MASTER

FINAL REPORT
G. M. KOELEMAY WELL NO. 1
JEFFERSON COUNTY, TEXAS

VOLUME I
COMPLETION AND TESTING

TESTING GEOPRESSURED GEOTHERMAL
RESERVOIRS IN EXISTING WELLS

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

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EXECUTIVE SUMMARY

The G. M. Koelemay Well No. 1, located approximately 19 miles west of Beaumont, Texas, was the fifth successful test of a geopressured-geothermal aquifer under the Wells of Opportunity Program. Eaton Operating Company, Inc. assumed control of the site on June 20, 1980, when Lear Petroleum Exploration, Inc. abandoned the well as a dry hole at a total depth of 14,885 feet.

The well was tested through the annulus between 5-1/2 inch casing and 2-3/8 inch tubing. The interval tested was from 11,639 to 11,780 feet. The geological section was the "Leger" sand, a member of the Yegua formation of Mid-Eocene age. Produced water was injected into a disposal well which was perforated from 3420 to 3520 feet in a Miocene salt water sand.

Three pressure drawdown and flow tests and two pressure buildup tests were conducted during a 13-day period. A total of 30,030 barrels of water was produced. The highest sustained flow rate was 3200 BWPD.

The natural gas content of 31 SCF/BBL observed during the early part of the first flow test was below the expected solubility of 35 SCF/BBL in the reservoir brine. Laboratory recombination studies were not able to successfully determine an actual gas saturation value for the brine.

During testing the well began to produce commercial quantities of oil and gas. The well was returned to Lear on September 26, 1980, producing about 75 BOPD, 1000 MCFD, and 3200 BWPD. The discovery of a commercial oil and gas well was unexpected. Production of large amounts of reservoir brine allowed hydrocarbons, updip in the geologic structure, to expand and reach the wellbore.

The measured original bottom-hole pressure was 9450 psia. The corresponding original static surface pressure was 4373 psia. The reservoir temperature was 260°F. The highest surface temperature observed during testing was 206°F. The reservoir pressure drawdown and flow tests depicted a very restricted flow area around the well bore, along with a lenticular sand pinchout and an updip "attic" type hydrocarbon-saturated zone. Fluid flow out of the perforated interval was not uniform, making determination of permeability, extent and distribution of sand and shale, and reservoir size impossible.

The total dissolved solids in the produced brine averaged 15,000 mg/l. No corrosion of the surface test equipment was observed. Scaling was extremely light at 0.0065 grams per square inch per 1000 barrels of water. Analysis of a deposit scraped from a coupon revealed a high amount of calcium, along with some other minerals. Chemical treatment required to prevent scaling would be minimal if long-term production were desired.

Production of solids was high. It is estimated that between 550 and 1150 pounds of solids were produced during testing. About 2% to 5% of the solids were carbonates, the remainder being very fine sand and formation clay particles.

A one-page summary of test data follows on page 1-3.

An article concerning the Koelemay No. 1 Well and the discovery of oil and gas during GEO² testing which appeared in "Drilling-DCW" magazine in January, 1981, follows the photograph on page 1-5.

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SUMMARY OF TEST RESULTS

G. M. KOELEMAY WELL NO. 1

JEFFERSON COUNTY, TEXAS

Total Depth of Well		14,885 Feet
Formation		Middle Eocene, Yegua "Leger"
Gross Sand Interval		139 Feet
Net Sand		77 Feet
Perforations		11,639 - 11,780 Feet (8 HPF)
Original Reservoir Pressure		9450 Psia
Original Reservoir Temperature		260°F
Original Shut-In Surface Pressure		4373 Psia
Average Porosity		20% (Density Log)
Average Permeability		.85 md (Sidewall Cores)

FLOW TESTS: (From 9-12-80 to 9-25-80)

Test No. 1		1.05-Day Reservoir Drawdown Test (Produced 2243 Barrels of Water) Followed by a 3.16-Day Continuous Reservoir Buildup Test.
Test No. 2		0.43-Day Reservoir Drawdown Test (Produced 1638 Barrels of Water) Followed by a 1.40-Day Reservoir Buildup Period.
Test No. 3		7.27 Day Flow Test (Produced 26,149 Barrels of Water).
Produced Dry Gas-to-saltwater Ratio		30 to 318 SCF/STB
Total Water Produced		30,030 Barrels (At standard conditions)

ANALYSIS OF POST-SEPARATOR WATER:

Total Dissolved Solids		15,000 mg/l
Chlorides		7,500 mg/l
pH		6.6

ANALYSIS OF FLARE LINE GAS:

Methane		87.2 to 75.6 Mole Percent
Carbon Dioxide		7.2 to 2.7 Mole Percent
Heavier Hydrocarbons		5.4 to 21.4 Mole Percent
Other		0.2 to 0.3 Mole Percent
Heating Value		987 to 1246 BTU/SCF
H ₂ S in Gas		7.4 ppm

Highest Flow Rate Achieved		6677 BWPd (Instantaneous), 3200 BWPd (Sustained)
Highest Surface Temperature Observed		206°F
Solids Production		High; 28 pounds per 1000 barrels of water
Corrosion		None Observed
Scaling		Light; 0.0065 Grams/1000 BBLs/SQ. In.
Lowest Flowing Surface Pressure Observed		426 Psia
Lowest Flowing Bottom Hole Pressure Measured		4262 Psia
Test Well Productivity Index		1.023
Maximum Explored Volume of Reservoir Water		Approximately 6.2 Million Barrels
Maximum Distance Explored (BHP Instrument)		1972 Feet
Reservoir		Lenticular sand pinch-out with very restricted flow area and an updip attic-type hydrocarbon saturated zone. Fluid permeability, in the order of 100 to 200 millidarcies, could not be determined due to two-phase saturation near the well bore.
Disposal Well Gross Perforations		3420 to 3520 (4 HPF)
Disposal Well Pressure Range		190 to 490 Psi

Photo 1-1 Well Producing Approximately One Million Cubic Feet of Gas per Day

2.0

INTRODUCTION AND BACKGROUND

2.1

Events Leading to Project Initiation

This report covers the acquisition, completion, and testing of a geopressured-geothermal (GEO²) well and reservoir by Eaton Operating Company, Inc. (Eaton) under contract with the United States Department of Energy, Division of Geothermal Energy (DOE-DGE). The work performed by Eaton is a continuation of the Wells of Opportunity (WOO) Program. This Program was initiated in 1977 to take advantage of the low cost of oil and gas wells previously drilled by industry to obtain short-term test data on the energy-producing potential of underground aquifers. Geopressured-geothermal resources could make an important contribution to our nation's energy supply if it should become commercially feasible to produce saltwater reservoirs and to extract the dissolved hydrocarbons, heat, and kinetic energy.

The G. M. Koelemay Well No. 1, acquired for this particular test, was drilled and tested by Lear Petroleum Exploration, Inc., at a cost of approximately \$2.6 million. Lear temporarily abandoned the well as a dry hole at a depth of 14,885 feet and offered the well to Eaton for GEO² testing. A contract with Lear was finalized on May 21, 1980, and field operations were initiated on June 20, 1980.

2.2

Location and Geography

The G. M. Koelemay Well No. 1 test site is located approximately 19 miles west of Beaumont, Texas and about 4 miles north of U. S. Highway 90. Beaumont is a rapidly growing major Texas city with a population of 118,000.

Highway 90 is a major interstate highway connecting Beaumont with other important towns and cities. The specific well location is 8100 feet south and 26,600 feet east of the northwest corner of Geomap Township 1N, Range 46E, in Jefferson County, Texas. The terrain is hilly, subject to flash flooding, and about 28 feet above sea level. The land is covered with a thick forest of pine trees and some hardwood trees.

Exhibit 2-1 indicates the location of the G. M. Koelemay Well No. 1 in relation to other GEO² test wells in Texas. Exhibit 2-2 is a topographic map of the area.

2.3

Operator Contract and Agreements

Lear Petroleum Exploration, Inc. is the operator and principal working-interest owner of the test well. Drilling of the well was completed on March 19, 1980, at a cost of approximately \$1.7 million. Lear then selected to plug back and test five different zones for commercial hydrocarbon potential. The tests indicated no commercial potential, and Lear agreed to temporarily plug the well so that Eaton could move in a small rig to complete the well for a GEO² test. Eaton's legal agreement with Lear can be found in Appendix "A".

During Eaton's GEO² testing, commercial quantities of both oil and gas were produced from the well. After Eaton completed its GEO² tests, the well was returned to Lear, on September 26, 1980, as a commercial oil and gas well. Lear agreed to release Eaton from any further expenses or liabilities related to the test site. A copy of the release letter is also in Appendix "A".

2.4 Rig Contractor Agreements

WellTech, Inc. was awarded the contract to complete the test well and to drill a disposal well on the site. WellTech's Rig No. 76 performed the work. The rig description and drilling contract can be found in Appendix "B".

Photo 2-1 A Section of the 1.4-mile Board Road to the Location

Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
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Houston, Texas 77027
713/627-0764

EXHIBIT 2-1

SOUR LAKE, TEX.

N3000-W9415/15

1955

AMS 7144 III-SERIES V782

Mapped, edited, and published
by the Geological Survey

ROAD CLASSIFICATION

Heavy-duty ————— Light-duty —————
Medium-duty ————— Unimproved dirt - - - - -
□ U.S. Route ○ State Route

SCALE 1:62 500

CONTOUR INTERVAL 5 FEET
DATUM IS MEAN SEA LEVEL

EXHIBIT 2-2

Eaton Industries of Houston, Inc.

Eaton Operating Co., Inc.

3100 Edloe

Houston, Texas 77027

(713) 827-0764

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

3.0

OBJECTIVES

The "Wells of Opportunity" program was designed to obtain short-term test data from several geopressed-geothermal aquifers in different geologic environments along the Gulf Coast region of Louisiana and Texas.

The task requires the capability to drill, complete, and test wells, the ability to interpret data, knowledge of the regional geology, communication and coordination with oil and gas operators, and a scouting system capable of locating potential GEO² wells.

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

- A. The aquifer fluid properties, including in situ temperature, chemical composition, hydrocarbon content, and pressure.
- B. The characteristics of geopressed-geothermal reservoirs, including permeability and porosity, extent and distribution of sands and shales, degree of compaction, and rock composition.
- C. The behavior of fluid and reservoir under conditions of fluid production at moderate and high rates, including pressure time behavior at different flow rates, fluid characteristics under varying production conditions, and other information related to the reservoir production drive mechanisms and physical and chemical changes that may occur with various production conditions.
- D. The evaluation of completion techniques and production strategies for geopressed-geothermal wells.
- E. Analysis of the long-term environmental effects of an extensive commercial application of geopressed-geothermal energy, to the extent determinable during testing.

4.0

GEOLOGY

4.1

Regional Setting

The Lear No. 1 Koelemay Well was tested in the "Leger" sand. This sand is a member of the Yegua formation of Mid-Eocene age.

The Yegua formation is primarily a continental deposit with sands of fluvial origin, lignites of swamp origin, and clays of lake origin. The lakes and swamps were laid inland and adjacent to the shore line, which was located to the southeast. [Deuseen and Owen 1939] The formation consists primarily of unconsolidated beds of carbonaceous and gypsiferous clays, fine to medium sands, and poor grade lignites. The clays predominate in the lower portions, lignites in the middle, and sands in the upper beds of the Yegua formation. [Meyer 1939]

4.2

Local Geology

The geopressed - geothermal test well is located on the western flank of the Doyle Field. The field consists of several blocks which have been isolated by very close, east-west trending, down-to-the-coast faults. The reservoir tested is in the southwestern-most block, approximately 3800 feet from the north-bounding fault. Adjacent to the well, the fault displaces the "Leger" sand 250 feet (Figure 4-1).

The Yegua "Leger" sand in the test well appears to be of a high constructive delta-front type depositional environment. Cross section A-A on Figure 4-2 shows the "Leger" sand to have a 135-foot gross thickness in the test well, faulted out and thinning updip.

DOYLE FIELD AREA

JEFFERSON COUNTY, TEXAS

GENERALIZED STRUCTURE MAP

TOP MID-EOCENE YEGUA "LEGER" SAND

CONTOUR INTERVAL = 50'

FAULT: STRIKE/DIP

DRY HOLE

EXHIBIT 4-1

A
NORTH

Forest Oil Corp.
Kirby Lbr. Corp.

Lear Petr. Expl
G. M. Koelemay

A'
SOUTH

DOYLE FIELD AREA
JEFFERSON COUNTY, TEXAS

NORTH-SOUTH (A-A') CROSS-SECTION

⊙ DRY HOLE

HOR. SCALE: 1" = 300'
VERT. SCALE: 1" = 500'

EXHIBIT 4-2

5.0 PETROPHYSICS

5.1 Open-Hole Log Analysis - Test Well

Lear Petroleum Exploration, Inc., during the drilling of their Koelemay Well No. 1, conducted several logging surveys for hydrocarbon evaluation. Upon the determination of a dry hole, the logs were made available to Eaton for use in reservoir evaluation for the Wells of Opportunity program of the DOE. The following logs were used in this evaluation:

1. Neutron/Density 5" (Exhibit 5-1)
2. ISF/Sonic 1" (Exhibit 5-2)
3. ISF/Sonic 5" (Exhibit 5-3)

The cited logs contain data from which the following formation measurements could be determined:

1. Spontaneous Potential
2. Gamma Ray
3. Induction
4. Neutron/Density Porosity
5. Sonic Time Travel
6. Computed Apparent Water Resistivity

5.1.1 Porosity

The mean porosity of the net pay sand was 20%, with a range of 16% to 25%. These values were determined from the Neutron Density Log (Exhibit 5-1). The porosity values were sampled on a two-foot interval using a formation grain density of 2.65 g/cc.

5.1.2 Sand Thickness

The net sand thickness of the geopressed-geothermal test zone was estimated to be 77'. This value was determined from the gross interval of 139' on the ISF/Sonic Logs (Exhibits 5-2 and 5-3). A porosity cut-off of 10% for "clean sand" was applied.

0 --- CAL (IN) --- 18
0 --- GR (API) --- 150

60 ————— NPHI (%) ————— 0
60 ————— DPHI (%) ————— 0

NEUTRON/DENSITY LOG - "Leger" SAND
LEAR PETR., NO. 1 KOELEMAY

"(5 - INCH)"

EXHIBIT 5-1

DOE CONTRACT NO.
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Eaton Operating Co., Inc.
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Houston, Texas 77027
(713) 627-9764

10 Millivolts

0 --- ILD (OHMM)---10

0 --- SFLA (OHMM)-2

0 --- ASFLA (OHMM)-10

ISF LOG "Leger" SAND
LEAR PETR., NO. 1 KOELEMAY

"(1- INCH)"

EXHIBIT 5-2

ISF SONIC LOG "Leger" SAND
 LEAR PETR., NO. 1 KOELEMAY

" (5 - INCH) "

EXHIBIT 5-3

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

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

5.1.3 Permeability

Sidewall cores were taken from the target zone during Lear Petroleum's evaluation of this reservoir. This mean permeability value was 86 md with a range of 4.7 md to 180 md. (See Exhibit 5-4).

5.1.4 Salinity

The actual formation water salinity is 15,000 ppm, as measured by IGT.

The estimated water salinity from electric logs ranges from 15,000 ppm to 38,000 ppm. These values were determined by the following methods:

1. Conventional SP Method
2. Modified Humble Method
3. Dunlap Corrected R_{mf} Method

5.1.4.1 Conventional SP Method: The estimated salinity using the Conventional SP (spontaneous potential) method was 15,000 ppm. This value was determined by solving for formation fluid resistivity using the maximum SP value from the induction log and then plotting on the Welex "Resistivity Salinity" graph (Exhibit 5-5). The equations used in determining formation fluid resistivity are as follows:

$$SSP = -(60 + 0.133T) \log_{10} R_{mf}/R_{we} \quad (1)$$

solving for R_{we} :

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

$$R_w = f R_{we} \quad (3)$$

where:

SSP = static spontaneous potential - millivolts

T = formation temperature - $^{\circ}\text{F}$

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

R_{we} = equivalent formation fluid resistivity - ohm-m

f = water resistivity correction factor - dimensionless

DOE CONTRACT NO.
DE-AC08-80ET-27081Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
3100 Edloe
Houston, Texas 77027
(713) 627-9764CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXASLEAR PETROLEUM CORP.
G. M. KOELEMAY NO. 1DATE : 20-MAR-80
FORMATION : YEGUAFILE NO : 2202-11444-F
ANALYSTS : HASON

SIDE WALL CORE ANALYSIS

REC IN	DEPTH FEET	PERM MD(*)	POR %	OILX PORE	WTRX PORE	PROD PROD	OILX BULK	GASX BULK	GAS DET	CRIT WTRX	DESCRIPTION
0.2	11643.0	61.	26.1	0.0	80.1	COND	0.0	5.2	0	54	SD FG SLTY SLMY N FLU
0.4	11648.0	95.	28.4	0.0	81.0	COND	0.0	5.4	0	55	SD FG SLTY SLMY N FLU
0.6	11650.0	110.	29.1	0.0	82.8	COND	0.0	5.0	0	53	SD FG SLTY SLMY N FLU
0.6	11652.0	86.	27.7	0.4	60.6	COND	0.1	10.8	0	55	SD FG SLTY SSHY STKD LMY VFT FLU
0.8	11660.0	70.	26.7	0.0	85.0	WTR	0.0	4.0	0	56	SD FG SLTY SSHY SLMY N FLU
0.9	11663.0	68.	26.0	0.0	75.0	WTR	0.0	6.5	0	56	SD FG SSLTY-SLTY LMY N FLU
0.6	11666.0	125.	29.1	0.3	85.6	WTR	0.1	4.1	0	52	SD FG SSLTY-SLTY LMY VFT FLU
0.8	11673.0	145.	33.4	0.3	85.9	WTR	0.1	4.6	0	52	SD FG SSLTY SLMY VFT FLU
0.5	11675.0	140.	29.5	0.0	84.7	WTR	0.0	4.5	0	51	SD FG SSLTY SLMY N FLU
0.8	11677.0	73.	26.9	0.0	81.4	WTR	0.0	5.0	0	56	SD FG SLTY LMY N FLU
0.7	11682.0	78.	27.6	0.0	81.2	WTR	0.0	5.2	0	56	SD FG SSLTY SLMY N FLU
0.8	11684.0	120.	28.4	0.0	86.6	WTR	0.0	3.8	0	52	SD FG SSLTY SLMY N FLU
0.7	11687.0	5.8	21.6	0.0	90.7	(6)	0.0	2.0	0	71	SD FG VSLTY SH LAMS LMY N FLU
0.9	11696.0	30.	24.4	0.6	81.1	WTR	0.2	4.4	0	63	SD FG SLTY LMY VFT FLU
1.2	11698.0	145.	28.9	0.0	83.4	WTR	0.0	4.8	0	48	SD FG SSLTY SLMY N FLU
0.8	11703.0	145.	27.7	1.1	83.0	WTR	0.3	4.4	0	49	SD FG SSLTY-SLTY LMY VFT FLU
0.8	11706.0	150.	28.3	0.0	73.1	WTR	0.0	7.6	0	48	SD FG SLTY SLMY N FLU
0.8	11712.0	110.	26.0	0.0	85.0	WTR	0.0	3.9	0	51	SD FG SLTY SLMY N FLU
0.7	11743.0	7.6	23.0	1.7	82.2	(6)	0.4	3.7	0	71	SD F-VFG VSLTY SLMY VFT FLU
0.8	11745.0	125.	27.0	0.4	77.8	WTR	0.1	5.9	0	50	SD FG SLTY-VSLTY SLMY VFT FLU
0.9	11747.0	95.	24.3	0.0	78.6	WTR	0.0	5.2	0	50	SD FG VSLTY SLMY N FLU
0.7	11750.0	180.	29.1	0.0	72.5	WTR	0.0	8.0	0	47	SD FG SLTY SLMY N FLU
0.8	11752.0	100.	25.2	0.0	78.6	WTR	0.0	5.4	0	51	SD FG SLTY SLMY N FLU
0.8	11756.0	8.4	21.7	0.0	77.9	(6)	0.0	4.8	0	70	SD FG VSLTY CARD STK SLMY N FLU
0.8	11760.0	9.7	23.2	0.0	75.0	(6)	0.0	5.8	0	70	SD FG VSLTY CARD STK SLMY N FLU
0.2	11768.0	4.7	20.9	0.0	79.7	(6)	0.0	4.2	0	72	SD FG VSLTY SSHY LMY N FLU
0.9	11772.0	5.5	21.2	0.0	82.5	(6)	0.0	3.7	0	71	SD FG VSLTY SSHY SLMY N FLU
1.2	11778.0	31.	24.8	0.0	78.2	WTR	0.0	5.3	0	63	SD FG SLTY-VSLTY SLMY N FLU

(*) PERMEABILITY VALUES FOR PERCUSSION TYPE SIDEWALL
CORES DETERMINED EMPIRICALLY.

(6) LOW PERMEABILITY

SIDE WALL CORE ANALYSIS
YEGUA "Leger" SAND
LEAR PETR., NO. 1 KOELEMAY

EXHIBIT 5-4

RESISTIVITY — SALINITY — TEMPERATURE CHART

EXHIBIT 5-5

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

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Eaton Operating Co., Inc.

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Houston, Texas 77027
(713) 627-9764

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

RWE CORRECTION CHART

EXHIBIT 5-6

Eaton Industries of Houston, Inc.

Eaton Operating Co., Inc.

3100 Edloe

Houston, Texas 77027

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and:

maximum SP (uncorrected)	= -10.0 mv
corrected SSP	= -10.1 mv
temperature	= 240°F
R_{mf} (Exhibit 5-5)	= .43 ohm-m @ 75°F = .14 ohm-m @ 240°F
R_{we} (equation 2)	= .108 ohm-m
f (Exhibit 5-6)	= .123
R_w (Equation 3)	= .32 ohm-m
Salinity (Exhibit 5-5)	= 15,000 ppm

5.1.4.2 Modified Humble Method: An estimated salinity of 25,000 ppm was calculated using the Modified Humble Method and was determined primarily as a function of porosity and true formation resistivity. The mathematical equation is as follows:

$$F = R_o / R_w \quad (4)$$

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

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

$$R_w = R_o \phi^2 / .81 \quad (7)$$

where:

F = formation factor - dimensionless

R_o = 100% water saturated rock - ohm-m

R_t = true formation resistivity - ohm-m

R_w = formation water resistivity - ohm-m

ϕ = porosity - %

and:

$$R_t = 1.7 \text{ ohm-m}$$

$$\phi = 20\%$$

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Assuming a 100% water-saturated formation where $R_t = R_o$, equation 7, and the previously listed log-derived parameters, a formation water resistivity of 0.84 ohm-m is obtained. Plotting the formation water resistivity on the Welex Resistivity Salinity graph (Exhibit 5-5) yields salinity of 25,000 ppm.

5.1.4.3 Corrected R_{mf} -SP Method: An estimated salinity of 38,000 was calculated using Henry Dunlap's Corrected R_{mf} -SP Method. This value was calculated by obtaining a corrected R_{mf} using Dunlap's $K_f = R_{mf}/R_m$ vs. Mud Weight graph (Exhibit 5-7) and using the Conventional SP Method of salinity determination. The equations used in correcting R_{mf} are as follows:

$$K_f = R_{mf}/R_m \quad (8)$$

solving for R_{mf} :

$$R_{mf} = K_f R_m \quad (9)$$

where:

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

R_m = mud resistivity - ohm-m

K_f = constant - dimensionless

MD = mud density - #/gal.

and:

SP (corrected) = 10.10 mv

R_m (uncorrected) = .89 ohm-m @ 75°F

MD = 16#/gal.

K_f (Exhibit 5-7) = .205

R_{mf} (Equation 9) = .182 ohm-m @ 75°F; .062 ohm-m @ 240°F

R_{we} = .048 ohm-m

f (Exhibit 5-6) = 1.23 ohm-m

R_w = .059 ohm-m

Salinity (Exhibit 5-5) = 38,000 ppm

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

EXHIBIT 5-7

Discrepancies arose between the chemical analysis of the produced water and two of the three log-calculated salinity measurements. The Conventional SP salinity matches the measured salinity, while the Modified Humble and Dunlap Methods are incorrect by a factor of 1.7 and 2.5 respectively. These errors may be due to higher actual porosity values than measured by the sonic log for the Modified Humble Method and to an over-correction of the mud resistivity in the case of the Dunlap SP Method.

5.2 Open-Hole Log Analysis - Disposal Well

The Eaton Koelemay SWD No. 1 was drilled for saltwater disposal purposes to a depth of 4384 feet. Five potential disposal sands were encountered and are identified as follows:

Sand "A" 4242' - 4368'

Sand "B" 4100' - 4175'

Sand "C" 3803' - 3891'

Sand "D" 3648' - 3726'

Sand "E" 3416' - 3529'

Disposal Sand "A" plugged up with solids during testing, and Sand "E" proved to have the best alternate potential. Therefore, Sand "E" was completed for saltwater disposal. It has a net thickness of 133 feet, porosity of 38%, salinity of 45,000 ppm, and an estimated temperature and pressure of 112°F and 1640 psi, respectively. (See Exhibits 5-8 through 5-11).

5.3 Cased Hole Log Analysis - Test Well

Exhibit 5-12 is a section of the gamma ray acoustic cement bond log which was provided to Eaton by Lear. Analysis of the log showed that the Yegua "Leger" sand (11,645' - 11,780') had excellent bonding throughout the entire zone.

5.4 Cased-Hole Log Analysis - Disposal Well

A Micro-Seismogram Bond Log was run on the disposal well. This log served a two-fold purpose:

1. Determine integrity of casing vs. cement and cement vs. formation bonding.
2. Establish an open-hole vs. casing collar correlation.

Analysis of the disposal log indicated that cement bonding of the disposal zones was excellent, thereby isolating these zones from one another and the overlying fresh water sands. (See Exhibits 5-13 and 5-14).

INDUCTION LOG - MIOCENE SANDS
LEAR PETR. NO. 1- SWD KOELEMAY

EXHIBIT 5-8

20 MV.
- +

OHM - M 4000 — COND. — 0
0-SHORT GUARD-10
0AMP SHORT GRD. 2 M-MHOS/M
0--INDUCTION--10

INDUCTION LOG - MIOCENE SANDS
LEAR PETR. NO.1 - SWD KOELEMAY

EXHIBIT 5-9

0—GR (APIU)—150
6--CAL (IN)---16

2.0—BULK DENSITY (GM/CC)—3.0
-.25 -- CORR --- 1.25

DENSITY LOG - MIOCENE "A" SAND
LEAR PETR. NO. 1 - SWD KOELEMAY

EXHIBIT 5-10

0-GR (APIU)—150
6-CAL (IN)---16

2.0 BULK DENSITY (GM/CC) 3.0
-.25--CORR.--+.25

DENSITY LOG - MIOCENE "E" SAND
LEAR PETR. NO. 1 - SWD KOELEMAY

EXHIBIT 5-11

8-GAMMA RAY—80 100 —% BONDING—0 0 — μ SEC —1000

ACOUSTIC CEMENT BOND LOG - YEGUA "Leger" SAND
LEAR PETR. NO. 1 KOELEMAY

EXHIBIT 5-12

ACOUSTIC SIGNATURE

8— GAMMA RAY—80

100— % BONDING — 00 — μ SEC. — 1000

ACOUSTIC CEMENT BOND LOG - MIOCENE "A" SAND
LEAR PETR. NO. 1 - SWD KOELEMAY

EXHIBIT 5-13

DOE CONTRACT NO.
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8 — GAMMA RAY — 80 100 — % BONDING — 00 — μ SEC. — 1000

ACOUSTIC CEMENT BOND LOG - MIOCENE "E" SAND
LEAR PETR. NO. 1-SWD KOELEMAY

EXHIBIT 5-14

6.0 RE-ENTRY AND COMPLETION OPERATIONS - TEST WELL

6.1 Drill Site and Support Facilities

6.1.1 Site Layout

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

Rain water, waste oil, and grease spillage were trapped and drained into a ditch around the location for disposal. The ditch was pumped out into the reserve pit.

6.1.2 Living Facilities and Utilities

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

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

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

EXHIBIT 6-1

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

Eaton Industries of Houston, Inc.

Eaton Operating Co., Inc.

3100 Edloe

Houston, Texas 77027

(713) 627-9764

Photo 6-1 Entrance Road to Location. This Area was subject to Flooding.

Photo 6-2

Generators placed high above Location in case of Flooding

Photo 6-3 Typical Two-bedroom living trailer

Photo 6-4 View of Location from Entry Road

Photo 6-5 View of Location from Far Side of Reserve Pit

6.2

Test Well Design

6.2.1

Initial and Testing Well Completion Status

Exhibit 6-2 is a schematic drawing of the test well, showing the well condition when Eaton took over operations from Lear. The lower portion of the well was abandoned by setting a cement retainer at 11,400 feet and cement squeezing the test perforations from 11,645 to 11,665 feet. A higher set of test perforations was also squeezed, leaving a cement plug at 11,184 feet.

EXHIBIT 6-2

Eaton Industries of Houston, Inc.

Eaton Operating Co., Inc.

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Houston, Texas 77027

(713) 627-0701

Exhibit 6-3 is a schematic diagram showing the tubular configuration of the well as completed for testing. A string of 2-3/8 inch tubing was run without a packer to 11,553 feet. The heavy mud was displaced with saltwater, and the well was perforated from 11,639 to 11,780 feet, using wireline perforating guns run through the tubing.

EXHIBIT 6-3

Eaton Industries of Houston, Inc.

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

Eaton Operating Co., Inc.

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Houston, Texas 77027
(713) 627-9764

This is the first annular-flow tubular arrangement used in the WOO program. The annular-flow configuration has two advantages over the conventional tubing-flow completion: 1) wireline tools, such as the Hewlett-Packard downhole pressure gauge, are not exposed to the turbulence caused by flowing fluids outside the tubing, and 2) the well can be killed efficiently in an emergency simply by circulating heavy mud down the tubing and up into the annulus.

6.2.2 Tubular Goods Design

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

LEAR G. H. ROSEMARY WELL NO. 1

TUBULAR SUMMARY

Tubular	O.D. Size (in.)	Depth		Weight lbs./ft.	Minimum Drift (in.)	Casing Description		Casing Design Factors		
		From (Ft.)	To (Ft.)			Grade	Thread	Burst	Collapse	Tension
Conductor Pipe	20	0	57	NA	NA	NA	Welded	*	*	*
Surface Casing	13-3/8	0	2,800	54.5	12.439	K-55	STC	*	*	*
		2,800	3,353	61.0	12.359	K-55	STC	*	*	*
Intermediate Casing	9-5/8	0	3,830	43.5	8.399	S-95	LTC	*	*	*
		3,830	5,410	40.0	8.679	N-80	LTC	*	*	*
		5,410	10,031	47.0	8.525	N-80	LTC	*	*	*
Production Casing	5-1/2	0	7,903	17.0	4.767	S-95	LTC	2.3	2.7	*
		7,903	12,073	23.0	4.545	N-80	LTC	12.3	2.3	*
		12,073	13,100	23.0	4.545	S-95	LTC	**	2.5	*
		13,100	13,925	23.0	4.545	N-80	LTC	**	**	*
Tubing	2-3/8	0	11,350	4.7	1.995	N-80	SRD	**	**	2.2

CEMENTING SUMMARY

Casing	O.D. Size (in.)	Hole Size (in.)	Cementing Summary
Surface	13-3/8	17-1/2	Cemented to surface with 1,800 sacks Halliburton light cement with 3% salt and 1,000 sacks class H with 3% salt.
Intermediate	9-5/8	12-1/4	Cemented with 750 sacks class H + 35% silica flour + 0.5% CFX-2 + 3% KCl + 0.2% CFX-2 mixed at 15.6 ppg. Estimated cement top at 7,300'.
Production	5-1/2	8-1/2	Cemented with 1,700 sacks class H + 35% silica flour + 13 #/ex hi-dense #3 + 0.5 baled 22 A + 0.5% CFX-2 + 0.5% HR-12. Mixed at 17.5 ppg. Estimated cement top at 9,500'. Installed wipers and centralizers and reciprocated casing.

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

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

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

EXHIBIT 6-4

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6.2.3

Wellhead Design

Exhibit 6-5 is a schematic of the wellhead and christmas tree used. The christmas tree was designed for annular flow of fluids. Produced fluids flowed up the casing-tubing annulus and exited through two outlets in the tubing head. Flow through each outlet was controlled by two 2-inch, 5000-psi working-pressure, hand-operated gate valves and one 2-inch, 5000-psi working-pressure, pneumatic-operated surface safety valve. Two sections of 3-inch XX grade "B" API line pipe connected the tubing head outlets to a common "Y" block at the head of the flow line.

The upper section of the christmas tree consisted of one 2-inch 5000-psi working-pressure master gate valve, a "tee" with a 2-inch valve for a kill line connection, and a 2-inch "swab" valve for wireline accessibility.

6.2.4

Logging Program

The suite of open-hole logs and sidewall core data obtained by Eaton supplied adequate information for formation evaluation purposes. A gamma-ray acoustic cement bond log run by Lear was also provided to Eaton. The only logs run by Eaton were a casing inspection log and a gamma-ray casing collar locator log for use as a reference for perforating operations.

6.3

Re-Entry Operations

The WellTech rig number 76 was moved to the location on June 22, 1980, to commence completion operations on the test well. A blowout preventer stack approved by Eaton was installed on the well and tested. A cement mill was run in the hole to 11,055 feet, and mud was circulated and conditioned to 16.5 ppg. A cement plug was then drilled from 11,055 feet to the top of a cement retainer at about 11,400 feet. The test perforations used by Lear, (11,278 - 11,313 feet) and the 5-1/2 inch O.D. casing were pressure-tested to 1600 psi surface pressure.

A casing inspection log was run by Dia-Log Company on the 5-1/2 inch O.D. casing from 11,159 feet to the surface. The casing appeared to be in good condition. A 40-foot section of casing at 8200 feet appeared to be a 17.0 lbs/ft joint of pipe, instead of a 23.0 lbs/ft joint as expected. The lighter joint, however, was considered strong enough to support the burst and collapse pressure loads to be imposed on it during subsequent operations.

A squeeze tool was then run in the hole and set at 11,109 feet. The mud in the tubing was displaced with saltwater to check the old test perforations for possible leakage into the well bore with a low hydrostatic pressure in the well. The perforations did not leak and were judged to be cemented well enough not to interfere with testing of the deeper proposed zone. The squeeze tool was pulled out of the hole, and the cement retainer at 11,400 feet was drilled. The hole was washed to 12,604 feet.

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CHRISTMAS TREE SCHEMATIC

EXHIBIT 6-5

Photo 6-6 Christmas Tree and Flow Line. First Annular Flow Tree to be used in the WOO Program

Photo 6-7 Closeup of Christmas Tree. Tubing Kill Line is at Upper Left

Photo 6-8

Silhouette of Upper Section of Christmas Tree

Completion Operations

A wireline guide and 2-3/8 inch tubing were run into the well at 11,553 feet. The blowout preventers were removed, and the christmas tree was installed. The mud was displaced with saltwater. The well produced about 15 barrels of water after displacement, and the shut-in surface pressure was 3300 psi. This verified that this lower set of old Lear test perforations (11,645-11,665 feet) was not completely cemented up. No remedial action was taken, since these perforations were in the same zone to be perforated by Eaton for testing. A perforating gun was run in the hole, but would not go below 11,678 feet because of thick mud contaminated with saltwater. The well was perforated from 11,658 to 11,678 feet. A coiled tubing unit was then used to wash the contaminated mud down to 11,900 feet. Perforating was completed from 11,639 to 11,700 feet with a total of 8 holes per foot. Several 1-9/16" O.D. through-tubing, hollow carrier, zero degree orientation guns were used for this operation.

The well was opened to flow during the perforating gun runs to lower the surface pressure and to clean the perforations. An estimated total of 4797 barrels of saltwater was produced during the period.

The rig was released on July 6, 1980. The shut-in surface pressure was 3900 psi.

7.0

DRILLING AND COMPLETION OPERATIONS - DISPOSAL WELL

7.1

Location

The brine disposal well was located about 85 feet southeast of the test well. Exhibit 7-1 is a surveyor's plat of the location, showing the positions of the two wells.

EXHIBIT 7-1

7.2

Design Requirements

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

- An injection capacity in excess of 15,000 barrels per day at an injection pressure not to exceed 500 psi, as specified by the Texas Railroad Commission.
- High temperature capability of up to 300°F.
- A minimum disposal depth of 1250 feet, as specified by the Texas Railroad Commission.
- Protection of fresh and brackish-water sands by setting two complete strings of casing through all such sands and circulating cement to the surface on both strings.

7.3

Drilling Operations

The WellTech Rig No. 76, which was selected for cleaning out and completing the test well, was also used for drilling the disposal well. While the rig was completing the test well, the structural casing was driven for the disposal well. The 14-inch O.D. pipe was driven to 75 feet below ground level with a Delmag D-12 diesel-operated hammer. The final blow count was 125 blows per foot.

The rig was moved over the structural casing, and the well was spudded on July 10, 1980. A 12-1/4 inch hole was drilled to 1518 feet. A string of 9-5/8 inch O.D., 43.5 lbs/ft, N-80, LT&C casing was set at 1517 feet. The pipe was cemented with 450 sacks of Halliburton "Light" cement mixed with 3% salt, having a weight of 12.7 ppg, followed by 200 sacks of class "H" cement mixed with 2% calcium chloride, having a weight of 15.6 ppg. Cement returns were seen at the surface during the displacement operation. The wiper plug was seated with 900 psi pump pressure which was then bled back to zero psi, indicating that the float valves were holding.

A casing head was installed on the 9-5/8 inch O.D. casing, and blowout preventers were installed on the casing head. An 8-1/2 inch hole was then drilled to a total depth of 4515 feet.

7.4

Selection of Disposal Zone

An induction electric log and a compensated density log were run in the hole from 4513 to 1518 feet. Analysis of the logs indicated that the following potential disposal sands had been penetrated:

<u>Sand</u>	<u>Top</u>	<u>Bottom</u>	<u>Net Sand Thickness</u>	<u>Porosity (%)</u> *
A	4242'	4368'	113'	44
B	4100'	4175'	75'	44
C	3803'	3891'	88'	48
D	3648'	3726'	77'	42
E	3416'	3529'	133'	38

*These porosity values appear to be excessive for a sand of this age and depth. The porosity of an ideally well-sorted, non-cemented, well-rounded, uncompacted sand is 47.6%.

It was decided to complete the well in sand "A" and reserve the other sands for additional disposal capacity.

7.5 Completion Operations

A string of 5-1/2 inch O.D. 15.5 lbs/ft, grade K-55, ST&C casing was run in the hole to 4515 feet. A down-jet float shoe was installed on the end of the casing string, and a float collar was placed two joints up from the float shoe. Five centralizers were installed on the bottom three joints of casing, and one centralizer was placed on each of the next 74 joints. Cable-type scratchers were placed at ten foot intervals from about 4200 feet to 4400 feet. The casing was cemented with 750 sacks of Halliburton "Light" cement mixed with 3% salt, at a density of 12.8 ppg, followed by 500 sacks of class "H" cement mixed at a density of 15.6 ppg. Saltwater was used to displace the cement, and approximately 150 barrels of cement returns were observed at the surface. The wiper plug was seated in the float collar with 1800 psi of pump pressure. The pressure was bled to zero psi, indicating that the float valves were holding. The blowout preventers were removed, and a tubing head was installed on the 5-1/2 inch O.D. casing. A gamma-ray cement bond log was run from 4370 to 2372 feet. The log indicated that excellent cement bonding had been achieved across all potential disposal zones. The rig was released on July 31, 1980.

7.5.1 Perforation and Injectivity Tests

After the rig had been moved off location, the well was perforated in Sand "A", 4336 - 4366', 4299 - 4329', and 4242 - 4292' with 3-1/8 inch casing guns, 4 shots per foot.

Injectivity tests were performed after the perforating operations were complete. Exhibit 7-2 is a graph of injection rate versus surface injection pressure. The highest injection rate achieved was 8640 BWPD at 2000 psi. Stimulation of the disposal zone was necessary.

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EXHIBIT 7-2

7.5.2 Disposal Well Stimulation

To improve acceptance of water by the well, it was treated with 5000 gallons of Halliburton "FE" acid with a diverting agent, followed by 10,000 gallons of regular HF acid. After the acid treatment, the well accepted saltwater at a rate of 12,240 BWPD at an injection pressure of only 175 psi. The well was considered capable of accepting all anticipated production from the test well without the use of surface pumps.

7.5.3 Well Setting and Christmas Tree

Exhibit 7-3 is a schematic diagram of the actual disposal well completion and wellhead. Two sets of perforations are shown in the diagram. The upper set was required because the lower zone was plugged off with solids early in the testing program. The plug back is discussed in the following paragraph.

G.M. KOELEMAY SWD WELL NO. 1

EXHIBIT 7-3

7.5.4 Plug Back to Alternate Sand

On September 16, 1980, it was discovered that the disposal well was plugged with solids at a depth of 4207 feet. Solids had accumulated in the well during one day of testing when 2422 barrels of produced water were injected into the perforations from 4292 to 4366 feet and during a shut-in period following the initial flow test. It was decided that the quickest and least expensive remedial operation would be to plug back to an alternate sand.

The well was perforated with 3-1/8 inch casing guns in Sand "E", from 3420 to 3520 feet, 4 holes per foot. The new zone was then acidized with 2500 gallons of "FE" acid mixed with a diverting agent, followed by 5000 gallons of regular HF acid. The upper disposal zone was used for the remainder of the testing. No injectivity test was performed on Sand "E".

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Photo 7-1 Pressure and Temperature Transducers Mounted on top of Disposal Well

Photo 7-2 Disposal Well. Living Quarters in Background

8.0

TEST OBJECTIVES

The test equipment and procedures for the G. M. Koelemay No. 1 were designed to obtain the maximum information within the time and funds allotted.

Specific information desired was the following:

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

9.0 SURFACE TESTING FACILITIES

9.1 Design Requirements

The test facilities were designed to produce and inject the well effluent continuously and to obtain data at points indicated on Exhibit 9-1.

Design criteria were as follows:

- Wellhead Working Pressure 5000 psi
- Flow Line Shut-In Pressure 5000 psi
- Temperature 300°F
- Brine Flow Rate 20,000 BPD
- Separator Operating Pressure 1200 psi
- Filter Operating Pressure 600 psi

9.2 Main Process Equipment

Exhibit 9-1 is a diagram of the surface test equipment. The well stream entered the flow line at the point where the two flow loops connected. The flow rate, pressure, and temperature were measured ahead of the choke manifold. Well effluent samples were obtained from a sampling port ahead of the choke manifold. The sample port was positioned in the flow stream so that sampling could be performed at flowing wellhead conditions and before the scale inhibitor injection point. The main flow then passed through a choke manifold and through a data header. The data header incorporated a sonic sand detector and a scale and corrosion measuring coupon. The flow then entered a conventional horizontal 3-phase separator. The gas was measured by an orifice meter and then flared. The separator brine passed through a flow meter manifold where water samples were obtained. The brine then passed through a 50 micron filter tower manifold before entering the disposal well. Pressure and temperature were measured at the disposal wellhead.

Reservoir Data Incorporated (RDI) provided a three-inch Camco turbine-type flow meter which was installed in the flow line close to the wellhead. This turbine meter was wired into the RDI digital recording instruments, so that fluid flow could be printed, along with pressure and temperature data. The RDI computer software for this meter failed to operate; however, IGT personnel were able to record the Camco meter readings. True water flow was recorded at the water metering skid as the water passed through a Halliburton three-inch turbine meter.

SURFACE TEST SCHEMATIC

EATON OPERATING COMPANY, INC.

EXHIBIT 9-1

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

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Photo 9-1 Chemical Injection Pumps and Choke Manifold

Photo 9-2 Safety Shut-in Pilot on Lower Right

Photo 9-3

Christmas Tree. Note RDI Lubricator Installation and Pit By-pass Line in foreground

Photo 9-4 Sampling Condensate during a Shut-in Period

Photo 9-5

Disposal Well, Separator, Filters, and Turbine
Meter Calibration Tanks

Photo 9-6 Close-up of Filter Unit. Note Size of Equipment Relative to Man

9.3

Safety Considerations

The test well christmas tree was equipped with two fail-safe pneumatic safety gate valves. The valves were set to close if the flow line pressure reached a low of 500 psi, separator pressure reached a high of 1200 psi, or the filter unit pressure reached a high of 600 psi. The pneumatic system could also be activated manually at a safe distance from the test well.

An active mud system was maintained at the location. Mud of sufficient weight and quantity to kill the well was thus immediately available for pumping down the tubing through a kill line.

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

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

9.4

Data Recording

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

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

Data recorded by each are described in the following sections.

9.4.1

Data Recording (Institute of Gas Technology)

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

- **Wellhead Temperature:** Wellhead temperature was sensed by a Foxboro temperature transmitter (0° to 400°F) installed in the high-pressure line between the wellhead and the choke manifold. This sensor was mounted in a tee on the side (90° from top dead center) of the high-pressure line to sense liquid temperature and to avoid problems due to sand erosion. Continuous readings were achieved, but values are a few degrees low because the thermal well was not in the flowing stream.
- **Wellhead Pressure (Annulus):** A Honeywell diffused silicon pressure transducer (0 to 10,000 psig) was attached to a flange on the wellhead to measure pressure

in the annulus. Production in this well was through the annulus, and the reliable continuous readings provided by this pressure transducer were important inputs to subsequent analysis.

- **Wellhead Pressure (Tubing):** A Honeywell diffused silicon pressure transducer (0 to 10,000 psig) was attached to RDI's wellhead lubricator. Continuous readings were recorded throughout the entire test period; however, these readings are higher than they normally would be, because there was a buildup of gas in the tubing. The gas was bled off twice during the second week of testing.
- **Wellhead Brine Production Rate:** Beginning with the second flow test on August 16, 1980, cumulative production upstream of the choke manifold was measured by use of RDI's Camco 3-inch turbine meter coupled to RDI's "Big Tex II" meter readout, which was linked to IGT's multiprogrammer for pulse counter/impulse interpretation and data storage. Due to two-phase flow in the line at the turbine, all readings, though virtually continuous, were higher than separator output turbine readings. These will be compared in a later section of this report.
- **Sand Detection:** IGT attempted unsuccessfully to tap into Weatherly's OIC Sand Systems, Inc., sonic sand detector. No output was obtained. This deficiency will be corrected for future well tests so that this channel can be recorded on IGT's digital equipment. Weatherly maintained a strip-chart recording of sand detector output.
- **Separator Pressure:** Separator pressure was recorded continuously during flow by a 0 to 2000-psig Statham-type pressure transducer installed on the flange of the orifice meter.
- **Orifice Meter Differential Pressure:** The orifice differential pressure was recorded continuously during production. A Statham-type differential pressure transducer with a range of 0 to 400 inches of water was used. Values recorded by this differential pressure transducer were reliable, though there were occasional periods of surging in the separator, which caused severe fluctuations in the readings. These fluctuations did not occur frequently and were damped out by adjusting the separator controls.
- **Gas Temperature:** Gas temperature from a thermal well approximately 3 feet downstream from the orifice meter was recorded at all times during gas production, using a Foxboro temperature transmitter with a range of 0° to 400°F.
- **Separator Brine Production Rate:** Electrical pulses corresponding to increments of 0.1 barrel of brine production were electronically and digitally recorded by tapping signals from Weatherly's 3-inch Halliburton turbine meter downstream from the separator. However, erroneous incremental jumps in recorded brine production were experienced throughout the test. Testing the IGT tap to the meter with an oscilloscope revealed that the pulses were not compatible with the IGT multiprogrammer/interface. Corrections to enable reliable recording from the Weatherly meter are being made for future well tests. Around-the-clock logging of the Halliburton turbine meter output by Weatherly provided the data on brine production used for test interpretation.

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- **Filter Differential Pressure:** The pressure drop across the filters was recorded continuously by a 0 to 100-psi Statham-type differential pressure transducer.
- **Disposal Well Pressure:** Data were recorded from a 0 to 2000-psi Statham-type transducer during all periods of brine injection into the disposal well.
- **Disposal Well Temperature:** Data from a Foxboro 0° to 400°F temperature transmitter were recorded continuously during the entire well test.

From the beginning of the well test, sufficient equipment was on site, and the necessary software had been written to accomplish digital recording of all data channels discussed above, with the noted exceptions. Data were recorded on an essentially continuous basis from before the first flow test. The only exception was a period from about 0900 on September 14 until 1230 on September 16, during which time the well was shut in.

Digitizing of the analog pressure and temperature data was accomplished by using a single analog-to-digital converter plus electronic switching. Wellhead flow data were recorded by electronic counting of pulses from the Camco turbine and the pulse amplifier in RDI's Tejas Controls, Inc., "Big Tex II".

Control software provided for scanning all analog channels every 5 seconds. Values for separator pressure and orifice differential pressure, measured each 5 seconds, were then squareroot-averaged over operator-selected time intervals for data recording. Linear averaging was performed for other analog channels. Time intervals for permanent records varied from 10 seconds at the beginning of each test up to as long as 10 minutes during long-term stable production. In addition, some 30-minute intervals for permanent records were used during shut-in periods. Cumulative counts from the brine turbines were recorded at the time of each permanent record. Permanent records were produced both by real-time printouts and by storing of digital data on magnetic cartridge tapes. Backup strip chart recording of analog channels was continued throughout the test.

9.4.2 Wireline Company Recording (Reservoir Data, Inc.)

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

- **Pre-Production Temperature Gradient:** Temperature was measured at depth increments of 1000 feet and at the 11,710-foot gauge datum, the midpoint of the zone tested. The temperature sensor was a thermistor-type Gearhart-Owens 1-7/16-inch differential temperature tool. Temperature, digitally displayed at the surface, was logged by hand.
- **Pre-Production Pressure Gradient:** Pressure from a Hewlett-Packard downhole pressure gauge was recorded digitally at depth increments of 1000 feet down to 11,000 feet and at the 11,710-foot gauge datum, the midpoint of the zone tested.

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Photo 9-7 IGT Terminal for Strip Chart Recorders

Photo 9-8

Section of the IGT Chemistry Lab, with Gas Chromatograph

Photo 9-9 IGT Work Table and Computer Module

Photo 9-10 Section of IGT Chemistry Lab.

Photo 9-11 RDI Wireline Equipment at Center and Right

Photo 9-12 Flaring Gas. Note RDI Lubricator and Pressure Control System at Right

- **Bottomhole Pressure:** During flow and buildup tests, pressure at the 11,540-foot gauge datum, 10 feet above the end of the tubing string, was sensed using a Hewlett-Packard quartz crystal pressure sensor.
- **Wellhead (Tubing) Pressure:** Wellhead pressure in the tubing during all flow and buildup tests was sensed with a Panex capacitance pressure sensor and digitally recorded.
- **Wellhead Brine Production Rate:** Production rate upstream of the large choke manifold was measured, while adjusting the choke, by use of a Camco 3-inch turbine meter and portable display. Digital recording of turbine meter output was not accomplished during the test by RDI.

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

RDI was not successful in recording data from the high-pressure turbine meter during the test of this well. The production rate was recorded by IGT, commencing with the second flow test on September 16, 1980.

All RDI raw data are presented in Appendix G in Volume II.

9.4.3 Weatherly Engineering, Inc.

Weatherly provided continuous hand-recording of the following four channels of data:

- **Separator Pressure:** Separator pressure at the flange tap for the orifice meter was recorded on a 24-hour circular chart with a pressure range of 0 to 1500 psi.
- **Orifice Meter Differential Pressure:** Orifice meter differential pressure was recorded by a second pen on the same 24-hour circular chart for a differential pressure range of 0 to 100 inches of water.
- **Gas Temperature:** Gas temperature downstream of the orifice meter was recorded by a third pen on the same circular chart with a temperature range of 0° to 400°F.
- **Sand Detection:** The strip chart recorded on an OIC Sand Systems, Inc. sonic sand detector provided a continuous record of sand detector output at all times during brine production.

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Photo 9-13 Work area with Deadweight Tester and Sand Detector Recorder. Air Compressor (for Separator Control Valves) at lower right.

Photo 9-15 Work Area. Note Mud Kill System in Left Background

Photo 9-16 General View of Location, with Separator at Right

Weatherly personnel also provided around-the-clock manual data logging of the following parameters:

- Separator pressure from the circular chart described above,
- Orifice differential pressure from the circular chart described above,
- Gas temperature downstream from the orifice,
- Trends in gas production, calculated manually by multiplying the square root of the product of separator pressure and differential pressure by an orifice factor characteristic of 0.6 specific gravity gas at standard temperature and pressure,
- Temperature from a thermometer installed between the large choke manifold and the separator,
- Cumulative brine production from the counter on the brine turbine operating at separator pressure,
- Calculated brine production rate and gas-to-brine ratio derived from the difference in cumulative brine production at successive data logging times and the gas production estimate described above,
- Differential pressure across the filters between the separator and the disposal well, and
- Disposal well pressure as indicated on a dial gauge installed on the outlet of the filter skid.

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

10.0

PRE-TEST OPERATIONS

10.1

Pre-Test Data Obtained From Operator

Lear Petroleum Exploration, Inc. (Lear) provided Eaton with a considerable amount of basic reservoir and engineering data on the G. M. Koelemay Well No. 1 during the time the well was being evaluated as a "Well of Opportunity". The upper 20 feet (11,645 - 11,665') of the target Yegua "Leger" sand had already been tested by Lear. Water with a salinity of 16,500 ppm was produced, along with a small amount of gas which was not recorded. Bottom hole pressure was estimated to be 9440 psi.

Sidewall core analysis data was available on 28 percussion-type cores taken from the sand interval between 11,643 feet and 11,778 feet. The average porosity of these cores was 26 percent. The permeability values of these cores were determined empirically, and the overall average was 84.5 millidarcies. The cored interval, between depths of 11,643 feet and 11,652 feet was analyzed as probably condensate-productive. Seven of the 28 cores had oil saturation from 0.3 to 1.7 percent of measured pore space. The oil saturation was noted down to a depth of 11,745 feet. Gas was detected in all the cores analyzed. This data suggested the possibility of free hydrocarbon saturation updip of the location of the cores analyzed. A hydrocarbon transition zone is defined as that interval where zero permeability to hydrocarbon phase begins and zero permeability to water phase ends. There is a zone below this, where free hydrocarbon saturation exists, but which has zero permeability to hydrocarbons at a specific temperature and pressure, and therefore will not flow in the free saturation phase.

The flow test results reported by Lear suggest that the gas produced was gas dissolved in the brine and not free gas. The upper twenty feet of the Yegua "Leger" sand perforated was probably in a section below the free hydrocarbon transition zone in the reservoir.

Information such as discussed above, obtained prior to a test, is valuable to planning and interpretation of GEO² tests.

10.2

Completion and Well Bore Cleaning

The well was prepared for perforation by displacing the 16.5 ppg mud with 9.0 ppg saltwater. The well produced about 15 barrels of water after displacement, and the shut-in surface pressure was 3300 psi. These facts indicated that the upper portion of the sand, originally tested by Lear, had not been completely cemented up when Lear abandoned the zone. As a result, all perforating was performed with a balanced pressure between the formation and the well bore.

During July 5th and 6th, the well was perforated from 11,780 to 11,639' with 8 shots per foot. Approximately 312 barrels of reservoir fluid was produced during each of twelve trips with the perforating guns.

The total production during all of the above pre-test operations is estimated to have been 4797 barrels of formation water.

During the pre-test period, two runs were made with a Gearhart Industries bottom hole fluid sampler. These operations are discussed in detail in Section 12.10.6.

10.3 Preliminary Well Bore Pressure and Temperature Recordings

Static well bore pressure and temperature gradient measurements were conducted on the day prior to flow testing. These pressure and temperature readings are plotted on Exhibit 10-1. The final pressure and temperature measurements were taken at about 11,710 feet, the midpoint of the perforations. The pressure at this depth was 9449.43 psia and the temperature was 260°F. The pressure and temperature recording instruments were pulled out of the hole, and the temperature recording gauge was removed. The Hewlett-Packard pressure element was then lowered back into the well to a depth of about 11,540 feet, 170 feet above the center of the perforations. The pressure gauge was inside of the 2-3/8 inch O.D. tubing, which protected the instrument and the electric cable from the turbulence of the flowing fluids during testing. Pressures reported during all of the flow tests were measured at a depth of 11,540 feet.

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EXHIBIT 10-1

11.0

TEST SEQUENCE

The test sequence for the G. M. Koelemay Well No. 1 included several short flow periods to clean the hole during perforating operations. Following these preliminary flow periods, a sequence of flow and buildup tests was carried out to evaluate reservoir parameters, produced fluids, and flow characteristics.

11.1

First Flow Test

The initial reservoir pressure drawdown flow test lasted 1.05 days, during which 2243 barrels of water were produced. This test provided early information on reservoir characteristics.

11.2

Buildup Test

The first flow test was followed by a 3.16-day continuous reservoir pressure buildup test. This test provided additional information on reservoir parameters.

11.3

Second Flow Test

The second reservoir pressure drawdown flow test lasted 0.43 days, during which 1638 barrels of water were produced. The test was terminated after a short flow period, because the disposal well was found to be plugged up with solids, and the reserve pit was full. The test well was shut in for 1.4 days, while the disposal well was recompleted in an alternate zone.

11.4

Third Flow Test

The third flow test lasted 7.27 days, during which 26,149 barrels of water were produced. During this flow period, the well began to produce significant amounts of oil and gas along with the brine. It was decided that little additional useful information could be obtained concerning the saline aquifer, and the WOO test was terminated on September 26th, 1980. Lear took over operations on the site and continued testing the well, which eventually proved to be a commercial oil and gas well.

11.5

Lear Flow Test

Lear continued Eaton's third flow test, allowing the well to flow for 12.11 more days, for a total of 19.34 days of flow. During Lear's 12.11-day flow period, the well produced 32,389 barrels of water, 2055.5 barrels of oil, and 18,671 MCF of gas.

11.6

Lear Buildup Test

After flowing the well for the additional 12.11 days, Lear shut the well in for a 5.96-day buildup test.

Data from both Lear tests were given to Eaton by Lear.

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12.0

TEST RESULTS AND ANALYSIS

12.1

First Flow Test

The initial plan was to open the well slowly and uniformly, over a two-minute period, to a constant production rate of about 100 barrels of water per hour or about 2400 barrels per day. This rate was to remain constant for at least a 24-hour period.

This first test began at 12:50 PM on September 12, 1980. The initial pressure at the 11,540-foot instrument datum was 9381.43 psia. The corresponding pressure at the wellhead was 4372.76 psia. The surface pressure was measured by a Panex surface recording gauge and checked by a deadweight tester.

When the choke was opened, the high pressure flow meter at the wellhead did not work properly. It required about 9 minutes to establish a flow rate of about 100 barrels per hour, using the flow meter downstream of the separator. The first 2-hour flow averaged 2409.6 barrels of separated water per day. A gradual decrease in flow rate from 2409 BWPD to 1980 BWPD occurred during the 25-hour and 10-minute initial flow test.

The final flowing pressures were 7251.35 psia at the datum depth and 2389.96 psia at the wellhead. This was a sandface flowing pressure loss of 2130.08 psi and a surface flowing pressure loss of 1982.80 psi. The surface flowing temperature rose from the initial 99°F to 166.3°F. The produced gas-to-water ratio appeared to run between 33 and 38 standard cubic feet per barrel during the first flow test, and it appeared to increase with flow time.

Exhibit 12-1a is a semilog plot of pressure drawdown as a function of the log of flow time. The pressure buildup that followed this first flow test is also plotted. There was an unusually low rate of drawdown for the first 14 minutes. The pressure loss was 171.24 psi, from 9381.43 psia to 9210.19 psia. After 15 minutes the slope increased to about 950 psi per log cycle or about 11 times the possible slope for the earlier flow period.

This relatively low drawdown is the result of a high Kh valve and a free gas saturation zone very close to the effective perforated interval. The gas cap effect reduces the normal expected water-saturated drawdown slope by a factor of the ratio of the two fluids' viscosities. In this particular case, the ratio is estimated by dividing 0.035 cps for the gas by water viscosity of 0.25 cps, which results in reduction of slope by a factor of 0.14. The close-by sand pinchout type permeability barriers, as well as possible fault barriers, cause the sharp increase in drawdown slope that appears after about 15 minutes into production.

The calculation of permeability, distance to close-by barriers, and skin effect from the radial flow equation is not possible, since the variation in fluid phase saturation just up dip of the perforated interval masks the slope of the one-phase radial flow needed. Therefore, the calculations depicted in Exhibits 12-2a, 12-2b, 12-3a and 12-3b are considered invalid and are presented only to show the basis for the conclusions. Permeability from a drawdown slope of 950 psi per cycle would be only 2.33 mds; skin effect would be negative. A negative skin is impossible for a cased hole completion that has been perforated.

Reservoir Data Inc.
2216 McGowen Street Houston, Texas 77052 (713) 683-9259

EXHIBIT 12-1a

DOE CONTRACT NO.
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Reservoir Data Inc.

2314 McAllister, Houston, Texas 77002 (713) 683-0259

EXHIBIT 12-1b

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

Test date: 9/12-13/80 Type Test: Drawdown Lease and Well No. G. M. Koelemay No. 1
Producing Formation: Yegua "Lager" Zone; Mid-Eocene Field: Doyle (Jefferson County)
Hole size: _____ Casing Size: _____ Tubing Size: 2-3/8" State: Texas
Cumulative Production: _____ Gas Gravity: _____ Z: _____
Constant Rate Production: 2177.9 (bbls/day) Water Salinity: 14,700 FPM Total Solids
Total Production Life: 4 days Porosity, Avg. of 28 Cores 0.26 Gas-Water Ratio: ±40 ft³/bbl
Reservoir Temperature: 260 °F Net Pay: ±77 ft. Perforations: 11,640' - 11,780' ft
 μ_g 0.035 cps μ_w 0.25e cps Bw 1.05e R.B./B. Bg _____ R.B./MCF
 C_T 4.03 $\times 10^{-6}$ C_g _____ $\times 10^{-6}$ C_w 3.5e $\times 10^{-6}$ C_r 1.5 $\times 10^{-6}$
 m 950 psi/cycle P at 1 hour: 8565 Sg _____ Sw 100% P_i 9449.43 psia @ 11,710 ft.

P_f 7251.35 psia

P_i 9381.00 psia

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

$$kh = 162.6 (Q)(B)(\mu)/(md)$$

$$kh = 162.2 (2177.89) (1.05) (0.25) / (950) = 97.85 \text{ md-ft}$$

$$k = (97.85 \text{ md-ft}) / (42 \text{ ft}) = 2.33 \text{ mds}$$

II. $B_g = (P_b)(T_f)(Z)(1000)/(5.61)(520)(P_R) =$

$$B_g = () () () .34279 / () = \text{Res. bbl/MCF}$$

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP_{skin}

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

$$s = 1.151 \left[\left(\frac{(9381) - (8565)}{(950)} \right) - \log \left(\frac{(2.33) 10^6}{(0.26)(0.25)(4.03)(0.0525)} \right) + 3.23 \right] = -4.77$$

$$\Delta P_{\text{skin}} = (0.87)(s)(m) = \text{psi}$$

$$\Delta P_{\text{skin}} = (0.87)(-4.77)(950) = -3938 \text{ psi}$$

IV. Diffusivity, η

$$\eta = .006328 (k) / \phi \mu C_T = \text{(from Build-up)}$$

$$\eta = .006328 (12.6) / (0.26)(0.25)(4.03) 10^{-6} = 304,382 \text{ ft}^2/\text{day}$$

$$C_T = \left[(3.5)(1.00) + \frac{(1.5)(0.26)}{.72} \right] \times 10^{-6} = 4.03 \times 10^{-6}$$

EXHIBIT 12-2a

RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)

RESERVOIR DRAWDOWN TEST (CONT'D)

Test Date: Sept. 12-13, 1980 Type Test: Drawdown Lease and Well No. G. M. Koelemay No. 1

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

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

$$J \text{ (ideal)} = \frac{Q_w}{(P_i - P_f) - \Delta P_{\text{skin}}} = \frac{(\quad)}{(\quad) - (\quad)} = \quad \text{bbls/D-psi}$$

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

Distance to Barriers or Discontinuities, d $d = 2 \sqrt{Wh}$
 $d = 2 \sqrt{(304,382)} \times \sqrt{t} = (1103) \sqrt{t}$

<u>time, days</u>	<u>t</u>	<u>d, ft.</u>	<u>(psi/cycle)</u>	<u>Flow Angle</u>	<u>Jones Y Function</u>	<u>Bbls of Aquifer Explored or Tested</u>
<u>1.0</u>	<u>1.0</u>	<u>1103</u>	<u>950</u>		<u>0.180622</u>	<u>1,506,500</u>

$$Y = (950)/(2.3)(2177.89)(1.05)(1.0) = 0.18062195 \text{ psi per day per reservoir barrel}$$

$$W = (1.00)/(1.05)(0.180622)(3.5 \times 10^{-6}) = 1,506,500 \text{ Bbls. of water explored}$$

$$(7758 \text{ Bbls./Ac. ft.})(0.26)/(1.05) = 1921 \text{ Bbls./Ac. ft.}$$

$$(1,506,500 \text{ Bbls.}) \div (1921)(42 \text{ ft.}) = 18.67 \text{ acres needed}$$

$$(1103)^2 \pi / (43,560) = 87.74 \text{ Acres}$$

$$\left(\frac{18.67}{87.74}\right) (950) = 202 \text{ psi/cycle} - \text{could be the expected drawdown slope for radial flow.}$$

EXHIBIT 12-2b

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

Test date: Sept. 13-18, 1980 Type Test: Buildup Lease and Well No. G.M. Koelemay No. 1
Producing Formation: Yegua "Lager" Zone, Mid-Eocene Field: Doyle, Jefferson County
Hole size: _____ Casing Size: 5 1/2" Tubing Size: 2 3/8" State: Texas
Cumulative Production: 2283.0 Gas Gravity: _____ Z: 1.381
Constant Rate Production: 2178 (bbls/day) Water Salinity: 14,700 PPM Total Solids
Total Production Life: 1,048 days Porosity, ϕ : 0.26 Gas-Water Ratio: _____ ft³/bbl
Reservoir Temperature: 260 °F Net Pay: 42 ft. Perforations: 11,641 - 11,780 ft
 μ_g _____ cps μ_w 0.25 cps Bw 1.05 R.B./B. Bg 0.5313 R.B./MCF
 C_T _____ $\times 10^{-6}$ C_g _____ $\times 10^{-6}$ Cw 3.5 $\times 10^{-6}$ C_r 0.5 $\times 10^{-6}$
m 176 psi/cycle P at 1 hour: 7592 Sg _____ Sw 1.00 Pi 9449.43 psia @ 11,710 ft.
Pf 7251 psia

I. Calculation of kh (md-ft) and k (md): h = 42 ft. approx. from flow meter

$$kh = 162.6 (Q)(B)(\mu)/(md)$$

$$kh = 162.2 (2178) (0.25) (1.05) / (176) = 528.20 \text{ md-ft}$$

$$k = (528.20) \text{ md-ft} / (42) \text{ ft} = 12.6 \text{ mds}$$

II. $B_g = (P_b)(T_f)(Z)(1000)/(5.61)(520)(P_R) =$

$$B_g = (14.73) (720) (1.381) .34279 / (9449.4) = 0.5313 \text{ Res. bbl/ MCF}$$

III. Calculation of Skin Effect, s, and Pressure Loss Due to Skin, ΔP_{skin}

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

$$s = 1.151 \left[\left(\frac{(7592) - (7251)}{(176)} \right) - \log \left(\frac{(12.6) 10^6}{(0.26)(0.25)(4.0)(0.0525)} \right) + 3.23 \right] = -4.37$$

$$\Delta P_{\text{skin}} = (0.87)(s)(m) = \text{psi}$$

$$\Delta P_{\text{skin}} = (0.87)(-4.37) (176) = -669 \text{ psi}$$

IV. Diffusivity, η

$$\eta = .006328 (k) / \phi \mu C_T =$$

$$\eta = .006328 (12.6) / (0.26)(0.25)(4.0) 10^{-6} = 306,665 \text{ ft}^2/\text{day}$$

EXHIBIT 12-3a

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

RESERVOIR LIMIT TEST
(J. DONALD CLARK, P.E.)
RESERVOIR DRAWDOWN TEST (CONT'D)

Test Date: Sept. 13-18, 1980 Type Test: Buildup Lease and Well No. G. M. Koelemay No. 1

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

$$J \text{ (actual)} = \frac{Q_w}{P_i - P_f} = \frac{(2178)}{(9381 - 7251)} = 1.0225 \text{ bbls/D-psi}$$

$$J \text{ (ideal)} = \frac{Q_w}{(P_i - P_f) - \Delta P_{\text{skin}}} = \frac{(2178)}{(9381 - 7251) - (-669)} = 0.7781 \text{ bbls/D-psi}$$

$$CE = \frac{J \text{ (actual)}}{J \text{ (ideal)}} = \frac{(1.0225)}{(0.7781)} = 1.3141 \text{ or } 131.41 \%$$

Distance to Barriers or Discontinuities, d $d = 2 \sqrt{r_w h}$

$$d = 2 \sqrt{(306,665)} \times \sqrt{t} = (1108) \sqrt{t}$$

time, days	t	d, ft.	(psi/cycle)	Flow Angle	Jones Y Function	Bbls of Aquifer Explored or Tested
-	-	-	176	360	-	-
0.00028	0.0167	18.5	294	216	124	-
0.0039	0.0624	69	341	186	-	-
0.0088	0.0938	104	430	147	-	-
0.06	0.2449	271	735	86	2.3289	116,837
0.30	0.548	607	735	86	0.465791	584,186
3.1696	1.780	1972	735e	-	0.440867	6,172,000

$$Y = (735)/(2.3)(2178)(1.05)(0.30) = 0.465791$$

$$W = (1.0)/(1.05)(0.46579)(3.5 \times 10^{-6}) = 548,186 \text{ Bbls. of water explored.}$$

$$(7758)(0.26)/(1.05) = 1921 \text{ Bbls. of water per acre-ft.}$$

$$(607)^2 \pi / 43,560 = 26.57 \text{ Ac.}$$

$$(1972)^2 \pi / 43,560 = 280.46 \text{ Ac.}$$

Assume 77 ft. Net:

$$W = (77)(1921)(26.57) = 3,930,000 \text{ Bbls. } (176/735) = 941,000 \text{ Bbls.}$$

$$W = (77)(1921)(280.46) = 41,485,000 \text{ Bbls. } (176/735) = 9,933,000 \text{ Bbls.}$$

Assume 42 ft. Net:

$$W = (42)(1921)(26.57) = 2,144,000 \text{ Bbls. } (176/735) = 513,300 \text{ Bbls.}$$

$$W = (42)(1921)(280.46) = 22,628,000 \text{ Bbls. } (176/735) = 5,418,000 \text{ Bbls.}$$

EXHIBIT 12-3b

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Photo 12-1 Eaton Engineers reviewing Reservoir Pressure Data with DOE Test Manager on Location

The calculation of the amount of water explored using the slope of the drawdown curve is also subject to possible error, since the assumption on the compressibility of the fluid is based on all water, and some free gas was originally present. Therefore, the conclusion that the test depicts a geopressed aquifer having a small associated gas cap updip with lenticular type permeability flow restrictions around the updip drainage is generally correct, but a more detailed description of the size of this attic gas and distances to permeability barriers is not feasible.

Geological descriptions of the test zone and area, along with core descriptions and analyses, agree very closely with the engineering interpretations of the geological effect on the pressure drawdown plot. The core analyses are presented on Exhibit No. 5-4, in Section 5. The tests that followed this original flow test present additional support of these conclusions.

The portion of this first drawdown plot that can be used to support mathematical conclusions from the test is the final drawdown slope of 950 psi per cycle. The reservoir fluid explored to 1 day of flow time, using this drawdown slope, is 1.506 million barrels. A reservoir having an average of 26 percent pore space, with an estimated formation volume factor for water of 1.05 barrels per barrel of reservoir space, would support 1921 barrels per acre-foot of surface-measured brine. Therefore, using 42 feet of net sand, the productive area required to support 1.506 million barrels of brine would be 18.67 acres.

Average air permeability from 28 sidewall cores analyzed was 84.5 mds., which would convert to about 17 mds. water permeability. The distance that would be explored in one day for 17 mds. water permeability is around 1282 feet. This would be equivalent to a radial area of 118.5 acres or about six times the area required to support 1.506 million barrels of reservoir brine. In other words, several flow barriers close to the well would be required to restrict or reduce the volume explored in one day of testing. Based on this information, the plan for closing in the well was changed for the buildup test that was to follow. For barriers close to the well to be seen in the test results, the well would have to be shut-in within 1.5 minutes if permeability was 17 mds. Other data indicated permeability much higher than this; therefore the plan developed was to shut the well in in a few seconds to try to gain a straight line buildup plot as early as possible.

12.2 First Buildup Test

The well was completely shut in in about 30 seconds. The buildup plot is also plotted on Exhibit 12-1a. These mirror-image type plots help to determine where the buildup plot becomes invalid. Exhibit 12-1b is the surface drawdown and buildup pressure for the same equivalent flow and buildup periods.

Exhibit 12-4 is an enlarged and detailed plot of the early buildup time, the first 30.5 minutes of buildup. Each pressure point plotted on the semilog graph represents a 10-second interval. The 30-second pressure point is located on the straight line of 294 psi per cycle. All of the 10-second pressure points recorded fall directly on the slopes

plotted after the first 30 seconds of buildup time. The extrapolation of the 294 psi per cycle slope falls below the final flowing pressure of 7251.35 psi. This extrapolation below flowing pressure is an obvious negative skin value, and is invalid.

The dashed straight line plot passing through the 10-second and 20-second pressure points and having a slope of 176 psi per cycle is not well defined. This slope is used in the calculations of permeability and skin effect on Exhibit 12-2a. This calculated permeability of 12.6 mds. and skin effect of -4.37 is also in error and cannot be used for detailed calculations.

An attempt to get a buildup slope equivalent to the 950 psi per cycle drawdown slope was not successful. Exhibit 12-1a depicts a slope of 735 psi per cycle between 0.05 and 0.30 days. Somewhat less slope could also be drawn through this portion of the plot, but not more. This is the effect expected when flow time preceding the buildup is not sufficient. A buildup test is valid up to about 1/4 to 1/3 of the total preceding drawdown time, at which time the buildup plot begins to bend to the right.

The Horner-type plot, which plots the log of the pseudo-time of flow time plus shut-in time divided by shut-in time versus pressure, is also invalid. This plot is depicted on Exhibit 12-5. The P^* extrapolation to 9351 psia, at the pseudo log time of one, is some 30 psi below the original measured pressure of 9381.43 psia (datum 11,540 feet).

The calculations from the buildup test, Exhibits 3a and 3b, give a radial distance of 607 feet to 0.3 days, or to the end of the straight-line slope, equivalent to a circular area of 26.57 acres. Assuming 42 feet of effective net pay, instead of the estimated 77 feet, would give a pore volume of 2,144,000 barrels of equivalent stock tank water. The slope of the buildup plot of 735 psi per cycle would depict a water-explored value in 0.3 days of 584,000 barrels, much smaller than a circular area of 607 foot radius. If the flow area around the well were reduced to the equivalent flow area of the slope changes (176/735) or to a flow angle of 86 degrees, the water pore volume would become 513,000 barrels, approximately the value calculated from the slope of the buildup plot. This again supports the conclusion of close-by permeability barriers and updip thinning out of the sand zone near the well bore.

The water explored, using the total buildup time of 3.169 days and assuming continuous slope buildup of 735 psi per cycle, would be 6,172,000 barrels. This approximates the pore volume for a distance of 1972 feet, with a restricted flow area of 86 degrees around the well bore, equivalent to 5,418,000 barrels of water. This is not the support desired for water exploration calculated by the two methods, but the result is in line with what can be expected under these specific reservoir conditions.

The net pay determined from the electric log for the perforated sand was originally estimated to be 77 feet. The use of this 77 feet of net sand in flow equations did not allow viable correlations. This can be explained in more detail by information obtained by Lear after the company again took over operation of the well and started producing commercial quantities of hydrocarbons.

Lear contracted a Schlumberger-engineered production logging study using downhole flow meters and temperature measuring devices to determine what portion of the sand was contributing to fluid flow into the well bore. Exhibit 12-6 is a reduced copy of the

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240°F ——— TEMPERATURE ——— 260°F
 0 ——— GRADIOMANOMETER ——— 2.0

PRODUCTION PROFILE LOG - YEGUA "Leger" SAND
 LEAR PETR. NO. 1 KOELEMAY

EXHIBIT 12-6

DOE CONTRACT NO.
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12-15

test log depicting this information. This test allowed the interpretation that some 95 percent of the total produced fluid was from the upper 42 feet of the perforated sand. The lower portion of the sand, even though perforating was attempted, contributed very little to the total fluid flowing. It also appears this lower zone does not have vertical communication with the upper portion of the sand within the area tested.

12.3 Second Flow Test

The well was opened for the second flow test at 5:52 PM on September 16, 1980. The shut-in pressure at this time was 9200 psia or about 181 psi below the initial shut-in pressure. Shortly after flow was initiated, it was discovered that the disposal well was unable to take the produced brine, and water was bypassed to the surface reserve pit. The well flowed at rates between 4308 and 3545 BWPD for a total of 10 hours and 23 minutes, to 4:15 AM on September 17th. The surface pit had filled at that time, and production was suspended.

Exhibit 12-7a is the bottom-hole drawdown pressure and buildup pressure plot for this short test. The average production rate for the first hour was about 4174 barrels of formation brine per hour. After 72 minutes, the flow rate increased to 4308 BWPD. This increase is depicted on the drawdown plot as an increased slope in pressure drawdown. Note the hyperbolic type drawdown plot. The production rate declined from 4308 to 3545 BWPD during the final 9 hours of the flow period. This is equivalent to a decrease in flow rate of about 85 barrels per hour. During this period the pressure at the sand face dropped from a measured 7600 psia to 6100 psia, about 167 psi per hour. This type of drawdown curve is typical for a well producing at a rate higher than it can sustain. The low productivity is not from low permeability, but from high permeability with a very restricted drainage area.

The buildup curve is a typical flat "S" shape curve common for a good permeable sand after a short flow period. No additional reservoir data can be obtained from this unplanned short test. The sand face pressure at the end of the flow period was 6207.91 psia, a loss of about one third of the original pressure. This would indicate a large loss in reservoir pressure in the updip attic portion of the drainage area.

The test well was shut-in while the disposal well was plugged back and perforated in a higher sand.

12.4 Third Flow Test

The third flow period started at 1:46 PM (1346) on September 18th, after about 33.5 hours of shut-in time. The measured datum pressure was 9004.16 psia or about 377 psi below the original pressure. The choke was opened very slowly to allow surface sampling of hydrocarbons that had risen to the top of the shut-in well bore. Some liquid hydrocarbons were taken from the flow lines during this period for laboratory analysis. The measured production rates varied between 1700 and 7800 barrels per day during the first 12 minutes of this flow test. The method of placing a well on test can affect the early data that are obtained. Exhibit 12-8 is a plot of the reservoir pressure drawdown for the first 20 hours. Problems developed in opening the choke, and it was opened too slowly for the first minute. The three pressure plots depict the

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EXHIBIT 12-7a

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EXHIBIT 12-7b

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effect on the early portion of the drawdown plot if the initial starting time is varied. The early pressures were taken at 10-second intervals, and the time origin of the starting plots are listed on the graph. The slopes of the curves are similar, but the early drawdown slopes vary considerably for each plot.

The inability of the well to maintain constant high production rates has been discussed. The flow rate of 7700 BWPD after 12 minutes of flow decreased to 6800 BWPD within 15 minutes, or after 27 minutes of flow. As expected, the higher flow rate also gave a higher rate of decline of production of about 60 barrels per minute. The reservoir was not capable of sustaining these rates of production. Any attempts to interpret this drawdown effect would give erroneous values.

The production rate dropped to about 5500 BWPD within 70 minutes with no change in the flow choke setting. The wellhead pressure was 1000 psia with a bottom-hole flowing pressure of 5745 psia, or a bottom-hole pressure loss of 3259 psi. The production separator pressure setting controlled the flow rate for this final test period. The surface pressure loss was 3030 psi for the same time period. Exhibit 12-9 is a plot of the bottom-hole and surface pressure for the third flow period.

The bottom-hole and surface pressure curves are similar in shape but do not correlate by a constant factor. Development of a method to determine flowing bottom-hole pressure from surface pressure would be desirable, because it would eliminate the need for expensive wireline instruments. Using the pressure data obtained during this test to develop a formula relating bottom-hole and surface tubing pressures is not practical because the average fluid density in the tubing was constantly changing. Gas and oil columns built up in the tubing and were bled off at certain times.

Development of a formula to relate flowing bottom-hole pressure to flowing surface pressure in the annulus is even less feasible because of temperature effects on fluid viscosity, changing gas-liquid ratios, and friction losses, which are very difficult to calculate.

Bottom-hole and surface pressures were measured continuously between 1:46 PM on September 18th and 5:45 PM on September 25, 1980. At midnight on September 25th, after a total of 7 days, 11 hours, and 20 minutes of flowing time during the third flow period, the well operations were turned back to Lear Petroleum Exploration, Inc. During the final test period as a Well of Opportunity the surface flowing pressure varied between 460 and 600 psia, with daily average production rates of approximately 3200 barrels of water, 1000 MCF of gas, and about 75 barrels of oil. The final flowing bottom-hole pressure was 4289 psia, a drop in flowing pressure of about 5092 psi from the original pressure.

Lear Petroleum continued to produce the well for an additional 12 days after taking over. On October 9, 1980, Lear ran an Amerada pressure gauge to obtain a pressure buildup test. The prior 24 hour production rate was 2181 barrels of water, 188 bbls. of 44° API oil, and 1,706 MCF of gas on a 20/64-inch choke, with 1135 psig flowing wellhead pressure. On September 26th, Lear was producing 3505 BWPD with 60 barrels of oil and 1000 MCF of gas and had 500 psig wellhead flowing pressure on a 46/64-inch choke.

Lear Petroleum produced 32,389 barrels of water, 2055.5 barrels of oil, and 18,671 MCF of gas between the time they took over operations and when they shut the well in, approximately 12 days. The gas-to-oil ratio averaged 9083 cubic feet of gas per

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EXHIBIT 12-9

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barrel of oil, or 576 cubic feet of gas per barrel of formation brine. Reducing this production to reservoir volume would approximate the percentage production as 73.3 percent water, 5.3 percent oil, and 21.4 percent gas. Therefore, this production would classify the well as a hydrocarbon producer and not a geopressed brine well. The hydrocarbons are being produced by lowering pressure in the attic zone, allowing the gas and oil to expand into the well bore and be produced. The conclusions developed from the first test were supported. The size of the hydrocarbon zone has not been determined, but it is believed to be relatively small.

The well was put back on production after a 5.9583-day buildup test. The first production that followed was mostly water with no oil. Once the pressure was lowered sufficiently at the sand face, the oil and gas again expanded into the wellbore. Problems developed in completely drying the produced gas at the well location. A water removal system was placed on the gas pipeline at a distance of one mile from the well location, and about 60 barrels of water were removed from the gas each day. Another water knock-out was planned further down the gas flow line to reduce the 9 pounds per MCF of gas to the marketable 7 pound gas required by the gas pipeline.

12.5 Lear's Buildup Data

The pressure buildup data for Lear collected by the M. M. Cooke Company was given to Eaton by Lear. This pressure data is plotted in Exhibits 12-10 and 12-11. The pressures were measured by an Amerada pressure gauge with the instrument located at 11,572 feet.

Exhibit 12-10 is the plot of pressure versus the log of time, and it appears to follow the shape of the previous plots. Three slopes of 411, 1090, and 1140 psi per cycle were depicted. The total flow time during this last flow period conducted by Lear was 19.382 days, which should allow a straight-line interpretation for the 6 days of measured buildup pressures.

Exhibit 12-11 is also the Horner-type plot of the log of the pseudo-time of $(t + \Delta t) / \Delta t$. The flow time used was 19 days, 9 hours, and 10 minutes. This flow time is a combination of Eaton's third flow test of 7 days, 11 hours, and 20 minutes and Lear's continued production of 11 days, 21 hours, and 50 minutes. The Horner plot extrapolation to the log of 1 gave a P^* value of 9000 psi. This pressure, corrected to the original pressure datum, is 9074 psia, 375 psi below the original pressure of 9449 psia. The Amerada gauge is not comparable to the quartz crystal gauge for determining absolute pressure, and no attempt to quantify this 375 psi pressure-loss was made. The Horner plot in itself is found not to be reliable as a method for original or static reservoir pressure extrapolations.

12.6 Reservoir Energy and Reservoir Size

The attic gas cap and/or volatile oil rim created difficulties in determining the size of the reservoir tested, and the relative size of the hydrocarbon zone compared to that of the aquifer. The hourly production details presented by IGT for the third flow test, between September 18th and September 23, 1980, gave corrected values of water production and standard cubic feet of gas per barrel of water produced. There were no values for liquid hydrocarbons that might have been produced.

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A calculation of the energy effect, assuming 35 cubic feet of gas in solution and the remaining gas to be free gas condensate in the reservoir, was attempted. A curve depicting the value of the gas formation volume factor as a function of pressure was constructed (Exhibit 12-12). The erratic pressure trends were replotted in Exhibits 12-13 and 12-14, on an equivalent hourly basis. The pressure on these plots appeared to follow a specific drawdown pattern and allowed a reasonable correlation of pressure loss and time.

This data allowed a "Y" function calculation on an hourly basis for the period from the 18th hour to the end of Eaton's third flow test. The "Y" functions calculated are plotted on log-log graph paper and depicted in Exhibit 12-15. The Bg curve allowed the free gas production to be converted to reservoir volume, and this was added to the reservoir barrels of water and gas in solution produced.

The assumption was then made that all reservoir expansion would be from the aquifer. Had this been true, each point would fit on a straight 45° line on the log-log graph. But instead of this "Y" plot decreasing with time, on a 45° slope, the values of the "Y" functions were increasing with time. This indicated that the amount of energy from the aquifer was decreasing with time; the energy from the gas was greater than that from the aquifer and nearly reversed the normally expected expansion trend. This is also seen in the plot of water explored as a function of time. The water explored reduced with time until after about 4 days, and then a normal increase in explored value was seen. This could mean the expansion of the gas cap was the predominant energy expansion effect for the first 5 days, and thereafter the larger aquifer began to become the major energy effect for production.

This effect could also explain the early low rate of pressure decline due to slower transmissibility through the less viscous fluid or gas cap. It was obvious that the free gas zone was expanding into the wellbore and being produced during the final period of the test. The primary purpose of the plot was to determine whether or not all reservoir limits had been seen and a steady-state reservoir flow existed. The final trend appears to show that transient flow does exist in the aquifer, and final reservoir limits were not reached.

These final correlations and conclusions appear minor in nature for our general testing purpose. It is clear that the well is not capable of producing the large volumes of water necessary for a geothermal-geopressured gas saturated brine well. The restricted area of drainage is the primary cause for the low well productivity. It is an ideal situation for attempting to recover the attic hydrocarbon zone from a down-dip reservoir location.

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EXHIBIT 12-11

EXHIBIT NO. 12 - 12

EXHIBIT 12-12

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EXHIBIT NO. 12-13

EXHIBIT NO. 12-14
 KOELEMAY NO. 1 WELL
 VARIABLE RATE PRODUCTION
 PRESSURE DRAWDOWN PLOT
 Sept. 18-23, 1981
 FLOW TEST

EXHIBIT 12-14

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EXHIBIT NO. 12-15
KOELEMAY NO.1 WELL

WATER EXPLORED
AQUIFER DRAWDOWN
Sept. 18 - 23, 1981
FLOW TEST

EXHIBIT 12-15

12.7 Properties of Produced Fluids

12.7.1 Overview of Raw Data

12.7.1.1 The Test Sequence: The following is a chronological description of production test activities and events that provides a background for detailed discussions of data obtained and of the data interpretation in subsequent sections.

- **9/5/80 0730-1100 hours:** Attempted to obtain a bottomhole fluid sample using a GO International tool and wireline unit but could not flow well because of leaks in the Christmas tree. Shot sample tool while in the hole, but it failed to work.

1400-1630 hours: After repairing leaks in christmas tree, GO International staff attempted to take a bottomhole sample. The disc on the tool was not punctured, the tool would not close, and no sample was obtained.
- **9/6/80 1600-2400 hours:** RDI performed pressure and temperature gradient measurements in the production well bore. There was a delay in further testing due to Hurricane Daniel.
- **9/11/80 0800 hours:** RDI went into the production well with a Hewlett-Packard quartz crystal pressure gauge and set the gauge at 11,540 feet. RDI began recording bottomhole pressure at 1150 hours.
- **9/12/80 1250 hours:** The initial flow test began after 25 hours of continuous recording of bottomhole and wellhead pressures. The choke was adjusted several times during the first 9 minutes of flow, but it was left set after that. Once adjusted, no changes were made in separator operating conditions.
- **9/13/80 1355 hours:** The well was shut-in for buildup tests. Bottomhole and wellhead pressures were recorded continuously during pressure buildups.
- **9/16/80 1752 hours:** The well was opened for the second flow test. The choke was adjusted within a few minutes but was opened further about an hour later to increase flow rate. Separator static pressure was increased slightly about 2 hours after flow began, to increase the disposal well pressure. Bottomhole and wellhead pressures were recorded continuously during the second flow test. The disposal well would not accept fluid, so brine flowed to the reserve pit. Injection could not be initiated by pumping with a Halliburton truck.
- **9/17/80 0414 hours:** The well was shut-in for the buildup test. Flow was stopped primarily because the reserve pit was filled and the disposal well required treatment. Bottomhole pressure was recorded continuously during buildup. RDI lost wellhead pressure gauge signal at about 0450 hours but repaired the problem and began recording again at 1045 hours.
- **9/18/80 1346 hours:** The third flow test began after recompleting the disposal well. The choke was opened stepwise until 1900 hours. Brine production continued to decline from about a 7000 BWPd rate, even with adjustments to

the choke, to about a 3200 BWP rate at the end of the test. Bottomhole pressure was recorded continuously until 9/25/80 at 1745 hours, when RDI was ordered to rig down. Wellhead pressure was recorded continuously throughout the entire test period. Separator static pressure was increased by numerous steps until the separator was operating at about 520 psi. These increases were necessitated by a pressure buildup in the disposal well, which actually dictated the flow conditions for much of the third flow test. The gas/water ratio increased throughout the test period.

- **9/20/80** 1830 hours: An equalizer valve was installed on the wellhead to bleed gas off tubing.
- **9/21/80** 1930 hours: Flowed brine into a 220-barrel settling tank and then attempted to use an injection pump to dispose of brine. An emulsion of oil, water, and sand formed on top of the liquids in the settling tank. The emulsion was apparently passing through filters and plugging the disposal well.
- **9/22/80** 0330 hours: Treated disposal well with 1000 gallons of xylene to unplug formation.
- **9/24/80** 0745-1545 hours: Diverted flow to reserve pit to treat disposal well with 3500 gallons of acid. Brine production not cut back.

1200-1545 hours: The separator was converted to three-phase separation to collect oil, and gas continued to be flared.

1545 hours: Resumed flowing through separator and into the disposal well. An estimated 1312 barrels of brine had been flowed into the pit.

- **9/25/80** 1745 hours: RDI was ordered to rig down. End of bottomhole pressure measurements.
- **9/26/80** 0000 hours: Lear Petroleum took over operation of the well, terminating the test. Subsequently well flow was continued, for commercial production.

1400-1600 hours: Western Crude Oil, Inc., took delivery of 116 barrels of oil at 39.8° API at 60°F.

12.7.1.2 Editing of Data for Interpretation: Raw data collected by IGT, RDI, and Weatherly Engineering, Inc. have been combined into a single data set that provided a basis for interpretation by IGT. This combination process involved engineering judgments regarding which sensors and meters provided information most likely to be true representations of the producing characteristics at each instant. IGT thus examined the totality of all data collected by the several subcontractors and combined those data, editing a portion (less than 2%) of the data for consistency, based on engineering judgments, to make the most realistic interpretation of actual well performance. Examples of this combination selection/editing process are discussed below.

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- **Orifice Meter Plate Change:** During the first hour of the initial flow test, a 0.75-inch orifice plate was used to meter the gas flow. The differential pressure readings were too low to allow accurate interpretation of the values recorded and have been eliminated from the analysis. A 0.50-inch orifice plate was then installed and was used to record the orifice differential pressure from the start of the second hour onward.
- **Orifice Differential Pressure Recording:** Although fluctuations did occur in the orifice differential pressure (ΔP) readings periodically, data editing was performed in only a few instances. In four cases, brine was carried over and out the flare line (separator upset), causing wide fluctuations in orifice ΔP measurements. These situations lasted from less than a minute to a maximum of 15 minutes. In each case three or fewer data records were changed to bring the ΔP values in line with operating conditions before and after the separator upset.

Another instance requiring data editing occurred when the separator and turbine meter were bypassed with the produced fluids going into the reserve pit. In this case, two data records accounting for a 15-minute interval were corrected to reflect the orifice ΔP measurements that would have been detected had production continued through the separator. These two records were required to properly run the computer program used to analyze fluid production. The edited data records were based on the relatively consistent, stable performance of the orifice ΔP prior to the bypass. Validity of the editing is supported by stable IGT wellhead pressure and temperature readings as well as stable RDI bottomhole pressure measurements prior to and during the 15-minute interval in question.

In addition, a number of ΔP data records were deleted when flow was temporarily resumed through the separator for about 2 hours during conversion to three-phase separator operation on 9/24/80. This was done because no turbine meter readings from Weatherly Engineering were available to be matched up with gas production. Orifice ΔP measurements were also deleted for that portion of the hour during which flow was resumed through the separator into the disposal well. As before, this decision was based on the need to have actual brine flow rates, which became available during the next hour. Essentially, only 15 minutes of measurements were affected.

A changeover in field generators caused a 2-1/2 hour gap in IGT's computerized data collection system during the morning of 9/25/80. Three data records were edited to provide hourly inputs for the computer analysis program for this interval. The orifice ΔP records were based on pre- and post-interruption data that showed consistent ΔP performance. These indicators included IGT ΔP measurements, RDI tubing and bottomhole pressures, and Weatherly Engineering production data recording.

- **Cumulative Brine Flow:** Hourly Weatherly tabulations for the amount of brine produced were incorporated into the IGT data base. Values recorded from the RDI turbine meter upstream of the choke gave considerably higher flow rates due to significant two-phase flow in the pipe. Impulses from Weatherly's Halliburton turbine meter downstream of the separator were incompatible with IGT's analog/digital convertor, causing unreliable readings to be recorded by IGT.

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Because of this, Weatherly's hourly cumulative barrel readings from the Halliburton meter provided the best source of data on brine volume flowed.

Some problems associated with manual data recording required careful examination to determine reasonable explanations for significant variances in brine flow rates calculated from these readings. Weatherly cumulative brine readings were edited for the following reasons:

- Apparent delays in reading the barrel counter exactly on the hour.
- Separator upsets causing brine production through the flare line
- Bypassing of the turbine meter.

The following discussion explains the editing process for cumulative brine flow:

A simple computer program provided the equivalent daily production rates for each hour of the test, based on the Weatherly input data and on IGT's cumulative readings upstream of the choke. The program also calculated hourly ratios of downstream (Weatherly) measurements to upstream measurements. Ratios inconsistent with the prevailing trend were investigated. Hourly plots of downstream production rates also indicated specific times that appeared not in accord with actual well performance. Bottomhole, annulus, and tubing pressures were also reviewed before any adjustments were made.

The first editing of data occurred on 9/19/80 at 0300 hours. The 0300 and 0400 flow rate readings (approximately 4700 bbl/day and 4200 bbl/day, respectively) were both considerably inconsistent with the 0200 and 0500 readings. Bottomhole and wellhead pressures indicated a consistent well production performance for this entire period. By decreasing the 0300 reading by 10 barrels, the production rates were brought in accord with well performance. This 10-barrel adjustment could have resulted from reading the barrel counter as little as 3 minutes late.

The next editing occurred at 0200 on 9/20/80 to correct for a 15-minute separator upset that resulted in brine flowing out the flare line. To bring the production rate in accord with the flow rate before and after the upset, 25.6 barrels were added to the cumulative production readings from the 0200 record on. This is in accord with the pressure and temperature measurements recorded at that time.

A low flow-rate reading occurred at 0900 hours on 9/20/80, which corresponded to a temporary switchover to a second Weatherly turbine meter. This lasted only a short time because the second barrel counter did not appear to be functioning properly. As a result, an estimated 16.4 barrels have been added to the cumulative production readings for 0900 hours. This increases the total adjusted production by 42.0 barrels.

At 0745 hours on 9/24/80 the separator and turbine meter were bypassed to convert the separator to three-phase operation. Because no barrel reading was made at 0800, IGT added 146.07 barrels to the adjusted 0700 reading. This estimate was based on the hourly average brine production of the 14 hourly readings on 9/24/80, seven readings before the meter was bypassed and seven afterwards.

This average was also used to correct the cumulative barrel reading for each hour through 1700 hours on 9/24/80, at which time flow had been resumed through the separator and turbine meter. IGT added 1314.6 barrels (146.07 bbl/hr for 9 hours) plus the previously discussed 42.0 barrels to arrive at a new adjusted cumulative production reading for the 1700 hours record. This correction was carried forward, adjusting the Weatherly readings for the remainder of the test.

It is important to note that the corrections were not made in standard barrels but rather in barrels compatible with the operating conditions. IGT's subsequent computer analysis corrects these barrels to standard conditions.

- Other Data Editing: The aforementioned 9/20/80 separator upset also required editing of three records (accounting for a 15-minute interval) for both separator static pressure and gas flare line temperature. Data records were edited to bring these measurements into accord with the pre-and post-upset values.

Editing was performed to fill in separator static pressure and gas flare line temperature data on 0800 records for 9/24/80. This was necessary because the separator had been bypassed at 0745. The edited values were consistent with the readings just prior to bypass, essentially assuming constant flow rate through the separator until 0800.

Separator static pressure and gas flare line temperatures were added to the data set for 0900 and 1000 on 9/25/80 when the IGT computerized data collection system was not operational. Selected values were based on IGT strip chart recordings and RDI and Weatherly measurements recorded during this period. IGT computer records prior to and after this interval showed remarkably consistent levels for the separator static pressure and gas temperature.

12.7.1.3 Edited Raw Data: The combined and edited data set used to define fluid production and properties is presented in Appendix F. Plots of selected data are presented in Exhibits 12-16 through 12-20, each of which is discussed below. Each graph is in two parts, representing the first and second weeks of testing.

- Production Well Pressures (Exhibit 12-16): This exhibit is a compilation of data recorded by IGT and by RDI. All points are machine-plotted from data recorded on magnetic tape. The IGT and RDI data points are tabulated in Appendixes F and G, respectively. The IGT pressures tabulated in Appendix F are in psig; however, for plotting purposes these have been converted to psia. Noteworthy characteristics of the production well pressure data are as follows:

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EXHIBIT 12-16, Part 1 PRODUCTION WELLHEAD, ANNULUS, TUBING, AND BOTTOMHOLE PRESSURES (9/12/80 to 9/18/80)

EXHIBIT 12-16, Part 2 PRODUCTION WELLHEAD, ANNULUS, TUBING, AND BOTTOMHOLE PRESSURES
(9/19/80 to 9/25/80)

- **Hydrocarbon Accumulation at the Wellhead:** The differences between tubing and annulus pressure at the wellhead were primarily due to hydrocarbon accumulation. This overwhelms the small friction drop due to producing up the annulus. This first became apparent when the second flow test began on 9/16/80. After a substantial gas flow, the well produced condensate and then brine.

The annulus was slowly bled for sampling of accumulating hydrocarbons at the time the difference between tubing and annulus pressure were equalized during the afternoon of 9/17/80. Analysis of the oil sample obtained after bleeding off gas is presented in Section 12.7.2.3.

The large pressure drawdown for the third flow test was accompanied by gas migration into the tubing. Equalizing of tubing and casing pressures on 9/20/80 resulted from connecting the tubing and annulus with about 15 feet of 1/4-inch stainless steel tubing. The difference between tubing and annulus pressures on 9/22/80 and 9/23/80 is due to closing and then opening a valve in this tubing.

- **Bottomhole and Surface Pressure Fluctuations:** The majority of simultaneous production well pressure fluctuations during the first and second drawdown test are due to downhole phenomena. One possible exception occurred during the first 2 hours of the second flow test. The last choke adjustment was made about 9 minutes after this test began. However, 25 minutes later the flow rate decreased from roughly 4500 to 3700 bbl/day. After an additional 35 minutes, and when produced volume equaled wellbore volume, the choke was opened further to increase production rate to about 4700 bbl/day. The flow rate increase at "bottoms-up" was accompanied by a large sand detector response during the time of flow rate increase.

During most of the third flow test, the choke was opened so wide that the stepwise changes in production well pressures are merely reflections of changes in separator pressure found necessary due to changing injection pressures on the disposal well.

- **Separator Static Pressure and Disposal Wellhead Pressure (Exhibit 12-17):** The first flow test began with production through the separator to the reserve pit. Brine flow from the separator was switched from the pit to the disposal well about 1-1/4 hours later, after orifice plates had been changed and stable separator operation had been achieved. The first test ran smoothly with a constant separator pressure of about 200 psig and an injection pressure only slightly above the value expected because of the low density of the hot, low-salinity brine produced. At the end of the first flow test, the master valve on the disposal well was closed before separator pressure had dropped to the injection pressure. Thus no backflow could have occurred. Nevertheless, when the second flow test began, the disposal well would not accept fluid. The disposal well pressures shown for 9/16/80 and 9/17/80 are values resulting from manual throttling of brine flow to the reserve pit. At 0100 hours on 9/17/80, the pressure gauge was disconnected from the wellhead so that a pump truck could be used to initiate injection. This was not successful. The test was terminated shortly after 0400 hours due to the high brine level in the reserve pit.

EXHIBIT 12-17, Part 1 SEPARATOR STATIC PRESSURE AND DISPOSAL WELLHEAD PRESSURE
(9/12/80 to 9/18/80)

EXHIBIT 12-17, Part 2 SEPARATOR STATIC PRESSURE AND DISPOSAL WELLHEAD PRESSURE
(9/19/80 to 9/25/80)

Careful examination of tabulated data in Appendix F suggests that backflow of the disposal well may have occurred for a few minutes during start-up of the second flow test. Between 1747:30 hours and 1748:00 hours on 9/16/80, disposal wellhead pressure increased from 5 psig to 17.5 psig, disposal wellhead temperature dropped almost 20°F, and the filter differential pressure became negative. Opening of the production well choke began 2 minutes later at 1750:00. However, another 7 minutes elapsed before disposal wellhead pressure and temperature returned to values appropriate to a shut-in disposal well containing low-density brine. Two additional instances of low wellhead pressure and negative filter pressure drop occurred before disposal wellhead pressure became consistently higher than prior injection pressure at 1844 hours.

During the second shut-in period (9/17/80 to 9/18/80) the disposal well was recompleted. The third flow test began with the use of produced brine to displace acid into the new disposal zone.

The overall pattern that developed during the second week of testing shows an increasing injection pressure at the disposal well. Treatment with xylene early on 9/22/80 and acid on 9/24/80 temporarily relieved this condition, but the disposal well continued to determine the operating pressures for the separator and production well.

An examination of fluids produced into a settling tank on 9/21/80 revealed a fine sand/salt-oil-water emulsion forming and rising to the top. This emulsion is believed responsible for plugging the disposal well.

Throughout the second week a significant drop in the disposal well pressure occurred on a number of occasions. Some of these were associated with increases in the separator back-pressure, which caused a temporary flow decrease to the disposal well to be reflected in a pressure decrease. However, the flow rate and disposal well pressure responded quickly to the new injection pressure.

On 9/20/80, a separator upset allowed brine to flow out the flare line. Attempts to adjust or control the separator caused a noticeable change in both the disposal well and separator static pressure records as reflected on Part 2 of Exhibit 12-17.

At about 1430 hours on 9/21/80, a gradual filling of the settling tank was begun by diverting some of the flow from the disposal well. A decrease in injection pressure occurred, and that pressure continued to fluctuate as flow to the settling tank was increased. The greatest pressure drop occurred when the location of the pressure transducer was changed to a wing valve for continuation of recording of the pressure once the injection pump was operational.

The next substantial pressure decrease in the disposal well occurred at about 0330 hours on 9/22/80 as 1000 gallons of xylene were injected to break down the emulsion presumed to be plugging the disposal formation. As shown on the graph, the disposal well pressure rapidly increased. The pressure fluctuation observed toward the end of 9/22/80 was a result of using the injection pump to

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lower the level of the reserve pit. This caused the pressure in the disposal well to increase at a faster rate.

The substantial pressure drop recorded on 9/23/80 was caused by moving the pressure transducer from the wing valve to the top of the disposal wellhead. The repositioning was completed in less than 10 minutes, so the computerized averaging routine actually recorded artificial numbers for only two 5-minute intervals. In addition, the injection pump was stopped, restarted, and finally stopped for good during the next 2 hours, causing fluctuations in the disposal well pressure measurements.

The apparent gap in pressure readings on 9/24/80 is a result of editing out the data during those hours when the separator and disposal well were bypassed to convert the separator to three-phase operation. During this time the disposal well was treated with 3500 gallons of acid.

The reason for the stepwise changes in disposal wellhead pressure on 9/25/80 is not known. One possibility is incomplete separation of brine and oil. During this period about 20 to 30 barrels of brine were delivered to the oil tank. Whether oil or an oil/brine emulsion periodically passed through the brine dump is not known.

The sharp downward spikes in injection pressure were much less frequent after conversion to three-phase separation. Examination of strip chart records for 9/19/80 to 9/23/80 reveals that many of these downward spikes in injection pressure had a duration equal to the time required for fluid to move from the disposal wellhead to the disposal well perforations. However, the relationship to oil, emulsion, or sand from the two-phase separator is not known.

- **Orifice Differential Pressure:** Digitized values used to calculate gas production are shown in Exhibit 12-18.

During portions of the production period, zero offsets in this measurement were a major factor in the accuracy of calculating gas production. The problem is illustrated by comparison of baseline levels before and after each of the first two flow tests. Before each of these tests, the gauge was zeroed with air in the lines. However, after the first test, the baseline had shifted from zero to about 3.3 inches of water. After the second test, the shift was to about 2.2 inches of water.

After careful comparison with Weatherly charts, it was concluded that these baseline shifts probably occurred at the onset of production and should be subtracted from recorded values. During the first flow test, recorded differential pressure averaged only about 15 inches of water. Since gas production is proportional to the square root of the value above the baseline shift, this correction reduces calculated production to 88% of the values that would be calculated without the correction. For the second flow test, the correction of 2.2 inches to measured values averaging 20 inches reduces calculated gas production to 94% of the value without the correction. On the other hand, for a recorded value of 50 inches of water, a baseline shift of 2.5 inches would change calculated gas production by only about 2.5%. For this reason, selection of

EXHIBIT 12-18, Part 1 ORIFICE DIFFERENTIAL PRESSURE (9/12/80 to 9/18/80)

EXHIBIT 12-18, Part 2 ORIFICE DIFFERENTIAL PRESSURE (9/19/80 to 9/25/80)

orifice sizes for the third flow test emphasized recording between 50 inches of water and the maximum of 100 inches that can be displayed on the Weatherly circular chart. (IGT's transducer is linear to 400 inches of water.)

Many of the wider fluctuations in orifice differential pressure readings correspond to changes in the separator static pressure. (See Exhibits 12-17 and 12-18.) This is most noticeable at flow test startups and at increases in separator static pressure.

Blowdown of the separator through the orifice, at the end of the first two flow tests, caused increases in orifice differential pressure measurements to over 400 inches of water. These huge differentials lasted only 3 to 4 minutes but are not edited out because they represent gas produced from the aquifer tested.

A notable separator upset occurred at approximately 0200 on 9/20/80. A few values were edited because of brine flow through the orifice. The remainder were not altered because they reflect real gas measurements made while establishing control over separator operation. Between 1830 and 1900 hours on 9/20/80, a large increase in differential pressure was caused by a bleed-off of gas trapped in the tubing into the annulus, through a piece of small diameter tubing connecting the two. This bleed-off process occurred again at 2015 hours. The equalizer valve was then left open until 1330 hours on 9/22/80 to prevent gas buildup in the tubing string. After closing the equalizer valve, pressure built up again in the tubing. At about 0100 hours on 9/23/80, the valve was again opened to bleed off the accumulated gas in the tubing and left open for the remainder of the test period.

Increasing separator static pressure produced an oscillation in the orifice differential pressure at about 0430 hours on 9/21/80. The large drop in orifice differential pressure toward the end of the day was caused by a change from a 0.500-inch to a 0.750-inch orifice metering plate.

No data were plotted for the time interval in which flow was diverted to the reserve pit while converting to three-phase separator operation on 9/24/80. There were some readings for the orifice differential pressure when flow was temporarily resumed through the separator during this interval, but the lack of barrel counter readings makes the data insignificant. The orifice meter plate was changed to 1.000-inch during this same time interval. Values for the period from 0800 to 1000 hours on 9/25/80 were from Weatherly Engineering data, since the computerized data collection system was down. These data points are based on orifice differential pressure measurements prior, during, and after the period of missing records. Within a half hour of resuming data collection, the separator static pressure was increased twice, by about 35 psi each time, for a total increase of approximately 70 psi.

- Temperature: Digitized data from all three of IGT's Foxboro temperature transmitters are shown in Exhibit 12-19.

A noticeable difference in brine temperature occurs between production and disposal well readings on Exhibit 12-19. Rather than being hotter, the brine at

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EXHIBIT 12-19, Part 1 BRINE AND GAS TEMPERATURE (9/12/80 to 9/18/80)

EXHIBIT 12-19, Part 2 BRINE AND GAS TEMPERATURE (9/19/80 to 9/25/80)

the production well appears to be at a consistently lower temperature than at the disposal well, except during the times when the disposal well was bypassed on 9/16/80, 9/17/80, and 9/24/80. The cause of these low readings is the method of mounting the production well temperature sensor. Rather than protruding into the pipe and fluid flow, the bottom of the thermal well was located at the circumference of the pipe. As a result, measurements of the fluid temperature were low due to air cooling. The reason for this method of mounting was concern that produced sand might eat through a properly installed thermal well on the high pressure side of the choke.

The sharp drops in disposal well temperature are attributed to several causes. Decreases in temperature at the start of the flow tests are due to the production of fluids which have cooled while trapped in the wellbore. This is followed by a rapid temperature increase as the hotter brine from the reservoir reaches the wellhead, production system, and disposal well. Diversion to the pit during a separator upset at about 0300 hours on 9/20/80 caused a discernible decrease in both gas and disposal well temperatures. Large drops in the disposal well temperature readings during 9/21/80 and 9/22/80 are due to filling the settling tank and pumping xylene into the disposal well, respectively.

The substantial difference between gas and brine temperature is believed to result from air cooling on about 15 feet of pipe between the outlet of the separator vessel and the thermal well 3 feet downstream from the orifice. This same difference was observed by Weatherly during the first day of testing. However, by the end of the test, Weatherly values for gas temperature had increased to higher than brine temperature. IGT's gas temperature measurements were adopted for data interpretation for the following reasons:

- Periodic drainage of condensation from the meter run was required. Therefore its temperature must have been lower than the brine temperature.
- Post-test calibration against a laboratory thermometer in a common heated water bath verified proper operation of the Foxboro temperature transmitter.

Weather conditions were an important factor in temperature measurements. For example, on 9/14/80 and 9/17/80, while no fluids were produced, the probes recorded warming by the sun. Rain accounted for the decreases in gas temperature from 2300 hours on 9/18/80 to 0200 hours on 9/19/80, at about 1500 hours on 9/20/80, and again on the night of 9/25/80.

- Brine Flow Rate (Exhibit 12-20): Neither IGT nor RDI was successful in digital recording of turbine meter data during the first well test (Wainoco P. R. Girouard Well No. 1) by the Eaton Operating Company team. One major problem was lack of an oscilloscope in the field. At the beginning of this test, IGT's newly acquired oscilloscope revealed incompatibility between the Halliburton counting electronics in use on the one hand and input requirements of IGT's Hewlett-Packard electronic system on the other.

Between the first and second flow tests, RDI called out an engineer from Camco for assistance with its production well turbine problems. Cooperative work

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EXHIBIT 12-20, Part 1 BRINE FLOW RATE (9/12/80 to 9/18/80)

EXHIBIT 12-20, Part 2 BRINE FLOW RATE (9/19/80 to 9/25/80)

revealed that the turbine pulse amplifier in RDI's Tejas Controls, Inc., "Big Tex II" unit provided a pulse that could be counted by IGT's equipment after modification for slow rise time signals as specified in Hewlett-Packard manuals and after appropriate computer programming. The result was successful IGT digital recording of output from RDI's production well turbine, starting with the second flow test. Since the calibration data on the turbine had been destroyed while welding on flanges, calibration was established by using Weatherly facilities to pump from tank to tank through the turbine prior to start of the second flow test.

Since only one "Big Tex II" was available, the only recording of separator output turbine data continued to be manual logging by Weatherly. However, IGT did order two of the Tejas Controls, Inc., units for use on future wells.

Exhibit 12-20 presents the following data:

- Production well turbine data at turbine pressure and temperature for each time interval digitally recorded is drawn as plotted points.
- One-hour averages of production rates calculated from production well turbine data at turbine pressure and temperature are plotted as a continuous line.
- One-hour average rates calculated from Weatherly hand logging of separator output turbine data are also plotted as a continuous line. These rates have been corrected to a pressure of 1 atmosphere and a temperature of 60°F.

Efforts to calculate brine rate from wellhead turbine data were moderately successful for the second flow test. However, success was not achieved for the rapidly increasing hydrocarbon/brine production ratio during most of the third test. A major reason is lack of PVT data for the oil and gas phases that coexisted in the separator. Therefore, raw data analysis to calculate the ratio of produced gas/produced brine utilizes only hand-digitized Weatherly data.

12.7.2 Characteristics of Produced Hydrocarbons

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

- The flare line between the orifice meter and back-pressure controller, and
- Flashed gas from brine samples collected at the inlet to the brine metering skid.

Details of collection and analyses for these samples are provided in Sections 12.7.2.1 and 12.7.2.2.

Many gaseous hydrocarbon samples were collected and analyzed during this well test because of continual change in both gas/brine ratio and relative abundance of hydrocarbon species throughout the three flow tests.

Several samples of condensate and oil were collected in the field. However, since production data were not adequate to relate oil production to brine production as a function of time, only one oil sample was analyzed. Details are presented in Section 12.7.2.3.

12.7.2.1 Flare Line Gas Sampling: Flare line gas samples were collected from a sampling point between the orifice meter and the back-pressure controller. All samples were collected at separator pressure. Temperature at the sampling point was lower than brine temperature in the separator, as previously discussed and shown in Exhibit 12-19.

During the first test, most of the samples were collected in vessels that had not been preheated. Analysis results revealed fluctuations in content of CO₂ and hydrocarbons that were hypothesized to be caused by condensation of water (with the associated solution of CO₂) and heavier hydrocarbons in the sample cylinder. With the exception of samples for further study of this question, all subsequent samples were collected in preheated vessels. The full sampling procedure used for preheated vessels is given below:

Gas Sampling

Equipment:

- 1800 psi-rated Teflon-lined stainless steel cylinders sealed at each end with soft- or hard-seated 316 stainless steel valves
- Vacuum pump
- Oven

Photo 12-2 Flaring Gas. IGT Test Trailer in background

Procedure:

A clean 300-ml cylinder was evacuated, sealed, and placed in an oven. The cylinder was heated to a temperature equal to or slightly greater than the brine temperature. A temperature greater than 100°C is used to discourage droplets of water from adhering to the sides of the cylinders. Before sampling, the sample line was purged at high flow rate to establish thermal equilibrium with the flare line. The sample line valve was then turned off, and the hot evacuated cylinder was attached to the sample port. All valves were then opened in sequence, starting with the sample port valve, and the system was flushed with gas at high flow rate for 10 seconds. The valves were then turned off in reverse sequence and the cylinder removed. If the analyses were not to be performed immediately on-site, the cylinder was doubly sealed with Swagelok caps. All samples transported to IGT's Chicago laboratories were collected in Teflon-lined sample vessels.

Results of field gas chromatograph plus Draeger apparatus analyses for H₂S are presented in Exhibit 12-21. Mass spectrometry analyses of samples returned to IGT's Chicago laboratory are shown in Exhibit 12-22. Footnotes on Exhibits 12-21 and 12-22 indicate which samples were collected in vessels that were not preheated. Samples collected in coordination with sampling by McNeese State University are similarly indicated. The relationship between preheating of sample vessels and analytical results is discussed in Section 12.7.2.5.

12.7.2.2 Gas Flashed From Brine to the Disposal Well: A measurable amount of gas remained in solution in the brine leaving the separator. To analyze this gas, brine samples were collected at separator pressure from the brine sampling point on the brine metering skid. These samples were taken in 500-ml Teflon-lined stainless steel cylinders, cooled, and flashed to atmospheric pressure. The sample collection and flashing procedure was as follows:

- Connecting a 500-cc sample vessel to the sampling point, with the outlet end of the vessel above the inlet end.
- Opening valves and flowing brine through the sample vessel for at least 60 seconds and until the vessel was hot to the touch.
- Closing the sample vessel outlet valve.
- Closing the sample vessel inlet valve.
- Disconnecting the sample vessel from the sampling point and immersing it in water until it cooled to the field laboratory ambient temperature (about 25°C). Cooling by water immersion provided the advantage that any sample vessel exhibiting leakage by bubble formation could be rejected.
- After cooling, connecting the sample vessel to an evacuated 30-cc cylinder with a valve on each end and a 500-cc syringe attached to the opposite end of the 30-cc cylinder.

EXHIBIT 12-21 CONCENTRATION OF GAS COMPONENTS IN FLARE LINE GAS
FROM LEAR G. M. KOELEMAY No. 1 WELL (Field Analysis)

Sample Date and Time	Methane	Ethane	Propane	n-Butane	i-Butane	n-Pentane	i-Pentane	C ₆ +	Carbon Dioxide	Nitrogen	H ₂ S (ppm)++	Sample Points	
												T, °F	Psig
12 Sept 80 † 2000	87.2	3.9	1.1	0.2	0.1	<0.1	0.1	0.1	7.0	0.4	N.D.**	119.8	198.3
13 Sept 80 † 0920	84.1	4.6	1.9	0.6	0.3	0.2	0.3	0.5	7.3	0.4	N.D.	136.4	197.9
13 Sept 80 1300	84.3	4.5	2.0	0.5	0.3	0.1	0.2	0.4	7.3	0.4	10.5	144.5	202.5
16 Sept 80 2145	84.0	4.9	2.3	0.7	0.4	0.3	0.3	0.6	5.9	0.5	N.D.	140.6	413
16 Sept 80 2250	83.9	4.9	2.4	0.7	0.5	0.4	0.4	0.7	5.7	0.4	8	147.9	414
17 Sept 80 0040	85.4	4.7	2.0	0.5	0.3	0.2	0.2	0.3	6.0	0.4	N.D.	150.6	412.9
18 Sept 80 1700	82.7	4.9	2.3	0.6	0.4	0.3	0.2	0.5	7.7	0.4	11	161.7	248.5
18 Sept 80 1740	82.7	4.9	2.4	0.7	0.4	0.3	0.3	0.5	7.5	0.4	N.D.	163.7	246.4
18 Sept 80 1950	82.3	4.9	2.4	0.7	0.5	0.3	0.3	0.6	7.7	0.3	N.D.	167.1	303.3
19 Sept 80 1110	81.2	5.5	3.0	0.9	0.6	0.4	0.4	0.8	6.6	0.5	8	167.6	303.7
19 Sept 80 1620	81.4	5.9	3.2	0.9	0.6	0.3	0.4	0.7	6.3	0.2	N.D.	177.1	307.9
20 Sept 80 0800	80.0	6.3	3.9	1.1	0.8	0.4	0.4	0.8	6.0	0.3	8	171.5	310.1
20 Sept 80 † 1930	77.3	6.9	4.6	1.6	1.1	0.7	0.7	1.4	5.3	0.4	7	171.1	344.7
21 Sept 80 0940	78.5	7.3	4.8	1.4	1.0	0.5	0.5	1.0	4.7	0.3	N.D.	171.7	418.1
21 Sept 80 1640	78.3	7.5	5.2	1.7	1.2	0.7	0.8	1.5	4.4	0.3	N.D.	173.7	410.3
22 Sept 80 0940	77.1	8.1	5.3	1.6	1.1	0.6	0.6	1.2	4.0	0.4	5.5	176.8	414.9
22 Sept 80 1720	77.0	8.2	5.4	1.6	1.2	0.6	0.6	1.2	3.8	0.4	N.D.	179.3	420.1
23 Sept 80 0920	76.6	8.7	5.7	1.6	1.2	0.6	0.6	1.2	3.4	0.3	5	185.2	467.4
23 Sept 80 1640	76.5	8.8	5.8	1.6	1.3	0.5	0.7	1.2	3.2	0.2	N.D.	182.9	454.7
25 Sept 80 0845	77.4	8.4	5.7	1.7	1.3	0.6	0.7	1.3	2.6	0.3	4	187.0	309.9
25 Sept 80 1150	75.6	9.2	6.3	1.8	1.4	0.6	0.8	1.4	2.7	0.2	N.D.	187.4	379.3
25 Sept 80 1810	75.7	9.2	6.3	1.8	1.4	0.6	0.7	1.3	2.7	0.3	N.D.	187.6	411.3
25 Sept 80 2110	75.7	9.2	6.3	1.8	1.4	0.6	0.7	1.3	2.7	0.3	N.D.	179.8	408.7
26 Sept 80 1100	75.1	9.3	6.4	1.9	1.5	0.7	0.8	1.4	2.6	0.3	N.D.	181.4	445.4

* C₆+ data, for compounds containing 6 or more carbon atoms, in field is unreliable. C₆+ concentration was made equal to the pentanes concentration following the trend of mass spectrometer data, for normalization purposes.

++ Hydrogen sulfide analysis performed with Draeger Apparatus. Ammonia and mercury were tested for in gas stream at same time as hydrogen sulfide. The concentrations of these components were always below minimum detectable limits - <1 ppm NH₃ and <0.005 mg/m³ Hg.

** N.D. = Not determined.

† Sample vessel was not pre-heated.

‡ Also sent to Chicago for mass spectrometer confirmation of higher NGL content.

Ref. 44093

INSTITUTE OF GAS TECHNOLOGY EXHIBIT 12-22 CONCENTRATIONS OF GAS COMPONENTS IN FLARE LINE GAS FROM LEAR G. M. KOELEMAY No. 1 WELL AND ITS HEATING VALUE AND SPECIFIC GRAVITY BY MASS SPECTROMETRIC ANALYSIS

Sample Date and Time	Heating Value	Specific Gravity	Methane	Ethane	Propane	n-Butane	Isobutane	Pentanes	Hexanes	Heptanes	Octanes	Nonanes	Decanes	Toluene	Xylenes	Carbon Dioxide	Nitrogen	Helium	Sample Point	
																			T, °F	Psig
12 Sept 80 + 1600	1000	0.646	88.63	4.12	1.25	0.19	0.10	0.06	0.02	0.01	0.00	ND	0.01	0.01	ND	5.12	0.27	0.01	114.4	201.6
12 Sept 80 + 1920	987	0.658	87.50	3.95	1.22	0.16	0.08	0.05	0.03	0.03	0.00	ND	0.03	0.03	0.01	6.53	0.28	0.01	119.4	200.4
13 Sept 80 + 0918	1037	0.694	84.91	4.58	1.85	0.40	0.20	0.48	0.20	0.17	0.02	0.01	0.04	0.07	0.01	6.90	0.25	0.01	136.4	197.9
13 Sept 80 + 1155	1021	0.685	85.16	4.62	2.96	0.39	0.30	0.21	0.11	0.05	0.02	ND	0.02	0.02	0.01	6.37	0.25	0.01	142.7	201.6
13 Sept 80 + 1200	1020	0.683	85.32	4.59	1.96	0.37	0.26	0.20	0.12	0.07	0.01	ND	0.02	0.02	0.01	6.51	0.23	0.01	143.4	201.4
17 Sept 80 0040	1046	0.680	85.65	4.90	2.20	0.46	0.34	0.26	0.17	0.08	0.01	ND	0.02	0.02	0.01	5.63	0.24	0.01	150.0	412.9
18 Sept 80 1840	1027	0.698	83.87	4.67	2.19	0.58	0.38	0.24	0.16	0.08	0.01	ND	0.02	0.02	ND	7.50	0.27	0.01	165.3	244.8
19 Sept 80 + 0005	1078	0.724	82.41	5.24	2.62	0.79	0.58	0.42	0.36	0.20	0.07	ND	0.04	0.07	0.02	7.05	0.12	0.01	169.3	304.9
19 Sept 80 + 0100	1063	0.714	82.59	5.38	2.85	0.71	0.51	0.31	0.24	0.15	0.02	ND	0.02	0.04	0.01	6.96	0.20	0.01	150.6	299.0
19 Sept 80 1445	1075	0.704	83.18	5.59	3.31	0.77	0.44	0.38	0.17	0.04	0.00	ND	0.01	0.01	ND	5.86	0.23	0.01	175.5	309.6
20 Sept 80 1200	1134	0.747	79.16	6.75	4.64	1.06	0.83	0.59	0.34	0.12	0.03	ND	0.02	0.03	0.01	6.20	0.22	0.00	168.3	351.9
20 Sept 80 1930	1166	0.752	79.09	7.05	4.82	1.32	0.96	0.66	0.41	0.16	0.04	ND	0.03	0.05	ND	5.12	0.28	0.00	171.6	346.5
20 Sept 80 + 1935	1135	0.735	80.05	6.95	4.66	1.16	0.64	0.57	0.25	0.07	0.01	ND	0.01	0.01	0.01	5.38	0.23	0.01	171.6	346.5
21 Sept 80 1640	1170	0.736	79.91	7.56	5.15	1.24	0.69	0.81	0.28	0.07	0.00	ND	0.01	0.01	ND	4.97	0.19	0.01	173.7	410.3
25 Sept 80 1145	1246	0.763	76.83	9.46	6.85	1.67	1.02	0.81	0.35	0.10	0.01	ND	0.02	0.02	ND	2.67	0.19	0.00	187.4	380.9

ND = Not detected

Ref. 44093, 44095, 44096, 44099, 44100, 44103, 44106, 44111, 44112, 44114, 44115, 44116, 44121, 44123

* Sampling coordinated with McNease State University.

+ Sample vessel not pre-heated.

** Forwarded to Tom Kraemer, USGS Gulf Coast HydroScience Center.

- Opening the valve closest to the sample vessel on the evacuated cylinder and then the valve on the sample vessel to allow gas flashed from brine in the sample vessel to move vertically into the evacuated cylinder.
- Opening the valve between the 30-cc cylinder and the 500-cc syringe to allow the pressurized gas and the additional gas coming out of solution to equilibrate at 1 atmosphere.
- After quantitatively determining the amount of gas entering the evacuated cylinder and the syringe at atmospheric pressure, repeating aspiration with the syringe to ensure an identical sample in the cylinder and the syringe.
- Sealing the 30-cc cylinder and sending the sample to IGT for mass spectrometer analysis.
- Injecting gas from the syringe into the field gas chromatograph for analysis.

Exhibit 12-23 shows results from both the field gas chromatograph and the mass spectrometer analyses for each sample. Also shown are the pressure and temperature at the sample collection point and the gas/brine ratio determined by flashing. The final line on Exhibit 12-23 shows the gas/brine ratio calculated by using the computer algorithm for methane solubility in water developed by Science, Systems and Software. This algorithm provided good correlation with measurements of gas content of brine to the disposal well during the test of the Wainoco P. R. Girouard Well No. 1, the previous test of a Well of Opportunity.

12.7.2.3 Hydrocarbon Liquid Sampling and Analysis: Liquid hydrocarbons were first observed as a surface film on brine samples collected for on-site analysis during the first flow test. When the second flow test was begun with flow to the pit, production of a slug of liquid hydrocarbons was observed between the initial gas flow and the onset of brine production. This observation, in combination with a difference between tubing and annulus pressure during the first buildup, made it apparent that separation into gas, liquid hydrocarbon, and brine phases had occurred in the production wellbore during the buildup.

On 9/17/80, during the second buildup, an increasing difference between annulus and tubing pressures again indicated accumulation of hydrocarbons above brine in the annulus. This accumulation was slowly bled off through a 1/4-inch valve to permit sampling. After bleeding gas for about an hour, a few gallons of colorless condensate were observed. Produced fluid then became an orange oil that turned brown after a few hours contact with air in a 1-liter polyethylene sample bottle. The orange oil was followed by a small amount of very dark fluid and then brine.

A sample of the dominant liquid hydrocarbon phase, the orange oil, was sealed in a 1-liter polyethylene bottle and transported to IGT for analysis. At IGT, the sample was refrigerated to minimize loss of volatile components. Although some loss of volatile components undoubtedly occurred, it was clearly less than in other (unsealed) samples. After about 48 hours, the unsealed samples had become so viscous that they could not be poured without prior agitation.

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

Photo 12-3 Flare, located next to levee around Reserve Pit

12-60

EXHIBIT 12-23 CONCENTRATIONS OF GAS COMPONENTS IN GAS FLASHED FROM SEPARATOR BRINE, LEAR G. M. KOELEMAY
No. 1 WELL AND ITS HEATING VALUE AND SPECIFIC GRAVITY BY MASS SPECTROMETER ANALYSIS

Gas Components	Sample Data and Time															
	9/12/80		9/13/80		9/17/80		9/18/80		9/20/80		9/21/80		9/22/80		9/25/80	
	1740		1145		0005		1850		1930		1020		1720		1635	
	MS**	GC*	MS	GC	MS	GC	MS	GC	MS	GC	MS	GC	MS	GC	MS	GC
Heating Value	1000		860		819		847		1104		1176		1655		1098	
Specific Gravity	790 0.646															
			0.801		0.849		0.806		0.937		0.905		1.159		0.787	
Methane	70.5	73.0	71.5	76.0	68.2	77.0	72.2	74.0	63.2		66.1	71.0	45.6	59.0	72.6	80.0
Ethane	3.3	3.0	3.8	3.7	3.9	3.6	3.7	3.6	6.7		6.8	6.7	10.6	10.5	9.2	8.0
Propane	0.8	0.7	1.3	1.1	1.4	1.1	1.3	1.0	4.6		5.3	4.2	16.3	10.6	5.0	3.5
n-Butane	0.1	<0.1	0.2	0.5	0.2	0.2	0.2	0.2	1.5		1.8	1.5	5.6	4.9	0.9	0.7
Isobutane	<0.1	<0.1	0.2	0.1	0.2	0.1	0.2	0.1	1.1		1.3	0.9	4.1	2.9	0.7	0.5
Pentanes	<0.1	<0.1	0.2	<0.1	0.2	0.2	0.1	0.1	1.7		1.7	1.1	3.8	3.8	0.5	0.9
Hexanes	<0.1		0.2		0.1		<0.1		1.3		1.2		2.0		0.2	
Heptanes	<0.1		0.1		<0.1		<0.1		0.4		0.4		0.6		<0.1	
Benzene	<0.1		0.1		<0.1		<0.1		0.1		0.1		0.1		<0.1	
Toluene	<0.1		0.2		0.1		<0.1		<0.1		0.1		0.1		<0.1	
Carbon Dioxide	22.7	23.0	17.7	18.5	24.8	18.0	20.7	21.1	18.7		13.8	14.5	9.7	8.2	9.5	7.2
Nitrogen	2.4		4.6		0.8		1.3		0.8		0.8		1.5		1.3	
Separator Pressure, psig	201		202		411		244		345		410		420		413	
Brine Temperature, °F	142		174		182		201		205		204		205		205	
Measured Gas-to-Brine Ratio, SCF/bbl	1.38		1.83		2.47		1.24		2.74		3.51		2.86		2.63	
Calculated Gas-to-Brine Ratio, SCF/bbl [†]	1.9		1.7		3.2		1.9		2.6		3.1		3.1		3.1	

* Field Gas Chromatograph.

** Mass spectrometer in Chicago.

† Calculated from correlations developed on the Wainoco P.R. Girouard Well No. 1.

The analysis of this single sample, while not necessarily representative of total liquid hydrocarbons produced, does generally indicate the type and range of components produced. Exhibit 12-24 presents IGT's routine characterization for the sample. Exhibit 12-25 provides results of gas chromatograph/mass spectrometer analysis for the same sample.

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

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

In addition, IGT provided samples for carbon isotope analysis to Dr. Dennis Coleman of the Illinois State Geological Survey. Other organizations invited to participate in sampling and analysis included the University of Texas at Austin, Lawrence Berkeley Laboratory, and Louisiana State University.

A combined sample log showing times of sample collection, location and type of samples collected, tests performed on location, and tests intended to be performed off-location is presented as Appendix H in Volume II.

Results of third-party hydrocarbon analyses that have been provided to IGT since the test are presented by organization below.

- USGS Gulf Coast HydroScience Center

Results of analyses of samples from this and other wells were provided in a letter from Mr. Thomas F. Kraemer dated January 22, 1981. Data from that letter for this well are presented in Exhibit 12-26. Results of gas chromatograph analysis for the 9/21/80 sample are not reported because air contamination, due to problems in handling the small sample, provided seriously distorted results.

Excerpts of those portions of Mr. Kraemer's letter relevant to these gas analyses follow:

"I took and/or got Chris to give me a total of five gas samples for this well. The radon content of the gas decreased as the gas production increased, indicating progressive dilution of the 'soluble' gas by free gas of a relatively low radon content.

"The organic analyses have recently been transmitted to me by George Claypool. They are also enclosed. Note the relatively high $^{13}\text{C}/^{12}\text{C}$ ratios of this methane compared with the Girouard and other geopressured-geothermal wells. I cannot explain this at present, but the ratio may reflect a relatively low temperature origin or even a biogenic component. I favor a relatively low temperature origin, as the reservoir temperature was only 250°F ."

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**EXHIBIT 12-24 CHARACTERIZATION OF LIQUID HYDROCARBON SAMPLE
CONDENSATE FROM HIGH-PRESSURE FLANGE**

Phase Separation

Liquid Processed	899 grams	
Oil Recovered	679 grams	75.5%
Water by Diff.	220 grams	24.4%
Solids Recovered	0 grams	0.0%

Specific Gravity

API Hydrometer - ASTM D1298

API	@	60°F	40.0
sp gr		60/60°F	0.825

Distillation - ASTM D86

Initial Boiling Point	147°F	64.0°C
5%	203°F	95.0°C
10%	236°F	113.5°C
20%	288°F	142.0°C
30%	332°F	166.5°C
40%	397°F	203.0°C
50%	449°F	231.5°C
60%	494°F	256.5°C
70%	533°F	278.5°C
80%	594°F	312.0°C
90%	702°F	372.0°C
95%	756°F	402.0°C

Final Boiling Point	760°F	404.5°C
---------------------	-------	---------

Volume % Recovery	97.0 %
Volume % Residue	2.0 %

Ultimate Analysis--Dry Basis, wt %

Carbon	86.78
Hydrogen	13.20
Sulfur	0.04
Nitrogen	
Ash	0.0
Total	100.0
C/H Weight Ratio	6.57

ASTM D2622

From Carbon-Hydrogen

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EXHIBIT 12-25 GC/MASS SPECTROSCOPY DATA FOR LIQUID HYDROCARBONS SAMPLES

Project: 65036-02
Sample: Lear Well Cond, 44087

Lab No.: 80-1047

Oil Composition by Compound Type

Wt %

Aliphatic Hydrocarbons	80.3
Aromatic Hydrocarbons	19.8
Nitrogen-Containing Compounds	No individual component > 0.05%
Oxygen-Containing Compounds	No individual component > 0.05%
Sulfur-Containing Compounds	No individual component > 0.005%
Other	—
Unidentified	—

Detailed Composition:

I. Aliphatic Hydrocarbons

Carbon No.	N-Alkane	Iso-Alkane	Cycloalkanes	Dicycloalkanes	Unidentified and Others	Total
5	0.70	0.59			0.72**	2.01
6	1.05	1.34	3.25			5.64
7	1.53	0.60	5.2		0.12	7.5
8	2.05	0.95	2.76		0.050	5.81
9	2.27	2.62	1.40	0.60	0.26	7.15
10	2.29	1.46	1.60	0.58	0.099	6.03
11	2.25	1.01	0.88	0.35	0.30	4.79
12	2.35	1.05	0.42	0.33	0.15	4.30
13	2.44	1.34	0.58	0.34	0.63	5.33
14	2.68	1.01	0.30	0.36	0.36	4.71
15	2.22	0.12	0.31	2.69	0.41	5.75
16	1.92	0.91	0.45	0.14	0.50	3.92
17	1.52	0.99	*	*	0.26	2.77
18	1.29	0.56	0.11	*	0.53	2.49
19	1.09	1.40	0.60	0.030	0.29	3.41
20	0.82	0.26	*	*	0.87	1.95
21	0.66	*	*	*	1.13	1.79
22	0.54	*	*	*	0.77	1.31
23	0.46	*	*	*	0.62	1.08
24	0.37	*	*	*	0.46	0.83
25	0.29	*	*	*	0.32	0.61
26	0.21	*	*	*	0.23	0.44
27	0.17	*	*	*	0.080	0.25
28	0.13	*	*	*	0.040	0.17
29	0.089	*	*	*	0.030	0.12
30	0.060	*	*	*	0.020	0.08
31	0.040	*	*	*	0.0099	0.05
32	0.020	*	*	*	0.015	0.035
33	0.020	*	*	*		0.02
SUM	31.53	16.21	17.9	5.42	9.27	80.3

* Included with unidentified.

** Includes 0.15% propane and 0.41% N-Butane.

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EXHIBIT 12-25, (Cont.) GC/MASS SPECTROSCOPY DATA OF LIQUID HYDROCARBON SAMPLE

Project: 63036-02
Sample: Lear Well Cond, 44087 Lab No.: 80-1047

Detailed Composition: Continued

II. Aromatic Hydrocarbons

Type	Base Compound	Methyl	C2	C3	C4	C5+	Total
Benzene	0.63	2.87	2.61	2.79	1.30	0.36	10.56
Indan	0.040	0.13	0.13	0.070	0.040	0.19	0.60
Naphthalene	0.48	1.69	1.85	1.83	1.06		6.91
Biphenyl	0.080	0.32	0.11	0.089			0.60
Fluorene	0.14	0.23	0.30				0.67
Phenanthrene } Anthracene }	0.17	0.23	0.050				0.45

Phenyl naphthylenes
Benzoacenaphthenes

Fluoranthene
Pyrene
Benzofluorene
Benzo(ghi)fluoranthene
Benzo(a)anthracene
Chrysene
Naphthacene
Triphenylene
Binaphthyls

Benzo(...)fluoranthenes
Benzo(a)pyrene
Benzo(e)pyrene
Perylene
Dibenzanthracenes
and Benzperylene

Probably present, but included with
unidentified in alphatic listing.

**EXHIBIT 12-26 GAS ANALYSIS RESULTS REPORTED
BY THE USGS GULF COAST HYDROSCIENCE CENTER**

<u>DATE</u>	<u>TIME</u>	<u>222Rn content (dpm/l at time of sampling)*</u>
9/18/80	17:00	262
9/19/80	14:45	226
9/20/80	19:30	150**
9/21/80	16:40	128
9/25/80	11:45	87

9/21/80 11:10
(probably contaminated by
atmospheric gases)

Methane $^{13}\text{C}/^{12}\text{C}$ -49.0 per mil***

<u>DATE</u>	<u>TIME</u>	<u>Composition</u>	<u>Vol %</u>
9/25/80	12:25	N ₂	0.44
		CH ₄	74.83
		CO ₂	2.69
		Ethane	9.87
		Propane	7.11
		Isobutane	1.65
		n-Butane	1.85
		Isopentane	0.78
		n-Pentane	0.78
		Methane $^{13}\text{C}/^{12}\text{C}$ -49.1 per mil	

* Analyses performed by T. F. Kraemer, USGS, Gulf Coast HydroScience Center.

** This sample was analysed using IGT's mass spectrometer before shipment to USGS. See Exhibit 12-22 for composition.

*** Analyses performed by George Claypool, USGS, Federal Center, Denver.

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

Gas and liquid samples collected by IGT were sent to Dr. Coleman for carbon isotope ratio analysis. The results of his analyses are summarized in Exhibit 12-27.

EXHIBIT 12-27 CARBON ISOTOPE RATIO ANALYSIS
(Source: Illinois State Geological Survey, Dr. Dennis Coleman)

<u>Sample No.</u>	<u>Time</u>	<u>Date</u>	<u>Source</u>	<u>δC_{13}</u>
40	1200	13 Sept 80	Flare Gas	-48.4
54	0040	17 Sept 80	Flare Gas	-48.8
208	1135	25 Sept 80	Flare Gas	-48.7
218	1510	26 Sept 80	Stock Tank Oil	-27.4

The C_{13} value is the difference between the C_{13}/C_{12} isotope ratios obtained for the samples and for an international standard. Dr. Coleman has previously stated that thermogenic gas usually ranged from -40 to -55 δC_{13} values, with more mature gases having more positive values (closer to -40). The values for biogenic gases usually fall between -60 and -100.

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

Weatherly Laboratories personnel collected samples of separator gas and brine at about 1200 hours on 9/21/80. At the time of sampling, the produced gas/brine ratio was approximately 90 SCF/bbl. This is about 2.5 times the solubility of methane in distilled water at reservoir temperature and pressure. Although designed for three-phase separation, the separator was being operated as a two-phase separator. Brine dumps were from the position from which oil would have been removed with three-phase operation. Thus, the entire brine surface in the separator was probably covered with oil at the time of sample collection by Weatherly Laboratories.

After recombining several gas/brine ratios in an unsuccessful attempt to define gas solubility versus bubble point pressure at reservoir temperature, Mr. John Neal of Weatherly Laboratories advised IGT that anomolous results were being obtained. Dr. Terry Osif of IGT then traveled to Weatherly Laboratories to participate in work on the remaining samples.

Although the laboratory studies were not able to define gas solubility in reservoir brine, they did provide the surprising conclusion that a very small amount of oil from the well decreased apparent gas solubility. Observations leading to this conclusion were:

- Recombination of 39 SCF/bbl pure methane with distilled water yielded the reasonable bubble point of 9585 + 35 psia at 260°F.

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- Adding 0.05 volume percent of oil from the Lear G. M. Koelemay No. 1 Well increased the bubble point to pressure in excess of 11,000 psi. Methane solubility in distilled water would have been in excess of 42 SCF/bbl at this pressure.
- Recombination of 19.6 SCF/bbl of pure methane with distilled water containing 0.025 volume percent oil from the well yielded a bubble point of about 3360 psi at a temperature of 260°F. This bubble point was determined by a discontinuity in the slope of a plot of pressure versus volume. At this pressure and temperature, methane solubility in the absence of the oil would be about 25 SCF/bbl.

The amount of oil present in the latter two cases is less than 1 SCF/bbl, if the oil is assumed to be gaseous at cell pressure and temperature. Thus, methane solubility in water is clearly decreased by the presence of small amounts of produced oil.

Additional details of laboratory studies performed are described in the Weatherly Laboratories report and letter to Mr. John Neal from Dr. Terry Osif that are provided in Appendix I.

12.7.2.5 Discussion of Hydrocarbon Data: The combination of field interpretation of production data plus field gas sample analyses for the first flow test revealed surprising characteristics in relation to prior experience in testing of geopressured-geothermal aquifers. Most notable of these were the following:

- During the 22 hours of production after the fresh brine reached the production wellhead, the produced gas/brine ratio slowly increased from less than 31 SCF/STB to about the 37 SCF/STB expected on the basis of reservoir pressures and temperatures measured by Reservoir Data, Inc.
- The initial percentages of ethane and propane (3.9 % and 1.1%, respectively) were substantially higher than the values of 1.8% and 0.3% observed on the Wainoco P. R. Girouard Well No. 1. Further, by the end of the first flow test, the mole percentages of ethane and propane in flare line gas had increased to 4.5% and 2.0%, respectively.
- An oil film had been observed on the surface of brine samples. The amount of oil was great enough to require careful removal of oil for reproducible measurement of pH and conductivity of the brine.

IGT's first reaction to these surprises was concern about validity of data. Actions to check the data during the first buildup test included:

- Field checking of the calibration of the pressure, differential pressure, and temperature transmitters used to provide data for calculation of flareline gas production.
- Promptly transporting gas samples to Chicago for mass spectrometer analysis.

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These actions verified the field data and confirmed substantial production of natural gas liquids (more than 2 gallons per MCF at the end of the first test).

As testing proceeded, natural gas liquids (NGL) content of flare line gas continued to increase, and occasional liquid production through the flare line (separator upsets) clearly revealed the presence of an oil phase in the separator.

These observations posed a major challenge in providing accurate documentation of production of marketable energy. Particular emphasis was placed upon understanding composition of flare line gas for the high temperature of the liquid in the separator (about 205°F for the third production test). Actions taken are described below:

- Adequacy of Field Gas Chromatograph for C6+: The Carle Model 111-H gas chromatograph used in the field was selected to provide rapid analyses for samples that were not expected to contain appreciable amounts of natural gas liquids. As such, the instrument had two shortcomings for samples from this well. First, maximum operating temperature for the chromatograph inlet and columns is about 160°F. This is substantially below the brine temperature of 205°F and the orifice meter sampling point temperature of about 185°F during much of the third flow test. The result was a buildup of C6+ background due to condensation inside the gas chromatograph.

Second, the C6+ determination for this instrument involves backflushing that results in interference between water vapor and the C6+ fraction.

Field actions in search of meaningful data on natural gas liquids included:

- Heating the sample and inlet tubing external to the instrument
- Extensive use of a vacuum pump to remove background water and natural gas liquids between analyses
- Use of drying agents in the inlet system to reduce water vapor interference.

These efforts had minimal success. Therefore, as stated in the footnote on Exhibit 12-21, the field analyses reported were normalized with the assumption that the mole percent C6+ was equal to that for pentanes.

- Preheating of Sample Cylinders: The samples promptly shipped to IGT to verify field analysis results on natural gas liquid (NGL) content revealed agreement with the field data to within ± 0.15 gallons per MCF or $\pm 10\%$. However, at the same time, CO₂ content from mass spectrometer analysis was less than from field analysis by an amount substantially greater than the resolution of the two instruments. This observation was tested later by performing a second mass spectrometric analysis of several samples. Results of the two analyses performed on each sample are shown in Exhibit 12-28. The first analysis for each of these samples was also tabulated in Exhibit 12-22.

The second analysis for each sample shown in Exhibit 12-28 revealed a greater content of both natural gas liquids and CO₂ than the first analysis. The reasons

EXHIBIT 12-28 REPEATED MASS SPECTROMETER ANALYSES*

Sample Vessel	No	No	No	No	No	Yes
Pre-heated:						
Date Sampled:	9/12/80	9/12/80	9/13/80	9/13/80	9/13/80	9/17/80
Time Sampled:	1600	1920	0918	1155	1200	0040
First Analyses:	9/16/80	9/16/80	9/16/80	9/23/80	9/23/80	9/23/80
Second Analyses:	10/15/80	10/15/80	10/15/80	10/15/80	10/15/80	10/15/80
<u>Gas Component</u>						
Methane	88.63 87.45	87.50 85.38	84.91 83.99	85.16 83.59	85.32 84.27	85.65 84.91
Ethane	4.12 4.33	3.95 4.13	4.58 4.74	4.62 4.99	4.59 4.80	4.90 5.00
Propane	1.25 1.41	1.22 1.58	1.85 2.11	1.96 2.13	1.96 2.18	2.20 2.39
n-Butane	0.19 0.19	0.16 0.13	0.40 0.53	0.39 0.55	0.37 0.46	0.46 0.58
i-Butane	0.10 0.13	0.08 0.10	0.20 0.35	0.30 0.36	0.26 0.34	0.34 0.40
Pentanes	0.06 0.03	0.05 0.04	0.48 0.22	0.21 0.24	0.20 0.24	0.26 0.27
Hexanes	0.02 0.09	0.03 0.03	0.20 0.21	0.11 0.19	0.12 0.16	0.17 0.16
Heptanes	0.01 0.09	0.03 0.03	0.20 0.21	0.11 0.19	0.12 0.16	0.17 0.16
Octanes	0 0	0 0	0.03 0.04	0.02 0.05	0.01 0.02	0.01 0.02
Benzene	0.01 0.01	0.03 0.02	0.04 0.03	0.02 0.03	0.02 0.01	0.03 0.02
Toluene	0.01 0.01	0.03 0.02	0.07 0.06	0.02 0.05	0.02 0.03	0.02 0.03
Xylene	0 0	0 0.01	0.01 0.02	0.01 0.02	0.01 0.01	0 0.01
Nitrogen	0.27 0.32	0.28 0.27	0.25 0.31	0.25 0.21	0.23 0.18	0.24 0.28
Carbon Dioxide	5.32 5.97	6.63 8.24	6.80 7.24	6.87 7.41	6.81 7.22	5.63 5.84
Helium	0.01 0	0.01 0.01	0.01 0	0.01 0.01	0.01 0	0.01 0.01
Total NGL (gal/MCF)	1.579 1.725	1.527 1.726	2.348 2.59	2.204 2.580	2.182 2.389	2.387 2.568

* For each table entry, the top number is from the first analysis performed and the bottom number is from the second analysis performed.

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for this are not completely understood. However, one key point is clear from this exhibit. The differences are less for the sample collected in a preheated cylinder. Since the only additional cost of collecting samples in preheated cylinders is that of one asbestos glove, preheating has been adopted as an operating procedure by IGT.

During coordinated collection of samples with McNeese State University, it was agreed that IGT would collect one additional sample in an unheated cylinder for later comparison of analytical results from the two laboratories. This sample was collected at 0005 hours on 9/19/80. Results of IGT's analysis are reported in Exhibit 12-22. Although CO₂ content is very similar to that of a sample collected in a preheated cylinder under the same conditions 55 minutes later, differences in analytical results for C₄+ hydrocarbons are apparent. Although calculated NGL content for the cylinder that was not preheated is 3.002 gal/MCF and only slightly higher than the value of 2.950 for the preheated cylinder, values for all C₄+ hydrocarbons are clearly greater for the cylinder that was not preheated. For C₆+ hydrocarbons, the difference exceeds 50%. This is believed to be caused by condensation on the cool cylinder walls during sample collection.

- CO₂ and Natural Gas Liquids (NGL) Content of Flare Line Gas: CO₂ and NGL content of flare line gas are both relevant to any future consideration of economics by others. Therefore, all data concerning these species have been summarized in Exhibits 12-29 and 12-30.

Exhibit 12-29 presents all analysis results on CO₂ content. If the symbols for field gas chromatograph or laboratory mass spectrometer analysis are overlain by a "+" sign, the sample was collected in a cylinder that had not been preheated. The horizontal bars will be discussed in Section 12.7.3.1. The repeated mass spectrometer analyses from Exhibit 12-28 are shown as second data points without distinction in symbols used. In all cases, the higher value is from the second analysis. NGL content of flare line gas has been calculated using values for SCF of gas per gallon of liquid from Figure 16-1 of the 1974 revised edition of the Engineering Data Book published by the Gas Processors Suppliers Association in cooperation with the Gas Processors Association. Results for all samples analyzed are shown in Exhibit 12-30. In this Exhibit, NGL content of samples analyzed in the field represents ethane through pentane only. This is due to the previously discussed limitations for C₆+ analysis of the instrument used. To facilitate understanding, separate symbols are used for results of two different calculations from mass spectrometer analyses. These are for ethane through pentane only and for total hydrocarbon content of flare line gas. Other characteristics of this exhibit are similar to those previously described for CO₂.

12.7.3

Produced Gas and Gas/Brine Ratio

The first three subsections below provide details of raw data interpretation used to deduce flare line gas production, brine production, and the total produced gas/brine

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EXHIBIT 12-29, Part 2 CARBON DIOXIDE CONTENT OF FLARE LINE GAS (9/19/80 to 9/25/80)

EXHIBIT 12-30, Part 1 NGL CONTENT OF FLARE LINE GAS (9/12/80 to 9/18/80)

ratio. The fourth subsection compares the produced gas/brine ratio with laboratory data on gas solubility.

12.7.3.1 Flare Line Gas Production: As previously discussed, the composition of produced gas underwent substantial changes during the three flow tests on this well. Since interpretation of raw data from the orifice meter (static pressure, differential pressure, and temperature) is dependent upon gas composition, judgment has been used to estimate the gas composition representative of producing time during each calendar day. The one exception is the second flow test. Since this test had a duration of only 10 hours, a constant gas composition was assumed.

Gas compositions used for each time interval were those from the mass spectrometer analysis closest in time to the mid-point of the period of assumed constant gas composition.

The steps used in calculating gas production as a function of time are as follows:

- Calculating the specific gravity and heating value for the average gas composition for each time interval, using methodology prescribed in ANSI/ASTM D 3588-77. This ANSI/ASTM procedure assigns the physical properties of normal hexane to all C6+ hydrocarbons. With this convention, the assumed gas composition, dry gas specific gravity, and dry gas heating value for each period of assumed constant gas properties are set forth in Exhibit 12-31. The CO₂ content and natural gas liquid content for these compositions are shown as horizontal bars in the previously discussed Exhibits 12-29 and 12-30.
- Calculating gas production to the flare line for each line entry of raw data using methodology prescribed in A.G.A. Gas Committee Measurement Report No. 3. Implementing this methodology requires independent calculation of supercompressibility ($F_{pv} = 1/z$) because temperature is higher than the 160°F maximum reported in the A.G.A. report. The values of z used for interpretation were calculated for various separator pressures and temperatures, using a computer program developed by IGT for a different project. Results of this calculation, for each hour of production, are reported in Appendix J (column 5).
- Summing the gas production from each entry of raw data to determine total gas production in each hour, and then expressing this as a daily rate for that hour. Results of this calculation for each hour are reported in Appendix J (column 6).
- Reducing calculated gas production for each hour by an amount corresponding to the ratio of partial pressure of water at the orifice meter to absolute separator pressure. The resultant calculated dry gas production tabulated for each hour is presented in Appendix F (column 7).

12.7.3.2 Brine and Thermal Energy Production: As previously described, brine production rates deduced from manual logging of cumulative readings from the separator output turbine by Weatherly were used to calculate the produced gas/brine

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ratio. Average brine production rates in stock tank barrels per day were deduced by subtracting successive 1-hour readings of cumulative brine production and then correcting for the average values of separator pressure and temperature during that hour. The resulting corrected brine production rates and average brine temperature for each hour of production are tabulated in Exhibit 12-31 and shown graphically in Exhibit 12-20. Both the brine rate recorded at separator pressure and temperature and the corrected brine rate are tabulated for each hour in Appendix J (columns 9 and 10).

Thermal energy production was calculated for each hour in which the brine temperature exceeded the assumed thermal energy-based temperature of 120°F, assuming a heat capacity of 1 Btu/day-°F. Thermal energy production during each calendar day is shown in Exhibit 12-31. Cumulative thermal production by hour is tabulated in Appendix J (column 17).

12.7.3.3 Total Produced Gas and Gas/Brine Ratio: Total produced gas is the sum of gas to the flare line plus gas remaining in solution in brine to the disposal well. This quantity has been estimated using the following steps:

- Dividing the flare line dry gas production rate for each hour by the corrected brine production rate for each hour to determine the flared dry gas/brine ratio. These results are tabulated in Appendix J (column 11).
- Estimating the gas/brine ratio in brine to the disposal well using the algorithm developed by System Science and Software to fit the data of Culbertson and McKetta for methane solubility in distilled water. Results of this calculation using hourly values for separator pressure and brine temperature are reported in Appendix J (column 12).
- Adding flare line dry gas/brine ratio to the estimated disposal well gas/brine ratio to estimate the total gas/brine ratio for the production well. Results of this addition are reported in Appendix J (column 13) and in Exhibits 12-31 and 12-32.
- Multiplying the total produced gas/brine ratio by corrected brine rate to deduce total gas production rate. Results of this calculation are given in Exhibit 16 for each hour of production. In addition, cumulative production of dry gas and gas energy is reported for each hour of production in Appendix J (columns 14 and 16). Cumulative production of natural gas and natural gas energy for each day and each test are also shown in Exhibit 12-31.

The discontinuities in produced gas/brine ratio at midnight (Exhibit 12-32, Part 2) are largely due to the assumption that gas composition remained constant for each 24-hour calendar day. These discontinuities would not exist if the continuous variation of gas composition with time were taken into account in interpretation of raw data from the orifice meter.

Other departures from a smooth increase in gas/brine ratio with time are discussed on page 12-84.

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Part 1. DAILY PRODUCTION SUMMARIES

IGT WELL TEST ANALYSIS *****

LEAR G. M. KOELEMAY NO. 1 WELL

DATE: 9/12/80

GAS COMPOSITION:

NITROGEN	0028
CARBON DIOXIDE	0663
METHANE	8750
ETHANE	0395
PROPANE	0122
ISOBUTANE	0008
n-BUTANE	0016
PENTANES	0005
C6+	0013

CALCULATED GAS PROPERTIES:
 DRY GAS HTG VAL... = 1004.72
 DRY GAS GRAVITY.... = .6589

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

PRODUCTION SUMMARY:

	-----GAS-----		THERMAL
	(MCF)	(MMBTU)	(MMBTU)
DAILY	28.8	28.9	8.2
CUM.	28.8	28.9	8.2

PRODUCTION DETAILS:

TIME	---BRINE---		-----GAS-----	
	DEGF	STBPD	MCF/D	SCF/STB
0100	-	0.	0.0	0.00
0200	-	0.	0.0	0.00
0300	-	0.	0.0	0.00
0400	-	0.	0.0	0.00
0500	-	0.	0.0	0.00
0600	-	0.	0.0	0.00
0700	-	0.	0.0	0.00
0800	-	0.	0.0	0.00
0900	-	0.	0.0	0.00
1000	-	0.	0.0	0.00
1100	-	0.	0.0	0.00
1200	-	0.	0.0	0.00
1300	-	0.	0.0	0.00
1400	-	0.	0.0	0.00
1500	107	2397	60.9	25.41
1600	121	2357	70.0	29.72
1700	132	2344	71.7	30.59
1800	141	2269	69.7	30.71
1900	148	2236	68.1	30.46
2000	153	2242	69.7	31.10
2100	156	2242	71.0	31.66
2200	159	2209	71.1	32.18
2300	161	2102	68.7	32.68
2400	163	2106	69.6	33.08

IGT WELL TEST ANALYSIS *****

LEAR G. M. KOELEMAY NO. 1 WELL

DATE: 9/13/80

GAS COMPOSITION:

NITROGEN	0026
CARBON DIOXIDE	0687
METHANE	8516
ETHANE	0462
PROPANE	0196
ISOBUTANE	0030
n-BUTANE	0039
PENTANES	0021
C6+	0023

CALCULATED GAS PROPERTIES:
 DRY GAS HTG VAL... = 1037.76
 DRY GAS GRAVITY.... = .6838

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

PRODUCTION SUMMARY:

	-----GAS-----		THERMAL
	(MCF)	(MMBTU)	(MMBTU)
DAILY	44.4	46.1	21.3
CUM.	73.2	75.0	29.5

PRODUCTION DETAILS:

TIME	---BRINE---		-----GAS-----	
	DEGF	STBPD	MCF/D	SCF/STB
0100	164	2255	73.1	32.44
0200	166	2096	74.7	35.63
0300	167	2112	74.7	35.36
0400	168	2116	76.1	35.95
0500	169	2057	75.3	36.62
0600	169	2050	75.0	36.96
0700	170	2080	78.8	37.88
0800	171	2070	78.6	37.96
0900	171	2055	76.4	37.16
1000	172	2041	73.0	35.78
1100	173	2090	75.1	35.93
1200	174	2091	77.8	37.20
1300	174	2063	77.9	37.74
1400	174	1929	79.0	46.97
1500	157	0.	0.0	0.00
1600	-	0.	0.0	0.00
1700	-	0.	0.0	0.00
1800	-	0.	0.0	0.00
1900	-	0.	0.0	0.00
2000	-	0.	0.0	0.00
2100	-	0.	0.0	0.00
2200	-	0.	0.0	0.00
2300	-	0.	0.0	0.00
2400	-	0.	0.0	0.00

EXHIBIT 12-31, Part 1

Eaton Industries of Houston, Inc.

Eaton Operating Co., Inc.

3104 Edloe, Suite 200

Houston, Texas 77027

(713) 627-9764

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

Part 2. DAILY PRODUCTION SUMMARIES

1GT WELL TEST ANALYSIS *****

LEAR G. M. KOELEMAY NO. 1 WELL

DATE: 9/16/80

GAS COMPOSITION:

NITROGEN.....	0025
CARBON DIOXIDE.....	0563
METHANE.....	8565
ETHANE.....	0490
PROPANE.....	0220
ISOBUTANE.....	0034
n-BUTANE.....	0046
PENTANES.....	0026
C6+.....	0031

CALCULATED GAS PROPERTIES:

DRY GAS HTG VAL... = 1063.27
DRY GAS GRAVITY... = .6900

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

PRODUCTION SUMMARY:

	-----GAS-----	THERMAL
	(MCF) (MMBTU)	(MMBTU)
DAILY	32.0 34.0	13.9
CUM.	32.0 34.0	13.9

PRODUCTION DETAILS:

TIME	-----BRINE-----	-----GAS-----
	DEGF STBPD	MCF/D SCF/STB
0100	- -	0.0 0.00
0200	- -	0.0 0.00
0300	- -	0.0 0.00
0400	- -	0.0 0.00
0500	- -	0.0 0.00
0600	- -	0.0 0.00
0700	- -	0.0 0.00
0800	- -	0.0 0.00
0900	- -	0.0 0.00
1000	- -	0.0 0.00
1100	- -	0.0 0.00
1200	- -	0.0 0.00
1300	- -	0.0 0.00
1400	- -	0.0 0.00
1500	- -	0.0 0.00
1600	- -	0.0 0.00
1700	105 -	0.0 0.00
1800	100 -	0.0 0.00
1900	107 4173	65.2 15.62
2000	137 4308	137.0 31.90
2100	163 4307	141.7 32.89
2200	174 4164	143.2 34.39
2300	179 3969	141.0 35.54
2400	181 3802	140.2 36.87

1GT WELL TEST ANALYSIS *****

LEAR G. M. KOELEMAY NO. 1 WELL

DATE: 9/17/80

GAS COMPOSITION:

NITROGEN.....	0025
CARBON DIOXIDE.....	0563
METHANE.....	8565
ETHANE.....	0490
PROPANE.....	0220
ISOBUTANE.....	0034
n-BUTANE.....	0046
PENTANES.....	0026
C6+.....	0031

CALCULATED GAS PROPERTIES:

DRY GAS HTG VAL... = 1063.27
DRY GAS GRAVITY... = .6800

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

PRODUCTION SUMMARY:

	-----GAS-----	THERMAL
	(MCF) (MMBTU)	(MMBTU)
DAILY	22.6 24.1	14.6
CUM.	54.6 58.1	28.5

PRODUCTION DETAILS:

TIME	-----BRINE-----	-----GAS-----
	DEGF STBPD	MCF/D SCF/STB
0100	183 3762	130.4 34.67
0200	185 3659	128.0 34.98
0300	186 3626	122.9 33.90
0400	187 3545	122.3 34.50
0500	175 757	39.3 51.84
0600	145 -	0.0 0.00
0700	- -	0.0 0.00
0800	- -	0.0 0.00
0900	- -	0.0 0.00
1000	- -	0.0 0.00
1100	- -	0.0 0.00
1200	- -	0.0 0.00
1300	- -	0.0 0.00
1400	- -	0.0 0.00
1500	- -	0.0 0.00
1600	- -	0.0 0.00
1700	- -	0.0 0.00
1800	- -	0.0 0.00
1900	- -	0.0 0.00
2000	- -	0.0 0.00
2100	- -	0.0 0.00
2200	- -	0.0 0.00
2300	- -	0.0 0.00
2400	- -	0.0 0.00

EXHIBIT 12-31, Part 2

Part 3. DAILY PRODUCTION SUMMARIES

IGT WELL TEST ANALYSIS *****

LEAR G. M. KOELEMAY NO. 1 WELL

DATE: 9/18/80

GAS COMPOSITION:

NITROGEN.....	.0028
CARBON DIOXIDE.....	.0750
METHANE.....	.8387
ETHANE.....	.0467
PROPANE.....	.0219
ISOBUTANE.....	.0038
n-BUTANE.....	.0058
PENTANES.....	.0024
C6+.....	.0029

CALCULATED GAS PROPERTIES:

DRY GAS HTG VAL... = 1044.39
DRY GAS GRAVITY.... = .6985

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

PRODUCTION SUMMARY:

	-----GAS-----		THERMAL
	(MCF)	(MMBTU)	(MMBTU)
DAILY	73.2	76.4	50.9
CUM.	73.2	76.4	50.9

PRODUCTION DETAILS:

TIME	-----BRINE-----		-----GAS-----	
	DEGF	STBPD	MCF/D	SCF/STB
0100	-	0.	0.0	0.00
0200	-	0.	0.0	0.00
0300	-	0.	0.0	0.00
0400	-	0.	0.0	0.00
0500	-	0.	0.0	0.00
0600	-	0.	0.0	0.00
0700	-	0.	0.0	0.00
0800	-	0.	0.0	0.00
0900	-	0.	0.0	0.00
1000	-	0.	0.0	0.00
1100	-	0.	0.0	0.00
1200	-	0.	0.0	0.00
1300	-	0.	0.0	0.00
1400	113	0.	0.0	0.00
1500	136	5810.	179.8	26.25
1600	182	6154.	195.0	31.68
1700	195	5565.	200.4	36.01
1800	198	5092.	194.8	38.26
1900	200	4850.	179.1	36.92
2000	202	4597.	167.7	36.48
2100	202	4459.	164.7	36.93
2200	203	4336.	161.8	37.32
2300	203	4222.	157.4	37.27
2400	202	4159.	156.6	37.65

IGT WELL TEST ANALYSIS *****

LEAR G. M. KOELEMAY NO. 1 WELL

DATE: 9/19/80

GAS COMPOSITION:

NITROGEN.....	.0024
CARBON DIOXIDE.....	.0586
METHANE.....	.8318
ETHANE.....	.0559
PROPANE.....	.0331
ISOBUTANE.....	.0044
n-BUTANE.....	.0077
PENTANES.....	.0038
C6+.....	.0023

CALCULATED GAS PROPERTIES:

DRY GAS HTG VAL... = 1093.22
DRY GAS GRAVITY.... = .7028

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

PRODUCTION SUMMARY:

	-----GAS-----		THERMAL
	(MCF)	(MMBTU)	(MMBTU)
DAILY	176.2	192.7	117.5
CUM.	249.4	269.1	168.4

PRODUCTION DETAILS:

TIME	-----BRINE-----		-----GAS-----	
	DEGF	STBPD	MCF/D	SCF/STB
0100	200	4337.	170.3	39.29
0200	203	4414.	175.3	39.72
0300	205	4324.	176.6	40.84
0400	205	4256.	178.1	41.85
0500	205	4219.	179.8	42.63
0600	205	4167.	179.6	43.11
0700	206	4118.	177.5	43.10
0800	206	4063.	175.2	43.12
0900	206	4023.	174.4	43.34
1000	206	3963.	170.2	42.95
1100	206	3894.	168.4	43.24
1200	205	3887.	171.9	44.23
1300	206	3871.	176.0	45.47
1400	206	3836.	175.2	45.68
1500	206	3808.	175.5	46.08
1600	206	3734.	173.8	46.55
1700	206	3739.	175.4	46.90
1800	206	3767.	178.5	47.38
1900	206	3725.	177.9	47.76
2000	206	3678.	177.0	48.12
2100	206	3697.	180.3	48.77
2200	206	3662.	178.0	48.59
2300	206	3639.	182.0	50.03
2400	206	3618.	182.7	50.50

EXHIBIT 12-31, Part 3

Part 4. DAILY PRODUCTION SUMMARIES

1GT WELL TEST ANALYSIS *****

LEAR G. M. KOELEMAY NO. 1 WELL

DATE: 9/20/80

GAS COMPOSITION:

NITROGEN.....	0022
CARBON DIOXIDE.....	0620
METHANE.....	7916
ETHANE.....	0675
PROPANE.....	0464
ISOBUTANE.....	0083
n-BUTANE.....	0106
PENTANES.....	0059
C6+.....	0055

CALCULATED GAS PROPERTIES:

DRY GAS HTG VAL. = 1153.18
DRY GAS GRAVITY = .7466

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

PRODUCTION SUMMARY:

	GAS		THERMAL
	(MCF)	(MMBTU)	(MMBTU)
DAILY	200.9	231.7	102.6
CUM.	450.3	500.8	271.0

1GT WELL TEST ANALYSIS *****

LEAR G. M. KOELEMAY NO. 1 WELL

DATE: 9/21/80

GAS COMPOSITION:

NITROGEN.....	0019
CARBON DIOXIDE.....	0407
METHANE.....	7991
ETHANE.....	0755
PROPANE.....	0515
ISOBUTANE.....	0069
n-BUTANE.....	0124
PENTANES.....	0081
C6+.....	0037

CALCULATED GAS PROPERTIES:

DRY GAS HTG VAL. = 1189.77
DRY GAS GRAVITY = .7353

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

PRODUCTION SUMMARY:

	GAS		THERMAL
	(MCF)	(MMBTU)	(MMBTU)
DAILY	358.5	307.5	97.9
CUM.	708.8	808.3	368.9

PRODUCTION DETAILS:

TIME	BRINE		GAS	
	DEGF	STBPD	MCF/D	SCF/STB
0100	205	3586	182.5	50.88
0200	206	3604	185.1	51.36
0300	205	3621	167.3	46.21
0400	205	3634	186.3	51.26
0500	205	3541	187.7	53.01
0600	205	3591	188.9	52.59
0700	205	3593	191.7	53.35
0800	205	3494	184.2	52.71
0900	205	3483	191.8	55.06
1000	204	3479	193.0	55.47
1100	204	3422	192.8	56.33
1200	204	3433	195.0	56.78
1300	204	3447	196.3	56.95
1400	204	3401	198.0	58.20
1500	204	3422	201.3	58.84
1600	204	3424	205.0	59.86
1700	205	3428	206.9	60.35
1800	205	3398	212.9	62.64
1900	204	3280	246.6	75.18
2000	205	3367	214.5	63.70
2100	205	3337	222.1	66.55
2200	205	3370	222.7	66.09
2300	205	3268	222.8	68.20
2400	205	3293	226.2	68.70

PRODUCTION DETAILS:

TIME	BRINE		GAS	
	DEGF	STBPD	MCF/D	SCF/STB
0100	205	3363	234.2	69.65
0200	206	3309	238.0	68.91
0300	205	3238	229.0	70.74
0400	205	3233	237.3	73.39
0500	205	3197	231.5	72.42
0600	204	3142	231.4	73.54
0700	204	3254	238.6	73.34
0800	204	3256	241.4	74.15
0900	204	3367	244.3	72.56
1000	204	3379	246.8	73.04
1100	204	3344	253.7	75.85
1200	204	3367	254.0	75.42
1300	204	3377	257.1	76.15
1400	204	3374	260.2	77.11
1500	204	3278	261.0	79.62
1600	204	3314	267.5	80.69
1700	204	3298	267.2	81.02
1800	203	3278	270.6	82.56
1900	203	3269	272.3	83.29
2000	203	3334	279.4	83.81
2100	203	3310	284.4	85.93
2200	205	3427	303.1	88.44
2300	205	3406	303.6	89.14
2400	205	3417	306.3	89.64

EXHIBIT 12-31, Part 4

Eaton Industries of Houston, Inc.

Eaton Operating Co., Inc.

3104 Edloe, Suite 200

Houston, Texas 77027

(713) 627-9764

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

12-81

Part 5. DAILY PRODUCTION SUMMARIES

IGT WELL TEST ANALYSIS *****

LEAR G. M. KOELEMAY NO. 1 WELL

DATE: 9/22/80

GAS COMPOSITION:

NITROGEN.....	.0020
CARBON DIOXIDE.....	.0360
METHANE.....	.7890
ETHANE.....	.0825
PROPANE.....	.0573
ISOBUTANE.....	.0077
n-BUTANE.....	.0135
PENTANES.....	.0080
C6+.....	.0040

CALCULATED GAS PROPERTIES:

DRY GAS HTG VAL... = 1213.88
 DRY GAS GRAVITY.... = .7432

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

PRODUCTION SUMMARY:

	-----GAS-----		THERMAL
	(MCF)	(MMBTU)	(MMBTU)
DAILY	375.3	455.5	101.5
CUM.	1084.0	1263.8	470.3

IGT WELL TEST ANALYSIS *****

LEAR G. M. KOELEMAY NO. 1 WELL

DATE: 9/23/80

GAS COMPOSITION:

NITROGEN.....	.0020
CARBON DIOXIDE.....	.0320
METHANE.....	.7829
ETHANE.....	.0875
PROPANE.....	.0601
ISOBUTANE.....	.0085
n-BUTANE.....	.0146
PENTANES.....	.0080
C6+.....	.0044

CALCULATED GAS PROPERTIES:

DRY GAS HTG VAL... = 1231.92
 DRY GAS GRAVITY.... = .7483

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

PRODUCTION SUMMARY:

	-----GAS-----		THERMAL
	(MCF)	(MMBTU)	(MMBTU)
DAILY	521.5	642.5	100.5
CUM.	1605.5	1906.3	570.9

PRODUCTION DETAILS:

TIME	---BRINE---		-----GAS-----	
	DEGF	STBPD	MCF/D	SCF/STB
0100	205	3429.	314.2	91.63
0200	205	3415.	319.7	93.62
0300	205	3357.	324.6	96.70
0400	205	3429.	333.9	97.38
0500	205	3380.	338.7	100.21
0600	206	3410.	342.5	100.44
0700	206	3394.	352.0	103.73
0800	206	3389.	354.0	104.45
0900	205	3375.	353.1	104.63
1000	205	3401.	364.7	107.24
1100	205	3385.	365.6	108.00
1200	205	3332.	366.9	110.12
1300	205	3346.	370.9	110.84
1400	205	3417.	388.8	113.77
1500	205	3366.	386.0	114.65
1600	205	3369.	390.4	115.89
1700	205	3373.	396.3	117.50
1800	205	3366.	405.2	120.37
1900	205	3348.	404.6	120.87
2000	206	3417.	418.2	122.38
2100	206	3437.	421.3	122.56
2200	206	3412.	424.3	124.36
2300	206	3400.	431.9	127.03
2400	206	3465.	438.6	126.57

PRODUCTION DETAILS:

TIME	---BRINE---		-----GAS-----	
	DEGF	STBPD	MCF/D	SCF/STB
0100	206	3375.	467.2	138.44
0200	205	3324.	478.8	144.01
0300	205	3311.	440.7	133.10
0400	205	3277.	451.7	137.84
0500	205	3293.	457.0	138.78
0600	205	3266.	466.1	142.74
0700	205	3407.	482.9	141.73
0800	205	3393.	491.8	144.93
0900	205	3397.	494.4	145.54
1000	206	3385.	502.0	148.28
1100	206	3392.	507.7	149.65
1200	206	3404.	520.4	152.88
1300	206	3429.	529.3	154.35
1400	206	3450.	532.2	154.25
1500	206	3355.	537.0	160.06
1600	205	3384.	544.9	161.03
1700	205	3414.	562.3	164.71
1800	205	3387.	565.1	166.87
1900	205	3345.	554.4	165.75
2000	205	3336.	563.1	168.80
2100	205	3361.	581.5	173.00
2200	205	3375.	592.3	175.47
2300	205	3348.	595.7	177.96
2400	204	3334.	597.9	179.31

EXHIBIT 12-31, Part 5

Part 6. DAILY PRODUCTION SUMMARIES

IGT WELL TEST ANALYSIS *****

LEAR G. M. KOELEMAY NO. 1 WELL

DATE: 9/24/80

GAS COMPOSITION:

NITROGEN.....	.0020
CARBON DIOXIDE.....	.0290
METHANE.....	.7788
ETHANE.....	.0905
PROPANE.....	.0620
ISOBUTANE.....	.0093
n-BUTANE.....	.0157
PENTANES.....	.0080
C6+.....	.0047

CALCULATED GAS PROPERTIES:

DRY GAS HTG VAL. = 1245.65
DRY GAS GRAVITY..... = .7522

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

PRODUCTION SUMMARY:

	-----GAS-----		THERMAL
	(MCF)	(MMBTU)	(MMBTU)
DAILY	518.4	648.9	101.5
CUM.	518.4	648.9	672.3

PRODUCTION DETAILS:

TIME	-----BRINE-----		-----GAS-----	
	DEGF	STBPD	MCF/D	SCF/STB
0100	205	3325	602.5	181.20
0200	205	3318	600.0	180.84
0300	205	3355	606.8	180.85
0400	205	3387	621.6	183.50
0500	205	3383	633.7	187.33
0600	205	3392	644.0	189.86
0700	205	3343	647.9	193.79
0800	204	3388	649.2	191.62
0900	204	3378	.4	.11
1000	206	3374	.4	.11
1100	205	3377	.4	.11
1200	206	3377	.4	.11
1300	206	3376	.4	.11
1400	206	3374	.4	.11
1500	206	3376	.4	.11
1600	206	3376	.4	.11
1700	206	3374	.4	.11
1800	207	3475	819.2	235.70
1900	207	3420	816.8	238.82
2000	207	3398	820.9	242.14
2100	207	3469	842.9	242.99
2200	207	3349	842.1	251.47
2300	207	3430	855.2	249.35
2400	206	3333	856.6	256.99

IGT WELL TEST ANALYSIS *****

LEAK G. M. KOELEMAY NO. 1 WELL

DATE: 9/25/80

GAS COMPOSITION:

NITROGEN.....	.0019
CARBON DIOXIDE.....	.0267
METHANE.....	.7683
ETHANE.....	.0946
PROPANE.....	.0685
ISOBUTANE.....	.0102
n-BUTANE.....	.0167
PENTANES.....	.0081
C6+.....	.0050

CALCULATED GAS PROPERTIES:

DRY GAS HTG VAL. = 1266.97
DRY GAS GRAVITY..... = .7620

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

PRODUCTION SUMMARY:

	-----GAS-----		THERMAL
	(MCF)	(MMBTU)	(MMBTU)
DAILY	938.2	1188.6	96.1
CUM.	1456.6	1837.6	768.4

PRODUCTION DETAILS:

TIME	-----BRINE-----		-----GAS-----	
	DEGF	STBPD	MCF/D	SCF/STB
0100	206	3285	872.8	265.73
0200	206	3261	887.6	272.14
0300	206	3150	892.4	283.28
0400	206	3190	907.8	284.61
0500	206	3236	914.9	282.75
0600	206	3368	917.2	272.32
0700	206	3197	917.4	286.97
0800	206	3204	939.7	293.30
0900	206	3329	932.1	280.02
1000	206	3322	931.9	280.52
1100	206	3126	950.6	304.09
1200	206	3272	927.0	283.29
1300	206	3226	923.9	286.36
1400	206	3242	943.4	290.96
1500	205	3222	958.9	297.64
1600	205	3171	953.6	300.72
1700	205	3137	932.0	297.12
1800	205	3174	950.6	299.46
1900	205	3188	946.6	296.89
2000	203	3167	969.0	305.97
2100	203	3158	960.7	304.26
2200	203	3202	985.0	307.65
2300	204	3175	1007.3	317.23
2400	205	3128	994.3	317.82

EXHIBIT 12-31, Part 6

- 0200 to 0300 hours, 9/20/80: This time correlates with a major separator upset that involved brine diversion to the pit after liquid production through the orifice meter. The calculated low gas/brine ratio is undoubtedly a result of data editing performed.
- 1800 to 1900 hours, 9/20/80: High gas production was recorded during this hour due to bleeding of gas that had accumulated in the tubing into the producing annulus.
- 0000 to 0200 hours, 9/23/80: High gas production rates were again experienced due to bleeding gas that had accumulated in the tubing to the producing annulus.
- 0000 to 1100 hours, 9/25/80: The variations in gas/brine ratio during this time correlate with variations in brine production rate from manual logging. They are assumed to be results of small variations in timing of manual data logging.

The tabulations in Exhibit 12-31 and Appendix J and the graphical presentation in Exhibit 12-32 revealed that a dramatic increase in the produced gas/brine ratio began during the second day of the third production test (9/19/80). After this time, the increasing gas/brine ratio, increasing content of heavier hydrocarbons in flare line gas, and oil production leave no doubt that hydrocarbon production was in excess of solubility in brine. At the end of the third production test at midnight on 9/25/80, the produced gas/brine ratio was approaching 320 SCF/STB. The vast majority of this is production to the flare line. Estimated gas/brine ratio for brine to the disposal well is only 3.2 SCF/STB or 1% of the total.

Production rates are not reported for midday on 9/24/80, because instrumentation was bypassed for conversion of the separator to three-phase operation. During the 32 hours after that conversion approximately 100 barrels of oil were produced, in addition to the hydrocarbons to the flare line and to the disposal well. Thus, producing characteristics when the well was returned to Lear Petroleum Company were as follows:

- Dry Natural Gas (including NGL)
1000 MCF/day
318 SCF/STB of brine
- Natural Gas Liquids (NGL)
137 bbl/day
5.76 gal/MCF of dry gas
43.5 bbl NGL/1000 STB brine
- Oil
about 75 bbl/day
about 3.2 gal oil/MCF dry gas
about 24 bbl oil/1000 STB brine

This estimate of hydrocarbon production is not complete due to the loss of volatile hydrocarbons from the oil stock tank. This loss was large due to the high temperature (about 205°F) of oil entering the stock tank.

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EXHIBIT 12-32, Part 1 PRODUCED GAS/WATER RATIO (9/12/80 to 9/18/80)

EXHIBIT 12-32, Part 2 PRODUCED GAS/WATER RATIO (9/19/80 to 9/25/80)

12.7.3.4 Comparison of Produced Gas/Brine Ratio With Laboratory Data on Methane Solubility: The procedure published by Haas et al. has been adopted to estimate gas solubility in reservoir brine. Reasons for this are:

- As discussed in Section 12.7.2.4., PVT studies on samples from this well were inconclusive due to laboratory problems caused by oil in the brine samples collected on 9/21/80.
- The Haas et al. procedure provided close agreement with total gas solubility determined by PVT studies on samples from the Wainoco P. R. Girouard Well No. 1.
- Dr. Charles Blount has verbally advised that he is revising his prior results downward due to a recently discovered problem in prior laboratory calculations.

Selection of values from Exhibits 12-31 and 12-32 for comparison with laboratory studies of solubility is complicated by the time variation of gas composition. For example, the jump from 33 SCF/STB to over 35 SCF/STB between 2300 and 2400 hours on 9/12/80 and 0100 and 0200 hours on 9/13/80 probably did not actually occur. This jump is probably due to differences in gas composition used to calculate production on these two days.

The most credible values for produced gas/brine ratios are those for the hours in which gas samples were taken to determine gas composition by mass spectrometer analysis. Those values are shown in Exhibit 12-33, below.

Exhibit 12-33. GAS/BRINE RATIOS AT THE TIME OF COLLECTING GAS SAMPLES FOR MASS SPECTROMETER ANALYSIS

<u>Date</u>	<u>Time</u>	<u>Total Produced Gas/ Brine Ratio, SCF/STB</u>
First Flow Test:		
9/12/80	1500 to 1600	29.72
9/12/80	1900 to 2000	31.10
9/13/80	0900 to 1000	35.78
9/13/80	1100 to 1200	37.20
Second Flow Test:		
9/17/80	0000 to 0100	34.67
Third Flow Test:		
9/18/80	1800 to 1900	36.92
9/19/80	0000 to 0100	39.28
9/19/80	1400 to 1500	46.08

For comparison, using the procedure developed by Haas et al. provides an estimate of 36 ± 2 for methane solubility in 15,000 mg/l brine at the reservoir conditions of 9449.4 psia and 260°F measured by RDI. Comparison with Exhibit 12-33 suggests that brine produced from 9/13/80 to 9/18/80 may well have been saturated if total gas solubility is independent of gas composition. On the other hand, gas produced at the times of sampling on those days averaged 84.8% methane. Thus, the average methane content of the produced gas was only about 30.6 SCF/STB or 85% of the value estimated using the procedure developed by Haas et al.

In any event, there is no doubt that natural gas content of only about 31 SCF/STB, observed for several hours on 9/12/80, was substantially below solubility in reservoir brine. Similarly the gas/brine ratio on 9/19/80 and thereafter was clearly in excess of solubility in reservoir brine.

12.7.4 Brine Collection and Analysis

Brine samples were obtained from the inlet to the brine metering skid downstream of the separator. Details of collection and analyses of these samples, a discussion of analytical results, and a summary of third party samples are presented in the following subsections.

12.7.4.1 Separator Output Sampling: Surface brine sample collection and analyses were performed according to IGT procedures, described in Appendix K, in accordance with the objectives of the current draft of a uniform plan for geopressed aquifers under development by a panel of experts chaired by Dr. B. E. Hankins of McNeese State University.

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

Results of analyses performed in the field and in IGT's Chicago laboratories are presented in Exhibits 12-34 and 12-35.

12.7.4.2 Departures from Planned Procedures: Several changes were made in the analytical procedures during both the field and laboratory phases of the analyses. These were described in the report for the Wainoco P. R. Girouard No. 1 well as modifications to the brine sample collection and onsite analysis procedures. They are repeated below, along with the variations used for the laboratory analyses.

A. Sample Collections

Brine samples from the well were collected in three Teflon-lined stainless steel cylinders of 500-ml capacity. For sampling, the cylinders were linked in series to the sampling port. An alternative method would have been to collect brine in one cylinder at a time. Cylinders were flushed with several volumes of brine to purge the air from the cylinders before the sample was taken. Cylinder valves were closed, outlet first, inlet last, to trap and seal the sample under pressure. Sample cylinders were cooled to near-ambient temperature before analysis. The pressure in each cylinder was maintained until the sample was ready for analysis.

The three steel cylinders (A, B, and C) of raw untreated brine were used for measurement of pH and specific conductance (Cylinder A); alkalinity (Cylinder B); and for gas analysis, total dissolved CO_2 (including carbonate and bicarbonate species), and sulfide (Cylinder C).

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

EXHIBIT 12-34 RESULTS OF ONSITE ANALYSES OF POST-SEPARATOR BRINE FROM LEAR G. M. KOELEMAY WELL No. 1

Sample Date and Time	Temp, °C	pH	Specific Conductance µmhos/cm @ 25°C	Suspended Solids mg/L	Alkalinity mgCO ₃ /L	CO ₂ mg/L	Dissolved Solids mg/L	Chloride mg/L	Sulfide mg/L
12 Sept 80 1430	46	6.7*	22,400	N.D.	1900	N.D.	14,700	7400	0.004
13 Sept 80 0913	68	6.6	22,500	66	1800	1550	15,500	7600	0.013
16 Sept 80 2325	76	6.5	22,600	77	1900	1720	15,400	7400	N.D.
18 Sept 80 1755	79	6.5	22,000	24	1800	1530	15,400	8000	N.D.
19 Sept 80 1545	78	6.6	19,900	74	1800	N.D.	15,400	7400	N.D.
20 Sept 80 1020	78	6.6	20,500	74	1800	1610	14,600	7400	N.D.
21 Sept 80 1020	79	6.6	19,600	43	1800	1500	14,400	7400	N.D.
22 Sept 80 1200	89	6.6	20,500	22	1800	1330	15,400	7400	N.D.
23 Sept 80 1445	83	6.7	N.D.	41	1800	N.D.	14,100	7500	N.D.
25 Sept 80 1625	N.D.	6.8	N.D.	N.D.	1800	1350	N.D.	N.D.	N.D.
26 Sept 80 1123	N.D.	N.D.	N.D.	N.D.	N.D.	1280	N.D.	N.D.	N.D.
Est. Accuracy of Analysis (+)	1	0.1	100	1	100	10	100	100	0.002
Mean	75	6.6	21,300	53	1800	1480	15,000	7500	0.009
Standard Deviation	12	0.1	1,200	21	40	140	500	200	--

* pH determination on non-bomb air exposed samples: 1430 hrs = 6.8; 1545 hrs = 6.8

N.D. = Not determined.

Ref. 44093

EXHIBIT 12-35 RESULTS OF LAB ANALYSIS OF POST-SEPARATOR BRINE FROM LEAR G. M. KOELEMAY WELL No. 1

Sample Date and Time	Concentration, mg/L																				
	NH ₃	Cl	F	SiO ₂	SO ₄	As	B	Ba	Ca	Cd	Cr	Cu	Fe	Hg ^a	K	Mg	Mn	Na	Pb	Sr	Zn
13 Sept 80 1050	6.2	7700	2.8	130	36	0.0018	45	25	45	<0.0013	0.14	0.06	10.7	0.22	61	6.1	0.21	5430	0.007	7.7	0.05
18 Sept 80 1710	5.0	7600	2.5	120	33	0.0048	44	40	45	0.0044	0.41	0.050	10.1	0.57	59	7.0	0.35	5120	0.011	7.6	0.29
19 Sept 80 0300	6.0	7500	2.6	110	45	0.0018	43	20	43	<0.0013	0.09	0.003	3.0	0.17	59	6.2	0.12	5200	0.004	7.7	0.15
19 Sept 80 1400	5.5	7500	2.4	120	42	0.0015	47	31	43	<0.0013	0.19	0.028	6.2	0.58	58	6.1	0.18	5310	0.007	7.5	0.28
21 Sept 80 1100	6.0	7500	2.2	130	39	0.0015	44	10	40	<0.0013	0.17	0.015	4.2	0.35	57	6.0	0.17	5550	0.006	7.3	0.07
23 Sept 80 1420	5.8	7600	2.6	140	27	0.0022	45	13	39	<0.0013	0.13	0.023	3.5	0.34	57	5.8	0.14	5470	0.002	7.3	0.05
25 Sept 80 1200	N.D.	7400	2.6	N.D.	N.D.	0.0045	44	6	39	0.0031	0.10	0.003	3.4	0.12	56	6.0	0.12	5630	0.011	7.4	0.05
Est. Accuracy of Analysis (+)	0.1	100	0.1	10	1	0.0002	1	1	1	0.003	0.01	0.001	0.1	0.01	1	0.1	0.01	10	0.0002	0.1	0.01
Mean	5.8	7500	2.5	130	37	0.0026	45	21	42	<0.0038	0.18	0.018	5.9	0.34	58	6.2	0.18	5390	0.007	7.3	0.13
Standard Deviation	0.4	90	0.2	10	6	0.0013	1	11	2	---	0.10	0.016	3.0	0.17	2	0.4	0.07	170	0.0032	0.2	0.10

^a Hg concentrations are in µg/L

N.D. = Not determined

Ref. 44144

Treatment	Tests
RU (Raw, untreated)	pH, Temperature, Total Dissolved CO ₂ , Alkalinity, Specific Conductance, Suspended Solids, Sulfide, Gas Analysis
RA (Raw, acidified with 3 ml 1:1 HNO ₃ /liter)	Radioactivity
FU (Filtered through 0.45-μ m membrane, untreated)	Dissolved Solids, B, Cl ⁻ , F ⁻ , NH ₃ , SiO ₂
FA (Filtered through 0.45-μ m membrane, acidified with 1:1 HNO ₃ to a pH of 1.5, the amount of acid used being noted)	As, Ba, Ca, Cd, Cl ⁻ , Cr, Cu, Fe, K, Mg, Mn, Na, Pb, SO ₄ , Sr, Zn

B. Onsite Test Procedures for Liquid Samples

• pH

A pH meter with automatic temperature compensation was used. It was calibrated with pH buffers of 7.0 and 4.0. A portion of the sample from Cylinder A was drained into a beaker and the pH measured and recorded immediately. The sample was not stirred. In the event that the pH drifted down, then up, as the solution exsolved CO₂, the lowest pH reading was recorded.

• Temperature

Flowing brine temperature was recorded; brine temperature was also measured in a freshly filled bottle or container.

• Specific Conductance

A commercial instrument calibrated with KCl at various temperatures was used to measure specific conductance. The unused portion of the brine sample in Cylinder A was used for measuring specific conductance. Specific conductance was recorded in mhos/cm; brine temperature at which measurement was made was also recorded. Variations during the third flow test were possibly due to oil in the brine sample.

• Alkalinity

A 50.00 ml brine sample from Cylinder B was placed in a 250-ml beaker using a pipet. Electrodes of a calibrated pH meter were placed in the sample and the sample titrated with 0.02 N H₂SO₄. The standard acid was added in increments of 1 to 2 ml at the beginning of the titration and the increments changed to 0.25 to 0.50 ml at pH = 5.0. The incremental volumes were determined from observation of the actual titration and the speed at which the pH was changing.

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The solution was titrated until the pH was 2.0. Values of pH and ml were tabulated and the end point determined graphically from a plot of pH versus ml.

Alkalinity was recorded as mg CO₂/liter. This procedure determines the total alkalinity, including the portion attributable to organic anions.

- Total CO₂

Brine in Cylinder C was used to determine total dissolved CO₂ (dissolved CO₂ and HCO₃⁻) after the gas had been flashed off for GC analysis. The brine was drained from the steel cylinder into a volumetric cylinder to determine the brine volume for the gas-to-brine ratio. While measuring the volume, the brine was immediately made alkaline to phenolphthalein with drops of 10 M NaOH (40 g NaOH to about 100 ml). A portion, 50 ml, of this solution was transferred to the carbonate train. Following addition of about 30 ml of water, it was acidified with 30 to 40 ml of 1:1 HCl, and the CO₂ purged into the tared Nesbitt bulb with nitrogen for 1 hour. The Nesbitt bulb was reweighed for the weight gain due to CO₂, which was reported as mg CO₂/liter.

- Sulfide

The remaining alkaline brine solution from Cylinder C was used for sulfide determination. A specific ion electrode was used according to the manufacturer's instructions.

- Barium

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

- Sulfate

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

- Strontium

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

- Potassium

Cesium was substituted for sodium, because it has a lower ionization potential and therefore acts as a so-called "ionization buffer" more readily. The need for any added reagent was questionable, since the solutions contained 8000 to 9000 ppm of sodium as received.

- Manganese

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

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12.7.4.3 Discussion of Analytical Results: Measured concentrations of several parameters, shown in Exhibit 12-35, were constant within the limits of experimental error throughout the test series. For these parameters, the average measured concentrations are probably representative of the brine in the reservoir. These parameters are:

Total Dissolved Solids	F ⁻	Sr
Cl ⁻	SiO ₂	B
Alkalinity	Na	Cr
Total Carbon Dioxide	K	SO ₄ ²⁻
Ammonia	Mg	S ²⁻

Whether some of the variations observed are due to changing reservoir characteristics is discussed in Section 12.7.4.4.

Measured concentrations of several parameters were quite variable, probably due in part to the hydrocarbon condensate being produced by this well. Both partitioning between the two liquid phases and sampling difficulties with the multi-phase flow contributed to the observed variability of the results. These are discussed as follows:

- Minimal Significance

For these species, a decrease in concentration with time suggests cleanup of material introduced by man. An anomaly occurs with the 9/19/80, 0300-hours sample. The results seem lower than those from samples either immediately before or after that time. No field analysis of this sample was made. Whether any significant amount of the materials are produced from the reservoir is questionable, and the concentrations shown in the tables can be regarded as maximums. These materials are:

Zn,
Pb, and
Cd.

- Possible Significance

Concentrations of these parameters varied substantially with time. The observed concentrations may be significant in relation to corrosion, scaling, or brine disposal. These are:

Fe: Although the mean concentration of total dissolved solids (15,000 mg/l) was almost 25% lower in this well than in the Wainoco P.R. Girouard well (23,500 mg/l), the mean iron concentration, 5.9 mg/l, was much higher than in the Girouard well (1.91 mg/l). Since a bottomhole sample was not obtained, it can only be speculated that corrosion of the well bore tubulars may be the source. If this is true, corrosion could cause the loss of about 45,000 pounds of iron in 10 years of production at 10,000 bbl/day.

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As: Although the concentration of 0.0026 mg/l was not as high as the 0.009 mg/l for the Girouard well, no decrease in the arsenic concentrations was seen with time. This may present a potential disposal problem if surface disposal is attempted.

Mn: Concentration declined with time to a minimum of about 0.12 mg/l.

Cu: Observed concentrations varied widely and erratically over the 0.050 to 0.003 mg/l range. Its origin is unresolved.

Ba: Concentrations decreased with time to 6 mg/l, which is almost 20 times greater than the lower barium levels found in the Girouard Well. It is, however, much closer to the expected equilibrium value corresponding to the 37 mg/l mean sulfate value than was the Ba/SO_4^{2-} ratio of the Girouard well. This should indicate little, if any, barite scale formation with time in the surface plumbing.

• Major Significance

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

Hg: Concentrations of 6.2 mg/l were considerably higher than those found in the Girouard well (<0.75 mg/l). They are also well above the $0.10 \mu\text{g/l}$ limit recommended by the U.S. EPA for the protection of fresh and marine aquatic organisms and for drinking water standards. At this concentration surface disposal of the brine is precluded, and care must be taken with subsurface disposal to avoid contamination of a drinking water aquifer.

B: Although about one-half the concentration observed for the Girouard well (80 mg/l), its mean value of 45 mg/l also precludes surface disposal of the brine. This concentration is extremely phytotoxic and would require massive dilution to make surface disposal feasible.

Ca: Concentrations found in this well, 49 mg/l, were about double those found in the Girouard well despite the 25% reduction in total dissolved solids. Although a downhole sample was not obtained, a relationship between surface and reservoir calcium concentrations similar to that observed on the Girouard well could be expected. That is, surface concentration would be lower than downhole due to the precipitation of CaCO_3 as the pressure is reduced.

12.7.4.4 Brine Changes in Relation to Reservoir Behavior: Although average concentrations of many species in solution are believed to be representative of brine in the reservoir, several individual measurements depart from the mean by many times the margin of analytical accuracy. These anomolous measurements may well reflect changes in details of brine production from the reservoir. Specific observations are discussed below:

- Variations in NaCl and CO₂ Concentrations

The analytical procedure used for Na⁺ analysis has much better sensitivity than that for Cl⁻. The increased Na⁺ concentration during the last 5 days of production may well reflect a change in the primary source of brine. During this same time period, the field measurements revealed a declining amount of total CO₂ liberated from brine by acid. The change in CO₂ content is greater than would be expected from the modest changes in separator pressure with the near-constant temperature and flow rates that existed at this time.

- Anomalies in Concentrations at 0300 Hours on 9/19/80

This sample was collected 12 hours after the third flow test had reduced bottomhole pressure by more than 4000 psi. Before the sample was taken, the corrected brine rate had increased from a low of 4159 STB/day just before midnight to a high of 4414 STB/day with minimal change in bottomhole pressure.

Analysis of this sample revealed concentrations of barium, chromium, cadmium, iron, mercury, manganese, lead, and zinc (Exhibit 12-35) that were much lower than for the preceding or following samples. Various analyses for these species were performed by different individuals and in different laboratory rooms in IGT's Chicago facility. Thus there is virtually no possibility of systematic error. Further, the concentrations of other species, such as sodium, chloride, calcium, and sulfate, preclude the possibility of erroneous dilution in the field.

These observations strongly suggest the onset of brine production from a previously isolated reservoir characterized by differences in brine chemistry. The increase in flow rate preceding collection of this brine sample correlates with onset of gas production substantially in excess of the expected solubility of about 37 SCF/STB. (See Section 12.7.3.1.)

- Anomalous Concentrations at 1200 Hours on 9/25/80

In relation to prior trends, analysis of this sample revealed very high concentrations for arsenic, cadmium, sodium, and lead (Exhibit 12-35). The concentration of copper was very low. One major difference is that this was the only sample analyzed in detail after the separator was converted to three-phase operation. This difference may be the reason for the very low copper concentration. However, we have identified no mechanism whereby three-phase separator operation could be responsible for the observed increases in concentration. It is therefore possible that observed differences again reflect onset of brine production from an additional increment of reservoir.

12.7.4.5 Brine Samples by Third Parties: Representatives of the following organizations collected brine samples on location:

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- Weatherly Laboratories
- U.S. Geological Survey
NSTL Station, Miss.
- McNeese State University
Lake Charles, La.
- Jack V. Matson,
Ph.D., P.E.
- U.S. Geological Survey
Menlo Park, Calif.

Other organizations invited to participate in sampling and analysis included the University of Texas at Austin, Lawrence Berkely Laboratory, and Louisiana State University.

A combined sample log showing times of sample collection, location and type of samples collected, tests performed on location, and tests intended to be performed off-location is presented in Appendix H in Volume 2.

Results of third-party hydrocarbon analyses that have been provided to IGT during the 4 months since the test was conducted are presented below by organization.

- USGS Gulf Coast HydroScience Center

Results of analyses of samples from this and other wells were provided in a letter from Mr. Thomas F. Kraemer dated January 22, 1981. Data from that letter for this well are presented in Exhibit 12-36.

**Exhibit 12-36 RADIOACTIVE MATERIAL CONTENT OF BRINE REPORTED BY
THE USGS GULF COAST HYDROSCIENCE CENTER**

<u>Date</u>	<u>Time</u>	<u>$^{226}\text{Ra}(\text{dpm/l})$</u>	<u>$\text{U}(\text{ug/l})$</u>	<u>$^{234}\text{U}/^{238}\text{U}$ Activity Ratio</u>
9/12/80	10:55	21.5		
9/12/80	19:35	15.3		
9/16/80	22:15	24.5		
9/18/80	--	--	0.054	1.37
9/19/80	14:10	27.8		
9/19/80	--	21.5		
9/20/80	11:25	24.3		
9/21/80	11:10	25.6		
9/22/80	10:00	19.0		
9/23/80	14:25	21.4		
9/25/80	12:25	21.2		

The following excerpts pertinent to these brine analyses are quoted from Mr. Kraemer's letter:

"The radium content of the water was low, generally less than 30 dpm/l. This correlates with a trend I have been observing in the Gulf Coast that the lower the formation water salinity, the lower the concentration of radium in the water.

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"The uranium concentration of the water was also low, although relative to the other wells sampled, it is one of the highest I have seen. This may be due to the high particulate content of the water, as my sample was not filtered. Again, the uranium activity ratio ($^{234}\text{U}/^{238}\text{U}$) was slightly above equilibrium, indicating that a presently active process is occurring in the reservoir which continually enriches the water in ^{234}U atoms, generated within the solid matrix."

- Weatherly Laboratories, Inc.

Weatherly Laboratories, Inc., personnel collected brine samples for use in recombination and differential liberation experiments described in Section 12.7.2.4 of this report. Weatherly Laboratories, Inc., did not perform brine analyses.

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

Representatives of this firm visited the project location on four separate occasions in relation to scale and corrosion studies. During the first visit, on September 12, 1980, a brine sample was collected from downstream of the separator. Analysis revealed the following results:

Well Sample Temperature:

98°F

Visual Observation:

Translucent, oil condensate

Total Hardness (EBT/EDTA):

159 ppm @ CaCO_3

Calcium Hardness (PNB/EDTA):

116 ppm @ CaCO_3

Total Alkalinity (Methyl Orange):

2244 ppm @ CaCO_3

pH:

7.1 pH Meter

In these units, total alkalinity measured by IGT for a sample collected 2-1/2 hours earlier was about 4300 mg CaCO_3/l and the pH was 6.7. Understanding of this difference has not been pursued. One possibility is CO_2 evolution during the reported 3 days between collection and analysis for the Jack V. Matson sample versus the short time delay with the IGT procedure.

The complete report provided to Eaton Operating Company is provided herewith as Appendix L.

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12.8 Solids Production, Scaling, and Corrosion

Little, if any, scaling or corrosion occurred during the test of this well. However, significant quantities of solids were produced. In contrast to the high carbonate content of solids from the Wainoco P. R. Girouard Well No. 1, produced solids were over 95% acid insoluble, with a dominant grain size of only about 20 μm . Relevant observations, data, analyses, and conclusions are discussed in this section.

12.8.1 Corrosion Coupon Observations

Individual corrosion coupons were in place between the choke manifold and the separator for the full duration of each of the flow tests. In addition, four coupons were placed in the stream at that position during successive 4 to 6-hour intervals at the beginning of the third flow test. Exhibit 12-37 is a record of the corrosion coupon weight gains during testing. Although a weight gain was recorded for each coupon, scale was only observed on the coupon in the stream for the full week of the third flow test. For that coupon, the weight gain was only 0.0065 grams per square inch per 1000 barrels of flow.

The deposit scraped from the coupon was analyzed for composition and structure, using X-ray elemental analysis and scanning electron microscopy. The elemental analysis revealed a high amount of calcium, along with some iron, silica, barium, chloride, and aluminum. Additional details on corrosion coupon observations are provided in the report from Jack V. Matson, Ph.D, P.E. provided herewith as Appendix L.

Surface piping was visually examined after both the first and third flow tests. No significant evidence of scaling or corrosion was observed upstream of the choke, between the choke and separator, or downstream from the separator.

12.8.2 Sand Detector Data

An OIC Sand System, Inc., sonic sand detector was installed in the surface data header between the choke manifold and the separator. The record produced was baseline for the vast majority of the test duration. A signal, possibly due to sand, was observed for 15 minutes following "bottoms-up" on the second flow test. A small signal, probably due to sand, declined to baseline in 3 hours following "bottoms-up" on the third flow test. During the next 48 hours of the third flow test, a half dozen small signals, each having a duration of 15 minutes or less, were observed. Exhibit 12-38 is a record of the sonic sand detector data and calculations of sand production.

From the start of conversion to three-phase separator operation on 9/24/80, until the end of DOE-funded testing at the end of 9/25/80, the sand detector consistently displayed a signal in excess of 10% of the most sensitive scale. Whether this signal was due to sand or only to background noise generated by the high gas/water ratio at low separator pressure cannot be resolved. However, background noise is considered likely, because onset of the signal coincides with pressure reduction at the sand detector with no accompanying change in brine flow rate.

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DE-AC08-80ET-27081Eaton Industries of Houston, Inc.
Eaton Operating Co., Inc.
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(713) 627-9764CORROSION COUPON RECORD
G. M. KOELEMAY WELL NO. 1

<u>Coupon No.</u>	<u>Time In</u>	<u>Time Out</u>	<u>Weight Gain (Grams)</u>	<u>Water Production (Barrels)</u>	<u>Temperature °F</u>	<u>Weight Gain g/1000 bbls/in²</u>
2019	12:00 PM 9-12-80	2:00 PM 9-13-80	0.2229	2,282	106 - 176	0.0340
2011	6:00 PM 9-16-80	5:00 AM 9-17-80	0.2060	1,789	135 - 195	0.0410
2018	9:00 AM 9-18-80	4:10 PM 9-18-80	0.2122	580	165 - 195	0.1275
2016	4:20 PM 9-18-80	10:20 PM 9-18-80	0.2085	1,217	198 - 204	0.0603
2013	4:20 AM 9-19-80	8:00 PM 9-26-80	0.4888	26,290	206 - 208	0.0065

EXHIBIT 12-37

SONIC SAND DETECTOR DATA AND CALCULATIONS
G. M. KOELEMAY WELL NO. 1

<u>Date</u>	<u>Flow Rate(Q) BWPD</u>	<u>Fluid Velocity Ft/Sec</u>	<u>Average Sonic Sand Detector Reading</u>	<u>Sand Production lbs/Day</u>	<u>Time of Sand Production(Hrs.)</u>	<u>Actual Sand Production(Lbs.)</u>
9-18-80	5,277	4.31	5	55.4	7.5	17.3
9-24-80	3,512	2.86	21	528.9	16	352.6
9-25-80	3,053	2.49	8	265.8	24	<u>265.8</u>
					TOTAL	635.7

Sample Calculation:

(For Data 9/18/80)

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

$$= \frac{206 \times 5}{4.31^2} = 55.4 \text{ lbs/Day}$$

EXHIBIT 12-38

Quantitative analysis of sand detector data is suspect due to inconsistency with data from the pressure drop across filters and the very small grain size of solids recovered after testing. Also, the sand detection signal is rate sensitive, and fluid velocities in the data header were low in relation to optimal detection operation.

12.8.3 Pressure Drop Across Filters

The development of pressure drop across filters suggests that production of solids was a more continuous process than is apparent from the minimal response of the sonic sand detector.

During the first flow test at slightly above 2000 STB/day, pressure drop across the filter unit in use remained essentially constant at only about 1.5 to 2.0 psi. The second flow test, at about 4000 STB/day, did not involve flow through the filters because the disposal well would not accept fluid.

Exhibit 12-39 is a plot of pressure drop across filters for the majority of the third flow test. During the first hour of the test, at 7000 STB/day, pressure drop across the one filter unit in use increased from 2 to 46 psi. Since the 50- m filters were rated for 50 psi maximum drop, production was then switched to a second filter unit. Pressure drop had increased to 13 psi before producing a volume as large as the wellbore (i.e. before "bottoms-up"). Thus some portion of the increase resulted from the 7000 STB/day rate washing previously accumulated solids from the separator and surface piping.

As shown in Exhibit 12-39, pressure drop across the second filter unit slowly increased to 40 psi during the next 5 days. The drop in filter differential pressure early on 9/20/80 occurred at the time brine flow was diverted to the pit due to a separator upset. Backflushing of the filter took place during 1/2 hour of production to the pit. The drop in mid-afternoon on 9/21/80 was due to temporary diversion of production to a 220-barrel tank. During this time some backflow occurred from the disposal well and through the filters to the tank.

Just before 2300 hours on 9/23/80, flow was switched to two filter units in parallel. The drops in pressure on 9/24/80 are due to diversion of flow to the pit for conversion of the separator to three-phase operation. Although not shown, pressure drop during the last 24 hours (9/25/80) increased to about 18.5 psi at 1700 hours. Pressure drop then fell off to about 9 psi, possibly due to failure of a filter. Then it climbed to about 17 psi at the end of the test.

This continued buildup of filter pressure drop over a 1-week period, with minimal drop in brine rate and bottomhole pressure, suggests a continuous low rate of production of solids.

12.8.4 Production to a 220-Barrel Tank

At about 1930 hours on 9/21/80, a portion and then all of the brine flow out of the separator was diverted to a 220-barrel tank. The intent was to allow solids to settle in the tank and then use a pump to inject the brine into the disposal well. This plan was

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EXHIBIT 12-39 FILTER DIFFERENTIAL PRESSURE (9/18/80 to 9/24/80)

abandoned after producing about 200 barrels into the tank, due to the fire hazard from volatile hydrocarbons produced with the hot brine.

After slowly draining the tank, recovery of solids was attempted by sweeping sludge out of the tank and into a pillow case. A large portion of observed solids were of very small grain size and passed through the pillow case. Nevertheless, 3.1 pounds of solids were recovered from drying the portion of solids actually trapped by the pillow case. Assuming that 50% of the solids were caught by the pillow case provides an estimate of 31 pounds per 1000 STB for the rate of solids production during the evening of 9/21/80.

12.8.5 Analysis of Solids Samples

Three categories of solid samples were collected during the test series: i) suspended solids trapped by a 0.45- μ m filter while collecting brine samples, ii) solids from either side of the filter apparatus after the third flow test, and iii) sludge from the separator after the third flow test. Each is described in the following subsections.

12.8.5.1 Suspended Solids: Results of X-ray diffraction analysis of suspended solids trapped on the 0.45- μ m filters are shown in Exhibit 12-40, below. After the first flow sample, (9/13/80), barium sulfate made up the only identifiable crystal phase in the suspended solids. Semiquantitative X-ray fluorescence examination indicated the presence of minor amounts (under 1%) of silicon. Thus, small amounts of SiO_2 may still have been present in the 9/19/80 to 9/23/80 samples but were obscured by the large amount of barium sulfate.

EXHIBIT 12-40. COMPOSITION OF SUSPENDED SOLIDS SAMPLES FROM THE LEAR G. M. KOELEMAY WELL No. 1

<u>Sample Date</u>	<u>Identified Compounds</u>	<u>Amount, lb/1000 STB</u>
9/13/80 0943*	BaSO_4 CaCO_3 SiO_2	23.1
9/18/80 2330	BaSO_4	27.0
9/19/80 1545	BaSO_4	25.9
9/21/80 1150	BaSO_4	15.1
9/23/80 1635	BaSO_4	14.4

* Compounds are listed in probable order of decreasing abundance in this sample.

The brine sampling point on the metering skid was selected to discriminate against collection of solids. Close agreement between solids content of brine through the 0.45 μ m sample collection filters and the 31 pounds per 1000 STB on 9/21/80 estimated from the settling tank suggests that the particles are so small that centrifugal forces in the brine stream provide little, if any, segregation.

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12.8.5.2 Filter Line Solids Analysis: Two solids samples were collected from piping on either side of the 50 μ m filters between the separator and the disposal well. The material sampled was in a layer between 1/4 and 1/2-inch thick on the lower side of horizontal pipes to and from the filter skid. The total quantity in about 100 feet of 3-inch pipe is estimated to be about 35 pounds. These samples were analyzed in accordance with the following procedure:

- Analysis of a portion of each sample for carbonate by evolution of CO₂ with boiling 6 N hydrochloric acid and subsequent trapping of CO₂ on Ascarite,²
- Filtration of the acidic solution and analysis of filtrate for Na, Ca, Mg, Ba, and Sr,
- Examination of the filterable solids by X-ray diffraction.

Results of the two X-ray diffraction analyses and of the filtrate analyses are given in Exhibit 12-41.

Calculations were made using the five measured cation concentrations in an attempt to form a material balance for the solid material. Assuming the calcium and magnesium to be present as carbonates, the barium as sulfate, the sodium and strontium as chlorides, and including the acid insoluble residue, approximately 98% of the material could be accounted for in these samples. Comparison of the CO₂ determined from the carbonate analysis with that calculated from the assumed calcium and magnesium carbonates showed close agreement, indicating that only about 2% of the solids were carbonates. The calculated CO₂ evolution and the calculated material balance are shown for each sample in Exhibit 12-41.

12.8.5.3 Separator Sludge Analysis: After the third flow test, the separator contained roughly 10 pounds of very fine solids dispersed in brine. A sample of this slurry was dried and analyzed in the same manner as the filter line samples discussed previously. The results of analysis of this sample are included in Exhibit 12-41. Again, comparison of the observed and calculated carbonate content showed good agreement. X-ray analysis shows that the majority of the material was sand, which had collected in the separator.

12.8.5.4 Particle Size Distribution of Solids: The solids obtained from the filter lines and the separator were analyzed for particle size distribution. The data obtained are shown in Exhibit 12-42.

The as-received material and the residue insoluble in 1 N hydrochloric acid showed very similar particle size distributions, unlike those from the P. R. Girouard No. 1 well. The low carbonate content of these samples probably prevented the cementation of the sand grains together with precipitated carbonate. This accounts for the similarity in the particle size distributions.

Separator sludge from this well is similar in carbonate content and particle size distribution to that analyzed from the separator at the P. R. Girouard No. 1

EXHIBIT 12-41 ANALYSES OF SOLID MATERIAL COLLECTED 9/30/80 FROM THE LEAR G. M. KOELEMAY No. 1 WELL

Sample Description	X-ray Diffraction Identified Samples [*] Acid Insoluble	Analysis of Acid Solution, Concentrations, Wt %							Residue Wt %	Total [‡] Wt. %
		Na	Sr	Ca	Mg	Ba	CO ₂	Calculated [†]		
Solids Upstream of Filters	SiO ₂ BaSO ₄ NaAlSi ₃ O ₈	0.17	0.01	0.65	0.17	0.18	0.92	1.03	95.1	98.3
Solids Downstream of Filters	SiO ₂ BaSO ₄ NaAlSi ₃ O ₈	0.19	0.01	0.60	0.18	0.23	0.91	0.99	94.0	97.3
Sludge from Separator	BaSO ₄ SiO ₂ NaAlSi ₃ O ₈	0.13	0.01	0.42	0.08	0.14	0.71	0.61	95.9	98.1

^{*} Compounds listed in probable order of decreasing abundance. NaAlSi₃O₈ less than 1 %, others above 1 %.

[†] Calculations based on Ca and Mg as carbonates.

[‡] Calculations based on Ca and Mg as carbonates plus Na, Sr as chlorides, Ba as sulfate and the residue.

Ref. 44350-44352

EXHIBIT 12-42 SCREEN ANALYSIS OF SOLID MATERIAL FROM LEAR G. M. KOELEMAY No. 1
WELL BEFORE AND AFTER TREATMENT WITH DILUTE[†] HYDROCHLORIC ACID

Effective Screen Diameter, Microns	Fraction Larger Than Effective Screen Diameter, Weight Percent					
	Solids Upstream of Filter		Solids Downstream of Filter		Solids From Separator Outlet	
	30 Sept 1980		30 Sept 1980		30 Sept 1980	
	As Rec'd	Acid Insol.	As Rec'd	Acid Insol.	As Rec'd	Acid Insol.
1180	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
600	0.1	<0.1	0.1	<0.1	<0.1	0.1
300	0.8	1.7	0.2	0.2	0.2	0.7
150	8.0	7.5	0.9	1.0	0.3	0.9
75	23.7	22.3	12.2	13.7	2.1	2.7
51*	8.1	9.0	7.9	9.6	3.4	4.6
40	6.9	6.4	6.6	9.1	6.3	6.1
32	9.2	9.8	8.7	13.0	12.6	12.8
25	9.2	9.4	10.7	12.2	15.6	16.5
20	9.4	9.7	12.0	12.0	19.5	19.7
16	7.4	7.9	11.4	10.0	15.5	14.8
13	5.9	6.1	10.0	7.1	10.9	9.7
10	4.1	4.3	7.8	5.1	6.5	5.6
8	3.0	2.9	5.7	3.6	4.1	3.4
6	2.3	2.1	4.1	2.6	2.5	2.1
5	0.9	0.8	1.5	0.9	0.5	0.2
4	0.3	<0.1	0.3	<0.1	<0.1	<0.1

* From 51 to 4 microns, results are for a Coulter Counter. Particles < 4 microns were not included in the normalization of these results.

† Dilute 1N hydrochloric acid.

well. Solids obtained from the plumbing upstream of the 50 m filters are dissimilar to comparable deposits collected from the filter elements at the Girouard well. Those from the Girouard well were about 60% carbonates, while those collected at this well were only about 2% carbonate. Also, the particle size distributions showed the acid-insoluble material from this well to consist of many smaller particles (40% 51 m) than the same material from the Girouard well, which had about 83% larger than 50 m.

12.8.6 Discussion of Solids Production

Both the single filling of the settling tank and the suspended solids caught on filters suggest production of 20 to 30 pounds of solids per 1000 barrels of brine. Thus, roughly 600 to 900 pounds of solids appear to have been produced during the tests of this well.

No scaling was observed. This is not surprising since only about 2% to 5%, or roughly 10 to 50 pounds of total solids were acid soluble carbonate species.

Grain size distributions revealed that 60% to 90% of solid particles were smaller than the nominal 50 m rating of the filters used. This small size was undoubtedly a major factor in the lack of response by the sonic sand detector and the minimal accumulation of solids in the separator vessel.

The relative amounts of sand, clays, and barium sulfate in the large acid insoluble fraction of produced solids has not been determined, due to funding limitations. However, the broad X-ray peaks for $\text{NaAlSi}_3\text{O}_8$ suggest probable occurrence as clay particles.

Similarly, although the 3.1-pound sample from the settling tank is the most representative sample of solids obtained, funding limitations have precluded any analysis. Nevertheless, the data and observations described above suggest that ultimate disposition of solids was roughly as set forth below:

DISPOSITION OF SOLIDS

	<u>Amount, lb</u>
Separator Sludge	5 to 15
Sludge in Surface Piping	20 to 50
Trapped on Filters	25 to 85
Disposal Well	<u>500 to 1000</u>
Total	550 to 1150

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12.9

Summary Discussion of Producing Characteristics

Several details of producing fluid chemistry suggest that the test of this well does not constitute a simple cause of "attic" hydrocarbon production.

The first indication is the low value of produced gas/brine ratio during the first day of the first flow test. Total gas content of the brine produced for several hours after fresh brine reached the wellhead (bottoms-up) was only about 85% of methane solubility in reservoir brine estimated using the procedures published by Haas et al. One possibility is that this initial brine production was from a lower portion of the sandstone that was isolated from the up-dip hydrocarbon cap by a shale break. This possibility is consistent with the observation in Section 12.2 to the effect that the use of the full 77 feet of estimated net sand in flow equations did not provide viable correlations for interpretation of the first drawdown and first buildup tests.

Additional complications in production interpretation due to changes in producing geometry are suggested by the variations in brine composition previously discussed in Section 12.7.4.4. The first observed anomalous concentrations were in the brine sample collected at 0300 hours on 9/19/80. The corrected brine production rate had increased about 6% during a 2-hour period preceding collection of this brine sample. Measured concentrations of several metallic species were much lower than for the prior or following samples. This behavior may represent initial "flush" production from a sand stringer that was not previously in flow communication with the well bore. Increase in the hydrocarbon production to values clearly in excess of solubility in reservoir brine began at about this same time.

The modest, but real increase in sodium content and the decrease in CO₂ content during the last several days, in combination with the high concentrations of arsenic, cadmium, and lead in the sample collected on 9/25/80, suggest continuing changes in reservoir geometry in relation to brine production. Whether these changes reflect depletion in the direction of pinch-outs, an overwhelming effect of gas drive from one or more gas caps, or other geometrical effect is conjectural.

12.10 Test Equipment Performance and Problems

12.10.1 Choke Manifold

A two-inch choke manifold, used for control of fluid flow, performed very well. The manifold was fabricated using DOE equipment in stock and mainly consisted of two Thornhill Craver Adjustable Chokes (Body No. 2520, Unitaper, 2-1/16", 10,000 PSI W.P.) and four WKM Pow-R-Seal gate valves (3-1/16", 10,000 PSI W.P.). This choke manifold will be used on future Eaton WOO tests.

12.10.2 Camco Turbine Meter

The Camco three-inch turbine meter readings were higher than the separator output turbine readings due to two-phase flow in the high pressure line from the wellhead. Successful recording of data from the meter was not accomplished by Reservoir Data,

Inc., because of a software problem. The meter output, however, was successfully recorded by IGT, commencing with the second flow test on August 16, 1980. The Camco turbine hardware performed very well and the meter will be used on future tests.

12.10.3 Halliburton Turbine Meter

Impulses from the three-inch turbine meter downstream of the separator were incompatible with IGT's Analog/Digital Converter, causing unreliable readings to be recorded by IGT. Because of this problem, Weatherly's hourly cumulative barrel readings from the Halliburton meter provided the best source of data on brine flow rates and total saltwater produced. Corrections have been made to obtain reliable digital recording from the meter for future well tests.

12.10.4 Foxboro Temperature Transmitter

Wellhead flowing temperature was measured by a Foxboro temperature transmitter installed in the high-pressure line between the wellhead and the choke manifold. The sensor was mounted in a tee on the side of the high-pressure line to sense liquid temperature and to avoid problems due to sand erosion. Temperature values are a few degrees low because the thermal well was not in the flow stream. Rather than protruding into the pipe, the bottom of the thermal well was located at the circumference of the pipe. As a result, measurements of the fluid temperature were low due to air cooling. The problem has not been successfully corrected at the time of this printing.

12.10.5 Carle Gas Chromatograph

The Carle Gas Chromatograph used in the field was selected to provide rapid analysis for samples that were not expected to contain appreciable amounts of natural gas liquids. Because of this, the instrument had two shortcomings for samples from this well. First, maximum operating temperature for the chromatography inlet and columns is about 160°F. This is lower than the gas sampling point temperature of about 185°F obtained during much of the third flow test. The result was a buildup of C6+ background due to condensation inside the instrument. Second, the C6+ determination for the instrument involves backflushing which results in interference between water vapor and the C6+ fraction. The field gas analyses reported were normalized with the assumption that the mole percent of C6+ was equal to that for pentanes. The Carle Gas Chromatograph will be used on future WOO tests, because high amounts of natural gas liquids are not expected to be encountered.

12.10.6 Bottomhole Fluid Sampler

Two attempts to obtain a downhole fluid sample using a Gearhart Industries sampler were unsuccessful. The two wireline runs, however, revealed the reasons for prior premature fillings and provided the basis for design modification.

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The sampler involves a rupture disc that separates liquid-filled space behind a floating piston from a chamber containing air at 1 atmosphere pressure. On both the Beulah Simon No. 2 Well and P. R. Girouard Well No. 1, failure of either the rupture disc or an associated "O" ring had triggered premature fillings. For this well, a higher strength rupture disc was used.

When the first sampler was recovered, the explosively driven cutter had been driven into the rupture disc. However, the disc had previously been domed upward by pressure such that it was not broken by the cutter. For the second run of the sampler, the cutter was left out so that detonation products from the small explosive charge would impinge directly upon the disc. Upon recovery, the disc was again found to be intact, but domed upward toward the explosive charge. The charge had detonated.

Engineering calculations revealed that the observed upward doming of the rupture disc required a pressure much greater than downhole pressure in the well. This great pressure is now believed to be the result of closure of the equalizing point between the wellbore and fluid behind the piston at the time of, or shortly after, exposing the sampler to wellhead pressure in the lubricator. Then, as temperature increased while lowering the sampler in the well, very high pressure was generated because thermal expansion of the trapped water exceeded that of the steel.

This failure mode explains the discrepancy between laboratory autoclave testing and downhole experience. In the laboratory autoclave, pressure increase is much less rapid than when charging a lubricator on the wellhead. Further, substantial temperature increase occurred in the laboratory autoclave before pressure was as high as the 4000 to 6500 psi representative of lubricators on geopressured wellheads. This portion of the sampler is being redesigned for future tests.

12.10.7 Filter System

Grain size measurements revealed that 60% to 90% of produced solids were smaller than the 50-micron filter elements used in the filter system. It is estimated that between 500 and 1,000 pounds of solids were injected into the disposal well. Smaller-micron filter elements can be used in the filter system, however frequent replacement of small-micron fiber filter cartridges during long-term production periods on a well such as the Koelemay No. 1 would be expensive and impractical. Evaluation of a self-cleaning 5-micron filter system has been proposed on a forthcoming WOO test well.

12.10.8 Separator Stability

Separator upsets occurred during testing, causing temporary flow of liquids out of the flare line. This problem was caused by rising disposal well pressure. As the injection pressure approached the preset separator operating pressure, the separator vessel would fill with liquids. The separator performed satisfactorily during three-phase separation, however constant attention was required because of the high disposal well pressure problem.

13.0**RETURN OF WELLS AND LOCATION TO OPERATOR**

On the morning of September 25, 1980, all concerned parties in the DOE Houston and Las Vegas offices and the Eaton office agreed to terminate the WOO test on the well. Little additional useful information could be obtained concerning the brine aquifer. Lear Petroleum Exploration, Inc. was contacted, and the company agreed to take over operation of the test well, disposal well, and location at midnight on September 26, 1980. The Lear takeover released Eaton Operating Company of the liability and the expense of plugging and abandonment of both wells and clean-up of the location. DOE-owned tubing and wellhead equipment left on location was later replaced by Lear.

14.0

CONCLUSIONS

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

<u>Item</u>	<u>Pre-Test Expectations</u>	<u>Actual Measurements</u>
Original Reservoir Pressure	9441 PSIA	9450 PSIA
Reservoir Temperature	240°F	260°F
Salinity	15,000 mg/l	15,000 mg/l
Gas-to-Water Ratio	35 SCF/BBL	31 SCF/BBL
Reservoir Size	1664 Acres	142.5 Acres (Minimum)

The measured reservoir temperature was 20 degrees higher than the corrected electric log temperature. Although there is no other verification of the 260°F measured temperature, it is believed to be correct. The implication here is that log temperatures and current correction methods can be subject to errors of 8% magnitude.

The natural gas content of only about 31 SCF/BBL, observed for several hours on September 12, 1980 was below expected solubility in the reservoir brine. Although laboratory recombination studies were not able to define gas solubility in reservoir brine, they did provide the surprising conclusion that a very small amount of oil from the well decreased apparent gas solubility.

The reservoir appears much smaller than originally anticipated, although the limits of the reservoir were not found during the flow tests. The reservoir is projected as much smaller because flow test data indicates a pinching out of the sand and a very restricted flow area.

The discovery of a commercial oil and gas well was unexpected. In retrospect, sidewall core data along with geological descriptions of the test zone and area indicated the possibility of free hydrocarbons updip in the reservoir. If the well had not been allowed to produce large amounts of brine, the updip hydrocarbons would not have reached the wellbore. Conventional industry thinking concerning brine disposal costs, high water-to-hydrocarbon producing formations, and well testing methods may not always be appropriate.

No corrosion and very little scaling were observed during the testing of this well. Chemical treatment required to prevent scaling would be minimal if long-term production were desired. It is possible that the oil produced during the testing acted as a chemical scale inhibitor.

The high amount of solids production is significant because of the potential long term effects of solids buildup in the disposal zone. No abrasion of the production equipment occurred because of the very small-grain sand and the relatively low flowing pressures.

Concentrations of mercury in the produced brine averaged 0.34 micrograms per liter. This value is well above the 0.10 micrograms per liter upper limit recommended by the U. S. Environmental Protection Agency for protection of aquatic organisms and for human consumption. Concentrations of boron averaged 45 milligrams per liter. This concentration is extremely toxic to plant life. Surface disposal of the produced brine would be precluded because of the mercury and boron concentrations.

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Photo 14-1 Approximately 14,000 BTU of Heat Energy being Generated every Second

15.0

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Eaton Industries of Houston, Inc.

Eaton Operating Co., Inc.

3104 Edloe, Suite 200

Houston, Texas 77027

(713) 627-9764

DOE CONTRACT NO. DE-AC08-80ET-27081
Eaton Industries of Houston, Inc.

APPENDIX A

LEAR PETROLEUM EXPLORATION, INC.

2202 TIMBERLOCH PLACE, SUITE 200
THE WOODLANDS, TEXAS 77380
PHONE 713/367-8250

September 26, 1980

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

Re: #1 Koelemay Well
Jefferson County, Texas

Gentlemen:

This is to confirm that Lear Petroleum Exploration, Inc. is going to take over operations on subject well effective 12:00 p.m., September 25, 1980 and releases Eaton from any further expenses or liabilities.

We would like to rent or pay in kind for the government-owned tubing presently in the well bore for a period of approximately two weeks. We would make arrangements for other rental equipment that is presently at the well site.

Very truly yours,

LEAR PETROLEUM EXPLORATION, INC.

W. E. Dunaway
Gulf Coast Division Manager

WED/pw

EATON OPERATING COMPANY, INC.

May 21, 1980

Lear Petroleum Exploration, Inc.
2022 Timberlock Place, Suite 200
The Woodlands, Texas 77380

Re: G. M. Koelemay Well #1
Jefferson County, Texas

Gentlemen:

This letter, if accepted by you and two signed copies thereof are returned to us by May 22, 1980, shall constitute the basis of an agreement between Lear Petroleum Exploration, Inc. (Lear) and Eaton Operating Company, Inc. (Eaton) as to the following matters.

I.

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

B. Lear has drilled the above referenced well to a total depth of 14,885 feet and has elected to plug the well as non-commercial.

II.

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

III.

A. Eaton shall be responsible for:

1. Obtaining all federal, state and local governmental permits required for such operations.
2. Providing insurance coverage through the length of the testing and research, at limits of \$40,000,000.00 liability and \$25,000,000.00 cost of well control (land).

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

4. Assumption of all liabilities associated with further operations of the well through plugging and the final clean up of the location.

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

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

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

B. Lear shall be responsible for:

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

IV.

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

V.

It is agreed that the name and address of the surface and mineral owner and Lessor in LEAR's Oil, Gas and Mineral Lease is:

Glen M. Koelemay and wife, Amber Koelemay
RDF 1, Box 741H, Winnie, Texas 77665

VI.

Eaton hereby agrees to indemnify and hold Lear et al harmless from any and all claims for injury or damages the cause of which may occur in connection with Eaton's operation of the said well, limited to \$40,000,000.00 liability and \$25,000,000.00 well control as described in Section III-A-2.

VII.

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

VIII.

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

If to Lear:

Lear Petroleum Exploration, Inc.
2022 Timberloch Place, Suite 200
The Woodlands, Texas 77380

Attention:
Telephone: 713/367-8520

If to Eaton:

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

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

IX.

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

X.

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

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

Sincerely yours,

EATON OPERATING COMPANY, INC.

By

B. A. Eaton
President and Project Manager

ACCEPTED AND AGREED TO THIS 21st DAY OF May, 1980.

LEAR PETROLEUM EXPLORATION, INC.

By

Attorney In Fact

EXHIBIT I
TERMS AND CONDITIONS OF PURCHASE ORDER

1. **INSPECTION AND ACCEPTANCE** — Inspection and acceptance will be at destination, unless otherwise provided. Until delivery and acceptance, and after any rejections, risk of loss will be on the Contractor unless loss results from negligence of the Purchaser.
2. **VARIATION IN QUANTITY** — No variation in the quantity of any item called for by this contract will be accepted unless such variation has been caused by conditions of loading, shipping, or packing, or allowances in manufacturing processes, and then only to the extent, if any, specified elsewhere in this contract.
3. **DISCOUNTS** — Discount time will be computed from date of delivery at place of acceptance or from receipt of correct invoice at the office specified by the Purchaser, whichever is later. Payment is made, for discount purposes, when check is mailed.
4. **FOREIGN SUPPLIES** — This contract is subject to the Buy American Act (41 CFR-1-6.10405).
5. **CONVICT LABOR** — In connection with the performance of work under this contract, the Supplier agrees not to employ any person undergoing sentence of imprisonment except as provided by (41 CFR-1-11.204).
6. **OFFICIALS NOT TO BENEFIT** — No member of, or delegate to, Congress, or resident commissioner, shall be admitted to any share or part of this contract, or to any benefit that may arise therefrom; but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.
7. **COVENANT AGAINST CONTINGENT FEES** — The Supplier warrants that no person or selling agency has been employed or retained to solicit or secure this contract upon any agreement or understanding for a commission, percentage, brokerage, or contingent fees, excepting bona fide employees or bona fide established commercial or selling agencies maintained by the Supplier for the purpose of securing business. For breach or violation of this warranty the Purchaser shall have the right to annul this contract without liability or in its discretion to deduct from the contract price or consideration, or otherwise recover the full amount of such commission, percentage, brokerage, or contingent fee.
8. **FEDERAL, STATE AND LOCAL TAXES** — Except as may be otherwise provided in this contract, the contract price includes all applicable Federal, State, and local taxes and duties in effect on the date of this contract but does not include any taxes from which the Purchaser, the Supplier on this transaction is exempt.
9. Goods must be shipped as per instructions; otherwise any extra handling charge will be billed back to seller.
10. In the event of Seller's failure to deliver as and when specified, Purchaser reserves the right to cancel this order, or any part thereof, without prejudice to its other rights, and seller agrees that purchaser may return part or all of any shipment so made and may charge Seller with any loss or expense sustained as a result of such failure to deliver.
11. In the event any article sold and delivered hereunder shall be covered by any patent, copyright, or application therefore, Seller will indemnify and save harmless Purchaser from any and all loss, costs, or expenses on account of any and all claims, suits or judgments on account of the use or sale of such article in violation of rights under such patent, copyright, or application.
12. In the event any article sold and delivered hereunder shall be defective in any respect whatsoever, seller will indemnify and save harmless purchaser from all loss or the payment of all sums of money by reason of all accidents, injuries, or damages to persons or property that may happen or occur in connection with the use or sale of such article and are contributed to by said defective condition.
13. If Seller performs services or constructs, erects, inspects or delivers hereunder, seller will indemnify and save harmless buyer from all loss or the payment of all sums of money by reason of all accidents, injuries, or damages to persons or property that may happen or occur in connection therewith.
14. Seller agrees not to release any advertisement copy mentioning Purchaser or quoting the opinion of any Purchaser's employees unless such copy is approved by Purchaser before release.
15. Seller represents and warrants that no Federal or state statute or regulation, or municipal ordinance, has been or will be violated in the manufacturing, sale and delivery of any article or service sold and delivered hereunder and if such violation has or does occur, seller will indemnify and save harmless purchaser from all loss, penalties, or the payment of all sums of money on account of such violation.
16. The terms and conditions of sale as stated in this order govern in event of conflict with any terms of Seller's proposal, and are not subject to change by reason of any written or verbal statements, by Seller or by any terms stated in Seller's acknowledgment unless same be accepted in writing.
17. Our purchase order number must appear on all applicable documentation, i.e. invoice, delivery tickets and freight bills.
18. Submit original and four copies of your invoice to Eaton Industries of Houston, Inc.
19. All invoices must be accompanied by signed delivery note.
20. The Vendor agrees that the prices charged to the Purchaser will be as low as or lower than those charged the suppliers most favored customer in addition to the discount for prompt payment.

Approved By: _____

Title: _____

Date: _____

EXHIBIT II

ADDITIONAL
TERMS AND CONDITIONS OF PURCHASE ORDER

Except where the word "Contractor" is used, substitute the word "Subcontractor", and where the word "Government" is used, substitute the word "Purchaser".

Applies to Subcontracts or purchase orders which exceed \$2,500

1. "Employment of the Handicapped" (41-CFR-1-12.904)

Applies to Subcontracts or purchase orders which exceed \$10,000

1. "Notice and Assistance Regarding Patent and Copyright Infringement" (41-CFR-9-9.104)
2. "Utilization of Small Business Concerns" (41-CFR-1-1.710-3)
3. "Utilization of Labor Surplus Area Concerns" (41-CFR-1-1.805-3)
4. "Utilization of Minority Business Enterprises" (41-CFR-1-1.1310.2)
5. "Equal Opportunity" (41-CFR-1-12.803.12)
6. "Disabled Veterans and Veterans of the Vietnam Era"
7. "Termination for Convenience of the Government" (41-CFR-1-8.705-1)
8. "Pricing Adjustment" (41-CFR-1-7.102-20)
9. "Walsh Healy Public Contracts Act" (41-CFR-1-12.605)

Applies to Subcontracts or purchase orders which provide for the performance of Service

1. "Contract Work Hours and Safety Standard Act - Overtime Compensation" (41-CFR-1-12.303)
2. "Service Contract Act of 1965 - As Amended" (41-CFR-1-12.904)

Applies to Subcontracts or purchase orders which exceed \$100,000

1. "Cost Accounting Standard" (41-CFR-1-3.1204-1)
2. "Authorization and Consent" (41-CFR-9-9.102-1)
3. "Examination of Records" (41-CFR-1-7.103-3)
4. "Audit and Record" (41-CFR-1-3.814.2)
5. "Subcontractor Cost and Pricing Data" (41-CFR-1-3.814-3)
6. "Price Reduction for Defective Cost or Pricing Data" (41-CFR-1-3.814-1)
7. "Notice of Labor Disputes"

APPENDIX B

24-HOUR WORKOVER RIGS
DESCRIPTION AND SPECIFICATIONS

RIG 76

Franks 550 Series Explorer double drum back-in rig, fully equipped for 24-hour a day operations. Rig power is supplied by 12V-71 Detroit Diesel engine driven by an Allison 5860 series transmission. Rig has water-cooled Hydrotarder brake system. The 102 foot derrick has a 250,000 pound hook load capacity. Rig is equipped with approximately 12,000' of 9/16" line sandline. Fulltime Rig Supervisor with Crew Chief, derrickman and two crewmen included on 12-hour tours.

POWER PLANT

Twin 30 KW generators, each powered by a Detroit Diesel 3-71 engine, are mounted on a utility skid.

MUD PUMP

One Gardner-Denver PA-8 Triplex mud pump powered by a Detroit Diesel 8V-71 engine. Pump has remote controls that can be operated from the rig floor.

SUBSTRUCTURE

The substructure adjusts to provide 14 feet rotary beams to ground clearance with a Gardner-Denver 12 $\frac{1}{2}$ " rotary table. The rig has V-door, pipe racks and catwalk.

MUD TANKS

Two 200 barrel mud tanks, equipped for mud mixing complete with a Brandt "Junior" shale shaker. One tank is partitioned into three compartments; 2 mud compartments and one "slugging" compartment. The second tank is partitioned into 2 mud compartments. Each mud compartment is equipped with 2 bottom jets for mud agitation. Mud mixing pump is a 5 x 6 inch centrifugal pump powered by a Detroit Diesel 4-71 engine mounted on a separate hopper skid.

BOP and CLOSING UNIT

Double 6"-1500 Series BOP with independent hydraulic closing system.

TONGS

Foster Type 5493R to handle tubing ranging from 2-3/8" through 3-1/2".

SWIVEL

Brewster Swivel with 150 ton capacity.

TRAVELING BLOCK

McKissick 150 ton, 4-sheave, grooved for 1" drill line.

FUEL OIL and LUBRICANT STORAGE

One skid with 2000 gallon diesel storage and 5 independent compartments for storage of various oils.

OFFICE

Skid-mounted Elder 8' x 14' air conditioned unit. Sleeping accommodations for WellTech Rig Supervisor and company man.

RIG 77

Ideco BIR-750 single drum back-in rig, fully equipped for 24-hour a day operations. Rig power is supplied by twin Detroit Diesel 8V-71 engines each driven by an Allison 5860 series transmission. The rig can operate either engine independently or both together. The 112 foot derrick has a 354,000 pound hook load capacity. Both Parkersburg V-80 hydramatic brakes and water circulating brakes are supplied. Full-time Rig Supervisor with Crew Chief, derrickman and two crewmen included on 12-hour tours.

POWER PLANT

Twin 60 KW generators, each powered by a Detroit Diesel 4-71 engine are mounted on a utility skid.

MUD PUMPS

Gardner-Denver PA-8 Triplex mud pump powered by a Detroit Diesel 8V-71 engine and Gardner-Denver PZ-7 powered by 3412 Caterpillar Design Engine. Both pumps have remote controls that can be operated from the rig floor. A 5 x 6 inch centrifugal pump, powered by a Detroit Diesel 4-71 engine, is mounted on the number 1 pump skid and is manifolded so that either mud pump can be charged.

SUBSTRUCTURE

The substructure hydraulically scopes to provide 16 feet rotary beams to ground clearance. The substructure is rated for a rotary load of 500,000 pounds. A Gardner-Denver 17 1/2 rotary table is installed. The rig has V-door, pipe racks and catwalk complete with lay-down line. A 7 foot pony structure can be supplied at an additional charge of \$100 per day.

MUD TANKS

Two 200 barrel mud tanks, equipped for mud mixing complete with a Brandt shale shaker. One tank is partitioned into three compartments; 2 mud compartments and one "slugging" compartment. The second tank is partitioned into 2 mud compartments. Each mud compartment is equipped with 2 bottom jets for mud agitation. Mud mixing pump is a 5 x 6 inch centrifugal pump powered by a Detroit Diesel 4-71 engine mounted on a separate hopper skid.

SPECIAL CONDITIONS AND RATES

Rig 76 and related equipment, 24 hours/day.....\$160.00/hour

Rig 77 and related equipment, 24 hours/day.....\$185.00/hour

Moving to location from base, rigging up, rigging down and moving back to base is charged at posted rig rates plus actual trucking cost, unless any trucking and rig time can be saved by moving from or to another location.

When round trip from base is in excess of 110 miles an additional charge of \$40.00 per man will be charged (8 men for total of \$320/day).

Fuel will be charged for actual gallons used at prevailing prices. (Fuel may be billed directly to customer; or billed to WellTech, Inc. and billed to customer on daily job tickets.)

Any dirt work needed to level rig up and prepare location for related equipment will be charged to customer at prevailing rates.

Rubber goods, slip segments, and tong dies will be charged at the manufacturer's current list price.

When our equipment remains on location for more than twelve hours, WellTech will be granted thirty minutes at the start of each tour to perform routine servicing and maintenance without any loss of revenue.

Trucking will be charged both ways on special equipment at published rates or at cost if hauled by a trucking company.

Upon completion of job, fluid end pump parts to redress pump will be charged at the manufacturer's current list price.

Cleaning of mud tanks and mud system will be charged at regular rig rates.

CONDITIONS AND TECHNICAL PROVISIONS

CTP-01. LOCATION

Well Name and Number G. M. Koelemay #1 County Jefferson
State Texas Field Name Wildcat Well Location and
Land Description _____

CTP-02. COMMENCEMENT AND COMPLETION

The Subcontractor shall complete mobilization within five (5) calendar days after the date of receipt of Notice to Proceed and shall complete the entire work under the Unit Price Schedule _____ days after the date of receipt of Notice to Proceed. The contract completion date will be extended by the amount of time spent on Contractor-Directed Operations and Standby, to the extent that is deemed necessary.

CTP-03. STATEMENT OF WORK

A. General Description of Work. The Subcontractor's work consists of furnishing all personnel, equipment, materials and services, and supplies as specified herein, for conducting the following work: See Tentative Drilling Program, Attachment _____

Clean out and complete test well.

Drill salt water disposal well.

B. Minimum Equipment and Services. The minimum equipment, facilities, services, and items required to complete the work is specified in CTP-07. All contractor-furnished items will be delivered to and picked up from the drill site by others. The minimum equipment and services designated to be furnished and operated by the Subcontractor will be at no additional cost to the Contractor.

C. Workweek and Personnel Requirement. The Subcontractor shall furnish minimum three man qualified drilling crew, including toolpusher, to maintain a 24-hour day, 7-day week operation.

CTP-04. MUD PROGRAM

Contractor agrees to furnish all mud additives and chemicals and will arrange to purchase all necessary engineering services. Mud program will be designed as dictated by hole conditions.

CTP-05. STRAIGHT HOLE SPECIFICATIONS

Except as authorized by the Contractor, the maximum allowable deviation of the hole is not to exceed one degree per 100-feet and not to exceed five degrees total depth.

CTP-06. PROPOSED CORING PROGRAM

CTP-07. MINIMUM EQUIPMENT AND SERVICES

	To Be Provided By And At Expense Of	
	<u>Contractor</u>	<u>Subcontractor</u>
1. Trucking service and other transportation, hauling or winching services as required to move Subcontractor's property to location, rig up Subcontractor's rig, and remove all of Subcontractor's property from location.		XX
2. Drilling bits, reamers, stabilizers, reamer cutters, and other drilling tools as required.	XX	
3. Fishing tool services and fishing tool rental.	XX	
4. Derrick timbers.		XX
5. Normal strings of drill pipe and drill collars. (See Items No. 43 and 44)		XX
6. Conventional drift indicator.		XX
7. Earthen mud pits and reserve pits.	XX	
8. Steel mud tanks if required.		XX
9. Necessary pipe racks and rigging up material.		XX
10. Normal storage for mud and chemicals.		XX
11. Necessary spools, flanges and fittings to connect blowout preventers.		XX

To Be Provided By
And At Expense of

	<u>Contractor</u>	<u>Subcontractor</u>
12. Furnish and maintain adequate roadway to location, rights-of-way, including rights-of-way for fuel and water lines, river crossings, highway crossing, gates and cattle guards.	<u>XX</u>	<u></u>
13. Staked, levelled and compacted location, including earth pits.	<u>XX</u>	<u></u>
14. Rat and mouse holes to meet subcontractor's requirement.	<u></u>	<u>XX</u>
15. Test tanks with pipe and fittings.	<u>XX</u>	<u></u>
16. Separator with pipe and fittings.	<u>XX</u>	<u></u>
17. Labor to connect and disconnect Subcontractor's mud tank.	<u></u>	<u>XX</u>
18. Labor to disconnect and clean test tanks and separator.	<u>XX</u>	<u></u>
19. Drilling mud, chemicals, lost circulation materials and other additives.	<u>XX</u>	<u></u>
20. All tubular goods, miscellaneous line pipe and fittings.	<u>XX</u>	<u></u>
21. All testing tools including inflatable and retrievable packers.	<u>XX</u>	<u></u>
22. Special tools, casing scraper, etc.	<u>XX</u>	<u></u>
23. Special mud pump capacity in excess of rig requirements.	<u>XX</u>	<u></u>
24. Wireline split and conventional core barrels and wireline core catchers: two each ten-foot long split core barrel; one each twenty-foot long conventional barrel.	<u>N/A</u>	<u></u>
25. Conventional core bits, barrels and catchers.	<u>XX</u>	<u></u>
26. Diamond wireline core bits.	<u>N/A</u>	<u></u>
27. Cement and cementing service.	<u>XX</u>	<u></u>
28. Logging services.	<u>XX</u>	<u></u>

To Be Provided By
And At Expense Of

	<u>Contractor</u>	<u>Subcontractor</u>
29. Directional, caliper, or other special services.	XX	
30. Gun or jet perforating services.	XX	
31. Core boxes, wrapping supplies, and storage facilities.	XX	
32. Formation testing, hydraulic fracturing, acidizing, and other related services.	XX	
33. Equipment for drill stem testing.	XX	
34. Mud Logging Services.	XX	
35. Sidewall Coring Services.	XX	
36. Welding Service (Except for Subcontractor's equipment).	XX	
37. Casing, tubing, liners, screen, float collars, guide and float shoes, and associated equipment.	XX	
38. Casing scratchers and centralizers.	XX	
39. Wellhead and connections for all equipment to be installed in or on well or on the premises for use in connection of well.	XX	
40. Water at Source and Water Hauling Service.	XX	
41. Water storage tanks <u>1000 gallon</u> capacity.		XX
42. Fuel _____ for Subcontractor's equipment. Contractor to reimburse Subcontractor for diesel fuel in excess of _____ per gallon.	XX	
43. Drill pipe. _____		
44. Drill collars. _____		
45. Handling tools, clamps, etc., for each drilling assembly.		
46. Weight indicator.		XX

To Be Provided By
And At Expense Of

	<u>Contractor</u>	<u>Subcontractor</u>
47. If applicable, drill pipe protectors for Kelly joint and each joint of drill pipe running inside of casing for use with normal strings of drill pipe.	XX	
48. Automatic driller (Optional).	N/A	
49. Materials for "boxing in" rig and derrick.	N/A	
50. Conventional core barrel.	XX	
51. Drilling recorder-minimum 2-pin.	XX	
52. Extra labor for running and cementing casing.	XX	
53. Casing tools.	XX	
54. Running of casing-conductor.	XX	
55. Running of casing-surface.	XX	
56. Running of casing protection, if applicable.	XX	
57. Running of casing production, if applicable.	XX	
58. Running of casing liner, if applicable.	XX	
59. Power casing tongs.	XX	
60. Tubing tools.	XX	
61. Power tubing tong.	XX	
62. Swabbing unit with swabbing line	XX	
63. Swab.	XX	
64. Swab lubricator.	XX	
65. Swab rubbers.	XX	
66. Light plant-adequate capacity for night-time operations, Subcontractor requirements.		XX

To Be Provided By
And At Expense Of

	<u>Contractor</u>	<u>Subcontractor</u>
67. Drill rig-minimum failing 1500 rotary rig or approved equal for continuous wireline coring and drilling to $\pm$ 1500 feet.	N/A	
68. Two adequate circulating pumps and adequate mud mixing pumps.		XX
69. 1000 gallon water truck with driver for hauling water within two miles of work sites.	N/A	
70. Minimum of one two-way communications system.	N/A	
71. IADC Daily Drilling Report, Bit Record and Tally Forms.		XX

The above Subcontractor designated items are the minimum acceptable requirements for the Subcontractor drilling equipment. This is not intended to be a complete list of items to be furnished by the Subcontractor. The Subcontractor is required to furnish all drilling maintenance tools, materials, and equipment not herein designated, but which are normal components for a complete drilling rig required for drilling and testing operations described in these specifications.

CTP-08. UNIT PRICE SCHEDULE ITEMS DEFINED

Paragraph headings in this Special Condition correspond to items of the Unit Price Schedule.

1. Mobilization. The Subcontractor shall move in and rig up his equipment, rig up any lower-tier Subcontractor's equipment, and pick up first drilling assembly. Mobilization shall be considered complete when all the equipment is on location and rigged up ready to spud. The Subcontractor shall be paid for the above mobilization work under Item 1 of the Unit Price Schedule.

2. Contractor-Directed Operations. Operations under this category shall include, but are not limited to: Contractor-furnished surveying, plug backs, drilling, coring, reaming, hydrologic testing, inserting and retrieving casing, placing cement and regaining lost circulation. All operations will be done as directed by the Contractor. All work on an hourly rate basis shall be performed with a full complement of operating personnel and at the direction of the Contractor. If it becomes necessary to shut down Subcontractor's rig for repairs while performing work on an hourly rate basis, Subcontractor shall be allowed compensation for such repair time at the applicable hourly rate. The number of hours devoted to repair work for which the Subcontractor may be compensated shall be limited to an accumulated total of 12 hours for each 15 day period.

Contractor-directed operations will be paid for Item 02. of the Unit Price Schedule.

3. Standby Ready. When directed by the Contractor, the Subcontractor shall cease all operations and standby in a ready condition. A full complement of personnel and equipment shall be maintained at the work site ready to resume operations immediately. Operations under this category shall include Geophysical Logging, Cement Hardening Time, or any operations not requiring the use of rig engines or drill assembly. Standby ready time will be paid under Item 03. of the Unit Price Schedule.
4. Demobilization. Upon completion of the work under this Subcontract, the Subcontractor shall remove all rubbish and debris from the drill site and shall remove all of his equipment within ten calendar days. The Subcontractor will not be responsible for levelling the work site or draining and backfilling pits. Demobilization will be paid under Item 04. of the Unit Price Schedule.

CTP-09. RECORDS AND OBSERVATIONS

Providing the following records and observations shall be a part of the Subcontractor's general responsibility for which no additional payment will be made.

1. A Daily Drilling Report shall be kept on the IADC official Standard Daily Drilling Report. The Unit Price Schedule quantities for pay estimate purpose will be taken from the IDAC Daily Drilling Report. The general remarks section shall contain an accurate record of hole conditions, work performed, and time required for all work to the nearest quarter-hour. The original and two copies of the Daily Drilling Report shall be submitted to the Contractor or his authorized representative.
2. Bit Records shall be maintained daily and posted in the doghouse. A complete bit record shall be furnished the Contractor at the completion of a hole. Records must show bit types, sizes, footages, depths, rotary speeds, bit weights, manufacturer, and serial number.
3. Accurate Pipe Tallies shall be the Subcontractor's responsibility and shall be available at the drill site for inspection at all times. Copies of steel tape measurements of drill pipe and casing shall be furnished by the Contractor.

CTP-10. SUBSURFACE INFORMATION

1. The subsurface information and data furnished both in these specifications and at the Contractor's office are not intended as representations or warranties, but are furnished for information only.
2. It is anticipated that the information contained herein generally represents the conditions that will be encountered in the performance of the Subcontract; however, any interpretation or conclusion reached by the Subcontractor in preparing his Unit Price Schedules will be his sole responsibility.

CTP-11. ACCOMMODATIONS

The Subcontractor will be required to make his own arrangements with his employees for housing and feeding. The Subcontractor may locate toolpusher's house trailer near the drilling location, as designated by the Contractor.

CTP-12. DERRICK MISALIGNMENT

If, at any time, the Subcontractor's derrick becomes misaligned over a hole, the Subcontractor shall be required to commence realignment operations within eight hours of the misalignment. If such misalignment occurs as the result of fault or negligence on the part of the Subcontractor, the Subcontractor shall receive no compensation for the time or cost spent in realignment. If the misalignment is not the fault of, or caused by, Subcontractor negligence, the Subcontractor shall be compensated under Item 2. of the Unit Price Schedule.

CTP-13. LOSS OF HOLE

A hole shall be termed "lost" if the Contractor determines that the condition of the hole will prevent its successful completion, or if for any reason the Contractor deems it impractical to continue drilling. If the Contractor determines that a hole has been lost before required depth has been attained, and that further attempts to complete it will be impractical, he shall order work on the hole stopped, shall investigate the circumstances in contributing to its loss, and shall notify the Subcontractor of his decision in writing. The Contractor may, at his option, order the commencement of work at an alternate location.

Contractor shall assume liability, while work is being performed under Contractor-directed operations, for loss of, damage to, or destruction of the hole, Subcontractor's in-hole equipment, including, but not limited to, drill pipe, drill collars, subs, stabilizers, and bits, unless such loss, damage, or destruction shall be caused by the Subcontractor's fault or negligence.

CTP-14. ABANDONMENT

In the event that, prior to completion of the work required, a hole covered by this Subcontract is abandoned, upon direction of the Contractor, the Subcontractor will be paid for work performed under the applicable items of the Unit Price Schedule.

The term "abandonment" as used in this paragraph shall mean abandonment to suit the convenience of the Contractor, as directed by the Contractor, under conditions which do not come within the scope of the paragraph entitled "Loss of Hole" of these specifications.

CTP-15. STANDARD FOR PRESSURE VESSELS

All Subcontractor's compressed air equipment and accessories shall be designed, fabricated, inspected, and certified in accordance with the SAME Boiler and

Pressure Vessel Code, Section VIII. For equipment fabricated under the 1968 Code, either Division I or Division II (but not both) of the Code may be used.

CTP-16. PRESERVATION OF ANTIQUITIES, WILDLIFE, AND LAND AREAS

Federal law provides for the protection of antiquities located on land owned or controlled by the U. S. Government. Antiquities include Indian graves, or campsites, relics, and artifacts. The Subcontractor shall control the movements of his personnel and his Subcontractor's personnel at the jobsite to ensure that any existing antiquities discovered thereon will not be disturbed or destroyed by such personnel. It shall be the duty of the Subcontractor to report the existence of any antiquities so discovered. The Subcontractor shall also preserve all vegetation except where such vegetation must be removed for survey or construction purposes. Further, all wildlife shall be protected.

CTP-17. RESPONSIBILITY FOR LOSS OF OR DAMAGE TO EQUIPMENT

1. Subcontractor's Surface Equipment. Subcontractor shall be liable at all times for damage to or destruction of Subcontractor's surface equipment including all drilling tools, machinery, and appliances for use above the surface and for any other type of equipment including in-hole equipment when such in-hole equipment is above the surface, regardless of when or how such damage or destruction occurs. The Contractor shall be under no liability to compensate the Subcontractor for any such loss except loss of damage thereto caused by negligence of the Contractor, its agents, or employees.
2. Loss of Tools in the Hole
 - a. Contractor-Directed Operations. When it is necessary to fish for tools in the hole, while working under Contractor-Directed Operations, the Subcontractor shall notify the Contractor or his authorized representative of the existing conditions immediately, to be confirmed in writing as soon as practicable, and initiate such action as is required to commence fishing operations as soon as practicable. The Contractor will review and evaluate the circumstances resulting in the loss of tools in the hole.
 - i. If the investigation by the Contractor shows that the Subcontractor was neither negligent nor in violation of good drilling practice, the Subcontractor will not be held responsible for costs resulting from the loss of tools or for costs of fishing efforts conducted to recover lost tools. The value of Subcontractor-owned tools lost or damaged in the hole during hourly rate operations will be equitably compensated.
 - ii. If the Contractor's investigation shows that the Subcontractor was negligent or was in violation of good drilling practice in the performance of his duties, the Subcontractor will not be compensated for the value of Subcontractor-owned tools or equipment which may have been lost or damaged. Additionally, the Subcontractor

will be held responsible to the Contractor for the value of any Contractor-furnished tools or equipment which may be lost or damaged. All costs incident to such loss of or damage to the Contractor-furnished tools or equipment will be determined by the negotiated agreement of the parties.

iii. Any dispute concerning a question of fact under this paragraph iii. shall be subject to Article 11, "Disputes", of the General Provisions.

- b. Contractor-Furnished Equipment. Except as provided for in paragraph ii. above, "Loss of Tools in the Hole", all machinery, tools, materials and equipment furnished by the Contractor, shall, at the completion or abandonment of the hole, be returned to the Contractor in as good condition as when received by the Subcontractor, ordinary wear and tear excepted. The Subcontractor shall be liable to the Contractor for any loss or damage to such equipment beyond such ordinary wear and tear, and for loss or damage due to the negligence or carelessness of the Subcontractor.

CTP-18. CONTRACTOR MINIMUM EQUIPMENT REQUIREMENTS AND STANDARDS

The following American Petroleum Institute Standards and Recommended Practices of the latest issue, as of the date of bid opening, are a part of these specifications whenever applicable to standardized equipment.

1.	API Std. 4A	Specifications for Steel Derricks
2.	API Std. 4E	Specifications for Drilling and Servicing Structures
3.	API Std. 7	Specification for Rotary Drilling Equipment
4.	API Std. 8A	Specification for Hoisting Equipment
5.	API Std. 9A	Specification for Wire Rope
6.	API RP-5C1	Recommended Practice for Care and Use of Casing, Drill Pipe and Tubing
7.	API RP-9B	Recommended Practice on Application, Care and Use of Wire Rope for Oil Field Service
8.	API RP-13B	Recommended Practice and Standard Procedures for Testing Drilling Fluids
9.		Manufacturer's Ratings Shall Apply for Equipment not Covered by the API Standards.

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APPENDIX C

APPENDIX "C"
SUMMARY OF RIG OPERATIONS
LEAR G. M. KOELEMAY WELL NO. 1

RE-ENTRY OF TEST WELL

<u>Report Date</u>	<u>Day No.</u>	<u>Operations</u>
6-20-80	1	Started moving in WellTech rig number 76.
6-21-80	2	Moving in and rigging up.
6-22-80	3	Continued rigging up. Picked up kelly and swivel. Nipped up the blowout preventers.
6-23-80	4	Finished nipping up and testing the blowout preventers. Drilled the rat hole. Picked up the bottom hole assembly.
6-24-80	5	Started running in the hole with 2-3/8" tubing and a cement mill. Installed kelly and circulated the well bore at 6000'. Continued running tubing.
6-25-80	6	Finished running tubing to 11,030', where barite fill was encountered. Washed to the top of cement at 11,055'. Circulated the well bore and conditioned mud to 16.5 pounds per gallon.
6-26-80	7	Drilled hard cement from 11,055' to 11,100'. Shut down temporarily to repair rig pumps.
6-27-80	8	Completed pump repairs. Drilled cement to 11,289'. Started pulling out of the well bore with the tubing string.
6-28-80	9	Finished pulling out of the well bore. Ran back in with a new cement mill to 11,289'. Drilled cement from 11,289' to 11,317'.
6-29-80	10	Washed from 11,317' to the top of the cement retainer at 11,403'. Circulated the well bore and conditioned mud. Pressure-tested the old perforations to 1600 psi surface pressure (19.2 pound per gallon equivalent mud weight at total depth). Pulled out of the well bore with the tubing and cement mill. Rigged up a wireline lubricator and ran a Dialog casing caliper tool from 11,159' to the surface. Installed a Halliburton RTTS packer on the 2-3/8" tubing and started running into the well bore.

<u>Report Date</u>	<u>Day No.</u>	<u>Operations</u>
6-30-80	11	Finished going in hole. Set the RTTS packer at 11,109' and pressure-tested the tubing/casing annulus to 1000 psi. Opened the packer circulating valve and displaced the tubing with 42 barrels of salt water to differentially pressure-test the well bore. Closed the circulating valve in the packer and bled off the surface tubing pressure. Observed 0.75 barrels of backflow, and then the well ceased flowing. Observed no further flow for 15 minutes. Opened the circulating valve and displaced the salt water in the tubing with mud. Pulled out of the well bore with the tubing string and the RTTS packer. Started running back in the well with the tubing and a cement mill to drill out the cement retainer at 11,403'.
7-1-80	12	Finished running in the well. Drilled the EZSV cement retainer at 11,403'. Drilled and washed to 12,604'. Circulated and conditioned the mud. The bottom mud indicated 650 gas units when circulated to the surface and weighed 15.3 pounds per gallon.
7-2-80	13	Pulled out of the well bore with the tubing string and mill. Ran a gauge ring and junk basket on electric wireline to 12,603'. Started nipping down the blowout preventers.
7-3-80	14	Nipped down the blowout preventers and installed the tubing head. Nipped up the blowout preventers on the tubing head and pressure-tested. Ran the 2-3/8" tubing into the well at 11,553' and seated it in the tubing head. Started nipping down the blowout preventers.
7-4-80	15	Finished rigging down the blowout preventers and installed the tree. Displaced mud with 9.0 pound per gallon salt water. Ran a gamma-ray correlation log from 11,668' to 11,393'. Ran in the hole with a 1-9/16" O.D. through-tubing perforating gun, but the gun would not pass below 11,681', due to thick mud.
7-5-80	16	Pulled the gun and added weight bars to the gun assembly. Ran back into the tubing and perforated the casing from 11,658' to 11,678' with four shots per foot. Ran in the tubing with another perforating gun, but the gun failed to detonate. Pulled back out of the hole. Rigged up an Otis coiled tubing unit to wash salt water-contaminated

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7-6-80

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mud from the well bore. Ran in the tubing and washed from 11,670' to 11,900' while flowing the well. Pulled the coiled tubing string out of the well and rigged the Otis equipment down.

Rigged up Welex and perforated the interval 11,720' to 11,740' with four shots per foot. Ran a gamma-ray correlation log from 11,780' to 11,458'. Perforated the following intervals by making multiple wireline runs with a 1-9/16" O.D. through-tubing perforating gun: 11,720' - 11,740', 4 shots per foot; 11,740' - 11,760', 8 shots per foot; 11,760' - 11,780', 8 shots per foot; and 11,700' - 11,720', 4 shots per foot.

7-7-80

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Continued perforating the following intervals: 11,700' - 11,720', 4 shots per foot; 11,680' - 11,700', 8 shots per foot; 11,600' - 11,680', 4 shots per foot; 11,639' - 11,660', 8 shots per foot. Released the drilling rig at 8:00 p.m. Starting moving the rig to the saltwater disposal well site. The shut-in tubing pressure was 3900 psi.

APPENDIX D

APPENDIX "D"
SUMMARY OF RIG OPERATIONS
LEAR G. M. KOELEMAY SWD WELL NO. 1

DISPOSAL WELL DRILLING

<u>Report Date</u>	<u>Day No.</u>	<u>Operations</u>
7-1-80	—	14" Nominal O.D. (.357" wall thickness) structural casing was driven to 75' below ground level with 125 blows per foot with a D-12 hammer. An 8" diverter system and a 12" hydril blowout preventer was installed on the drive pipe.
7-8-80	1	Moving rig off test well to disposal well site.
7-9-80	2	Rigging up WellTech Rig No. 76.
7-10-80	3	Spotting rig over center of hole. Rigged up flow lines, shale shaker, rotary drive, Totco recorder, desander, and hydril lines. Drilled rat hole.
7-11-80	4	Finished drilling rat hole and mouse hole. Laid down kelly and picked up short kelly. Repaired pump and waited for parts for same. Spudded well at 5:00 p.m. on 7/10/80 and started to drill 12-1/4" hole. Pulled out of the hole to change jets and ran back in hole to 40 feet to continue drilling.
7-12-80	5	Continued drilling for 9-1/2 hours. Unloaded 9-5/8" casing. Installed tongs and repaired mouse hole. Pulled out of the hole and laid down drill pipe. Picked up 2 stabilizers and 6 drill collars. Ran in hole and drilled to 460'.
7-13-80	6	Layed down 6 joints of drill pipe and picked up 6 drill collars. Drilled for 10-1/2 hours and ran inclination survey to 746' (1/2"). Repaired geolograph air line and drilled to 1130'.
7-14-80	7	Drilled for 4-1/2 hours. Stopped drilling to repair pump. Drilled to 1518' and ran inclination survey (1/4"). Circulated and conditioned mud. Pulled out of hole. Started to rig up casing tools.
7-15-80	8	Made up guide shoe and float collar and spaced out 5 centralizers on bottom 3 joints. Ran 9-5/8"

<u>Report Date</u>	<u>Day No.</u>	<u>Operations</u>
		O.D. 43.5 lbs/ft N-80 LT&C casing with shoe at 1517'. Rigged up cementing head and cementing lines. Cemented casing with 12.7 ppg lead slurry of 450 sacks of Halliburton light with 3% salt. The lead slurry was to be followed by a 15.6 ppg tail slurry of 300 sacks class "H" cement with 2% calcium chloride, but the pump broke down on the Halliburton truck, and it was not possible to finish mixing 100 sacks of the class "H" cement. A wiper plug was used to displace the cement. Bumped plug with 900 psi and held for 24 minutes; released pressure and plug held. Waited for cement for 9 hours. Cut window in 14" drive pipe and welded plate onto it. Nipped down hydril, rigged down diverter lines, and cleaned out cellar.
7-16-80	9	Cut off 9-5/8" casing and welded on 10" casinghead. Tested same to 1200 psi. Nipped up and attempted to get test tool in hole. Rigged down bell nipple to make room for test tool.
7-17-80	10	Tested blowout preventers to 2000 psi and hydril to 1500 psi. Rigged up bell nipple and made up kelly. Ran in hole to drill float collar and cement with 8-1/2" O.D. bit.
7-18-80	11	Finished running in hole and drilled float collar at 1433'. Continued to drill cement until rig air compressor broke down. Repaired air compressor. Drilled guide shoe and 12' of hole to 1530'. Pulled out of hole. Repaired bell nipple and welded handle onto slips. Started running back in hole.
7-19-80	12	Drilled to 1888'. Circulated and conditioned mud. Drilled to 2000'. Repaired hydraulic lines on rig.
7-20-80	13	Drilled to 2463', and pulled out of the hole. Changed the jets on bit number 3 and ran back in the hole. Repaired rig pump.
7-21-80	14	Drilled to 2763'. Ran an inclination survey (2° deviation from vertical). Drilled to 2976' and made repairs on rig tong lines and pump.
7-22-80	15	Continued repairs on tong lines, removing and replacing broken and badly damaged ones. Pulled out of the hole. The bit was badly balled up. Ran back in the hole and circulated flow lines clean. Drilled to 3425' and attempted inclination survey (misfired). Laid down 12 joints of short drill pipe.

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7-23-80	16	Picked up 12 joints of drill pipe and ran in hole. Made one complete circulation and pulled out of the hole (32 stands). Waited for Gardner Denver rig pump. Changed pump and rigged up lines. Preparing to test same.
7-24-80	17	Finished testing pump. Circulated before pulling out of the hole to change jets in bit. Ran in hole and made one complete circulation at 2945' (bridges at 1750' and 2010'). Pulled out of the hole to surface pipe. Repaired rotary drive gear box and repaired stand-by pump. Started to go back in hole.
7-25-80	18	Finished running back in hole to bridge at 2775' and washed to 2800'. Continued to run on in hole at 3332'. Washed and rotated on bridge. Continued washing to a total depth of 3425'. Drilled to 3618' and attempted inclination survey (tool misfired). Worked on rig pump and drilled to 3954'.
7-26-80	19	Drilled to 4276' and changed over to Halliburton pump.
7-27-80	20	Drilled to a total depth of 4500'. Circulated hole clean and pulled out of the hole to 3508'. Ran inclination survey at 3508' and pulled out of the hole to 1600'. Went in hole to 4500' and found no fill. Circulated and conditioned hole. Pulled out of the hole and rigged up Welex. Logging tool would not go to below 1650' (bridge). Pulled out of the hole with Welex and ran in hole to wash out bridge.
7-28-80	21	Finished running in hole to 4500'. Circulated and conditioned mud to run electric logs. While pulling out of hole (9 stands), transmission broke down. Spent 19 hours repairing rig transmission.
7-29-80	22	Finished repairing rig transmission and ran back in hole. Circulated and conditioned mud to run electric logs. Pulled out of the hole to log. Ran gamma-ray, caliper, density, and induction logs from 4515' to 1518'. Rigged down Welex and ran in hole with bit to 4500'. Repaired rig pump. Circulated and conditioned mud to run 5-1/2" casing.

<u>Report Date</u>	<u>Day No.</u>	<u>Operations</u>
7-30-80	23	Pulled out of the hole and laid down 3-1/2" O.D. drill pipe and 6" O.D. drill collars. Rigged up to run 5-1/2" casing. Ran 5-1/2" O.D. casing and landed shoe at 4515'. Rigged up cementing head and cementing lines. Circulated well and worked pipe. Cemented casing with a 12.8 ppg lead slurry of 750 sacks of Halliburton light cement with 3% salt. The lead slurry was followed by a 15.6 ppg tail slurry of 500 sacks of class "H" cement. Washed out lines and displaced with 109 barrels of 9.2 ppg saltwater. Bumped plug with 1800 psi. Circulated approximately 150 barrels of cement returns to surface.
7-31-80	24	Set 5-1/2" casing slips and nipped down blowout preventers. Loaded out rental tools and cleaned out mud tanks. Rigged up Welex and ran in hole with cement bond logging tool.
8-1-80	25	Ran cement bond log and gamma-ray log from 4370' to 2372'. Released rig and moved off location. Rigged up Welex and Halliburton and perforated well from 4292' to 4366' with 3-1/8" casing guns, 4 holes per foot. After perforating Welex tagged bottom at 4317'. Tested injection rate. Maximum injection rate was 3640 BWPD at 2000 psi.
8-2-80	26	Waiting for acid trucks.
8-3-80	27	Rigged up Halliburton and acidized well with 5000 gallons FE acid with 250 gallons OWG diverter and 10,000 gallons HF acid inhibited for 194°F. Displaced acid with 125 barrels of saltwater and performed injection test. Final injection rate was 12,240 BWPD at 175 psi.
9-18-80	—	Well would not take fluid with 1500 psi injection pressure. Made two runs with sample bailer to 4207'. Recovered samples of fine solids. Perforated well 3490' - 3520' with 3-1/8" casing gun with 4 holes per foot.
9-19-80	—	Finished perforating from 3420' to 3500'. Acidized well with 2500 gallons FE acid and 5000 gallons regular HF acid.
9-20-80	—	Pumped 1000 gallons of xylene down the well. Injection pressure dropped by 100 psi.

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9-21-80

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Acidized well with 3500 gallons FE acid and 4000 gallons of HF acid. Injection pressure decreased from 450 psi to 245 psi.