂. This data has been plotted in figure 2. If CO₂ simply displaced methane from solution on a mole for mole basis, methane concentrations would follow a straight line reduction with increasing CO₂ (simple displacement line (S.D.L.)). We do not have any measurements of the effect of CO₂ on methane concentration at experimental conditions approximating those at formation levels in the Pleasant Bayou No. 2 well. The closest similar data is at 302°F, 5000 psi and at a salinity of 51.7 grams per liter. Calculated solubility of methane in solutions lacking CO₂ is 28 SCF/Bbl. The curves have been proportionately adjusted to fit 27 SCF. It is evident that adding CO₂ increases the total gas in solution and only gradually reduces methane concentration at least up to 10% CO₂ in the gas. At higher concentrations, CO₂ really suppresses methane solubility while the total gas content increases significantly. Thus at 11% CO₂ we would expect little if any reduction in methane concentration vs solution lacking CO₂ (about 1 SCF less). What is even more interesting is the reference to J. M. Campbell's work showing that solubilities of mixtures of light hydrocarbon gasses is greater than that of pure components. If this is true at higher temperatures and pressures, then the total hydrocarbon gasses should be greater than the indicated 27-28 SCF/Bbl in solutions lacking CO₂.

The tentative conclusions that we can make here based on the information presently available is that the concentration of methane and hydrocarbon gas totals is less than what should be there at the CO₂ concentration involved. There is a shortfall of at least 3 SCF per barrel relative to the methane curve in figure 2 based upon effect of CO₂ at 5000 psi in 5% NaCl. There would be an additional shortfall in methane if other hydrocarbons were to actually enhance methane concentrations. This would suggest that the Pleasant Bayou waters in the well may be slightly undersaturated with methane. There are two specific effects that need further evaluation. First we need to know more about the effect of CO₂ at the appropriate conditions of 302°F, 11,000 psi and 130 g/liter salinity. Second we need to determine independently what effect ethane has upon methane concentrations in saturated solutions. These experimental parameters will be employed as soon as we can possibly get equipment together.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Table 1. Experimental Results - Solubility of Methane in Pleasant Bayou No. 2 Well Brines.

ROW	TFAREN	PSI	SCF/BL	CALCH4
* 1 *	203.00000	12081.66406	20.56000	21.00953
* 2 *	200.29999	11994.64258	18.76000	20.76665
* 3 *	200.29999	11994.64258	21.61000	20.76665
* 4 *	203.00000	11994.64258	20.47000	20.98095
* 5 *	198.31998	9108.38672	20.36000	19.06415
* 6 *	198.31998	9108.38672	19.64000	19.06415
* 7 *	194.00000	9137.39453	20.51000	18.74704
* 8 *	194.00000	9137.39453	19.38000	18.74704
* 9 *	196.87997	9137.39453	19.11000	18.97328
* 10 *	197.95999	5134.34473	13.92000	14.36617
* 11 *	197.95999	5134.34473	13.68000	14.36617
* 12 *	198.50000	5018.31445	12.60000	14.20597
* 13 *	198.50000	5018.31445	13.54000	14.20597
* 14 *	198.67999	2001.52441	8.60000	7.44561
* 15 *	199.03998	2030.53198	7.94000	7.54393
* 16 *	199.03998	2030.53198	8.28000	7.54393
* 17 *	199.03998	1058.77734	4.21000	4.45738
* 18 *	198.50000	1058.77734	4.16000	4.44320
* 19 *	198.50000	1058.77734	4.24000	4.44320
* 20 *	248.17999	11994.64258	24.11000	24.33393
* 21 *	248.00000	11951.13086	24.07000	24.30803
* 22 *	248.00000	11951.13086	24.22000	24.30803
* 23 *	248.00000	11893.11523	25.52000	24.28943
* 24 *	248.00000	12038.15430	25.49000	24.33508
* 25 *	248.00000	12038.15430	24.71000	24.33508
* 26 *	248.00000	9108.38672	21.85000	22.75832
* 27 *	249.79999	9006.85938	21.23000	22.79697
* 28 *	250.69998	9108.38672	23.44000	22.94310
* 29 *	250.69998	9108.38672	22.81000	22.94310
* 30 *	250.25000	5032.81836	18.44000	17.53644
* 31 *	250.25000	5032.81836	16.49000	17.53644
* 32 *	250.25000	5003.81055	18.55000	17.47985
* 33 *	250.25000	5003.81055	16.32000	17.47985
* 34 *	248.89999	2059.53955	9.88000	9.68718
* 35 *	250.25000	2001.52441	9.23000	9.54066
* 36 *	250.25000	2001.52441	9.13000	9.54066
* 37 *	250.25000	2001.52441	10.63000	9.54066
* 38 *	250.25000	2001.52441	9.11000	9.54066
* 39 *	250.25000	2001.52441	8.96000	9.54066
* 40 *	250.25000	1000.76221	6.19000	5.60288
* 41 *	250.25000	1000.76221	5.38000	5.60288
* 42 *	250.25000	1000.76221	5.65000	5.60288
* 43 *	250.25000	1000.76221	5.61000	5.60288
* 44 *	301.09998	12299.22266	29.69000	27.42771
* 45 *	301.09998	12299.22266	28.95000	27.42771
* 46 *	301.09998	12081.66406	26.70000	27.38019
* 47 *	301.09998	12081.66406	26.85000	27.38019
* 48 *	301.09998	11994.64258	26.70000	27.35918
* 49 *	301.09998	11994.64258	28.61000	27.35918
* 50 *	300.01996	9006.85938	24.24000	25.78226
* 51 *	304.25000	9064.87500	26.47000	26.03215
* 52 *	304.25000	9050.37109	24.42000	26.02061
* 53 *	299.47992	5076.33008	19.57000	20.35548
* 54 *	299.47992	5076.33008	19.06000	20.35548
* 55 *	299.47992	5076.33008	20.23000	20.35548
* 56 *	299.47992	5076.33008	19.45000	20.35548
* 57 *	301.09998	2001.52441	12.35000	11.51192
* 58 *	301.09998	2001.52441	11.97000	11.51192
* 59 *	304.25000	1015.26599	7.25000	7.12098
* 60 *	297.67993	1000.76221	8.03000	6.87442
* 61 *	298.39996	1000.76221	7.90000	6.89318
* 62 *	298.39996	1000.76221	7.58000	6.89318
* 63 *	301.09998	507.63300	3.92000	4.13682
* 64 *	301.09998	269.77063	2.34000	2.51426
* 65 *	301.09998	269.77063	2.07000	2.51426
* 66 *	301.63995	259.61798	2.12000	2.44520
* 67 *	301.63995	259.61798	2.09000	2.44520
* 68 *	301.09998	249.46530	2.59000	2.36270
* 69 *	301.09998	249.46530	2.31000	2.36270
* 70 *	300.20001	104.42735	1.28000	1.17134
* 71 *	300.20001	104.42735	1.34000	1.17134

Table 3. Empirical Equations for the Solubility of Methane in Aqueous Solutions.

A. Pleasant Bayou No. 2 brines.

$$\log_e CH_4 = A + Bt + Cp + D\log_e p + Et\log_e p + Ft^2.$$

CH_4 is expressed in SCF per petroleum barrel.

p is pressure in psi.

t is temperature in degrees Fahrenheit.

A-F are empirical parameters derived by least squares regression.

$$A = -7.45$$

$$B = 1.6067E-02$$

$$C = 5.8446E-05$$

$$D = 1.0622$$

$$E = -8.3876E-04$$

$$F = -1.0878E-05$$

Adjusted Multiple R = 0.996

Standard deviation of Residuals in $\log_e$ of CH_4 values = 0.075

71 observations

B. NaCl Solutions.

$$\log_e CH_4 = A + Bt + Cp + D\log_e p + Et\log_e p + Ft^2\log_e p + GS + Hst^{\frac{1}{2}} + Is^2 + Jt^2s^2 + Ks\log_e p + Lts\log_e p + Mt^2s\log_e p.$$

CH_4 is in SCF per petroleum barrel.

p is pressure in psi.

s is grams per liter of solution at S. T. P.

t is temperature in degrees Fahrenheit.

A-M are empirical parameters derived by least squares regression.

$$A = -3.1720$$

$$B = 4.7219E-03$$

$$C = -1.2292E-05$$

$$D = 6.9761E-01$$

$$E = -4.8596E-04$$

$$F = 8.5455E-07$$

$$G = 2.4434E-02$$

$$H = -1.7581E-03$$

$$I = -8.2950E-06$$

$$J = 1.1460E-10$$

$$K = -1.6687E-03$$

$$L = 8.7371E-06$$

$$M = -8.8269E-09$$

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Adjusted Multiple R = 0.996

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71 observations

B. NaCl Solutions.

$$\log_e CH_4 = A + Bt + Cp + D\log_e p + Et\log_e p + Ft^2\log_e p + GS + Hst^{\frac{1}{2}} + Is^2 + Jt^2s^2 + Ks\log_e p + Lts\log_e p + Mt^2s\log_e p.$$

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$$D = 6.9761E-01$$

$$E = -4.8596E-04$$

$$F = 8.5455E-07$$

$$G = 2.4434E-02$$

$$H = -1.7581E-03$$

$$I = -8.2950E-06$$

$$J = 1.1460E-10$$

$$K = -1.6687E-03$$

$$L = 8.7371E-06$$

$$M = -8.8269E-09$$

Fig. 1

fig. 2

APPENDIX E
Monthly Production Summaries

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 1. IGT MONTHLY PRODUCTION REPORTS^a

MARCH 1988

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	-----	-----	0.0	0	0	0.0	0.0	0.00	0.00	0
2	4,172	-----	62.3	0	15	0.0	0.0	0.00	0.00	14
3	4,072	-----	61.2	0	15	0.0	0.0	0.00	0.00	14
4	4,254	-----	55.0	0	15	0.0	0.0	0.00	0.00	12
5	4,232	-----	61.3	0	39	0.0	0.0	0.00	0.00	11
6	4,254	-----	63.4	0	75	0.0	0.0	0.00	0.00	11
7	4,191	-----	110.6	3,087	242	71.1	61.4	23.03	0.00	115
8	4,176	-----	177.8	5,492	417	130.9	108.2	23.84	0.00	259
9	4,304	-----	66.0	0	167	0.0	0.0	0.00	0.00	41
10	4,277	-----	66.6	0	101	0.0	0.0	0.00	0.00	25
11	4,268	-----	71.4	0	70	0.0	0.0	0.00	0.00	20
12	4,264	-----	75.2	0	54	0.0	0.0	0.00	0.00	17
13	4,260	-----	65.5	0	50	0.0	0.0	0.00	0.00	15
14	4,168	-----	55.4	0	45	0.0	0.0	0.00	0.00	13
15	4,251	-----	57.1	0	42	0.0	0.0	0.00	0.00	12
16	2,523	-----	54.3	0	41	0.0	0.0	0.00	0.00	12
17	4,256	-----	63.0	0	39	0.0	0.0	0.00	0.00	12
18	4,253	-----	52.2	0	38	0.0	0.0	0.00	0.00	11
19	4,252	-----	53.4	0	36	0.0	0.0	0.00	0.00	10
20	4,254	-----	61.8	0	35	0.0	0.0	0.00	0.00	11
21	4,254	-----	66.9	0	35	0.0	0.0	0.00	0.00	11
22	4,254	-----	67.5	0	34	0.0	0.0	0.00	0.00	11
23	4,253	-----	71.1	0	33	0.0	0.0	0.00	0.00	12
24	4,253	-----	75.9	0	32	0.0	0.0	0.00	0.00	11
25	4,253	-----	78.7	0	32	0.0	0.0	0.00	0.00	12
26	4,253	-----	77.1	0	31	0.0	0.0	0.00	0.00	11
27	4,253	-----	74.3	0	30	0.0	0.0	0.00	0.00	11
28	4,253	-----	72.5	0	30	0.0	0.0	0.00	0.00	11
29	4,253	-----	69.9	0	29	0.0	0.0	0.00	0.00	11
30	4,251	-----	52.6	0	27	0.0	0.0	0.00	0.00	10
31	4,253	-----	67.7	0	27	0.0	0.0	0.00	0.00	13

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
8,579	202	23.55	170	19.77	0.00

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
8,579	202	23.55	170	19.77	0.00

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 2. IGT MONTHLY PRODUCTION REPORTS^a

APRIL 1988

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	4,252	-----	70.2	0	26	0.0	0.0	0.00	0.00	13
2	4,252	-----	74.1	0	26	0.0	0.0	0.00	0.00	13
3	4,230	-----	71.6	0	25	0.0	0.0	0.00	0.00	13
4	4,252	-----	73.2	0	25	0.0	0.0	0.00	0.00	13
5	4,253	-----	77.1	0	24	0.0	0.0	0.00	0.00	14
6	4,253	-----	75.7	0	24	0.0	0.0	0.00	0.00	13
7	4,252	-----	70.5	0	23	0.0	0.0	0.00	0.00	12
8	4,252	-----	65.3	0	23	0.0	0.0	0.00	0.00	11
9	4,253	-----	71.8	0	23	0.0	0.0	0.00	0.00	12
10	4,252	-----	62.4	0	23	0.0	0.0	0.00	0.00	9
11	4,252	-----	56.9	0	21	0.0	0.0	0.00	0.00	10
12	4,252	-----	62.2	0	21	0.0	0.0	0.00	0.00	10
13	4,253	-----	69.1	0	21	0.0	0.0	0.00	0.00	10
14	4,253	-----	70.8	0	22	0.0	0.0	0.00	0.00	10
15	4,266	-----	72.3	0	22	0.0	0.0	0.00	0.00	11
16	4,253	-----	66.4	0	21	0.0	0.0	0.00	0.00	10
17	4,253	-----	71.6	0	21	0.0	0.0	0.00	0.00	10
18	4,260	-----	102.5	1,308	247	36.6	29.5	28.00	0.00	52
19	4,280	-----	67.0	0	219	0.0	0.0	0.00	0.00	26
20	4,533	-----	74.0	524	159	0.0	0.0	0.00	0.00	37
21	4,489	-----	81.7	535	188	0.9	0.0	1.77	0.00	87
22	4,023	10,810	189.3	6,206	506	146.7	118.6	23.64	0.00	261
23	3,703	10,488	271.7	12,798	635	303.6	262.6	23.72	0.00	529
24	3,822	-----	226.3	9,722	603	224.9	197.4	23.13	0.00	421
25	4,319	-----	80.1	0	418	0.0	0.0	0.00	0.00	13
26	4,290	-----	77.9	0	343	0.0	0.0	0.00	0.00	4
27	4,279	-----	75.4	0	300	0.0	0.0	0.00	0.00	3
28	4,273	-----	74.3	0	270	0.0	0.0	0.00	0.00	2
29	4,269	-----	68.6	0	236	0.0	0.0	0.00	0.00	2
30	4,266	-----	66.1	0	191	0.0	0.0	0.00	0.00	1

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
31,094	713	22.92	608
			19.56
			0.00

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
39,673	915	23.06	778
			19.60
			0.00

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 3. IGT MONTHLY PRODUCTION REPORTS^a

MAY 1988

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	4,264	-----	70.0	0	159	0.0	0.0	0.00	0.00	1
2	4,335	-----	73.4	0	152	0.0	0.0	0.00	0.00	1
3	4,263	-----	78.0	0	113	0.0	0.0	0.00	0.00	1
4	4,262	-----	77.5	0	52	0.0	0.0	0.00	0.00	1
5	4,261	-----	77.1	0	15	0.0	0.0	0.00	0.00	1
6	4,260	-----	75.4	0	15	0.0	0.0	0.00	0.00	1
7	4,217	-----	73.8	0	15	0.0	0.0	0.00	0.00	1
8	1,469	-----	76.5	0	15	0.0	0.0	0.00	0.00	1
9	57	-----	79.9	0	16	0.0	0.0	0.00	0.00	1
10	51	-----	81.1	0	16	0.0	0.0	0.00	0.00	1
11	48	-----	76.6	0	16	0.0	0.0	0.00	0.00	1
12	32	-----	72.9	0	16	0.0	0.0	0.00	0.00	1
13	32	-----	77.4	0	16	0.0	0.0	0.00	0.00	1
14	32	-----	78.7	0	16	0.0	0.0	0.00	0.00	1
15	31	-----	80.2	0	16	0.0	0.0	0.00	0.00	1
16	31	-----	80.9	0	16	0.0	0.0	0.00	0.00	2
17	31	-----	80.9	0	16	0.0	0.0	0.00	0.00	2
18	31	-----	81.8	0	16	0.0	0.0	0.00	0.00	2
19	31	-----	80.4	0	16	0.0	0.0	0.00	0.00	2
20	31	-----	78.9	0	15	0.0	0.0	0.00	0.00	3
21	31	-----	76.6	0	14	0.0	0.0	0.00	0.00	3
22	31	-----	75.7	0	14	0.0	0.0	0.00	0.00	4
23	31	-----	80.9	0	15	0.0	0.0	0.00	0.00	4
24	31	-----	83.8	0	328	0.0	0.0	0.00	0.00	8
25	875	-----	82.9	0	538	0.0	0.0	0.00	0.00	10
26	2,537	-----	79.7	0	525	0.0	0.0	0.00	0.00	10
27	4,066	-----	145.3	3,571	472	84.0	73.5	23.53	0.00	109
28	3,915	10,284	260.8	10,190	572	248.7	215.3	24.41	0.00	363
29	3,704	10,195	259.2	10,140	591	255.0	217.9	25.15	0.00	378
30	4,037	-----	239.8	7,699	589	186.4	158.2	24.21	0.00	314
31	4,244	-----	121.1	2,354	433	56.1	47.9	23.84	0.00	144

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
33,954	830	24.45	713	20.99	0.00

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
73,627	1,745	23.70	1,490	20.24	0.00

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 4. IGT MONTHLY PRODUCTION REPORTS^a

JUNE 1988

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	4,079	-----	214.1	5,916	314	142.2	116.5	24.04	0.00	243
2	4,323	-----	112.3	147	469	0.0	0.0	0.00	0.00	54
3	4,300	-----	83.2	2,122	420	2.4	0.3	1.15	0.00	109
4	4,284	-----	114.9	1,129	542	29.8	20.9	26.36	0.00	90
5	4,273	-----	149.9	2,684	562	62.8	52.6	23.38	0.00	144
6	4,228	-----	142.6	2,662	513	68.3	57.6	25.63	0.00	106
7	3,666	-----	179.7	3,854	548	94.6	81.5	24.55	0.00	199
8	4,017	-----	160.0	6,199	439	144.3	123.6	23.28	0.00	144
9	3,183	10,167	284.8	18,595	675	445.5	375.0	23.96	0.01	478
10	1,853	-----	199.5	6,772	534	158.3	133.0	23.38	0.03	243
11	3,074	10,111	287.3	19,814	679	478.3	400.9	24.14	0.03	534
12	3,079	10,127	288.3	19,864	688	481.2	400.4	24.23	0.02	544
13	3,069	10,115	288.1	19,887	684	482.3	401.1	24.25	0.02	544
14	3,061	10,092	288.4	19,895	683	481.2	400.8	24.19	0.02	544
15	3,050	10,080	289.0	19,853	683	480.3	400.4	24.20	0.03	543
16	3,034	10,073	289.4	19,759	679	467.1	398.0	23.64	0.04	541
17	3,040	10,069	289.7	19,905	688	479.9	401.2	24.11	0.06	546
18	3,031	10,056	290.0	19,981	667	478.5	400.8	23.95	0.06	549
19	3,103	10,085	289.6	19,282	615	445.1	358.7	23.08	0.04	534
20	3,286	10,212	288.3	17,580	873	401.3	308.0	22.82	0.04	500
21	3,186	10,186	289.6	19,327	715	439.3	339.5	22.73	0.03	573
22	3,471	-----	285.4	15,390	772	352.0	271.1	22.87	0.05	479
23	3,785	10,564	282.4	12,026	753	279.1	230.8	23.21	0.06	383
24	3,490	10,365	286.6	15,971	673	374.8	307.5	23.47	0.02	481
25	3,168	10,165	289.6	19,618	587	463.2	381.6	23.61	0.04	578
26	3,157	10,161	289.9	19,597	664	463.4	385.5	23.65	0.04	579
27	3,148	10,160	290.2	19,593	705	464.9	387.5	23.73	0.08	580
28	3,142	10,155	290.3	19,582	706	464.0	386.4	23.69	0.03	581
29	3,137	10,153	290.1	19,572	705	462.7	385.9	23.64	0.03	580
30	3,136	10,148	290.2	19,575	706	465.4	386.5	23.78	0.04	580

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
426,151	10,052	23.59	8,294
			19.46
			0.83

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
499,778	11,797	23.61	9,784
			19.58
			0.83

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 5. IGT MONTHLY PRODUCTION REPORTS^a

JULY 1988

Day	-PROD WELL-		----BRINE----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	3,123	10,138	290.0	19,531	706	462.7	384.8	23.69	0.05	578
2	3,120	10,134	290.1	19,560	700	465.1	386.4	23.78	0.06	581
3	3,119	10,136	290.2	19,553	705	463.4	385.1	23.70	0.05	579
4	3,117	-----	290.1	19,551	709	463.2	384.1	23.69	0.05	577
5	3,113	10,114	290.4	19,541	711	464.1	383.5	23.75	0.05	578
6	3,108	10,109	289.7	19,534	711	464.7	383.9	23.79	0.03	576
7	3,105	10,099	289.9	19,551	702	465.9	385.2	23.83	0.03	578
8	3,120	-----	288.5	19,351	704	460.8	380.7	23.82	0.02	567
9	3,157	10,128	289.7	18,942	700	449.9	372.3	23.75	0.02	561
10	3,153	10,127	290.1	18,953	696	449.7	373.2	23.73	0.03	562
11	3,151	10,126	289.6	18,948	699	448.8	372.0	23.68	0.04	562
12	3,147	10,123	289.2	18,951	697	448.2	371.8	23.65	0.03	562
13	3,145	10,119	289.6	18,953	697	448.3	372.5	23.65	0.04	564
14	3,141	10,115	289.5	18,951	695	448.1	372.2	23.64	0.05	564
15	3,139	10,112	289.6	18,949	699	447.9	371.9	23.63	0.03	564
16	3,135	10,108	290.1	18,950	696	447.1	372.3	23.59	0.04	567
17	3,131	10,102	290.3	18,934	693	446.5	372.0	23.58	0.05	568
18	3,127	10,099	290.3	18,928	694	446.1	371.6	23.57	0.03	568
19	3,126	10,098	289.3	18,927	701	444.6	370.7	23.49	0.02	559
20	3,122	10,095	290.4	18,943	697	445.2	371.6	23.50	0.02	557
21	3,120	10,091	290.5	18,940	698	444.8	371.6	23.49	0.03	559
22	3,117	10,089	290.6	18,947	695	443.6	371.3	23.41	0.06	561
23	3,115	10,086	290.5	18,943	695	444.0	371.3	23.44	0.03	564
24	3,114	10,086	290.6	18,938	696	443.2	370.7	23.41	0.02	568
25	3,111	10,083	290.6	18,945	695	442.1	369.8	23.33	0.03	570
26	3,109	10,081	290.3	18,931	697	442.0	368.9	23.35	0.03	566
27	3,105	10,076	290.4	18,927	696	443.9	370.3	23.45	0.03	567
28	3,103	10,075	290.5	18,941	696	444.7	371.0	23.48	0.03	567
29	3,103	10,076	290.4	18,969	694	445.2	371.2	23.47	0.02	568
30	3,101	10,075	290.7	18,955	698	444.4	370.5	23.45	0.03	570
31	3,098	10,072	290.7	18,954	698	442.6	368.7	23.35	0.05	572

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
591,891	13,961	23.59	11,613	19.62	1.09

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
1,091,670	25,758	23.60	21,397	19.60	1.92

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 6. IGT MONTHLY PRODUCTION REPORTS^a

AUGUST 1988

Day	-PROD WELL-		----BRINE----		SEP	--GAS RATE--		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	3,096	10,070	290.4	18,946	698	442.9	368.2	23.38	0.02	574
2	3,095	10,068	290.3	18,940	701	442.8	367.5	23.38	0.02	572
3	3,361	10,220	288.6	15,681	698	368.4	302.9	23.49	0.02	486
4	3,505	10,325	287.7	14,080	698	331.7	270.7	23.56	0.02	441
5	3,507	10,330	287.6	14,132	695	332.9	271.7	23.55	0.01	442
6	3,291	10,237	288.9	16,763	698	393.9	322.7	23.50	0.02	511
7	3,087	10,130	290.5	19,073	696	455.1	372.6	23.86	0.02	575
8	3,081	10,123	290.6	19,044	694	455.3	372.6	23.91	0.01	575
9	3,079	10,121	290.9	19,001	697	453.8	371.5	23.88	0.03	578
10	3,065	10,105	290.4	19,088	699	456.0	373.4	23.89	0.03	579
11	3,230	10,175	289.0	17,079	699	404.1	329.4	23.66	0.02	523
12	3,073	10,063	290.5	19,010	700	439.4	370.9	23.11	0.02	576
13	3,068	10,058	290.6	18,981	695	451.1	371.0	23.76	0.02	581
14	3,066	10,056	290.4	18,965	697	451.1	370.2	23.79	0.02	583
15	3,063	10,052	290.5	18,949	696	450.8	370.0	23.79	0.02	585
16	3,061	10,050	290.8	18,939	695	450.0	369.8	23.76	0.02	587
17	3,059	10,048	290.8	18,924	695	449.9	369.5	23.77	0.02	587
18	3,058	10,046	291.0	18,896	697	449.6	369.3	23.79	0.03	582
19	3,058	10,045	291.0	18,869	697	448.7	368.6	23.78	0.02	570
20	3,057	10,044	290.9	18,861	697	448.1	367.9	23.76	0.02	575
21	3,055	10,047	290.7	18,851	698	448.4	367.5	23.79	0.02	579
22	3,052	10,064	290.8	18,855	695	450.1	367.8	23.87	0.03	583
23	3,050	10,039	291.0	18,869	696	447.0	367.5	23.69	0.02	532
24	3,048	10,038	291.0	18,854	698	447.3	366.9	23.72	0.02	489
25	3,046	10,036	291.2	18,845	697	447.2	366.7	23.73	0.03	492
26	3,045	10,034	291.1	18,845	698	447.6	366.5	23.75	0.02	495
27	3,043	10,033	290.9	18,863	697	447.9	366.4	23.74	0.03	498
28	3,042	10,033	290.9	18,842	697	447.9	366.4	23.77	0.02	502
29	3,036	10,030	290.7	18,918	696	450.0	367.9	23.79	0.02	507
30	3,005	10,015	290.9	19,277	697	460.5	375.8	23.89	0.03	523
31	3,646	-----	183.8	7,381	299	173.3	143.5	23.48	0.00	290

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
558,622	13,243	23.71	10,873	19.46	0.67

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
1,650,291	39,001	23.63	32,271	19.55	2.59

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 7. IGT MONTHLY PRODUCTION REPORTS^a

SEPTEMBER 1988

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	4,039	-----	82.5	0	14	0.0	0.0	0.00	0.00	107
2	4,040	-----	75.6	0	15	0.0	0.0	0.00	0.00	90
3	4,042	-----	76.7	0	18	0.0	0.0	0.00	0.00	81
4	4,045	-----	83.0	0	17	0.0	0.0	0.00	0.00	76
5	4,048	-----	79.1	0	17	0.0	0.0	0.00	0.00	73
6	4,051	-----	78.9	0	18	0.0	0.0	0.00	0.00	70
7	4,053	-----	80.1	0	20	0.0	0.0	0.00	0.00	67
8	4,055	-----	79.8	0	20	0.0	0.0	0.00	0.00	64
9	3,882	-----	140.4	4,730	254	105.1	82.9	22.22	0.02	151
10	3,079	10,116	286.6	19,582	702	468.0	384.9	23.90	0.02	525
11	3,050	10,078	288.9	19,495	701	465.5	382.4	23.88	0.01	531
12	3,036	10,061	289.2	19,474	700	465.9	381.4	23.92	0.01	534
13	3,026	10,048	289.9	19,442	698	465.1	381.1	23.92	0.03	536
14	3,020	10,040	290.5	19,386	698	463.4	380.3	23.90	0.05	537
15	-----	-----	141.2	8,420	342	197.3	165.5	23.44	0.00	-----
16	-----	-----	-----	0	0	0.0	0.0	0.00	0.00	-----
17	-----	-----	-----	0	0	0.0	0.0	0.00	0.00	-----
18	-----	-----	-----	0	188	0.0	0.0	0.00	0.00	-----
19	-----	-----	-----	2,160	474	39.5	36.0	18.29	0.00	-----
20	-----	-----	-----	10,191	596	240.7	200.3	23.61	0.05	-----
21	3,079	10,101	288.3	19,322	686	463.8	386.7	24.01	0.15	570
22	3,061	10,076	289.6	19,226	691	461.6	384.1	24.01	0.15	566
23	3,050	10,063	289.9	19,181	692	460.6	382.8	24.01	0.15	568
24	3,041	10,054	290.2	19,147	691	460.2	382.3	24.03	0.15	570
25	3,034	10,046	290.6	19,138	693	458.5	380.4	23.96	0.20	573
26	3,027	10,038	290.8	19,112	688	459.0	382.0	24.02	0.24	574
27	3,022	10,032	290.9	19,097	686	459.0	381.8	24.03	0.14	575
28	3,017	10,025	290.8	19,090	685	459.1	381.9	24.05	0.08	576
29	3,013	10,022	290.3	19,075	688	459.1	380.9	24.07	0.02	576
30	3,010	10,020	290.7	19,049	697	458.0	379.1	24.04	0.14	576

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
314,317	7,509	23.89	1.58

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
1,964,609	46,510	23.67	4.17

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 8. IGT MONTHLY PRODUCTION REPORTS^a

OCTOBER 1988

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	3,006	10,015	291.1	19,057	693	458.1	380.0	24.04	0.03	578
2	3,002	10,013	290.6	19,077	690	460.1	381.1	24.12	0.02	578
3	2,997	10,007	291.0	19,075	695	458.8	380.1	24.05	0.02	578
4	2,994	10,005	291.1	19,089	690	459.9	381.4	24.09	0.04	579
5	2,994	10,004	291.1	19,089	693	459.6	380.8	24.08	0.01	579
6	2,993	10,003	290.9	19,070	697	459.2	379.5	24.08	0.03	579
7	2,990	9,999	291.0	19,069	695	458.4	378.8	24.04	0.03	579
8	2,988	9,998	291.1	19,057	697	458.6	379.0	24.06	0.02	580
9	2,985	9,993	291.1	19,058	692	458.3	379.4	24.05	0.02	580
10	2,983	9,992	291.3	19,050	692	458.0	379.2	24.04	0.03	581
11	2,980	9,989	291.4	19,038	690	458.0	379.7	24.06	0.03	581
12	2,978	9,988	291.1	19,041	690	458.6	379.4	24.09	0.02	581
13	2,976	9,986	290.8	19,031	691	459.2	379.1	24.13	0.30	580
14	2,975	9,984	291.0	19,026	696	457.9	377.9	24.07	0.17	580
15	2,974	9,984	291.2	19,001	695	457.2	377.5	24.06	0.13	581
16	2,971	9,981	291.3	18,999	690	457.2	378.1	24.06	0.12	582
17	3,226	-----	261.3	14,303	660	342.9	284.4	23.98	0.02	482
18	3,749	-----	131.4	3,903	555	89.6	74.5	22.97	0.06	214
19	3,011	9,997	289.9	18,978	696	453.9	377.1	23.92	0.05	588
20	2,995	9,977	290.7	18,935	691	453.3	376.6	23.94	0.06	595
21	2,988	9,968	291.3	18,914	692	452.2	376.0	23.91	0.06	598
22	2,983	9,965	290.3	18,898	693	453.6	375.2	24.00	0.01	597
23	2,980	9,961	290.7	18,886	691	452.5	375.3	23.96	0.05	599
24	2,977	9,958	290.5	18,877	689	453.3	375.5	24.01	0.04	599
25	2,975	9,956	290.7	18,879	693	452.7	374.8	23.98	0.07	600
26	2,974	9,953	291.2	18,867	692	452.1	374.9	23.96	0.05	601
27	2,972	9,952	290.8	18,865	691	451.9	374.6	23.96	0.04	601
28	2,970	9,949	291.3	18,858	690	451.3	374.7	23.93	0.03	606
29	2,967	9,946	290.8	18,846	691	452.7	374.8	24.02	0.04	604
30	2,965	9,945	290.9	18,828	694	452.1	374.1	24.01	0.02	604
31	2,964	9,943	290.7	18,804	696	452.1	374.0	24.05	0.10	603

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	MCF	STB
568,463	13,653	11,308	1.70

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	MCF	STB
2,533,071	60,163	49,795	5.87

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 9. IGT MONTHLY PRODUCTION REPORTS^a

NOVEMBER 1988

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,962	9,941	290.9	18,793	698	451.6	373.3	24.03	0.12	604
2	2,960	9,939	291.0	18,787	697	451.2	373.4	24.02	0.07	604
3	2,959	9,938	290.6	18,792	698	450.6	372.3	23.98	0.04	604
4	2,958	9,937	290.3	18,789	699	450.4	371.3	23.97	0.04	604
5	2,955	9,934	290.9	18,759	697	450.3	372.2	24.01	0.08	606
6	2,954	9,931	291.4	18,753	693	450.4	372.5	24.02	0.04	608
7	2,953	9,931	290.2	18,750	696	450.1	371.0	24.01	0.05	607
8	2,952	9,929	291.0	18,747	695	448.9	370.9	23.94	0.02	609
9	3,236	10,101	286.8	15,210	695	362.4	296.8	23.82	0.07	505
10	2,939	9,924	291.0	18,940	698	454.5	373.6	24.00	0.04	608
11	2,936	9,920	290.6	18,903	700	454.3	372.3	24.03	0.02	608
12	2,933	9,920	290.2	18,893	700	454.8	372.1	24.07	0.06	608
13	2,931	9,916	291.1	18,874	699	454.1	372.2	24.06	0.04	610
14	2,929	9,915	290.6	18,874	697	454.0	371.8	24.05	0.04	610
15	2,811	-----	284.8	17,691	697	419.4	346.7	23.71	0.06	581
16	2,956	9,933	290.5	18,663	704	449.9	367.7	24.11	0.14	608
17	2,953	9,931	290.1	18,644	707	450.4	367.2	24.16	0.05	610
18	2,952	9,930	289.6	18,649	707	449.1	365.9	24.08	0.02	610
19	2,950	9,927	289.6	18,633	705	449.5	366.0	24.12	0.01	612
20	2,948	9,923	290.3	18,591	710	450.6	366.7	24.24	0.14	615
21	2,946	9,921	291.0	18,582	707	449.9	367.0	24.21	0.02	620
22	2,945	9,920	291.5	18,576	708	448.0	365.2	24.12	0.04	621
23	2,943	9,919	291.5	18,563	706	447.6	364.1	24.11	0.04	622
24	2,959	9,927	290.9	18,396	704	444.0	359.9	24.14	0.02	615
25	2,942	9,918	290.1	18,583	708	447.3	361.4	24.07	0.12	620
26	2,940	9,914	290.4	18,583	699	446.9	362.6	24.05	0.04	621
27	2,937	9,911	290.6	18,564	693	448.4	364.5	24.16	0.10	621
28	2,935	9,910	290.9	18,532	700	448.2	363.4	24.19	0.06	622
29	2,935	9,908	291.3	18,535	704	447.3	362.2	24.13	0.05	624
30	2,934	9,909	290.7	18,534	702	448.2	362.0	24.18	0.03	622

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
556,186	13,382	24.06	10,948
			19.68
			1.66

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
3,089,257	73,546	23.81	60,743
			19.66
			7.53

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 10. IGT MONTHLY PRODUCTION REPORTS^a

DECEMBER 1988

Day	-PROD WELL-		----BRINE----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,933	9,907	291.6	18,511	699	447.1	361.9	24.15	0.07	617
2	2,933	9,907	291.5	18,500	707	446.5	359.8	24.13	0.09	603
3	2,931	9,906	291.4	18,494	710	446.0	359.0	24.12	0.07	605
4	2,930	9,904	291.6	18,490	709	445.5	358.6	24.09	0.08	606
5	2,928	9,903	291.4	18,489	704	446.5	359.0	24.15	0.09	607
6	2,927	9,902	291.3	18,479	707	446.4	358.4	24.16	0.07	608
7	2,925	9,902	290.5	18,498	702	447.0	358.1	24.16	0.08	606
8	2,924	9,900	290.6	18,490	702	447.2	358.3	24.18	0.02	605
9	2,923	9,899	290.4	18,436	711	447.9	357.9	24.29	0.03	605
10	2,922	9,898	290.7	18,437	710	447.7	357.8	24.28	0.03	606
11	2,922	9,898	290.6	18,430	713	447.1	356.9	24.26	0.02	606
12	2,921	9,895	290.9	18,425	710	447.1	357.3	24.27	0.02	607
13	2,919	9,891	291.4	18,414	710	445.7	356.6	24.21	0.07	610
14	2,917	9,890	291.1	18,451	709	445.1	355.8	24.12	0.07	610
15	2,915	9,888	291.0	18,475	703	445.2	356.2	24.10	0.04	610
16	2,913	9,887	290.8	18,431	708	446.8	356.6	24.24	0.03	609
17	2,911	9,885	291.2	18,421	704	446.4	356.7	24.24	0.03	611
18	2,911	9,883	291.4	18,427	705	445.9	356.1	24.20	0.04	612
19	2,910	9,884	290.6	18,446	707	445.4	354.8	24.15	0.04	611
20	2,909	9,883	290.8	18,467	703	445.0	355.0	24.10	0.06	612
21	2,907	9,881	291.4	18,461	698	444.5	355.7	24.08	0.07	614
22	2,906	9,881	290.6	18,461	698	445.1	355.4	24.11	0.06	613
23	2,905	9,880	290.4	18,439	703	445.9	354.8	24.18	0.07	610
24	2,904	9,879	291.2	18,453	700	443.9	354.6	24.06	0.06	613
25	2,903	9,878	290.2	18,435	704	446.1	354.2	24.20	0.05	612
26	2,902	9,878	289.9	18,442	703	445.3	353.6	24.14	0.05	612
27	2,902	9,878	290.0	18,434	704	444.4	353.2	24.11	0.07	613
28	2,900	9,875	290.5	18,388	706	445.4	354.6	24.22	0.01	612
29	2,898	9,874	290.4	18,388	699	446.5	355.9	24.28	0.00	614
30	2,899	9,872	291.0	18,403	705	444.7	354.6	24.16	0.04	616
31	2,899	9,870	291.4	18,398	708	442.6	353.5	24.06	0.04	618

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
571,913	13,822	24.17	11,051
			19.32
			1.53

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
3,661,170	87,368	23.86	71,794
			19.61
			9.07

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 11. IGT MONTHLY PRODUCTION REPORTS^a

JANUARY 1989

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,897	9,870	290.9	18,389	705	444.1	353.4	24.15	0.04	618
2	2,896	9,868	291.1	18,409	704	442.5	351.5	24.04	0.06	620
3	2,895	9,865	291.1	18,419	698	441.8	352.0	23.99	0.06	621
4	2,893	9,861	290.7	18,393	700	443.4	352.3	24.11	0.02	621
5	2,894	9,863	290.2	18,403	703	442.4	351.1	24.04	0.06	621
6	2,892	9,859	290.6	18,404	702	442.2	351.2	24.03	0.03	622
7	2,892	9,860	290.2	18,400	702	441.8	351.0	24.01	0.06	622
8	2,890	9,849	290.1	18,366	702	443.1	351.5	24.13	0.04	619
9	2,889	9,829	289.9	18,326	708	442.0	351.4	24.12	0.01	616
10	2,889	9,822	290.7	18,325	711	439.3	350.6	23.97	0.12	620
11	2,889	9,819	290.7	18,350	710	435.2	349.0	23.72	0.03	622
12	3,070	9,945	288.1	16,142	698	383.4	305.8	23.75	0.02	551
13	2,962	9,891	289.8	17,554	711	425.5	336.4	24.24	0.01	589
14	2,961	9,892	290.2	17,539	709	425.5	336.8	24.26	0.01	593
15	2,959	9,890	291.0	17,547	706	423.6	336.0	24.14	0.04	597
16	2,960	9,892	290.6	17,527	715	423.9	334.1	24.18	0.02	597
17	2,959	9,892	290.4	17,547	710	424.0	334.2	24.17	0.04	599
18	2,958	9,891	289.4	17,580	707	423.0	333.2	24.06	0.07	591
19	2,958	9,890	290.0	17,564	717	423.3	331.6	24.10	0.07	586
20	2,957	9,889	289.4	17,566	715	423.3	331.9	24.10	0.02	587
21	2,956	9,887	290.5	17,546	715	422.2	332.3	24.06	0.05	593
22	2,955	9,886	290.8	17,543	717	420.8	331.4	23.99	0.03	596
23	2,954	9,885	290.6	17,552	713	420.0	331.3	23.93	0.03	597
24	2,954	9,884	290.1	17,566	713	418.7	329.8	23.83	0.02	596
25	2,952	9,884	289.5	17,586	703	419.2	330.7	23.84	0.01	596
26	2,951	9,879	290.4	17,581	697	417.9	331.3	23.77	0.04	600
27	2,949	9,880	289.9	17,571	700	423.5	335.2	24.10	0.01	601
28	2,949	9,880	289.9	17,585	698	422.6	334.7	24.03	0.03	603
29	2,948	9,879	289.8	17,572	700	422.4	334.5	24.04	0.04	600
30	2,948	9,877	290.6	17,553	705	421.7	333.8	24.03	0.08	602
31	2,948	9,879	290.6	17,549	708	421.2	333.3	24.00	0.04	605

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
551,953	13,264	24.03	10,503	19.03	1.20

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
4,213,123	100,631	23.89	82,298	19.53	10.27

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 12. IGT MONTHLY PRODUCTION REPORTS^a

FEBRUARY 1989

Day	-PROD WELL-		----BRINE----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,947	9,877	290.0	17,567	706	420.5	332.4	23.93	0.02	606
2	2,946	9,875	289.8	17,562	703	421.2	332.9	23.98	0.07	606
3	2,945	9,875	288.9	17,492	708	424.6	334.1	24.27	0.03	600
4	2,943	9,871	289.5	17,479	707	423.5	336.5	24.23	0.00	601
5	2,942	9,866	289.8	17,486	702	423.1	347.8	24.20	0.01	603
6	2,942	9,872	289.1	17,475	704	409.8	338.1	23.45	0.00	605
7	2,941	9,867	289.5	17,479	704	425.1	353.6	24.32	0.02	605
8	2,940	9,866	290.2	17,503	698	424.0	353.1	24.22	0.01	609
9	2,939	9,865	289.9	17,515	702	423.6	351.2	24.19	0.02	610
10	2,938	9,861	290.6	17,530	693	421.9	351.5	24.07	0.03	613
11	2,938	9,855	290.5	17,545	697	419.7	348.5	23.92	0.03	617
12	2,939	9,855	289.6	17,531	711	419.5	345.5	23.93	0.06	616
13	2,938	9,858	289.5	17,522	710	419.6	345.6	23.95	0.04	615
14	2,937	9,855	289.7	17,518	708	419.1	345.5	23.92	0.03	616
15	2,937	9,843	290.4	17,508	710	405.7	345.4	23.17	0.05	619
16	2,938	9,848	290.3	17,476	724	411.4	343.3	23.54	0.04	618
17	2,936	9,857	290.1	17,445	725	421.2	343.7	24.15	0.05	556
18	2,934	9,854	290.5	17,431	712	421.3	345.2	24.17	0.08	501
19	2,933	9,853	290.5	17,430	713	421.3	344.2	24.17	0.03	501
20	2,933	9,853	290.2	17,476	706	420.2	343.6	24.05	0.02	501
21	2,932	9,851	290.0	17,452	710	420.8	342.5	24.11	0.03	501
22	2,931	9,850	290.3	17,446	710	420.9	342.9	24.13	0.03	501
23	2,930	9,850	290.6	17,398	715	421.3	342.4	24.22	0.02	501
24	2,929	9,849	290.0	17,421	713	421.9	341.6	24.22	0.02	501
25	2,929	9,849	290.1	17,462	710	420.4	341.1	24.08	0.03	501
26	2,928	9,836	290.0	17,473	707	405.1	340.2	23.18	0.01	501
27	2,928	9,839	289.5	17,459	706	412.4	339.8	23.62	0.02	500
28	2,926	9,846	290.2	17,407	710	421.1	339.9	24.19	0.01	500

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
489,491	11,740	23.98	9,612
			19.64
			0.79

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
4,702,614	112,372	23.90	91,909
			19.54
			11.06

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 13. IGT MONTHLY PRODUCTION REPORTS^a

MARCH 1989

Day	-PROD WELL-		----BRINE----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,926	9,845	290.3	17,408	710	421.2	339.4	24.19	0.02	501
2	2,926	9,844	290.9	17,422	708	420.5	339.3	24.13	0.03	502
3	2,925	9,844	289.7	17,448	704	420.3	338.0	24.09	0.01	500
4	2,925	9,845	289.1	17,410	708	421.1	337.5	24.19	0.03	498
5	2,923	9,846	287.6	17,335	717	419.8	338.0	24.21	0.04	495
6	2,922	9,839	289.6	17,376	716	422.3	337.1	24.30	0.02	501
7	2,915	9,833	290.7	17,396	714	422.3	342.9	24.27	0.04	508
8	2,919	9,837	290.5	17,396	712	420.5	351.1	24.17	0.05	507
9	2,919	9,835	290.9	17,414	708	420.0	350.3	24.12	0.05	508
10	2,919	9,826	291.1	17,433	708	417.5	348.1	23.95	0.03	509
11	2,918	9,814	290.9	17,430	706	416.0	346.4	23.86	0.08	508
12	2,918	9,819	290.6	17,426	707	416.9	345.4	23.92	0.08	508
13	2,917	9,825	290.0	17,420	706	418.0	344.8	24.00	0.09	507
14	2,917	9,841	289.3	17,408	706	419.9	345.0	24.12	0.03	506
15	2,917	9,839	290.4	17,416	705	419.5	345.0	24.09	0.08	509
16	2,916	9,838	290.3	17,438	706	420.1	344.5	24.09	0.01	509
17	2,916	9,837	289.9	17,445	704	419.5	343.7	24.05	0.01	508
18	2,915	9,836	290.4	17,428	704	418.8	343.3	24.03	0.05	509
19	2,915	9,836	290.4	17,424	704	418.7	343.0	24.03	0.02	509
20	2,915	9,836	289.9	17,414	704	418.8	342.6	24.05	0.03	508
21	2,913	9,833	289.1	17,367	712	420.5	342.4	24.21	0.06	504
22	2,912	9,834	290.3	17,371	713	416.2	340.7	23.96	0.10	506
23	2,968	9,891	290.2	16,718	713	388.3	312.7	23.23	0.03	501
24	2,938	9,871	290.5	17,163	713	414.7	330.5	24.16	0.03	513
25	2,937	9,872	289.8	17,165	712	415.7	330.0	24.22	0.02	513
26	2,936	9,872	289.2	17,168	712	415.8	330.6	24.22	0.01	512
27	2,936	9,858	288.7	17,165	711	414.8	330.3	24.17	0.02	510
28	2,935	9,849	288.7	17,161	712	413.8	330.0	24.11	0.02	511
29	2,932	9,845	289.3	17,209	712	412.9	330.5	23.99	0.09	513
30	2,931	9,844	290.1	17,211	710	412.7	330.7	23.98	0.03	515
31	2,930	9,843	290.1	17,179	715	412.7	330.0	24.03	0.03	514

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
537,168	12,930	24.07	10,504	19.55	1.26

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
5,239,781	125,301	23.91	102,413	19.55	12.32

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 14. IGT MONTHLY PRODUCTION REPORTS^a

APRIL 1989

Day	-PROD WELL-		----BRINE----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,930	9,842	289.8	17,196	714	413.6	329.6	24.05	0.03	514
2	2,930	9,843	289.2	17,287	711	413.9	329.7	23.94	0.01	514
3	2,930	9,842	289.6	17,230	710	412.7	329.5	23.95	0.02	516
4	2,929	9,841	289.7	17,206	710	412.2	328.4	23.96	0.02	516
5	2,927	9,837	289.9	17,193	713	412.7	328.5	24.00	0.08	516
6	2,927	9,836	290.3	17,155	714	412.4	330.0	24.04	0.02	517
7	2,927	9,835	290.5	17,157	712	412.2	334.6	24.02	0.01	517
8	2,926	9,838	288.9	17,145	709	413.2	335.9	24.10	0.01	513
9	2,925	9,835	289.5	17,118	716	413.8	335.9	24.18	0.02	513
10	2,924	9,833	289.5	17,086	720	414.6	335.5	24.26	0.04	512
11	2,924	9,832	289.6	17,115	716	414.8	336.0	24.23	0.01	513
12	2,927	9,837	289.4	17,100	717	414.5	335.3	24.24	0.02	513
13	2,926	9,837	288.9	17,109	720	414.4	334.6	24.22	0.01	508
14	2,927	9,835	290.4	17,113	720	412.6	333.9	24.11	0.03	512
15	2,925	9,833	290.8	17,143	710	412.1	334.4	24.04	0.08	514
16	2,924	9,833	290.5	17,147	711	412.3	334.3	24.05	0.03	513
17	2,923	9,834	289.8	17,167	709	413.0	333.9	24.06	0.02	512
18	2,923	9,832	290.4	17,169	709	411.7	333.6	23.98	0.02	515
19	2,923	9,832	290.8	17,142	710	411.4	333.5	24.00	0.05	516
20	2,922	9,831	290.7	17,124	710	411.2	333.1	24.01	0.06	515
21	2,922	9,829	290.8	17,107	710	411.0	333.4	24.03	0.07	515
22	2,921	9,829	290.5	17,095	710	411.6	333.4	24.08	0.03	513
23	2,920	9,830	290.1	17,092	709	411.7	333.0	24.09	0.01	512
24	2,920	9,831	289.7	17,124	709	412.1	332.8	24.06	0.01	512
25	2,920	9,830	289.5	17,152	709	411.7	332.0	24.00	0.01	511
26	2,919	9,829	289.8	17,128	708	411.6	332.2	24.03	0.02	512
27	3,047	9,895	288.3	15,545	710	373.2	300.3	24.01	0.03	473
28	3,338	10,083	285.7	12,162	714	291.5	233.6	23.97	0.06	381
29	3,346	10,091	285.9	12,169	714	293.0	234.8	24.08	0.02	380
30	3,350	10,095	285.9	12,201	716	293.8	235.6	24.08	0.03	379

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
497,877	11,981	24.06	9,661	19.40	0.87

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
5,737,659	137,282	23.93	112,074	19.53	13.19

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 15. IGT MONTHLY PRODUCTION REPORTS^a

MAY 1989

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	3,353	10,098	286.5	12,197	714	292.3	234.3	23.97	0.01	379
2	3,356	10,102	286.1	12,190	715	292.5	233.9	24.00	0.01	379
3	3,358	10,106	285.4	12,186	716	293.2	233.8	24.06	0.00	377
4	3,359	10,108	284.9	12,200	715	292.7	233.4	23.99	0.02	376
5	3,360	10,107	286.2	12,200	717	293.5	234.2	24.05	0.08	378
6	3,362	10,108	286.7	12,216	714	292.2	234.4	23.92	0.02	379
7	3,363	10,109	286.7	12,206	716	292.1	234.3	23.93	0.01	379
8	3,364	10,112	285.5	12,210	714	292.4	234.1	23.95	0.01	377
9	3,364	10,114	284.9	12,108	713	293.0	234.0	24.20	0.02	373
10	3,365	10,112	286.3	12,233	717	292.6	234.1	23.92	0.04	380
11	3,365	10,115	285.5	12,239	717	293.8	234.4	24.00	0.01	379
12	3,366	10,116	285.2	12,167	719	293.9	234.4	24.15	0.00	380
13	3,367	10,116	285.3	12,256	714	293.0	234.1	23.91	0.01	387
14	3,363	10,115	284.9	12,222	712	292.5	233.3	23.93	0.02	389
15	3,673	-----	177.5	4,918	636	109.4	88.2	22.25	0.00	186
16	3,855	-----	81.7	0	497	0.0	0.0	0.00	0.00	10
17	3,851	-----	81.3	0	429	0.0	0.0	0.00	0.00	10
18	1,648	-----	75.5	0	392	0.0	0.0	0.00	0.00	7
19	31	-----	84.6	0	368	0.0	0.0	0.00	0.00	6
20	31	-----	85.9	0	352	0.0	0.0	0.00	0.00	6
21	31	-----	87.1	0	339	0.0	0.0	0.00	0.00	6
22	31	-----	84.7	0	329	0.0	0.0	0.00	0.00	6
23	32	-----	87.3	0	323	0.0	0.0	0.00	0.00	6
24	32	-----	86.2	0	318	0.0	0.0	0.00	0.00	5
25	1,087	-----	86.1	0	313	0.0	0.0	0.00	0.00	6
26	3,274	-----	107.5	1,920	356	35.1	27.7	18.30	0.03	60
27	3,275	10,099	280.8	14,563	705	349.6	285.6	24.00	0.03	380
28	3,249	10,079	285.3	14,469	706	346.4	282.5	23.94	0.02	386
29	3,237	10,063	286.0	14,450	705	346.1	281.8	23.95	0.01	388
30	3,230	10,056	285.7	14,439	705	346.2	280.6	23.98	0.19	388
31	3,530	-----	217.7	8,073	652	189.5	155.7	23.47	0.14	277

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
243,661	5,822	23.89	4,679	19.20	0.70

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
5,981,320	143,104	23.93	116,753	19.52	13.89

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 16. IGT MONTHLY PRODUCTION REPORTS^a

JUNE 1989

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	3,482	-----	178.1	7,286	607	171.9	141.2	23.59	0.15	243
2	3,191	10,028	287.0	14,934	706	357.9	294.8	23.96	0.04	413
3	3,180	10,020	287.2	14,900	705	358.0	293.6	24.02	0.01	415
4	3,173	10,013	287.0	14,892	703	358.1	293.1	24.05	0.02	416
5	3,014	9,917	289.4	16,568	704	396.9	325.7	23.95	0.04	464
6	2,885	9,826	290.7	17,832	702	426.2	350.2	23.90	0.02	502
7	2,880	9,822	289.6	17,803	705	426.4	348.2	23.95	0.05	502
8	2,875	9,814	290.4	17,772	707	426.3	348.4	23.99	0.03	505
9	2,872	9,811	290.5	17,748	706	426.3	348.1	24.02	0.01	506
10	2,869	9,809	289.9	17,743	704	426.8	347.7	24.06	0.01	505
11	2,866	9,805	289.9	17,743	705	425.9	347.0	24.00	0.01	506
12	2,864	9,803	289.5	17,750	704	425.6	346.4	23.98	0.01	506
13	2,862	9,800	289.6	17,750	703	425.2	345.8	23.96	0.01	507
14	2,861	9,796	290.1	17,727	707	425.1	345.7	23.98	0.04	507
15	2,858	9,792	290.7	17,735	707	424.7	345.5	23.95	0.04	509
16	2,856	9,789	291.1	17,729	707	424.6	345.2	23.95	0.04	511
17	2,854	9,787	290.8	17,735	704	424.8	345.2	23.95	0.03	510
18	2,853	9,785	290.7	17,733	702	424.3	344.9	23.92	0.03	510
19	2,852	9,784	291.0	17,711	702	422.6	344.1	23.86	0.04	510
20	2,851	9,783	290.6	17,697	704	422.8	343.9	23.89	0.05	509
21	2,850	9,781	290.5	17,697	702	423.0	343.6	23.90	0.01	507
22	2,897	9,806	290.0	17,172	702	410.9	333.1	23.93	0.01	493
23	2,994	9,872	288.1	16,183	702	389.2	313.9	24.05	0.01	464
24	2,995	9,875	286.3	16,183	705	389.9	313.6	24.09	0.01	458
25	2,995	9,873	287.8	16,190	704	388.9	313.6	24.02	0.01	458
26	2,242	-----	257.2	10,869	666	261.1	209.9	24.02	0.01	353
27	1,557	-----	170.7	4,556	555	107.2	87.8	23.53	0.02	203
28	3,041	9,918	287.4	16,035	702	383.7	311.7	23.93	0.04	445
29	3,030	9,902	288.8	15,986	705	383.2	310.9	23.97	0.03	450
30	3,025	9,898	288.2	15,978	706	383.9	310.4	24.03	0.03	449

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
481,635	11,541	23.96	9,393
			19.50
			0.87

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
6,462,954	154,645	23.93	126,146
			19.52
			14.76

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 17. IGT MONTHLY PRODUCTION REPORTS^a

JULY 1989

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	3,023	9,893	288.9	15,975	706	381.8	309.4	23.90	0.04	451
2	3,020	9,891	288.6	15,975	703	381.5	309.0	23.88	0.03	451
3	3,019	9,887	289.6	15,960	705	381.0	308.6	23.87	0.04	453
4	3,017	9,885	289.5	15,967	701	381.0	308.9	23.86	0.04	454
5	3,016	9,885	289.0	15,965	701	381.9	309.1	23.92	0.03	453
6	3,014	9,882	289.4	15,954	705	381.2	313.2	23.89	0.05	454
7	3,014	9,880	289.6	15,952	705	380.6	315.6	23.86	0.05	454
8	3,013	9,880	289.3	15,950	704	381.1	313.6	23.89	0.04	453
9	3,011	9,879	289.0	15,962	701	381.9	312.8	23.93	0.02	453
10	3,010	9,880	288.4	15,957	700	382.3	312.4	23.96	0.02	453
11	3,009	9,878	288.8	15,955	700	381.9	312.5	23.94	0.02	453
12	3,009	9,876	289.4	15,951	699	380.8	310.4	23.88	0.02	456
13	3,008	9,875	289.4	15,945	699	381.5	306.9	23.93	0.02	458
14	3,007	9,874	289.4	15,947	700	381.4	311.2	23.92	0.02	457
15	3,006	9,874	289.1	15,942	699	381.5	311.0	23.93	0.02	456
16	3,006	9,872	289.5	15,942	699	381.0	310.9	23.90	0.02	457
17	3,005	9,871	289.4	15,927	698	381.0	309.1	23.92	0.04	457
18	3,004	9,871	289.1	15,897	700	381.5	308.9	24.00	0.03	457
19	3,003	9,870	289.4	15,735	699	381.7	310.6	24.26	0.04	454
20	-----	-----	184.5	5,405	610	128.1	105.8	23.70	0.00	259
21	-----	-----	87.9	0	437	0.0	0.0	0.00	0.00	121
22	-----	-----	87.7	0	369	0.0	0.0	0.00	0.00	104
23	-----	-----	84.2	0	329	0.0	0.0	0.00	0.00	95
24	-----	-----	79.0	0	297	0.0	0.0	0.00	0.00	89
25	-----	-----	75.9	0	271	0.0	0.0	0.00	0.00	85
26	-----	-----	76.3	0	248	0.0	0.0	0.00	0.00	81
27	-----	-----	83.2	0	174	0.0	0.0	0.00	0.00	79
28	-----	-----	88.9	0	58	0.0	0.0	0.00	0.00	76
29	-----	-----	86.5	0	36	0.0	0.0	0.00	0.00	74
30	-----	-----	87.8	0	30	0.0	0.0	0.00	0.00	72
31	-----	-----	87.8	0	27	0.0	0.0	0.00	0.00	72

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
308,262	7,375	23.92	6,010	19.50	0.57

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
6,771,217	162,020	23.93	132,156	19.52	15.32

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 18. IGT MONTHLY PRODUCTION REPORTS^a

AUGUST 1989

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	-----	-----	90.2	0	24	0.0	0.0	0.00	0.00	68
2	-----	-----	89.8	0	22	0.0	0.0	0.00	0.00	69
3	-----	-----	88.4	0	20	0.0	0.0	0.00	0.00	67
4	-----	-----	89.6	0	19	0.0	0.0	0.00	0.00	66
5	-----	-----	91.1	0	19	0.0	0.0	0.00	0.00	65
6	-----	-----	89.8	0	19	0.0	0.0	0.00	0.00	64
7	-----	-----	87.6	0	19	0.0	0.0	0.00	0.00	63
8	-----	-----	76.9	0	19	0.0	0.0	0.00	0.00	62
9	-----	-----	79.4	0	19	0.0	0.0	0.00	0.00	61
10	3831	-----	122.1	2,487	248	48.4	39.5	19.46	0.03	99
11	3494	10,278	273.7	11,539	708	281.4	228.2	24.39	0.13	321
12	3,113	9,992	286.3	16,046	701	387.3	316.9	24.14	0.12	447
13	3,095	9,970	287.1	15,991	700	385.6	315.4	24.12	0.05	451
14	3,084	9,955	288.0	15,942	700	384.4	314.6	24.11	0.03	454
15	3,077	9,947	288.6	15,983	701	382.9	312.9	23.95	0.04	457
16	3,071	9,939	288.6	15,685	701	382.6	312.3	24.39	0.02	458
17	3,066	9,929	289.2	15,935	700	382.0	312.1	23.98	0.10	458
18	3,063	9,926	290.0	15,888	700	381.7	310.1	24.03	0.02	460
19	3,059	9,922	290.6	15,889	701	381.3	311.1	24.00	0.02	460
20	3,057	9,919	290.7	15,885	700	381.2	310.8	24.00	0.02	461
21	3,054	9,915	290.9	15,885	698	380.9	310.5	23.98	0.02	461
22	3,052	9,912	291.2	15,866	701	380.2	309.3	23.96	0.02	462
23	3,050	9,909	291.3	15,860	700	379.8	309.1	23.95	0.02	462
24	3,052	9,910	291.3	15,818	708	379.1	307.7	23.97	0.05	461
25	3,047	9,906	291.3	15,848	701	380.2	307.9	23.99	0.03	460
26	3,045	9,904	291.2	15,854	698	380.7	308.8	24.01	0.01	451
27	3,043	9,902	291.4	15,924	699	380.0	308.5	23.86	0.04	437
28	3,040	9,898	291.5	15,969	699	379.6	308.1	23.77	0.03	420
29	3,037	9,894	291.6	16,053	701	379.4	306.8	23.63	0.03	419
30	3,035	9,893	291.6	15,945	702	379.1	307.9	23.77	0.05	440
31	3,034	9,891	291.5	15,955	703	378.8	310.2	23.74	0.01	435

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
332,246	7,957	23.95	0.88

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
7,103,463	169,977	23.93	16.21

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 19. IGT MONTHLY PRODUCTION REPORTS^a

SEPTEMBER 1989

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	3,032	9,888	291.5	15,978	702	379.1	314.2	23.72	0.02	419
2	3,031	9,886	291.7	15,984	702	378.5	314.4	23.68	0.02	419
3	3,029	9,885	291.8	15,956	702	378.2	314.5	23.70	0.02	421
4	3,029	9,883	291.8	15,948	702	378.4	311.2	23.73	0.02	421
5	3,027	9,882	291.8	15,939	701	379.1	309.0	23.78	0.03	423
6	3,026	9,880	291.7	15,893	702	379.3	307.0	23.86	0.04	430
7	3,025	9,881	291.6	15,902	702	378.7	306.3	23.81	0.05	446
8	-----	-----	-----	10,778	656	252.8	207.5	23.45	0.00	-----
9	-----	-----	-----	0	456	0.0	0.0	0.00	0.00	-----
10	-----	-----	-----	0	397	0.0	0.0	0.00	0.00	-----
11	-----	-----	-----	0	336	0.0	0.0	0.00	0.00	-----
12	-----	-----	-----	0	241	0.0	0.0	0.00	0.00	-----
13	-----	-----	-----	0	227	0.0	0.0	0.00	0.00	-----
14	-----	-----	-----	0	215	0.0	0.0	0.00	0.00	-----
15	-----	-----	-----	0	203	0.0	0.0	0.00	0.00	-----
16	-----	-----	-----	0	194	0.0	0.0	0.00	0.00	-----
17	-----	-----	-----	0	187	0.0	0.0	0.00	0.00	-----
18	-----	-----	-----	0	180	0.0	0.0	0.00	0.00	-----
19	-----	-----	-----	0	174	0.0	0.0	0.00	0.00	-----
20	-----	-----	-----	0	168	0.0	0.0	0.00	0.00	-----
21	-----	-----	-----	0	163	0.0	0.0	0.00	0.00	-----
22	-----	-----	-----	0	157	0.0	0.0	0.00	0.00	-----
23	-----	-----	-----	0	151	0.0	0.0	0.00	0.00	-----
24	-----	-----	-----	0	143	0.0	0.0	0.00	0.00	-----
25	-----	-----	-----	0	137	0.0	0.0	0.00	0.00	-----
26	-----	-----	-----	0	40	0.0	0.0	0.00	0.00	-----
27	-----	-----	-----	0	14	0.0	0.0	0.00	0.00	-----
28	-----	-----	-----	0	14	0.0	0.0	0.00	0.00	-----
29	-----	-----	-----	0	14	0.0	0.0	0.00	0.00	-----
30	-----	-----	-----	0	14	0.0	0.0	0.00	0.00	-----

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
122,379	2,904	23.73	2,384	19.48	0.19

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
7,225,842	172,881	23.93	141,019	19.52	16.39

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 20. IGT MONTHLY PRODUCTION REPORTS^a

OCTOBER 1989

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	-----	-----	76.4	0	14	0.0	0.0	0.00	0.00	36
2	-----	-----	80.1	0	14	0.0	0.0	0.00	0.00	36
3	-----	-----	77.7	0	14	0.0	0.0	0.00	0.00	19
4	-----	-----	81.6	0	14	0.0	0.0	0.00	0.00	15
5	-----	-----	81.5	0	14	0.0	0.0	0.00	0.00	15
6	-----	-----	83.1	0	15	0.0	0.0	0.00	0.00	16
7	3,898	-----	81.1	0	15	0.0	0.0	0.00	0.00	17
8	3,901	-----	72.7	0	15	0.0	0.0	0.00	0.00	16
9	3,903	-----	69.3	0	15	0.0	0.0	0.00	0.00	17
10	3,851	-----	71.2	0	15	0.0	0.0	0.00	0.00	17
11	-----	-----	73.6	0	15	0.0	0.0	0.00	0.00	14
12	3,887	-----	73.4	37	53	0.0	0.0	0.00	0.00	15
13	3,894	-----	78.0	0	97	0.0	0.0	0.00	0.00	16
14	3,895	-----	77.2	0	88	0.0	0.0	0.00	0.00	16
15	3,899	-----	73.6	0	82	0.0	0.0	0.00	0.00	15
16	3,649	-----	158.1	6,537	374	150.4	125.1	23.01	0.07	171
17	3,226	10,083	283.7	15,464	710	370.1	305.8	23.93	0.05	401
18	3,201	10,050	286.1	15,417	715	370.0	303.8	24.00	0.05	382
19	3,191	10,037	287.4	15,382	715	369.3	304.6	24.01	0.04	382
20	3,156	10,012	288.4	15,710	708	373.6	314.3	23.78	0.05	397
21	3,096	9,968	289.2	16,247	707	387.7	321.3	23.86	0.05	412
22	3,089	9,959	289.3	16,202	703	386.7	319.4	23.87	0.07	415
23	3,084	9,953	289.5	16,132	704	385.2	318.8	23.88	0.03	436
24	3,080	9,948	289.6	16,041	702	384.5	318.5	23.97	0.03	449
25	3,077	9,944	289.8	16,234	705	384.6	324.3	23.69	0.08	411
26	3,072	9,939	289.8	16,245	705	383.9	323.8	23.63	0.02	404
27	3,068	9,935	289.9	16,124	707	383.4	323.2	23.78	0.02	424
28	3,064	9,930	290.1	15,976	707	383.3	322.4	24.00	0.02	452
29	3,060	9,925	290.1	15,973	710	382.8	322.1	23.97	0.02	452
30	3,056	9,920	290.3	15,971	707	383.0	323.1	23.98	0.06	452
31	3,055	9,918	290.6	15,941	717	382.3	320.8	23.98	0.08	452

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
245,632	5,861	23.86	4,891	19.91	0.75

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
7,471,474	178,742	23.92	145,911	19.53	17.14

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 21. IGT MONTHLY PRODUCTION REPORTS^a

NOVEMBER 1989

Day	-PROD WELL-		----BRINE----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	3,052	9,916	290.6	16,059	718	383.5	318.1	23.88	0.06	447
2	3,047	9,910	290.6	16,228	713	383.0	317.9	23.60	0.03	410
3	3,047	9,909	290.7	16,223	722	381.8	316.9	23.53	0.03	410
4	3,047	9,910	290.6	16,220	712	381.9	316.3	23.55	0.02	411
5	3,045	9,907	290.4	16,228	704	381.5	315.4	23.51	0.02	407
6	3,044	9,906	290.4	16,184	710	380.6	313.7	23.52	0.10	416
7	3,041	9,903	290.4	16,236	707	381.3	313.7	23.48	0.03	409
8	3,039	9,901	290.6	16,181	704	381.2	313.9	23.56	0.05	416
9	3,039	9,899	290.9	16,190	709	381.2	314.5	23.55	0.04	417
10	3,037	9,897	290.9	16,178	703	381.6	315.7	23.59	0.03	418
11	3,036	9,896	290.8	16,113	707	381.7	312.2	23.69	0.02	414
12	3,034	9,894	290.6	16,129	704	382.9	311.5	23.74	0.02	407
13	3,033	9,893	290.7	16,123	705	381.9	310.9	23.69	0.06	407
14	3,032	9,891	290.6	16,091	704	381.9	310.2	23.73	0.03	406
15	3,031	9,890	290.6	15,972	709	382.3	310.1	23.93	0.00	423
16	3,331	-----	241.0	10,238	672	243.3	201.2	23.76	0.00	353
17	3,870	-----	65.9	0	503	0.0	0.0	0.00	0.00	114
18	3,868	-----	58.2	0	435	0.0	0.0	0.00	0.00	72
19	3,926	-----	58.0	0	406	0.0	0.0	0.00	0.00	56
20	4,052	-----	67.7	0	394	0.0	0.0	0.00	0.00	49
21	4,082	-----	69.4	0	388	0.0	0.0	0.00	0.00	44
22	3,999	-----	122.9	893	457	3.8	0.5	4.30	0.00	62
23	3,885	10,548	232.3	3,977	700	85.4	71.6	21.47	0.02	163
24	3,558	10,309	269.6	9,742	696	229.2	190.1	23.53	0.02	319
25	3,112	9,970	288.3	15,599	688	377.8	310.7	24.22	0.04	466
26	3,056	9,922	289.6	15,977	687	386.4	319.4	24.18	0.04	479
27	3,049	9,914	289.8	15,930	684	385.8	318.0	24.22	0.03	480
28	3,043	9,908	290.1	15,928	692	386.5	314.4	24.26	0.03	479
29	3,038	9,905	290.3	15,879	693	387.3	314.6	24.39	0.02	478
30	3,035	9,901	290.5	15,848	702	385.9	313.7	24.35	0.01	480

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
362,366	8,599	23.73	7,065
			19.50
			0.75

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
7,833,840	187,341	23.91	152,976
			19.53
			17.89

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 22. IGT MONTHLY PRODUCTION REPORTS^a

DECEMBER 1989

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	3,032	9,897	290.9	15,845	700	384.4	313.5	24.26	0.01	482
2	3,029	9,894	290.9	15,848	695	384.6	312.6	24.27	0.00	482
3	3,027	9,892	290.8	15,831	697	385.1	311.0	24.33	0.01	481
4	3,025	9,889	291.0	15,847	694	384.0	313.2	24.23	0.08	484
5	3,022	9,886	291.0	15,847	692	383.9	312.2	24.23	0.03	484
6	3,020	9,885	290.9	15,849	689	383.0	310.0	24.16	0.05	484
7	3,019	9,883	291.0	16,022	689	383.4	312.8	23.93	0.05	444
8	3,018	9,883	290.7	15,971	694	386.7	313.6	24.21	0.03	439
9	3,016	9,881	291.2	15,960	691	385.2	313.3	24.14	0.03	446
10	3,015	9,880	291.0	15,969	689	384.4	312.6	24.07	0.01	440
11	3,014	9,878	291.1	15,943	692	386.1	311.9	24.22	0.04	443
12	3,013	9,877	290.9	15,939	695	385.8	312.5	24.20	0.04	443
13	3,011	9,875	291.5	16,002	687	385.4	312.1	24.09	0.02	445
14	3,010	9,873	291.4	16,006	688	385.6	309.7	24.09	0.01	444
15	3,009	9,872	291.2	15,996	691	385.7	308.3	24.11	0.01	440
16	3,009	9,872	291.1	15,906	704	388.7	307.5	24.44	0.03	435
17	3,007	9,871	291.1	15,978	700	389.7	309.1	24.39	0.03	431
18	3,006	9,869	291.2	15,980	701	390.0	312.1	24.41	0.04	439
19	3,006	9,869	291.2	16,004	704	388.9	310.2	24.30	0.03	440
20	3,005	9,868	291.4	15,994	691	384.9	311.4	24.07	0.01	441
21	3,004	9,868	291.3	15,984	690	383.9	309.7	24.02	0.05	443
22	3,004	9,868	290.9	15,916	700	387.9	309.2	24.37	0.13	445
23	3,003	9,866	291.3	15,692	696	386.3	309.5	24.61	0.01	475
24	3,000	9,863	291.6	15,702	688	383.3	307.1	24.41	0.02	485
25	2,999	9,863	291.6	15,737	687	383.5	308.8	24.37	0.02	487
26	2,998	9,861	291.5	15,730	683	383.1	309.6	24.35	0.11	489
27	2,996	9,859	291.5	15,711	679	381.8	313.3	24.30	0.01	490
28	2,996	9,860	291.4	15,692	683	382.9	310.6	24.40	0.03	490
29	2,995	9,859	291.4	15,643	680	382.2	308.4	24.43	0.02	451
30	2,994	9,858	291.2	15,894	684	382.5	310.7	24.07	0.01	427
31	2,994	9,858	291.3	15,905	688	383.6	313.1	24.12	0.01	424

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	MCF	STB
492,344	11,937	9,639	0.96

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	MCF	STB
8,326,183	199,277	162,615	18.85

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 23. IGT MONTHLY PRODUCTION REPORTS^a

JANUARY 1990

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,993	9,857	291.6	15,960	683	381.7	312.2	23.92	0.01	425
2	2,993	9,857	291.3	15,973	690	383.7	308.9	24.02	0.04	424
3	2,992	9,856	291.0	15,983	689	384.6	307.9	24.07	0.02	422
4	2,991	9,855	291.3	16,028	685	381.4	310.5	23.79	0.02	421
5	2,990	9,854	291.3	16,022	688	382.3	309.7	23.86	0.02	414
6	2,990	9,854	291.3	16,024	691	382.5	308.6	23.87	0.02	414
7	2,988	9,852	291.3	16,031	688	382.1	311.2	23.83	0.01	415
8	2,987	9,851	291.2	16,038	687	381.6	309.4	23.79	0.06	417
9	2,987	9,851	291.2	16,037	690	381.1	309.8	23.76	0.02	419
10	2,985	9,849	291.3	16,020	684	380.3	309.8	23.74	0.05	420
11	2,985	9,849	291.2	16,031	689	381.7	310.1	23.81	0.02	422
12	2,984	9,849	291.1	16,017	689	383.5	310.6	23.94	0.02	419
13	2,983	9,848	291.2	15,977	691	380.9	311.0	23.84	0.00	419
14	2,983	9,847	291.1	15,976	691	383.2	309.1	23.99	0.00	422
15	2,982	9,847	291.0	15,976	692	382.7	307.1	23.96	0.04	424
16	2,981	9,847	290.8	15,992	686	383.8	307.0	24.00	0.01	425
17	2,980	9,846	291.0	15,918	684	380.7	307.3	23.92	0.01	438
18	2,980	9,845	290.9	15,969	685	383.4	307.2	24.01	0.01	422
19	2,980	9,846	290.8	15,952	695	382.8	304.9	24.00	0.02	421
20	2,979	9,844	291.3	15,936	689	382.9	307.4	24.03	0.01	418
21	2,978	9,843	291.4	15,944	686	381.8	306.7	23.95	0.00	420
22	2,977	9,843	291.5	15,778	687	381.2	305.5	24.16	0.02	454
23	2,976	9,841	291.5	15,665	686	380.3	304.5	24.28	0.00	483
24	2,976	9,842	291.0	15,653	687	382.1	302.3	24.41	0.03	483
25	2,976	9,841	291.2	15,629	693	383.1	303.2	24.52	0.02	482
26	2,975	9,840	291.2	15,634	691	382.1	302.7	24.44	0.02	486
27	2,974	9,840	291.0	15,644	689	382.8	301.1	24.47	0.01	487
28	2,973	9,840	291.0	15,621	689	382.3	301.5	24.47	0.02	486
29	2,973	9,839	291.3	15,717	688	381.5	307.5	24.27	0.04	468
30	2,972	9,837	291.5	15,865	691	380.1	305.6	23.96	0.03	452
31	2,974	9,838	291.0	15,873	705	382.5	303.4	24.10	0.01	449

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
492,881	11,847	24.04	9,524	19.32	0.61

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
8,819,064	211,124	23.94	172,139	19.52	19.46

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 24. IGT MONTHLY PRODUCTION REPORTS^a

FEBRUARY 1990

Day	-PROD WELL-		----BRINE----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,972	9,837	290.9	15,869	702	381.9	302.3	24.07	0.01	450
2	2,972	9,835	291.1	15,858	701	381.2	302.6	24.04	0.00	452
3	2,972	9,836	291.0	15,758	705	381.4	302.5	24.20	0.00	470
4	2,971	9,835	291.3	15,587	706	381.3	303.8	24.46	0.00	494
5	2,971	9,834	291.2	15,597	705	381.5	301.6	24.46	0.07	496
6	2,970	9,834	291.5	15,710	699	379.2	304.8	24.14	0.01	483
7	2,969	9,833	291.4	15,852	703	379.6	309.5	23.95	0.02	456
8	2,968	9,831	291.1	15,828	703	379.8	308.1	24.00	0.01	455
9	2,968	9,832	290.9	15,827	703	379.7	306.6	23.99	0.02	455
10	2,967	9,831	291.3	15,827	704	379.3	307.5	23.96	0.02	456
11	2,967	9,830	291.5	15,830	700	377.3	307.3	23.83	0.03	460
12	2,966	9,830	291.2	15,830	701	378.7	305.6	23.92	0.01	460
13	2,965	9,829	290.9	15,827	703	379.6	303.9	23.98	0.00	460
14	2,965	9,829	291.0	15,826	703	380.0	303.9	24.01	0.00	458
15	2,964	9,828	291.0	15,811	704	378.7	303.1	23.95	0.02	456
16	2,964	9,828	291.2	15,818	705	379.7	304.9	24.00	0.00	454
17	2,964	9,828	291.2	15,804	710	381.0	305.7	24.11	0.01	454
18	2,964	9,828	291.1	15,816	710	381.2	304.4	24.10	0.00	453
19	2,963	9,827	291.3	15,829	706	379.7	304.5	23.98	0.00	454
20	2,962	9,827	291.0	15,828	710	381.2	301.9	24.09	0.00	429
21	2,962	9,826	290.9	15,830	708	381.1	303.5	24.08	0.02	410
22	2,961	9,825	291.0	15,805	708	380.0	304.0	24.04	0.03	415
23	2,960	9,825	291.3	15,859	704	379.5	310.0	23.93	0.02	440
24	2,959	9,824	291.3	15,791	701	379.0	311.4	24.00	0.03	450
25	2,959	9,823	291.3	15,781	702	378.0	309.2	23.95	0.01	453
26	2,958	9,822	290.9	15,792	700	380.7	307.0	24.11	0.01	454
27	2,957	9,822	290.9	15,777	702	380.5	306.9	24.12	0.00	457
28	2,957	9,821	290.9	15,815	703	380.2	305.5	24.04	0.04	435

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
442,383	10,641	24.05	8,552
			19.33
			0.42

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
9,261,447	221,765	23.94	180,691
			19.51
			19.88

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 25. IGT MONTHLY PRODUCTION REPORTS^a

MARCH 1990

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,957	9,821	291.0	15,798	711	379.7	304.7	24.03	0.03	410
2	2,956	9,819	291.2	15,806	707	379.1	305.4	23.99	0.01	414
3	2,955	9,818	291.3	15,658	703	377.8	303.0	24.13	0.02	454
4	2,955	9,818	291.2	15,389	704	377.6	301.8	24.54	0.01	487
5	2,954	9,817	290.9	15,886	704	380.1	305.6	23.93	0.03	415
6	2,953	9,816	290.8	15,859	705	380.2	310.7	23.98	0.31	423
7	2,953	9,816	290.8	15,841	706	378.0	311.6	23.87	0.21	432
8	2,952	9,815	290.8	15,872	701	378.5	311.8	23.85	0.01	419
9	2,951	9,813	290.8	15,870	701	382.1	310.4	24.08	0.02	418
10	2,951	9,813	290.7	15,860	702	383.0	306.7	24.15	0.02	417
11	2,950	9,812	290.6	15,853	702	382.5	307.1	24.13	0.02	416
12	2,950	9,812	290.5	15,842	704	383.6	305.9	24.22	0.03	416
13	2,949	9,811	290.5	15,816	701	382.0	305.1	24.15	0.00	426
14	2,949	9,810	290.7	15,793	702	379.4	305.7	24.02	0.03	438
15	2,949	9,809	291.3	15,796	705	380.6	306.5	24.09	0.03	442
16	2,948	9,809	291.3	15,796	705	381.6	307.5	24.16	0.03	445
17	2,947	9,808	291.3	15,774	700	380.7	305.9	24.14	0.00	448
18	2,947	9,808	291.1	15,774	702	380.8	303.8	24.14	0.02	450
19	2,946	9,807	291.2	15,779	703	380.8	303.0	24.13	0.02	452
20	2,946	9,807	291.3	15,770	704	381.5	304.2	24.19	0.00	455
21	2,946	9,807	291.1	15,774	701	381.9	303.6	24.21	0.03	452
22	2,945	9,806	290.8	15,817	700	381.7	302.2	24.13	0.01	425
23	2,944	9,806	290.9	15,808	698	381.8	306.1	24.15	0.01	423
24	2,945	9,806	291.0	15,745	702	381.3	305.0	24.22	0.02	450
25	2,945	9,806	291.2	15,750	704	381.0	304.0	24.19	0.02	453
26	2,945	9,806	291.2	15,748	708	381.1	302.5	24.20	0.04	455
27	2,944	9,805	291.1	15,746	706	382.1	302.0	24.27	0.02	456
28	2,942	9,805	290.8	15,749	701	382.3	300.9	24.28	0.02	457
29	2,942	9,804	290.8	15,754	703	382.3	300.1	24.26	0.04	451
30	2,942	9,804	291.0	15,583	701	381.4	299.6	24.48	0.01	454
31	2,941	9,803	291.0	15,736	702	380.8	300.5	24.20	0.02	424

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
489,041	11,807	24.14	9,453	19.33	1.09

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
9,750,488	233,572	23.95	190,144	19.50	20.97

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 26. IGT MONTHLY PRODUCTION REPORTS^a

APRIL 1990

Day	-PROD WELL-		----BRINE----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,940	9,802	291.1	15,729	701	380.3	300.3	24.17	0.03	420
2	2,939	9,801	291.2	15,733	694	379.0	298.7	24.09	0.02	421
3	2,940	9,802	291.1	15,707	706	379.8	298.4	24.18	0.03	417
4	2,939	9,800	291.2	15,693	700	379.2	299.6	24.17	0.03	433
5	2,941	9,801	290.9	15,711	702	379.9	298.8	24.18	0.01	417
6	2,938	9,800	290.9	15,690	704	381.5	297.0	24.32	0.02	425
7	2,938	9,800	290.9	15,687	708	382.5	301.4	24.38	0.03	415
8	2,936	9,799	291.0	15,680	702	382.1	301.1	24.37	0.01	422
9	2,936	9,798	290.8	15,711	707	381.7	299.1	24.30	0.02	425
10	2,936	9,798	290.9	15,688	703	380.4	298.5	24.25	0.03	430
11	2,936	9,798	291.0	15,700	704	380.8	299.8	24.25	0.01	417
12	2,935	9,797	291.0	15,686	700	381.3	300.2	24.31	0.02	419
13	2,934	9,797	290.6	15,680	701	382.2	298.7	24.37	0.03	415
14	2,935	9,796	291.0	15,669	705	379.3	298.2	24.21	0.05	417
15	2,934	9,796	291.0	15,669	703	379.4	298.9	24.21	0.03	419
16	2,933	9,795	290.8	15,679	703	380.0	297.4	24.24	0.02	420
17	2,932	9,794	290.8	15,580	704	379.4	296.0	24.35	0.02	450
18	2,932	9,795	290.7	15,437	707	380.6	295.6	24.66	0.03	484
19	2,932	9,794	290.4	15,615	707	381.2	294.7	24.41	0.02	440
20	2,931	9,793	290.4	15,682	709	380.5	294.1	24.27	0.02	416
21	2,929	9,792	290.6	15,693	701	379.8	295.3	24.20	0.02	417
22	2,928	9,791	290.6	15,695	700	380.0	294.9	24.21	0.01	416
23	2,928	9,791	290.6	15,679	702	379.6	293.4	24.21	0.02	418
24	2,928	9,791	290.3	15,676	704	380.7	294.7	24.29	0.03	414
25	2,927	9,790	290.1	15,690	698	382.0	299.6	24.35	0.02	414
26	2,927	9,791	290.1	15,673	702	382.0	298.6	24.37	0.03	411
27	2,926	9,789	290.4	15,668	702	379.7	297.0	24.23	0.04	412
28	2,926	9,788	290.7	15,664	699	379.2	295.3	24.21	0.01	410
29	2,925	9,788	290.2	15,675	697	379.6	300.6	24.22	0.02	413
30	2,925	9,787	290.4	15,680	700	379.3	297.7	24.19	0.02	415

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
470,219	11,413	24.27	8,933	19.00	0.70

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
10,220,707	244,985	23.97	199,077	19.48	21.67

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 27. IGT MONTHLY PRODUCTION REPORTS^a

MAY 1990

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,924	9,787	290.4	15,685	699	379.7	295.1	24.21	0.02	417
2	2,924	9,787	290.2	15,680	701	380.3	294.7	24.26	0.02	416
3	2,923	9,786	290.2	15,679	699	380.3	296.9	24.25	0.04	415
4	2,923	9,786	290.8	15,656	704	378.1	302.2	24.15	0.02	415
5	2,923	9,785	290.8	15,641	706	378.5	312.0	24.20	0.07	416
6	2,922	9,784	291.0	15,654	702	377.4	310.2	24.11	0.03	423
7	2,922	9,784	290.8	15,650	704	378.0	307.8	24.16	0.03	421
8	2,922	9,783	290.8	15,658	703	378.7	307.0	24.19	0.05	422
9	2,921	9,782	290.9	15,664	701	377.5	303.1	24.10	0.02	427
10	2,920	9,782	290.5	15,674	701	380.2	308.6	24.26	0.03	423
11	2,920	9,780	290.2	15,680	699	381.0	309.9	24.30	0.02	423
12	2,920	9,776	290.3	15,676	701	379.7	308.2	24.22	0.03	425
13	2,919	9,772	290.8	15,692	696	377.9	307.1	24.08	0.02	428
14	2,919	9,769	290.5	15,677	699	379.1	305.9	24.18	0.02	429
15	2,918	9,770	290.3	15,675	699	379.3	305.5	24.20	0.01	432
16	2,918	9,770	290.3	15,668	699	378.9	304.9	24.18	0.03	433
17	2,917	9,770	290.8	15,664	702	377.7	304.5	24.11	0.02	437
18	2,916	9,770	290.4	15,670	700	379.5	304.3	24.22	0.02	435
19	2,916	9,770	290.3	15,666	701	379.0	303.3	24.19	0.02	435
20	2,916	9,769	290.4	15,664	700	378.6	302.9	24.17	0.02	437
21	2,915	9,768	290.7	15,661	700	377.3	302.6	24.09	0.03	441
22	2,916	9,765	290.9	15,580	703	376.9	304.5	24.19	0.03	449
23	2,915	9,764	290.7	15,644	700	378.6	305.6	24.20	0.03	437
24	2,914	9,763	290.6	15,652	697	378.7	304.7	24.19	0.03	438
25	2,914	9,762	290.5	15,646	698	378.2	306.0	24.18	0.01	442
26	2,913	9,761	290.5	15,627	697	378.4	305.6	24.22	0.02	451
27	2,913	9,761	290.6	15,316	698	377.7	304.6	24.66	0.03	498
28	2,912	9,759	290.8	15,351	696	377.3	304.5	24.58	0.02	504
29	2,912	9,760	290.5	15,339	698	379.5	304.2	24.74	0.02	509
30	3,393	-----	186.9	6,806	608	158.6	126.8	23.30	0.01	370
31	3,736	-----	90.9	0	448	0.0	0.0	0.00	0.00	248

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
459,994	11,141	24.22	8,963	19.49	0.79

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
10,680,700	256,126	23.98	208,040	19.48	22.45

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 28. IGT MONTHLY PRODUCTION REPORTS^a

JUNE 1990

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	3,737	-----	84.9	0	401	0.0	0.0	0.00	0.00	229
2	3,742	-----	88.5	0	381	0.0	0.0	0.00	0.00	218
3	3,746	-----	87.9	0	371	0.0	0.0	0.00	0.00	210
4	3,749	-----	86.3	0	363	0.0	0.0	0.00	0.00	205
5	3,752	-----	87.5	0	358	0.0	0.0	0.00	0.00	95
6	3,755	-----	89.0	0	352	0.0	0.0	0.00	0.00	13
7	3,757	-----	90.0	0	348	0.0	0.0	0.00	0.00	13
8	3,760	-----	90.0	0	346	0.0	0.0	0.00	0.00	13
9	3,762	-----	88.8	0	345	0.0	0.0	0.00	0.00	13
10	3,765	-----	85.2	0	343	0.0	0.0	0.00	0.00	13
11	3,767	-----	87.7	0	341	0.0	0.0	0.00	0.00	13
12	3,770	-----	89.1	0	341	0.0	0.0	0.00	0.00	13
13	3,772	-----	88.6	0	340	0.0	0.0	0.00	0.00	13
14	3,774	-----	68.4	0	339	0.0	0.0	0.00	0.00	13
15	3,776	-----	91.8	0	339	0.0	0.0	0.00	0.00	13
16	3,778	-----	91.3	0	339	0.0	0.0	0.00	0.00	13
17	3,780	-----	90.1	0	338	0.0	0.0	0.00	0.00	13
18	3,782	-----	90.2	0	338	0.0	0.0	0.00	0.00	13
19	3,784	-----	91.0	0	338	0.0	0.0	0.00	0.00	13
20	3,786	-----	90.8	0	162	0.0	0.0	0.00	0.00	13
21	3,788	-----	57.0	0	15	0.0	0.0	0.00	0.00	13
22	3,790	-----	0.0	0	16	0.0	0.0	0.00	0.00	13
23	3,792	-----	0.0	0	16	0.0	0.0	0.00	0.00	13
24	3,794	-----	0.0	0	16	0.0	0.0	0.00	0.00	13
25	3,796	-----	0.0	0	15	0.0	0.0	0.00	0.00	13
26	3,798	-----	0.0	0	15	0.0	0.0	0.00	0.00	13
27	3,800	-----	0.0	0	15	0.0	0.0	0.00	0.00	14
28	3,802	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
29	3,803	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
30	3,805	-----	0.0	0	15	0.0	0.0	0.00	0.00	15

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	MCF	STB
0	0	0	0.00

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	MCF	STB
10,680,700	256,126	208,040	22.45

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 29. IGT MONTHLY PRODUCTION REPORTS^a

JULY 1990

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	3,807	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
2	3,808	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
3	3,810	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
4	3,812	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
5	3,813	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
6	3,815	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
7	3,816	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
8	3,818	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
9	3,820	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
10	3,821	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
11	3,823	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
12	3,824	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
13	3,826	-----	0.0	0	15	0.0	0.0	0.00	0.00	15
14	3,845	-----	56.8	0	189	5.1	2.0	0.00	0.00	15
15	3,880	-----	98.0	126	523	6.4	4.7	50.83	0.00	15
16	3,867	-----	78.5	233	470	0.0	0.0	0.00	0.00	15
17	3,855	-----	85.6	0	425	0.0	0.0	0.00	0.00	15
18	3,865	-----	88.5	0	466	7.2	3.6	0.00	0.00	15
19	3,894	-----	138.0	1,270	546	31.1	29.0	24.52	0.00	15
20	3,896	-----	142.0	1,183	487	26.4	24.2	22.27	0.00	15
21	3,882	-----	88.6	0	387	0.0	0.0	0.00	0.00	15
22	3,873	-----	88.4	0	346	0.0	0.0	0.00	0.00	15
23	3,870	-----	80.6	0	315	0.0	0.0	0.00	0.00	15
24	3,869	-----	89.5	0	289	0.0	0.0	0.00	0.00	14
25	3,868	-----	89.0	0	266	0.0	0.0	0.00	0.00	13
26	3,868	-----	89.4	0	234	0.0	0.0	0.00	0.00	13
27	3,600	-----	166.9	6,111	443	157.5	130.5	25.78	0.03	176
28	3,148	10,004	284.9	15,431	704	376.7	313.2	24.41	0.02	415
29	3,119	9,969	287.3	15,411	701	375.9	311.6	24.39	0.04	418
30	3,103	9,949	288.2	15,375	703	374.4	309.2	24.35	0.02	418
31	3,093	9,937	288.6	15,354	702	374.1	308.2	24.36	0.03	419

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
70,494	1,735	24.61	0.14

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
10,751,195	257,861	23.98	22.59

- ^a Pressures and temperatures are averages for the day.
Rates and volumes are corrected to 14.65 psia and 60°F.
Gas rates are from the separator meter runs.
Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 30. IGT MONTHLY PRODUCTION REPORTS^a

AUGUST 1990

Day	-PROD WELL-		----BRINE----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	3,083	9,925	288.9	15,362	701	373.7	307.0	24.33	0.04	420
2	3,024	9,887	289.7	15,898	705	386.5	316.2	24.31	0.04	435
3	2,965	9,842	290.0	16,371	702	398.0	324.7	24.31	0.04	448
4	2,956	9,831	290.2	16,356	701	397.3	323.6	24.29	0.04	450
5	2,951	9,826	290.5	16,337	702	396.1	322.5	24.25	0.04	450
6	2,946	9,817	290.5	16,323	701	395.7	321.5	24.24	0.04	449
7	2,943	9,811	290.5	16,306	703	395.9	320.3	24.28	0.04	449
8	2,946	9,814	290.6	16,336	704	396.5	320.4	24.27	0.04	452
9	2,941	9,810	290.9	16,330	702	395.4	320.1	24.21	0.05	454
10	2,940	9,808	291.0	16,320	703	395.1	319.7	24.21	0.04	455
11	2,937	9,805	291.0	16,311	702	394.9	319.3	24.21	0.03	457
12	2,935	9,802	291.0	16,295	704	394.6	318.3	24.22	0.04	458
13	2,933	9,799	291.1	16,293	704	394.7	317.9	24.23	0.04	460
14	2,930	9,796	291.0	16,286	702	394.6	317.3	24.23	0.03	460
15	2,928	9,793	291.1	16,285	702	394.3	316.8	24.21	0.03	462
16	2,926	9,791	291.1	16,282	702	394.4	316.3	24.22	0.03	463
17	2,924	9,790	291.1	16,271	704	394.5	315.5	24.25	0.03	465
18	2,922	9,788	291.2	16,269	703	394.6	315.4	24.26	0.03	466
19	2,920	9,786	291.2	16,265	701	394.1	315.1	24.23	0.03	467
20	2,814	9,722	291.7	17,283	704	417.6	334.2	24.17	0.04	496
21	2,719	9,654	292.3	18,105	709	435.7	350.4	24.06	0.04	524
22	2,715	9,644	292.4	18,053	710	434.7	352.4	24.08	0.05	524
23	2,710	9,634	292.5	18,041	706	435.4	354.0	24.13	0.03	526
24	2,708	9,631	292.3	18,031	707	435.0	352.8	24.12	0.03	527
25	2,705	9,628	292.4	18,025	705	434.5	352.2	24.10	0.03	528
26	2,702	9,627	292.4	18,021	703	434.2	352.9	24.09	0.03	528
27	2,700	9,626	292.3	18,021	702	433.9	354.3	24.08	0.02	527
28	2,699	9,625	292.5	18,025	706	433.1	352.9	24.03	0.03	529
29	2,697	9,623	292.4	18,029	705	433.4	352.4	24.04	0.04	529
30	2,695	9,621	292.3	18,024	703	433.3	351.9	24.04	0.03	527
31	2,694	9,619	292.3	18,017	704	434.3	351.4	24.10	0.04	524

Total Production for the Month:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
524,169	12,676	24.18	10,260
			19.57
			1.09

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----	-----Sales/Flare Gas-----	Condensate
STB	MCF	SCF/STB	STB
11,275,364	270,537	23.99	219,736
			19.49
			23.68

- ^a Pressures and temperatures are averages for the day.
Rates and volumes are corrected to 14.65 psia and 60°F.
Gas rates are from the separator meter runs.
Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 31. IGT MONTHLY PRODUCTION REPORTS^a

SEPTEMBER 1990

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,692	9,617	292.4	18,008	707	434.6	350.6	24.14	0.04	524
2	2,691	9,615	292.1	18,016	704	435.9	350.4	24.19	0.03	521
3	2,689	9,613	292.3	18,008	705	435.1	350.1	24.16	0.03	524
4	2,688	9,611	292.4	17,999	704	434.3	349.5	24.13	0.03	526
5	2,574	9,544	292.9	18,993	703	457.9	368.5	24.11	0.04	556
6	2,471	9,471	293.2	19,842	706	478.5	389.4	24.11	0.03	581
7	2,466	9,464	293.2	19,830	704	477.7	399.0	24.09	0.03	581
8	2,468	9,467	293.3	19,840	706	477.7	398.9	24.08	0.05	584
9	2,470	9,468	293.4	19,816	709	477.7	398.5	24.11	0.04	584
10	2,471	9,467	293.2	19,781	707	479.0	397.9	24.21	0.04	580
11	2,469	9,465	293.3	19,769	711	478.3	397.2	24.19	0.05	579
12	2,467	9,462	293.3	19,779	793	473.3	383.9	23.93	0.03	578
13	2,464	9,459	292.9	19,791	846	471.7	376.6	23.83	0.04	578
14	2,461	9,455	293.3	19,789	841	469.6	377.0	23.73	0.03	585
15	2,458	9,452	293.3	19,791	838	469.3	377.3	23.71	0.03	587
16	2,457	9,451	293.4	19,760	841	468.8	376.5	23.72	0.03	587
17	2,455	9,449	293.1	19,740	839	469.9	376.5	23.81	0.04	583
18	2,453	9,446	293.2	19,705	838	470.1	376.4	23.86	0.02	584
19	2,280	9,347	293.6	21,074	840	501.7	403.2	23.81	0.04	630
20	2,128	9,241	294.0	22,300	842	528.1	425.8	23.68	0.04	674
21	2,125	9,238	294.0	22,327	841	527.3	425.7	23.62	0.04	676
22	2,122	9,235	294.1	22,317	841	526.6	425.4	23.60	0.03	676
23	2,123	9,234	293.9	22,285	847	527.9	424.3	23.69	0.04	671
24	2,123	9,232	294.3	22,262	850	527.6	424.2	23.70	0.07	672
25	2,119	9,229	294.4	22,277	844	525.9	424.4	23.61	0.07	677
26	2,118	9,228	294.3	22,280	845	524.0	423.3	23.52	0.04	678
27	2,116	9,225	294.3	22,272	843	524.4	423.7	23.54	0.04	675
28	2,114	9,223	294.3	22,273	843	524.1	423.2	23.53	0.04	675
29	2,113	9,221	294.3	22,268	843	524.5	422.9	23.55	0.05	675
30	2,111	9,219	294.4	22,262	841	524.2	422.9	23.54	0.04	674

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
614,455	14,646	23.84	11,863	19.31	1.18

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
11,889,818	285,182	23.99	231,600	19.48	24.85

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit E-1, Part 32. IGT MONTHLY PRODUCTION REPORTS^a

OCTOBER 1990

Day	-PROD WELL-		-----BRINE-----		SEP	---GAS RATE---		PERF	COND	DISP
	WHP	C.BHP	TEMP	RATE	PRES	PERF	SL/FL	GWR	RATE	WHP
	psia	psia	Deg F	STB/d	psia	MCF/d	MCF/d	SCF/STB	Gal/d	psia
1	2,110	9,218	294.4	22,257	842	523.7	422.3	23.53	0.04	673
2	2,111	9,218	294.2	22,250	843	524.5	422.0	23.57	0.03	670
3	2,110	9,216	293.9	22,251	843	524.8	421.7	23.59	0.04	667
4	2,098	9,209	294.4	22,320	842	525.5	423.0	23.54	0.06	646
5	2,078	9,195	294.4	22,470	843	529.2	425.5	23.55	0.06	617
6	2,076	9,193	294.4	22,453	844	528.2	424.8	23.52	0.03	617
7	2,074	9,190	294.2	22,460	842	528.4	424.7	23.53	0.03	620
8	2,073	9,188	294.2	22,450	843	528.5	424.4	23.54	0.03	619
9	2,075	9,189	294.2	22,417	851	530.6	423.9	23.67	0.04	617
10	2,073	9,186	294.5	22,406	849	532.1	425.1	23.75	0.03	620
11	2,070	9,184	294.9	22,416	844	530.5	425.2	23.67	0.03	627
12	2,069	9,183	294.8	22,408	846	529.6	423.8	23.63	0.03	631
13	2,067	9,179	294.8	22,400	844	528.6	422.9	23.60	0.05	637
14	2,067	9,172	294.7	22,393	844	527.4	422.1	23.55	0.02	642
15	2,066	9,171	294.4	22,398	842	527.6	421.8	23.56	0.03	647
16	1,981	9,125	294.5	23,030	844	542.0	433.6	23.53	0.05	671
17	1,827	9,032	294.7	24,139	845	566.1	454.8	23.45	0.05	714
18	1,824	9,030	294.8	24,115	847	566.5	454.6	23.49	0.03	714
19	1,820	9,028	295.0	24,110	844	566.1	455.3	23.48	0.03	716
20	1,821	9,028	294.8	24,099	846	564.5	453.5	23.42	0.04	717
21	1,820	9,027	294.8	24,085	848	564.9	453.4	23.45	0.05	715
22	1,817	9,025	295.0	24,084	851	565.2	453.5	23.47	0.04	715
23	1,813	9,020	295.2	24,103	842	565.6	454.7	23.46	0.09	717
24	1,813	9,018	295.2	24,086	844	565.1	453.7	23.46	0.06	712
25	1,815	9,018	295.1	24,076	847	564.8	452.7	23.46	0.11	706
26	1,813	9,016	295.2	24,081	846	564.7	453.2	23.45	0.05	704
27	1,811	9,017	295.1	24,119	843	564.6	453.8	23.41	0.07	706
28	2,083	9,164	294.6	21,880	836	509.2	408.7	23.27	0.06	642
29	2,647	9,535	292.8	17,226	823	398.8	319.5	23.15	0.04	513
30	3,111	9,842	289.5	12,255	825	283.7	226.6	23.15	0.06	379
31	3,127	9,858	289.7	12,277	826	281.4	227.1	22.92	0.04	378

Total Production for the Month:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
687,513	16,152	23.49	12,962	18.85	1.42

Cumulative Production Since March 1, 1988:

--Brine--	-----Perforation Gas-----		-----Sales/Flare Gas-----		Condensate
STB	MCF	SCF/STB	MCF	SCF/STB	STB
12,577,332	301,335	23.96	244,562	19.44	26.28

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.

APPENDIX F

Brine Temperature Changes Through the Choke and Surface Equipment

One of the things that was surprising when the production tests were started in 1988 at Pleasant Bayou was that the measured temperature in the brine flow line downstream from the choke and separator was higher than the wellhead temperature upstream from the choke. At first it was thought that the temperature transmitters were incorrect, but careful calibration revealed that the increased downstream temperature was real. It had been assumed, without doing the engineering calculations, that the wellhead temperature would be the highest, and that cooling of the brine and gas as it flowed through the pipes and vessels would cause all of the downstream temperatures to be lower than the wellhead temperature. This elevated downstream temperature had not been noted or looked for in previous geopressured-geothermal well tests.

The reason for the elevated downstream temperature is clear when the thermodynamics of the system are considered. The reason is that the heat generated by the turbulent release of energy as the brine passes through the choke exceeds the expansion cooling of the gas as it passes through the choke. Whether the net effect will be heating or cooling of the line downstream of the choke will depend on the ratio of the gas and brine as they pass through the choke together. For the geopressured-geothermal aquifer wells, the volume of brine is so much larger than the gas that the heating effect dominates.

The change in temperature through the choke can be calculated from the thermodynamic equation for enthalpy and the heat capacities of the gas and brine. The enthalpy equation (in consistent units) is --

$$H = PV + TS \quad (1)$$

where --

H = Enthalpy
P = Pressure
T = Temperature
S = Entropy

Fluid flow through a choke with free expansion is a constant-enthalpy process such that Equation 1 can be written as --

$$\Delta H = 0 = \Delta(PV) + \Delta(TS) \quad (2)$$

For the brine passing through the choke, the brine volume and entropy will change much less than the pressure and temperature such that for a first-order calculation they can be ignored and Equation 2 rewritten as --

$$0 = V \Delta P + S \Delta T \quad (3)$$

The mechanical energy stored in the pressurized brine ($V \Delta P$) is thus all converted to thermal energy ($S \Delta T$) as the brine pressure is reduced by the choke if there is no other device in the system, such as a turbine, which extracts mechanical energy.

Equation 3 can be rearranged and rewritten in more familiar engineering units using heat capacity rather than entropy as follows:

$$T_1 - T_2 = 0.1842 (P_1 - P_2) / \beta C_v \quad (4)$$

where --

T_1 = Upstream Temperature, °F

T_2 = Downstream Temperature, °F

P_1 = Upstream Pressure, psi

P_2 = Downstream Pressure, psi

β = Brine Density, lb/ft³

C_v = Heat Capacity, Btu/lb-°F

0.1842 = Units conversion factor, ft-lbf to Btu and lbf/in² to lbf/ft²

The density of the Pleasant Bayou brine is about 67 lb/ft³, and if it is assumed that the heat capacity is about the same as water (1.0 Btu/lb-°F) Equation 4 reduces to --

$$(T_1 - T_2)_{\text{pure brine}} \approx 0.00275 (P_1 - P_2) \quad (5)$$

The temperature change for the expansion of the gas flowing with the brine is also a constant-enthalpy process ($\Delta H = 0$), but pressure, volume, temperature, and entropy all change at the same time. For an engineering calculation of the temperature change of a pure gas (not commingled with brine), the Joule-Thompson coefficient can be used in the equation --

$$\Delta T_{\text{pure gas}} = \mu \Delta P \quad (6)$$

where --

$$\mu = (\partial T / \partial P)_H = \text{Joule-Thompson coefficient, } ^\circ\text{F/psi} \quad (7)$$

The value of the Joule-Thompson coefficient ranges between 0.02 and 0.04 for the pressure and temperature range of the Pleasant Bayou well. Figure 4-53 in the *Handbook of Natural Gas Engineering* plots some values for a typical gas composition. As the pressure decreases there will be additional enthalpy change from the heat of solution of gas that comes out of solution, but this can be ignored for a first-order calculation.

When the gas is commingled with the brine, the gas does not cool adiabatically with pressure reduction, but rather it absorbs heat from the brine to remain at the same temperature as the brine. The enthalpy change in the gas can be determined from the enthalpy-entropy diagrams given as Figures 4-62 to 4-65 in the *Handbook of Natural Gas Engineering*. The amount of heat absorbed by the gas is given by the difference in enthalpy between the initial and final pressures and temperatures.

The final temperature of the gas/brine mixture is found by first calculating the amount of heat generated by the pressure reduction and then subtracting the amount of heat absorbed by the gas. This net amount of heat divided by the heat capacity of the brine gives the temperature change. For example, the experimental data for 21-May-1990 is --

$$\begin{aligned} P_{\text{wellhead}} &= 2915 \text{ psi} \\ P_{\text{hps}} &= 522 \text{ psi} \\ T_{\text{wellhead}} &= 287.4^{\circ}\text{F} \\ T_{\text{hps}} &= 291.2^{\circ}\text{F} \end{aligned}$$

The amount of heat liberated by the brine pressure reduction per barrel is (rearranging Equations 3 and 4) --

$$(\Delta H/V)_{\text{brine}} = 1.034 \Delta P \text{ Btu/STB} \quad (8)$$

$$(\Delta H/V)_{\text{brine}} = 1.034 (2915-522) = 2474 \text{ Btu/STB} \quad (8a)$$

The amount of heat absorbed by the gas is determined by taking the difference between the initial and final pressure and temperatures in the enthalpy-entropy diagram (Figure 4-63 in the *Handbook of Natural Gas Engineering*):

$$\Delta H_{\text{gas}} = H_{\text{pt1}} - H_{\text{pt2}} \text{ Btu/lb-mol.} \quad (9)$$

$$\Delta H_{\text{gas}} = 2650 - 1900 = 750 \text{ Btu/lb-mol.} \quad (9a)$$

The gas/brine ratio is about 23 SCF/STB such that the heat absorbed by the gas is --

$$(\Delta H/V)_{\text{gas in brine}} = 23 \text{ SCF/STB} \times 750 \text{ Btu/lb-mol.} / 379 \text{ cu ft/lb-mol.}$$

$$(\Delta H/V)_{\text{gas in brine}} = 46 \text{ Btu/STB}$$

The calculated temperature increase from choke heating is then --

$$\Delta T_{\text{choke}} = [(\Delta H/V)_{\text{brine}} - (\Delta H/V)_{\text{gas in brine}}] / \beta C_v$$

$$\Delta T_{\text{choke}} = (2474 - 46) \text{ Btu/STB} / 380 \text{ lbs/STB} / 1.0 \text{ Btu/lb-}^{\circ}\text{F}$$

$$\Delta T_{\text{choke}} = 6.4^{\circ}\text{F}$$

After passing through the choke, the brine will continue to cool by transfer of heat to the atmosphere from the pipes and vessels. This cooling depends of the ambient temperature and weather conditions such as wind and rain. For a first approximation, the cooling can be estimated with the equation --

$$\Delta T_{\text{brine}} = K A (T_b - T_a) / Q C_v$$

where --

K = heat-transfer coefficient, Btu/d- $^{\circ}\text{F-ft}^2$

A = area of pipes and equipment exposed to heat loss, ft^2

T_b = temperature of the brine in the pipes and equipment, $^{\circ}\text{F}$

T_a = ambient temperature, $^{\circ}\text{F}$

Q = brine flow rate, STB/d

C_v = brine heat capacity, Btu/STB- $^{\circ}\text{F}$

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

The heat-transfer coefficient K is a strong function of the wind velocity and precipitation across the equipment and is constantly changing with the changing weather conditions. The only weather parameter routinely measured at the Pleasant Bayou location is the ambient temperature. The wind, rain, and humidity are not measured. Therefore quantitative calculations of the expected temperature change are difficult to make.

APPENDIX G
HPS Monthly Production Summaries

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit G-1, Part 1. IGT HPS MONTHLY PRODUCTION REPORT^a

AUGUST 1989

Day	---HPS TEMP---		---SWD WELL---		GAS TAKE MCF/d	--BRINE RATE--		-----ENERGY-----		
	T in Deg F	T out Deg F	TEMP Deg F	PRESS. psia		HPS STB/d	TOTAL STB/d	GAS MMbtu	BRINE MMbtu	THEOR MMbtu
1	96	---	98	72	0.0	0	0	0.0	0.0	0.0
2	90	---	90	69	0.0	0	0	0.0	0.0	0.0
3	88	---	88	67	0.0	0	0	0.0	0.0	0.0
4	90	---	89	66	0.0	0	0	0.0	0.0	0.0
5	91	---	91	65	0.0	0	0	0.0	0.0	0.0
6	90	---	90	64	0.0	0	0	0.0	0.0	0.0
7	88	---	90	63	0.0	0	0	0.0	0.0	0.0
8	77	---	78	62	0.0	0	0	0.0	0.0	0.0
9	79	---	81	61	0.0	0	0	0.0	0.0	0.0
10	122	---	121	99	0.0	0	2497	0.0	0.0	0.0
11	274	---	270	321	0.0	0	11539	0.0	0.0	0.0
12	286	---	285	447	0.0	0	16046	0.0	0.0	0.0
13	287	---	285	451	0.0	0	15991	0.0	0.0	0.0
14	288	---	286	454	0.0	0	15942	0.0	0.0	0.0
15	289	---	287	457	0.0	0	15983	0.0	0.0	0.0
16	289	154	287	458	0.0	0	15685	0.0	0.0	0.0
17	289	---	288	458	0.0	0	15935	0.0	0.0	0.0
18	290	275	288	460	0.0	0	15888	0.0	0.0	0.0
19	291	275	289	460	0.0	0	15889	0.0	0.0	0.0
20	291	275	289	461	0.0	0	15885	0.0	0.0	0.0
21	291	275	289	461	0.0	0	15885	0.0	0.0	0.0
22	291	274	290	462	0.0	0	15866	0.0	0.0	0.0
23	291	276	290	462	0.0	0	15860	0.0	0.0	0.0
24	291	275	289	461	0.0	0	15818	0.0	0.0	0.0
25	291	261	288	460	13.0	408	15848	12.4	8.3	32.1
26	291	236	280	451	24.3	1056	15854	23.2	52.5	83.0
27	291	205	264	437	6.6	2849	15924	6.3	138.0	224.2
28	292	142	242	420	10.7	5277	15969	10.3	269.0	415.9
29	292	149	240	419	1.9	5726	16053	1.8	278.2	451.4
30	292	208	267	440	17.4	2581	15945	16.6	123.2	203.6
31	291	199	262	435	51.6	3084	15955	49.3	153.2	242.8

Total HPS usage for the Month:

-Gas-	-Brine-	-----ENERGY-----		
MCF	MSTB	-Gas-	-Brine-	-Theo. Brine-
		MMbtu	MMbtu	MMbtu
125.6	21.0	119.9	1022.6	1653.1

Cumulative HPS Usage Since August 1, 1989:

-Gas-	-Brine-	-----ENERGY-----		
MCF	MSTB	-Gas-	-Brine-	-Theo. Brine-
		MMbtu	MMbtu	MMbtu
125.6	21.0	119.9	1022.6	1653.1

^a Pressures and temperatures are averages for the day.

Rates and volumes are corrected to 14.65 psia and 60°F.

Gas rates are from the separator meter runs.

Brine rates are from the orifice meter data.

Theo. Energy is the theoretical energy available with a brine discharge temperature of 60°F.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit G-1, Part 2. IGT HPS MONTHLY PRODUCTION REPORT^a

SEPTEMBER 1989

Day	---HPS TEMP---		---SWD WELL---		GAS TAKE MCF/d	--BRINE RATE--		ENERGY		
	T in Deg F	T out Deg F	TEMP Deg F	PRESS. psia		HPS STB/d	TOTAL STB/d	GAS MMbtu	BRINE MMbtu	THEOR MMbtu
1	292	138	242	419	101.9	5124	15978	97.3	265.9	403.8
2	292	141	241	419	113.5	5332	15984	108.4	272.1	420.5
3	292	138	242	421	114.5	5104	15956	109.3	266.2	402.6
4	292	138	242	421	69.3	5138	15948	66.2	269.2	405.4
5	292	148	244	423	31.9	4922	15939	30.4	251.9	388.3
6	292	175	255	430	8.9	3819	15893	8.5	193.6	301.4
7	292	236	276	446	7.1	1520	15902	6.8	76.1	120.0
8	252	210	244	360	0.0	274	10778	0.0	7.1	21.6
9	98	100	92	137	0.0	0	0	0.0	0.0	0.0
10	86	87	86	127	0.0	0	0	0.0	0.0	0.0
11	83	84	84	118	0.0	0	0	0.0	0.0	0.0
12	83	84	84	110	0.0	0	0	0.0	0.0	0.0
13	83	84	83	103	0.0	0	0	0.0	0.0	0.0
14	76	77	77	89	0.0	0	0	0.0	0.0	0.0
15	73	75	75	69	0.0	0	0	0.0	0.0	0.0
16	76	77	78	59	0.0	0	0	0.0	0.0	0.0
17	78	80	80	54	0.0	0	0	0.0	0.0	0.0
18	80	81	81	51	0.0	0	0	0.0	0.0	0.0
19	78	80	80	48	0.0	0	0	0.0	0.0	0.0
20	80	82	82	47	0.0	0	0	0.0	0.0	0.0
21	80	81	81	46	0.0	0	0	0.0	0.0	0.0
22	79	81	81	44	0.0	0	0	0.0	0.0	0.0
23	73	74	74	41	0.0	0	0	0.0	0.0	0.0
24	70	71	71	42	0.0	0	0	0.0	0.0	0.0
25	70	72	72	43	0.0	0	0	0.0	0.0	0.0
26	73	75	75	43	0.0	0	0	0.0	0.0	0.0
27	77	78	79	43	0.0	0	0	0.0	0.0	0.0
28	73	74	74	40	1.5	0	0	1.4	0.0	0.0
29	59	60	76	39	0.0	0	0	0.0	0.0	0.0
30	75	77	77	38	0.0	0	0	0.0	0.0	0.0

Total HPS usage for the Month:

-Gas-	-Brine-
<u>MCF</u>	<u>MSTB</u>
448.6	31.2

----- ENERGY -----		
-Gas-	-Brine-	-Theo. Brine-
<u>MMbtu</u>	<u>MMbtu</u>	<u>MMbtu</u>
428.4	1602.0	2463.7

Cumulative HPS Usage Since August 1, 1989:

-Gas-	-Brine-
<u>MCF</u>	<u>MSTB</u>
574.1	52.2

----- ENERGY -----		
-Gas-	-Brine-	-Theo. Brine-
<u>MMbtu</u>	<u>MMbtu</u>	<u>MMbtu</u>
548.3	2624.5	4116.8

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.
 Theo. Energy is the theoretical energy available with a brine discharge temperature of 60°F.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit G-1, Part 3. IGT HPS MONTHLY PRODUCTION REPORT^a

OCTOBER 1989

Day	---HPS TEMP---		---SWD WELL---		GAS TAKE MCF/d	--BRINE RATE--		ENERGY		
	T in Deg F	T out Deg F	TEMP Deg F	PRESS. psia		HPS STB/d	TOTAL STB/d	GAS MMbtu	BRINE MMbtu	THEOR MMbtu
1	76	79	80	---	0.0	0	0	0.0	0.0	0.0
2	80	83	68	---	0.0	0	0	0.0	0.0	0.0
3	78	79	0	---	0.0	0	0	0.0	0.0	0.0
4	82	84	27	---	0.0	0	0	0.0	0.0	0.0
5	81	84	83	---	0.0	0	0	0.0	0.0	0.0
6	83	85	84	---	0.0	0	0	0.0	0.0	0.0
7	81	83	83	---	0.0	0	0	0.0	0.0	0.0
8	73	74	75	---	0.0	0	0	0.0	0.0	0.0
9	69	71	72	---	0.0	0	0	0.0	0.0	0.0
10	71	74	74	---	0.0	0	0	0.0	0.0	0.0
11	74	77	77	---	0.0	0	0	0.0	0.0	0.0
12	73	76	77	---	0.0	0	37	0.0	0.0	0.0
13	78	81	80	---	0.0	0	0	0.0	0.0	0.0
14	77	80	79	---	0.0	0	0	0.0	0.0	0.0
15	74	75	74	---	0.0	0	0	0.0	0.0	0.0
16	158	152	157	171	0.0	0	6537	0.0	0.0	0.0
17	284	195	260	401	0.0	2109	15464	0.0	111.8	161.4
18	286	117	228	382	0.0	5089	15417	0.0	292.2	391.7
19	287	115	227	382	28.1	5193	15382	26.9	304.3	401.9
20	288	136	235	397	0.0	5113	15710	0.0	277.7	397.6
21	289	136	235	412	14.5	5618	16247	13.8	292.2	438.4
22	289	127	237	415	0.0	5082	16202	0.0	280.8	396.6
23	290	206	264	436	0.0	2523	16132	0.0	128.0	197.4
24	290	243	282	449	51.5	597	16041	49.2	30.9	46.7
25	290	148	231	411	209.2	6547	16234	199.8	317.4	512.1
26	290	150	220	404	208.3	8034	16245	198.9	381.3	628.5
27	290	199	247	424	206.2	4769	16124	197.0	225.2	373.4
28	290	267	287	452	194.7	0	15976	185.9	0.0	0.0
29	290	261	287	452	206.2	0	15973	197.0	0.0	0.0
30	290	265	287	452	207.4	0	15971	198.1	0.0	0.0
31	291	265	287	452	204.3	0	15941	195.1	0.0	0.0

Total HPS usage for the Month:

-Gas-	-Brine-	ENERGY		
<u>MCF</u>	<u>MSTB</u>	-Gas-	-Brine-	-Theo. Brine-
		<u>MMbtu</u>	<u>MMbtu</u>	<u>MMbtu</u>
1530.5	50.7	1461.6	2641.8	3945.7

Cumulative HPS Usage Since August 1, 1989:

-Gas-	-Brine-	ENERGY		
<u>MCF</u>	<u>MSTB</u>	-Gas-	-Brine-	-Theo. Brine-
		<u>MMbtu</u>	<u>MMbtu</u>	<u>MMbtu</u>
2104.6	102.9	2009.9	5266.3	8062.5

^a Pressures and temperatures are averages for the day.

Rates and volumes are corrected to 14.65 psia and 60°F.

Gas rates are from the separator meter runs.

Brine rates are from the orifice meter data.

Theo. Energy is the theoretical energy available with a brine discharge temperature of 60°F.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit G-1, Part 4. IGT HPS MONTHLY PRODUCTION REPORT^a

NOVEMBER 1989

Day	---HPS TEMP---		---SWD WELL---		GAS TAKE MCF/d	--BRINE RATE--		ENERGY		
	T in Deg F	T out Deg F	TEMP Deg F	PRESS. psia		HPS STB/d	TOTAL STB/d	GAS MMbtu	BRINE MMbtu	THEOR MMbtu
1	291	227	280	447	204.7	756	16059	195.5	39.6	59.3
2	291	151	231	410	190.2	6700	16228	181.6	318.9	525.9
3	291	151	229	410	146.5	7019	16223	139.9	333.1	551.3
4	291	151	230	411	178.9	6929	16220	170.9	330.1	544.0
5	290	148	224	407	200.3	7420	16228	191.3	358.5	581.9
6	290	150	235	416	170.8	6237	16184	163.1	298.8	489.2
7	290	149	224	409	201.9	7564	16236	192.8	363.2	593.1
8	291	154	234	416	190.2	6316	16181	181.6	305.2	495.7
9	291	147	237	417	168.8	5999	16190	161.2	293.0	471.4
10	291	155	238	418	121.9	5934	16178	116.4	283.1	466.5
11	291	147	232	414	186.6	6512	16113	178.2	318.3	511.6
12	291	149	221	407	143.6	7705	16129	137.2	372.5	604.8
13	291	149	220	407	181.0	7918	16123	172.8	382.3	621.7
14	291	149	219	406	192.4	8014	16091	183.8	385.3	629.1
15	291	186	243	423	179.9	4935	15972	171.8	233.6	387.3
16	241	231	233	353	115.4	0	10238	110.2	0.0	0.0
17	66	68	59	114	0.0	0	0	0.0	0.0	0.0
18	58	59	59	72	0.0	0	0	0.0	0.0	0.0
19	58	59	59	56	0.0	0	0	0.0	0.0	0.0
20	68	69	69	49	0.0	0	0	0.0	0.0	0.0
21	69	71	72	44	0.0	0	0	0.0	0.0	0.0
22	123	122	111	62	0.0	0	893	0.0	0.0	0.0
23	232	223	215	163	0.0	0	3977	0.0	0.0	0.0
24	270	261	263	319	0.0	0	9742	0.0	0.0	0.0
25	288	276	285	466	33.4	0	15599	31.9	0.0	0.0
26	290	270	287	479	0.0	0	15977	0.0	0.0	0.0
27	290	270	287	480	2.3	0	15930	2.2	0.0	0.0
28	290	265	285	479	90.5	0	15928	86.4	0.0	0.0
29	290	263	284	478	171.2	0	15879	163.5	0.0	0.0
30	291	266	286	480	178.4	0	15848	170.3	0.0	0.0

Total HPS usage for the Month:

-Gas-	-Brine-	ENERGY		
MCF	MSTB	-Gas-	-Brine-	-Theo. Brine-
		MMbtu	MMbtu	MMbtu
3249.0	96.0	3102.8	4615.5	7533.0

Cumulative HPS Usage Since August 1, 1989:

-Gas-	-Brine-	ENERGY		
MCF	MSTB	-Gas-	-Brine-	-Theo. Brine-
		MMbtu	MMbtu	MMbtu
5353.6	198.8	5112.7	9881.8	15595.5

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.
 Theo. Energy is the theoretical energy available with a brine discharge temperature of 60°F.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit G-1, Part 5. IGT HPS MONTHLY PRODUCTION REPORT^a

DECEMBER 1989

Day	---HPS TEMP---		---SWD WELL---		GAS TAKE MCF/d	--BRINE RATE--		ENERGY		
	T in Deg F	T out Deg F	TEMP Deg F	PRESS. psia		HPS STB/d	TOTAL STB/d	GAS MMbtu	BRINE MMbtu	THEOR MMbtu
1	291	270	287	482	203.0	0	15845	193.9	0.0	0.0
2	291	270	287	482	203.1	0	15848	194.0	0.0	0.0
3	291	267	286	481	186.1	0	15831	177.7	0.0	0.0
4	291	271	288	484	203.3	0	15847	194.1	0.0	0.0
5	291	271	288	484	203.0	0	15847	193.8	0.0	0.0
6	291	267	288	484	205.8	60	15849	196.6	2.8	4.7
7	291	146	237	444	206.6	5743	16022	197.3	285.1	451.7
8	291	144	232	439	209.8	6001	15971	200.4	298.9	471.2
9	291	149	239	446	195.3	5442	15960	186.5	271.7	428.3
10	291	144	235	440	208.2	5863	15969	198.8	293.2	461.0
11	291	146	235	443	203.4	5742	15943	194.3	285.0	451.6
12	291	149	236	443	193.8	5515	15939	185.1	274.6	433.6
13	291	143	235	445	203.3	5974	16002	194.2	301.4	470.8
14	291	147	234	444	136.7	6206	16006	130.5	305.0	488.8
15	291	145	229	440	206.3	6599	15996	197.0	328.1	519.4
16	291	147	224	435	210.9	6885	15906	201.4	339.6	541.7
17	291	145	221	431	208.9	7160	15978	199.5	357.0	563.1
18	291	145	230	439	215.4	6418	15980	205.7	318.9	505.0
19	291	149	228	440	205.4	6556	16004	196.1	321.9	516.1
20	291	146	228	441	215.3	6779	15994	205.6	336.3	534.0
21	291	147	229	443	217.7	6508	15984	207.9	320.3	512.4
22	291	147	231	445	216.3	5915	15916	206.6	289.1	464.9
23	291	232	275	475	218.9	1128	15692	209.1	54.5	88.8
24	292	267	288	485	215.0	0	15702	205.3	0.0	0.0
25	292	268	288	487	213.8	0	15737	204.1	0.0	0.0
26	291	271	288	489	183.7	0	15730	175.5	0.0	0.0
27	292	272	289	490	220.2	0	15711	210.3	0.0	0.0
28	291	271	288	490	218.2	0	15692	208.4	0.0	0.0
29	291	153	239	451	188.8	5336	15643	180.3	264.3	420.1
30	291	147	214	427	167.3	8334	15894	159.8	409.8	655.9
31	291	141	210	424	223.5	8312	15905	213.4	424.9	654.4

Total HPS usage for the Month:

-Gas-	-Brine-	ENERGY		
<u>MCF</u>	<u>MSTB</u>	-Gas-	-Brine-	-Theo. Brine-
		<u>MMbtu</u>	<u>MMbtu</u>	<u>MMbtu</u>
6306.9	122.5	6023.1	6082.3	9637.5

Cumulative HPS Usage Since August 1, 1989:

-Gas-	-Brine-	ENERGY		
<u>MCF</u>	<u>MSTB</u>	-Gas-	-Brine-	-Theo. Brine-
		<u>MMbtu</u>	<u>MMbtu</u>	<u>MMbtu</u>
11660.6	321.3	11135.8	15964.2	25233.0

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.
 Theo. Energy is the theoretical energy available with a brine discharge temperature of 60°F.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit G-1, Part 6. IGT HPS MONTHLY PRODUCTION REPORT^a

JANUARY 1990

Day	---HPS TEMP---		---SWD WELL---		GAS TAKE MCF/d	--BRINE RATE--		ENERGY		
	T in Deg F	T out Deg F	TEMP Deg F	PRESS. psia		HPS STB/d	TOTAL STB/d	GAS MMbtu	BRINE MMbtu	THEOR MMbtu
1	292	141	212	425	221.3	8414	15960	211.3	431.4	663.3
2	291	143	212	424	221.2	8470	15973	211.2	426.7	666.7
3	291	148	211	422	198.0	8671	15983	189.1	422.5	681.9
4	291	147	211	421	220.3	8779	16028	210.4	432.6	691.2
5	291	145	206	414	202.3	9072	16022	193.2	451.0	714.3
6	291	146	206	414	163.7	9177	16024	156.3	452.9	722.4
7	291	145	206	415	217.9	9175	16031	208.1	456.9	722.3
8	291	145	207	417	198.9	9159	16038	190.0	456.6	721.0
9	291	147	208	419	191.6	9100	16037	183.0	448.1	716.2
10	291	147	208	420	134.2	9166	16020	128.2	449.2	721.8
11	291	148	209	422	182.4	9115	16031	174.2	443.3	717.3
12	291	145	206	419	211.3	9126	16017	201.8	452.9	718.0
13	291	144	205	419	219.0	9174	15977	209.2	459.3	722.0
14	291	148	208	422	220.3	9179	15976	210.4	445.9	722.1
15	291	149	208	424	219.9	9193	15976	210.0	443.3	723.0
16	291	150	208	425	219.2	9199	15992	209.4	440.6	722.9
17	291	169	227	438	189.3	6984	15918	180.8	335.0	549.0
18	291	151	209	422	221.5	9139	15969	211.5	435.8	718.4
19	291	151	207	421	221.4	9251	15952	211.4	440.5	726.8
20	291	147	205	418	219.0	9355	15936	209.2	458.6	736.4
21	291	146	205	420	216.8	9324	15944	207.1	461.4	734.3
22	291	214	251	454	216.7	4162	15778	207.0	208.9	328.2
23	292	274	289	483	216.4	0	15665	206.6	0.0	0.0
24	291	268	287	483	213.8	0	15653	204.2	0.0	0.0
25	291	266	286	482	213.3	0	15629	203.7	0.0	0.0
26	291	270	287	486	214.3	0	15634	204.7	0.0	0.0
27	291	270	286	487	214.8	0	15644	205.1	0.0	0.0
28	291	266	285	486	214.1	0	15621	204.4	0.0	0.0
29	291	201	261	468	216.2	2950	15717	206.5	148.7	232.3
30	291	146	240	452	216.2	5595	15865	206.4	276.3	440.8
31	291	145	237	449	216.3	5605	15873	206.6	277.7	440.7

Total HPS usage for the Month:

-Gas-	-Brine-
<u>MCF</u>	<u>MSTB</u>
6461.8	206.5

----- ENERGY -----		
-Gas-	-Brine-	-Theo. Brine-
<u>MMbtu</u>	<u>MMbtu</u>	<u>MMbtu</u>
6171.0	10156.2	16253.3

Cumulative HPS Usage Since August 1, 1989:

-Gas-	-Brine-
<u>MCF</u>	<u>MSTB</u>
18122.4	527.9

----- ENERGY -----		
-Gas-	-Brine-	-Theo. Brine-
<u>MMbtu</u>	<u>MMbtu</u>	<u>MMbtu</u>
17306.8	26120.3	41486.3

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.
 Theo. Energy is the theoretical energy available with a brine discharge temperature of 60°F.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit G-1, Part 7. IGT HPS MONTHLY PRODUCTION REPORT^a

FEBRUARY 1990

Day	---HPS TEMP.---		---SWD WELL---		GAS TAKE MCF/d	--BRINE RATE--		ENERGY		
	T in Deg F	T out Deg F	TEMP Deg F	PRESS. psia		HPS STB/d	TOTAL STB/d	GAS MMbtu	BRINE MMbtu	THEOR MMbtu
1	291	146	237	450	215.3	5611	15869	205.6	277.0	441.1
2	291	146	238	452	215.3	5605	15858	205.6	276.6	440.9
3	291	198	259	470	119.7	3153	15758	114.3	152.2	247.9
4	291	268	286	494	0.0	0	15587	0.0	0.0	0.0
5	291	268	287	496	0.0	0	15597	0.0	0.0	0.0
6	291	200	268	483	70.3	2237	15710	67.1	114.7	176.2
7	291	146	238	456	220.6	5690	15852	210.6	282.5	448.1
8	291	146	237	455	220.9	5703	15828	211.0	281.3	448.5
9	291	146	236	455	218.1	5720	15827	208.3	281.2	449.5
10	291	144	237	456	220.0	5700	15827	210.1	285.6	448.8
11	291	144	238	460	219.9	5693	15830	210.0	286.6	448.6
12	291	146	237	460	219.0	5708	15830	209.2	282.5	449.2
13	291	148	237	460	217.2	5721	15827	207.4	279.0	449.6
14	291	146	237	458	216.0	5725	15826	206.3	281.9	450.2
15	291	146	237	456	213.4	5738	15811	203.8	283.7	451.1
16	291	145	236	454	218.1	5718	15818	208.3	284.4	449.9
17	291	145	235	454	218.3	5810	15804	208.4	288.5	457.2
18	291	147	234	453	219.0	5894	15816	209.1	290.1	463.7
19	291	147	235	454	216.5	5993	15829	206.8	294.6	471.8
20	291	144	217	429	220.9	7806	15828	211.0	389.4	613.7
21	291	148	207	410	220.6	9070	15830	210.7	442.5	712.7
22	291	144	211	415	218.6	8456	15805	208.8	421.9	665.0
23	291	153	236	440	166.7	5791	15859	159.2	285.5	456.0
24	291	146	239	450	225.3	5620	15791	215.2	277.3	442.5
25	291	146	239	453	225.5	5544	15781	215.4	274.9	436.6
26	291	147	238	454	224.3	5560	15792	214.2	272.5	437.0
27	291	148	239	457	225.8	5564	15777	215.7	271.1	437.4
28	291	148	220	435	223.9	7674	15815	213.9	372.1	603.0

Total HPS usage for the Month:

-Gas-	-Brine-	ENERGY		
MCF	MSTB	-Gas-	-Brine-	-Theo. Brine-
		MMbtu	MMbtu	MMbtu
5409.5	152.5	5166.0	7529.5	11996.4

Cumulative HPS Usage Since August 1, 1989:

-Gas-	-Brine-	ENERGY		
MCF	MSTB	-Gas-	-Brine-	-Theo. Brine-
		MMbtu	MMbtu	MMbtu
23531.8	680.3	22472.9	33649.9	53482.7

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.
 Theo. Energy is the theoretical energy available with a brine discharge temperature of 60°F.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit G-1, Part 8. IGT HPS MONTHLY PRODUCTION REPORT^a

MARCH 1990

Day	---HPS TEMP---		---SWD WELL---		GAS TAKE MCF/d	--BRINE RATE--		ENERGY		
	T in Deg F	T out Deg F	TEMP Deg F	PRESS. psia		HPS STB/d	TOTAL STB/d	GAS MMbtu	BRINE MMbtu	THEOR MMbtu
1	291	144	205	410	226.3	8983	15798	216.1	448.9	706.4
2	291	144	206	414	223.9	8960	15806	213.8	448.4	705.2
3	291	212	252	454	222.2	4053	15658	212.2	203.0	319.4
4	291	256	283	487	221.9	458	15389	211.9	23.2	36.1
5	291	150	205	415	123.7	9472	15886	118.1	453.3	744.4
6	291	147	215	423	198.3	8122	15859	189.4	396.0	638.1
7	291	147	222	432	221.2	7367	15841	211.3	358.9	578.7
8	291	150	209	419	222.0	9055	15872	212.0	434.2	711.5
9	291	150	209	418	220.8	9098	15870	210.9	435.3	714.9
10	291	151	208	417	220.2	9166	15860	210.2	435.9	719.9
11	291	151	208	416	219.6	9169	15853	209.7	435.5	719.8
12	290	151	208	416	197.9	8992	15842	189.0	426.9	705.5
13	290	151	223	426	107.3	7279	15816	102.5	346.1	571.1
14	291	149	235	438	130.9	5914	15793	125.1	285.1	464.5
15	291	148	237	442	218.2	5887	15796	208.4	288.1	463.5
16	291	147	237	445	221.0	5879	15796	211.1	287.7	462.8
17	291	148	237	448	217.4	5880	15774	207.6	287.2	462.9
18	291	148	237	450	215.0	5891	15774	205.4	286.1	463.5
19	291	149	237	452	217.9	5893	15779	208.1	286.2	463.8
20	291	149	237	455	216.9	5877	15770	207.1	285.4	462.6
21	291	149	232	452	150.5	6463	15774	143.7	311.8	508.3
22	291	150	209	425	83.6	9037	15817	79.8	432.3	710.0
23	291	148	211	423	220.7	8726	15808	210.8	423.2	685.9
24	291	147	239	450	220.6	5610	15745	210.6	274.2	441.2
25	291	147	239	453	216.8	5610	15750	207.1	275.2	441.5
26	291	147	238	455	214.7	5606	15748	205.1	275.8	441.2
27	291	146	238	456	215.6	5603	15746	205.9	276.6	440.7
28	291	147	237	457	213.9	5620	15749	204.3	274.7	441.5
29	291	147	229	451	211.3	6538	15754	201.8	320.8	513.8
30	291	180	239	454	199.3	5363	15583	190.3	258.2	421.8
31	291	146	207	424	212.5	9055	15736	202.9	447.1	712.1

Total HPS usage for the Month:

-Gas-	-Brine-	ENERGY		
MCF	MSTB	-Gas-	-Brine-	-Theo. Brine-
		MMbtu	MMbtu	MMbtu
6222.0	214.6	5942.0	10421.2	16872.8

Cumulative HPS Usage Since August 1, 1989:

-Gas-	-Brine-	ENERGY		
MCF	MSTB	-Gas-	-Brine-	-Theo. Brine-
		MMbtu	MMbtu	MMbtu
29753.9	895.0	28414.9	44071.0	70355.5

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.
 Theo. Energy is the theoretical energy available with a brine discharge temperature of 60°F.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit G-1, Part 9. IGT HPS MONTHLY PRODUCTION REPORT^a

APRIL 1990

Day	---HPS TEMP---		---SWD WELL---		GAS TAKE MCF/d	--BRINE RATE--		ENERGY		
	T in Deg F	T out Deg F	TEMP Deg F	PRESS. psia		HPS STB/d	TOTAL STB/d	GAS MMbtu	BRINE MMbtu	THEOR MMbtu
1	291	147	208	420	210.6	9052	15729	201.1	443.4	712.0
2	291	148	209	421	176.4	9056	15733	168.5	441.8	712.9
3	291	144	206	417	209.7	9053	15707	200.3	452.2	712.3
4	291	152	220	433	169.4	7568	15693	161.8	375.7	595.4
5	291	149	206	417	153.5	9336	15711	146.6	450.0	733.7
6	291	156	217	425	150.2	7853	15690	143.4	380.4	617.2
7	291	143	205	415	214.8	8953	15687	205.1	450.6	703.8
8	291	153	214	422	197.2	8231	15680	188.3	406.0	647.3
9	291	148	215	425	214.0	8228	15711	204.4	399.2	646.4
10	291	154	218	430	199.9	7925	15688	190.9	380.9	622.8
11	291	147	204	417	214.3	9322	15700	204.7	457.5	733.0
12	291	147	206	419	214.7	9165	15686	205.0	449.7	720.6
13	291	150	204	415	212.8	9433	15680	203.2	452.4	740.6
14	291	150	206	417	213.9	9424	15669	204.2	452.3	740.8
15	291	150	206	419	212.0	9378	15669	202.5	451.2	737.4
16	291	151	206	420	211.9	9385	15679	202.4	447.6	737.2
17	291	205	244	450	211.2	5070	15580	201.7	240.6	398.5
18	291	264	287	484	211.3	0	15437	201.8	0.0	0.0
19	290	169	229	440	210.9	6587	15615	201.4	317.3	516.4
20	290	151	206	416	213.5	9287	15682	203.9	442.2	728.3
21	291	151	207	417	210.5	9293	15693	201.1	443.2	729.6
22	291	151	207	416	208.8	9296	15695	199.4	443.2	729.8
23	291	150	208	418	207.1	9050	15679	197.8	433.5	710.4
24	290	151	205	414	189.4	9450	15676	180.9	446.5	740.9
25	290	152	205	414	207.0	9392	15690	197.7	442.2	735.6
26	290	151	203	411	204.8	9451	15673	195.6	446.4	740.2
27	290	151	205	412	182.3	9445	15668	174.1	447.0	740.7
28	291	152	203	410	120.8	9791	15664	115.3	462.3	768.7
29	290	154	204	413	121.5	9815	15675	116.1	453.7	769.1
30	290	155	205	415	110.5	9822	15680	105.5	452.2	770.3

Total HPS usage for the Month:

-Gas-	-Brine-	ENERGY		
<u>MCF</u>	<u>MSTB</u>	-Gas-	-Brine-	-Theo. Brine-
		<u>MMbtu</u>	<u>MMbtu</u>	<u>MMbtu</u>
5785.0	257.1	5524.7	12361.2	20192.1

Cumulative HPS Usage Since August 1, 1989:

-Gas-	-Brine-	ENERGY		
<u>MCF</u>	<u>MSTB</u>	-Gas-	-Brine-	-Theo. Brine-
		<u>MMbtu</u>	<u>MMbtu</u>	<u>MMbtu</u>
35538.9	1152.0	33939.6	56432.2	90547.6

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.
 Theo. Energy is the theoretical energy available with a brine discharge temperature of 60°F.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit G-1, Part 10. IGT HPS MONTHLY PRODUCTION REPORT^a

MAY 1990

Day	---HPS TEMP.---		---SWD WELL---		GAS TAKE MCF/d	--BRINE RATE--		ENERGY		
	T in Deg F	T out Deg F	TEMP Deg F	PRESS. psia		HPS STB/d	TOTAL STB/d	GAS MMbtu	BRINE MMbtu	THEOR MMbtu
1	290	155	205	417	115.5	9790	15685	110.3	450.6	767.7
2	290	155	204	416	114.2	9791	15680	109.0	450.8	767.4
3	290	155	203	415	116.6	9792	15679	111.4	451.9	767.3
4	291	153	204	415	138.9	9740	15656	132.7	458.2	765.0
5	291	149	204	416	227.9	9484	15641	217.6	458.8	745.2
6	291	149	209	423	222.2	9084	15654	212.2	438.8	714.4
7	291	150	206	421	219.8	9436	15650	209.9	451.7	741.3
8	291	152	206	422	221.5	9481	15658	211.5	448.2	744.8
9	291	153	208	427	168.7	9487	15664	161.1	444.3	745.6
10	291	152	205	423	222.3	9573	15674	212.3	451.6	751.1
11	290	155	206	423	228.7	9640	15680	218.4	443.8	755.5
12	290	156	206	425	224.5	9643	15676	214.4	440.2	755.8
13	291	157	208	428	220.3	9645	15692	210.4	440.6	757.7
14	290	156	208	429	220.3	9590	15677	210.3	437.8	752.4
15	290	156	208	432	220.8	9483	15675	210.9	432.9	743.6
16	290	156	208	433	220.4	9483	15668	210.5	432.6	743.4
17	291	156	210	437	221.5	9396	15664	211.5	431.5	738.2
18	290	156	208	435	218.9	9476	15670	209.1	433.5	743.2
19	290	156	208	435	219.3	9507	15666	209.4	434.0	745.4
20	290	157	208	437	217.7	9537	15664	207.9	433.8	748.0
21	291	157	209	441	216.5	9486	15661	206.7	432.1	744.8
22	291	158	215	449	213.4	8667	15580	203.8	400.1	681.4
23	291	157	206	437	173.2	9796	15644	165.4	447.4	769.3
24	291	158	207	438	179.4	9854	15652	171.3	444.0	773.5
25	291	155	208	442	231.1	9483	15646	220.7	436.5	744.2
26	291	168	218	451	231.0	8263	15627	220.6	381.7	648.3
27	291	271	288	498	231.0	0	15316	220.6	0.0	0.0
28	291	269	289	504	228.9	0	15351	218.6	0.0	0.0
29	290	256	286	509	228.5	0	15339	218.3	0.0	0.0
30	187	174	182	370	75.9	0	6806	72.5	0.0	0.0
31	91	92	90	248	0.0	0	0	0.0	0.0	0.0

Total HPS usage for the Month:

-Gas-	-Brine-	ENERGY		
MCF	MSTB	-Gas-	-Brine-	-Theo. Brine-
MMbtu	MMbtu	MMbtu	MMbtu	MMbtu
5988.8	246.7	5719.3	11407.5	19354.4

Cumulative HPS Usage Since August 1, 1989:

-Gas-	-Brine-	ENERGY		
MCF	MSTB	-Gas-	-Brine-	-Theo. Brine-
MMbtu	MMbtu	MMbtu	MMbtu	MMbtu
41527.7	1398.8	39658.9	67839.7	109902.0

- ^a Pressures and temperatures are averages for the day.
 Rates and volumes are corrected to 14.65 psia and 60°F.
 Gas rates are from the separator meter runs.
 Brine rates are from the orifice meter data.
 Theo. Energy is the theoretical energy available with a brine discharge temperature of 60°F.

APPENDIX H
Log of Significant Events

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

2/24/88-03/07/88: Wireline operations to get a caliper survey and initial shut-in bottomhole pressure. Need to find more details on problems due to the aluminum plug.

03/07/88-03/08/88: First test flow using all surface facilities. Times, choke openings, and resultant rates were --

<u>Date</u>	<u>Time</u>	<u>Choke</u>	<u>Rate</u>
03/07	12:44	10/64"	2100 STB/d
	13:20	15/64"	3000 STB/d
	14:00	18/64"	4800 STB/d
	15:36	24/64"	6600 STB/d
	16:36	24/64"	7200 STB/d
	17:00	30/64"	9200 STB/d
03/08	13:15	0/64"	0 STB/d

03/30/88: A slick-line bailer tagged sand at the bottom of the shallowest set of perforations (6260 feet). A slick-line dump bailer was used to spot caustic on the obstruction in the production well at a depth of 14,024 feet.

04/06/88: An Atlas Spectralog was run and tagged up on the obstruction at a depth of 14,012 feet. The depth of radioactive bullets was about 7 feet deeper than previously reported. But the difference is measurement uncertainty, not subsidence.

04/18/88: Brine was produced from 10:50 until 17:20 to clean the caustic residue from the production wellbore. For the last 5 hours, the choke opening was 24/64". After an hour with this choke opening, a noise was heard in the flow line and the brine rate increased from 4000 to 7500 STB/d.

04/20/88: Pumped an inhibitor pill into the formation. The planned chase fluid could not be displaced into the formation.

04/21/88-04/24/88: Inhibitor pill cleanup flow. The first 24 hours was at a rate of only 2000 barrels per day so that good resolution could be obtained in collecting samples for laboratory analysis. The last 2 days of production were with a choke opening of 36/64" and at a brine rate of about 13,000 STB/d.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

04/24/88-05/25/88: Shut in for repair of the middle flange in the flow loop and the production wellhead swab valve.

05/26/88-06/01/88: Bottomhole pressure measurements were made. The obstruction was found to still be at a depth a little below 14,000 feet, so the Panex gage was run to a depth of 13,950 feet. The overnight stabilized BHP was 10,685 the morning of 05/27/88. The choke was then opened in steps as follows:

<u>Date</u>	<u>Time</u>	<u>Choke</u>	<u>Rate</u>
05/27	07:33	20/64"	4,800 STB/d
	19:03	28/64"	7,400 STB/d
05/28	07:03	34/64"	11,800 STB/d
05/29	13:50	30/64"	9,800 STB/d
05/29	14:00	-- Started tripping out with wireline to replace the Panex.	
05/29	20:25	-- New Panex sensor was at 13,950 feet.	
05/30	18:08	-- Shut in the flow line to record buildup BHP	
05/31	16:34	28/64"	9,000 STB/d -- Resumed production.
06/01	07:06	-- Started out recording flowing pressures at depth steps.	
	12:40	-- BHP Panex was in the lubricator ready to rig down.	
	14:20	-- Shut in production.	
	17:15-23:45	-- Low-rate production to fill tanks.	

06/02/88-06/08/88: Cleaned out the disposal well to a fish of 1-1/2 joints of 2-3/8 inch tubing with the top cut off at a depth of 6476 feet (4 feet above the bottom of the fourth set of perforations). Brine was produced periodically in support of the cleanout operation.

06/08/88: The small separator was initially charged with nitrogen. Production was then started through the small separator with a choke opening of 14/64" and a brine rate of 2600 STB/d. After sufficient gas had been produced to charge the large separator and incremental increases in choke opening, production was switched to the large separator. The small separator was bled down to repair an "O"-ring leak and then put back on-line. After both separators were on-line, brine rate was increased to 17,000+ STB/d.

It was not possible to achieve the desired 1/3 - 2/3 split of flow between the two separators. The problem was that the vast majority of the gas went to the large separator unless more than 1/3 of the brine was flowing through the small separator.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

06/09/88-06/10/88: The brine production rate was increased from 17,000 STB/d to slightly less than 20,000 STB/d by opening the choke to 48/64". After 14 hours at 20,000 STB/d, the brine rate spontaneously dropped to 16,000 STB/d and pressures changed as if the main choke opening had been reduced. A couple hours later, a similar drop to 10,000 STB/d occurred and the brine turbine on the small separator stopped operating. After additional rate drops to 9500 and then 8500 STB/d during the next 2-1/2 hours, the production well was shut in with the ESD valve at 03:05 on June 10, 1988.

Disassembly of the main choke revealed two thumb-size pieces of aluminum, one of which was halfway through the opening in the Willis choke discs. A third similar piece of aluminum was recovered from the block upstream of the choke. Inspection of the flow loop and the top of the gate in the closed ESD valve did not reveal any more pieces of the pump-out plug that had been run with the tubing.

Production at a brine rate of about 20,000 STB/d was resumed during the evening of June 10, 1988.

06/11/88-06/19/88: Production was continuous with various parameters being varied as steps toward determining the operating limits of the wells and surface facilities. The brine rate was a constant 20,000 BPD rate with the two separators on separate back-pressure controllers until June 18. During June 18, 1988, the entire flow was sent to the large separator. The next day, separator pressure was increased to 1000 psi to ensure enough pressure to drive the disposal well at higher brine rates. Brine rate was then reduced to 16,000 BPD to see whether the gas/brine ratio would rebound from the reduction due to increasing separator pressure.

06/20/88-06/24/88: During June 20, brine rate was increased stepwise to 20,000 BPD, then 22,000, and finally 25,000 BPD in a few hours. After 2 hours at the maximum rate, the rate was reduced to 17,000 BPD due to sand production.

Overnight flow at 17,000 BPD indicated cessation of sand production, and the rate was increased in two steps to 22,500 BPD during June 21. The rate of buildup of filter pressure drop and increases in disposal well injection pressure mandated rate reduction to stop sand production the next morning. The reduction was to 11,000 BPD so that the full flow could be switched to the small separator and the large separator could be opened to determine total sand production. About 4 cubic feet were found.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Brine rate through the small separator was increased from 11,000 to 15,000 BPD on the June 23. The small separator was able to handle more than 14,000 STB/d with no control problems and no loss of efficiency for separating gas from brine for 2 days. At this rate the brine residence time is less than 3/4 minute. Because the large separator alone was found capable of handling more than 20,000 STB/d the week before, there was no doubt that the two separators in parallel were adequate for production rates at least as high as 30,000 STB/d.

On June 24, the large separator was put on-line and the brine rate was increased to 20,000 BPD

06/25/88-07/07/88: Production was continuous at a rate slightly below 20,000 STB/d. The flushing of old debris from the system was apparent due to decreasing frequency of brine turbine problems and the slower loading of filter elements.

07/08/88: The separator choke openings were decreased to see whether higher pressure between the main choke and the separator chokes would allow operation with equal brine residence time for the two separators. With the separator pressure at 700 psia, the pressure on the brine line between the chokes was increased from 880 to 1140 psia. This in turn increased the wellhead pressure from 3102 to 3157 psia and reduced the brine rate from 19,870 to 19,120 STB/d. The change did not provide enough gas to the small separator for operation with equal brine residence times for the two separators (large separator brine rate of twice that for the small separator).

07/09/88-08/02/88: Production was continuous with the rate near 19,000 STB/d.

08/03/88-08/06/88: A brine leak developed in the piping spool immediately upstream of the large separator. During August 3, the main choke opening was reduced from 46/64" to 34/64" and the production was switched to the small separator so that the large separator could be taken off-line. Brine rate was a little over 14,000 STB/d. Upon completion of the repair during August 6, the large separator was put back on-line and the main choke opening was again increased to 46/64". The separator choke openings were a little bigger than before the repair and the brine rate was a little higher.

Injection of Champion Technologies, Inc., Cortron RN-97 corrosion inhibitor was started on August 5 at a concentration of 20 ppmv (parts per million by volume) in the brine.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

08/07/88-08/28/88: With the exception of 10 hours on August 11, production was continuous with the rate near 19,000 STB/d. During those 10 hours, brine rate was reduced to about 14,000 STB/d and the full stream of produced fluids as sent to the small separator. This was done so that one of the block valves for the turbine meter on the large separator could be replaced and debris could be removed from the turbine.

08/29/88-09/09/88: A small brine leak was noticed in old piping upstream of the separator chokes the evening of August 28, 1988. The next evening, the separator chokes were opened more to minimize the pressure in the brine line. This increased the pressure drop across the main choke with the result that flow rate increased 2.4%. The well was shut in the morning of August 31 for repair/replacement of the leaking surface piping and associated hardware.

The entire tee from the 8-inch brine line to the two separator chokes was replaced. In addition, the large separator choke was rebuilt. A lining of 8018B2L welding rod was built up on the badly corroded inlet section and a stainless steel bonnet was installed.

Production was resumed at a brine rate of about 20,000 STB/d the afternoon and evening of September 9. This was done by first charging the small separator with nitrogen and then flowing through it until "bottoms up." After charging the large separator with produced gas, it was put on-line. The main choke was opened stepwise to a final value of 50/64", which gave a brine production rate near 20,000 STB/d.

09/10/88-09/15/88: Production was continuous with the rate of about 19,500 STB/d.

09/15/88-09/20/88: Production was shut in on the morning of September 15 due to the threat of Hurricane Gilbert. All electrical power was turned off and safety considerations mandated that all personnel leave the location. Water levels had subsided enough for it to be practical to restore electrical power and to open the production well master valve so that tubing pressure could be recorded after 3 days.

While attempting to resume production on September 19, the flow rate did not change from 18,000 STB/d when the main choke opening was changed from 48/64" to 50/64". Also, the choke could not be closed. The ESD valve was closed to stop production.

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A spare choke of unknown metallurgy was installed and production was resumed at the previous rate of about 19,500 STB/d during September 20. Examination of the failed choke revealed that the two layers of the upstream half of the Willis choke trim had been put together with Epoxy, rather than brazed. The Epoxy had failed at the brine temperature of 290°F.

09/21/88-10/16/88: Production was continuous with the rate slowly declining from about 19,500 to about 19,000 STB/d.

10/17/88-10/18/88: During October 17, production was shut in to replace the spare primary choke with the repaired, stainless steel lined, primary choke. New brazed trim had been installed. The spare choke was found to be in excellent condition. It has metallurgy adequate for long-term use.

During the shut-in, maintenance actions performed included 1) greasing the wellhead valves, 2) replacing the turbine and bearings in the 4-inch brine turbine, 3) installing a signal amplifier on the 4-inch turbine output, 4) changing out the C-1018 corrosion coupons in the flow loop upstream of the primary choke, and 5) changing out the filter elements.

The well was put back into production on October 18. The choke was opened stepwise to a final value of 48/64" while the two separators were brought on-line in a manner similar to that previously described.

10/18/88-11/08/88: Production was continuous with a choke opening of 48/64" and a brine rate that slowly declined from about 19,000 to about 18,800 STB/d.

11/09/88: Rate was reduced for 11 hours during November 9 so that the large separator could be taken off-line to replace a leaking gasket at the gas outlet. This was done by reducing the main choke opening from an equivalent bean size of 48/64" to 32/64" and sending the resulting 11,000 STB/d rate to the small separator. The choke opening was returned to 48/64" after replacing the gasket, inspecting the choke on the large separator, and restoring flow through the large separator.

11/10/88-11/14/88: Production was continuous with a choke opening of 48/64" and a brine rate of about 18,900 STB/d.

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- 11/15/88: The well was shut in for a total of 80 minutes on November 15 after the fire-sensing tubing on the large separator broke during moderately high wind (roughly 20 mph). The plastic tubing had become somewhat brittle. Brine rate was brought back up to about 19,200 STB/d by incrementally opening the main choke to 48/64" over a time of 10 minutes.
- 11/16/88-11/23/88: Production was continuous with a choke opening of 48/64" and a brine rate of about 18,600 STB/d.
- 11/24/88: A half hour after the beginning of November 24, production well tubing pressure increased by 45 psi and the brine rate dropped by 500 BPD. Pressures throughout the system reacted as if the main choke opening had been reduced by a small amount. Eight hours later pressures and rates returned to their prior values. The choke was not touched at either time and the stepwise changes were not caused by any other operator action. It is hypothesized that debris, possibly from a disintegrating corrosion coupon, temporarily lodged on the choke aperture.
- 11/25/88-01/11/89: Production was continuous with a choke opening of 48/64" and a brine rate that slowly declined from about 18,600 to about 18,300 STB/d.
- 01/12/89: After reading progressively lower, erroneous, values for several days, the 4-inch turbine meter on the brine outlet of the large separator was removed. The primary choke opening was first decreased from 48/64" to 32/64" and the full stream was sent to the small separator. The bearings in the turbine were found to have high friction due to scale formation. The scale was removed with hydrochloric acid and the turbine was put back into service.
- After putting the large separator back on-line and verifying proper turbine operation, the choke was opened to 47/64", a slightly lower value than before. The lower brine rate of 17,600 STB/d had the desired effect of lowering the disposal well injection pressure from 624 to 585 psia.
- 01/13/89-3/14/89: Production was continuous with a choke opening of 47/64" and a brine rate that slowly declined from about 17,600 to about 17,400 STB/d.

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Routine operation was interrupted by switching of brine flows on six occasions as follows:

01/26	The small separator was bypassed to repair a sight glass leak.
02/4,5,&6	Rates were erratic due to freezing in the level-control bridles.
02/15,16	Scale was removed from bearings on the 3-inch turbine.
02/25,26	Scale was removed from bearings on the 3-inch turbine.
03/13	Scale was removed from bearings on the 4-inch turbine.

The disposal well was treated with hydrochloric acid on two occasions. Treatment with 10 barrels of 28% inhibited hydrochloric acid on February 17 resulted in the reduction in the average daily disposal well tubing pressure from 618 psia on February 16 to 501 psia on February 18, 1989. Dilution due to injection of the acid into the flow of produced brine reduced the concentration of acid reaching the perforations to 1.6%. Pressure was still dropping when the last of the acid entered the perforations.

On March 6, 40 barrels of the same acid were pumped by the same supplier and at the same rate. The expected decrease in injection pressure was not experienced. There was no drop in pressure when the acid hit the perforations 12 minutes (0.2 hour) after start of pumping. Indeed, injection pressure increased from 495 psia the day before treatment to 508 psia the day after.

03/14/89: Surface scale-inhibitor injection was started at a point upstream of the separator chokes and downstream of the main choke. The combination of supply concentration of inhibitor and the injection pump rate was set to deliver between 0.1 and 0.15 mg of ATMP per liter of brine. This is in addition to the ATMP from the inhibitor pill, which has provided an average 0.03 mg of ATMP per liter of brine since August 1988.

Brine production since the inhibitor pill had been 4.94 million STB. It is now recognized that the seizing of turbine bearings that was first observed on January 12, 1989, (3.87 million STB after the pill) was an earlier indicator of declining effectiveness of the pill. The scale formed first in the turbine bearings because they are the highest temperature point in the system due to friction. Scale was not observed in the filter pots when the elements were changed on March 7, but it was found at the next filter change, which was on March 29.

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03/14/89-04/27/89: With the exception of a brief shut-in on March 23, production was continuous with a choke opening of 47/64" and a brine rate that slowly declined from about 17,400 to about 17,100 STB/d. The shut-in was due to hydrate formation in the level-control bridle on the small separator and the resultant triggering of the ESD system by the high-level cutoff in that separator. These upsets in the small separator flushed old rust flakes to the turbine meter and caused erroneously high readings until they were removed on March 27.

04/27/89-05/14/89: On April 27, the main choke opening was reduced from 47/64" to 34/64" to reduce brine rate from about 17,100 to about 12,200 STB/d in preparation for wireline bottomhole pressure measurements during the week of May 14.

05/14/89-05/26/89: A flowing pressure gradient for a brine rate of 12,200 STB/d was measured with stops 2000 feet apart on May 14. Production was shut in on May 15 and resumed on May 26. Observations and actions performed in conjunction therewith were --

1. A large eroded block of aluminium, approximately 5-1/2 X 4 X 3 inches, was found lodged against the corrosion coupon holder at the top of the flow loop. This is presumed to be the remains of the aluminum "pump out" plug that had been found lodged in the well at 14,024 feet in the spring of 1988.
2. Recorded bottomhole pressure buildup for the shut-in on May 15. Recording ended when the Panex failed at 00:46 on May 18.
3. Installed the "flow splitter" hardware to provide natural gas and brine to the Hybrid Power System (HPS).
4. Refaced the flange at the bottom of the flow loop.
5. Rebuilt the disposal well master valve to eliminate a valve-stem leak.
6. Obtained a bailer sample from the top of fill in the disposal well at 6348 feet. This depth is 86 feet below the shallowest set of perforations and 14 feet above the second set.
7. Perforated the depth intervals 6060 to 6092, 6100 to 6190, and 6198 to 6216 feet in the disposal well on May 26.

Brine was pumped into the disposal well while perforating. Production was started as soon as perforating was finished and before the injection pump was turned off. Injection pressure leveled out at 388 psi for the brine rate of 14,500 STB/d. This is the same pressure as at 12,200 STB/d before production was shut in on May 15, 1989.

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05/26/89-06/05/89: Production was started at 6:30 p.m. on May 26, 1989, the Friday night at the start of the 3-day Memorial Day weekend. By 10:00 that night, the well was producing 14,500 STB/d with both separators on-line. Gas sales had resumed.

After 4-1/2 days of production, on the morning of May 31, the brine rate had decreased to 14,430 STB/d. That day, the well was shut in shortly after noon due to a very small leak at the middle flange of the flow loop.

Production was resumed the morning of June 1, 1989, after retorquing the bolts on the leaking flange on the production wellhead loop. The choke was set to restrict production rates to 14,900 STB/d. On the morning of June 5, the choke was opened from 42/64" to 47/64" to increase production rate to 17,800 STB/d. Disposal well injection pressure was 495 psia.

06/05/89-06/22/89: Production was continuous with a choke opening of 47/64" and a brine rate that slowly declined from about 17,800 to about 17,700 STB/d.

06/22/89-06/27/89: The choke opening was reduced from 47/64" to 44/64" the afternoon of June 22 to reduce the brine rate to about 16,200 STB/d. This action was taken in conjunction with testing of the back-pressure control on the brine flow splitter. Reduction in disposal well injection pressure was essential to staying below 600 psi at the inlet to the HPS while maintaining sufficient pressure drop across the HPS for control of brine rate through the heat exchangers.

Four days later, on June 26, production was shut in, electricity was turned off, and personnel evacuated the location due to high winds and rising water caused by tropical storm Allison. Production was resumed on June 27 with a final choke setting of 44/64" and a brine rate of about 16,100 STB/d. Disposal well injection pressure was 443 psia and the brine pressure at the inlet to the HPS was being held at 566 psia by the back-pressure controller in the flow splitter.

06/28/89-07/19/89: Production was continuous with a choke opening of 44/64" and a brine rate that slowly declined from about 16,100 to about 15,900 STB/d. Disposal well injection pressure had built up from 443 to 458 psia.

07/20/89-08/11/89: Production was shut in the morning of July 20 for repair of a stem leak in the ESD valve in the production wellhead. Other actions during the downtime included --

1. The 4-inch stainless dump valve on the large separator was reworked. A small brine leak had been noticed at the flange on which the controller is mounted. The nuts could not be tightened on three of the eight studs that hold the flange in place. The studs appear to have broken in tension between one and two threads into the body of the valve. Shop inspection also revealed wear on the trim sufficient for rework or replacement of several internal valve parts to be appropriate.

2. The inspection ports on the small separator were opened to replace the rubber "O" rings with Teflon. The interior of the vessel was visually examined. There was about a cubic foot of sheet rust (pieces up to 6 inches across and 3/32 inch thick), sand, and sheets of scale (up to 3 inches across and 1/4 inch thick with sand and/or rust imbedded in the scale) laying loose on the bottom of the separator. The inside walls below the water level had scale about 1/4 inch thick with imbedded sand grains at the inlet end. The scale was much thinner on the curved wall at the outlet end, and there was no scale on the vertical weir.

3. Electric power was turned off and personnel were evacuated the location on the evening of July 31, 1989, due to the threat of Hurricane Chantal. Power was restored and location manning returned to normal on the morning of August 2. There was no damage.

Production was resumed on August 10, 1989, with the choke set to provide a rate of about 9250 BPD. After flowing overnight, with subsequent heating of the wellhead, inspection revealed no leaks. Then, the main choke opening was increased to the 44/64" that was in use before the well was shut in on July 20. This brought the rate up to about 16,000 BPD.

08/12/89-09/08/89: Production was continuous with a choke opening of 44/64" and a brine rate that slowly declined from about 16,000 to about 15,800 STB/d. Disposal well injection pressure had built up from 450 to 458 psia.

The first delivery of gas to the HPS was on August 24 and the HPS first took brine on August 25. The peak delivery rate for either fluid was only slightly above one-half of the design rate during this time interval.

09/08/89-10/16/89: Production was shut in on September 8 for safety inspection and system component testing prior to full operation of the HPS. Actions performed prior to resuming production on October 16 included --

1. Recertification or replacement of all of the pressure-relief valves.
2. Recalibration of all of the ESD system sensors.

3. Recalibration of all of the pressure, differential-pressure, and temperature transmitters essential to production data recording and interpretation.
4. Ultrasonic wall thickness measurements on the separators.
5. Preparation of comprehensive Safety Analysis Report (SAR).
6. Conduct of a comprehensive safety and QA/QC review meeting in DOE's Idaho Falls offices.

10/16/89-11/16/89: On October 16, the choke was opened stepwise while the separators were individually charged and brought on-line. The final choke setting of 44/64" gave a brine rate of about 15,400 STB/d. The next day, October 17, the HPS began taking brine at a rate of about 5000 STB/d.

On October 20, the choke opening was increased to 46/64". Brine rate increased by about 5% to 16,200 STB/d. No further adjustments were made before the well was shut in on November 16. Brine rate had declined to 16,000 STB/d.

Delivery rates to the HPS reached the nominal rates of a little over 8000 STB/d for brine and a little over 200,000 SCF/d for gas for the first time the evening of October 25. At least one of the fluids was taken by the HPS at all times from then until production was shut in on November 16.

Cooling of brine by the HPS increased the density and thereby decreased the surface pressure required to drive any particular rate into the disposal formation. With the HPS cooling 8000 STB/d of brine, the disposal wellhead temperature was down to 200°F and the injection pressure was about 50 psi less than for the 290°F brine that is injected when the HPS is not in operation.

11/16/89-11/25/89: The well was shut in on November 16 after it became clear that the surface scale-inhibitor system was plugged up. The well remained shut-in until November 19, when the inhibitor pill was successfully injected into the formation. After allowing 60 hours for the pill to adsorb on the formation, low-rate flow-back began on November 22.

Testing of polymaleic anhydride inhibitor had been started on November 2, 1990. But chemical analysis revealed that the plug in the inhibitor-injection point was in fact the previously used phosphonate, rather than the new material.

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A total of 1400 barrels, including the 100-barrel pill, was displaced down the well and into the producing formation. Maximum tubing and casing pressures recorded during injection were 4104 and 4231 psia, respectively. The well was shut in for 60 hours to allow the pill to adsorb in the reservoir.

Production rate was increased in steps appropriate to adequate time resolution in collection of samples to determine the amount of inhibitor that was returned. It started with an initial rate of 2400 STB/d on November 22. This was increased to 4800 STB/d on November 23, 15,100 STB/d on November 24, and 16,000 STB/d on November 25. The final choke opening was 46/64".

11/26/89-05/29/90: Production was continuous with a choke opening of 46/64" and a brine rate that slowly declined from about 16,000 to about 15,300 STB/d. The production well flowing wellhead pressure declined from 3065 to 2911 psia.

The primary objective of this 6 months of continuous production was providing a reliable source of gas and brine for the Hybrid Power System experiment. This was accomplished, including through a record cold snap between Christmas and New Years.

The separators were operated in parallel off the same gas back-pressure regulator with the pressure held at 690 psia. The back pressure in the brine line was held at 530 psia at the inlet to the HPS. This pressure had to be substantially below the 600 psig working-pressure rating of the heat exchangers to avoid activation of the pressure-relief valve at times of rapid shutdown of the HPS brine loop.

The maximum disposal well injection pressure was 509 psia and occurred on the day before the shut-in while the HPS was not taking brine. The back-pressure valve at the flow splitter was wide open and pressure at the inlet to the HPS was up to 550 psia. It would have still been possible to operate the HPS because the cooling of the brine would have caused disposal well injection pressure to decrease by about 50 psi.

As of May 16, 1990, 2.75 million STB of brine had been produced since the second inhibitor pill. Scale was found in the bearing of the 3-inch turbine meter on the small separator. Surface injection of polymaleic anhydride scale inhibitor was then started.

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05/30/90-07/11/90: Production was shut in on May 30 so that the disposal could be reworked to eliminate pressure communication between the tubing and the annulus. Preparations for a comprehensive safety and QA/QC review prior to high-rate production were undertaken. All of the relief valves were tested and recertified. The three brine turbine meters were removed from the separators and, along with the spare 3-inch turbine and the replacement rotor for the 4-inch turbine, were sent to the manufacturer for recalibration. The calibrations of the 4 to 20-mA transmitters were checked against standards that were traceable to the NBS. For differential-pressure transmitters the standard was a mercury manometer whose scale is certified traceable to NBS. A recertified deadweight tester was the standard for pressure-transmitter calibration, and the calibration of the electronic portion of the platinum resistance temperature detectors was checked using a rental, certified decade resistance box. Recalibration of the ESD system sensors by the supplier revealed that all pressure sensors triggered within 10 psi of the desired value. The separators were cleaned out and lack of significant corrosion was verified by visual inspection.

07/12/90-07/25/90: A small amount of fluid was produced in support of the disposal well cleanout work. The tubing was pulled from the disposal well. Fifty-nine joints of tubing were rejected using the criterion that at least 85% of the original thickness was a prerequisite for reuse. On July 18, 1990, nitrogen foam was circulated down the disposal well to remove a few tens of barrels of sand. During the night of July 19-20, brine was produced directly to the disposal well for several hours at a rate of about 8000 BPD. The reason was to displace nitrogen gas back into the formation. The well was then successfully killed with heavy brine.

Two Fisher control valves were removed and taken apart to evaluate internal condition. The Fisher experts suggested that the scoring of the valve stems was due to the chloride attack and buildup of corrosion inhibitor. They recommended changing to a Monel valve stem.

07/26/90-08/19/90: Continuous production at about 16,000 BPD was shut in May 30, 1990, and was resumed on July 27, 1990. Operation was without incident. Comparison of disposal well performance from before and after the cleanout revealed an improvement in injectivities of 33% from 43 to 57 STB/d/psi, assuming a shut-in pressure of 150 psia. Casing pressure no longer tracks variations in tubing pressure. Assuming no deterioration of the disposal well and considering pressure drop due to friction, the injection pressure at

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from 6.3 to 11.3 psi. That evening pressure drop increased much more rapidly, reaching 19.4 psi by the morning of the 27th. The fifth pot, which contained new 50-micron cotton filter elements, was put on-line. Then, on the morning of the 28th, new 50-micron cotton elements were put into all five pots, and one of them was left blocked-in.

10/28/90-10/31/90: Between 14:00 and 14:30 on October 28, pressure drop across the new filter elements jumped from 7.3 to 18.9 psi. Wellhead pressure on both wells and brine rate increased slightly at the same time. This was interpreted as indicating production of a slug of sand. The brine rate was then reduced from 24,000 to 18,000 STB/d. The evening of October 29, the brine rate was reduced to 12,500 STB/d so that the sand could be removed from the separators.

The sand checkpoint on the large separator was blown twice after the brine rate was reduced from 24,000 to 18,000 STB/d on October 28. About 1/2 cup of solids was recovered on the first blow and an additional 1/4 cup was recovered from the second blow. About three-quarters of the volume of these samples was grey sand.

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30,000 BPD was predicated to be about 835 psi. This was judged to be adequate for stepwise increasing brine rate to find the onset of sand production.

08/20/90-09/04/90: The brine rate was increased from 16,000+ to 18,000+ STB/d on August 20, 1990, by changing the main choke setting from 52/64" to 56/64".

09/04/90-09/18/90: On September 4, suspended solids samples were collected from the brine just after the primary choke and from a point between the filters and the disposal well while the brine rate was about 18,000 STB/d. The sample collected near the production well contained 0.2 mg/L of suspended solids, or 0.07 pounds of solids per 1000 barrels of brine. The sample collected near the disposal well contained 0.3 mg/L of suspended solids, or 0.09 pounds of solids per 1000 barrels of brine. The brine rate was then increased from 18,000+ to 20,000 STB/d on September 5 by changing the choke opening from 56/64" to 60/64".

With the brine rate remaining at 20,000 STB/d, separator pressure was increased from 700 to 850 psia during September 12, and the separator chokes were adjusted. It was observed that the slow recovery of tubing pressure after cooling by rain suggested the possibility of improving the injectivity by treating with very dilute acid.

09/19/90-10/04/90: The brine rate was increased from 19,750 to 22,300 STB/d on September 19 by changing the choke from 60/64" to 66/64".

High pressure drop across new 10-micron cotton filters at 22,000 STB/d resulted in changing to filter elements with a nominal rating of 20 microns starting on September 26.

10/04/90-10/15/90: During October 4, 25 barrels of concentrated hydrochloric acid were injected at the disposal wellhead and resulted in a 50-psi reduction in injection pressure. The daily average injection pressure was 667 psia the day before the acid treatment and 617 psia the day after. Brine rate remained at about 22,300 STB/d.

10/16/90-10/28/90: The brine rate was increased from 22,400 to 24,200 STB/d on October 16 by changing the choke opening from 66/64" to 72/64".

Three pots filled with 50-micron elements and one filled with 20-micron elements had been put on-line on October 18, 1990. By midday October 26, the pressure drop had increased

APPENDIX I
Brine Analyses

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This appendix contains details of the sample collection and analysis of brine samples, with the results of the numerous analyses. The entries and their descriptions are as follows:

Exhibit I-1 -- The analytical techniques employed for routine brine analyses.

Exhibit I-2 -- The results of thirty-two brine analyses of samples collected from just after the primary choke, performed between May 1988 and October 1990, and the "average" of data reported by Anacon for the Phase I testing in 1980.

Exhibit I-3 -- The results of four analyses of samples collected from just after the filter skid.

Exhibit I-4 -- The analytical procedure for determining trace levels of phosphonate in brine.

"Parametric Study of Separator Performance" -- A paper containing the procedure used for measuring the gas content of brine leaving the separator.

A representative brine analysis report containing quality control data from the Bureau of Economic Geology, University of Texas.

Exhibit I-1. 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	Turbidometric
Bromide, Iodide	Spectrophotometric
Fluoride	Ion Electrode
Alkalinity ^a	pH Titration
Density, TDS	Gravimetric
Sulfide ^a , Iron ^a	Colorimetric
Radium	Radon Generation

^a Sample is also analyzed for this element onsite.

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Exhibit I-2, Part 1. PLEASANT BAYOU BRINE ANALYSES^a

Date	<u>Avg 1980</u>	<u>30 May 88</u>	<u>14 Jun 88</u>	<u>01 Jul 88</u>	<u>21 Jul 88</u>	<u>05 Aug 88</u>
Laboratory	Anacon	BEG	BEG	BEG	BEG	BEG
Brine Temp, °F	268-284	259	288	290	291	287
Sp Gravity @ 60°F	1.0907	1.085	1.082	1.080	1.080	1.070
Total Dissolved Solids, mg/L	137,008	127,000	124,000	132,900	132,900	132,600
Alkalinity, as mg CaCO ₃ /L	272	309	310	211	291	295
Ammonia	92	—	83	83	85	86
Arsenic	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5
Barium	764	803	805	757	765	769
Boron	31	23	23	24	25	25
Bromide	—	—	74	80	73	78
Cadmium	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Calcium	9,360	7,620	7,700	7,760	7,940	7,890
Chloride	78,363	70,200	70,400	72,200	71,200	72,400
Chromium	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Copper	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Fluoride	1.2	—	1.5	1.6	1.5	1.7
Iodide	—	—	23	21	22	22
Iron	56	44	42	45	45	47
Lead	<1	<1	<1	<1	<1	<1
Lithium	—	30	30	31	31	32
Manganese	23	14	14	15	16	16
Magnesium	658	553	564	593	603	604
Mercury	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005
Nickel	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25
Potassium	—	522	530	542	554	565
Silica, as SiO ₂	114	103	100	106	106	108
Sodium	37,767	35,000	35,300	35,900	36,400	36,900
Strontium	1053	838	855	864	866	827
Sulfate	0	—	13	1	4	2
Tin	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25
Zinc	1.6	0.6	0.7	0.5	0.4	0.6

^a All results in milligrams per liter unless otherwise specified.

Samples are collected just after the primary choke. The samples are cooled by passing through a water bath prior to flashing to atmospheric pressure and are collected under carbon dioxide.

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Exhibit I-2, Part 2. PLEASANT BAYOU BRINE ANALYSES^a

Date	24 Aug 88	03 Oct 88	17 Oct 88	28 Oct 88	11 Nov 88	29 Nov 88	19 Dec 88
Laboratory	BEG	BEG	BEG	BEG	BEG	BEG	BEG
Brine Temp, °F	290	291	290	290	290	290	289
Sp Gravity @ 60°F	1.080	1.085	1.087	1.084	1.085	1.082	1.080
Total Dissolved Solids, mg/L	133,900	133,000	134,100	133,400	134,300	134,200	133,800
Alkalinity, as mg CaCO ₃ /L	301	286	283	292	298	311	315
Ammonia	86	87	88	86	89	89	89
Arsenic	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5
Barium	767	770	760	750	770	770	780
Boron	25	20	19	19	20	20	27
Bromide	75	73	77	75	75	75	78
Cadmium	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Calcium	7,960	8,010	7,970	7,890	7,860	7,900	7,940
Chloride	72,000	71,700	72,000	71,600	72,100	72,600	71,600
Chromium	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Copper	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Fluoride	1.6	1.5	1.4	1.5	1.4	1.4	1.4
Iodide	23	20	21	21	21	21	21
Iron	45	55	58	56	52	54	54
Lead	<1	<1	<1	<1	<1	<1	<1
Lithium	32	30	29	29	32	31	27
Manganese	16	19	19	19	19	19	18
Magnesium	604	612	609	603	574	577	590
Mercury	<0.025	<0.025	<0.025	<0.025	<0.025	<0.025	<0.025
Nickel	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25
Potassium	561	570	580	570	540	550	600
Silica, as SiO ₂	108	94	88	92	90	90	88
Sodium	36,700	37,400	36,800	36,500	35,800	35,700	37,000
Strontium	850	930	930	900	890	870	950
Sulfate	6	<1	<1	<1	<1	4	<1
Tin	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25
Zinc	0.5	0.4	0.3	0.4	0.3	0.3	0.2

^a All results in milligrams per liter unless otherwise specified.

Samples are collected just after the primary choke. The samples are cooled by passing through a water bath prior to flashing to atmospheric pressure and are collected under carbon dioxide. The minimum detection limit for mercury has been raised from 0.005 to 0.025 mg/L.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit I-2, Part 3. PLEASANT BAYOU BRINE ANALYSES^a

Date	10 Jan 89	20 Jan 89	9 Feb 89	28 Feb 89	20 Mar 89	4 Apr 89	27 Apr 89
Laboratory	BEG	BEG	BEG	BEG	BEG	BEG	BEG
Brine Temp, °F	290	289	289	289	289	290	288
Sp Gravity @ 60°F	1.079	1.081	1.088	1.091	1.086	1.085	1.088
Total Dissolved							
Solids, mg/L	132,800	133,900	133,100	134,900	135,100	133,700	124,940
Alkalinity, as mg CaCO ₃ /L	305	272	208	226	227	245	170
Ammonia	88	88	88	88	89	90	87
Arsenic	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5
Barium	760	770	790	790	790	790	750
Boron	27	29	31	31	31	31	23
Bromide	76	75	75	77	77	70	75
Cadmium	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Calcium	7,860	7,890	7,920	7,990	7,940	7,970	7,920
Chloride	71,700	72,300	71,900	72,900	72,800	72,900	72,900
Chromium	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Copper	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Fluoride	1.4	1.5	1.7	1.8	1.9	1.7	1.7
Iodide	21	21	20	20	21	19	22
Iron	49	53	49	49	49	49	39
Lead	<1	<1	<1	<1	<1	<1	<1
Lithium	27	27	29	29	29	29	30
Manganese	18	18	17	17	17	17	15
Magnesium	590	590	584	588	585	588	584
Mercury	<0.025	<0.025	<0.025	<0.025	<0.025	<0.025	<0.025
Nickel	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25
Potassium	580	580	600	600	610	610	583
Silica, as SiO ₂	89	85	91	89	90	90	99
Sodium	36,700	36,500	35,900	36,700	36,100	35,900	37,400
Strontium	880	910	930	930	900	900	880
Sulfate	<1	<1	4	4	4	3	<5
Tin	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25
Zinc	0.3	0.2	0.4	0.4	0.4	0.4	0.5

^a All results in milligrams per liter unless otherwise specified.

Samples are collected just after the primary choke. The samples are cooled by passing through a water bath prior to flashing to atmospheric pressure and are collected under carbon dioxide.

The minimum detection limit for mercury has been raised from 0.005 to 0.025 mg/L.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit I-2, Part 4. PLEASANT BAYOU BRINE ANALYSES^a

Date	12 May 89	6 Jun 89	7 Jul 89	23 Aug 89	7 Nov 89	19 Dec 89	6 Feb 90
Laboratory	BEG	BEG	BEG	BEG	BEG	BEG	BEG
Brine Temp, °F	285	291	290	290	290	290	290
Sp Gravity @ 60°F	1.082	1.083	1.078	1.086	1.084	1.079	1.087
Total Dissolved Solids, mg/L	137,590	137,020	136,220	135,900	134,360	136,880	129,240
Alkalinity, as mg CaCO ₃ /L	210	280	284	243	265	299	378
Ammonia	85	86	85	87	86	85	88
Arsenic	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5
Barium	848	788	883	755	826	762	795
Boron	30	25	31	25	26	25	27
Bromide	78	76	76	80	83	81	84
Cadmium	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Calcium	8,220	7,900	8,450	7,860	8,220	8,230	7,900
Chloride	73,800	71,800	72,400	71,400	71,650	71,550	70,850
Chromium	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Copper	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Fluoride	1.7	1.7	1.7	1.7	1.6	1.6	1.4
Iodide	22	22	22	22	22	22	22
Iron	53	61	58	52	38	39	47
Lead	<1	<1	<1	<1	<1	<1	<1
Lithium	32	28	32	27	27	28	33
Manganese	19	16	19	16	14	15	18
Magnesium	609	581	615	573	621	595	581
Mercury	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
Nickel	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25
Potassium	555	608	525	567	639	606	582
Silica, as SiO ₂	118	105	120	102	101	100	117
Sodium	36,300	35,900	36,500	34,400	37,000	37,400	35,700
Strontium	937	934	978	841	992	981	933
Sulfate	<5	<5	<5	<5	<5	<5	<5
Tin	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25
Zinc	0.6	0.7	0.7	0.7	0.5	0.6	0.4

^a Copper (0.22 mg/L), Chromium (0.16 mg/L), and Nickel (0.35 mg/L) were found in the November 7, 1989, sample.

All results in milligrams per liter unless otherwise specified.

Samples are collected just after the primary choke. The samples are cooled by passing through a water bath prior to flashing to atmospheric pressure and are collected under carbon dioxide.

The minimum detection limit for mercury has been raised from 0.025 to 0.05 mg/L.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit I-2, Part 5. PLEASANT BAYOU BRINE ANALYSES^a

Date	22 Mar 90	19 Apr 90	6 Aug 90	4 Sept 90	19 Sept 90	8 Oct 90
Laboratory	BEG	BEG	BEG	BEG	BEG	BEG
Brine Temp, °F	291	290	291	292	294	294
Sp Gravity @ 60°F	1.085	1.085	1.090	1.087	1.085	1.083
Total Dissolved Solids, mg/L	140,480	137,680	136,760	135,400	136,400	133,400
Alkalinity, as mg CaCO ₃ /L	316	310	311	311	262	298
Ammonia	84	86	84	84	84	83
Arsenic	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Barium	797	770	805	800	772	749
Boron	27	26	22	21	25	25
Bromide	88	85	79	77	79	76
Cadmium	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Calcium	7,880	7,780	7,890	7,620	8,620	8,560
Chloride	70,500	70,100	71,750	71,700	71,500	70,500
Chromium	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Copper	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Fluoride	1.4	1.5	1.6	1.5	1.5	1.6
Iodide	20	21	21	20	22	21
Iron	42	41	42	42	41	43
Lead	<1	<1	<1	<1	<1	<1
Lithium	28	28	28	27	29	29
Manganese	16	16	15	15	15	15
Magnesium	602	586	595	571	626	626
Mercury	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
Nickel	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25
Potassium	602	599	536	544	688	687
Silica, as SiO ₂	111	109	111	107	110	116
Sodium	36,100	35,300	35,300	35,900	36,100	36,100
Strontium	904	887	906	935	918	929
Sulfate	<5	<5	<5	<5	<5	<5
Tin	<0.25	<0.25	<0.25	<0.25	<0.25	<0.25
Zinc	0.5	0.6	0.6	0.4	0.8	0.8

^a Chromium was found in the September 19, 1990, and October 8, 1990, samples at 0.11 mg/L, near the minimum detection limit of 0.10 mg/L. Nickel was also found at 0.31 and 0.32 mg/L, just above the minimum detection limit of 0.25 mg/L.

All results in milligrams per liter unless otherwise specified.

Samples are collected just after the primary choke. The samples are cooled by passing through a water bath prior to flashing to atmospheric pressure and are collected under carbon dioxide.

Exhibit I-3. COMPOSITION OF BRINE COLLECTED AFTER THE FILTER SKID^a

Date	<u>30 May 88</u>	<u>14 Jun 88</u>	<u>01 Jul 88</u>	<u>05 Aug 88</u>
Description	After Filter	After Filter	After Filter	After Filter
Brine Temp, °F	251	283	288	290
Sp Gravity @ 60°F	1.084	1.083	1.080	1.073
Total Dissolved Solids, mg/L	126,000	124,000	132,600	133,200
Alkalinity, as mg CaCO ₃ /L	308	314	231	246
Ammonia	--	--	--	--
Arsenic	<0.5	<0.5	<0.5	<0.5
Barium	811	802	755	769
Boron	23	23	24	25
Bromide	--	--	71	77
Cadmium	<0.1	<0.1	<0.1	<0.1
Calcium	7,530	7,730	7,820	7,950
Chloride	69,900	70,000	71,500	72,400
Chromium	<0.1	<0.1	<0.1	<0.1
Copper	<0.1	<0.1	<0.1	<0.1
Fluoride	--	--	1.6	1.7
Iodide	--	--	21	22
Iron	44	42	46	46
Lead	< 1	< 1	< 1	< 1
Lithium	29	30	31	31
Manganese	14	14	15	16
Magnesium	552	559	598	603
Mercury	--	--	<0.005	<0.005
Nickle	<0.25	<0.25	<0.25	<0.25
Potassium	526	537	545	561
Silica, as SiO ₂	100	105	106	106
Sodium	34,400	35,300	35,900	37,100
Strontium	834	842	869	843
Sulfate	--	--	2	5
Tin	--	--	<0.25	<0.2
Zinc	0.6	0.6	0.7	0.6

^a All results in milligrams per liter unless otherwise specified. Analysis by BEG.

Exhibit I-4. PROCEDURE TO MEASURE TRACE PHOSPHONATE LEVELS IN BRINE

The following procedure was adapted from a procedure provided by Dr. Mason Tomson and associates at Rice University.

Phosphonates are organic phosphorus compounds used to control scale formation. These compounds are UV-catalytically oxidized to orthophosphate by persulfate. The orthophosphate reacts with sodium molybdate in an acidic medium to form molybdophosphoric acid, which upon reduction with stannous chloride yields a blue-colored complex. This complex has a maximum absorbance at 725 nm and is measured spectrophotometrically.

Interferences

Silicates and arsenates react quantitatively with sodium molybdate to form blue heteropoly acids. The isobutyl alcohol extraction step is designed to eliminate these interferences, and those from other molybdo-metal complexes. Inorganic phosphates or phosphites present may also be included in the phosphonates determination, but their additive effects should be accounted for by the use of the sample blank solution. The following ions that occur in the brine waters may potentially interfere: Al, Fe(III), Mg, Ca, Ba, Sr, Li, Na, K, NH_4^+ , carbonate, nitrate, sulfate.

Apparatus

1. 2-oz Square Glass Bottles, reaction bottles
2. UV Lamp, Hach catalog #20823-00
3. Pipets, 10-ml, Class A; various Eppendorf pipets
4. Separatory Funnels, 125-ml
5. UV-VIS Absorption Cells, two matched, 5-cm path length
6. UV-VIS Spectrophotometer, Hitachi Model 100-60

Reagents

1. Perchloric Acid, 70% AR-grade
2. Molybdate Solution: Dissolve 25 g sodium molybdate in 250 ml deionized water (DDIW).
3. Stannous Chloride Solution: Dissolve 0.30 g AR-grade stannous chloride in 20 ml concentrated HCl and dilute to 250 ml with DDIW.
4. Isobutyl Alcohol, AR-grade
5. Methyl Alcohol, AR-grade
6. Potassium Persulfate Crystals
7. 1.00-ppm Phosphorous Solution: Prepared by diluting 1.0 ml of a 1000-ppm stock standard to 1000 ml with DDIW.

Procedure

1. Pipet an aliquot of 10 ml of sample into five reaction bottles. Pipet 1, 2, and 3 ml of the 1-ppm standard into three of the bottles, respectively. This results in spikes of 1, 2, and 3 ug P. Add 1 ml perchloric acid to each. Take appropriate care when dispensing perchloric acid. Allow the solutions to react until all solids are dissolved (approximately 5 minutes).
2. Add 0.1 g potassium persulfate crystals to each of the three spiked bottles and one of the unspiked bottles and immerse the UV lamp in each for 15 minutes.
3. Transfer the contents of each bottle to five separate 125-ml separatory funnels with DDIW washings. Make up to a constant volume with DDIW. To this add 4 ml perchloric acid and mix well. Then add 5 ml of the sodium molybdate reagent. Mix well again and wait exactly 10 minutes.
4. Add 40 ml isobutyl alcohol, stopper the funnel, and shake the contents vigorously for 60 seconds. Let the two layers separate and discard the aqueous phase (the bottom layer).
5. Add 25 ml DDIW, stopper and shake for 30 seconds. Let the two layers separate again and discard the aqueous. Repeat this washing twice.
6. Add 25 ml of the stannous chloride reagent and shake vigorously for 45 seconds. Let the layers separate.
7. Pipet 10 ml off from the top of the organic phase into a clean, dry screw-top test tube. Add 0.5 ml methyl alcohol to remove turbidity. Stopper and shake.

Calculation

A graph is made of ug P spike added (x-axis) versus absorbance (y-axis). The method of standard additions is used to extrapolate and calculate the ug of P present in the original sample.

$$\text{phosphonates, mg/L P} = \frac{\text{ug P from graph}}{\text{ml sample used}}$$

QA/QC

The multiple-point standard addition technique provides its own internal standard QC check. The curve should be a straight line and the correlation should not be less than 0.95. A replicate sample is run for every 10 samples.

Limits of Detection

With a 10-ml sample, the detection limit in typical brines will be 0.005 mg/L P.

References

1. C. H. Lueck and D. F. Boltz, *Analytical Chemistry*, 28, 1953, p. 1168.
2. *Standard Methods for the Examination of Water and Wastewater*, 15th Ed., American Public Health Association, Washington, D.C.

PARAMETRIC STUDY OF SEPARATOR PERFORMANCE

by

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TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

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ABSTRACT

After testing to determine reservoir characteristics of the HO&M Prairie Canal Co., Inc., Well No. 1, an additional flow test was performed to study operating characteristics of the separator used on tests of Wells of Opportunity. The separator study consisted of combining gas and brine flow-rate data with analyses of simultaneously collected gas and brine samples at each of six separator pressures in the range of 140 to 1029 psia. Brine temperatures at sample collection times varied between 187°F and 238°F. Temperatures, pressures, and brine chemistry were such that significant carbonate precipitation did not occur.

Total gas remaining in solution in brine leaving the separator varied between 0.6 and 7.0 SCF/bbl and was reasonably consistent with laboratory data on gas solubility. This dissolved gas contained 27 to 35 mole percent CO₂.

The partition of hydrocarbon species between the gas and brine was found to be a linear function of partial pressure of each species. At a methane partial pressure of 922 psia, 4.9 SCF of methane (11.6% of total produced) remained in solution in brine leaving the separator. For the gas compositions produced, separator efficiencies (percentage of component in the gas stream) varied between extremes as follows:

Gas Component	Separator Efficiency	
	at 140 psia	at 1025 psia
Gaseous CO ₂	83.4-86.0	36.0-39.6
CO ₂ +HCO ₃ ⁻ + CO ₃ ²⁻ as CO ₂	62.0-64.0	27.4-30.0
Methane	98.7-98.8	84.5-86.6
C2+	99.0-99.1	88.8-91.0

CO₂ content of flare line gas leaving the separator varied between extremes of 6.2 mole percent at 1029 psia and 11.6 mole percent at 140 psia. The sum of quantities of CO₂ in gas and brine from the separator also varied with operating conditions. However, total CO₂ content of produced brine including HCO₃⁻ and CO₃²⁻ was found to be constant.

The partition of hydrocarbons and CO₂ between gas leaving the separator and brine leaving the separator was found to depend upon temperatures as well as pressure. This dependence is such that thermal energy recovery from brine before separation would improve the quality of gas recovered at any specific separator pressure.

INTRODUCTION

Conduct of the three flow tests to determine reservoir and fluid properties of the HO&M Prairie Canal Co., Inc., Well No. 1 required numerous increases in separator pressure because of increasing injection pressure on the disposal well. Field data interpretation during those tests revealed substantial variations in CO₂ content of gas from the separator plus variations in total produced gas/brine ratio that appeared to correlate with separator pressure rather than production well conditions.

During the first two flow tests, a Rice University team headed by Drs. John Oddo and Mason Thomson was on location performing inhibitor studies. Their evaluation of scaling potential required knowledge of separator efficiency for CO₂ removal (Oddo and Thomson, 1981). Field interactions between IGT and Rice University personnel developed mutual understanding of the importance of equilibria between CO₂(g), CO₂(aq), HCO₃⁻, and CO₃²⁻ (the CO₂/HCO₃⁻/CO₃²⁻ system) in relation to both removal of CO₂ gas by the separator and the formation of carbonate scale. It was recognized that total inorganic carbon in this system should be constant but that the partition among species in the CO₂/HCO₃⁻/CO₃²⁻ system may well depend upon operating conditions. This in turn led to definition of a practicable sample collection and analysis procedure to provide relevant quantitative data.

An additional flow test was performed so that the sample collection and analysis procedure could be implemented for a wide range of separator pressures. Details of that flow test, presentation of data obtained, and interpretation of that data are covered in this paper.

PROCEDURES

Operational Constraints and Sample Collection

The March 5, 1981, study of separator performance was preceded by about 8 days of production involving three flow tests between February 21, 1981, and March 2, 1981. This operating experience defined operational constraints upon conduct of the separator study. The most significant of these were as follows:

- Brine rates in excess of 4500 bpd were accompanied by substantial sand production and rapidly increasing injection pressure at the disposal well.
- Operation at separator pressures less than 250 psig would require brine flow to the reserve pit which had to be minimal because the remaining pit capacity was limited.
- Reasonably stable operation was only possible in the range of separator pressures and temperatures encompassed by the points shown in Figure 1. These points are the brine temperatures and separator pressures at the times of collection of 52 gas samples analyzed during the entire sequence of well tests.

The overall effect of these constraints was that operation at low separator pressure required low production rates and that high separator pressure required high rates. This in turn resulted in higher brine temperatures for the higher separator pressures.

Production for the separator study began at 1940 hours on March 4, 1981. Since the wellhead had been cooling during a prior 2-day shut-in period, an initial flow rate of about 4500 bpd was selected to provide the fastest heating possible without excessive sand production and buildup of disposal well injection pressure. By 0030 hours on March 5, 1981, surface brine temperature had increased to above 200°F and reasonably stable

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Figure 1. BRINE TEMPERATURES AND SEPARATOR PRESSURES AT GAS SAMPLE COLLECTION TIMES

operation had been achieved. Therefore, the first suite of gas samples were collected at that time.

Changes in operating conditions for the separator study during March 5, 1981, are portrayed graphically in Figure 2. Collection of suites of samples for analysis after changes in brine production rate was delayed until after "bottoms up" following each change. In addition, an hour of consistent production following each change in separator pressure was a prerequisite for sample collection. Two suites of samples were collected for each of six different separator pressures. However, one of the samples collected at 266 psia was lost due to a leaky valve on the sample vessel.

Produced Gas/Brine Ratio

One-half-hour average flare line gas and brine production rates, corrected to 14.73 psia and 60°F, were deduced from orifice meter and separator brine turbine data using the procedures described in the companion paper, "Gas/Brine Ratios from Tests of Five Wells of Opportunity" by P. L. Randolph. Aspects of those procedures particularly relevant to the separator study are as follows:

- Orifice meter gas flow was calculated using measured gas composition for each separator pressure and with correction for water vapor content at orifice meter temperature.
- Brine Rate for each 1/2-hour interval was reduced to standard conditions using average values of separator pressure and brine temperature for that time interval plus properties of water.
- An estimate of gas content of brine to the disposal well was calculated for each 1/2-hour time interval using the algorithm developed by S. K. Garg for methane solubility in distilled water. (Garg et al., 1978).

Resultant calculated gas/brine ratios are shown in Figure 3. The ratio of flare line gas to produced brine and the calculated total produced gas/brine ratios are shown in the upper two curves. The lower portion of the figure shows calculated gas content of disposal well brine as well as measured values for quantity of gas liberated by reducing pressure on cooled brine to ambient temperature and pressure. Sampling and analysis procedures to develop these data points are described in the next section of this paper.

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Figure 2. OPERATING CONDITIONS FOR SEPARATOR STUDY, March 5, 1981

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Figure 3. GAS/BRINE RATIOS DURING SEPARATOR PERFORMANCE STUDY

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The largest excursions in flare line gas/brine ratio are due to changes in stored gas content of the separator during changes in pressure and flow rate. Gas/brine ratio was reasonably constant at the time of the collection of each suite of samples for analysis.

Gas/Brine ratios used for several calculations in this study are field data. Further data refinement at IGT showed minor differences between the actual produced gas/brine ratio shown in Figure 3 and gas/brine ratios used in the narrative of this paper. These minor differences do not affect trends and conclusions reached in this study.

Sampling and Analytical Procedures

To obtain definitive data on the partitioning of various gaseous species between the aqueous and gas phases in the separator, IGT collected and analyzed suites of samples in the following manner:

- Samples of flare line gas and brine after the separator were collected at separator pressure in preheated stainless steel pressure vessels.
- Gas chromatographic analyses were performed immediately on flare line gas samples.
- Brine samples were cooled to ambient temperature by immersion of the sample vessels in a cold water bath.
- After cooling, gas was liberated from the brine by reducing the pressure to 1 atmosphere using apparatus appropriate for quantitative determination of the released gas volume. The sample was agitated to promote equilibrium between the gas and the liquid phases.
- Gas chromatographic analysis was performed on the gas liberated during the pressure reduction.
- After reducing the pressure to 1 atmosphere, the brine volume was measured while simultaneously the carbon dioxide and carbonates were stabilized by addition of aqueous sodium hydroxide.
- A quantitative acid liberation/nitrogen purge was performed on an aliquot of the alkaline brine to measure the total inorganic carbon remaining in solution. This includes both dissolved carbon dioxide and carbonate species.
- An aliquot of untreated brine was titrated with 1N sulfuric acid to determine alkalinity, which was reported as bicarbonate. For total carbon dioxide calculations 1 mole of bicarbonate is equivalent to 1 mole of carbon dioxide, because the two species are indistinguishable using these analytical techniques.

The full procedure as described above was used only on samples collected on March 5, 1981. During earlier flow tests, many samples were analyzed that were not in suites of simultaneously collected gas and brine samples. The majority were flare line gas samples. These are useful in examining the effect of separator temperature on the quality of the gas recovered.

RESULTS

Gas Liberated by Pressure Reduction to 1 Atmosphere

Quantities of various gaseous species per stock tank barrel of brine determined from the flare line and from pressure reduction on brine to the disposal well are tabulated in Table 1. The right side of the table provides a tabulation of sums of these quantities. Means and standard deviations for these sums are also tabulated.

Examination of Table 1 reveals an overall increase in hydrocarbon gas/brine ratio during the experiment with possible perturbations associated with changes in brine production rate. The increase is most notable for the heavier hydrocarbons. We believe these variations are due to reservoir characteristics. They are substantially greater than those observed using the same field equipment and procedures on tests of aquifers whose gas content was below saturation.

In contrast, the CO_2 content of gas liberated by pressure reduction is greatest for the lowest separator pressure and does not vary in the same manner as hydrocarbon content of brine. This is due to the dependence of CO_2 liberated upon the pressure and temperature steps in the liberation process.

Total CO_2 Content of Produced Brine

After liberation of CO_2 by the separator and by pressure reduction to 1 atmosphere on cooled brine, a substantial quantity of CO_2 remains in the brine in the forms of

- Dissolved CO_2
- Bicarbonate (HCO_3^-) ions
- Carbonate (CO_3^{--}) ions.

All these species must be taken into account in relation to both gas production and formation of carbonate scale. Brine from the HO&M Prairie Canal Co., Inc., Well 1 had two characteristics that greatly facilitate understanding of gas production:

- Calcium and magnesium content of produced brine was too low for significant carbon loss due to carbonate scale formation at any of the pressure and temperature conditions of the experiment.
- The alkalinity titration did not reveal end points suggestive of interference from other chemical species.

Table 2 augments the previous sum of gases liberated by pressure reduction to 1 atmosphere. This augmentation consists of taking into account total CO_2 content, including $\text{CO}_2(\text{aq})$, HCO_3^- , and CO_3^{--} remaining in the cooled brine at 1 atmosphere pressure. Total CO_2 content of the brine is that from analysis of gases liberated by pressure reduction plus the CO_2 liberated from the remaining brine by acid. It averages 7.53 SCF/STB with a standard deviation of only 1.9 percent of this average.

The column labeled Total CO_2 Plus Hydrocarbons reflects the total quantity of gas

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Table 1. GAS LIBERATED BY PRESSURE REDUCTION

Date	Time	Flow Rate (STB/Day)	Separator Pressure (psia)	Brine Temperature °F	Flare Line (SCF/STB)					Disposal Well Brine (SCF/STB)					Sum (SCF/STB)				
					CO ₂	CH ₄	C ₂ H ₆	C ₃ +	Total	CO ₂	CH ₄	C ₂ H ₆	C ₃ +	Total	CO ₂	CH ₄	C ₂ H ₆	C ₃ +	Total*
5 Mar 81	2238	6050	1025	238	2.24	31.80	0.96	0.166	35.17	1.99	4.91	0.111	0.011	7.02	4.23	36.71	1.07	0.18	42.19
5 Mar 81	2112	6110	1029	235	2.12	30.59	1.00	0.194	33.90	2.19	4.69	0.107	0.011	7.00	4.31	35.28	1.11	0.21	40.91
5 Mar 81	1933	4260	630	221	3.05	33.14	0.95	0.150	37.29	1.44	2.73	0.061	0.005	4.24	4.49	35.87	1.01	0.16	41.53
5 Mar 81	1815	4300	632	216	2.89	34.07	0.99	0.157	38.11	1.50	2.73	0.061	0.006	4.30	4.39	36.80	1.05	0.16	42.40
5 Mar 81	1520	1730	140	187	4.98	36.65	0.99	0.133	42.75	0.19	0.46	0.010	0.001	0.66	5.17	37.11	1.00	0.13	43.41
5 Mar 81	1340	1790	140	187	4.64	34.58	0.94	0.125	40.29	0.16	0.43	0.010	0.001	0.60	4.80	35.01	0.95	0.13	40.89
5 Mar 81	1008	1760	266	187	3.81	34.27	0.91	0.122	39.11	0.55	1.13	0.025	0.002	1.71	4.36	35.40	0.94	0.12	40.82
5 Mar 81	0453	4160	487	215	3.22	32.99	0.90	0.123	37.23	1.15	2.06	0.044	0.004	3.26	4.37	35.05	0.94	0.13	40.49
5 Mar 81	0330	4180	485	213	3.09	31.89	0.86	0.119	35.96	1.23	2.25	0.048	0.004	3.53	4.32	34.14	0.91	0.12	39.49
5 Mar 81	0045	4240	360	204	3.46	32.44	0.84	0.115	36.86	0.72	1.43	0.030	0.003	2.18	4.18	33.87	0.87	0.12	39.04
5 Mar 81	0040	4240	360	204	3.46	32.44	0.84	0.115	36.86	0.85	1.26	0.026	0.002	2.14	4.31	33.70	0.87	0.12	39.00
		Mean Value													4.45	35.36	0.98	0.14	40.93
		Standard Deviation													0.29	1.18	0.08	0.03	1.41
		Standard Deviations as Percent of Mean Value													6.5	3.3	8.2	19	3.4

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Table 2. GAS CONTENT OF BRINE, INCLUDING ALL CARBON DIOXIDE

Date	Time	Flow Rate (STB/Day)	Separator Pressure (psia)	Brine Temperature °F	Gas Liberated From Cooled Brine by Pressure Reduction to One Atmosphere (SCF/STB)					Acid Liberated CO ₂ (SCF/STB)	"Total" CO ₂ (SCF/STB)	Alkalinity Bicarbonate as CO ₂ (SCF/STB)	Gaseous CO ₂ (SCF/STB)	Total CO ₂ Plus Hydrocarbons (SCF/STB)	Total Gaseous Species (SCF/STB)	Gaseous CO ₂ in Total Gas (Mole %)
					CO ₂	CH ₄	C ₂ H ₆	C ₃ ⁺	total							
5 Mar 81	2238	6050	1025	238	4.23	36.71	1.07	0.18	42.19	3.24	7.47	1.81	5.66	45.43	43.62	13.0
5 Mar 81	2112	6110	1029	235	4.31	35.28	1.11	0.21	40.91	3.41	7.72	1.84	5.88	44.32	42.48	13.8
5 Mar 81	1933	4260	630	221	4.49	35.87	1.01	0.16	41.53	3.13	7.62	1.86	5.76	44.66	42.80	13.5
5 Mar 81	1815	4300	632	216	4.39	36.80	1.05	0.16	42.40	3.19	7.58	1.89	5.69	45.59	43.70	13.0
5 Mar 81	1520	1730	140	187	5.17	37.11	1.00	0.13	43.41	2.56	7.73	1.94	5.79	45.97	44.03	13.2
5 Mar 81	1340	1790	140	187	4.80	35.01	0.95	0.13	40.89	2.68	7.48	1.92	5.56	43.57	41.66	13.3
5 Mar 81	1008	1760	266	187	4.36	35.40	0.94	0.12	40.82	2.99	7.35	1.94	5.41	43.81	41.87	12.9
5 Mar 81	0453	4160	487	215	4.37	35.05	0.94	0.13	40.49	3.16	7.53	1.86	5.67	43.65	41.79	13.6
5 Mar 81	0330	4180	485	213	4.32	34.14	0.91	0.12	39.49	3.28	7.60	1.81	5.79	42.77	40.96	14.1
5 Mar 81	0045	4240	360	204	4.18	33.87	0.87	0.12	39.04	3.28	7.46	—	—	42.32	40.45	13.8
5 Mar 81	0040	4240	360	204	4.31	33.70	0.87	0.12	39.00	2.96	7.27	—	—	41.96	40.09	13.5
Mean Value					4.45	35.36	0.98	0.14	40.93		7.53	1.87	5.69	44.01	42.13	13.4
Standard Deviation					0.29	1.18	0.08	0.03	1.41		0.14	0.05	0.14	1.34	1.33	0.4
Standard Deviation as Percent of Mean Value					6.5	3.3	8.2	18.9	3.4		1.9	2.7	2.5	3.0	3.2	2.9

• Hydrocarbons, plus CO₂ gas, plus acid liberated CO₂.

† Hydrocarbons, plus CO₂ gas, plus acid liberated CO₂, minus alkalinity CO₂ (mean values used where none others were available).

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that could be recovered from produced brine by acid treatment. The column labeled Gaseous Species is total gas recoverable from the brine without breakdown of HCO_3^- . As revealed in the last column, this gas would contain about 13.4 percent CO_2 . For the Prairie Canal well, these last two columns provide upper limits on gas recovery from a separator and CO_2 content of such recovered gas.

Effect of Separator Static Pressure on Gas Remaining in Post-Separator Brine

The relationship between the volume of gas remaining in the brine after the separator and the separator static pressure is given in Figure 4. The volume of gas increases approximately linearly with increasing pressure, but the y-intercept does not equal zero. Determining the quantity of each gaseous species resolves this apparent anomaly.

Figure 5 is a plot of the volume of methane liberated from the brine by a pressure reduction to 1 atmosphere versus the partial pressure of methane in the separator. The data form a straight line ($r^2 = 0.994$) with a y-intercept of -0.21 SCF/STB. This negative intercept is primarily due to the amount of methane remaining in the brine after the pressure reduction. The partial

pressure of methane above the brine varies from 8.65 psia to 10.43 psia after the pressure reduction, which would leave about 0.10 to 0.13 SCF/STB still dissolved in the brine (Yamamoto et al., 1976), assuming Henry's law is valid in this range.

Another factor which lowers the y-intercept is the previously discussed coupling of separator pressure and brine temperature due to operational constraints on this experiment. Samples collected at the lower separator pressures had lower temperatures because of the low brine production rates. Similarly, high separator pressures required high flow rates and therefore involved higher brine temperature.

The temperature dependence of methane solubility in water would cause more methane to remain in the brine at higher temperature-pressure regimes than would pressure alone in an isothermal system.

Figure 6 is a plot of the volume of ethane liberated from brine after the separator by a pressure reduction to 1 atmosphere. The data form a straight line ($r^2 = 0.989$) with a y-intercept of 0.0002 SCF/STB. The same factors that affect the slope of the methane plot should also affect the ethane plot. The values are much smaller than

Figure 4. DISPOSAL BRINE "TOTAL GAS" CONTENT VS. SEPARATOR STATIC PRESSURE

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Figure 5. DISPOSAL BRINE METHANE CONTENT
VS. METHANE PARTIAL PRESSURE

those of methane, and the scatter in the data prohibits a careful analysis of the plot. The scatter is even more pronounced in Figure 7, which is a plot of the sum of propane, butanes, and pentanes liberated from the disposal brine by reduction of pressure to 1 atmosphere. The plotted data form a straight line ($r^2 = 0.974$) with a y-intercept equal to 0.0004 SCF/STB.

These data clearly indicated that the quantities of hydrocarbons liberated from disposal brine are primarily dependent on the partial pressure of each hydrocarbon species in the gas phase of the separator. In addition, there is very little deviation from simple Henry's law plots that would consist of straight lines passing through the origin.

The behavior of carbon dioxide is very different from that of hydrocarbons. Figure 8 is a plot of the total inorganic carbon system versus the partial pressure of CO_2 in the separator. The total amount of CO_2 in the system remains relatively constant, as is indicated by the darkened circles forming a line across the top of the plot. The partitioning of this inorganic carbon helps explain why the total gas versus separator pressure plot does not have a zero-intercept.

The total amount of inorganic carbon left in the brine leaving the separator is shown by the open circles. The points are obtained by adding

the amount of CO_2 liberated at 75°F and 1 atmosphere to the CO_2 in solution at 75°F and 1 atmosphere, which is represented by the diamonds in the plot. The data points form a relatively straight line ($r^2 = 0.965$) with a y-intercept of 2.1 SCF/STB.

There are two factors which would move the y-intercept from the origin. The overriding factor we have identified is the presence of bicarbonate. As noted earlier, a mole of bicarbonate is indistinguishable from a mole of dissolved carbon dioxide with the analytical techniques employed. Titrations of the brine solution indicate that there is an average of 1.87 SCF CO_2 /STB of equivalent bicarbonate in solution. The bicarbonate, as determined by an acid titration, is expressed as SCF CO_2 /STB in the plot by the triangles.

Apparently the bicarbonate does not appreciably add to the partial pressure of carbon dioxide in the solution. The pH of the solution and the high partial pressure of carbon dioxide in the solution favor bicarbonate as the stable form. This evidence supports the practice of subtracting bicarbonate from the sum of the inorganic carbon before determining separator efficiency for removing carbon dioxide from the brine.

The separator pressure-brine temperature

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Figure 6. DISPOSAL BRINE ETHANE CONTENT VS. ETHANE PARTIAL PRESSURE IN SEPARATOR

coupling also affects the slope of the plot, but the effect is opposite to that of hydrocarbons. Hydrocarbon solubility in brine decreases with decreasing temperature to a minimum which occurs at about 160°F. Carbon dioxide solubility, however, increases with decreasing temperature in the temperature range discussed. The observed pressure-temperature coupling would tend to raise the y-intercept, and the effect would be more pronounced than in the hydrocarbon-brine systems. This may be the reason that the intercept of 2.1 SCF/STB is above the 1.87 SCF/STB CO₂ content of bicarbonate determined by titration.

Figure 9 summarizes the partial pressure dependence of all species reported. Hydrocarbon solubility characteristics appear remarkably consistent and markedly different from those of carbon dioxide. The behavior of each component deviates little from the linear dependence predicted by Henry's law.

Similar but less complete data have been obtained by IGT on tests of other wells. Figure 10 contains data on the volume of methane

liberated from disposal brine by a pressure reduction to 1 atmosphere versus the partial pressure of methane in the separator for three wells (Eaton Operating Company, 1981; Randolph and Rockar, 1981). The volumes are within a fairly small range for a given separator pressure. Many factors other than pressure are known to affect methane solubility in brine; these include temperature, salinity, and volume of carbon dioxide. In the absence of consideration of such factors, data from the Prairie Canal well test cannot be considered predictive of other wells, but the close agreement shown is encouraging for development of a prediction procedure.

Comparisons to Previously Published Data at Separator Pressures and Temperatures

Interpretation of data from the test of the Wainoco P. R. Girouard Well No. 1 included testing of published algorithms for calculating methane solubility in brines against observed gas content of brine from the separator (Eaton Operating

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Figure 7. DISPOSAL BRINE C3+ CONTENT VS. C3+ PARTIAL PRESSURE

Company, 1981). It was concluded that the algorithm developed by S. K. Garg et al. (1978) for methane solubility in distilled water provided a reasonably accurate estimate of total gas liberated from separator brine by pressure reduction to 1 atmosphere. Comparisons were made between values calculated with this algorithm and measured values for the 25 analyses of gas from brine during tests of this well. Agreement was within 0.5 SCF/STB for all but three data points. Those three data points were all for samples collected when free gas was believed entrained in brine to the disposal well because of the combination of high brine rate and sand loading in the separator. The algorithm provided similarly excellent agreement with the small number of data points from the Riddle-Saldana Well No. 2 (Eaton Operating Company, forthcoming) and the Pleasant Bayou No. 2 Well (Randolph and Rockar, 1981).

Figure 11 provides comparisons between data from the controlled study of separator performance and reported laboratory data points on methane solubility in distilled water at 220°F. Actual laboratory data points from the papers by J. E. Davis and J. J. McKetta (1980) and by O. L. Culberson and J. J. McKetta (1951) are shown. Lines connecting these points were drawn only to illustrate data trends. The circles on this figure again illustrate the excellent agreement

between total gas liberated from separator brine by pressure reduction to 1 atmosphere after cooling and the data published by Culberson and McKetta. (The Garg algorithm [Garg et al., 1978] was developed to fit the data of Culberson and McKetta.)

Total gas content of separator brine, including CO₂ liberated by acid, is greater than laboratory observed solubility of methane in distilled water. On the other hand, methane content of brine from the separator is only 50 to 80 percent of laboratory measured methane solubility in distilled water. This reflects a greater depression of methane solubility than could be caused by the modest amount of dissolved solids in brine from this well (43,000 mg/l).

Figure 12 provides a comparison between measured CO₂ content of brine from the separator and laboratory data points on CO₂ solubility in distilled water at 212°F published by G. Houghton, A. M. McLean, and P. O. Ritchie (1957). As previously shown in Figure 8, the y-axis intercept of field data is primarily due to HCO₃⁻ and CO₃²⁻ species in the brine. The difference in slopes of the two lines exceeds reasonable expectation for solubility depression due to dissolved salts. Depression of CO₂ solubility by dissolved hydrocarbons is hypothesized to be a major factor.

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Figure 8. CARBON DIOXIDE PARTITIONING AMONG EXPERIMENTAL STEPS

Effect of Separator Pressure and Temperature Upon Quality of Gas

Figure 13 shows CO_2 content of flare line gas vs. separator pressure for 44 of the 52 flare line gas samples analyzed in the field during the test of the HO&M Prairie Canal Co., Inc., Well No. 1. The other 8 samples were collected during times of transient conditions that often cause anomalous gas compositions. A substantial portion of the scatter in the points shown is still due to long-term variations of both composition of produced gas and the produced gas/brine ratio.

The symbols for plotted points are coded for 25°F ranges in brine temperature. Lines on the graph have been drawn to roughly indicate areas characterized by these temperature ranges. These lines are not isotherms from data interpretation or from theory.

The CO_2 content of separator gas at the highest brine temperatures achieved varied between 11.6% at a separator pressure of 125 psig and 6.2% at a separator pressure of 1014 psig. For lower

temperatures at any specific pressure, CO_2 content of gas is reduced.

Figure 14 shows the relationship between heating value of gas from the separator and separator pressure for several temperature ranges. Lines have again been drawn to provide an approximate separation of temperature ranges. The relationships are less clear than for CO_2 because of the long-term variations in natural gas liquids content of produced gas during the series of well tests. The range was between 0.75 and 1.0 gallons/MCF. Such range has a greater effect upon heating value of produced gas than upon volume.

Nevertheless, the observed range of heating values of about 920 to 975 Btu/SCF may well be significant in relation to gas sales. If separator pressure had to be as high as 1000 psig to meet CO_2 and heating value requirements of a gas sales contract from a well having the characteristics of Figures 11 and 12, the penalty would be about 5000 Btu of hydrocarbon energy left in each barrel of brine from the separator.

Although quantitative evaluation of various

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Figure 9. GAS LIBERATED FROM POST-SEPARATOR BRINE
VS. SEPARATOR PARTIAL PRESSURES

conceivable surface facilities is beyond the scope of this paper, it is interesting to note that recovery of thermal energy before separation of gas and brine would improve the quality of gas recovered at any particular separator pressure. Or from a different perspective, prior thermal energy recovery may permit lower separator pressure for gas meeting the quality criteria of a sales contract. Thus, quantity of gas marketed per barrel of produced brine could increase.

Separator Efficiency

Separator efficiency is defined as the percentage of specific species present in produced brine that leaves the separator through the gas line. This percentage is useful in relation both to consideration of scaling potential and to examining the trade-off between gas quality and gas recovery.

However, separator efficiency determined on one test will not be valid for other tests. This is because the absolute amount of each chemical

species remaining in separator output brine is dependent upon partial pressure in the separator for that species. This partial pressure is, in turn, dependent upon the gas composition and the separator pressure, not on the produced GWR.

Figure 15 shows separator efficiency as a function of separator pressure for CO₂, methane, and natural gas liquids (C2+). The points shown are those for all gas and brine samples that were simultaneously collected from the Prairie Canal well, including the separator study on March 5, 1981. Efficiencies for CO₂ are shown on two bases. The open circles are on the basis of total CO₂, including that liberated from HCO₃⁻ or CO₃²⁻ species by acid. The basis for the closed circles is gaseous CO₂ as estimated by subtracting CO₂ in the form of HCO₃⁻, determined by the alkalinity titration, from the total CO₂.

The scatter in points at any particular pressure is due both to variations in temperature and to changes in gas composition during the series of well tests. The effect of composition changes is particularly large for natural gas liquids (C2-C5 hydrocarbons).

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Figure 10. COMPARISON OF METHANE REMAINING IN DISPOSAL BRINE AFTER THE SEPARATOR FOR THREE WELLS

Effect of Brine Residence Time

IGT's work on Wells of Opportunity indicates that efficiency of the separator used is independent of brine residence time for residence times of 2 minutes or longer. The separator used consisted of a single 10-foot-long horizontal pressure vessel with an inside diameter of 38.5 inches. It had a minimum of internal baffles so that sand could be readily removed. The upper portion contained brine deflectors near the inlet. The lower half contained a weir so that three-phase separation was possible in the event of significant oil production. On the Prairie Canal well test the separator was operated with the brine level at mid-elevation and above the weir. Brine was removed from the "oil" outlet so that brine residence time was maximized. In the absence of sand, liquid volume was about 7.2 barrels so that a brine rate of 10,400 BPD would have given a 1-minute brine residence time.

The only data to date that suggest declining separator efficiency due to short residence time were obtained while producing brine at 6000 to 6500 STB/day after experiencing heavy sand production. That evidence consisted of the following:

- Calculated total produced gas/brine ratio was about 3 SCF/STB lower than those representative of both earlier and later test data.
- All five brine samples liberated excess gas upon pressure reduction to 1 atmosphere after cooling. For one of these, the excess was greater than 27 SCF/STB. The excess gas in this 300 ml brine sample would have occupied a bubble volume of about 1 ml at the separator pressure of 1014 psig at the time of sample collection.

Brine residence time when these data were collected was probably less than the 1.7 minute calculated from brine rate and separator volume. This is because sampling was preceded by heavy sand production and both ends of the separator were found to contain about 14 inches of sand after the test. Also, at the times of possible degraded separator efficiency, gas from the separator was oscillating between extremes of zero and about one million cubic feet per day with a period of about 1 minute. Whether brine rate out of the separator, and therefore residence time, was also varying is not known.

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Figure 11. COMPARISON BETWEEN SEPARATOR PERFORMANCE STUDY AND LABORATORY DATA ON METHANE SOLUBILITY

CONCLUSIONS AND OBSERVATIONS

Data and analyses support several conclusions of substantial relevance to both conduct of well tests on aquifers and to economics of energy production from aquifers.

1. Quantity of each hydrocarbon component of a gas mixture in solution in brine leaving a conventional separator can be estimated at constant temperature using a linear relationship to partial pressure of that component in the separator gas.
2. Total gas in solution in brine leaving a separator is consistent with the limited laboratory data on solubility of gases in brine at separator pressure and temperature. Consistency includes the depression of hydrocarbon solubility by CO_2 that has been observed in the laboratory at much higher pressures.
3. Carbon dioxide gas in the separator is but one entity in several equilibria between $\text{CO}_2(\text{g})$, $\text{CO}_2(\text{aq})$, HCO_3^- , CO_3^{--} , and carbonate solids. Carbonate solids were absent from surface facilities on the Prairie Canal well test, and the total equivalent CO_2 in the species present per barrel of brine was found to be constant. However, the fraction observed as CO_2 gas, and also total produced gas, was found to be dependent upon separator operating conditions.
4. Quality of gas from the separator increases with increasing separator pressure because solubility of CO_2 increases more rapidly than solubility of methane and solubility of natural gas liquids does not increase as fast as that of methane.
5. Thermal energy recovery from brine before the separator would improve the quality of gas recovered at any specific separator pressure. Or, conversely, in the particular case of a gas having the composition observed at the Prairie Canal well, prior cooling of brine may well increase marketable gas from single-stage separation by 2 to 4 SCF per barrel of brine.
6. Separator efficiency for gas recovery from brine is not an inherent characteristic of the

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Figure 12. COMPARISON BETWEEN MEASURED CO_2 CONTENT OF POST-SEPARATOR BRINE AND LABORATORY DATA ON CO_2 SOLUBILITY IN WATER

separator hardware. In addition to operating pressure, this efficiency is a function of brine temperature, gas composition, and produced gas/brine ratio.

7. Secondary recovery of gas from disposal brine is possible by using a second separator in series operating at a lower pressure. The feasibility of this recovery is governed by disposal well pressure requirements, salable gas requirements, and other economic factors.

A corollary outcome of this separator performance study is the focusing of attention on the importance and complexity of the $\text{CO}_2/\text{HCO}_3^-/\text{CO}_3^{--}$ system with respect to evaluating production from aquifers. Observations resulting from consideration of this system are as follows:

1. Heating value of hydrocarbons produced with each barrel of brine is a more relevant measure of energy production than standard cubic feet of gas produced.
2. Quantitative definition of the CO_2 component of produced gas requires simultaneous sampling of gas and brine streams plus analyses to define CO_2 content as CO_2 gas, $\text{CO}_2(\text{aq})$, HCO_3^- , and CO_3^{--} . These data should be obtained and analyzed at multiple separator pressures to establish validity of results obtained.

3. It is questionable whether laboratory studies of the NaCl brine/ CH_4/CO_2 system will provide an adequate basis for conclusions regarding saturation of real brines at reservoir pressure and temperature. This is due to the effect of HCO_3^- and CO_3^{--} observed on real well tests.
4. CO_2 content of recovered gas, and therefore total produced gas, may well differ between scaling and nonscaling surface conditions. Also, use of carbonate scale inhibitors that affect the equilibria between CO_2 , HCO_3^- , and CO_3^{--} may well change CO_2 content of gas through the orifice meter.

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Figure 13. CARBON DIOXIDE CONTENT OF FLARE LINE GAS VS. SEPARATOR PRESSURE

Figure 14. HEATING VALUE OF FLARE LINE GAS (Btu/SCF)

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Figure 15. SEPARATOR EFFICIENCY VS. SEPARATOR PRESSURE FOR VARIOUS FRACTIONS

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30(3000)/PSSP

Representative Brine Analysis Report From
the Bureau of Economic Geology

ANALYSIS REPORT

Page 1

UNIVERSITY STATION, BOX X
AUSTIN, TEXAS 78713-7506
(512) 471-7721 (ext. 426)

MINERAL STUDIES LABORATORY
BUREAU OF ECONOMIC GEOLOGY
THE UNIVERSITY OF TEXAS AT AUSTIN

STEVEN W. TWEEDY
CHIEF CHEMIST

INVESTIGATOR:
C. HAYDEN

PROJECT/ACCOUNT:
IGT - PL. BAYOU

DATE:
JANUARY 30, 1990

REPORT #:
R-096-89

MSL ID#: 89-986, 89-987, 90-001, and 90-002

SAMPLE PREPARATION / TREATMENT

These samples were analyzed on an as received basis. For all analyses, the samples were shaken prior to removing an aliquot for analysis to include any precipitated solids.

SAMPLE ANALYSIS METHODS

Constituents	Technique	MSL Procedure #
Na, K, Mg, Ca, Fe, Mn, Sr, Ba, Zn, Li, SiO ₂ , Cr, Cu, Ni, As, Cd, Pb, Sn, B	ICP-OES	SWI 1.6 SWI 1.5
Mercury	Cold-Vapor AA	-----
Ammonia (NH ₃)	Distillation- titration	MSL 001
Chloride	Titration	SWI 1.1
Sulfate	Turbidimetric	SWI 1.3
Bromide	Spectrophotometric	SWI 1.2
Iodide	Spectrophotometric	SWI 1.4
Fluoride	Ion Electrode	SWI 1.11
Alkalinity	pH Titration	-----
Density, TDS	Gravimetric	-----

RESULTS

Sample analysis results are presented in Table 1. The associated QA/QC analysis results are presented in Tables 2 and 3.

COMMENTS

This completes the requested analyses for these samples.

SAMPLE DISPOSITION:

The remains of these samples are being archived at the MSL.

ANALYSTS:

HP Herrera, Tweedy

< less than indicated value

nd - not determined

* reported value near detection limit

Ins - Insufficient sample

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

ANALYSIS REPORT

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MINERAL STUDIES LABORATORY
BUREAU OF ECONOMIC GEOLOGY
THE UNIVERSITY OF TEXAS AT AUSTIN

STEVEN W. TWEEDY
CHIEF CHEMIST

TABLE 1
SAMPLE ANALYSIS RESULTS

MSL ID#	SAMPLE ID#	SAMPLE DATE	Na (mg/L)	K	Mg	Ca	Fe	Mn
89-986	P.B. (1:1)	07-NOV-89	37100	597	621	8270	38.6	14.6
89-987	PL. Bayou	07-NOV-89	37000	639	621	8220	38.0	14.4
90-001	PL. Bayou	19-DEC-89	37400	606	595	8230	39.2	14.9
90-002	P.B. (1:1)	19-DEC-89	38400	631	616	8500	39.4	15.0

MSL ID#	Cr (mg/L)	Cu	Ni	Zn	As	Cd	Pb	Sn	Li
89-986	*0.15	*0.19	*0.32	0.62	<0.10	<0.1	<1.0	<0.25	27.3
89-987	*0.16	*0.22	*0.35	0.49	<0.10	<0.1	<1.0	<0.25	27.4
90-001	<0.1	<0.1	<0.25	0.61	<0.10	<0.1	<1.0	<0.25	27.8
90-002	<0.1	<0.1	<0.25	0.65	<0.10	<0.1	<1.0	<0.25	27.5

MSL ID#	Sr (mg/L)	Ba	B	SiO2	NH3	Alk. (meq/L)	Density (g/cc)	TDS (mg/L)
89-986	985	835	25.8	104			1.042	133620
89-987	992	826	25.7	101	85.7	5.30	1.084	134360
90-001	981	762	24.7	100	85.2	5.99	1.079	136880
90-002	1030	795	24.5	99.3			1.050	129280

MSL ID#	Cl (mg/L)	Br	I	SO4	F	Hg
89-986	71520					
89-987	71650	83.4	22.0	<5	1.60	<0.05
90-001	71550	81.4	21.7	<5	1.60	<0.05
90-002	71180					

< less than indicated value

nd - not determined

* reported value near detection limit

Ins - Insufficient sample

ANALYSIS REPORT

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CHIEF CHEMIST

TABLE 2
REFERENCE SAMPLE RESULTS

MSL ID#	Na (mg/L)	Mg	Ca	K	Sr	Fe	Mn
Standard Sea Water:	11038	1331	420	406	8.2		
Accepted:	11040	1320	422	409	8.1		
Bias	-2	11	-2.0	-3.0	0.1		
% Bias	-0	1	-0.5	-0.7	0.7		
EPA 18 TM#2:						1.840	1.022
Accepted:						1.852	0.989
Bias						-0.012	0.033
% Bias						-0.648	3.337

MSL ID#	Zn (mg/L)	Cr	Cu	Ni	As	Cd
EPA 18 TM#2:	1.677	0.204	0.494	0.347	<0.10	0.448
Accepted:	1.656	0.191	0.492	0.320	0.02	0.445
Bias	0.021	0.013	0.002	0.027		0.003
% Bias	1.268	6.806	0.407	8.438		0.674

MSL ID#	Pb (mg/L)	Cl	Br	SO4	F
Standard Sea Water:		19390	72.0	2692	1.39
Accepted:		19373	69.0	2776	1.40
Bias		17	3.0	-84	-0.01
% Bias		0	4.3	-3	-0.71
EPA 18 TM#2:	0.278				
Accepted:	0.392				
Bias	-0.114				
% Bias	-29				

	I (mg/L)	SiO2 (90-001)	SiO2 (90-002)
SAMPLE	4.27	100.1	99.3
SAMPLE + SPIKE	6.16	106.0	108.3
AMT SPIKE	2.00	10.7	10.7
% RECOVERY	98.2	95.7	98.5

< less than indicated value

nd - not determined

* reported value near detection limit

Ins - Insufficient sample

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

ANALYSIS REPORT

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Page 4

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TABLE 3
REPLICATE SAMPLE RESULTS

MSL ID#	Na (mg/L)	Mg	Ca	K	Sr	Ba	Fe	Mn	Zn	Li
89-0987A	36948	621	8221	639	992	826	38.0	14.4	0.49	27.4
89-0987B	36629	618	8191	629	1003	827	35.0	13.4	0.48	25.7
89-0987C	36609	620	8218	615	973	825	37.3	14.3	0.49	26.9
MEAN	36729	620	8210	628	989	826	36.8	14.0	0.49	26.7
STDEV	190	2	17	12	15	1	1.6	0.6	****	0.9
RELSTDEV	5e-01	****	2e-01	2	2	****	4.3	3.9	1.52	3.3
MSL ID#	SiO2 (mg/L)	Cr	Cu	Ni	As	Cd	Pb	Sn		
89-0987A	101	0.16	0.22	0.35	<0.10	<0.1	<0.4	<0.25		
89-0987B	96.3	0.21	0.33	0.43	<0.10	<0.1	<0.4	<0.25		
89-0987C	101	0.14	0.14	0.30	<0.10	<0.1	<0.4	<0.25		
MEAN	47	0.17	0.23	0.36						
STDEV	1	0.04	0.09	0.066						
RELSTDEV	3	21.2	41.5	18.2						
MSL ID#	B (mg/L)	NH3	Alk. (meq/L)	Density (g/cc)	TDS (mg/L)	Cl (mg/L)	Br	I		
89-0987A	25.7	85.7	5.30	1.084	134360	71645	83.4	22.0		
89-0987B	24.3	86.5	4.23	1.084	137520	71774	82.8	22.0		
89-0987C	25.4	86.6	5.16	1.081	138520	71413	83.3	21.4		
MEAN	25.7	86.3	4.90	1.083	136800	71611	83.2	21.8		
STDEV	0.7	0.5	0.58	0.002	2171	183	0.3	0.3		
RELSTDEV	2.9	0.6	11.9	0.160	2	3e-01	0.4	1.6		
MSL ID#	SO4 (mg/L)	F	Hg							
89-0987A	<5.0	1.6	<0.05							
89-0987B	<5.0	1.6	<0.05							
89-0987C	<5.0	1.6	<0.05							
MEAN		1.6								
STDEV		0.0								
RELSTDEV		0.0								

< less than indicated value

nd - not determined

* reported value near detection limit

ins - insufficient sample

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

GET pH 21 # 1229
Id.#1 89-987
Id.#2 1
C00= 10 ml
pH(init) 6.80

V/ml pH
EP1 3.216 3.70
RS1 .0053 mol/l
RS2 5.30 mmol
#EP not corresponding
stop volt.reached
=====

date 90-01-05 time 09:51
GET pH 21 # 1229
1.0ml/div $\Delta pH=1/\text{div}$
start V .000 ml

date 90-01-05 time 10:56
GET pH 21 # 1230
Id.#1 89-987
Id.#2 2
C00= 10 ml
pH(init) 6.70

V/ml pH
EP1 1.132 5.79
EP2 2.564 4.59
EP3 2.841 4.23
EP4 3.214 3.70
RS1 .0019 mol/l
RS2 1.87 mmol
RS3 .0042 mol/l
RS4 4.23 mmol
stop volt.reached
=====

date 90-01-05 time 10:57
GET pH 21 # 1230
1.0ml/div $\Delta pH=1/\text{div}$
start V .000 ml

date 90-01-05 time 11:51
GET pH 21 # 1231
Id.#1 89-987
Id.#2 3
C00= 10 ml
pH(init) 6.63

V/ml pH
EP1 3.133 3.83
RS1 .0052 mol/l
RS2 5.16 mmol
#EP not corresponding
stop volt.reached
=====

date 90-01-05 time 11:51
GET pH 21 # 1231
1.0ml/div $\Delta pH=1/\text{div}$
start V .000 ml

date 90-01-03 time 14:10
GET pH 21 # 1223
Id.#1 90-001
Id.#2 0
C00= 25 ml
pH(init) 6.44

V/ml pH
EP1 9.089 3.71
RS1 .0060 mol/l
RS2 5.99 mmol
#EP not corresponding
stop volt.reached
=====

date 90-01-03 time 14:11
GET pH 21 # 1223
1.0ml/div $\Delta pH=1/\text{div}$
start V .000 ml

PLEASANT BAYOU ALKALINITY
(HCl = 0.01648 N)

APPENDIX J
Gas Analyses

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

This appendix contains details of gas analysis methods and the results of analyses of samples taken from various points in the flow system. Exhibits include --

Exhibit J-1 -- Methods used to determine the major components in a gas.

Exhibit J-2 -- Methods used to determine the minor components in a gas.

Exhibit J-3 -- Results of analyses by IGT of twenty-five samples taken from the sales/flare meter run.

Exhibit J-4 -- Results of analyses by Core Laboratories, Inc., of five samples taken from the sales/flare meter run.

Exhibit J-5 -- Results of analyses by IGT of fourteen samples taken from the large separator meter run.

Exhibit J-6 -- Results of analyses by Core Laboratories, Inc., of seven samples taken from the large separator meter run.

Exhibit J-7 -- Results of the analyses by IGT of eleven samples taken from the small separator meter run.

Exhibit J-8 -- Results of analyses by Core Laboratories, Inc., of seven samples taken from the small separator meter run.

The Gas Processors Association's *Tentative Method of Test for Hydrogen Sulfide in Natural Gas Using Length of Stain Tubes* (1977).

Exhibit J-1. DETERMINATION OF THE MAJOR COMPONENTS IN A GAS

Principle

Determination and quantitation of gaseous fuels is accomplished by gas/solid and gas/liquid chromatographic separation.

Scope

This gas chromatographic method is for the quantitative determination of the major components in a gas sample. The compounds that are analyzed include the fixed gases and the saturated and unsaturated hydrocarbons between methane and hexane with a hexane and heavier (C6+) backflush. The typical limit of detection is 0.01 volume percent.

Apparatus

Hach-Carle Series 500 multi-oven, multi-valve, multiple column bypass microprocessor-controlled gas chromatograph with thermal conductivity detector (TCD) and flame ionization detector (FID).

Digital Manometer (0 - 1000 torr absolute)

Vacuum Manifold attached to Sample Inlet

PE-Nelson "Turbochrom" P.C.-Based Data System

Instrument Parameters: Hach-Carle Series 500 Gas Chromatograph

Columns

<u>#</u>	<u>Length</u>	<u>Mesh</u>	<u>Description</u>
1	20"	45/60	28% DC 200/500 on Chromosorb P-AW
2	6'	60/80	3% Sabaconatrille on Carbopack B
3A	8"	60/80	0.4% Carbowax 1500 on Carbopack B
3B	16'	80/100	0.1% Carbowax 1540 on Spermasil XOB-015
4A	17'	45/60	27.5% Bis-2-(EE)A on Chromosorb P-AW
4B	12'	80/100	2.7% Carbowax 1540 on Porasil C
5	9"	50/80	80% Porapak N + 20% Porapak Q
6A	4'	80/100	Molecular Sieve 13X
6B	9'	45/60	Molecular Sieve 13X
7	3'	80/100	Molecular Sieve 5A
8	4"	45/60	Molecular Sieve 13X

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Column Temperatures

	<u>Oven 1</u>	<u>Oven 2</u>
Initial Col Temp, °C	70	68
Initial Hold, min	23	8
Program Rate #1, °C/min	NA	2
Program Rate #2, °C/min	NA	NA
Final Temp, °C	70	100
Hold Time, min	NA	12.5
Injection Temp, °C	180	180
Flow Rate -- Gas	30-He; 30-N2	30-He
Column Pressure, 9 psig	100-He; 60-N2	100-He
Split Ration, ml/min	NA	NA
Detector Type	TCD	FID
Detector Temp, °C	180	150

Valve Timing

<u>Valve Description</u>		<u>Time, min</u>
Sample Isolation	(V3)	0.01
TCD Injection	(V4)	0.10
Mol Sieve Isolation	(V5)	3.70
(Propane +) Backflush	(V4)	10.50
Mol Sieve Return	(V5)	10.75
FID Injection	(V1)	23.10
(Hexane +) Backflush	(V1)	25.75
C4 and C5 Separation	(V2)	28.50
V2 Return	(V2)	58.50

Quantitation

The quantitation method uses relative response factors with normalization of the sample to 100%. All response factors are calculated with reference to methane determined by the TCD. Methane is assigned the RRF value of 10.000.

Summary of Method

Sample Preparation

Stainless steel gas cylinders are heated to ~60°C before sampling to ensure vaporization of any condensed hydrocarbons.

Preparation of Instrument

The temperature set points of the instrument are checked and the flame is ignited before the first standard is analyzed. No other instrument preparation is necessary.

Sample Analysis

The gas sample is introduced into the GC via a vacuum manifold sampling system consisting of a fine needle valve and a digital manometer. The vacuum manifold is used for sub-ambient pressure samples and linearity checks. Two chromatographic methods are used in this analysis. The first is a column-isolation method that analyzes for the non-hydrocarbon gases, CH₄, and the C₂'s using a thermal conductivity detector. Hydrogen is detected using the hydrogen transfer tube (HTT) with an auxiliary N₂ carrier gas. The second method is a column bypass method that analyzes only for hydrocarbons with the flame ionization detector. This method will resolve the unsaturated C₄ isomers and is used for a refinery gas-type analysis. The C₆+ backflush peak also includes any pentadienes.

The two chromatographic methods are run in series. Therefore, two separate injections are made at different times. This is accomplished through the use of the sample loop isolation valve (V3) in the instrument. The first injection is for the TCD analysis, which requires approximately 20 minutes, followed by the second injection for the FID analysis. The total running time is 60 minutes.

Standards are run daily depending on the types of samples to be analyzed that day. Several standards are used for calibration. These include synthesis gases, IGT certified natural gas standards, refinery gas standards, and other various gas standards. In addition to these standard mixtures, air is injected routinely to calculate the oxygen/argon RRF. All response factors are recorded in a lab notebook to monitor operation of the instrument.

List of Components

<u>TCD</u>	<u>Expected Retention Time, min</u>	<u>FID</u>	<u>Expected Retention Time, min</u>
Hydrogen	3.22	C6+ (Backflush)	27.19
Carbon Dioxide	4.93	Methane	27.90
Ethene	6.70	Ethane + Ethene	28.46
Ethane	8.20	Acetylene	29.15
Acetylene	9.70	Propane	30.35
Oxygen/Argon	11.07	Propene	31.10
Nitrogen	12.00	Propadiene	31.70

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

<u>TCD</u>	<u>Expected Retention Time, min</u>	<u>FID</u>	<u>Expected Retention Time, min</u>
Methane	14.40	Methyl Acetylene	35.50
Carbon Monoxide	15.80	i-Butane	38.38
		n-Butane	40.60
		I-Butene	40.87
		i-Butene	41.40
		t-2-Butene	42.87
		c-2-Butene	43.35
		1,3 Butadiene	44.80
		Pentene	46.70
		i-Pentene	50.70
		n-Pentene	54.63
		I-Pentene	54.83
		t-2-Pentene	56.04
		c-2-Pentene	58.00
		Pentene	58.60

Data Processing

All components are calculated as volume percent of the original sample. A computerized report format calculates the Heating Value and Relative Density from the volume percent, and all components are also reported as weight percent. The Heating Value and Relative Density calculations are based on ASTM Method D-3588.

Quality Assurance/Quality Control

All standard runs are recorded in a laboratory notebook with their Relative Response Factors (RRF) for that day. Day-to-day reproducibility and trends are checked for each entry.

Time

Instrument Time: 1 hour
Analyst Time: 45 minutes

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit J-2. DETERMINATION OF HEXANE AND HEAVIER COMPONENTS IN A GAS

Principle

Quantitation of hydrocarbons is accomplished by a gas/liquid chromatographic separation.

Scope

This analysis is for the quantitation and identification of trace components that have boiling points between pentane (C5) and approximately dodecane (C12) in a gas by high-resolution capillary column gas chromatography/flame ionization detection (HRCC-GC/FID). The analytical report includes the volume percent of benzene, toluene, xylenes, and the remainder of the sample by carbon number. The typical range of analysis is between 0.5 and 1000 ppmv.

Apparatus

Sigma 1 Capillary GC

Heated Gas Sampling Valve

PE-Nelson "Turbochrom" P.C.-Based Data System

Instrument Parameters: Sigma 1 Capillary GC

Column	60-meter DB-5; RSL-200' or equivalent
Column Temp Program	
Initial Col Temp, °C.	0
Initial Hold, min	1
Program Rate #1, °C/min	5.0
Program Rate #2, °C/min	NA
Final Temp, °C	275
Hold Time, min	0 19
Injection Type	1-ml Gas Loop (Heated)
Injection Temp, °C	325
Flow Rate -- Gas	NA
Column Pressure, psig	30
Split Flow, ml/min	300
Detector Type	FID
Detector Temp, °C	300

Quantitation

Quantitation is performed by an internal standard calculation relative to the butanes and/or pentanes determined from the procedure for the Major Components in a Gas Analysis. The

specified aromatic compounds are tabulated separately, and their contribution to the chromatogram areas are subtracted from the appropriate carbon-number range. The remaining compounds are tabulated by carbon number ending at each *n*-alkane.

Summary of Method

Sample Preparation

The gas cylinders are heated to ~60°C before sampling to ensure vaporization of any condensed hydrocarbons.

Preparation of Instrument

The capillary column is heated to 275°C for approximately 1/2 hour to bake off contaminants that have accumulated overnight before the first standard injection. The appropriate sensitivity range is selected for the standard that is selected. A gas standard of 1000 ppmv *n*-alkanes (CH₄ - C₆) is run in duplicate and checked for reproducibility of the peak areas and retention times. The second injection is allowed to run to the end of the column temperature program to clean the column and serve as a blank for the sample.

Sample Analysis

The gas standard and samples are injected using a 1-ml heated gas sampling loop connected to the split/splitless injection port of the gas chromatograph. The injection is split at a flow rate of 300 ml/min.

List of Components

<u>Compound</u>	<u>Expected Retention Time, min</u>
i-Butane	2.95
<i>n</i> -Butane	3.50
neo-Pentane	3.75
i-Pentane	5.40
<i>n</i> -Pentane	6.30
<i>n</i> -Hexane	10.50
Benzene	12.65
<i>n</i> -Heptane	15.15
Toluene	17.60
<i>n</i> -Octane	19.50
Ethyl Benzene	21.80

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

<u>Compound</u>	<u>Expected Retention Time, min</u>
<i>m,p</i> -Xylene	22.20
<i>o</i> -Xylene	23.15
<i>n</i> -Nonane	24.05
<i>n</i> -Decane	28.00
<i>n</i> -Undecane	31.50
Naphthalene	34.45
<i>n</i> -Dodecane	34.70

Data Processing

The quantitation method uses an internal standard that was obtained from the procedure for Major Components in a Gas Analysis. This is typically one of the butanes or pentanes. The specified aromatic compounds are tabulated separately, and their areas are subtracted from the appropriate carbon-number range. The remaining compounds are tabulated by carbon number ending at each *n*-alkane.

All components are calculated by volume percent from the internal standard compound that was used.

Sample Calculation

$$\text{Conc}_i (\text{ppmv}) = (\text{Area}_i) * [\text{Conc}_s (\text{ppmv})] / (\text{Area}_s) * (\text{MW}_s) / (\text{MW}_i)$$

$\text{Conc}_i (\text{ppmv})$ = Concentration of Analyte (i)

Area_i = Area of Analyte (i)

MW_i = Molecular Weight of Analyte (i)

$\text{Conc}_s (\text{ppmv})$ = Concentration of Internal Standard

Area_s = Area of Internal Standard

MW_s = Molecular Weight of Internal Standard

Quality Assurance/Quality Control

The standard is checked for the correct retention time and peak areas of the components present.

Time

Instrument Time: 3 hours

Analyst Time: 1 hour

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit J-3, Part 1. PLEASANT BAYOU WELL SALES/FLARE METER GAS ANALYSES BY IGT^a

Date	30 May 88 ^b	17 Jun 88	22 Jul 88	29 Aug 88	25 Sept 88	02 Nov 88	20 Jan 89
Pressure, psia	342	397	397	400	395	388	391
Gas Temp, °F	90	99	107	100	98	80	78
Brine Temp, °F	267	290	286	291	290	285	290
<u>Mole Percent of:</u>							
Helium	0.009	0.019	0.009	0.009	0.009	0.008	0.008
Hydrogen	0.055	0.026	0.023	0.026	0.020	0.019	0.020
Nitrogen	0.49	0.51	0.53	0.55	0.52	0.51	0.55
Carbon Dioxide	10.9	10.7	10.3	10.3	10.3	10.3	10.3
Methane	84.2	84.4	84.8	84.8	84.8	84.8	84.8
Ethane	2.87	2.91	2.93	2.91	2.89	2.93	2.93
Propane	0.89	0.93	0.93	0.93	0.95	0.96	0.93
iso-Butane	0.14	0.15	0.15	0.15	0.15	0.15	0.15
n-Butane	0.13	0.14	0.13	0.14	0.14	0.14	0.13
iso-Pentane	0.04	0.04	0.03	0.04	0.04	0.04	0.04
n-Pentane	0.02	0.02	0.02	0.02	0.02	0.02	0.02
neo-Pentane	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Hexanes	0.015	0.016	0.014	0.016	0.016	0.016	0.014
Heptanes	0.022	0.024	0.019	0.024	0.022	0.025	0.020
Octanes	0.009	0.012	0.008	0.012	0.009	0.012	0.008
Nonanes	0.002	0.001	0.001	0.001	0.001	0.002	0.001
Decanes	0.001	0.001	BDL	0.001	BDL	0.001	BDL
Undecanes	0.002	0.001	BDL	0.001	BDL	0.001	BDL
Dodecanes	0.003	0.001	BDL	0.001	BDL	0.001	BDL
Tridecanes	0.001	BDL ^c	BDL	BDL	BDL	BDL	BDL
Tetradecanes +	0.001	BDL	BDL	BDL	BDL	BDL	BDL
Benzene	0.065	0.058	0.040	0.060	0.048	0.055	0.044
Toluene	0.040	0.033	0.019	0.037	0.022	0.031	0.021
C2 Benzenes	0.020	0.014	0.005	0.015	0.006	0.012	0.005
C3 Benzenes	0.009	0.005	0.001	0.004	0.001	0.003	0.001
Naphthalene	0.004	BDL	BDL	BDL	BDL	0.002	BDL
C1 Naphthalenes	0.005	BDL	BDL	0.001	BDL	BDL	BDL
C2 Naphthalenes +	0.002	BDL	BDL	BDL	BDL	BDL	BDL
<u>Heating Value, Btu/SCF</u>							
Dry, 14.69 psia, 60°F	944	947	948	951	949	952	949
Gravity (air=1.000)	0.694	0.692	0.686	0.689	0.687	0.689	0.687
Gal/1000 SCF	1.19	1.20	1.18	1.21	1.19	1.22	1.19
Gal/1000 SCF, CO ₂ -Free	1.33	1.35	1.32	1.35	1.33	1.36	1.33

^a Analyses performed at IGT using gas chromatography with TC and FID detectors. Ideal Gas Gravity (air=1) and Heating Value were calculated following the procedures in ASTM D-3588-91.

Ideal Natural Gas Liquids Content was calculated treating the gas as an ideal gas. Values are at 14.69 psia and 60°F. Input data were obtained from ASTM D-3588-91, *GSPA Engineering Data Book, Tenth Edition* (1987), and the *CRC Handbook of Chemistry and Physics, 53rd Edition* (1972).

^b The fin-fan cooler and glycol dehydrator, upstream of the sales/flare meter run, was bypassed on May 30, 1988.

^c BDL = Less than 0.001%.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit J-3, Part 2. PLEASANT BAYOU WELL SALES/FLARE METER GAS ANALYSES BY IGT^a

Date	27 Apr 89	12 May 89	7 Jul 89	23 Aug 89	7 Nov 89	19 Dec 89	6 Feb 90
Pressure, psia	426	407	529	422	400	427	438
Gas Temp, °F	97	83	115	110	94	68	108
Brine Temp, °F	289	285	289	290	290	291	292
<u>Mole Percent of:</u>							
Helium	0.009	0.011	0.008	0.008	0.009	0.009	0.008
Hydrogen	0.019	0.027	0.018	0.017	0.016	0.017	0.018
Nitrogen	0.54	0.52	0.53	0.52	0.51	0.52	0.61
Carbon Dioxide	10.5	10.3	10.5	10.4	10.3	10.3	10.5
Methane	84.6	84.8	84.5	84.7	84.8	85.0	84.0
Ethane	2.92	2.95	2.98	2.92	2.91	2.90	2.96
Propane	0.93	0.93	0.95	0.94	1.03	0.87	1.04
iso-Butane	0.14	0.14	0.15	0.14	0.15	0.14	0.17
n-Butane	0.13	0.13	0.13	0.13	0.13	0.12	0.16
iso-Pentane	0.04	0.04	0.04	0.04	0.04	0.04	0.05
n-Pentane	0.02	0.02	0.02	0.02	0.02	0.02	0.03
neo-Pentane	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Hexanes	0.015	0.015	0.015	0.014	0.015	0.013	0.028
Heptanes	0.024	0.021	0.022	0.023	0.021	0.019	0.050
Octanes	0.008	0.008	0.009	0.010	0.010	0.008	0.033
Nonanes	0.002	0.002	0.002	0.002	0.001	0.001	0.011
Decanes	BDL ^b	0.001	0.001	0.001	0.001	BDL	0.006
Undecanes	BDL	0.002	0.001	0.001	0.001	BDL	0.001
Dodecanes	BDL	0.002	0.003	0.001	0.001	BDL	BDL
Tridecanes	BDL	0.001	0.006	0.002	BDL	BDL	BDL
Tetradecanes +	0.001	0.006	0.006	0.011	BDL	BDL	0.001
Benzene	0.044	0.030	0.062	0.032	0.040	0.030	0.177
Toluene	0.021	0.011	0.039	0.017	0.023	0.008	0.105
C2 Benzenes	0.005	0.007	0.017	0.008	0.012	0.001	0.054
C3 Benzenes	0.001	0.005	0.005	0.005	0.005	BDL	0.012
Naphthalene	BDL	0.006	0.001	0.002	0.004	BDL	0.001
C1 Naphthalenes	0.001	0.010	0.007	0.002	0.003	BDL	BDL
C2 Naphthalenes +	BDL	0.012	0.005	BDL	0.002	BDL	BDL
<u>Heating Value, Btu/SCF</u>							
Dry, 14.69 psia, 60°F	946	950	950	948	952	947	963
Gravity (air=1.000)	0.689	0.688	0.692	0.689	0.689	0.685	0.701
Gal/1000 SCF	1.19	1.20	1.24	1.20	1.22	1.15	1.38
Gal/1000 SCF, CO ₂ -Free	1.33	1.35	1.39	1.34	1.36	1.28	1.54

^a Analyses performed at IGT using gas chromatography with TC and FID detectors. Ideal Gas Gravity (air=1) and Heating Value were calculated following the procedures in ASTM D-3588-91.

Ideal Natural Gas Liquids Content was calculated treating the gas as an ideal gas. Values are at 14.69 psia and 60°F. Input data were obtained from ASTM D-3588-91, *GSPA Engineering Data Book, Tenth Edition* (1987), and the *CRC Handbook of Chemistry and Physics, 53rd Edition* (1972).

^b BDL = Less than 0.001%.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit J-3, Part 3. PLEASANT BAYOU WELL SALES/FLARE METER GAS ANALYSES BY IGT^a

Date	22 Mar 90	19 Apr 90	6 Aug 90	4 Sept 90	6 Sept 90	19 Sept 90	8 Oct 90
Pressure, psia	438	410	425	430	435	440	453
Gas Temp, °F	80	84	101	88	86	97	97
Brine Temp, °F	290	290	290	292	291	293	293
<u>Mole Percent of:</u>							
Helium	0.009	0.008	0.008	0.008	0.010	0.009	0.009
Hydrogen	0.020	0.020	0.013	0.012	0.014	0.012	0.012
Nitrogen	0.55	0.55	0.46	0.61	0.57	0.59	0.51
Carbon Dioxide	10.6	10.4	10.7	10.2	10.3	9.64	9.67
Methane	84.4	84.8	84.5	84.9	84.8	85.4	85.5
Ethane	2.94	2.90	2.93	2.87	2.8	2.95	2.94
Propane	0.98	0.95	0.89	0.93	0.96	0.93	0.88
iso-Butane	0.15	0.15	0.14	0.14	0.15	0.14	0.14
n-Butane	0.14	0.13	0.13	0.13	0.13	0.13	0.13
iso-Pentane	0.04	0.04	0.04	0.04	0.04	0.04	0.04
n-Pentane	0.02	0.02	0.02	0.02	0.02	0.02	0.02
neo-Pentane	0.001	0.001	BDL	0.001	BDL	0.001	0.001
Hexanes	0.016	0.014	0.016	0.014		0.015	0.016
Heptanes	0.013	0.011	0.023	0.012		0.012	0.012
Octanes	0.009	0.007	0.013	0.009		0.008	0.007
Nonanes	0.001	BDL	0.003	0.001		BDL	BDL
Decanes	BDL ^b	BDL	0.004	BDL		BDL	BDL
Undecanes	BDL	BDL	0.003	BDL		BDL	BDL
Dodecanes	BDL	BDL	0.001	BDL		BDL	BDL
Tridecanes	BDL	BDL	0.001	BDL		BDL	BDL
Tetradecanes +	BDL	BDL	BDL	BDL		BDL	BDL
Benzene	0.065	0.050	0.064	0.057		0.057	0.058
Toluene	0.024	0.016	0.025	0.023		0.023	0.019
C2 Benzenes	0.007	0.004	0.011	0.007		0.006	0.004
C3 Benzenes	0.001	BDL	0.003	0.001		0.001	BDL
Naphthalene	BDL	BDL	BDL	BDL		BDL	BDL
C1 Naphthalenes	0.001	BDL	BDL	BDL		BDL	BDL
C2 Naphthalenes +	0.002	0.001	BDL	BDL		BDL	BDL
Heating Value, Btu/SCF							
Dry, 14.69 psia, 60°F	948	9.48	9.46	9.49	942	9.55	9.54
Gravity (air=1.000)	0.691	0.688	0.691	0.686	0.683	0.681	0.680
Gal/1000 SCF	1.22	1.18	1.20	1.17	1.12	1.19	1.17
Gal/1000 SCF, CO ₂ -Free	1.37	1.32	1.34	1.30	1.25	1.32	1.30

^a Analyses performed at IGT using gas chromatography with TC and FID detectors. Ideal Gas Gravity (air=1) and Heating Value were calculated following the procedures in ASTM D-3588-91.

Ideal Natural Gas Liquids Content was calculated treating the gas as an ideal gas. Values are at 14.69 psia and 60°F. Input data were obtained from ASTM D-3588-91, *GSPA Engineering Data Book, Tenth Edition* (1987), and the *CRC Handbook of Chemistry and Physics, 53rd Edition* (1972).

^b BDL = Less than 0.001%.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit J-3, Part 4. PLEASANT BAYOU WELL SALES/FLARE METER GAS ANALYSES BY IGT^a

Date	09 Oct 90	16 Oct 90	16 Oct 90	16 Oct 90
Pressure, psia	472	472	471	472
Gas Temp, °F	91	91	91	93
Brine Temp, °F	294	294	294	294
<u>Mole Percent of:</u>				
Helium	0.009	0.009	0.009	0.009
Hydrogen	0.010	0.010	0.011	0.010
Nitrogen	<0.01	<0.01	<0.01	<0.01
Carbon Dioxide	9.55	9.55	9.57	9.51
Methane	86.4	86.4	86.4	85.9
Ethane	2.93	2.93	2.93	2.91
Propane	0.85	0.85	0.85	0.85
iso-Butane	0.13	0.13	0.13	0.13
n-Butane	0.12	0.12	0.12	0.12
iso-Pentane	0.04	0.03	0.03	0.03
n-Pentane	0.01	0.01	0.01	0.02
neo-Pentane	<0.01	<0.01	<0.01	<0.01
Hexanes				
Heptanes				
Octanes				
Nonanes				
Decanes				
Undecanes				
Dodecanes				
Tridecanes				
Tetradecanes +				
Benzene				
Toluene				
C2 Benzenes				
C3 Benzenes				
Naphthalene				
C1 Naphthalenes				
C2 Naphthalenes +				
Heating Value, Btu/SCF				
Dry, 14.69 psia, 60°F	956	956	956	951
Gravity (air=1.000)	.673	.673	.673	.670
Gal/1000 SCF	1.11	1.11	1.11	1.11
Gal/1000 SCF				
CO ₂ - Free	1.23	1.23	1.23	1.22

^a Analyses performed at IGT using gas chromatography.

Ideal Gas Gravity (air=1) and Heating Value were calculated following the procedures in ASTM D-3588-91.

Ideal Natural Gas Liquids Content was calculated treating the gas as an ideal gas. Values are at 14.69 psia and 60°F. Input data were obtained from ASTM D-3588-91, *GSPA Engineering Data Book, Tenth Edition* (1987), and the *CRC Handbook of Chemistry and Physics, 53rd Edition* (1972).

Exhibit J-4. PLEASANT BAYOU WELL SALES/FLARE METER RUN
GAS ANALYSES BY CORE LABORATORIES, INC.^a

Date	8 Mar 88 ^b	24 Apr 88 ^b	30 May 88 ^b	5 Jul 88	25 Sept 88
Pressure, psia	84	540	342	433	400
Gas Temp, °F	80	87	90	93	100
Brine Temp, °F	242	263	267	291	291
<u>Mole Percent of:</u>					
Nitrogen	0.54	0.52	0.49	0.5	0.5
Carbon Dioxide	12.18	11.28	11.95	11.06	12.03
Methane	83.03	82.88	83.27	84.12	82.94
Ethane	2.91	2.83	2.83	2.89	2.83
Propane	0.89	0.91	0.92	0.94	0.92
iso-Butane	0.14	0.14	0.15	0.15	0.14
n-Butane	0.13	0.13	0.13	0.13	0.13
iso-Pentane	0.03	0.03	0.04	0.04	0.03
n-Pentane	0.02	0.02	0.02	0.04	0.02
Hexanes	0.02	0.06	0.02	0.02	0.02
Heptanes	0.05	0.05	0.09	0.06	0.25
Octanes	0.04	0.1	0.05	0.03	0.09
Nonanes	0.01	0.06	0.03	0.01	0.04
Decanes +	0.01	0.01	0.01	0.01	0.06
Heating Value, Btu/SCF					
Dry, 14.69 psia, 60°F	930	937	937	944	949
Gravity (air=1.000)	0.705	0.696	0.706	0.696	0.717
Gal/1000 SCF	1.18	1.25	1.19	1.19	1.23
Gal/1000 SCF, CO ₂ -Free	1.34	1.41	1.35	1.34	1.40

^a Ideal Gas Gravity (air=1) and Heating Value were calculated by IGT following the procedures in ASTM D-3588-91.

Ideal Natural Gas Liquids Content was calculated by IGT treating the gas as an ideal gas. Values are at 14.69 psia and 60°F. Input data were obtained from ASTM D-3588-91, *GSPA Engineering Data Book, Tenth Edition* (1987), and the *CRC Handbook of Chemistry and Physics, 53rd Edition* (1972).

^b The fin fan cooler and glycol dehydrator, upstream of the sales/flare meter run, were put on-line on June 8, 1988. They were not operational at the time of the earlier samples.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit J-5, Part 1. PLEASANT BAYOU WELL LARGE SEPARATOR METER GAS ANALYSES BY IGT^a

Date	17 Jun 88	20 Jan 89	27 Apr 89	12 May 89	7 Jul 89	7 Nov 89	19 Dec 89
Pressure, psia	661	718	702	719	697	700	719
Gas Temp, °F	272	257	268	255	266	260	254
Brine Temp, °F	290	290	289	285	289	290	291
<u>Mole Percent of:</u>							
Helium	0.009	0.007	0.008	0.012	0.008	0.009	0.009
Hydrogen	0.023	0.017	0.018	0.026	0.018	0.017	0.018
Nitrogen	0.53	0.53	0.52	0.52	0.52	0.51	0.53
Carbon Dioxide	10.5	10.2	10.4	10.4	10.5	10.2	10.4
Methane	84.3	84.8	84.7	84.3	84.5	84.7	84.7
Ethane	2.91	2.93	2.94	2.93	2.96	2.92	2.89
Propane	0.95	0.94	0.94	0.94	0.94	0.87	0.93
iso-Butane	0.15	0.15	0.14	0.15	0.15	0.15	0.15
n-Butane	0.14	0.14	0.13	0.14	0.13	0.14	0.13
iso-Pentane	0.04	0.04	0.04	0.04	0.04	0.04	0.04
n-Pentane	0.02	0.02	0.02	0.02	0.02	0.02	0.02
neo-Pentane	0.001	0.001	0.001	0.001	0.001	BDL	0.001
Hexanes	0.018	0.015	0.015	0.024	0.016	0.017	0.016
Heptanes	0.031	0.023	0.024	0.054	0.025	0.027	0.024
Octanes	0.017	0.009	0.009	0.031	0.011	0.017	0.011
Nonanes	0.017	0.002	0.002	0.007	0.001	0.002	0.001
Decanes	0.005	0.001	0.001	0.005	0.001	0.004	BDL
Undecanes	0.007	0.001	0.001	0.006	0.001	0.012	BDL
Dodecanes	0.012	0.001	0.001	0.004	0.002	0.013	BDL
Tridecanes	0.004	BDL ^b	0.001	0.001	0.002	0.003	BDL
Tetradecanes +	0.011	0.013	0.007	0.001	BDL	BDL	BDL
Benzene	0.106	0.057	0.063	0.159	0.069	0.091	0.072
Toluene	0.085	0.034	0.041	0.151	0.043	0.085	0.046
C2 Benzenes	0.058	0.013	0.017	0.085	0.016	0.068	0.018
C3 Benzenes	0.030	0.004	0.005	0.025	0.006	0.037	0.004
Naphthalene	0.012	0.001	BDL	0.006	0.002	0.014	BDL
C1 Naphthalenes	0.024	0.001	0.001	0.005	0.004	0.010	BDL
C2 Naphthalenes +	0.018	0.002	BDL	0.003	0.006	0.004	BDL
<u>Heating Value, Btu/SCF</u>							
Dry, 14.69 psia, 60°F	959.8	951.5	950.7	965.3	950.5	959.4	950.4
Gravity (air=1.000)	0.701	0.688	0.690	0.701	0.692	0.695	0.690
Gal/1000 SCF	1.33	1.22	1.22	1.36	1.23	1.29	1.21
Gal/1000 SCF, CO ₂ -Free	1.48	1.36	1.36	1.52	1.38	1.43	1.35

^a Analyses performed at IGT using gas chromatography with TC and FID detectors.

Ideal Gas Gravity (air=1) and Heating Value were calculated following the procedures in ASTM D-3588-91.

Ideal Natural Gas Liquids Content was calculated treating the gas as an ideal gas. Values are at 14.69 psia and 60°F. Input data were obtained from ASTM D-3588-91, *GSPA Engineering Data Book, Tenth Edition* (1987), and the *CRC Handbook of Chemistry and Physics, 53rd Edition* (1972).

^b BDL = Less than 0.001%.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit J-5, Part 2. PLEASANT BAYOU WELL LARGE SEPARATOR METER GAS ANALYSES BY IGTA

Date	6 Feb 90	22 Mar 90	19 Apr 90	6 Aug 90	4 Sept 90	19 Sept 90	8 Oct 90
Pressure, psia	693	693	704	698	706	830	834
Gas Temp, °F	271	260	252	270	275	275	278
Brine Temp, °F	292	290	290	290	292	293	293
<u>Mole Percent of:</u>							
Helium	0.007	0.009	0.009	0.008	0.009	0.008	0.009
Hydrogen	0.016	0.021	0.020	0.013	0.001	0.011	0.011
Nitrogen	0.52	0.53	0.51	0.49	0.51	0.53	0.54
Carbon Dioxide	10.4	10.4	10.3	10.8	10.0	9.66	9.53
Methane	84.7	84.6	84.8	84.3	85.2	85.4	85.6
Ethane	2.88	2.94	2.94	2.98	2.87	2.95	2.93
Propane	0.97	0.99	0.93	0.92	0.93	0.94	0.91
iso-Butane	0.15	0.15	0.15	0.15	0.14	0.14	0.14
n-Butane	0.14	0.14	0.13	0.13	0.13	0.13	0.13
iso-Pentane	0.04	0.04	0.04	0.04	0.04	0.04	0.03
n-Pentane	0.02	0.02	0.02	0.02	0.01	0.02	0.02
neo-Pentane	BDL ^b	0.001	0.001	BDL	BDL	0.001	0.001
Hexanes	0.016	0.016	0.014	0.017	0.013	0.015	0.015
Heptanes	0.028	0.013	0.012	0.016	0.005	0.012	0.012
Octanes	0.013	0.009	0.008	0.014	0.009	0.009	0.008
Nonanes	0.002	0.001	0.001	0.001	0.001	0.001	0.001
Decanes	0.001	BDL	BDL	BDL	BDL	BDL	BDL
Undecanes	0.001	BDL	0.001	0.001	0.001	BDL	BDL
Dodecanes	0.001	BDL	BDL	0.001	0.001	BDL	BDL
Tridecanes	BDL	BDL	BDL	0.001	BDL	0.002	BDL
Tetradecanes +	0.002	BDL	BDL	0.001	BDL	BDL	BDL
Benzene	0.066	0.077	0.073	0.073	0.069	0.067	0.068
Toluene	0.042	0.037	0.036	0.037	0.037	0.031	0.034
C2 Benzenes	0.018	0.015	0.012	0.017	0.018	0.012	0.012
C3 Benzenes	0.004	0.004	0.007	0.004	0.005	0.003	0.002
Naphthalene	0.001	BDL	BDL	0.001	0.001	0.001	BDL
C1 Naphthalenes	0.001	BDL	BDL	0.001	0.001	0.002	BDL
C2 Naphthalenes +	BDL	BDL	BDL	0.001	BDL	0.002	BDL
<u>Heating Value, Btu/SCF</u>							
Dry, 14.69 psia, 60°F	951.7	951	950.8	947.2	952.6	956.7	956.9
Gravity (air=1.000)	0.691	0.690	0.688	0.694	0.685	0.682	0.680
Gal/1000 SCF	1.22	1.23	1.25	1.22	1.24	1.17	1.23
Gal/1000 SCF, CO ₂ -Free	1.36	1.37	1.38	1.35	1.35	1.28	1.34

^a Analyses performed at IGT using gas chromatography with TC and FID detectors.

Ideal Gas Gravity (air=1) and Heating Value were calculated following the procedures in ASTM D-3588-91.

Ideal Natural Gas Liquids Content was calculated treating the gas as an ideal gas. Values are at 14.69 psia and 60°F. Input data were obtained from ASTM D-3588-91, *GSPA Engineering Data Book, Tenth Edition* (1987), and the *CRC Handbook of Chemistry and Physics, 53rd Edition* (1972).

^b BDL = Less than 0.001%.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit J-6. PLEASANT BAYOU WELL LARGE SEPARATOR METER RUN GAS ANALYSES BY CORE LABORATORIES, INC.^a

Date	8 Mar 88 ^b	5 Jul 88	22 Jul 88	29 Aug 88	25 Sept 88	23 Nov 88	23 Aug 89
Pressure, psia	506	719	698	692	700	700	695
Gas Temp, °F	239	278	277	269	275	274	272
Brine Temp, °F	251	291	290	291	291	291	290
<u>Mole Percent of:</u>							
Nitrogen	0.5	0.53	0.51	0.5	0.5	0.5	0.52
Carbon Dioxide	12.24	10.99	9.75	11.79	11.95	11.04	10.77
Methane	83.01	84.14	85.32	83.37	82.88	83.92	84.24
Ethane	2.89	2.91	2.93	2.87	2.83	3.05	3.04
Propane	0.89	0.95	0.98	0.94	0.92	0.95	0.93
iso-Butane	0.15	0.15	0.16	0.15	0.15	0.14	0.16
n-Butane	0.13	0.14	0.14	0.13	0.13	0.14	0.13
iso-Pentane	0.04	0.04	0.04	0.04	0.04	0.04	0.04
n-Pentane	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Hexanes	0.02	0.02	0.07	0.02	0.02	0.02	0.02
Heptanes	0.05	0.07	0.04	0.06	0.14	0.1	0.06
Octanes	0.04	0.03	0.03	0.03	0.12	0.05	0.05
Nonanes	0.01	0.01	<0.01	0.01	0.11	0.01	0.02
Decanes +	0.01	<0.01	0.01	0.07	0.19	<0.01	<0.01
<u>Heating Value, Btu/SCF</u>							
Dry, 14.69 psia, 60°F	931	944	959	940	960	947	949
Gravity (air=1.000)	0.706	0.695	0.683	0.704	0.720	0.697	0.694
Gal/1000 SCF	1.18	1.19	1.25	1.22	1.38	1.23	1.24
Gal/1000 SCF, CO ₂ -Free	1.34	1.34	1.38	1.38	1.56	1.39	1.38

^a Ideal Gas Gravity (air=1) and Heating Value were calculated by IGT following the procedures in ASTM D-3588-91.

Ideal Natural Gas Liquids Content was calculated by IGT treating the gas as an ideal gas. Values are at 14.69 psia and 60°F. Input data were obtained from ASTM D-3588-91, *GSPA Engineering Data Book, Tenth Edition* (1987), and the *CRC Handbook of Chemistry and Physics, 53rd Edition* (1972).

^b The fin fan cooler and glycol dehydrator, upstream of the sales/flare meter run, were put on-line on June 8, 1988. They were not operational at the time of the earlier samples.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit J-7, Part 1. PLEASANT BAYOU WELL SMALL SEPARATOR METER GAS ANALYSES BY IGT^a

Date	20 Jan 89	27 Apr 89	07 Jul 89	07 Nov 89	19 Dec 89	22 Mar 90	19 Apr 90
Pressure, psia	716	700	696	700	719	693	704
Gas Temp, °F	233	239	242	232	249	244	228
Brine Temp, °F	290	289	289	290	291	290	290
<u>Mole Percent of:</u>							
Helium	0.008	0.009	0.008	0.009	0.009	0.009	0.008
Hydrogen	0.019	0.020	0.018	0.017	0.017	0.020	0.020
Nitrogen	0.53	0.54	0.50	0.51	0.51	0.54	0.51
Carbon Dioxide	10.5	10.5	10.6	10.6	10.6	10.6	10.4
Methane	84.5	84.6	84.4	84.5	84.7	84.4	84.8
Ethane	2.92	2.90	2.94	2.89	2.86	2.94	2.88
Propane	0.93	0.90	0.92	0.88	0.88	0.98	0.93
iso-Butane	0.15	0.14	0.14	0.15	0.14	0.15	0.14
n-Butane	0.13	0.13	0.13	0.14	0.13	0.14	0.13
iso-Pentane	0.03	0.04	0.04	0.04	0.04	0.04	0.04
n-Pentane	0.02	0.02	0.02	0.02	0.02	0.02	0.02
neo-Pentane	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Hexanes	0.015	0.014	0.016	0.016	0.016	0.016	0.014
Heptanes	0.024	0.024	0.025	0.022	0.025	0.014	0.011
Octanes	0.010	0.009	0.010	0.010	0.011	0.011	0.008
Nonanes	0.002	0.002	0.003	0.001	0.001	0.001	BDL ^b
Decanes	0.001	0.001	0.001	0.001	BDL	0.001	BDL
Undecanes	0.002	0.001	0.002	0.001	BDL	0.002	BDL
Dodecanes	0.001	0.001	0.005	0.001	BDL	0.001	BDL
Tridecanes	BDL ^b	0.001	0.004	BDL	BDL	BDL	BDL
Tetradecanes +	0.005	0.003	0.004	BDL	BDL	BDL	0.001
Benzene	0.068	0.065	0.070	0.074	0.061	0.087	0.071
Toluene	0.048	0.045	0.042	0.045	0.035	0.044	0.034
C2 Benzenes	0.025	0.021	0.018	0.017	0.012	0.018	0.010
C3 Benzenes	0.009	0.007	0.007	0.005	0.003	0.006	0.005
Naphthalene	0.002	0.001	0.004	0.001	BDL	0.001	BDL
C1 Naphthalenes	0.002	0.001	0.008	0.002	BDL	0.002	BDL
C2 Naphthalenes +	0.001	BDL	0.004	0.010	BDL	0.001	0.001
Heating Value, Btu/SCF							
Dry, 14.69 psia, 60°F	949.5	948.6	948.8	948.2	947.1	950.2	949.
Gravity (air=1.000)	0.691	0.691	0.693	0.692	0.690	0.693	0.689
Gal/1000 SCF	1.22	1.20	1.22	1.20	1.17	1.24	1.18
Gal/1000 SCF, CO ₂ -Free	1.36	1.20	1.23	1.21	1.18	1.25	1.32

^a Analyses performed at IGT using gas chromatography with TC and FID detectors.

Ideal Gas Gravity (air=1) and Heating Value were calculated following the procedures in ASTM D-3588-91.

Ideal Natural Gas Liquids Content was calculated treating the gas as an ideal gas. Values are at 14.69 psia and 60°F. Input data were obtained from ASTM D-3588-91, *GSPA Engineering Data Book, Tenth Edition* (1987), and the *CRC Handbook of Chemistry and Physics, 53rd Edition* (1972).

^b BDL = Less than 0.001%.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit J-7, Part 2. PLEASANT BAYOU WELL SMALL SEPARATOR METER GAS ANALYSES BY IGT^a

Date	06 Aug 90	04 Sept 90	19 Sept 90	08 Oct 90
Pressure, psia	698	706	830	835
Gas Temp, °F	251	246	235	231
Brine Temp, °F	290	292	293	293
<u>Mole Percent of:</u>				
Helium	0.009	0.008	0.009	0.010
Hydrogen	0.014	0.012	0.012	0.012
Nitrogen	0.65	0.58	0.53	0.59
Carbon Dioxide	10.7	10.5	9.79	9.79
Methane	84.4	84.6	85.3	85.3
Ethane	2.88	2.85	2.93	2.91
Propane	0.87	0.93	0.93	0.88
iso-Butane	0.14	0.14	0.14	0.14
n-Butane	0.12	0.13	0.13	0.12
iso-Pentane	0.03	0.04	0.04	0.03
n-Pentane	<0.01	0.02	0.02	0.02
neo-Pentane	BDL ^b	0.001	0.001	0.001
Hexanes	0.012	0.014	0.015	0.014
Heptanes	0.010	0.012	0.012	0.012
Octanes	0.009	0.009	0.008	0.008
Nonanes	0.001	0.001	0.001	0.001
Decanes	0.001	BDL	BDL	BDL
Undecanes	0.001	0.001	BDL	BDL
Dodecanes	0.001	0.001	BDL	BDL
Tridecanes	BDL	BDL	BDL	BDL
Tetradecanes +	BDL	BDL	BDL	BDL
Benzene	0.061	0.070	0.067	0.066
Toluene	0.030	0.034	0.032	0.032
C2 Benzenes	0.013	0.015	0.013	0.011
C3 Benzenes	0.004	0.004	0.003	0.002
Naphthalene	BDL	0.001	BDL	BDL
C1 Naphthalenes	BDL	0.003	0.001	BDL
C2 Naphthalenes +	BDL	0.004	BDL	BDL
Heating Value, Btu/SCF				
Dry, 14.69 psia, 60°F	941.4	947.2	954.9	952.2
Gravity (air=1.000)	0.690	0.690	0.683	0.682
Gal/1000 SCF	1.15	1.18	1.20	1.17
Gal/1000 SCF, CO ₂ -Free	1.16	1.19	1.21	1.18

^a Analyses performed at IGT using gas chromatography with TC and FID detectors. Ideal Gas Gravity (air=1) and Heating Value were calculated following the procedures in ASTM D-3588-91.

Ideal Natural Gas Liquids Content was calculated treating the gas as an ideal gas. Values are at 14.69 psia and 60°F. Input data were obtained from ASTM D-3588-91, *GSPA Engineering Data Book, Tenth Edition* (1987), and the *CRC Handbook of Chemistry and Physics, 53rd Edition* (1972).

^b BDL = Less than 0.001%.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit J-8. PLEASANT BAYOU WELL SMALL SEPARATOR METER RUN GAS ANALYSES BY CORE LABORATORIES, INC.^a

Date	<u>8 Mar 88^b</u>	<u>5 Jul 88</u>	<u>22 Jul 88</u>	<u>29 Aug 88</u>	<u>25 Sept 88</u>	<u>23 Nov 88</u>	<u>23 Aug 89</u>
Pressure, psia	488	718	698	691	715	700	695
Gas Temp, °F	239	216	232	217	255	210	240
Brine Temp, °F	251	291	290	291	291	291	290
<u>Mole Percent of:</u>							
Nitrogen	0.46	0.49	0.46	0.48	0.50	0.52	0.51
Carbon Dioxide	12.19	11.63	11.23	12.77	12.14	11.22	10.77
Methane	83.01	83.75	84.49	82.51	82.78	83.72	84.32
Ethane	2.95	2.83	2.66	2.73	2.82	3.01	2.99
Propane	0.89	0.89	0.78	0.85	0.92	0.94	0.92
iso-Butane	0.15	0.14	0.11	0.13	0.14	0.15	0.14
n-Butane	0.13	0.12	0.11	0.12	0.13	0.14	0.13
iso-Pentane	0.04	0.04	0.03	0.05	0.04	0.04	0.04
n-Pentane	0.02	0.01	0.01	0.02	0.02	0.02	0.02
Hexanes	0.02	0.01	0.06	0.02	0.02	0.04	0.02
Heptanes	0.06	0.05	0.04	0.11	0.13	0.11	0.07
Octanes	0.05	0.03	0.02	0.06	0.12	0.07	0.05
Nonanes	0.02	0.01	<0.01	0.02	0.09	0.01	0.02
Decanes +	0.01	<0.01	<0.01	0.13	0.15	<0.01	<0.01
<u>Heating Value, Btu/SCF</u>							
Dry, 14.69 psia, 60°F	934	934	935	936	954	947	948
Gravity (air=1.000)	0.707	0.698	0.692	0.717	0.719	0.700	0.693
Gal/1000 SCF	1.20	1.13	1.07	1.21	1.33	1.25	1.21
Gal/1000 SCF, CO2-Free	1.37	1.27	1.21	1.38	1.52	1.41	1.36

^a Ideal Gas Gravity (air=1) and Heating Value were calculated by IGT following the procedures in ASTM D-3588-91.

Ideal Natural Gas Liquids Content was calculated by IGT treating the gas as an ideal gas. Values are at 14.69 psia and 60°F. Input data were obtained from ASTM D-3588-91, *GSPA Engineering Data Book, Tenth Edition* (1987), and the *CRC Handbook of Chemistry and Physics, 53rd Edition* (1972).

^b The fin fan cooler and glycol dehydrator, upstream of the sales/flame meter run, were put on-line on June 8, 1988. They were not operational at the time of the earlier samples.

GPA Publication 2377-77

GPA

**Tentative Method of Test for
Hydrogen Sulfide in Natural Gas
Using Length of Stain Tubes**

Adopted as Tentative Standard, 1977

Gas Processors Association

1812 First Place

Tulsa, Oklahoma 74103

J-23

Tentative Method of Test for Hydrogen Sulfide in Natural Gas Using Length of Stain Tubes

1. SCOPE-

1.1 This method covers the determination of hydrogen sulfide in natural gas in the range of 3 ppmv to 120 ppmv.

Note 1—Available apparatus extends the range up to 7 percent by volume. Cooperative testing by GPA has been completed only up to 120 ppmv.

1.2 The method as written is applicable to the determination of hydrogen sulfide in hydrocarbon vapors and in air.

2. SUMMARY OF METHOD

The sample is passed through the detector tube filled with a specially prepared chemical. Any hydrogen sulfide present in the sample reacts with the chemical to produce a color change. The length of stain (or color change) produced in the detector tube when exposed to a measured volume of sample is directly proportional to the amount of hydrogen sulfide present in the sample being tested. A bellows or piston type pump is used to suck a measured volume of sample through the tube at a controlled rate of flow. The length of stain produced is converted to ppm of H_2S by comparison with a calibration scale supplied by the manufacturer with each box of detector tubes. The apparatus is easily portable, is completely suited to making spot checks for hydrogen sulfide under field conditions.

3. APPARATUS

3.1 *Piston or bellows pump*—The pump is hand-operated and must be capable of sucking a minimum of 100 ml per stroke of sample through the detector tube with an accuracy of ± 2 ml.

3.2 *Detector Tube*—Tubes must be made of glass with break-off tips sized to fit the orifice of the pump. The chemical sealed in the tube must be specific for hydrogen sulfide and produce a distinct color change when exposed to a sample of gas containing hydrogen sulfide. Any substances known to interfere must be listed in instructions accompanying the tubes. The tube should have the calibration scale etched directly on the tube or other markings which provide for easy interpretation of hydrogen sulfide content from a separate calibration scale supplied with the tubes. Shelf life of the detector tubes must be a minimum of 2 years when stored according to manufacturer's recommendations.

3.3 *Gas Sampling Container*—Any container which provides for access of the detector tube into a uniform flow of sample gas at atmospheric pressure and isolated from the surrounding atmosphere.

3.3.1 A suitable container may be devised from a one pint polyethylene bottle. A $\frac{1}{4}$ -inch O.D. polyethylene tubing sealed into the bottle and discharging near the bottom provides for flow of sample gas into the bottle. A $\frac{1}{2}$ -inch hole cut into the cap of the bottle provides both access for the detector tube and vent for gas flow. See Figure 1.

Note 2—A one pint polyethylene wash bottle is easily adapted to a suitable sample container.

3.3.2 Mylar gas collection bags are useful as gas sample containers when the supply of sample gas is limited. Mylar bags with a minimum capacity of two liters are an acceptable substitute for bottle described in 3.3.1.

3.4 *Barometer*—Any barometer equipped with a scale graduated in 1 mm of mercury subdivision and a range including the expected atmospheric pressure condition at the sampling site.

3.5 *Thermometer*—Standard laboratory thermometer graduated in $1^\circ C$ subdivisions and including the range of sample temperatures expected during the test.

3.6 *Needle Valve and Tubing*—Any stainless steel needle valve which can be adjusted to control the flow of gas from source pressure into the gas sampling container. Polyethylene or gum rubber tubing may be used to connect the gas sampling container to the needle valve outlet.

Note 3—A pressure regulator may be used to control flow of the sample gas, in lieu of a needle valve.

4. SAMPLING

4.1 Select a sampling point which affords access to a representative sample of the gas to be tested (i.e.—a point on the main flow line). Flow line connections should have a centerline tap.

4.1.1 Open source valve, Figure 1, and blow down vigorously to clear foreign materials from source valve and connecting nipple. Close source valve.

4.1.2 Install needle valve (or pressure regulator) on outlet of source valve. Connect outlet of needle valve to gas sampling container using shortest length practicable of polyethylene or other suitable tubing.

4.1.3 Open source valve A and crack control valve B to obtain positive flow of gas through gas sample container venting to atmosphere through tube access and vent C.

4.1.4 Purge gas sample container until all air is displaced. A minimum purge time of 3 minutes is recommended.

Note 4—When using collection bags the same procedure is followed except that the deflated bag is attached directly to control valve B. The bag is filled once, disconnected and deflated. The bag is filled a second time and is then ready for the analysis.

5. PROCEDURE

5.1 Immediately before each series of measurements, test the pump for tightness by inserting an unopened tube and operating the pump. A loss in vacuum on the pump after 30 sec. indicates a leak.

5.1.1 Select the tube range that includes the expected amount of hydrogen sulfide present in the sample. Reading

FIG. 1—Sampling manifold to be used with H_2S detector.

accuracy is improved when the stain extends at least 50 percent of the tube length. Consider multiple strokes and/or a lower range tube to achieve this length of stain.

5.1.2 Break off tip and insert outlet end of tube snugly into the pump head. Temperature of the tube must remain in the 0° to $40^\circ C$ range throughout the test period.

5.1.3 Place detector tube well into gas sampling container through the tube access and vent C.

Note 5—Gas sample container must be completely purged of air and with control valve B adjusted to maintain a positive flow of gas leaving the tube access and vent C for the duration of the test.

5.1.4 Operate the pump to suck a measured volume of gas through the detector tube. Within limits set by manufacturer's instructions, use multiple strokes to maximize length of stain.

5.1.5 Remove the tube from the pump and immediately read the concentration of hydrogen sulfide from graduations

on the tube or charts supplied with the tubes. The number opposite the end of the stain is the approximate hydrogen sulfide concentration. If the number of strokes used is different from the number specified by the manufacturer for particular concentration, a correction must be made as follows:

$$\text{Corrected } H_2S \text{ Conc.} = \text{Scale reading} \times \frac{\text{Specified Strokes}}{\text{Actual Strokes}}$$

5.7 Record temperature of gas flowing through gas sample container and barometric pressure to provide data for gas volume corrections if required.

6. CALCULATIONS

6.1 Gas volume corrections may be desirable to improve precision of results. The effect of temperature is usually negligible; however, the barometric pressure becomes significant at altitudes above 2,000 feet. Correction for barometric pressure is done as follows:

$$\text{Corr. PPMV} = \text{ppmv (read from tube)} \times \frac{760 \text{ mm Hg}}{\text{Baro. Press. mm Hg}}$$

6.2 Check with manufacturer if it becomes necessary to test at gas temperatures outside the 0 to $40^\circ C$ range.

7. PRECISION

7.1 The following criteria should be used for judging the acceptability of hydrogen sulfide concentration when determined using a "length of stain" detector tube (95% confidence limit)

7.1.1 *Repeatability*—Duplicate results by the same operator should be considered suspect if they differ by more than the following amounts:

Range of Sample Conc.	Repeatability
3-120	10% of amount found

7.1.2 *Reproducibility*—The results submitted by each of two laboratories should be considered suspect if the two results differ by more than the following amounts:

Range of Sample Conc.	Reproducibility
3-120	12% of amount present

Note 6—Precision limits shown above were obtained from raw data generated by 10-13 laboratories involved in cooperative testing of eight separate samples. Computations on the raw data were made using ASTM bulletin RR D-2-1007 "Manual on Determining Precision Data for ASTM Methods on Petroleum Products and Lubricants." The cooperative tests were completed prior to finalizing the method write-up.

Note 7—Cooperative test results indicate a major source of error to be in the variance in response from lot number to lot number of tubes supplied by the manufacturer. The fidelity of a given lot number of tubes can be verified by calibrating one or more tubes using a gas with known concentration of hydrogen sulfide.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

TABLE I
Length of Stain Method for Determination of H₂S in Natural Gas
Reproducibility of Labs

	Samples Mean/Lab					
	Lab Fld Gas 9 ppm	Lab Fld Gas 98 ppm	Lab Permeation Tube—44 ppm	Ecospan 88 ppm	Ecospan 18 ppm	Fld Gas 35 ppm
Lab A	—	100	54	91	15	29
Lab B	—	101	42	89	13	28
Lab C	11	118	53	—	—	31
Lab E	9	—	47	84	14	—
Lab F	9	98	48	—	14	—
Lab G	—	—	43	79	21	29
Lab I	10	110	45	—	—	28
Lab J	9	91	43	86	10	29
Lab K	9	95	39	80	12	—
Lab P	7	98	—	86	9	38
Lab S	—	—	—	—	—	30
No. of Labs Participating	7	8	9	7	8	8
ppm H ₂ S Mean	9	101	46	85	13.5	30
% Error	0	3.1	4.5	3.4	25	14
Std. Deviation	1.2	8.7	5	4.4	3.6	3
Probable Error of Mean	.31	2.06	1.13	1.12	.87	.78
Probable Error	.81	5.83	3.38	2.96	2.5	2.2
Std. Deviation from Mean	.46	3.05	1.7	1.66	1.2	1.2
Std. Deviation for 95% Confidence Level	1.1	7.2	3.8	4.07	3.0	2.5

TABLE II
GPA Sulfur Analysis Work Group H₂S Data, May 11-June 7, 1976

Gas Source	PPM H ₂ S	% Error	Experimental Data—Detector Tubes		
			No. Determinations	PPM H ₂ S (Ave.)	
Ecospan	18	22%	38	14 ± 5	σ = 1.4
Ecospan	88	6%	36	83 ± 8	σ = 2.2
Permeation Tubes	44	5%	73	46 ± 8	σ = 1.6
Field Gas	9 ± 1*	11%	83	10 ± 3	σ = 0.55
Field Gas	98 ± 8*	5%	73	103 ± 13	σ = 2.53
Shamburger Lake Plant Inlet	35 ± 3*	11%	124	31 ± 4	σ = 0.79
Sun-Lateral #2	221 ± 15	2%	36	226 ± 13	σ = 4.75
Sun M. T. Cole #21	93 ± 7	9%	39	101 ± 6	σ = 2.2

σ (Standard Deviation for 95% Confidence Unit)

* Precision reflects repeatability of CdSO₄ method according to GPA Bulletin B-14

+ H₂S concentration was apparently continuously increasing during 4-5 hour period of CdSO₄ gas sampling. Determinations by detector tubes occurred near end of CdSO₄ method sampling and instrumental determinations even later.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

TABLE III
Detector Tube H₂S Measurements by Tube Lot Numbers—June 7-8, 1976

Drager 5,b Ch29801 5-60 ppm Range								Average
Lot No. _____	157091	1050184	1050185	1050126	1056371	1052101	255761	
No. Measurements _____	5	8	4	12	3	4	3	39
PPM H ₂ S _____	32 ± 1	30 ± 1	29 ± 1	29 ± 2	28 ± 0	29 ± 1	31 ± 1	30 ± 1
% Error _____	9%	14%	17%	17%	20%	17%	11%	17%

Gastec 4LL 0-60 ppm Range								Average
Lot No. _____	51215	30710	30912	40113	40809	60116	50217	50913
No. Measurements _____	19	13	6	9	6	4	4	4
PPM H ₂ S _____	30 ± 2	28 ± 2	38 ± 1	35 ± 1	35 ± 1	28 ± 1	27 ± 1	30 ± 1
% Error _____	14%	20%	9%	3%	3%	20%	23%	14%

Field Gas Source

Shamburger Lake Plant Inlet—35 PPM

APPENDIX K
Condensate Analyses

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit K-1, Part 1. PLEASANT BAYOU NO. 2 WELL GUNBARREL CONDENSATE ANALYSES^a

	<u>17 Jun 88</u>	<u>22 Jul 88</u>	<u>29 Aug 88</u>	<u>23 Sept 88</u>	<u>24 Sept 88</u>	<u>20 Jan 89</u>	<u>27 Apr 89</u>
Benzene	0.44	0.32	1.47	1.21	2.52	4.53	2.62
C7-	0.09	0.05	0.30	0.29	0.59	1.70	0.82
Toluene	2.65	2.90	5.62	4.49	7.30	11.49	8.83
C8	0.23	0.27	0.82	0.65	1.18	1.67	1.17
Ethylbenzene	1.28	1.31	1.63	1.45	1.86	2.53	2.24
<i>m,p</i> -Xylenes	4.38	4.45	5.43	4.90	6.11	8.38	7.57
<i>o</i> -Xylene	3.11	3.04	3.49	3.22	3.85	4.99	4.68
C9	0.28	0.19	0.26	0.23	0.32	0.75	0.64
C3-Benzenes	9.79	9.12	9.08	8.08	9.47	10.91	9.02
C10	0.43	0.34	0.35	1.25	0.41	0.95	3.86
C11	7.32	5.84	5.26	5.45	5.36	5.40	4.49
Naphthalene	10.40	10.04	9.37	9.55	8.88	6.94	8.25
C12	4.57	5.09	4.31	4.48	4.20	4.40	5.14
C13	4.24	3.58	3.52	3.60	3.31	2.11	2.82
C1-Naphthalenes	18.47	19.20	17.44	18.08	16.17	12.27	13.77
C14	3.45	3.43	3.81	2.99	3.54	3.68	4.11
C2-Naphthalenes	15.00	13.92	12.71	13.20	10.74	8.67	9.40
C15	7.17	4.33	2.60	4.20	3.38	0.63	0.92
C3-Naphthalenes	^b	5.01	4.29	4.25	3.63	2.22	2.69
C16	4.12	4.29	2.87	2.95	2.52	1.81	2.06
C17	2.58	3.28	5.37	5.48	4.66	1.46	1.31
C18	^c	^c	^c	^c	^c	1.02	1.40
C19						0.64	0.82
C20						0.44	0.63
C21						0.22	0.31
C22						0.09	0.18
C23						0.06	0.14
C24						0.03	0.09
C25+						^d	0.02

^a Analyses performed at IGT by capillary column gas chromatography using a flame ionization detector.

^b C3-Naphthalenes were not individually identified for this sample, but were grouped with the C15 and C16 hydrocarbons.

^c Results were not reported for C higher than 17.

^d C25 was not reported separately.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit K-1, Part 2. PLEASANT BAYOU NO. 2 WELL GUNBARREL CONDENSATE ANALYSES^a

	<u>12 May 89</u>	<u>7 Jul 89</u>	<u>23 Aug 89</u>	<u>8 Nov 89</u>	<u>19 Dec 89</u>	<u>6 Feb 90</u>	<u>22 Mar 90</u>
Benzene	2.99	1.95	1.52	2.95	2.32	2.19	1.59
C7-	1.13	0.67	0.52	0.91	0.73	0.74	0.18
Toluene	8.56	5.97	5.20	7.15	6.42	6.57	5.15
C8	1.22	0.83	0.62	0.34	0.86	0.90	0.60
Ethylbenzene	2.17	1.60	1.60	1.83	1.63	1.65	1.47
<i>m,p</i> -Xylenes	7.03	5.30	5.47	5.99	5.36	5.50	4.84
<i>o</i> -Xylene	4.44	3.44	3.56	3.86	3.40	3.45	3.09
C9	0.68	0.46	0.38	0.46	0.42	0.39	0.31
C-3 Benzenes	10.35	8.40	8.96	7.59	6.73	8.42	7.74
C10	0.68	0.60	0.66	0.65	0.61	0.70	0.47
C11	5.22	5.11	5.05	6.74	6.42	3.91	3.72
Napthalene	5.18	8.64	9.02	8.75	8.14	7.86	8.41
C12	7.98	5.04	5.00	4.93	4.27	4.69	4.66
C13	2.80	2.58	3.18	2.68	2.62	2.54	1.52
C-1 Naphthalenes	14.38	16.83	16.74	15.90	15.90	15.76	16.79
C-14	3.37	2.36	2.58	2.32	1.87	2.17	2.77
C-2 Naphthalenes	8.00	9.61	14.28	12.80	13.20	14.33	14.42
C15	3.55	5.30	0.83	1.58	2.61	2.34	3.72
C-3 Naphthalenes	2.56	4.09	3.42	4.68	4.89	3.75	5.24
C16	2.20	2.86	3.20	1.48	1.93	3.06	2.38
C17	2.26	2.98	2.94	1.98	3.28	2.55	3.82
C18	1.36	1.89	1.81	1.86	2.24	2.15	2.24
C19	0.81	1.11	1.07	0.96	1.42	1.58	1.48
C20	0.68	0.88	0.92	0.72	1.09	1.09	1.07
C21	0.21	0.48	0.51	0.39	0.62	0.62	0.68
C22	0.12	0.34	0.36	0.24	0.40	0.39	0.40
C23	0.03	0.29	0.21	0.16	0.29	0.29	0.41
C24	0.03	0.17	0.20	0.08	0.22	0.25	0.19
C25+	0.04	0.22	0.20	0.02	0.11	0.15	0.58

^a Analyses performed at IGT by capillary column gas chromatography using a flame ionization detector.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit K-1, Part 3. PLEASANT BAYOU NO. 2 WELL GUNBARREL CONDENSATE ANALYSES^a

	<u>19 Apr 90</u>	<u>24 May 90</u>	<u>6 Aug 90</u>	<u>19 Sept 90</u>	<u>8 Oct 90</u>
Benzene	3.45	2.45	2.31	2.19	2.38
C7-	0.64	2.56	0.42	2.39	0.32
Toluene	8.74	7.29	6.07	6.12	6.33
C8	1.22	0.86	0.81	0.81	0.89
Ethylbenzene	2.19	1.92	1.59	1.63	1.67
<i>m,p</i> -Xylenes	6.97	6.25	5.08	5.31	5.34
<i>o</i> -Xylene	4.40	3.99	3.23	3.34	3.37
C9	0.56	0.49	1.16	0.69	0.49
C3-Benzenes	10.15	8.56	7.88	8.51	8.52
C10	0.59	1.55	0.20	0.20	0.72
C11	4.04	3.96	3.48	3.94	3.44
Naphthalene	8.20	8.88	8.85	8.72	7.87
C12	5.56	5.48	4.86	5.01	5.67
C13	2.11	2.18	2.40	2.01	2.69
C1-Naphthalenes	13.97	10.53	16.67	16.48	15.44
C14	2.07	7.30	2.24	2.24	3.10
C2-Naphthalenes	10.51	12.33	12.66	13.05	13.59
C15	2.94	2.10	3.85	1.89	2.14
C3-Naphthalenes	3.38	4.04	4.04	4.74	3.81
C16	1.73	1.85	2.42	1.52	1.89
C17	2.38	2.50	2.92	2.36	2.20
C18	1.29	1.69	1.71	2.33	2.13
C19	0.84	0.99	1.21	1.62	1.57
C20	0.60	0.83	0.93	1.12	1.00
C21	0.35	0.45	0.54	0.88	1.00
C22	0.20	0.26	0.43	0.48	0.61
C23	0.26	0.35	0.43	0.36	0.39
C24	0.11	0.17	0.34	0.35	0.33
C25+	0.56	0.34	1.27	0.26	0.93

^a Analyses performed at IGT by capillary column gas chromatography using a flame ionization detector.

APPENDIX L

Corrosion Coupon Data

This appendix contains results of corrosion coupon analyses from six parts of the flow system. Three locations (Exhibits L-1 to L-3) used coupons in holders that could be sampled at system pressure. These locations were sampled most frequently. The other three locations required system shutdown for sampling and were not sampled as often. Exhibits include --

Exhibit L-1 -- Summarizes data from coupon samples in the line before the separators.

Exhibit L-2 -- Summarizes data from coupon samples in the line after the separator.

Exhibit L-3 -- Summarizes data from coupon samples in the line before the disposal well (near the filter skid).

Exhibit L-4 -- Summarizes data from coupon samples near the top of the wellhead flow loop.

Exhibit L-5 -- Summarizes data from coupon samples near the bottom of the wellhead flow loop.

Exhibit L-6 -- Summarizes data from coupon samples in the HPS discharge line.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit L-1. COUPON BEFORE SEPARATOR

<u>Date In</u>	<u>Date Out</u>	<u>Weight In,</u> <u>grams</u>	<u>Weight Out,</u> <u>grams</u>	<u>Wt Loss,</u> <u>grams</u>	<u>Time In,</u> <u># of Days^a</u>	<u>Loss Rate,</u> <u>mils/yr</u>
07/20/88	07/26/88	10.866	3.043	7.823	6	1274.05
07/26/88	08/02/88	10.870	9.280	1.590	7	221.95
08/02/88	08/09/88	10.851	3.485	7.366	7	1028.25
08/09/88	08/16/88	10.867	10.859	0.008	7	1.12
08/16/88	08/23/88	23.620	23.615	0.005	7	0.70
08/23/88	08/30/88	23.512	23.502	0.010	7	1.40
09/10/88	09/22/88	17.985	17.919	0.066	12	5.37
09/22/88	09/29/88	18.241	18.208	0.033	7	4.61
09/29/88	10/12/88	18.318	18.255	0.063	13	4.74
10/12/88	10/25/88	17.792	17.697	0.095	13	7.14
10/25/88	11/08/88	18.128	18.024	0.104	14	7.26
11/08/88	11/22/88	18.199	18.008	0.191	14	13.33
11/22/88	12/06/88	18.218	18.044	0.174	14	12.14
12/06/88	12/20/88	9.010	8.947	0.063	14	4.40
12/20/88	01/03/89	9.286	9.205	0.081	14	5.65
01/03/89	01/17/89	9.187	9.126	0.061	14	4.26
01/17/89	01/31/89	9.277	9.199	0.078	14	5.44
01/31/89	02/14/89	9.237	9.159	0.078	14	5.44
02/14/89	03/17/89	9.545	9.419	0.126	31	3.97
03/17/89	04/18/89	9.531	9.380	0.151	32	4.61
04/18/89	05/17/89	9.451	9.364	0.087	29	2.93
05/17/89	06/28/89	9.852	9.693	0.159	31	5.01
06/28/89	08/25/89	9.990	9.092	0.898	37	23.72
08/25/89	10/19/89	9.410	9.097	0.313	17	17.99
10/19/89	12/20/89	10.308	10.074	0.234	56	4.08
12/20/89	03/19/90	10.058	9.636	0.422	89	4.63
03/19/90	05/08/90	9.606	9.364	0.242	50	4.73
05/08/90	06/07/90	9.336	9.187	0.149	22	6.62
07/27/90	10/02/90	10.387	9.127	1.260	67	18.38

^a Time tabulated is days of production with the coupon installed.
Coupon material is C1018 carbon steel for all coupons in this table.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit L-2. COUPON AFTER SEPARATOR

<u>Date In</u>	<u>Date Out</u>	<u>Weight In, grams</u>	<u>Weight Out, grams</u>	<u>Wt Loss, grams</u>	<u>Time In, # of Days^a</u>	<u>Loss Rate, mils/yr</u>
07/20/88	07/22/88	10.930	10.613	0.317	2	154.88
07/22/88	07/26/88	10.895	10.119	0.776	4	189.57
07/26/88	08/02/88	10.916	9.642	1.274	7	177.84
08/02/88	08/09/88	10.872	10.399	0.473	7	66.03
08/09/88	08/16/88	10.893	10.921	-0.028	7	-3.91
08/16/88	08/23/88	23.340	23.24	0.100	7	13.96
09/10/88	09/22/88	18.113	18.054	0.059	12	4.80
09/22/88	09/29/88	18.301	18.258	0.043	7	6.00
09/29/88	10/12/88	18.209	18.185	0.024	13	1.80
10/12/88	10/25/88	18.276	17.756	0.520	13	39.09
10/25/88	11/08/88	18.315	18.290	0.025	14	1.74
11/08/88	11/22/88	18.337	18.317	0.020	14	1.40
11/22/88	12/06/88	18.099	18.018	0.081	14	5.65
12/06/88	12/20/88	9.058	8.9557	0.102	14	7.14
12/20/88	01/03/89	8.069	8.040	0.029	14	2.02
01/03/89	01/17/89	9.191	9.040	0.151	14	10.54
01/17/89	01/31/89	9.373	9.253	0.120	14	8.38
01/31/89	02/14/89	9.257	9.054	0.203	14	14.17
02/14/89	03/17/89	9.475	9.321	0.154	31	4.85
03/17/89	04/18/89	9.417	9.218	0.199	32	6.08
04/18/89	05/17/89	9.405	9.240	0.165	29	5.56
05/17/89	06/28/89	9.509	8.619	0.890	31	28.05
06/28/89	08/25/89	10.222	9.338	0.884	37	23.35
08/25/89	10/19/89	9.253	8.969	0.284	17	16.32
10/19/89	12/20/89	10.302	9.590	0.712	56	12.42
12/20/89	03/19/90	10.444	10.152	0.292	89	3.21
03/19/90	05/08/90	9.261	9.207	0.054	50	1.06
05/08/90	06/07/90	9.285	9.171	0.114	22	5.06
07/27/90	10/02/90	10.389	8.814	1.575	67	22.97

^a Time tabulated is days of production with the coupon installed.
Coupon material is C1018 carbon steel for all coupons in this table.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit L-3. COUPON BEFORE DISPOSAL WELL (After Filter Skid)

<u>Date In</u>	<u>Date Out</u>	<u>Weight In, grams</u>	<u>Weight Out, grams</u>	<u>Wt Loss, grams</u>	<u>Time In, # of Days^a</u>	<u>Loss Rate, mils/yr</u>
07/20/88	07/26/88	10.933	10.256	0.677	6	110.26
07/26/88	08/02/88	10.904	10.109	0.795	7	110.98
08/02/88	08/09/88	10.874	10.492	0.382	7	53.32
08/09/88	08/16/88	23.31	23.21	0.100	7	13.96
08/16/88	08/23/88	23.540	23.505	0.035	7	4.89
09/10/88	09/22/88	18.083	18.005	0.078	12	6.35
09/22/88	09/29/88	17.927	17.892	0.035	7	4.89
09/29/88	10/12/88	18.165	18.140	0.025	13	1.88
10/12/88	10/25/88	17.843	17.812	0.031	13	2.33
10/25/88	11/08/88	18.347	18.310	0.037	14	2.58
11/08/88	11/22/88	17.958	17.906	0.052	14	3.63
11/22/88	12/06/88	8.995	8.890	0.105	14	7.33
12/06/88	12/20/88	10.057	9.976	0.081	14	5.65
12/20/88	01/03/89	9.211	9.139	0.072	14	5.03
01/03/89	01/17/89	9.087	9.026	0.061	14	4.26
01/17/89	01/31/89	9.842	9.750	0.092	14	6.42
01/31/89	02/14/89	9.364	9.276	0.088	14	6.14
02/14/89	03/17/89	9.324	8.966	0.358	31	11.28
03/17/89	04/18/89	9.370	9.224	0.146	32	4.46
04/18/89	05/17/89	9.495	9.391	0.104	29	3.50
05/17/89	06/28/89	9.422	NO DATA -- Sheared Coupon with Extractor			
06/28/89	08/25/89	10.353	9.940	0.413	37	10.91
08/25/89	10/19/89	8.968	8.880	0.088	17	5.06
10/19/89	12/20/89	10.194	9.906	0.288	56	5.03
12/20/89	03/19/90	10.485	10.226	0.259	89	2.84
03/19/90	05/08/90	9.504	9.440	0.064	50	1.25
05/08/90	06/07/90	9.506	9.475	0.031	22	1.38
07/27/90	10/02/90	10.544	9.876	0.668	67	9.74

^a Time tabulated is days of production with the coupon installed.
Coupon material is C1018 carbon steel for all coupons in this table.

TESTING OF THE PLEASANT BAYOU WELL THROUGH OCTOBER 1990

Exhibit L-4. COUPON FROM TOP OF WELLHEAD LOOP

<u>Date In</u>	<u>Date Out</u>	<u>Weight In, grams</u>	<u>Weight Out, grams</u>	<u>Wt Loss, grams</u>	<u>Time In, # of Days^a</u>	<u>Loss Rate, mils/yr</u>
06/10/88	09/02/88	23.465	--	23.465 ^{b,c}	84	>272.96
09/07/88	10/18/88	18.258	9.546	8.712 ^b	33	257.97
10/18/88	05/25/89	18.032	--	18.032 ^{b,c}	209	>84.31

a Time tabulated is days of production with the coupon installed.

b Coupon material is C1018 carbon steel.

c Coupon missing -- presumed to have corroded away.

Exhibit L-5. COUPON FROM BOTTOM OF WELLHEAD LOOP

<u>Date In</u>	<u>Date Out</u>	<u>Weight In, grams</u>	<u>Weight Out, grams</u>	<u>Wt Loss, grams</u>	<u>Time In, # of Days^a</u>	<u>Loss Rate, mils/yr</u>
06/10/88	09/02/88	23.123	8.939	14.184 ^b	84	165.00
09/07/88	10/18/88	18.212	17.260	0.952 ^b	33	28.19
10/18/88	05/25/89	18.742	--	18.742 ^{b,c}	209	>87.63
05/25/89	07/20/89	10.386	9.666	0.720 ^d	54	13.03
08/09/89	11/17/89	10.690	9.323	1.367 ^d	60	22.26
11/17/89	07/05/90	10.423	9.620	0.803 ^d	189	4.15

a Time tabulated is days of production with the coupon installed.

b Coupon material is C1018 carbon steel.

c Coupon missing -- presumed to have corroded away.

d Coupon material is 4130 steel.

Exhibit L-6. COUPON FROM HPS DISCHARGE

<u>Date In</u>	<u>Date Out</u>	<u>Weight In, grams</u>	<u>Weight Out, grams</u>	<u>Wt Loss, grams</u>	<u>Time In, # of Days^a</u>	<u>Loss Rate, mils/yr</u>
08/25/89	09/07/89	8.929	8.925	0.004	13	0.30
10/19/89	12/20/89	9.348	9.361	-0.013	56	-0.23
12/20/89	03/19/90	10.435	10.440	-0.005	89	-0.05
03/19/90	05/8/90	9.537	9.580	-0.043	50	-0.84
05/08/90	06/07/90	9.465	9.479	-0.014	22	-0.62

a Time tabulated is days of production with the coupon installed.
Coupon material is C1018 carbon steel for all coupons in this table.

APPENDIX M

Corrmet Metallurgical Reports

Exhibit M-1. MARCH 8, 1989, REPORT

METALLURGICAL EXAMINATION OF
VARIED CARBON STEEL PIPING
SYSTEM COMPONENTS - IGT GEO-
THERMAL PROJECT, PLEASANT
BAYOU, ALVIN, TEXAS

**CORRUMET
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Consulting Corrosion and Metallurgical Engineers

12820 So. Main • P.O. Box 35387, Houston, Tx 77035 • (713) 721-3274

March 8, 1989

Mr. Philip L. Randolph
Institute of Gas Technology
P.O. Box 1775
Alvin, Texas 77512

Dear Mr. Randolph:

As per your request, we have examined the varied Carbon Steel brine line piping system components that had experienced varying degrees of internal localized corrosion attack. These piping components were removed from the IGT Geothermal Project at Pleasant Bayou No. 2/Eaton Operating Company, Inc. located in Alvin, Texas. It was reported that this brine line piping system had previously seen about 4 million barrels of brine between 1980-1982, and then the system was shut-down and left idle for six (6) years. After the six (6) year stagnation period, the piping system had seen a flow of approximately one million barrels of brine. During this short period of time numerous brine line leaks had developed and finally the corroded components affected were removed and replaced in kind.

On 10/14/1988 a trip was made to the project site in Alvin, Texas and the following piping, fittings, chokes and valve components were submitted for further laboratory and metallurgical examination. This investigation was instituted in order to examine not only the material's integrity or quality but to what extent the brine line piping components, being of Carbon Steel construction, may have contributed to the aforementioned localized pitting corrosion (erosion-corrosion attack) previously experienced within this system.

Specimens

- A. An 8" dia. Main Choke's Bonnet (Carbon Steel construction) that had experienced severe localized pitting corrosion attack.
- B. A representative corroded section of the 8 X 4 inch diameter Carbon Steel Reducing "Tee" located downstream of the 8" dia. Main Choke.
- C. A representative corroded sample of a 4" dia. Carbon Steel Pipe section (split lengthwise) containing several welded thread-o-let fittings.

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- D. A 900# Rated 4" dia. Forged Steel "Rockwell" Shut-off Plug Valve located upstream of a 4" Willis Choke.
- E. A 4 inch dia. Carbon Steel "S" shaped Riser Pipe section (downstream of the 4" Willis Choke).
- F. A 900 # Rated 4" dia. Forged Steel "WKM" Shut-off Plug Valve located on the brine discharge line off separator # V 101.
- G. A short section of 4" dia. sch. 160 Carbon Steel Pipe submitted to verify the material's metallurgy.

Metallurgical Analysis

1. Main Choke Bonnet

The round bonnet sample removed from the 8" dia. main choke was 6-5/8 of an inch at the base and 3-5/8 of an inch at the face and was of Carbon Steel construction. The bonnet's face area had experienced extensive localized pitting as well as erosion-corrosion attack in the form of washed-out areas that appeared to have occurred or was related to high flow rates (velocity) and turbulence. The major corrosion damage was limited to the face area (exposed to the environment). Additional and descriptive details of the corrosion attack experienced is better shown in figure 1.

Metallographic Examination

A cross-sectional area of the corroded area was prepared for metallographic examination by using an optical microscope. Photomicrograph of the polished and etched specimen is shown in figure 2. The microstructure consists of a mixture of pearlite, bainite and ferrite, which indicates the section was heat treated by the normalizing process. The corroded areas were generally free of scale deposits. The corrosion attack pattern appeared "jagged" and moderately grooved which can best be seen in figure 3. The grooving and gouging resulted or was caused by an erosion-corrosion form of attack that was related to velocity and turbulence.

Microhardness Testing

Microhardness testing of the prepared specimen revealed the following data:

Mr. Philip L. Randolph

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<u>Location</u>	<u>Knoop Hardness (300 gr. load)</u>	<u>Brinell Hardness (converted)</u>	<u>Rockwell "B" (converted)</u>
Random Area	218	197	95
Random Area	218	197	95
Random Area	209	190	93
Random Area	212	193	94

Recommendation

The existing bonnet material appears to be a suitable material of construction for this application. However, it can be improved or used more effectively if the exposed surface area (face) is altered metallurgically. This can be accomplished by applying a proper type of case-hardening treatment that will not only increase the surface hardness (to improve wear resistance) but will also enhance its corrosion resistance.

2. An 8 inch dia. "Straight Tee" Concentrically Reduced to two (2) 4" dia. Outlets.

The above Carbon Steel Reducer fitting sample "as received" consisted of half sections that was split lengthwise through the 8 inch diameter "Straight Tee" Section as well as its adjoining (by welding) Concentric Reducer (8 inch to 4 inch outlet) Section. Close examination of the interior surface of the split fitting fabricated sample revealed pronounced pitting corrosion attack of a localized nature at two different sites. One of the sites affected occurred within the radial bend (radius of curvature) of the 8 inch "Tee" Section. The other site affected was of a more severe nature and occurred within the 4 inch outlet's "Throat" Section (Swaged area). In either case, the cause of such localized attack was related to velocity and turbulence. The 8 inch Straight Tee's wall thickness varied and measured anywhere from 0.765 inches to 0.835 inches. The Straight Tee Section and Concentric Reducers were both manufactured by the forging process and then were joined by welding. Additional details of the interior condition of this Reducer Assembly are shown in figures 4 and 5.

Metallographic Examination

One metallographic specimen was prepared through the corroded site for microscopic examination. The microstructure of the Tee Section consisted of mixed fine grains of ferrite and pearlite. The corroded site was covered by scale deposits and the attack experienced was pitting type corrosion. See photomicrographs 6 and 8.

Microhardness Testing

Microhardness testing of the Tee Section revealed the following data:

<u>Location</u>	<u>Knoop Hardness (300 gr. load)</u>	<u>Brinell Hardness (converted)</u>	<u>Rockwell "B" (converted)</u>
Random Area	151	139	80
Random Area	144	133	78
Random Area	141	131	77
Random Area	138	127	76

3. Nominal Four (4) Inch Diameter Line Pipe Containing Several Thread-O-Let Fittings.

This 4 inch diameter piping sample received was a 3-1/2 foot long half section of pipe containing a weld-neck flange. This half section was previously split lengthwise. It was reported that a leak developed within the butt-welded joint approximately one foot past the 4 inch Reducer "Tee" Section.

The interior of the piping assembly was visually examined for defects and revealed extensive localized pitting corrosion attack around the flange area. Again, the form of corrosion damage that was observed was velocity related, that is, it resulted from erosion-corrosion. The observed poor workmanship (i.e., poor joint fit-up and finish weldment) largely contributed to the erosion-corrosion form of attack. A detail of this form of corrosion is better shown in figures 8 and 9. The pipe wall thickness measured 0.337 inches, that is, it was Sch. 80 pipe. The upper half section of this 4 inch dia. piping contained several welded-in thread-o-let fittings. The fit-up and weldment joint design of these fittings was very poor since it did not fully penetrate the pipe wall which resulted in a suck-up or countersunk condition. The end of the fitting was not flush with the interior pipe wall. This prevailing poor joint design and fit-up contributed to the erosion-corrosion attack that eventually led to the leakage. See figures 10 and 11 for more details.

Metallographic Examination

Two metallographic specimens were prepared from the 4 inch diameter piping assembly; one specimen was made through the joint that had previously experienced leakage. The second specimen was made from the thread-o-let's weldment joint-to-pipewall. Microscopic examination in the unetched condition revealed the pipe material was clean and free from harmful non-metallic inclusions.

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Etched microscopic examination indicated the pipe material was in the "as-rolled" condition. Its microstructure consists of mixed grains of ferrite and pearlite which is a typical structure of this grade of pipe (indications show pipe to be ASTM 106 grade "B" Seamless - Sch. 80). The corrosion attack at the welded site was extensive and appeared mostly in the form of pitting. Photomicrographs 12 and 13 show the pipe's general microstructure and the localized corrosion attack.

Examination of the specimen made from the thread-o-let's welded junction indicated that the joint had suffered localized pitting corrosion attack. The pits were slightly undercut and this type attack generally is due or related to velocity and turbulence. See photomicrograph No. 14 for details.

Microhardness Testing

The microhardness testing of the specimen prepared from the weldment revealed the following data:

<u>Location</u>	<u>Knoop Hardness (300 gr. load)</u>	<u>Brinell Hardness (converted)</u>	<u>Rockwell "B" (converted)</u>
Base Metal	168	154	85
Base Metal	168	154	85
Base Metal	168	154	85
HAZ	190	171	90.5
HAZ	190	171	90.5
HAZ	195	180	91
Weld Metal	168	154	85
Weld Metal	168	168	85
Weld Metal	168	168	85

The pipe hardness value averaged 85 Rb which is equivalent to about 78,000 Psi Ultimate Tensile Strength.

Thread-0-Let Weldment Joint

<u>Location</u>	<u>Knoop</u>	<u>Brinell</u>	<u>Rockwell "B"</u>
Weld Metal	157	145	82
Weld Metal	148	136	79

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Thread-0-Let Weldment Joint (Continued)

<u>Location</u>	<u>Knoop</u>	<u>Brinell</u>	<u>Rockwell "B"</u>
Weld Metal	148	136	79
HAZ	148	136	79
HAZ	171	158	85.5
HAZ	171	126	85.5
Base Metal	140	126	80.5
Base Metal	135	122	74
Base Metal	132	120	73

4. Four (4) Inch Dia. Rockwell Shut-Off Plug Valve.

This valve was located upstream to the 4 inch diameter Willis Choke. Reportedly there was no evidence of any form of internal corrosion attack within the valve and its associated flanges. The valve bore size measured 3.848 inches which is almost the same bore size of the 4 inch (nominal) Sch. 80 pipe. This uniform or matching bore size is good pipe design. It aids in assuring a laminar flow condition as opposed to turbulent flow that can result in or enhance wear.

Chemical Analysis

<u>Elements</u>	<u>Percent Present</u>	
	<u>Rockwell Valve</u>	<u>AISI 102 5 Carbon Steel</u>
Carbon	0.25	0.22-0.28
Manganese	0.53	0.30-0.60
Phosphorus	0.019	0.040 Max
Sulfur	0.028	0.050 Max
Silicon	0.29	*
Chromium	0.12	*
Molybdenum	0.04	*
Nickel	0.12	*
Copper	0.09	*
Aluminum	0.057	*

* Not specified

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Metallographic Examination

One metallographic specimen was prepared thru an area encompassing the Rockwell Valve's flange face. An unetched microscopic examination revealed a valve material that was clean and free from harmful non-metallic inclusions.

An etched microscopic examination indicated the valve body was forged (manufactured by the forging process). Its' microstructure consists of large grains of ferrite surrounded by pearlite grains. Photomicrograph No. 15 shows the typical microstructure of this Rockwell Valve.

Microhardness Testing

<u>Location</u>	<u>Knoop Hardness (300 gr. load)</u>	<u>Brinell Hardness (converted)</u>	<u>Rockwell "B" (converted)</u>
Random Area	190	170	90.5
Random Area	168	154	85.0
Random Area	190	170	90.5
Random Area	165	152	<u>84.0</u>
Average			87.5

5. A Nominal 4 Inch Dia. Carbon Steel "S" Shaped Pipe Riser

A 4 inch diameter Carbon Steel Pipe assembly complete with flanges, being of an "S" shaped configuration, was received. This particular piping section was located immediately downstream of the 4 inch Willis Choke. It was reported that leaks had previously developed (mostly due to pitting) through the vertical riser section of this piping section and at an area where the pipe wall was only equal to Sch. 80 (wall thickness 0.337 inches). At this point, specifications called for Sch. 160 pipe. Additional details of the interior conditions of this piping assembly are shown in figures 16, 17, 18 and 19.

Both corrosion attack as well as velocity-related erosion-corrosion was observed on the pipe's interior surface adjacent to the welded joint. This particular joint was butt-welded even though the wall thickness of the two butting piping sections were different. The pipe section welded to the flange was Sch. 160 pipe while the other half section of pipe was Sch 80. As a result, the OD of the two adjoining pipe sections appears to be of the same size, however, the ID side or pipe bore was totally different. One was slightly larger than the other one. This type pipe joint design resulted in a high-low (step) joint fit-up condition within the pipe bore which ultimately

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created a turbulent condition that can increase wear or erosion of the pipe at this point.

Metallographic Examination

Several metallographic specimens were prepared through the weld joints. Mixed microstructure patterns were observed on this piping. The microstructure of the Sch. 80 pipe consists of mixed grains of pearlite and ferrite, which is a typical structure for "as-rolled" or "hot-rolled" Carbon Steel. The typical microstructure is shown in figure 20.

The microstructure of Sch. 160 (90 deg. elbow) consists somewhat of banded fine grains of ferrite and pearlite as is shown in figure 21. This grade of steel is preferred over the Sch. 80 grade as it has better corrosion resistance. This 90 deg. elbow was manufactured by the forging process. Photomicrographs of the heat affected zone (HAZ) and weldment are shown in figures 22 and 23. Since the weldment appears to be metallurgically sound, it apparently did not contribute to the localized pitting corrosion attack experienced.

Photomicrographs of the flange-to-pipe welded joint is shown in figures 24 and 25. The flange material's microstructure consists of banded grains of ferrite and pearlite. It was manufactured by the forging process. The corroded site was covered with a scale deposit. There was no evidence of any destructive pitting corrosion attack. (See figure 14). A photomicrograph of the weldment joining the 90 deg. elbow-to-flange piping section indicates a metallurgically sound joint. Furthermore, the weldment was free from any critical weld defects. Figure 26 shows the representative weldment section that was examined.

Microhardness Testing

Microhardness Testing of the prepared specimen made from the Sch 80 Pipe-to-90 deg. Elbow welded joint revealed the following data:

<u>Location</u>	<u>Knoop Hardness (300 gr. load)</u>	<u>Brinell Hardness (converted)</u>	<u>Rockwell "B" (converted)</u>
Base Metal	125	113	70
Base Metal	122	111	69
Base Metal	118	106	67
* HAZ	139	127	76
HAZ	173	160	86

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Continued

HAZ	143	131	77
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HAZ	182	168	88
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* HAZ = Heat Affected Zone

<u>Location</u>	<u>Knoop Hardness (300 gr. load)</u>	<u>Brinell Hardness (converted)</u>	<u>Rockwell "B" (converted)</u>
Weld Metal	138	127	76
Weld Metal	139	127	76
Weld Metal	132	120	73

Microhardness Testing of the prepared specimen made from the Sch 80 Pipe-to-90 deg. Elbow welded joint revealed the following data:

<u>Location</u>	<u>Knoop Hardness (300 gr. load)</u>	<u>Brinell Hardness (converted)</u>	<u>Rockwell "B" (converted)</u>
Base Metal	168	154	85
Base Metal	163	150	83
Base Metal	168	154	85
HAZ	218	197	75
HAZ	198	183	82
HAZ	209	190	93
Weld Metal	203	185	92.5
Weld Metal	182	168	88.00
Weld Metal	200	183	92

6. Four (4) Inch Dia. WKM Shut-Off Valve

This valve was located downstream of the discharge line off one of the separators. There was no corrosion attack within the valve bore especially within both its flanges. However, the pipe bore at the mating (downstream) piping flange area experienced severe corrosion attack. The WKM valve bore measured 4.251 inches. An explanation for the internal corrosion attack experienced within the pipe bore of the downstream and mating flanged piping run most likely resulted from the differences in bore sizes (i.e., the bore variances between the valve bore and the mating flanged piping assembly).

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The mating flanged piping assembly could not be submitted for further laboratory examination. Also, it is quite apparent that the mating flanged piping assembly was like any other pipe sections in the discharge line, that is, it was fabricated of Sch. 80 pipe which has pipe bore of 3.836 inches. Consequently, since the 4 inch WKM valve bore size was larger (4.251 inches) than the mating flanged piping bore (3.836 inches) this difference in bore size largely attributed to the immediate flanged area's corrosion attack (i.e., pronounced increase in turbulent flow conditions).

Chemical Analysis

<u>Elements</u>	<u>Percent Present WKM Valve</u>	<u>AISI 1022 Spec.</u>
Carbon	0.21	0.18-0.23
Manganese	0.77	0.70-1.00
Phosphorus	0.023	0.040 Max
Sulfur	0.031	0.050 Max
Silicon	0.38	*
Chromium	0.36	*
Molybdenum	0.16	*
Nickel	0.26	*
Copper	0.09	*

* Not specified

Metallographic Examination

One metallographic specimen was prepared from a pie-shaped segment cut thru the WKM valve flange thickness. Unetched microscopic examination revealed a valve material that was relatively free from harmful non-metallic inclusions.

Etched microscopic examination indicated the valve body was manufactured by the forging process. Its microstructure consists of very fine grains of ferrite and pearlite. See photomicrograph No. 27 which shows the representative microstructure for this particular WKM Valve. A comparison of the microstructure of each of the two valve's material indicated totally different microstructures. Factors such as chemical composition (alloying content), the forging process and method of post heat treating can largely govern a metallic material's microstructure.

Microhardness Testing

<u>Location</u>	<u>Knoop Hardness (300 gr. load)</u>	<u>Brinell Hardness (converted)</u>	<u>Rockwell "B" (converted)</u>
Random Area	212	193	94.0
Random Area	212	193	94.0
Random Area	231	215	97.0

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Microhardness Testing (Continued)

<u>Location</u>	<u>Knoop Hardness (300 gr. load)</u>	<u>Brinell Hardness (converted)</u>	<u>Rockwell "B" (converted)</u>
Random Area	206	190	93.0
	Average		94.5

The WKM valve hardness value averaged 94.5 Rockwell "B" (Rb). This hardness is equivalent to about 97,000 Psi Ultimate Tensile Strength (UST) as compared to the Rockwell valve's lower value of 84,000 Psi UTS. By virtue of this higher UTS value, the WKM valve possesses better hardness properties and generally should have somewhat better erosion-corrosion resistance. However, while in this service, neither one of these two valves have experienced any form or degree of corrosion attack but indirectly they may have contributed to turbulent flow conditions that resulted in internal erosion-corrosion attack of the adjacent or adjoining piping downstream of the valve installation of a different bore diameter than the piping.

7. 4 Inch Dia. Sch. 160 Pipe Sample

A short section of new nominal 4 inch dia. Sch 160 Carbon Steel Pipe which was stored in the pipe yard was also submitted for laboratory evaluation. This particular stored pipe is used as spare or replacement pipe for 4 inch dia. pipe removed from service. The pipe's outer diameter (OD) measures 4.5 inches and is schedule 160 (0.533 inch wall thickness). One metallographic specimen was made from this section. Microscopic examination in the unetched condition revealed a pipe material that was clean and free from harmful non-metallic inclusions.

Etched microscopic examination indicated the pipe was furnished in the "as-rolled" or "hot-rolled" condition. Its microstructure consists of mixed grains of ferrite and pearlite and appeared to be similar to ASTM A53 Type S-Grade B or A106 Grade B Seamless Pipe. See figure 28

Microhardness Testing

<u>Location</u>	<u>Knoop Hardness (300 gr. load)</u>	<u>Brinell Hardness (converted)</u>	<u>Rockwell "B" (converted)</u>
Random Area	106	93	59.0
Random Area	125	113	70.0
Random Area	118	106	67.0
Random Area	115	104	66
	Average		65.5

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The pipe hardness value averaged 65.5 Rb which is equivalent to about 56,000 Psi Ultimate Tensile Strength. Both ASTM specs for Type S - Grade B A53 or A106 Grade B Seamless Pipe specifies a minimum UTS of 60,000 Psi.

Discussion

Close laboratory examination and tests of the varied carbon steel piping components (pipe, fittings, risers, valves, chokes, etc.) that were received indicated that the metallurgy of all component's material examined could not have significantly contributed to the overall corrosion attack that was experienced. Further, even though some slight differences occurred in the material properties of the varied components examined they were not of any real significance. Also, the comparative microstructure of each components' material appeared to be slightly different from each other. In general, the overall hardness properties of those sections examined showed some slight variance from section to section. Nonetheless, there was not any direct or real evidence indicating differences in hardness values as having contributed to the existing problem.

The internal localized corrosion attack that occurred within those piping components affected is believed primarily to be of a four fold nature, namely: (a) Piping Design/Fluid Flow variables, (b) Wear Susceptible Material of Construction, (c) Inadequate Piping Fit-up for joining by butt-welding, and (D) Built-in Welding Defects due to poor welding practice and joint design (i.e., fabrication deficiencies).

In keeping with the above premise, the major cause of the grooves, gouging or pitting observed within the piping components examined was not totally due to chemical (hot brine) corrosion attack. Such attack was generally prompted and related to fluid velocity and erosion factors which accelerated the rate of pitting corrosion at critical sites within the pipe run. Erosion and corrosion when coupled usually complement each other. Where velocities are high, any protective corrosion products formed are often removed by the erosive action thereby causing the corrosion reaction to proceed or continue at a more rapid pace. Such combined actions was the cause of localized corrosion attack in the piping components examined as all these components were constructed of a wear susceptible material (low carbon steel).

The wear of carbon steels may occur through direct contact either with other metals (with or without the presence of solids - this is known as Double-Sided Wear) or where the contacting medium is a flowing liquid or fluid (Single-Sided Wear which usually contains entrained loose solids or liquid particles). For Single-Side Wear (such as in the brine piping) and where fluids are active, wear can be in the form of erosion (liquid or solid particles impinging on a solid surface) and in turn is usually associated

with a corrosion process which contributes to rate of metal removal or attack.

Hence, the erosion of a solid surface by solid or liquid particles entrained in a flowing fluid is dependent on the number of particles striking the surface, their velocity, and their direction relative to the surface. Fluid flow conditions largely determine the effects of the above factors concerning erosive wear. Many practical examples exist or can be found where a change or interruption in fluid flow conditions has either greatly increased or decreased erosion. In high pressure piping (carbon steel) runs where the fluid or liquid direction of flow changes fairly rapidly (i.e., through valving, pipe fittings, pipe bends, etc.) erosion is considered to be more severe than in "straight-run" piping. Built-in local turbulence due to a roughened metal surface, changes in bore sizes or misaligned internal piping fit-up (high-lows) used for butt-welding (joining) greatly increase erosional effects. For this reason, internal pitting corrosion attack can be increased or accelerated, thereby shortening the service life of the piping components operating under such erosive conditions.

A case in point, is the erosion-corrosion attack suffered by the "downstream" piping that was flanged to the 4 inch diameter WKM valve. This type attack was basically due to improper piping design (valve bore selection). That is, mismatched piping and valve bore sizes. The 4 inch WKM valve had a bore size of 4.251 inches versus the flanged downstream piping which had a 3.836 inch bore size. This appreciable difference in bore sizes resulted in increased turbulence and erosional effects of the fluid flowing in the flanged piping assembly "downstream" of the valve installation.

Piping design as well as fabrication and welding deficiencies were noted on the "S" shaped piping section examined. There was both poor joint fit-up and welding due to pipe make-up involving two different pipe schedules (i.e., mixing Sch 160 pipe with Sch 80 pipe) that was installed in the four (4) inch nominal diameter pipe run. This is definitely not good piping design practice, since, as a pipe's schedule increases, the bore (ID) decreases to accommodate the increased pipe wall thickness thereby resulting in two different mismatched pipe bores (turbulent flow).

The relative erosion resistance of different materials depends on the impingement angle at which a surface is being contacted by loose solids or liquid particles. An assessment of erosive wear resistance on the basis of hardness alone can be misleading. That is, it is thought that steel pipe of higher hardness values will have considerably longer-life than steel pipe of lower hardness values (softer) when handling abrasive materials. Studies have shown, however, that the erosion resistance of different materials could vary as the angle of particle impingement changes.

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Conclusions

- (1) Both the microstructures and hardness values of the varied piping components examined and compared indicated or showed only slight variances from section to section.
- (2) The internal erosion-corrosion attack that was experienced within these critical piping components of the brine piping system appears to be independent of the carbon steel material's metallurgy and mechanical properties.
- (3) The combined action of erosion (due mainly to fluid flow variances and inadequate piping design and fit-up) coupled with corrosion contributed greatly to the localized corrosion pitting attack experienced in the piping components examined since all of these components were constructed of a wear susceptible material such as low carbon steel.
- (4) The overall or major cause of the severe localized pitting corrosion experienced within this brine piping components examined appears to be primarily related to the following:
 - (a) Improper Piping Design Practices/Fluid Flow Variables
 - (b) A Wear susceptible piping material (low carbon steel)
 - (c) Inadequate pipe joint fit-up for joining by butt-welding
 - (d) Built-in welding defects due to poor welding practices, welding procedures and improper joint design (i.e., fabrication deficiencies).

Respectfully submitted,
CORRMET ENGINEERING SERVICE

Robert H. Zand, P.E.
Metallurgical Engineer

Michael C. Deodati
Sr. Consultant Specialist

Figure 1 1/2 of Actual Size
A view of the Main Choke's Bonnet section (high pressure service) submitted for examination. Velocity-related erosion-corrosion is quite prevalent on its face.

Figure 2 200 Magnification Etched
Photomicrograph showing the representative microstructure of the bonnet's material. Its microstructure consisted largely of ferrite (light) and pearlite (dark).

Figure 3 200 Magnification Etched
Another photomicrograph of the bonnet material taken at the corroded site which shows the erosion-corrosion pattern. The corrosion pattern appears "jagged" in nature.

Figure 4 Reduced in Size
A view of the interior surface of an 8x4 inch Reducing "TEE" showing the localized pitting corrosion attack which occurred mostly at the reducer end.

Figure 5 Reduced in Size
A view of the top half section of an 8x4 Reducing "TEE" seen in figure 4. Again, severe localized corrosion attack is evident at the 4" reduced neck area.

Figure 6 200 Magnification Etched
Photomicrograph showing the representative microstructure of the 8"x4" Reducing Tee. It consists of mixed grains of ferrite and pearlite.

Figure 7 200 Magnification Etched
Photomicrograph showing the general appearance of one of the
internally corroded sites that is covered with scale deposits.

Figure 8 Reduced in Size
A view of the internal surface of the 4" line (downstream of
8"x4" Tee) and its welded flange fitting. Both the flange and
adjacent area at the weld joint experienced severe erosion-
corrosion attack.

Figure 9 Reduced in Size
A closer view of the internal surface of the 4" line seen
in figure 8. Again, an extensive erosion-corrosion attack
pattern is apparent.

Figure 10 Reduced in Size
A view of the interior surface of the 4" line showing its
top-half portion containing welded thread-o-let type fittings.

Figure 11 Reduced in Size
A closer view of one of the thread-o-let welded fittings observed in figure 10. This particular fitting experienced pitting attack due to erosion-corrosion that resulted in leakage. Poor fit-up as well as workmanship attributed to the problem.

Figure 12 200 Magnification Etched
Photomicrograph showing the representative microstructure of 4" line seen in figure 8. It consists of ferrite and pearlite. This pipe material is in an "as-rolled" condition.

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Figure 13 200 Magnification Etched
Photomicrograph showing the general pattern of corrosion
attack taken from one of the corroded sites (4" pipe weld-
to-flange area).

Figure 14 200 Magnification Etched
A representative photomicrograph taken at the corroded site
of the sample seen in figure 11. Deep "gouging" due to
erosion action is prevalent.

Figure 15 200 Magnification Etched
Photomicrograph showing the representative microstructure
of the 4" dia. "Rockwell" valve material. It consists of
blocky grains of ferrite (light) and pearlite (dark).

Figure 16 Reduced in Size
A view of the ID surface of the straight run section of the 4 inch dia. "S" shaped pipe riser downstream of the Willis Choke. Note the changes or variance in the pipe section's ("A" versus "B") wall thickness as well as the poor workmanship (weldment and fit-up) of the welded joint. These defects ultimately attributed to the erosion-corrosion attack.

Figure 17 Reduced in Size
A closer view of the ID surface of pipe section Marked "A" as seen in figure 16. Poor fit-up of the butt-joint as well as localized erosion-corrosion attack are evident.

Figure 18 Reduced in Size
A closer view of the ID of pipe section Marked "B" as seen in figure 16. Note that the welded joint (pipe-to-flange) has experienced severe corrosion penetration within the weld metal.

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Figure 19 Reduced in Size
A view of the top mating half to the 4" "S" shaped riser section seen in figure 16 (section Marked "B").

Figure 20 200 Magnification Etched
Photomicrograph showing the representative microstructure of Sch. 80 straight run pipe (section "A" seen in figure 16). It consists of mixed grains of ferrite and pearlite which is typical of hot-rolled carbon steel pipe.

Figure 21 200 Magnification Etched
Photomicrograph showing the representative microstructure of
Sch. 160 Elbow fitting (Section "B" in figure 16) which was
welded to Sch. 80 pipe (Section "A").

Figure 22 200 Magnification Etched
Photomicrograph showing the representative microstructure of
the weldments of the heat-affected zone (HAZ) of section "A"
in figure 16.

Figure 23 200 Magnification Etched
Photomicrograph showing the representative microstructure of
the weld metal (section "A" in figure 16).

Figure 24 2.5 Magnification Etched
Macrograph showing the cross-section prepared for microscopic
examination (weldment of section "B" in figure 16). Slight
corrosion attack is evident on the ID wall (arrow). The
weldment appears metallurgically sound.

Figure 25 200 Magnification Etched
Photomicrograph showing the representative microstructure of
the flange material (of section "B" in figure 16). it consists
of ferrite and pearlite.

Figure 26 200 Magnification Etched
Another photomicrograph showing the corroded site as shown by
arrow in figure 24. A heavy built-up of scale deposit is
apparent.

Figure 27 200 Magnification Etched
Photomicrograph showing the representative microstructure of the 4" dia. "WKM" valve material. It consists of fine grains of ferrite and pearlite. Note: the two valves examined exhibited two different microstructures.

Figure 28 200 Magnification Etched
Photomicrograph showing the representative microstructure of Sch. 160 pipe that was reportedly put-in service recently. It consists of ferrite (light) and pearlite (dark) which is comparable to ASTM A106, grade "B" composition seamless steel pipe.

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Exhibit M-2. JUNE 15, 1989, REPORT

METALLURGICAL EXAMINATION OF
INTERNALLY CORRODED OF TWO
FITTING SECTIONS - 6" BRINE
LINE TO THE BRINE DISPOSAL WELL

**CORROSION
ENGINEERING
SERVICES**

Consulting Corrosion and Metallurgical Engineers

12820 So. Main • P.O. Box 35387, Houston, Tx 77035 • (713) 721-3274

June 15, 1989

Mr. Philip Randolph
Institute of Gas Technology
P.O. Box 1775
Alvin, TX 77512

Dear Mr. Randolph:

As per your request, we have examined the two fitting sections removed from the Carbon Steel Brine Line. These two fitting sections had experienced severe localized internal corrosion attack and were located at different sites within the 6" brine flow line to the brine disposal well. The results of our laboratory investigations are as follows:

Specimens

- A. Mating half sections (split longitudinally) of a 4" X 6" Carbon Steel reducer fitting that had experienced severe localized internal corrosion attack.
- B. A 6" dia. in-line Carbon Steel "Tee" Section with a weld-neck flange on one end that experienced severe localized internal corrosion attack.

Laboratory Analysis

Visual Examination

Both specimens "A" and "B" were visually examined. For both examined specimens, the severe localized internal corrosion attack that existed was located adjacent to a weld seam and was confined to the fitting side. Both fitting sections (i.e. the Tee and Reducer) appeared to be manufactured by the forging process. The corrosion attack was of a ring-like form called "weld line" corrosion and was rather deep and about 1/2 inch wide, running around the pipe in circumferential path. Further, the ring-like corroded sites had a grooved-out pattern appearance which was relatively free from scale deposits. It appeared that the corrosion attack mechanism was somehow further enhanced by an erosion-corrosion form of attack. See figures 1 thru 7.

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Metallographic Examination

Several metallographic specimens were prepared through the ring-like corroded site for microscopic examination. Microscopic examination in the etched condition indicated that the severe pitting attack observed was within the Weld Heat Affected Zone (HAZ) of the welded joint assembly. The material's microstructure consisted predominately of mixed grains of ferrite and pearlite which is a typical structure for this grade of material.

The corrosion pits examined were generally quite deep but free of scale deposits. Also some of them were gouged out or undercut, indicating some form of erosion-corrosion attack had occurred. The pitting initiated from the weld HAZ and proceeded in both directions, i.e., into the base metal and into the weld metal. See figures 7 thru 11.

Microhardness Testing

Microhardness Testing of both section revealed the following data:

1. 4" X 6" Reducer Section

<u>Location</u>	<u>Knoop Hardness (300 gram load)</u>	<u>Brinell Hardness (converted)</u>	<u>Rockwell "B" (converted)</u>
Bottom of the Pit	218	197	95
Bottom of the Pit	195	180	91
Base Metal	190	174	90
Base Metal	190	174	90
Weld-Pit Area	190	174	90
Weld-Metal	218	197	95

2. Tee Shaped Assembly

Bottom of the Pit	167	154	86
Bottom of the Pit	178	162	87
1/4 Wall	165	152	84
1/4 Wall	165	152	84
OD Wall	212	193	94
OD Wall	190	174	90

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No unusual or pronounced variations in the hardness values were noticed.

The materials approximate tensile strength is 78,000 psi based on average hardness value of 85 HRb.

Discussion and Conclusions

Both macroscopic and microscopic examination of the ring-like (weld-line) corroded site prevalent within these two fitting sections of the submitted piping assembly indicated this form of corrosion attack experienced was limited or confined within the weld Heat Affected Zone (HAZ) of all welded joints in the assembly. Microscopic examination of the material's structure at the weld-line corroded site indicated a typical micro-structure for a weld Heat-Affected Zone. Hardness survey indicated uniform hardness values for each of the welded joint assemblies.

The pattern and form of weld-line corrosion experienced indicated that corrosion attack most likely initiated as a result of metallurgical changes or alterations that had occurred during the welding process. It was then further accelerated by a velocity related form of corrosion attack that is best known as erosion-corrosion.

The following is offered to try to explain the mechanism responsible for the weld-line corrosion attack that had been experienced within these sections:

1. Initially, all corrosion attack was located and limited to the fitting's end sections. The fittings involved herein were manufactured by a forging process which involves a forming process whereby the material is in a highly stressed condition. Also, its grain structure is somewhat different than for "as-rolled" or "hot-rolled" materials.
2. The heat generated by the welding process caused the fitting material, in the vicinity of the weld seam, to have a different grain structure than that of the rest of the forged fitting.
3. Due to differences in grain structure adjacent to the weldment (HAZ) and the fitting parent metal, these two areas have different tendencies to preferentially corrode. This is providing the environment media is also corrosive. As a result, "weld-line" corrosion at the HAZ can occur.

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4. Sometimes a similar problem can result from an improper choice of welding electrodes. This problem is avoided by proper welding practices. In this case, this condition can be overcome by fully normalizing the finished weld seam and surrounding area. Normalizing is a heat treatment process that gives uniformity to grain structure.

Respectively submitted,
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Figure 1 Reduced in Size
A view of the "as-received" mating half sections of a 6"x4" reducer that had experienced internal localized pitting attack which occurred in the form of a grooved-out "ring" (arrows).

Figure 2 Reduced in Size
A closer view of one of the half sections seen in figure 1. The ring-like corrosion attack (area A) in the forged reduced assembly adjacent to the welded joints. Localized and deep circular pitting attack has also been experienced (area B).

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Figure 3 1.5 Magnification
A close-up view of the severe ring-like localized corrosion attack (note the uniform grooving) shown in area A of Figure 2. The corrosion attack is located adjacent to the welded joint.

Figure 4 1.5 Magnification
A close-up view of the localized and circular pits (shown in area B figure 2). Again, this type pitting attack is located next to a weld seam.

Figure 5 Reduced in Size
An overall view of the interior surface of a half section of a 6" "Tee" removed from the brine flow line to the disposal well. Note the localized (ring-like) pitting corrosion that has occurred on the forged Tee assembly adjacent to all weld seams (area C and D).

Figure 6 1.5 Magnification
A close-up view of the localized ring-like pitting corrosion attack (area C in figure 5). Again, this form of corrosion attack is adjacent to a weld seam.

Figure 7 1.5 Magnification
A close-up view of localized pitting attack (area D in figure 5) which is again typically located adjacent to the weld seam.

Figure 8 2 Magnification Etched
Macrograph showing the two cross-sections thru the corroded area prepared for microscopic examination. In each case, the severe corrosion attack is on the forged fitting side and adjacent to the weld joint (i.e. the weld Heat-Affected Zone).

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Figure 9 2 Magnification Etched
Another macrograph showing a welded joint localized corrosion
attack in the Heat-Affected Zone (HAZ) adjacent to the weldment.

Figure 10 150 Magnification Etched
Photomicrograph showing the microstructure of the reducer
material at the corroded site. Some slight indication of
erosion-corrosion attack (undercutting) is apparent.

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Figure 11 150 Magnification Etched
Photomicrograph of the Tee section showing the general appearance
of the corroded site which has occurred within the HAZ. The
microstructure of both fitting's material consisted of both
ferrite (white) and pearlite (dark).