CORRELATION OF BOTTOM HOLE SAMPLE DATA

GUY BORDEN, JR. AND MICHAEL J. RZASA, STANOLIND OIL AND GAS CO., TULSA, OKLA., MEMBERS AIME

ABSTRACT

Laboratory data on bubble point pressures and reservoir volume factors have been correlated as functions of solution gas-oil ratio, calculated gas gravity of the pentanes-and-lighter fraction of the entire fluid, differential residual oil gravity, and reservoir temperatures.

INTRODUCTION

Several correlations of crude oil properties have appeared in the literature.

D. L. Katz[4] in 1942 presented five methods of predicting oil shrinkage, these being of decreasing accuracy for decreasing amounts of information available.

M. B. Standing[6] in 1947 published three correlations of laboratory flash vaporization data of California crudes. From values of GOR (gas-oil ratio), gas gravity, liquid gravity, and temperature, his correlations will predict bubble point pressure, formation volumes of bubble point liquids, and two-phase formation volumes.

Curtis and Brinkley[2] in 1949 presented several correlations. From the gas-oil ratio, an approximation of reservoir volume factor and barrels of condensate recoverable per barrel of reservoir space may be obtained; along with liquid gravity and reservoir temperature, the GOR will allow prediction of bubble point pressure. These last correlations seem to be more qualitative than quantitative.

Generally, laboratory bottom hole sample tests furnish information on solution gas-oil ratios, residual oil gravities, bubble point pressures, viscosities of oils, liquid shrinkages, and occasionally gas gravities. Each of these data has its own applications and use in reservoir engineering calculations. The particular uses of correlated bottom hole sample data are found in

(1) Providing a basis for obtaining estimates of formation crude properties in fields where bottom hole sampling is impractical or impossible.

(2) Greatly reducing the time in obtaining the desired information.

(3) Determining the applicability of the results from various bottom hole samples to particular field problems.

(4) Avoiding, in many cases, the uncertainties of sampling by replacing it with an element over which greater control can be exercised.

(5) Permitting use of preliminary field data in application of production procedures before a bottom hole sample can be obtained and analyzed in the laboratory.

(6) Serving as a check on data which may appear out of line.

(7) Estimating for a particular type crude the appropriate equilibrium constants by working backward from the bubble point pressure.

(8) Estimating original or other past history properties of reservoirs that were not sampled in the past.

PROCEDURE

Application of the published correlations[4,6] to Stanolind laboratory data indicated that the general scheme presented by Standing[6] could give desirable results if changes were made in parameter positions and scales. The correlation curves were drawn with all the variables having consistent gradations except the temperature increments which were drawn in to best fit the data.

The variables from available Stanolind laboratory data are defined below:

(1) Gas-oil Ratio: Gas is liberated at reservoir temperature by differential vaporization (or rather by a series of flashes, approaching differential vaporization) and measured at atmospheric pressure and temperature, at which the compressibility factor is assumed to be unity. The oil is the residual liquid remaining after the pressure has been reduced to atmospheric. For the gas-oil ratio both volumes are corrected to standard conditions of 14.7 psia and 60°F.

(2) Gas Gravity: It was decided to arbitrarily divide the hydrocarbons of the entire bottom hole sample into pentanes-and-lighter and hexanes-and-heavier, and use a calculated gas gravity of the pentanes-and-lighter for a correlating variable. (Sample calculation is shown in Table III.)

(3) Liquid Gravity: This is the API gravity of the residual liquid from the differential vaporization. The gravity is measured at room temperature and corrected to 60°F.

[1]References given at end of paper.

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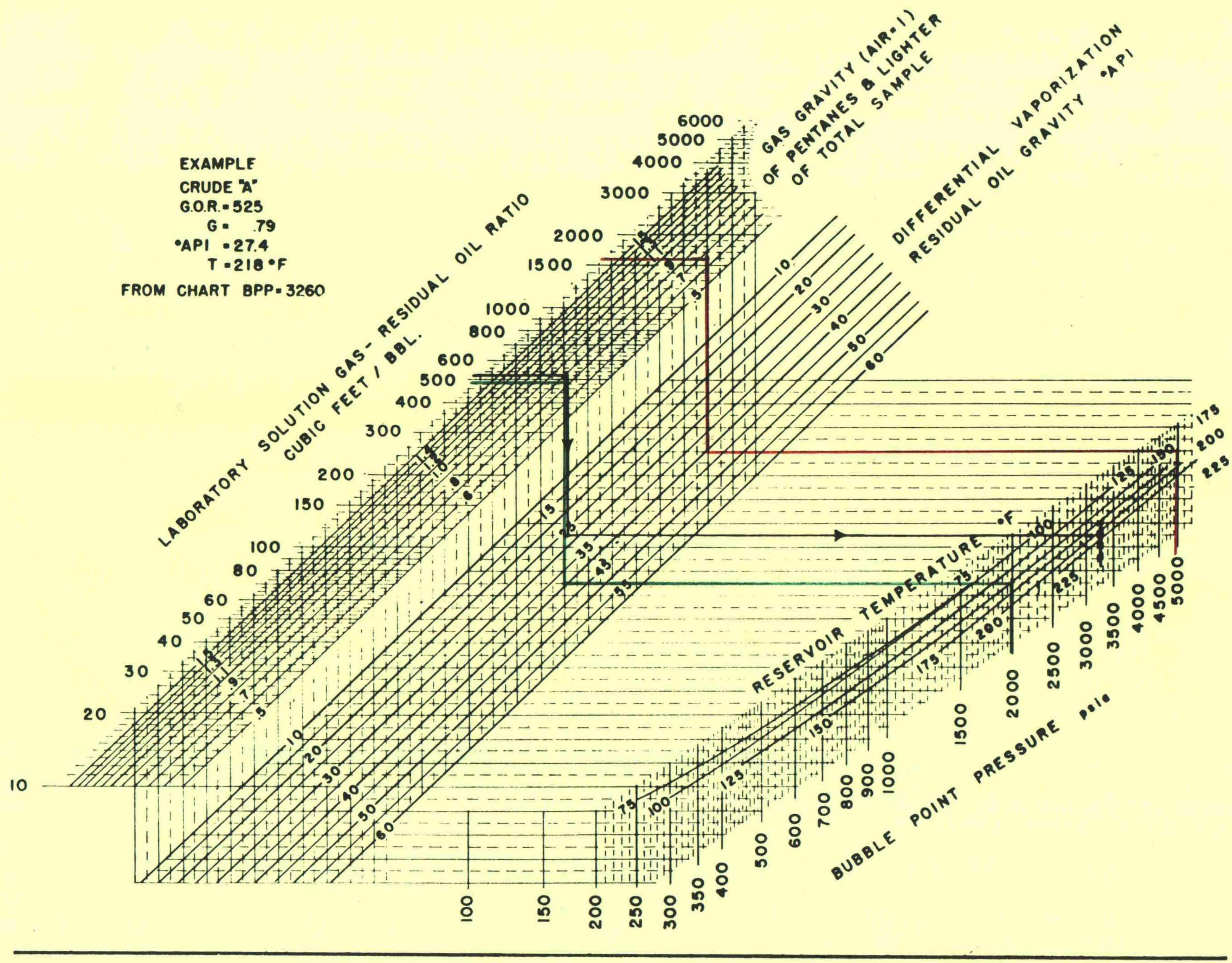


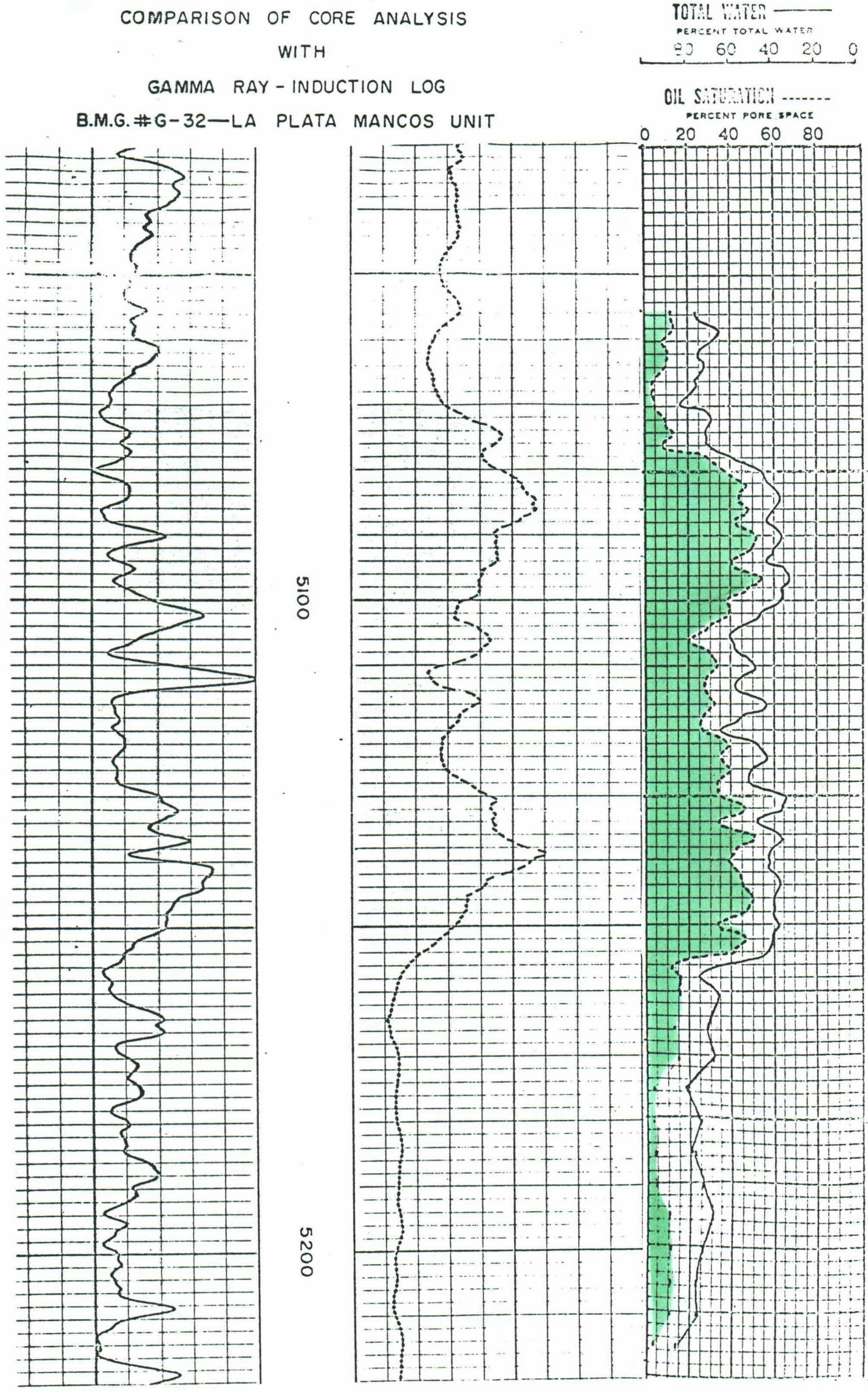
FIG. 1 — BUBBLE POINT PRESSURE CORRELATION.

COMPARISON OF CORE ANALYSIS

WITH

GAMMA RAY - INDUCTION LOG

B.M.G. #G-32—LA PLATA MANCOS UNIT



CANADA OJITOS UNIT #2 (K-13)

DRILLING HISTORY

1785' FSL, 2120' FWL, Sec. 13, Twp. 25N, Rge, 1W, Rio Arriba County, New Mexico.

7/21/62	6:00 AM	Rigging up rotary.
7/21/62	10:30 AM	Spudded in 17½" hole.
7/22/62	2:30 AM	TD 310' RKB. Set 9 joints 293' of 13-3/8" OD 48# H-40 casing at 305' RKB with 350 sacks cement, 2% calcium chloride.
7/23/62	2:30 AM	Tested casing to 500#. Tested O.K.
	6:00 AM	Drilling at 580' in sand and shale. Vis. 32, wt. 8.9. Pump pressure 1600#, 56 SPM, 6" liners.
7/24/62	6:00 AM	TD 2335' in sand and shale. Making trip for Bit #4. 1¼° at 1424'. Vis. 31, wt. 9.0, WL 20, FC 2/32. Pump pressure 1300#, 52 SPM, 6" liners.
7/25/62	6:00 AM	TD 2497'. Circulating for Core #1. Vis. 48, wt. 9.0, WL 4.8, FC 2/32. 3-3/4° at 2327'. Show of gas and fluorescence in samples.
7/25/62	10:00 AM	TD 2499'. Went in hole with core barrel.
		Core barrel plugged. Made trip.
7/26/62	12:15 AM	On bottom with core barrel.
	6:00 AM	Coring (Core #1) at 2530'.
		1¼° at 2499'. Vis. 70, wt. 9.0, WL 8, FC 1/32. Pump pressure 900#, 45 SPM, 6" liners.
7/26/62		Pulled Core #1 from 2499' to 2559'. Reamed core-hole. Drilled 16'. Circulated 1½ hours. Logged well.
7/27/62	6:00 AM	Waiting on orders. TD 2575'.
<u>Core #1</u>		Cored 2499' to 2559'. Cored 60', recovered 36'.
2499-2500'		Dark grey very fine silty very fossiliferous and finely micaceous shale.
2500-01'		Same, slightly fossiliferous, slightly sandy, very fine.
2501-03'		Same.
2503-04'		Same, abundant slicken sides, 45° vertical and horizontal fracture.
2504-05'		Same.
2505-06'		Same, very fossiliferous.
2506-08'		Same, slightly sandy, very fine.
2508-10'		Same, slightly sandy, very fine.
2510-15'		Same, non-fossiliferous.
2515-16'		Same, very very fossiliferous, snail, clams, etc.
2516-25'		Same, non-fossiliferous.
2525-30'		Same, few fossiliferous fragments.
2530-31'		Same, shale becomes much darker.
2531-36'		Dark grey black very very fine mica and silt.

F

7/28/62	6:00 AM	Drilling at 3180' in 9-7/8" hole in shale. 3/4° at 2899'. Vis. 47, wt. 9.0, WL 5.0, FC 1/32. Pump pressure 1350#, 54 SPM, 6" liners.
7/29/62	6:00 AM	Drilling at 3640' in sand and shale. 1-3/4° at 3240'. Vis. 48. wt. 9.0, WL 4.0, FC 1/32. Pump pressure 1350#, 54 SPM, 6" liners.
7/30/62	6:00 AM	Drilling at 3940' in sand and shale. Bit #8 in the hole. Vis. 46, wt. 9.1, WL 4.4, FC 1/32. 2° at 2692'. Pump pressure 1400#, 54 SPM, 6" liners.
7/31/62	6:00 AM	TD 4123'. Making trip for core barrel. 1-3/4° at 3956'. Vis. 46, wt. 9.2, WL 4.5, FC 1/32. Pump pressure 1400#, 54 SPM, 6" liners.

CORE DESCRIPTION

Core #2	Cored 4123.3' to 4142.8'. Cored 19.5', recovered 19.5'.
4123.3-25'	Medium fine light grey salt and pepper varicolor sandstone, very very fine mica matrix, slight gas stain and fluorescence.
4125-26'	Same, harder, good stain and fluorescence.
4126-29'	Same, hard, slight stain and fluorescence.
4129-30'	Same, hard, heavy stain and fluorescence.
4130-31'	Same, hard, with thin fine varved sandstone, slightly carbonaceous streaks, stain and fluorescence.
4131-32'	Same.
4132-33'	Same, very fractured, good stain and fluorescence.
4133-35'	Same, good odor, good stain and fluorescence.
4135-36'	Same with black shale streaks, slightly carbonaceous, good odor, good stain and fluorescence.
4136-37'	Same with thin carbonaceous pyritic partings, good odor, good stain and fluorescence.
4137-40'	Same, heavy odor, good stain and fluorescence.
4140-41'	Same with thin slightly carbonaceous shale streaks, varved, good odor, good stain and fluorescence.
4141-42'	Same with thin brown shale streaks, varved, slicken sides, slight odor and fluorescence.
4142-42.8'	Dark grey very fine salt and pepper varicolor sandstone with thin brown grey silty shale streaks, slight bleed.

7/31/62		Pulled Core #2 from 4123.3' to 4142.8'.
8/1/62	6:00 AM	Coring (Core #3) at 4164'. 2-3/4° at 4154'. Vis. 50, wt. 9.9, WL 3.6, FC 1/32. Pump pressure 800#, 54 SPM, 6" liners.
8/1/62		Pulled Core #3 from 4154' to 4214'. Cored 60', recovered 46'.
8/2/62	5:00 AM	TD 4214'. Vis. 52, wt. 9.9, WL 5.8, FC 1/32. 2° at 4214'. Pump pressure 1400#, 41 SPM, 6" liners. Preparing to drill stem test.

8/2/62		DST #1 from 4076' to 4214'. Upper packer set at 4072', lower at 4076'. Tool open 10 minutes on initial flow. Good blow of air to surface immediately. Initial shut in 30 minutes. Second flow 60 minutes, final shut in 45 minutes. Initial hydrostatic pressure 2170#, initial FP 280#, initial SIP 810#. Final FP 590#, final SIP 810#. Bottom hole temperature 142°. Good blow throughout test. Gas to surface at end of test.
8/3/62	6:00 AM	Drilled to TD 4383'. Circulating for Core #4. Vis. 59, wt. 9.9, WL 5.8, FC 1/32. Pump pressure 1400#, 54 SPM, 6" liners.

CORE DESCRIPTIONS

Core #3	Cored 4154' to 4216'. Cored 62', recovered 46'.
4154-55'	Dark brown carbonaceous shale.
4155-56'	Same.
4156-57'	Same, amber specks.
4157-59'	Same, very carbonaceous.
4159-60'	Impure coal.
4160-61'	Dark grey brown carbonaceous shale.
4161-64'	Dark brown slightly carbonaceous sand, medium fine, very silty.
4164-64½'	Dark grey brown silty carbonaceous sand, thin laminations.
4164½-65'	Light grey medium fine varicolor silty sandstone.
4165-71'	Same with brown shale clay balls, very micaceous.
4171-72'	Light grey tan medium fine varicolor sandstone, micaceous.
4172-72½'	Dark grey brown shale, very very finely micaceous.
4172½-73'	Light grey tan medium fine varicolor sandstone, micaceous, with clay balls and brown shale.
4173-74'	Same with thin shale laminations.
4174-75'	Dark grey brown shale, very fine mica.
4175-76'	Light tan grey medium fine varicolor sandstone, micaceous.
4176-78'	Light tan grey medium varicolor sandstone, micaceous, compact.
4178-80'	Same, slight stain.
4180-81'	Same, slight stain, very silty.
4181-82'	Black very coaly shale.
4182-83'	Black slightly coaly shale.
4183-85'	Black very slightly coaly shale.
4185-87'	Dark brown coaly shale.
4187-97'	Dark brown grey slightly silty carbonaceous shale.
4197-97½'	Dark grey hard very slightly carbonaceous shale.
4197½-99'	Dark grey brown very silty carbonaceous sand with thin brown shale streaks.
4199-4199½'	Dark grey brown very silty carbonaceous sand with dark brown shale streaks.

Core #3 (continued)

4199½-4200'	Dark brown shale with thin medium fine to medium varicolor silty sandstone streaks.
Core #4	Cored 4491' to 4551'. Cored 60', recovered 54'.
4491-92'	Dark grey brown very fine silty slightly carbonaceous shale.
4492-93'	Dark grey brown very fine silty slightly carbonaceous shale and grey medium fine angular varicolor slightly carbonaceous sandstone.
4493-98'	Same.
4498-4502'	Dark grey brown shale, slightly carbonaceous.
4502-06'	Dark grey medium fine sub-angular sandstone, silty, slightly carbonaceous and micaceous.
4506-10'	Light grey medium fine sub-angular sand and pepper sandstone, slightly silty.
4510-12'	Dark grey brown very fine silty shale.
4512-13'	Dark grey brown very fine sandy micaceous shale.
4513-14'	Dark grey brown shale.
4514-15'	Coal.
4515-16'	Dark grey brown shale.
4516-17'	Light grey medium varicolor compact micaceous and slightly carbonaceous sandstone, kaolin clay cmt.
4517-27'	Light grey medium varicolor compact micaceous sand. Kaolin clay cmt.
4527-28'	Dark medium varicolor compact micaceous sand, kaolin clay cmt, thin carbonaceous partings.
4528-31'	Light grey medium varicolor compact micaceous sand, kaolin clay cmt.
4531-32'	Same with trace gilsonite.
4531-32'	Same, no gilsonite.
4532-39'	Same with dark grey brown clay balls.
4539-51'	Same.

8/4/62		Pulled Core #4 from 4491' to 4551'. Cored 60', recovered 54'.
8/6/62	6:00 AM	Drilled to TD 4900'. Circulating to run casing. Vis. 58, wt. 10, WL 8, FC 2/32. Pump pressure 1500#, 54 SPM, 6" liners. Lost 300 barrels mud at 4772'. Now have full returns.
8/6/62	8:00 PM	TD 4900' RKB. Set 155 joints 4904' of 7-5/8" OD 26.40# J-55 casing at 4898' RKB with 100 sacks cement, 2% gel, 12½# Gilsonite/sk, ½# flocele/sk, followed by 300 sacks cement, 1% gel, 12½# Gilsonite/sk, ½# flocele/sk.
8/7/62	6:00 AM	WOC
8/7/62	8:00 AM	TC 3700'. Ran temperature survey. Set slips. Cut off casing. Rigging up air drilling equipment while WOC.

8/8/62	6:00 AM	Nipped up. Picked up drill collars. Going in hole with drill pipe.
8/9/62	6:00 AM	TD 4911'. Drilled cement and 11' of formation. Formation wet. Blowing to dry up.
8/10/62	6:00 AM	Drilling at 5550' with air. Compressor pressure 150#. 6½° at 5400'. 7° at 5480'. 7½° at 5520'.
8/13/62	6:00 AM	TD 6022'. Preparing to run tubing.
		TD 6022'. Ran 184 joints tubing. Blew well 6:00 PM to 11:00 PM.
8/14/62	6:00 AM	Shut in.
8/15/62	6:00 AM	TD 6022'. Blowing well.
	8:00 AM	Released rotary rig.
8/16/62	6:00 AM	Shut down.
10/ 5/62		Moved in pulling unit to run Kobe pumping equipment. Rigged up and started pulling 2-3/8" tubing. Moved in D-6 cat to build pad for tank battery. Moved 1" tubing, 2-3/8" EUE tubing, Kobe equipment, power oil tank (300 bbl special) and one 210-barrel storage tank from B-M-G #1 Pilgrim.
10/ 6/62		Finished pulling 2-3/8" EUE tubing. Started in hole with Kobe bottom hole assembly. Ran as follows:

Perforated nipple:	6.60'
Kobe bottom hole assembly	14.40
1-2' 2-3/8" EUE sub	2.00
156 jts 2-3/8" EUE	4874.83
Total string	4897.83'

Start in hole with 1" Kobe tbg. Set power oil tank and 210 bbl. storage tank. Laid flow lines and set Kobe triplex pump.

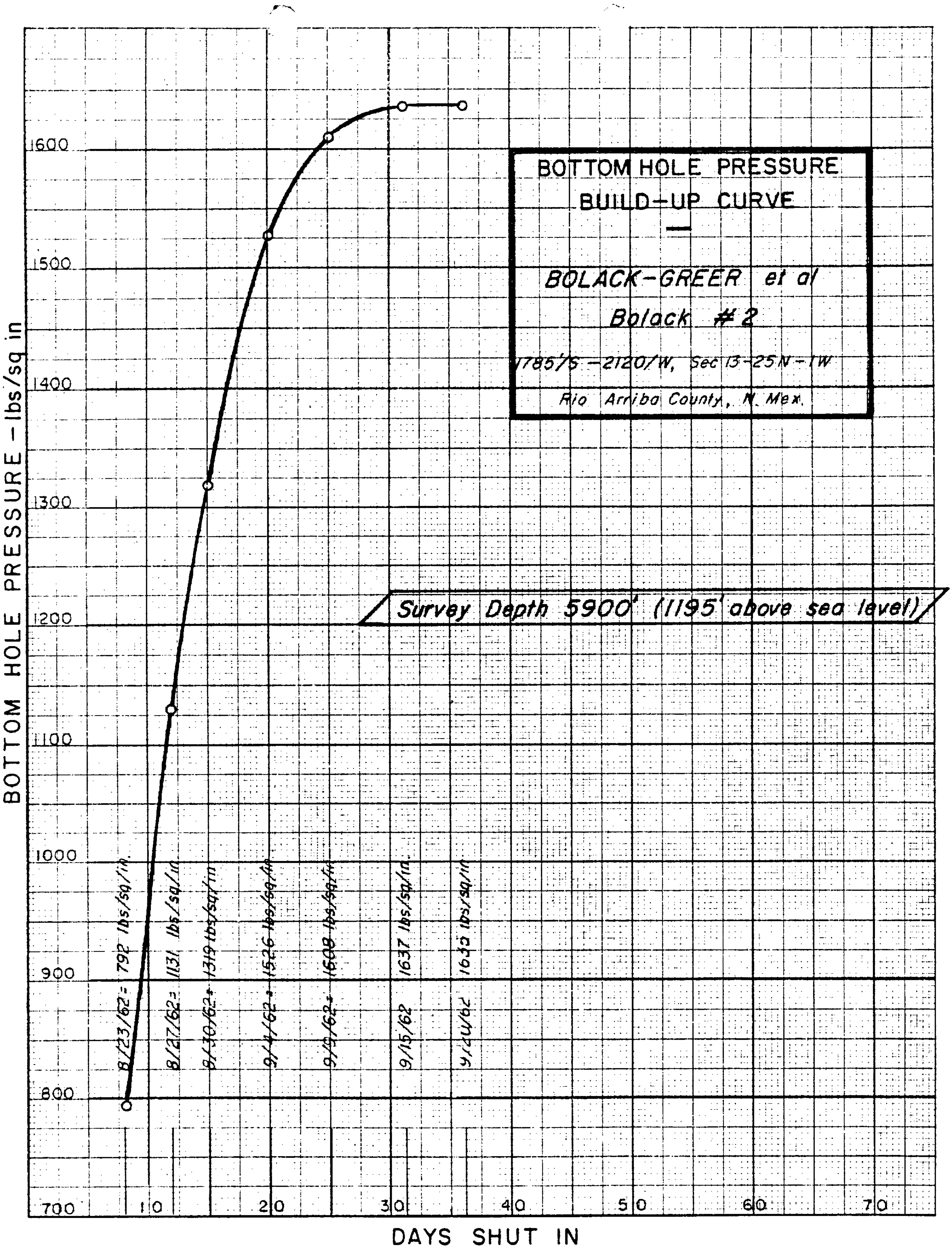
10/ 7/62 Finished running 1" Kobe tubing. Tubing as follows:

162 joints	4853.67'
1 sub	10.00
1 sub	4.00
	4867.67
Kobe stinger on bottom of 1"	1.00
	4868.67'

Landed 1" with stinger seated in bottom hole assembly bowl and spaced out with two subs. Released pulling unit.

	3:00 PM	Started well pumping.
		Pressures of 1100# to 1200# while bringing fluid to surface. Pressure decreased to 250-500# during first few hours of pumping operations.
10/ 8/62		Well pumped 36 barrels in 16 hours. Triplex pressure 500#.
10/ 9/62		Pump down. (Apparently ran out of annulus gas).
10/10/62		Pumping with pressure of 550# on Triplex pump.
10/11/62		Well pumped 35 barrels in last 29 hours. Total new production to date 133 bbls. Pressure on Triplex 700#.

10/12/62		Pumped 50 barrels last 24 hours. Increased triplex speed to full throttle. Triplex pressure 1050#. Gravity of oil 38.5 at 70°.
10/13/62		Pumped 35 barrels in 24 hours. Triplex pressure 1000#. Gravity 37.2 at 65°.
10/14/62		Pumped 21 barrels last 24 hours. Triplex pressure 1000#.
10/15/62		Pumped 14 barrels last 24 hours. Triplex pressure 1000#.
10/16/62		Pumped 9 barrels last 24 hours. Triplex pressure 1000#.
10/17/62		Pumped 7 barrels last 24 hours. Triplex pressure 900#.
10/18/62	7:00 AM	Pump inoperative. No production last 24 hours.
	7:30 PM	Ran new pump.
10/19/62	7:00 AM	Well pumped 39 barrels oil last 11½ hours.
10/20/62	7:00 AM	Pumped 19 barrels last 24 hours.
10/21/62	7:00 AM	Pumped 14 barrels last 24 hours.
10/22/62	7:00 AM	Pumped 15 barrels last 24 hours.
10/22/62		Pumped 15 barrels oil in 12 hours.
10/23/62		Pumped 15 barrels oil in 12 hours.
10/24/62		Pumped 13 barrels oil in 12 hours.
10/25/62		Pumped 13 barrels oil in 12 hours.
10/26/62		Pumped 12 barrels oil in 12 hours.
10/27/62		Pumped 12 barrels oil in 12 hours.
10/28/62		Pumped 13 barrels oil in 12 hours.
10/29/62		Pumped 6 barrels in 12 hours.
10/30/62		Pumped 5 barrels in 6 hours.
10/31/62		Pumped 9 barrels oil in 6 hours.



BOTTOM HOLE PRESSURE
BUILD-UP CURVE
BOLACK-GREER et al
Bolack #2
1785'/S – 2120'/W, Sec 13-25N-1W
Rio Arriba County, N. Mex.
Survey Depth 5900' (1195' above sea level)
8/23/62= 792 lbs/sq/in.
8/27/62= 1131 lbs/sq/in
8/30/62= 1319 lbs/sq/in
9/4/62= 1526 lbs/sq/in
9/9/62= 1608 lbs/sq/in
9/15/62 1637 lbs/sq/in.
9/20/62 1633 lbs/sq/in
BOTTOM HOLE PRESSURE – lbs/sq in
700
800
900
1000
1100
1200
1300
1400
1500
1600
10
20
30
40
50
60
70
DAYS SHUT IN

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

November 7, 1962

RESERVOIR FLUID DIVISION

Benson-Montin-Greer Drilling Corporation
158 Petroleum Center Building
Farmington, New Mexico

Attention: Mr. Virgil Stoabs

Subject: Reservoir Fluid Study
Bolack No. 2 Well
Wildcat
Rio Arriba County, New Mexico
Our File Number: RFL 2302

Gentlemen:

Subsurface fluid samples were collected from the subject well by a representative of Core Laboratories, Inc. on October 2, 1962, and transported to our Dallas laboratory, where they arrived on October 15, 1962. Presented in this report are the results of a reservoir fluid study performed using these samples.

The saturation pressure of the fluid was measured to be 1524 psig at the reservoir temperature of 152° F. The reservoir pressure at the sampling depth was measured to be 1631 psig.

During differential pressure depletion the fluid evolved 481 standard cubic feet of gas per barrel of residual oil. The associated formation volume factor was measured to be 1.292 barrels of saturated fluid per barrel of residual oil. Under similar depletion conditions the viscosity of the fluid varied from a minimum of 0.625 centipoise at the saturation pressure to a maximum of 1.750 centipoises at atmospheric pressure.

Separator tests were performed at four operating pressures and atmospheric temperature to determine the effect of changes in surface separation pressure upon the produced fluid. These tests indicate that the optimum separator pressure is approximately 90 psig; however, near optimum recovery will be obtained at pressures as low as 40 psig.

It was a pleasure to perform this study for you. If you have any questions or if we may assist you further, please do not hesitate to contact us.

Very truly yours,

Core Laboratories, Inc.
Reservoir Fluid Division
P. L. Moses

A. C. Carnes, Jr.

A. C. Carnes, Jr.
Senior Engineer

ACC:dc
7 cc. - Addressee

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 2302

Company	Benson-Montin-Greer Drilling Corporation	Date Sampled	October 2, 1962
Well	Bolack No. 2	County	Rio Arriba
Field	Wildcat	State	New Mexico

FORMATION CHARACTERISTICS

Formation Name	Gallup
Date First Well Completed	August 15, 19 62
Original Reservoir Pressure	1631 PSIG @ 5957 Ft.
Original Produced Gas-Oil Ratio	SCF/Bbl
Production Rate	Bbl/Day
Separator Pressure and Temperature	PSIG, °F.
Oil Gravity at 60° F.	°API
Datum	Ft. Subsea
Original Gas Cap	

WELL CHARACTERISTICS

Elevation	7100 KB Ft.
Total Depth	6022 Ft.
Producing Interval	4900-6022 OH Ft.
Tubing Size and Depth	2-3/8 In. to 6003 Ft.
Productivity Index	Bbl/D/PSI @ Bbl/Day
Last Reservoir Pressure	1631 PSIG @ 5975 Ft.
Date	October 2, 19 62
Reservoir Temperature	152 °F. @ 5975 Ft.
Status of Well	Shut in
Pressure Gauge	Amerada (DO)
Normal Production Rate	Bbl/Day
Gas-Oil Ratio	SCF/Bbl
Separator Pressure and Temperature	PSIG, °F.
Base Pressure	PSIA
Well Making Water	% Cut

SAMPLING CONDITIONS

Sampled at	5975 Ft.
Status of Well	Shut in
Gas-Oil Ratio	SCF/Bbl
Separator Pressure and Temperature	PSIG, °F.
Tubing Pressure	0 PSIG
Casing Pressure	PSIG
Core Laboratories Engineer	NT
Type Sampler	Perco

REMARKS:

CL-818

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 2302
Well Bolack No. 2

VOLUMETRIC DATA OF Reservoir Fluid SAMPLE

1. Saturation pressure (bubble-point pressure) 1524 PSIG @ 152 °F.
2. Thermal expansion of saturated oil @ 5000 PSI = $\frac{V @ 152\ °F}{V @ 73\ °F}$ = 1.04245
3. Compressibility of saturated oil @ reservoir temperature: Vol/Vol/PSI:

   From 5000 PSI to 3500 PSI = 7.92×10^{-6}

   From 3500 PSI to 2500 PSI = 8.93×10^{-6}

   From 2500 PSI to 1524 PSI = 10.34×10^{-6}

4. Specific volume at saturation pressure: ft^3/lb 0.02223 @ 152 °F.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 2302
Well Bolack No. 2

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 152 °F., RELATIVE VOLUME OF OIL AND GAS, V/VSAT.	VISCOSITY OF OIL @ 152 °F., CENTIPOISES	DIFFERENTIAL LIBERATION @ 152 °F. GAS/OIL RATIO LIBERATED PER BARREL OF RESIDUAL OIL	GAS/OIL RATIO IN SOLUTION PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/VR
5000	0.9694	0.845			1.252
4500	0.9732	0.818			1.257
4005		0.787			
4000	0.9770				1.262
3500	0.9811	0.758			1.268
3000	0.9854	0.726			1.273
2505		0.691			
2500	0.9899				1.279
2100	0.9938				1.284
2000	0.9947	0.661			1.285
1900	0.9957				1.286
1800	0.9969				1.288
1700	0.9980	0.635			1.289
1600	0.9991				1.291
1524	1.0000	0.625	0	481	1.292
1516	1.0020				
1508	1.0041				
1483	1.0102				
1447	1.0204				
1400		0.631			
1381	1.0407				
1376			37	444	1.277
1299	1.0698				
1250		0.682			
1221			75	406	1.261
1201	1.1121				
1123			100	381	1.251
1100		0.720			
1090	1.1734				
971	1.2552				
968			139	342	1.235
950		0.760			
850	1.3679				
818			176	305	1.220

V = Volume at given pressure
VSAT. = Volume at saturation pressure and the specified temperature.
VR = Residual oil volume at 14.7 PSI absolute and 60° F.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 2302
Well Bolack No. 2

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 152 °F., RELATIVE VOLUME OF OIL AND GAS, V/VSAT.	VISCOSITY OF OIL @ 152 °F., CENTIPOISES	DIFFERENTIAL LIBERATION @ 152 °F. GAS/OIL RATIO LIBERATED PER BARREL OF RESIDUAL OIL	GAS/OIL RATIO IN SOLUTION PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/VR
800		0.802			
728	1.5320				
669			213	268	1.204
650		0.858			
600	1.7783				
518			251	230	1.188
500		0.912			
469	2.1799				
365			290	191	1.170
354	2.7950				
350		0.977			
258	3.8098				
223			332	149	1.151
200		1.083			
112			371	110	1.130
0		1.750	481	0	1.044
				@ 60° F. =	1.000

Gravity of residual oil = 38.6° API @ 60° F.

V = Volume at given pressure
VSAT. = Volume at saturation pressure and the specified temperature.
VR = Residual oil volume at 14.7 PSI absolute and 60° F.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 2302
Well Bolack No. 2

Differential Pressure Depletion at 152° F.

Pressure PSIG	Oil Density Gms/Cc	Gas Gravity	Deviation Factor Z
1524	0.7206		
1376	0.7246	0.693	0.869
1221	0.7290	0.694	0.879
1123	0.7319	0.696	0.886
968	0.7367	0.699	0.895
818	0.7413	0.708	0.909
669	0.7462	0.720	0.920
518	0.7512	0.739	0.932
365	0.7566	0.783	0.945
223	0.7627	0.856	0.965
112	0.7688	1.014	
0	0.7957	1.589	

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 2302
Well Bolack No. 2

SEPARATOR TESTS OF Reservoir Fluid SAMPLE

SEPARATOR PRESSURE, PSI GAUGE	SEPARATOR TEMPERATURE, ° F.	SEPARATOR GAS/OIL RATIO See Foot Note (1)	STOCK TANK GAS/OIL RATIO See Foot Note (1)	STOCK TANK GRAVITY, ° API @ 60° F.	SHRINKAGE FACTOR, $V_R/V_{SAT.}$ See Foot Note (2)	FORMATION VOLUME FACTOR, $V_{SAT.}/V_R$ See Foot Note (3)	SPECIFIC GRAVITY OF FLASHED GAS
0	79	503		38.4	0.7645	1.308	0.997
40	77	414	32	39.7	0.7924	1.262	
80	76	371	61	39.9	0.7994	1.251	
160	77	328	117	39.7	0.7930	1.261	

(1) Separator and Stock Tank Gas/Oil Ratio in cubic feet of gas @ 60° F. and 14.7 PSI absolute per barrel of stock tank oil @ 60° F.

(2) Shrinkage Factor: $V_R/V_{SAT.}$ is barrels of stock tank oil @ 60° F. per barrel of saturated oil @ 1524 PSI gauge and 152 ° F.

(3) Formation Volume Factor: $V_{SAT.}/V_R$ is barrels of saturated oil @ 1524 PSI gauge and 152 ° F. per barrel of stock tank oil @ 60° F.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 2302

Company Benson-Montin-Greer Drilling Corporation

Formation Gallup

Well Bolack No. 2

County Rio Arriba

Field Wildcat

State New Mexico

HYDROCARBON ANALYSIS OF Reservoir Fluid SAMPLE

COMPONENT	WEIGHT PER CENT	MOL PER CENT	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Hydrogen Sulfide					
Carbon Dioxide	0.05	0.14			
Nitrogen	0.04	0.16			
Methane	3.68	26.38			
Ethane	1.70	6.48			
Propane	2.45	6.39			
iso-Butane	0.50	1.00			
n-Butane	2.23	4.41			
iso-Pentane	1.16	1.86			
n-Pentane	1.53	2.44			
Hexanes	3.33	4.45			
Heptanes plus	83.33	46.29	0.8449	35.8	207
	100.00	100.00			

Core Laboratories, Inc.
Reservoir Fluid Division

A. C. Carnes, Jr.

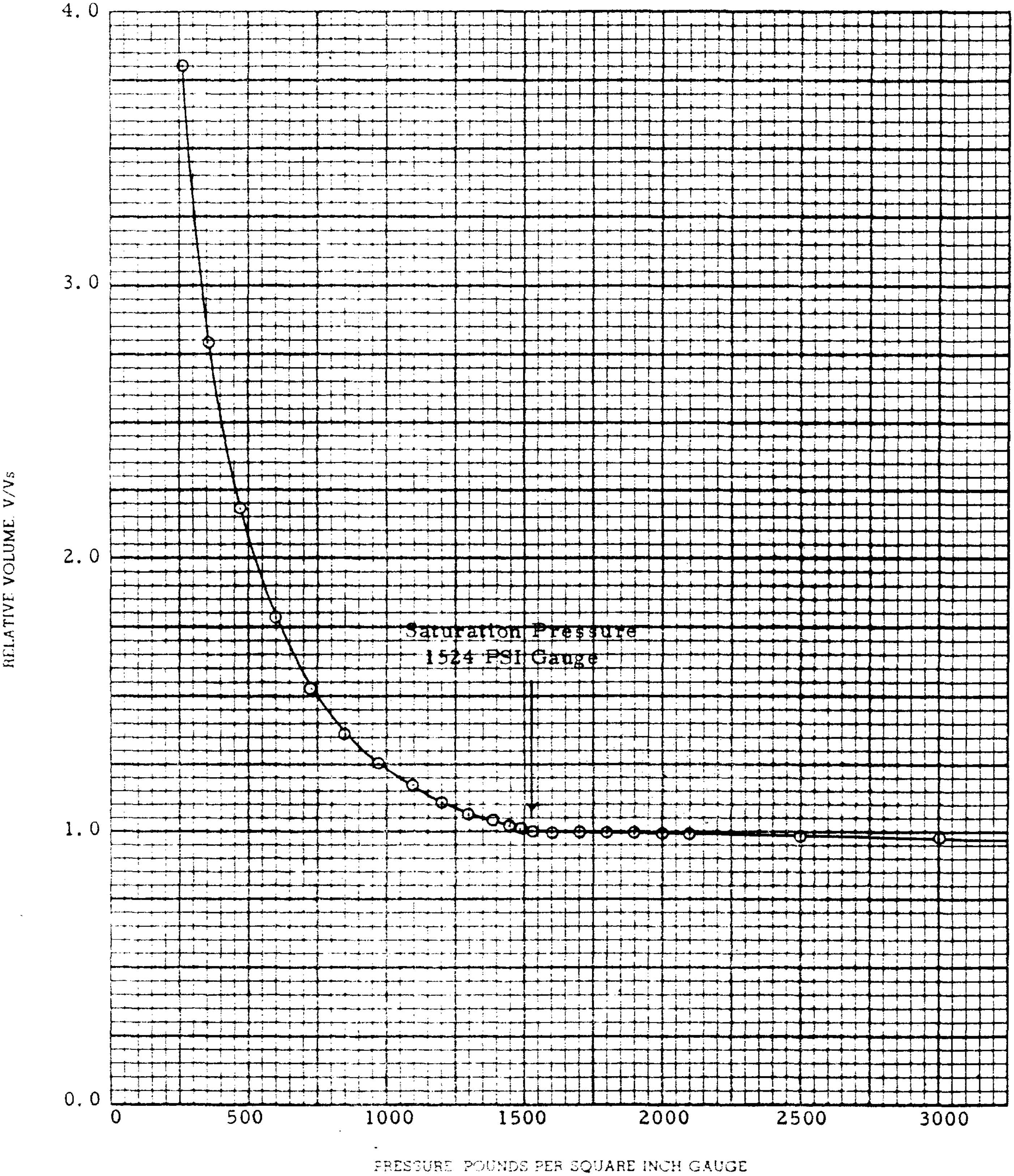
A. C. Carnes, Jr.
Senior Engineer

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 2302

PRESSURE VOLUME RELATIONS OF RESERVOIR FLUID

Company: Benson-Montin-Greer Drilling Corporation
Formation: Gallup
Well: Bolack No. 2
County: Rio Arriba
Field: Wildcat
State: New Mexico



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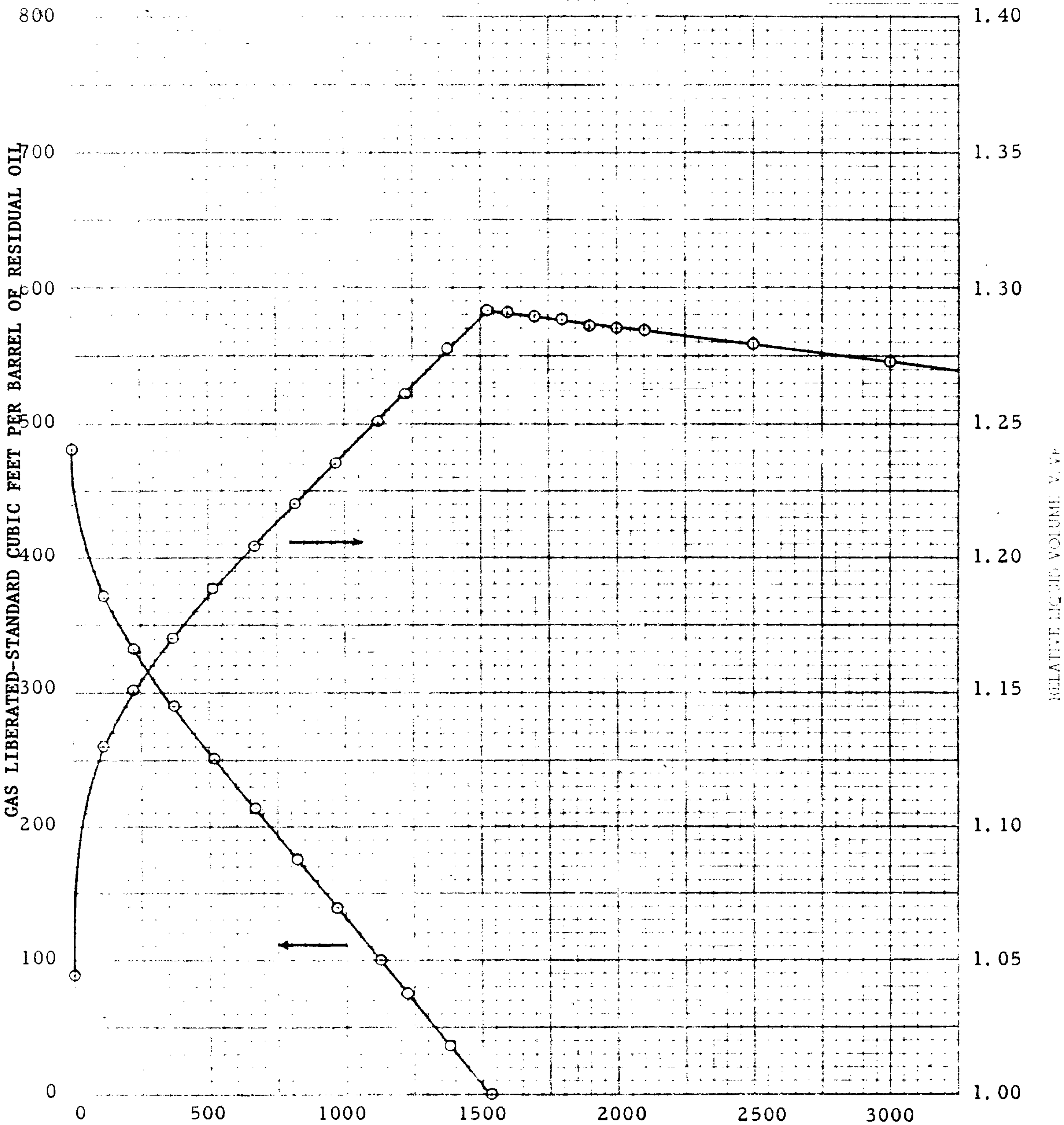
RFL 2302

Benson-Montin-Greer Drilling Corporation
Bolack No. 2
Wildcat

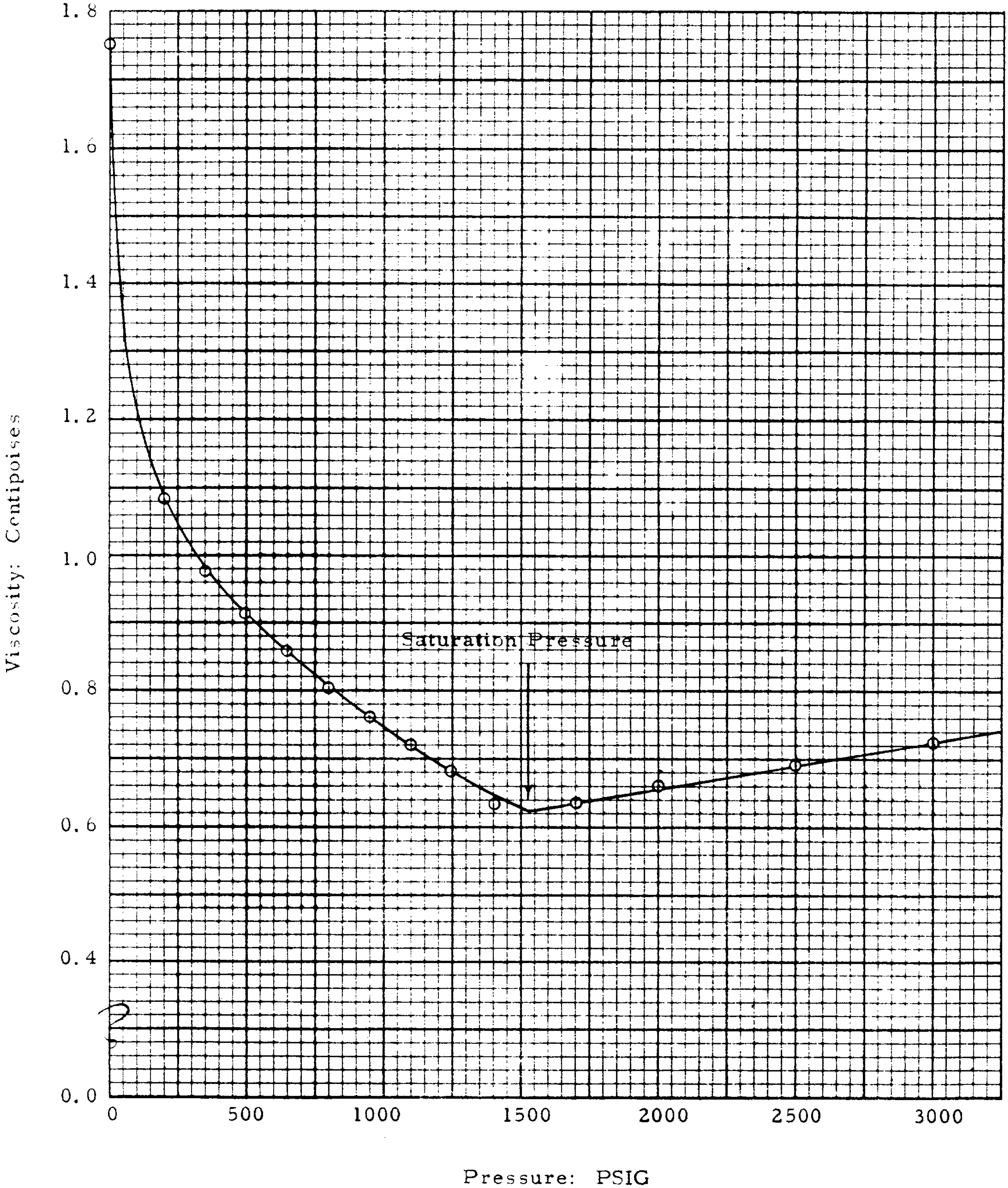
Gallup
Rio Arriba
New Mexico



CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

Viscosity of Reservoir Fluid

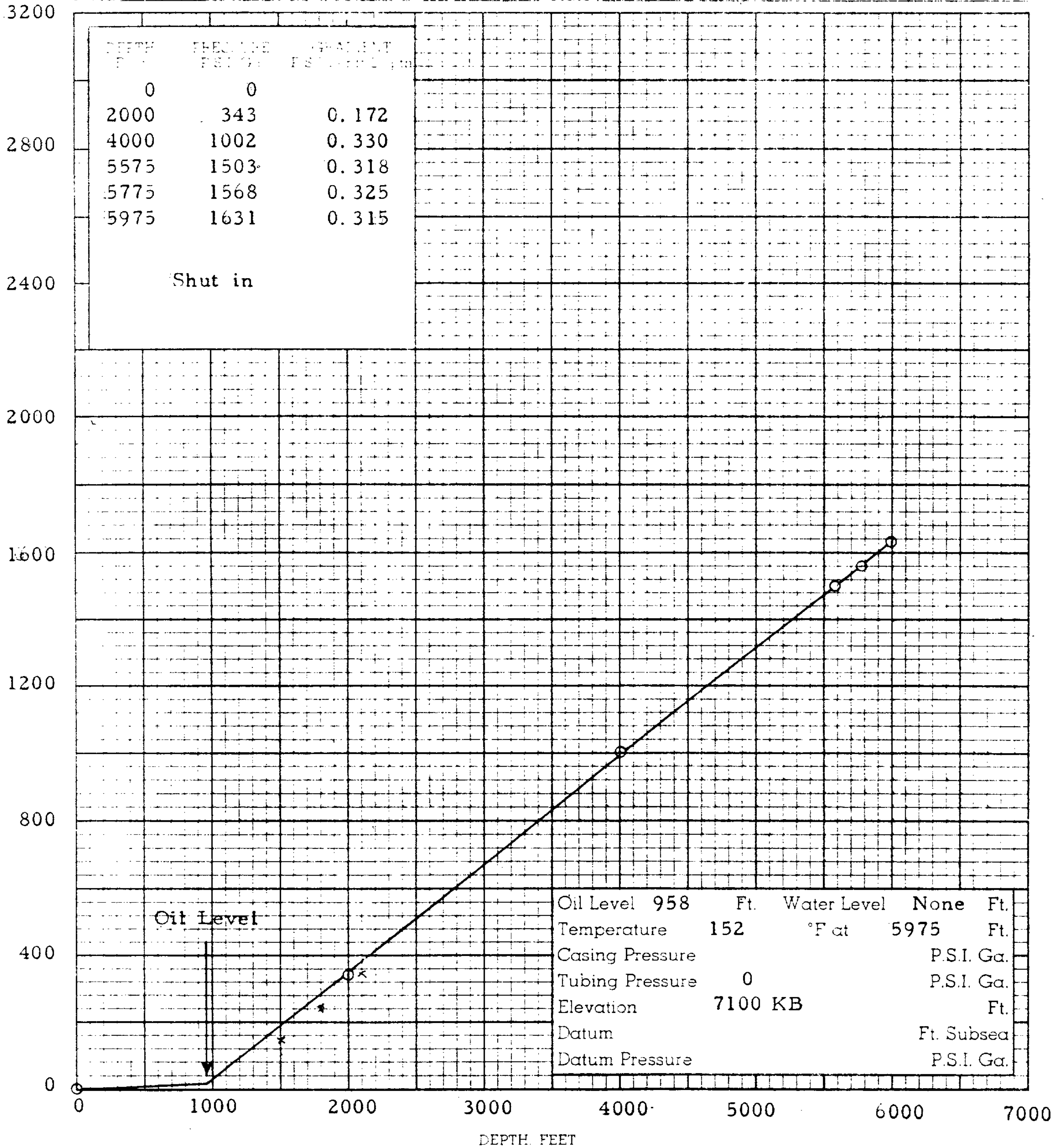
Company	Benson-Montin-Greer Drilling Corporation	Formation	Gallup
Well	Bolack No. 2	County	Rio Arriba
Field	Wildcat	State	New Mexico



CORE LABORATORIES, Inc.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 2302

Company Benson-Montin-Greer Drilling Corporation
Well Bolack No. 2
Field Wildcat
Formation Gallup
County Rio Arriba
State New Mexico



DRILLING STATUS

CANADA OJITOS UNIT L-11

	1908' FSL, 523' FWL, Sec. 11, T-25N, R-1W, Rio Arriba County, New Mexico. Elevation 7220' GL.
8- 6-64	Spudded.
8- 7-64	TD 330' RKB. Set 10 joints 312' of 13-3/8" OD 48# H-40 casing at 324' RKB with 350 sacks regular cement, 2% calcium chloride.
8-10-64	Drilling at 1450'. 1° at 430'.
8-11-64	Drilling at 2783'.
8-12-64	Drilling at 3223'. $3/4^{\circ}$ at 3223'
8-13-64	TD 3771'. Lost circulation. Vis. 45, wt. 9.3, WL 8.6, FC 2/32. Mixed lost circulation material.
8-14-64	Drilling at 4130'. 3° at 4105'
8-15-64	Drilling at 4380'. Vis. 49, wt. 9.2, WL 4.2, FC 2/32, tr. sand, 6% oil, 8.5 Ph. $2\frac{1}{4}^{\circ}$ at 4359'
8-19-64	Drilling at 5315'. Vis. 48, wt. 8.9, WL 5.0, FC 1/32, tr. sd., 22% oil. Lost 100 barrels mud at 5250'. 2° at 5298'
8-20-64	Drilling at 5515'. 2° at 5455'
	Drilled to TD 5550'. Logged well. Drilled 145' to 5695'. Laid down drill pipe.
8-21-64	TD 5695'. $2\frac{1}{4}^{\circ}$ at 5550'.Ran 38 joints 1229.49' TO 7-5/8" OD N-80 LT&C casing (1 joint on top, balance on bottom) and 137 joints 4479.22' TO 7-5/8" J-55 ST&C casing, landed at 5694' RKB, cemented with 100 sacks, 2% gel, $12\frac{1}{2}$# Gilsonite and $\frac{1}{4}$# flocele per sack, followed with 300 sacks, 1% gel, $4\frac{1}{2}$# Gilsonite and $\frac{1}{4}$# flocele per sack.
8-22-64	Temperature survey showed top of cement at 4050'.
8-24-64	Drilled cement. Cement dusted.
8-25-64	Drilling at 5930' with 175# air pressure. $1\text{-}3/4^{\circ}$ at 5843'.
8-26-64	Drilling at 6425' with 190# air pressure. $2\frac{1}{4}^{\circ}$ at 6272'
	Drilled to TD 6526'. Logged well. Started back in hole with bit. Bit stopped 9' inside 7-5/8" casing. Casing parted.
8-27-64	Attempted to screw in to 7-5/8". Were unable to with regular joint. Ran die nipple and chased threads. Screwed in. Pulled 140,000#, set slips.
8-28-64	Went back to bottom, drilled to 6590'.
8-29-64	Drilled to TD 6660'. Circulated with air for 1 hour. Attempted to reverse circulate with air. Could not get dusting. Conventionally circulated for additional 2 hours. Rigged up to circulate with oil. Loaded hole with oil down drill pipe. When returns established, started reverse circulating oil. Reverse circulated for 2 hours. Came out of hole. Laid down square drill collar.

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8-29-64 (contd.)	Picked up core barrel. Went back to bottom. Reverse circulated to clean up hole. Plugged pipe. Worked plug free. Attempted to reverse core. Plugged pipe again. Worked out plug. Commenced coring conventionally.
	Pulled Core #1 from 6660' to 6665.5'. Core barrel jammed. Came out of hole.
	Went in with core barrel. Plugged core barrel. Worked plug out. Pulled Core #2 from 6665.5' to 6687'. Recovered 21.5'.
8-30-64	Ran gamma ray induction log. Found cavings in hole at 6671'.
	Ran calseal plug from 6671' to 6648' using Schlumberger logging truck and dump bailer.
8-31-64	Started in hole with bit.
9- 1-64	Cleaned out to PBTD 6648'. Circulated 2 hours. Laid down drill pipe. Ran 40 joints 1296.16' TO 5-1/2" OD 17# J-55 casing, landed at 6648' RKB, cemented with 160 sacks regular cement. Top of liner 5348'.
9- 2-64	Temperature survey showed top of cement at 5350', plug at 6621'
9- 3-64	Ran tapered string of drill pipe (1500' of 2-7/8" on bottom, 4" on top). Pressure tested system with 2,000# with 75# pressure drop in 15 minutes. Pressure tested again with 1,000# with 25# pressure drop in 15 minutes. On both tests had surface leak which apparently accounted for pressure drop.
	Drilled cement plug and calseal and cleaned out to original TD 6687'. Circulated hole clean. Came out of hole and ran gamma ray induction log over zone below 5½" liner shoe.
9- 4-64	Started pumping oil into formation to determine injection rate. Pumped in a 3 BPM at 400# pressure. Pumped in at 6 BPM at 1300#. Dumped radioactive material to attempt to determine point of injection. Ran McCulloch gamma ray tracer log and determined injection point 6680-86'. Perforated with Schlumberger frac jets 2 per foot from 6668-6680'. System pressured up to 1500#. Would not take fluid at any measurable rate. Found cavings in hole. Circulated hole conventionally and reverse circulated. Pressured up on formation. Established new injection rate of 6 BPM at approximately 1150#.
9- 5-64	Laid down drill pipe. Rigged down rotary.

9-29-64	Sand-oil fraced 6648-87' using 12 Dowell Allison pump trucks and 4 blenders. Treated with 4,400 barrels oil, 150,000# 20/40 sand and 25,000# 10/20 sand, flushed with 260 barrels oil. Average overall injection rate 75 BPM. Breakdown pressure 2000#. Avg. TP 3000#, max. 3200#, min. 2900#. Inst. SIP 1300#, 1-min. SIP 1200#, 8-min. SIP 1100#, 12-min. SIP 1035#.
	After $3\frac{1}{2}$ hours well on vacuum.
	Total load oil 4,660 barrels.
10- 9-64	Moved in cable tools.
10-10-64	Rigged up.
10-26-64	Completed pressure survey. Lost bottom hole pressure bomb in hole.
10-27-64	Cleaning out and fishing for bomb at 6675' RKB. Top of cavings 6668'. Cleaned out shale and lost circulation material, no sand.
	Ran sand pump. Cleaned out small amount of shale, lost circulation material and rubber. Cleaned out to 6675' RKB.
10-29-64	Ran 169 joints 2-7/8" OD EUE tubing landed at 5323' RKB, with Kobe bottom hole assembly.
10-30-64	Ran $1\frac{1}{4}$" tubing.
11- 1-64	Pumped 635 barrels load oil in 25 hours.
11- 9-64	Pumped 476 barrels oil in 24 hours. 92 barrels balance of load, 384 barrels new oil.
	State Potential Test: 295 barrels oil in 15 hours.

DRILLING STATUS
CANADA OJITOS UNIT L-11 (12-11)

05/04/65	Shut well in to condition for taking bottom hole sample.
05/19/65	Moved in rig to pull tubing to condition well for bottom hole sample.
05/20/65	Pulled 1-1/4" and 2-7/8" OD EUE tubing.
05/21/65	7:00 AM Running 2-3/8" OD EUE tubing preparatory to swabbing to condition well for bottom hole sample. Ran 2-3/8" tubing to 2002' with perforated nipple and bull plug on bottom. Commenced swabbing.
05/22/65	Swabbed for 5 hours at rate of 3 barrels oil per hour. Swabbed total of 15 barrels. Shut down.
05/23/65	7:00 AM Shut down.
05/24/65	7:00 AM Preparing to resume swabbing. Swabbed at average rate of 4 barrels oil per hour. Total swabbed today 40 barrels. Total swabbed for conditioning 55 barrels.
05/25/65	Swabbed at average rate of 4 barrels oil per hour. Total swabbed this day 48 barrels. Total swabbed for conditioning 103 barrels.
05/26/65	Swabbed 49 barrels of oil in 8 hours. Approximate rate of 4-3/4 barrels oil per hour. Total swabbed for conditioning 141 barrels. Total subsequent to 12:00 noon 5/26 34 barrels.
05/27/65	Swabbed 39.5 barrels of oil in 11 hours. Approximate rate of 3-3/4 barrels of oil per hour. Total swabbed for conditioning 180.5 barrels. Total subsequent to 12:00 noon 5/26 73.5 barrels.
05/28/65	Swabbed 44.4 barrels oil in 11 hours at approximate rate of 4 barrels per hour. Total swabbaed for conditioning 224.9 barrels. Total swabbed subsequent to 12:00 noon 5/26 117.9 barrels.
05/29/65	Swabbed 46 barrels oil in 11 hours at approximate rate of 4 barrels per hour. Total swabbed for conditioning 270.9 barrels. Total swabbed subsequent to 12:00 noon 5/26 163.9 barrels.
05/30/65	Swabbed 42.3 barrels oil in 12 hours at approximate rate of 3.5 barrels per hour. Total swabbed for conditioning 313.2 barrels. Total swabbed subsequent to 12:00 noon 5/26 206.2 barrels.
05/31/65	Swabbed 47.1 barrels oil in 12 hours at approximate rate of 4 barrels per hour. Total swabbed for conditioning 360.3 barrels. Total swabbed subsequent to 12:00 noon 5/26 253.3 barrels.
06/01/65	7:00 AM CP 15#. Swabbed 27.9 barrels oil in 7 hours at approximate rate of 4 barrels oil per hour. Total swabbed for conditioning 388.2 barrels. Total swabbed subsequent to 12:00 noon 5/26 281.2 barrels.
06/02/65	7:00 AM CP 15#. Swabbed 46 barrels oil in 12 hours at approximate rate of 4 barrels per hour. Total swabbed for conditioning 434.2 barrels. Total swabbed subsequent to 12:00 noon 5/26 327.2 barrels.
06/03/65	Swabbed 48.2 barrels oil in 12 hours at approximate rate of 4 barrels per hour. Total swabbed for conditioning 482.4 barrels. Total swabbed subsequent to 12:00 noon 5/26 375.4 barrels.
06/04/65	6:00 AM CP zero. Started swabbing through separator. 12:00 noon CP 35#. 5:00 PM Swabbed 32.5 barrels oil in 11 hours. Shut down. Total swabbed for conditioning 514.9 barrels. Total swabbed subsequent to 12:00 noon 5/26 407.9 barrels.

06/07/65 Pulled tubing.

Ran Halliburton wire line. Found total depth at 6681' RKB.

Ran wooden float. Bailed clean oil off bottom. No water or sediment. Fluid level 1582' RKB.

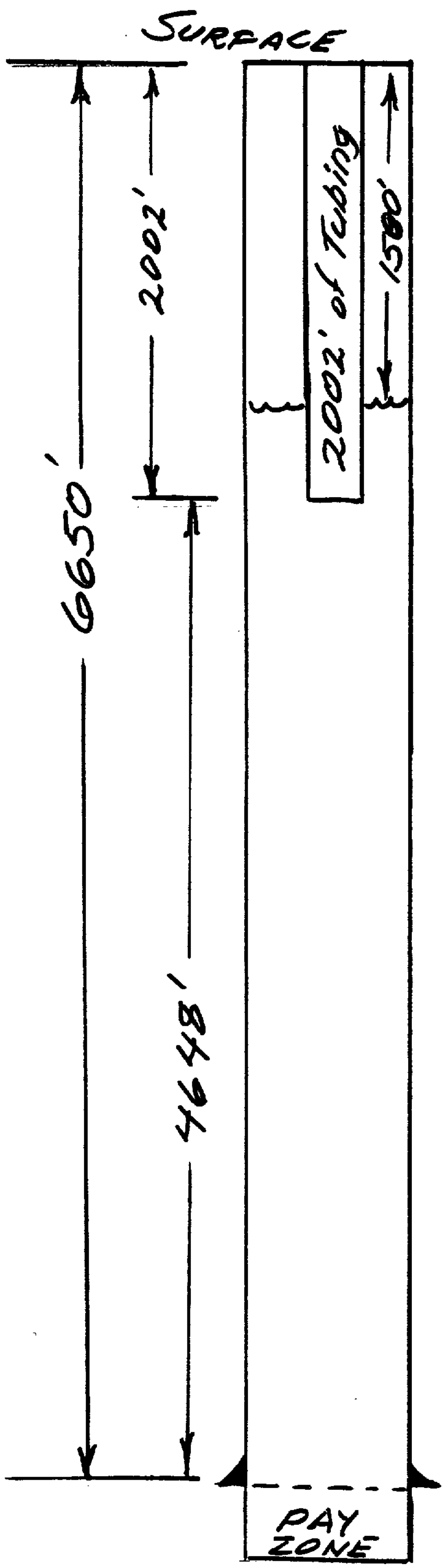
Ran bottom hole pressure bomb.

All wells shut in for interference test.

Report discontinued until operations resumed.

07/01/65 Took bottom hole sample.

CONDITIONING OF CANADA OJITOS UNIT L-11 (12-11)
MAY, 1965
PRIOR TO TAKING BOTTOM HOLE SAMPLE



Fluid Level 1580'

Swabbed at maximum rate of approximately 100 BOPD during daylight tour for 12 days for a total of 482 barrels.

At the well's PI of ± 2.25, drawdown pressure approximately 45#.

With static bottom hole pressure of ± 1670#, minimum bottom hole pressure while swabbing ± 1625#.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

July 27, 1965

RESERVOIR FLUID DIVISION

Benson-Montin-Greer Drilling Corporation
158 Petroleum Center Building
Farmington, New Mexico

Attention: Mr. Albert R. Greer

Subject: Reservoir Fluid Study
Bolack-Greer Inc.
Canada Ojitos Unit No. 12-11 Well
Puerto Chiquito Field
Rio Arriba County, New Mexico
Our File Number: RFL 3366

Gentlemen:

Subsurface fluid samples were collected from the subject well by a representative of Core Laboratories, Inc. and were delivered to our laboratory in Dallas for use in a reservoir fluid study. The results of this study are presented on the following pages.

The saturation pressure of the fluid was found to be 1519 psig at the reservoir temperature of 162° F. The associated formation volume factor was found to be 1.297 barrels of saturated fluid per barrel of residual oil. By differential pressure depletion the fluid evolved 478 standard cubic feet of gas per barrel of residual oil. Under similar depletion conditions the viscosity increased from a minimum of 0.625 centipoise at the saturation pressure to a maximum of 1.704 centipoises at atmospheric pressure. The saturation pressure of the fluid was measured at several different temperatures as you requested.

It has been a pleasure to perform this study for you. If you have any questions or if we may assist you further in any way, please do not hesitate to contact us.

Very truly yours,

Core Laboratories, Inc.
Reservoir Fluid Division

P. L. Moses (B)

P. L. Moses
Operations Supervisor

PLM:JB:bjm
7 cc. - Addressee

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

Company	Benson-Montin-Greer Drilling Corporation	Date Sampled	July 1, 1965
Well	Canada Ojitos Unit No. 12-11	County	Rio Arriba
Field	Puerto Chiquito	State	New Mexico

FORMATION CHARACTERISTICS

Formation Name	Nio Braro (Gallup)
Date First Well Completed	October, 1962
Original Reservoir Pressure	1631 PSIG @ 5957 Ft.
Original Produced Gas-Oil Ratio	SCF/Bbl
Production Rate	Bbl/Day
Separator Pressure and Temperature	PSIG, °F.
Oil Gravity at 60° F.	°API
Datum	Ft. Subsea
Original Gas Cap	

WELL CHARACTERISTICS

Elevation	7232 KB Ft.
Total Depth	6687 Ft.
Producing Interval	6648-6687 Ft.
Tubing Size and Depth	In. to Ft.
Productivity Index	Bbl/D/PSI @ Bbl/Day
Last Reservoir Pressure	1693 PSIG @ 6650 Ft.
Date	July 1, 1965
Reservoir Temperature	162 °F. @ 6650 Ft.
Status of Well	Shut in 27 days
Pressure Gauge	Amerada
Normal Production Rate	Bbl/Day
Gas-Oil Ratio	SCF/Bbl
Separator Pressure and Temperature	PSIG, °F.
Base Pressure	15.025 PSIA
Well Making Water	None % Cut

SAMPLING CONDITIONS

Sampled at	6650 KB Ft.
Status of Well	Shut in 27 days
Gas-Oil Ratio	SCF/Bbl
Separator Pressure and Temperature	PSIG, °F.
Tubing Pressure	0 PSIG
Casing Pressure	0 PSIG
Core Laboratories Engineer	NT
Type Sampler	Perco

REMARKS:

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

Well Canada Ojitos Unit No. 12-11

VOLUMETRIC DATA OF Reservoir Fluid SAMPLE

1. Saturation pressure (bubble-point pressure) 1519 PSIG @ 162 °F.

2. Thermal expansion of saturated oil @ 5000 PSI $= \frac{V @ 162 °F}{V @ 76 °F} =$ 1.04528

3. Compressibility of saturated oil @ reservoir temperature: Vol/Vol/PSI:

   From 5000 PSI to 3500 PSI = 8.24×10^{-6}

   From 3500 PSI to 2500 PSI = 9.49×10^{-6}

   From 2500 PSI to 1519 PSI = 10.68×10^{-6}

4. Specific volume at saturation pressure: ft^3/lb 0.02218 @ 162 °F.

5. Saturation pressure at various temperatures:

Temperature, °F.	Saturation Pressure, PSI	
	BHS No. 1	BHS No. 2
76	1203	1204
110	1351	-
152	1491	1492
162	1519	1519
172	1540	

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

Well Canada Ojitos Unit No. 12-11

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 162 °F., RELATIVE VOLUME OF OIL AND GAS, V/VSAT.	VISCOSITY OF OIL @ 162 °F., CENTIPOISES	DIFFERENTIAL LIBERATION @ 162 °F. GAS/OIL RATIO LIBERATED PER BARREL OF RESIDUAL OIL	GAS/OIL RATIO IN SOLUTION PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/VR
5000	0.9680	0.841			1.256
4500	0.9718				1.260
4000	0.9759	0.781			1.266
3500	0.9801	0.751			1.271
3000	0.9847	0.719			1.277
2500	0.9895	0.686			1.283
2300	0.9916				1.286
2100	0.9936				1.289
2000	0.9947	0.652			1.290
1900	0.9957				1.291
1800	0.9968				1.293
1700	0.9981				1.294
1600	0.9991				1.296
1519	1.0000	0.625	0	478	1.297
1508	1.0028				
1498	1.0054				
1481	1.0101				
1457	1.0162				
1429	1.0254				
1389			32	446	1.284
1369	1.0458				
1350		0.684			
1288	1.0766				
1259			65	413	1.270
1250		0.696			
1196	1.1174				
1129			96	382	1.257
1100		0.731			
1084	1.1789				
968	1.2610				
963			136	342	1.239
950		0.780			
858	1.3638				
812			173	305	1.224

V = Volume at given pressure
VSAT. = Volume at saturation pressure and the specified temperature.
VR = Residual oil volume at 14.7 PSI absolute and 60° F.

File RFL 3366
Well Canada Ojitos Unit
No. 12-11

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 162 °F., RELATIVE VOLUME OF OIL AND GAS, V/VSAT.	VISCOSITY OF OIL @ 162°F., CENTIPOISES	DIFFERENTIAL LIBERATION @ 162 °F.		
			GAS/OIL RATIO LIBERATED PER BARREL OF RESIDUAL OIL	GAS/OIL RATIO IN SOLUTION PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/VR
800		0.835			
750	1.4975				
658			211	267	1.207
657	1.6518				
650		0.900			
566	1.8577				
519			246	232	1.192
500		0.980			
479	2.1482				
413	2.4573				
359			287	191	1.175
350	2.8694				
298	3.3145				
250	3.8813	1.161			
218			328	150	1.156
108			367	111	1.133
0		1.704	478	0	1.049
				@ 60° F. =	1.000

Gravity of residual oil = 38.2° API @ 60° F.

V = Volume at given pressure
VSAT. = Volume at saturation pressure and the specified temperature.
VR = Residual oil volume at 14.7 PSI absolute and 60° F.

File RFL 3366

Well Canada Ojitos Unit
No. 12-11

Differential Pressure Depletion at 162° F.

Pressure PSIG	Oil Density Gms/Cc	Gas Gravity	Deviation Factor Z
1519	0.7223		
1389	0.7258	0.696	0.882
1259	0.7298	0.698	0.887
1129	0.7336	0.701	0.894
963	0.7389	0.709	0.902
812	0.7438	0.718	0.914
658	0.7487	0.731	0.929
519	0.7534	0.753	0.943
359	0.7589	0.791	0.958
218	0.7642	0.886	0.976
108	0.7716	1.067	
0	0.7939	1.702	

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

Well Canada Ojitos Unit No. 12-11

SEPARATOR TESTS OF Reservoir Fluid SAMPLE

SEPARATOR PRESSURE, PSI GAUGE	SEPARATOR TEMPERATURE, ° F.	SEPARATOR GAS/OIL RATIO See Foot Note (1)	STOCK TANK GAS/OIL RATIO See Foot Note (1)	STOCK TANK GRAVITY, ° API @ 60° F.	SHRINKAGE FACTOR, $V_R/V_{SAT.}$ See Foot Note (2)	FORMATION VOLUME FACTOR, $V_{SAT.}/V_R$ See Foot Note (3)	SPECIFIC GRAVITY OF FLASHED GAS
0	74	483		38.1	0.7639	1.309	0.986
40	74	386	27	39.6	0.7943	1.259	
80	74	354	55	39.6	0.7968	1.255	
160	74	300	110	39.4	0.7943	1.259	

(1) Separator and Stock Tank Gas/Oil Ratio in cubic feet of gas @ 60° F. and 14.7 PSI absolute per barrel of stock tank oil @ 60° F.

(2) Shrinkage Factor: $V_R/V_{SAT.}$ is barrels of stock tank oil @ 60° F. per barrel of saturated oil @ 1519 PSI gauge and 162 ° F.

(3) Formation Volume Factor: $V_{SAT.}/V_R$ is barrels of saturated oil @ 1519 PSI gauge and 162 ° F. per barrel of stock tank oil @ 60° F.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

Company Benson-Montin-Greer Drilling Corporation
Formation Nio Braro (Gallup)

Well Canada Ojitos Unit No. 12-11
County Rio Arriba

Field Puerto Chiquito
State New Mexico

HYDROCARBON ANALYSIS OF Reservoir Fluid SAMPLE

COMPONENT	MOL PER CENT	WEIGHT PER CENT	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Hydrogen Sulfide					
Carbon Dioxide	0.20	0.08			
Nitrogen	0.13	0.03			
Methane	26.36	3.65			
Ethane	6.86	1.78			
Propane	6.19	2.36			
iso-Butane	1.20	0.60			
n-Butane	4.29	2.15			
iso-Pentane	1.80	1.12			
n-Pentane	2.14	1.33			
Hexanes	4.49	3.34			
Heptanes plus	46.34	83.56	0.8474	35.3	209
	100.00	100.00			

Core Laboratories, Inc.
Reservoir Fluid Division

P. L. Moses (B)

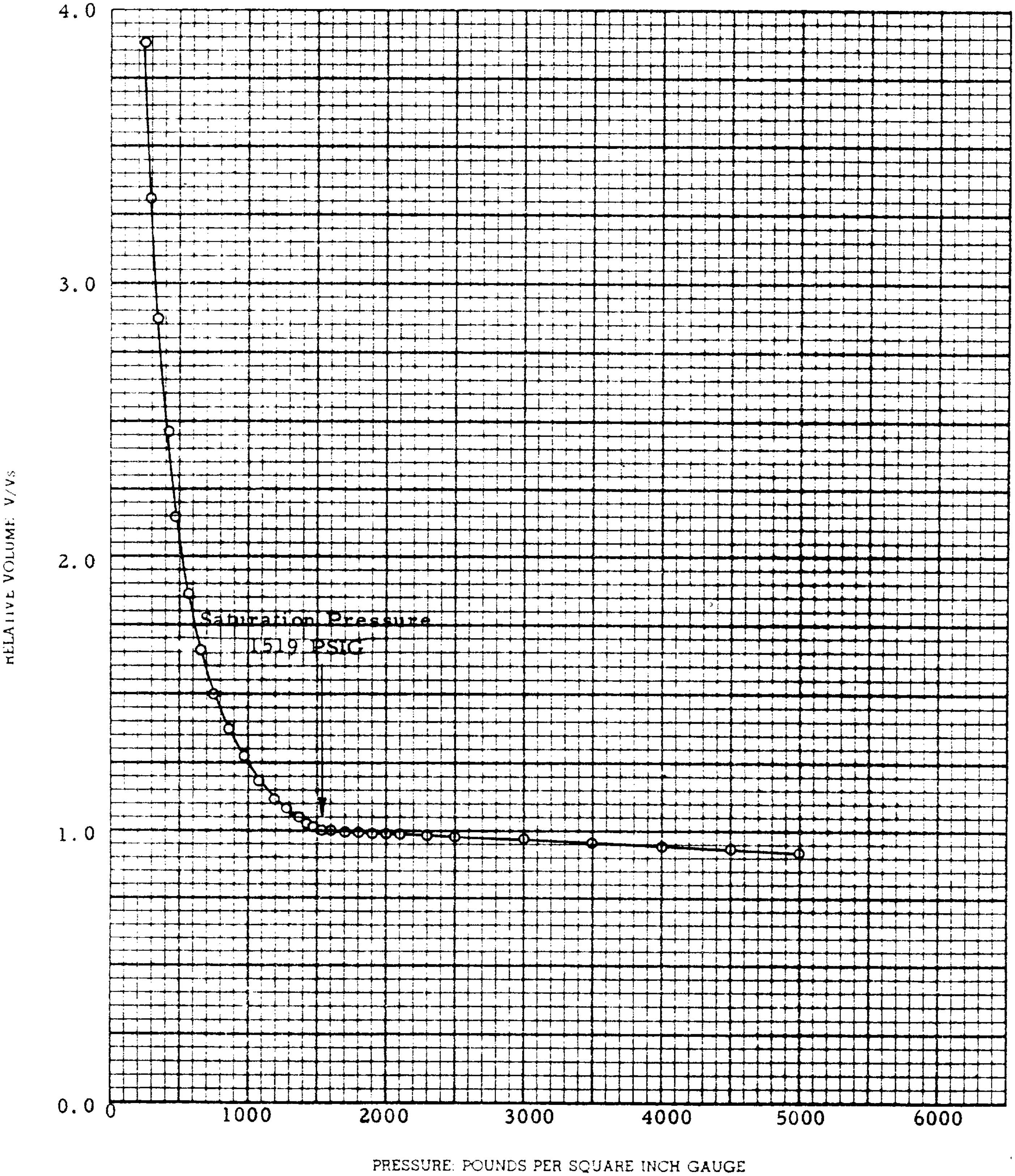
P. L. Moses
Operations Supervisor

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

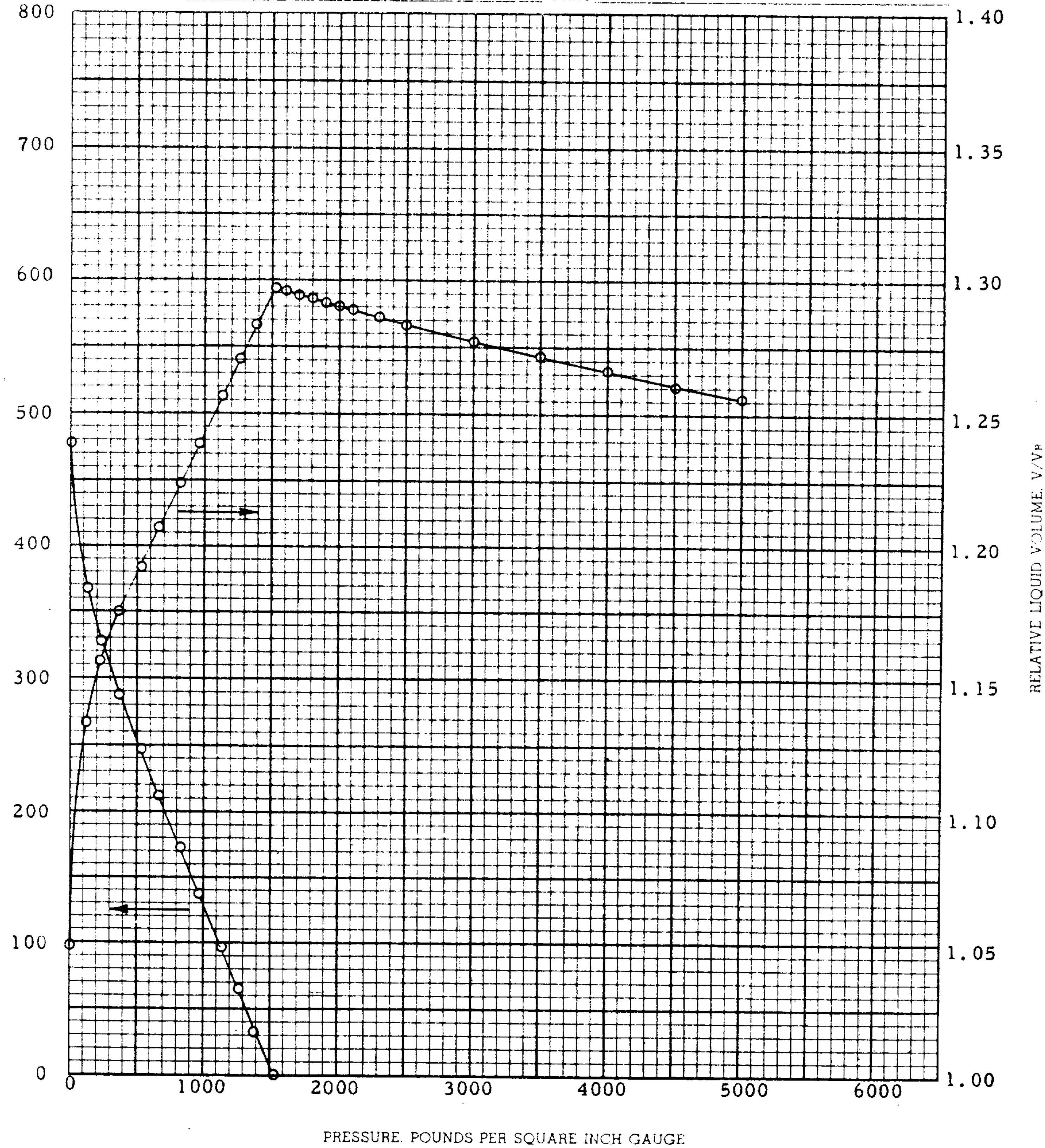
PRESSURE-VOLUME RELATIONS OF RESERVOIR FLUID

Company Benson-Montin-Greer Drilling Corporation
Formation Nio Braro (Gallup)
Well Canada Ojitos Unit No. 12-11
County Rio Arriba
Field Puerto Chiquito
State New Mexico



DIFFERENTIAL VAPORIZATION OF RESERVOIR FLUID

Company Benson-Montin-Greer Drilling Corporation
Formation Nio Braro (Gallup)
Well Canada Ojitos Unit No. 12-11
County Rio Arriba
Field Puerto Chiquito
State New Mexico



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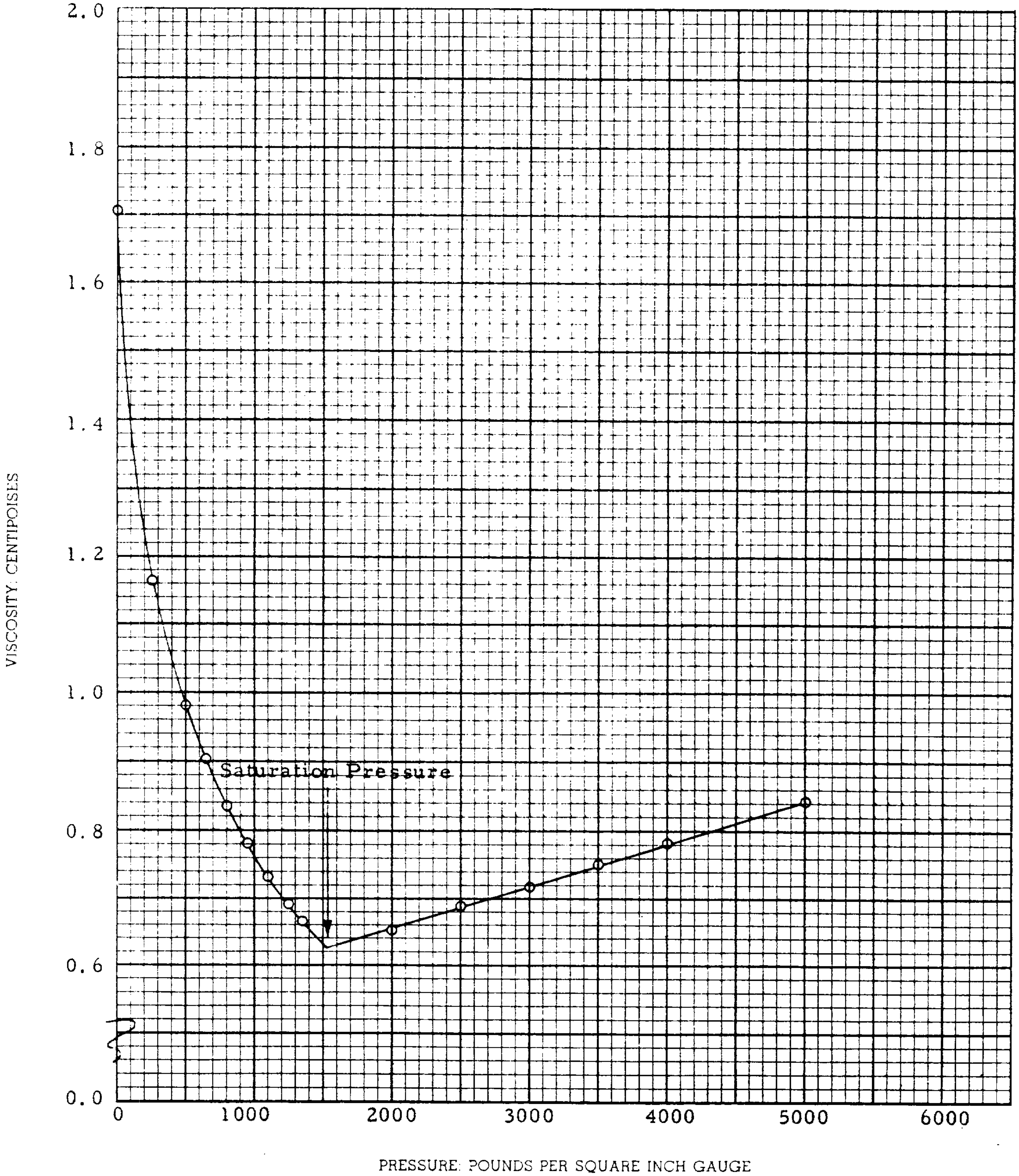
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

VISCOSITY OF RESERVOIR FLUID

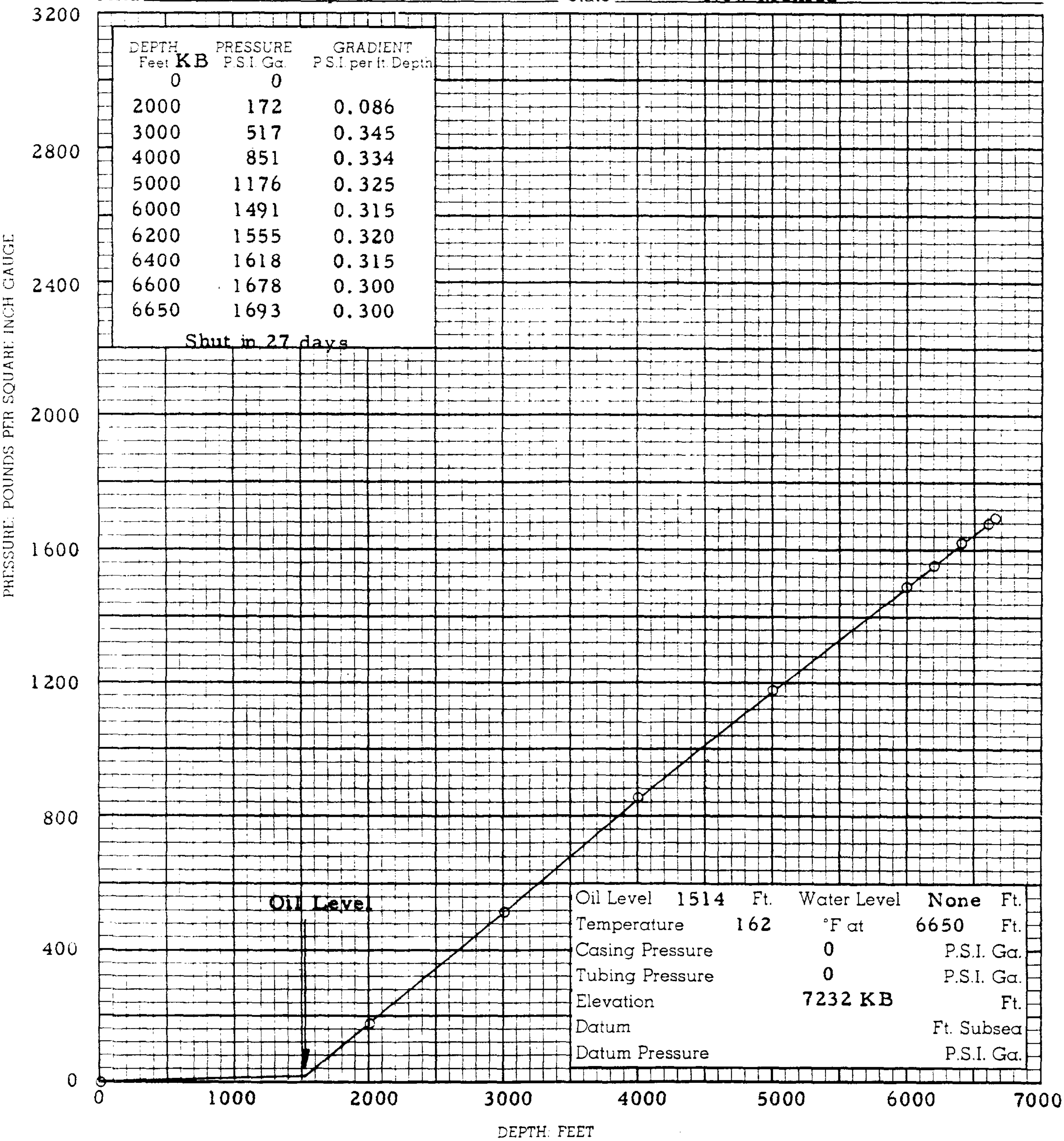
Company Benson-Montin-Greer Drilling Corporation | Formation Nio Braro (Gallup)
Well Canada Ojitos Unit No. 12-11 | County Rio Arriba
Field Puerto Chiquito | State New Mexico



CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

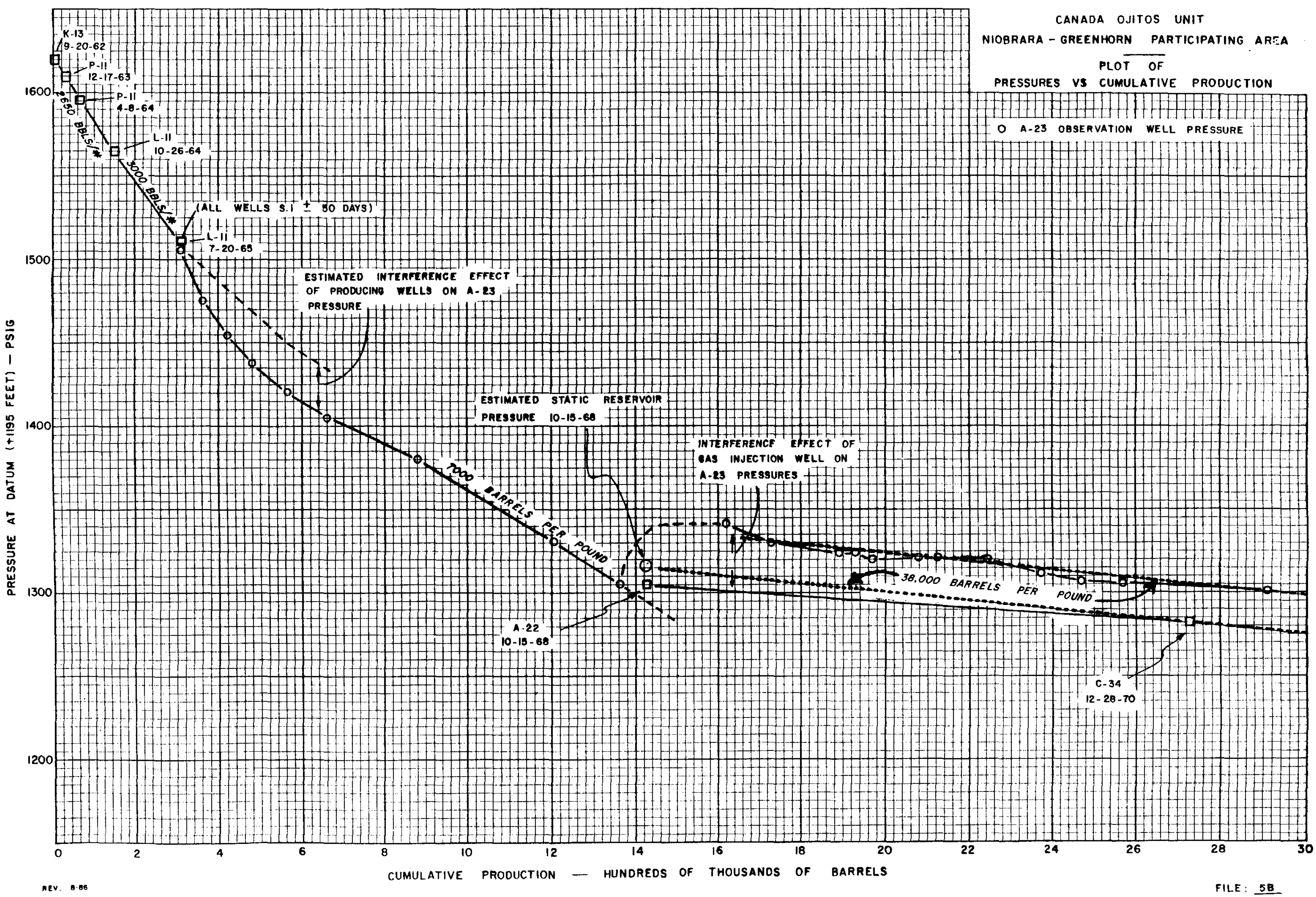
Company	Benson-Montin-Greer Drilling Corporation	Formation	Nio Braro (Gallup)
Well	Canada Ojitos Unit No. 12-11	County	Rio Arriba
Field	Puerto Chiquito	State	New Mexico



DEPTH Feet KB	PRESSURE P.S.I. Ga.	GRADIENT P.S.I. per ft. Depth
0	0	
2000	172	0.086
3000	517	0.345
4000	851	0.334
5000	1176	0.325
6000	1491	0.315
6200	1555	0.320
6400	1618	0.315
6600	1678	0.300
6650	1693	0.300

Shut in 27 days

Oil Level	1514 Ft.	Water Level	None	Ft.
Temperature	162	°F at	6650	Ft.
Casing Pressure		0		P.S.I. Ga.
Tubing Pressure		0		P.S.I. Ga.
Elevation		7232 KB		Ft.
Datum				Ft. Subsea
Datum Pressure				P.S.I. Ga.



CANADA OJITOS UNIT
NIOBRARA - GREENHORN PARTICIPATING AREA
PLOT OF
PRESSURES VS CUMULATIVE PRODUCTION
O A-23 OBSERVATION WELL PRESSURE
K-13
9-20-62
P-11
12-17-63
P-11
4-8-64
L-11
10-26-64
2650 BBLS/#
3000 BBLS/#
(ALL WELLS S.I ± 50 DAYS)
L-11
7-20-65
ESTIMATED INTERFERENCE EFFECT
OF PRODUCING WELLS ON A-23
PRESSURE
ESTIMATED STATIC RESERVOIR
PRESSURE 10-15-68
7000 BARRELS PER POUND
INTERFERENCE EFFECT OF
GAS INJECTION WELL ON
A-23 PRESSURES
38,000 BARRELS PER POUND
A-22
10-15-68
C-34
12-28-70
1600
1500
1400
1300
1200
PRESSURE AT DATUM (+1195 FEET) — PSIG
0
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30
CUMULATIVE PRODUCTION — HUNDREDS OF THOUSANDS OF BARRELS
REV. 8-66
FILE: 5B

ESTIMATED BUBBLE POINT
FOR
GAVILAN

From Canada Ojitos Unit K-13	1524# (@ 152°)	+	54#*	= 1578#
From Canada Ojitos Unit L-11	1519# (@ 162°)	+	24#*	= 1543#

* At 3 psi/degree (from Core Lab tests)

GAVILAN MANCOS FIELD, RIO ARRIBA CO., N.M.
J.P. MCHUGH, NATIVE SON #1 (NE 34-25N-2W) NATIV1
Working Interest: 1.000000 Net Interest: 1.000000

			Oil/Cond Bbls			Gas MCF				Water Bbls				Days
Mo	Year	Status	Day*	Month	Cum	Day*	Month	Cum	GOR	Day*	Month	Cum	WC	Prod
7	1984		191.2	5927.	5927.	0.	0.	0.	0.	1.2	38.	38.	0.6	19.0
8	1984		288.4	8939.	14866.	0.	0.	0.	0.	2.0	62.	100.	0.7	30.0
9	1984		422.8	12683.	27549.	2.	48.	48.	4.	0.3	10.	110.	0.1	30.0
10	1984		299.5	9284.	36833.	2.	50.	98.	5.	0.3	10.	120.	0.1	30.0
11	1984		398.1	11944.	48777.	2.	48.	146.	4.	0.0	0.	120.	0.0	30.0
12	1984		2.0	62.	48839.	0.	2.	148.	32.	0.0	0.	120.	0.0	1.0
Subtotal 1984				48839.			148.				120.			140.0
1	1985	SI	0.0	0.	48839.	0.	0.	148.	0.	0.0	0.	120.	0.0	0.0
2	1985	SI	0.0	0.	48839.	0.	0.	148.	0.	0.0	0.	120.	0.0	0.0
3	1985		40.1	1244.	50083.	0.	6.	154.	5.	0.0	1.	121.	0.1	4.0
4	1985		156.2	4686.	54769.	167.	5004.	5158.	1068.	0.0	0.	121.	0.0	30.0
5	1985		184.0	5705.	60474.	11.	331.	5489.	58.	0.0	0.	121.	0.0	31.0
6	1985		415.1	12454.	72928.	20.	586.	6075.	47.	0.0	0.	121.	0.0	0.0
7	1985		367.1	11381.	84309.	175.	5428.	11503.	477.	0.0	0.	121.	0.0	31.0
8	1985		421.8	13075.	97384.	195.	6039.	17542.	462.	0.6	20.	141.	0.2	31.0
9	1985		357.1	10714.	108098.	134.	4009.	21551.	374.	0.0	0.	141.	0.0	30.0
10	1985		371.0	11500.	119598.	123.	3828.	25379.	333.	0.0	0.	141.	0.0	31.0
11	1985		419.2	12575.	132173.	147.	4395.	29774.	350.	0.0	0.	141.	0.0	27.0
12	1985		302.3	9370.	141543.	81.	2514.	32288.	268.	0.0	0.	141.	0.0	31.0
Subtotal 1985				92704.			32140.				21.			246.0
1	1986		371.6	11521.	153064.	117.	3623.	35911.	314.	0.0	0.	141.	0.0	27.0
2	1986		419.6	11750.	164814.	173.	4851.	40762.	413.	0.0	0.	141.	0.0	27.0
3	1986		379.9	11776.	176590.	136.	4216.	44978.	358.	0.0	0.	141.	0.0	31.0
4	1986		287.9	8636.	185226.	81.	2432.	47410.	282.	0.0	0.	141.	0.0	30.0
5	1986		334.5	10370.	195596.	62.	1912.	49322.	184.	0.0	0.	141.	0.0	31.0
Subtotal 1986				54053.			17034.				0.			146.0

* Per Calendar Day

Initial Potential: 6/84 198 BOPD, 324 MCFD, IPF

MALLON & MESA GRANDE
EXHIBIT MARKED
PRODUCING HISTORY
CASE NO. 8946

H

GAVILAN MANCOS FIELD, RIO ARRIBA CO.
J.P. MCHUGH, HOMESTEAD RANCH #2, (SW 34-25N-2W) HORA2
Working Interest: 1.000000 Net Interest: 1.000000

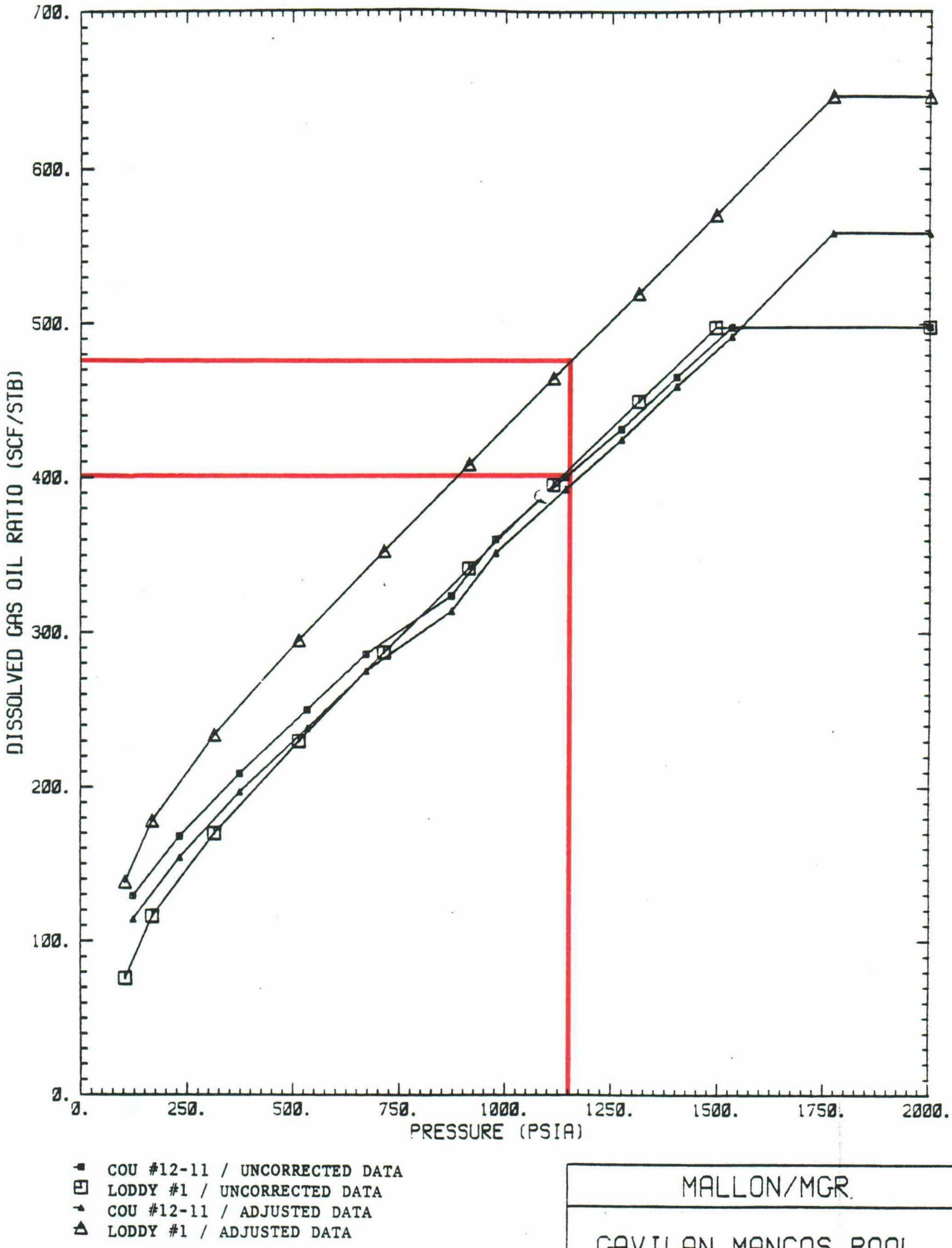
			Oil/Cond Bbls			Gas MCF				Water Bbls				Days
.o	Year	Status	Day*	Month	Cum	Day*	Month	Cum	GOR	Day*	Month	Cum	WC	Prod
5	1985	0	533.4	2667.	2667.	122.	610.	610.	229.	0.0	0.	0.	0.0	5.0
6	1985	SI	0.0	0.	2667.	0.	0.	610.	0.	0.0	0.	0.	0.0	0.0
7	1985	0	323.0	646.	3313.	120.	240.	850.	372.	5.0	10.	10.	1.5	2.0
8	1985	SI	0.0	0.	3313.	0.	0.	850.	0.	0.0	0.	10.	0.0	0.0
9	1985	SI	0.0	0.	3313.	0.	0.	850.	0.	0.0	0.	10.	0.0	0.0
10	1985	0	517.1	4654.	7967.	192.	1727.	2577.	371.	0.6	5.	15.	0.1	9.0
11	1985	0	670.2	20105.	28072.	249.	7460.	10037.	371.	0.3	10.	25.	0.0	30.0
12	1985	0	648.7	12973.	41045.	241.	4814.	14851.	371.	0.5	10.	35.	0.1	20.0
Subtotal	1985			41045.			14851.				35.			66.0
1	1986	SI	0.0	0.	41045.	0.	0.	14851.	0.	0.0	0.	35.	0.0	0.0
2	1986	SI	0.0	0.	41045.	0.	0.	14851.	0.	0.0	0.	35.	0.0	0.0
3	1986	SI	0.0	0.	41045.	0.	0.	14851.	0.	0.0	0.	35.	0.0	0.0
4	1986	SI	0.0	0.	41045.	0.	0.	14851.	0.	0.0	0.	35.	0.0	0.0
5	1986	0	570.0	14249.	55294.	120.	2992.	17843.	210.	0.0	0.	35.	0.0	25.0
Subtotal	1986			14249.			2992.				0.			25.0

* Per Producing Day

Initial Potential: 5/85 700 BOPD, 260 Mcfd, IPF

GREER NOTE:
1st delivery into
McH P/L system

MALLON & MESA GRANDE
EXHIBIT MARKED
PRODUCING HISTORY
CASE NO. 8946



MALLON/MGR	
GAVILAN MANCOS POOL DISSOLVED GAS OIL RATIO PLOTS	
SCALE: NTS	DATE: 04-AUG-86
SOURCE:	DRAWING NO. 1
Jerry R. Bergeson & Associates Inc.	

OIL CONSERVATION DIVISION

MR. STAMETS

BENSON-MONTIN-GREER DRILLING CORP.
EXHIBITS IN CASE NOS. 8946 & 8950
BEFORE THE OIL CONSERVATION DIVISION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

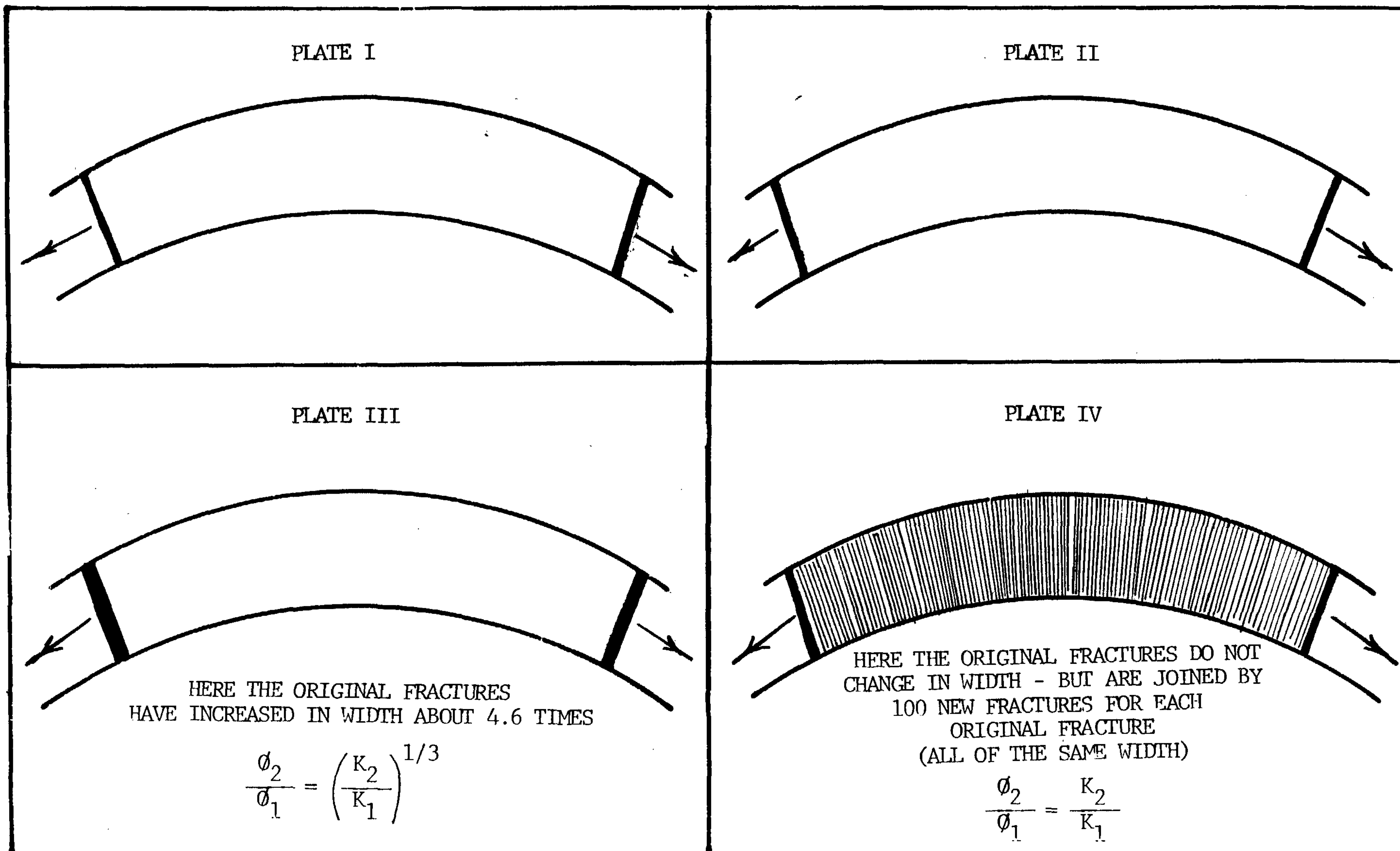
AUGUST 7, 1986

Exhibit #7

COMPARISON OF POROSITY AND PERMEABILITY FOR TWO SYSTEMS OF FRACTURING

IN PLATES I AND II THE FORMATION AT TWO DIFFERENT LOCATIONS IS STRESSED (TENSION) TO SAME DEGREE AND EACH HAS SAME NUMBER OF SAME SIZE FRACTURES

IN PLATES III AND IV THE FORMATIONS HAVE BEEN STRESSED AN ADDITIONAL AMOUNT SO THAT THE PERMEABILITY HAS BEEN INCREASED 100-FOLD



DIRECT COMPARISON OF POROSITY TO PERMEABILITY RELATIONS FOR OIL WELL RECOVERIES

(Actual recoveries from any well will depend on a number of factors, including the area drained by the well, but assuming these ancillary matters to be the same, then the following shows how unlikely it is that porosity will bear a direct relation to permeability.)

Example Wells:

Compare Canada Ojitos Unit C-2 initial productivity with the Canada Ojitos Unit B-29, use the C-2 cumulative recovery and project the B-29 cumulative recovery (C-2 cumulative = 230 Mbbls):

Comparative Productivities			Cube Root of Ratio of Productivities	Projected Recovery of B-29	
C-2 (BOPD)	B-29 (BOPD)	Ratio B-29 to C-2		By Cube Root of Ratio of Productivities (Mbbls)	By Direct Ratio of Productivities (Mbbls)
56	15,000	270	6.45	1,500	62,000

VOL. 52, NO. 1 (JANUARY, 1968), PP. 57–65, 5 FIGS., 1 TABLE

QUANTITATIVE FRACTURE STUDY—SANISH POOL, McKENZIE COUNTY, NORTH DAKOTA[1]

GEORGE H. MURRAY, JR.[2]
Billings, Montana 59102

ABSTRACT

The Devonian Sanish pool of the Antelope field has several unusual characteristics which make it almost unique in the Williston basin. Some of these are: (1) high productivity of several wells from a nebulous, ill-defined reservoir; (2) association with the steepest dip in the central part of the basin; (3) very high initial reservoir pressure; and (4) almost complete absence of water production.

Analysis of these factors indicates that Sanish productivity is a function of tension fracturing associated with the relatively sharp Antelope structure. Fracture porosity and fracture permeability can be related mathematically to bed thickness and structural curvature (the second derivative of structure). It is found that fracture porosity varies directly as the product of bed thickness times curvature and that fracture permeability varies as the third power of this product. A map of structural curvature in the Sanish pool shows good coincidence between areas of maximum curvature and areas of best productivity.

Volumetric considerations show that the quantities of oil being produced cannot be coming from the Sanish zone. It is concluded that the overlying, very petroliferous Bakken Shale is the immediate, as well as the ultimate, source of this oil. The role of the Sanish fracture system is primarily that of a gathering system for many increments of production from the Bakken.

The extremely high initial reservoir pressure indicates that the Sanish-Bakken accumulation is in an isolated, completely oil-saturated reservoir and, hence, is independent of structure in the normal sense. Similar accumulations should be present anywhere in the Williston basin where a permeable bed, of limited areal extent, is in direct contact with either of the two Bakken shale beds.

INTRODUCTION

The Sanish pool is one of several oil accumulations in the Antelope field of McKenzie County, North Dakota. As shown in Figure 1, this field is on a relatively sharp, southeast-trending anticline on the east side of the Nesson uplift of the central Williston basin. The field discovery, the Pan American No. 1 Woodrow Starr, SW¼ SE¼, Sec. 21, T. 152 N., R. 94 W., was completed in December 1953 with an initial flow potential of 550 bbl a day from 10,526–10,566 ft in the Devonian Sanish zone. Production in the Mississippian Madison Group was established in May 1956, and production in the Devonian Nisku and Duperow Formations and in the Silurian section was found in 1960. One well, the Amerada No. 1 Nelson, SW¼ SW¼, Sec. 5, T. 152 N., R. 94 W., recently has been recompleted as a discovery well in the Mississippian Lodgepole Formation. Cumulative production as of July 1, 1966 was 7,986,141 bbl from the Madison, 7,140,448 bbl from the Sanish, 1,072,890 bbl from the Duperow, and 1,477,410 bbl from the Silurian, a total of approximately 17 million bbl.

The Madison, Nisku, Duperow, and Silurian pools generally may be considered to be conventional structural accumulations. The Sanish pool, however, has several unusual characteristics which make it almost unique in the Williston basin. To date, the only other Sanish production in the United States part of the basin has been in the one-well, subcommercial Elkhorn Ranch field in Sec. 5, T. 143 N., R. 101 W., Billings County, North Dakota. Some of the very interesting aspects of the Antelope Sanish accumulation are a very high initial reservoir pressure, the high productivity of several wells from a nebulous, ill-defined reservoir, and, in contrast to most Williston basin fields, an almost complete absence of water production.

LITHOLOGIC AND RESERVOIR CHARACTERISTICS

SANISH ZONE

As shown in Figure 2, the so-called "Sanish zone" is at the very top of the Devonian Three Forks Formation, just below the lower Bakken shale. A thin, very dolomitic sandstone at the top of this interval was termed the "Sanish Sand" during the early development of the field. It originally was believed that the limits of Sanish production would be related to the areal extent

[1] Manuscript received, November 5, 1966; accepted, June 16, 1967. Modified from a paper presented before the 15th annual meeting, AAPG Rocky Mountain Section, Billings, Montana, September 28, 1965.

[2] Independent geologist.

The writer is indebted to W. H. Somerton, Univ. California, Berkeley, for checking the mathematical treatment presented herein.

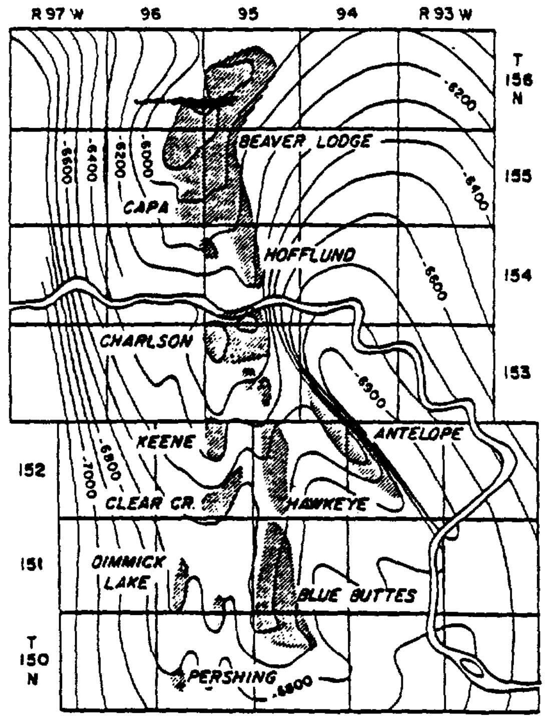


FIG. 1.—Regional structural contour map of McKenzie County area, North Dakota. Structural datum, base of lowest Charles (Mississippian) salt. Map shows location of oil pools on part of Nesson anticline. Contour interval, 100 ft. Contour datum, sea level.

and degree of development of this sandstone. However, subsequent drilling showed that this sandstone is absent in much of the field. Where the sandstone is absent, the Sanish zone consists of gray, very dense dolomite, commonly sandy, interbedded and intercalated with waxy, greenish, pyritic shale typical of the underlying Three Forks section.

Surprisingly, some of the wells with the best-developed Sanish sandstone have been among the poorest producers, whereas others with no sandstone have been among the best producers. For example, the No. 1 Reed-Norby Unit, NW¼ NE¼, Sec. 6, T. 152 N., R. 94 W., penetrated 4 ft of sandstone but has been a poor producing well. Cumulative production to July 1, 1966, was 73,876 bbl and productive capability at that time was less than 15 bbl a day. In contrast, the Carter No. 1 Norby-Melby Unit, SW¼ NE¼, Sec. 7, T. 152 N., R. 94 W., found no sandstone but has been one of the best wells in the field. Cumulative production to July 1, 1966 was 511,910 bbl and the producing rate then was approximately 270 bbl a day.

Core analyses of the Sanish section indicate poor reservoir parameters regardless of the presence or absence of sandstone development. Porosity averages between 5 and 6 percent and plug permeability almost invariably is less than 0.1 md. Despite a universal absence of initial water production, core analyses indicate wide variations in oil and water saturations among wells.

BAKKEN FORMATION

The Mississippian Bakken Formation is composed of three easily differentiated units. The most striking of these are the two shale beds at the top and bottom of the formation, respectively. These are very radioactive, black, petroliferous shale and undoubtedly are source beds throughout the central Williston basin. They invariably have shows of oil and gas in cuttings and their log characteristics also are strong evidence for their identification as source beds. Their fluid-filled pore space, as indicated by velocity and/or neutron logs, is normal or greater than normal for shale at the depth at which they are found. Their

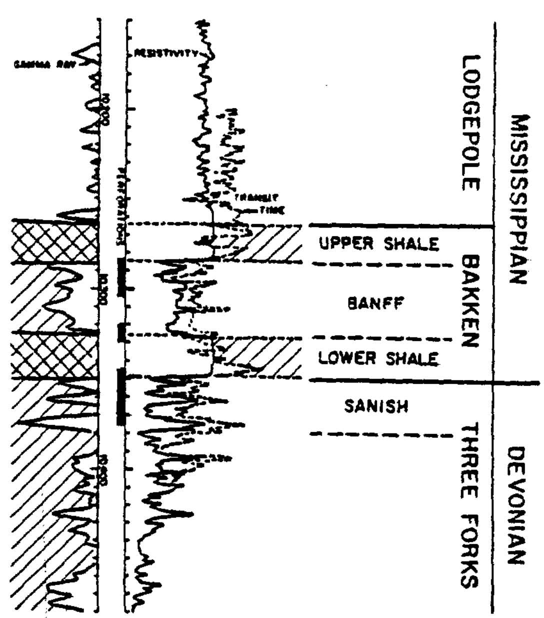


FIG. 2.—Logs from Lloyd H. Smith No. 1-A Weedeman, SE¼ SW¼, Sec. 29, T. 153 N., R. 94 W., McKenzie County, North Dakota, showing typical productive section. Curve on left is gamma ray. Solid curve on right is resistivity. Dashed curve is interval transit time. Depths (from surface) in feet.

resistivity, however, is essentially infinite. This fact, in conjunction with the visibly petroliferous character of the two shales, indicates that their pore space is hydrocarbon-saturated. The lower shale was perforated together with the Sanish section in several wells. However, no attempt has been made to separate the production by zones. Consequently, the direct contribution of the shale to the total production is unknown.

The section between the two shale zones is composed of dolomite, dolomitic siltstone, and minor quantities of shale. As might be expected, this section, called the "Banff member" by some workers, generally carries oil shows. This section also was perforated in conjunction with the Sanish zone in several wells in the field. However, as in the case of the lower shale, no attempt has been made to measure the production from the Banff independently of that from the Sanish.

LODGEPOLE FORMATION

The interbedded limestone and shale of the Mississippian lower Lodgepole Formation overlie the upper Bakken shale. This lower part of the Madison Group recently has been proved to be productive in a rework of the Amerada No. 1 Nelson, SW¼ SW¼, Sec. 5, T. 152 N., R. 94 W. Although not discussed here, this Lodgepole accumulation probably is related closely to the Bakken-Sanish pool.

Role of Fracturing in Sanish Production

THEORY

Because the productivity of individual Sanish wells appears to be unrelated to variations in reservoir lithology and because measured porosity and plug permeability are very low, it appears reasonable to assume that productivity is related to fracturing. Although core descriptions do not indicate an unusual degree of fracturing, a few fractures were noted. The data from the Carter No. 1 Norby-Melby Unit illustrate the peculiarities of the Sanish reservoir which lead to the hypothesis that fracturing is the controlling parameter. This well found no sandstone in the Sanish section—only dense dolomite and shale with some slight fracturing. Whole-core analysis shows an average porosity of approximately 5.5 percent and permeability below 1.0 md, except for a value of 27 md in a 1-ft zone and another value of 6.7 md in another 1-ft zone. Nevertheless, this well has been one of the best in the field! The writer believes that the only logical hypothesis to explain this fact is that the more than 500,000 bbl which has been produced from this well has come from fractures in the 2 ft of section with whole-core permeability values greater than 1.0 md.

The important role of fracturing also is suggested by the association of this production with the area of steepest dip in the central Williston basin. A cursory examination of the Sanish pool shows that the best wells are concentrated along the northwest-southeast line where the Antelope anticline bends abruptly from the relatively flat crest into the steep, northeast flank (Fig. 4). It is intuitively reasonable that the greatest intensity of tension fracturing would be in this position, where structural curvature (rate of change of dip, or structural second derivative) is greatest. Although this simple observation reinforces the hypothesis of a fractured reservoir, it indicates nothing about the magnitudes of fracture porosity and fracture permeability or about the minimum curvature necessary for the development of fractures.

To attempt to answer these questions, with particular reference to the Sanish pool and the individual wells in the pool, the writer has derived two mathematical relations which express fracture porosity and fracture permeability, respectively, as functions of bed thickness and structural curvature. Because the Antelope anticline is relatively elongate, the equations have been derived for a structural configuration which is infinite in the axial direction. This greatly simplifies the mathematical treatment.

Figure 3 shows a cross section of a segment of a competent bed, of thickness T feet, folded into an arc, of radius of curvature R feet. The folding is assumed to be sufficiently sharp to have caused stress greater than the ultimate tensile strength of the bed and, consequently, to have resulted in tension fractures represented by the idealized pie-shape voids. For convenience, the neutral surface (surface of no change in length, or no strain) has been taken as the base of the competent bed. The Z axis of Figure 3 is vertical; the Y axis—normal to the page—is chosen to coincide with the direction of the structural axis; and the X axis is the horizontal axis at right angles to the structure. The angle θ, measured in radians in a counter-

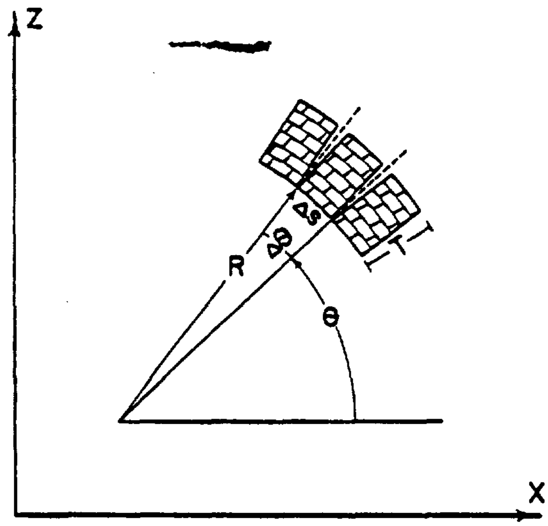


FIG. 3.—Geometry of fracture system used in deriving expressions for fracture porosity and fracture permeability.

clockwise direction from the positive X axis, is the angle made by a normal to the competent bed. The angular increment between adjacent fractures is represented by $\Delta\theta$. The corresponding increment in the surface of the fractured bed is represented by Δs.

The fractional porosity of the fracture system is determined easily from the geometry of the figure. Because the structural configuration and porosity are unchanging in the axial direction, the porosity may be calculated by considering a "slice" of the structure of unit length in the Y direction. Thus, from the expression for the area of a sector of a circle, the fractional porosity, ϕ, of that segment of the reservoir bounded by the two sides of angle $\Delta\theta$, the top and bottom of the bed, and unit length in the Y direction is given by

$$\phi = \frac{\frac{1}{2}(2RT + T^2)\Delta\theta - T\Delta s}{\frac{1}{2}(2RT + T^2)\Delta\theta}.$$

Because

$$\Delta s = R\Delta\theta,$$

this may be reduced to

$$\phi = \frac{T}{2R + T}.$$

T generally is very small in comparison with R. For example, the greatest thickness of any single competent bed, T, in the Sanish zone is on the order of 10 ft, whereas the minimum value of R for the Antelope structure is approximately 10,000 ft. Hence, the last expression may be reduced to

$$\phi = T/2R. \qquad (1)$$

It is useful to express the radius of curvature R in terms of the derivatives in the $X-Z$ coordinate system permitting the graphical evaluation of equation (1) from structural cross sections. In the usual structural situation, dz/dx, the dip measured in feet per feet is very small in comparison with unity. Hence, as is proved in most elementary calculus texts (Sherwood and Taylor, 1946), it is sufficiently accurate to take

$$R = 1 \Big/ \frac{d^2z}{dx^2}.$$

From this expression it may be observed that the curvature, which is defined as the reciprocal of the radius of curvature, is simply the second derivative of structure, d^2z/dx^2. Substitution into (1) yields the simple expression

$$\phi = \frac{1}{2}T\frac{d^2z}{dx^2} \qquad (2)$$

for fractional porosity as a function of bed thickness and structural curvature.

It should be noted that fracture porosity generally is very small. For example, use of the maximum and minimum values of T and R, respectively, for the Sanish pool gives a maximum fracture porosity of approximately 1/2,000, or 1/20 of 1 percent.

As might be expected, fracture permeability is much more significant. The basic expression used in deriving the relationship between fracture permeability, bed thickness, and structural curvature is the equation for the volume of fluid flow per unit length between two parallel plates (Lamb, 1932),

$$q_p = -\frac{h^3}{12\mu}\frac{dp}{dy}$$

where h is the separation of the plates, μ is fluid viscosity, and dp/dy is the pressure gradient in the direction of flow. The minus sign arises because the direction of flow is in the direction of decreasing pressure. Because the angular divergence of the fracture faces is very small, the total volume of flow through one of the pie-shape fractures may be approximated by

$$Q = \int_0^T q_p dl = -\frac{1}{12\mu}\frac{dp}{dy}\int_0^T h^3 dl$$

where t is the distance in the fracture above the point of zero separation, or above the base of the fractured bed. For the pie-shape fracture, $h=kt$ and

$$Q=-\frac{k^3}{12\mu}\frac{dp}{dy}\int_0^T t^3dt=-\frac{k^3T^4}{48\mu}\frac{dp}{dy}.$$

The average flow per unit area is the total flow per fracture divided by the average area A per fracture,

$$q=\frac{Q}{A}=-\frac{k^3T^4}{48\mu A}\frac{dp}{dy}.$$

In order to evaluate k, it is noted that

$$\frac{\frac{1}{2}h_0T}{A}=\phi \quad \text{and thus } k=\frac{A}{T^2}\left(T\frac{d^2z}{dx^2}\right),$$

where h_0 is fracture width at the top of the bed. Hence,

$$q=-\frac{A^2}{48T^2\mu}\left(T\frac{d^2z}{dx^2}\right)^3\frac{dp}{dy}.$$

From the last expression the permeability is seen to be given by

$$K=\frac{A^2}{48T^2}\left(T\frac{d^2z}{dx^2}\right)^3.$$

After conversion from cgs units to the more familiar millidarcy (Pirson, 1950) and evaluation of A in terms of an assumed fracture spacing of 6 in., this expression reduces to

$$K=4.9\times10^{11}\left(T\frac{d^2z}{dx^2}\right)^3. \qquad (3)$$

$\phi \doteq 0.0006\sqrt[3]{k, \text{darcys}}$

Although the assumption of a fracture spacing of 6 in. admittedly is arbitrary, there are certain considerations leading to this as a reasonable approximation. If the fracture spacing were much greater than this it would be possible for some of the favorably located wells to have missed the fracturing altogether. There is no evidence of this in the Sanish pool. Also, assumption of wider spacing leads to unreasonably large values of calculated permeability. Finally, the writer's field experience leaves the impression that a 6-in. fracture spacing may be somewhat short, but that it is not entirely unreasonable.

Because permeability increases as the third power of $T\,d^2z/dx^2$, it becomes appreciable with relatively small values of this parameter. The tabulations in Table I give illustrative permeability values for different values of T and d^2z/dx^2.

TABLE I. EXAMPLES OF PERMEABILITY VALUES

$T=5$ ft		$T=10$ ft	
$\frac{d^2z}{dx^2}(\times10^{-6})$	K (md)	$\frac{d^2z}{dx^2}(\times10^{-6})$	K
1	0.06	1	0.49
2	0.49	2	3.92
4	3.92	4	31.20
6	13.20	6	106.00

The figures in Table I should not be taken too literally. The configuration of a natural fracture system undoubtedly varies considerably from the assumptions made in deriving the above expressions for porosity and permeability. Particularly subject to question are the assumptions that the base of the competent bed is a neutral surface and that the fracture spacing is 6-in. It also is apparent that the regular, pie-shape fracture voids are an oversimplification. In some cases the value of bed thickness is uncertain. T represents the thickness of a single competent bed unbroken by shale intercalations capable of providing slippage. In a section like the Sanish, with abundant shale intercalations, a value for T is difficult to ascertain. Despite these uncertainties, it is believed that the above expressions are important as indications of the order of magnitude of fracture porosity and fracture permeability which might be expected with a particular bed thickness and structural configuration.

It should be noted that a minimum value of the parameter $T\,d^2z/dx^2$ must be exceeded before fracturing is developed. It is easily shown that the tensile stress in the upper surface of the bed of Figure 3 is given by

$$F=ET\frac{d^2z}{dx^2}$$

where F is the stress in the upper surface and E is Young's modulus for the bed (Stephenson, 1952). If $T\,d^2z/dx^2$ is such that F exceeds the ultimate tensile strength of the bed, fractures will develop. A rough idea of this critical value may be obtained from measured values of the ultimate tensile strength and Young's modulus of building stones. Some average values (Kidder and Parker, 1935) would give a critical value of about 1.2×10^{-4} for $T\,d^2z/dx^2$ in the case of a limestone. As discussed hereafter, the empirically determined critical value of structural curvature, d^2z/dx^2, for the presence of Sanish fracturing appears to be about 2×10^{-6}. Depending on the exact value of T, this would place $T\, d^2z/dx^2$ near the above figure of 1.2×10^{-4}.

APPLICATION TO SANISH POOL

Figure 4 shows the correlation between well productivity and structural curvature in the Sanish pool. Figure 5 shows how the values of curvature on the map were obtained. At the top of Figure 5 is a structural profile of the Bakken Formation along section A-B. The central profile is a plot of dip magnitude along this line of section. This second curve has been obtained from the first by drawing tangents to the first curve, as indicated, measuring the dip in feet per hundred feet, and plotting this magnitude at the position measured. West dip has been chosen arbitrarily as positive and east dip as negative. The bottom profile of structural curvature has been obtained from the second curve just as the second was obtained from the first. Tangents are drawn on the dip-magnitude curve, their slopes measured, and the values of these slopes plotted at their respective positions.

Across the Antelope field from west to east, the curvature increases to a maximum of about 5×10^{-5}/ft where the dip is changing abruptly into the steep east flank, then returns to zero at the inflection point in the middle of the east flank, and reaches a second maximum where the beds bend sharply into the syncline on the east. As indicated in the legend in Figure 4, the dotted areas show where the curvature is between 2×10^{-5}/ft and 4×10^{-5}/ft and the dashed areas show where the curvature is greater than 4×10^{-5}/ft. As outlined above, the minimum curvature necessary for the development of tension fractures in a 10-ft bed is approximately 2×10^{-5}/ft. Hence, as a first approximation, production should be restricted to the dotted and dashed areas. This appears to be empirically correct. The few producing wells in areas where the structural curvature is less than 2×10^{-5}/ft are all subcommercial.

The matter of sign is arbitrary. Downward curvature has been taken as negative and upward curvature as positive. However, the direction and sign of the curvature in a few cases could be significant with regard to fracture geometry. The widest part of a fracture is at the top of the competent bed if the curvature is downward. If the curvature is upward, the widest parts of the fractures are at the base of the bed.

After several similar cross sections were constructed, the areas where the curvature exceeds the critical value for the development of fracture permeability (dotted) and the areas where the curvature and fracture permeability are the greatest (dashed) were mapped. As indicated in the legend in Figure 4, the well spots are keyed to their productivity. The match between actual productivity and the theoretical fairway is not perfect, as shown by the presence of some of the best wells and a few very poor wells in the dotted areas. However, if the statistical variation which is inevitable in a fracture reservoir is considered, the match between theory and experience is remarkably good.

SANISH PRODUCTION AND RESERVES

There is a wide variation in productivity of the Sanish wells. Prior to recent drilling on the north end of the field, there were 14 wells along the fairway of maximum structural curvature which had produced most of the oil from the pool. Each of these 14 wells, as of January 1, 1966, had produced more than 250,000 bbl and together had produced 74 percent of the oil recovered from the pool. The average producing rate of each well was 178 bbl a day at that time. The other 19 wells had produced the other 26 percent of the total. The 16 of these 19 poorer wells which were still producing as of the first of 1966 had an average producing rate at that time of only 17 bbl a day apiece.

The five northernmost wells in the fairway have been drilled during the past 1½ yr. Although there is some variation in the productivity of these recently completed wells, their average is as good as that of the best 14 older wells.

It is impossible to derive a meaningful reserve estimate for the Sanish from volumetric calculations. The better wells already have produced several times as much oil as could be estimated for the ultimate recovery from core analysis. For example, the discovery well, the No. 1 Woodrow Starr, SW¼ SE¼, Sec. 21, T. 152 N., R. 94 W., had a January 1, 1966, cumulative production of 607,467 bbl. (This includes production from the Starr No. 1-A which was drilled on the same 160-acre location after the casing collapsed in the original well.) The 14 best wells had a cumulative

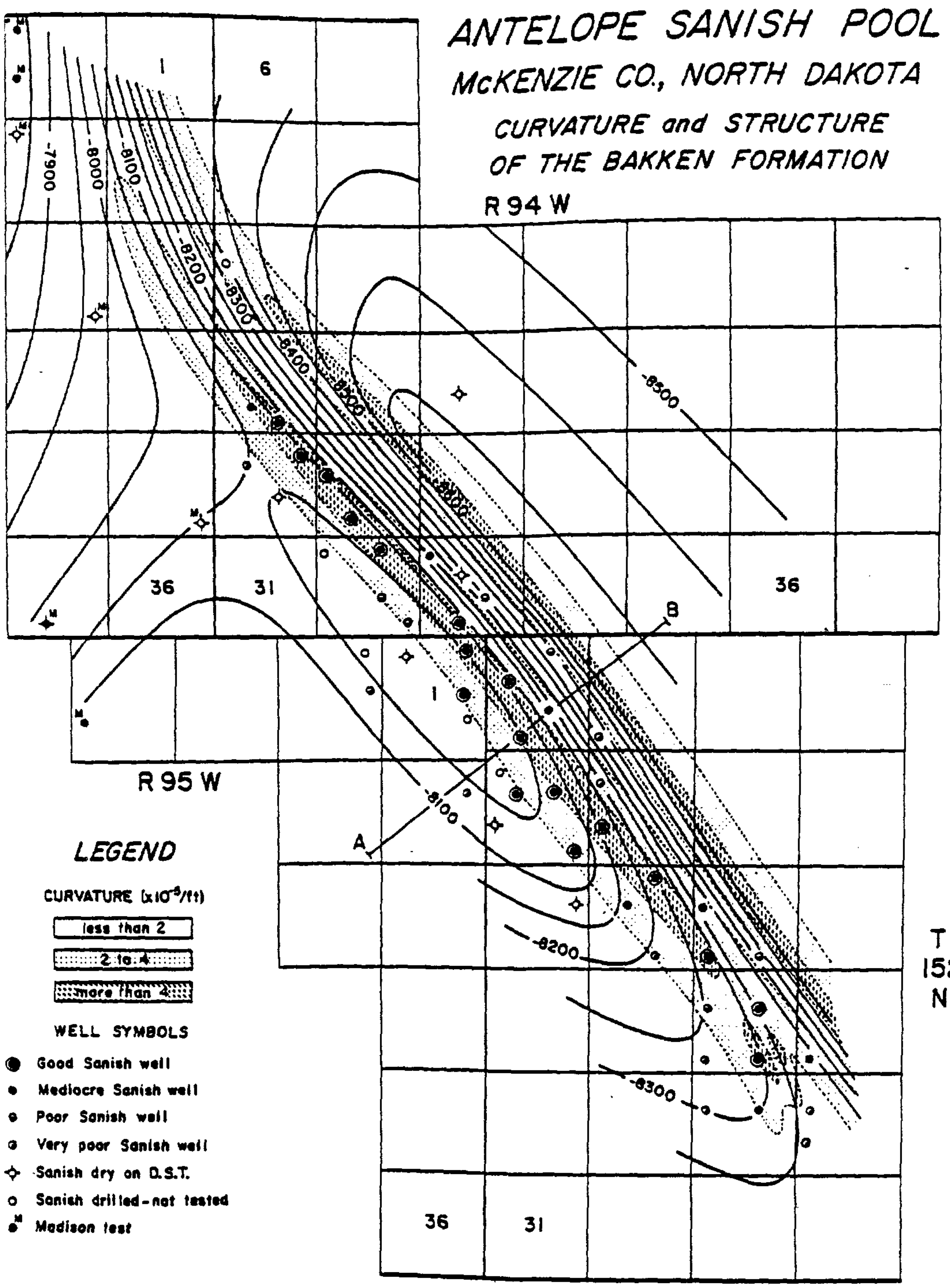


FIG. 4.—Structural contour map of Antelope Sanish pool, McKenzie County, North Dakota. Structural datum, top of Mississippian Bakken Formation. As noted on legend, well spots are keyed to their productivity and values of structural curvature are mapped by patterned areas. Contour interval, 50 ft. Contour datum, sea level. Section A-B is location of Figure 5.

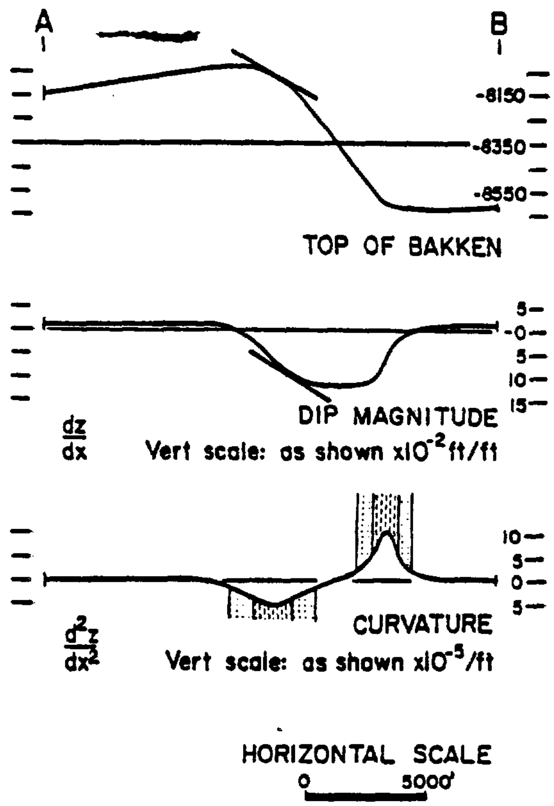


FIG. 5.—Comparison profiles of Bakken structure, dip magnitude, and structural curvature along line of section A-B of Figure 4.

production as of January 1, 1966 of 4,940,261 bbl, or an average of 2,200 bbl/acre. Average reservoir pressure at that time was 3,644 psi. Reservoir-pressure decline has been a straight-line function of barrels produced, indicating that production to date has been the result of fluid expansion.

SIGNIFICANCE OF RESERVOIR PRESSURE

The initial reservoir pressure of the Sanish pool was 7,670 psi at a datum of −8,400 ft. This is more than 2,500 psi above normal for the depth of the accumulation. For example, the original Sanish pressure was 2,150 psi greater than the original pressure in a Silurian reservoir which is about 1,500 ft deeper.

This indicates that the Sanish accumulation is in a closed, completely oil-saturated reservoir. The most important consequence of this fact is that the Sanish pool is independent of structure in the normal sense and there is no risk of penetrating a water column in the Sanish. To date, this conclusion generally has been supported by the productive history of the pool. There was essentially no water production until the reservoir pressure had declined considerably. There now are four or five wells with appreciable water cuts, but this water production is not structurally related because the wells with the largest cuts are very high on the structure. It is believed that this water may be true connate water—or "associated" water—being expelled from the Three Forks shale interbedded with the reservoir.

BAKKEN SHALE AS SOURCE OF OIL

Because the Sanish reservoir is performing much better than could be expected from volumetric calculations, it is believed that the Bakken shale beds are the immediate, as well as the ultimate, source of most of the oil. As has been outlined, the visual and log characteristics of the Bakken shale beds indicate that the pore space in the shales is oil-saturated. With approximately 30 ft of lower Bakken shale, containing 30–35 percent porosity (the pore space is oil-saturated), there is sufficient in-place oil to account for the Sanish production, provided that only a small percentage of this Bakken oil moves into the well bore. The role of the Sanish fracture system is primarily that of a gathering system for many increments of Bakken production.

These shale beds are, in a larger sense, saturated or even supersaturated oil reservoirs throughout the central basin area. If the internal pressures could be measured, they would be found to be abnormally high throughout the central basin. Indirect evidence for abnormally high internal pressures can be seen in the greater-than-normal shale porosity (as indicated by mechanical logs) of these two units. The excess porosity and internal pressure result from the difficulty of expulsion of the oil from these beds through the overlying Lodgepole and the underlying Three Forks sections. As a consequence, any restricted reservoir in direct contact with either of the two shale units should be productive anywhere in the deeper part of the basin, regardless of structural position.

CONCLUSIONS

Analysis of the Sanish pool supports the immediat[illegible]ssion that the production is from a tension-fracture system associated with the relatively sharp Antelope fold. In the local context of the Williston basin, one of the most important conclusions is the recognition that the upper and lower Bakken shale beds are supercharged oil shales and that they probably are the immediate source of most of the oil. Hence, discovery of permeability in beds adjacent to either of these two shale units—either in another fracture system or an area of matrix permeability in sandstone or carbonate rocks—would probably mean the discovery of prolific production comparable with that of the Sanish pool. Equally *intriguing* is the conclusion that, because the two shale beds are everywhere oil-saturated, such production is independent of structure in the normal sense and might be found in a synclinal location. Most important, it is believed that the relations between fracture porosity, fracture permeability, bed thickness, and structural curvature may prove useful in the analysis of similar problems in other geologic provinces.

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BENSON-MONTIN-GREER DRILLING CORP.
REBUTTAL TESTIMONY
RESPECTING INTERFERENCE TESTS
CANADA OJITOS UNIT

With respect to Mr. Hueni's response to the Chairman's questions about interference tests conducted in the Canada Ojitos Unit, we assume that Mr. Hueni apparently did not understand the nature of the subject interference tests, for his responses were to the effect that:

1. Interference testing can only show information about the formation between the test wells, and is complicated by fracturing.

2. The EI straight line solution does not apply to a heterogeneous reservoir.

3. The best way to determine the reservoir characteristics is from individual well pressure build up tests.

Since all three of these statements are incorrect as to the subject reservoir and tests, it is assumed that Mr. Hueni didn't have time to study them, so his failure to correctly assess the tests is understandable; however his statements are in the record, and the record needs to be set straight.

First we note that it was the heterogeneity of the formation, whose average characteristics could not be determined from well testing that made need for the interference tests. A reservoir substantially larger than the drilled area was indicated from some of the pressure testing; and the Unit Operator required more information about the reservoir so that an orderly, and informed, development plan could be implemented. One option was pressure maintenance by gas injection and a question here was the degree of anticipated gas channelling; the answer to which turned on the level of transmissibility (Kh) - not of the "tight blocks" in which the wells were completed - but of the reservoir average.

Interference testing was decided on since it was the only method - then and now - available to determine the necessary characteristics of this fractured reservoir rock.

As set out in our direct testimony, the stratified reservoir of Gavilan presents problems in interference testing (as well as for individual well pressure build up surveys), but the Canada Ojitos Unit 1965 and 1968 interference tests were of only one zone and were thus not affected by this complication.

With respect to the above-numbered items, we state:

1. Although most interference tests may be those B

conducted for a relatively short period of time (ordinarily "short" because of the cost of delayed production for a long test) and are in reservoirs whose rate of diffusion of pressure transients is slow (and consequently they "sample" only a small portion of the reservoir), in contrast, in the Canada Ojitos Unit, the diffusivity constant at the time of the 1965 test ranged up to 1×10^7 and tests of 15 to 20 days reflected average quantities for distances of 2 or 3 miles beyond the locations of the test wells. This is the consequence of the fractured formation's high transmissibility coupled with its low per acre volume of oil in place.

That the EI formula can be used to fairly describe the reservoir properties beyond the test wells can be confirmed by examining the transient pressure equations for a reservoir with a "large internal radius", as, for example, an oil field in a large aquifer; and comparing this with the EI solution as described herein. What we do here is to "expand" the wellbore radius to a distance equal to that of the interference observation well, and assume that the "wellbore" has a small volume (but infinite transmissibility).

This comparison shows very clearly how interference testing "filters out" the problems of induced fractures, wellbore resistance, heterogeneous rock characteristics, etc.

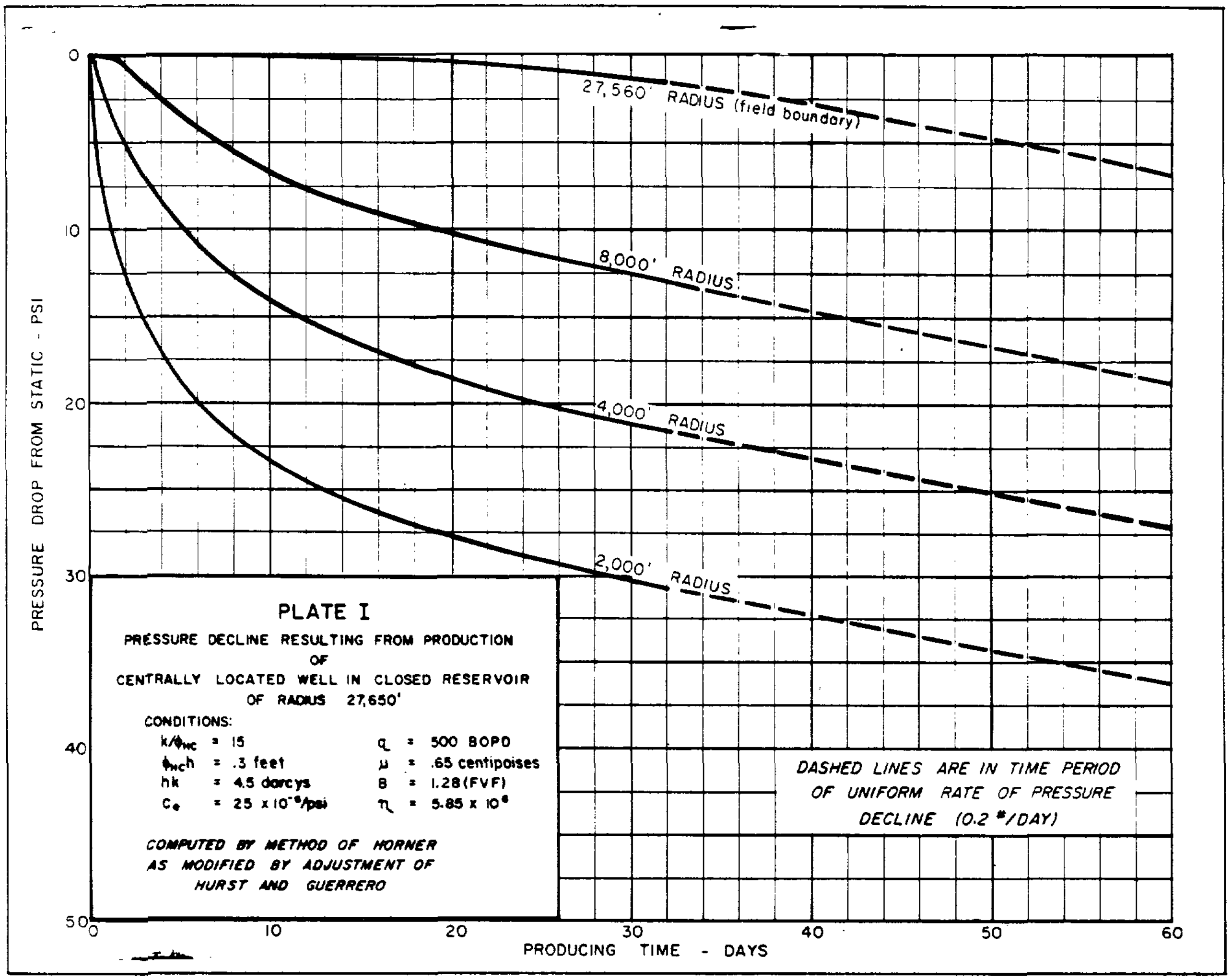
The example shown here derives from Muskat's solution to this problem; but others are available, as for instance, through use of the Laplace Transformation; and clearly shows the powerful potential of interference testing to "sample" a large part of the reservoir.

2. The degree of heterogeneity that can be tolerated by an interference test and give reliable results as to the <u>average</u> physical properties depends strictly on the rate of diffusion of the pressure transients in the affected areas. In the Canada Ojitos Unit test area the geometry of the reservoir is that of individual "tight blocks" surrounded by a high capacity fracture system. The information following shows clearly that the rate of diffusion is high enough that valid results can be anticipated. The proof, here, of course, is that such actually happened and was measured in observation wells in the 1965 interference test.

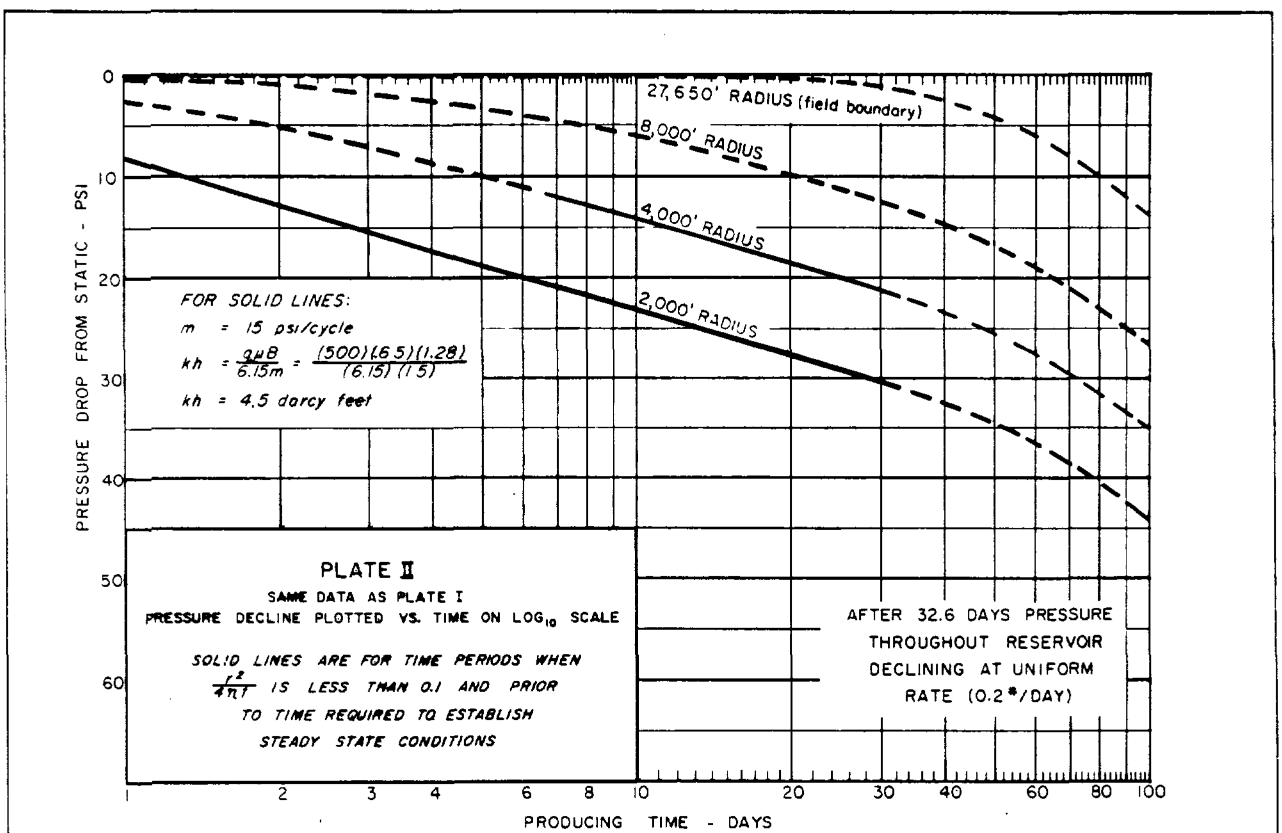
3. Individual well test Kh's had been determined prior to the 1965 test and they showed that transmissibility varied twenty-fold, from .02 darcy feet to .45 darcy feet. (No way here to determine a reasonable "weighted average".) Moreover it appeared that the true reservoir average Kh was substantially higher than that shown for any of the wells; so any "average" of their properties would be totally incorrect. After the interference test was run, it revealed that the reservoir average Kh was on the order of 5 to 10 darcy feet - ten to twenty times higher than the highest individual well test at that time.

Here again, the proof that the interference test provided more definitive data than the individual well tests was revealed when a well drilled two years after the interference test was completed showed the high capacity system to exist; and when gas injection commenced it was possible to confirm under steady state conditions the transmissibility for a 2-1/2 mile distance to be in the same 5 to 10 darcy feet range.

Time does not permit introduction here of all the supporting data, however it is well documented in Case No. 3455 before the Oil Conservation Division in November 1966 and December 1969.



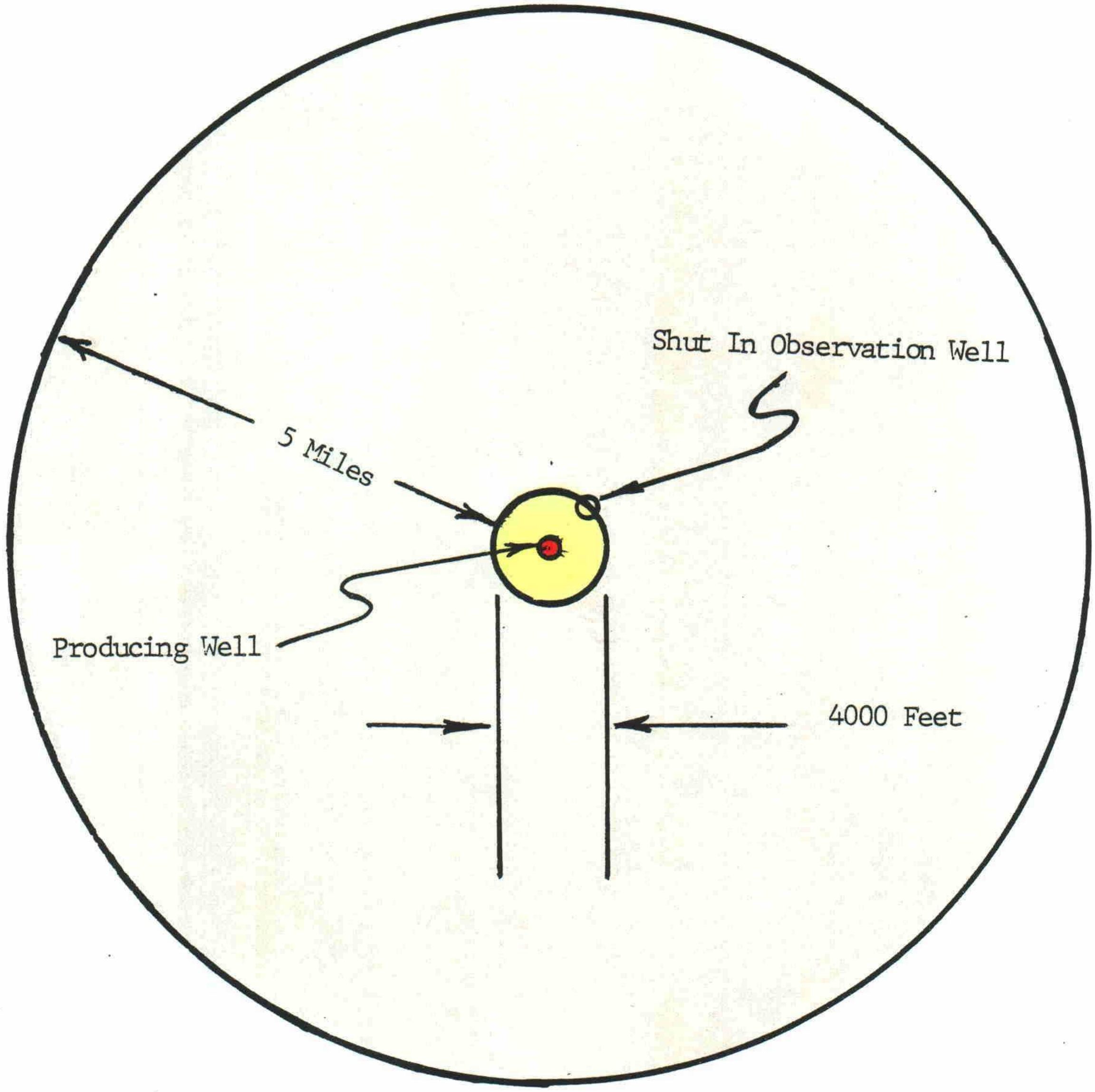
PRESSURE DROP FROM STATIC - PSI
PRODUCING TIME - DAYS
27,560' RADIUS (field boundary)
8,000' RADIUS
4,000' RADIUS
2,000' RADIUS
PLATE I
PRESSURE DECLINE RESULTING FROM PRODUCTION OF CENTRALLY LOCATED WELL IN CLOSED RESERVOIR OF RADIUS 27,650'
CONDITIONS:
k/ϕHC = 15
ϕHCh = .3 feet
hk = 4.5 darcys
Ce = 25 x 10⁻⁶/psi
q = 500 BOPD
μ = .65 centipoises
B = 1.28(FVF)
η = 5.85 x 10⁶
COMPUTED BY METHOD OF HORNER AS MODIFIED BY ADJUSTMENT OF HURST AND GUERRERO
DASHED LINES ARE IN TIME PERIOD OF UNIFORM RATE OF PRESSURE DECLINE (0.2 #/DAY)



PRESSURE DROP FROM STATIC - PSI
PRODUCING TIME - DAYS
27,650' RADIUS (field boundary)
8,000' RADIUS
4,000' RADIUS
2,000' RADIUS
FOR SOLID LINES:
m = 15 psi/cycle
kh = qμB / 6.15m = (500)(.65)(1.28) / (6.15)(15)
kh = 4.5 darcy feet
PLATE II
SAME DATA AS PLATE I
PRESSURE DECLINE PLOTTED VS. TIME ON LOG10 SCALE
SOLID LINES ARE FOR TIME PERIODS WHEN r²/4ηt IS LESS THAN 0.1 AND PRIOR TO TIME REQUIRED TO ESTABLISH STEADY STATE CONDITIONS
AFTER 32.6 DAYS PRESSURE THROUGHOUT RESERVOIR DECLINING AT UNIFORM RATE (0.2 #/DAY)

COMPARISON OF SOLUTIONS
OF THE DIFFUSIVITY EQUATION

POINT SOURCE (EXPONENTIAL INTEGRAL)
WITH
LARGE INTERNAL RADIUS



PHYSICAL PRINCIPLES OF OIL PRODUCTION

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1949

MUSKAT

The specific system to be analyzed here will be defined by the initial and boundary conditions (cf. Fig. 11.3)

$$\left.\begin{aligned} t = 0 &\ :\ \gamma = \gamma_i (p = p_i), \\ r = r_f &\ :\ 2\pi r \gamma v_r = q(t), \end{aligned}\right\} \tag{1}$$

where the radius r_f is taken as the equivalent oil-field radius, assumed circular, and p_i is the initial pressure in the water reservoir. In actual

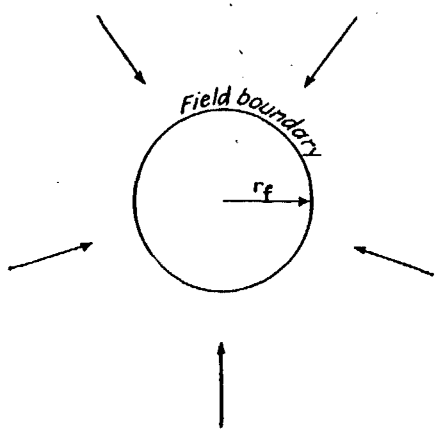


FIG. 11.3

complete-water-drive fields the mass flux $q(t)$ at the field boundary is to be considered as representing the fluid withdrawal within the field, except for that replaced by expansion of its own fluid content.

By means of the solution of Eq. 11.3(13), subject to the conditions of Eq. (1), the fluid density and pressure at $r = r_f$, or field boundary, can be determined as a function of time. This solution can be verified to be[1]

$$\gamma = \gamma_i + \frac{1}{\pi^2 f r_f} \int_0^\infty \frac{e^{-au^2 t}[J_0(ur)Y_1(ur_f) - Y_0(ur)J_1(ur_f)]\,du}{J_1^2(ur_f) + Y_1^2(ur_f)} \int_0^t q(\lambda) e^{au^2\lambda}\,d\lambda. \tag{2}$$

where J_n, Y_n denote Bessel functions[2] of order n of the first and second kinds, respectively.

For the special case where $q(t)$ is a constant q_o, Eq. (2) reduces to

$$\gamma = \gamma_i + \frac{q_o}{\pi^2 a f r_f} \int_0^\infty \frac{(1 - e^{-au^2 t})\,[J_0(ur)Y_1(ur_f) - Y_0(ur)J_1(ur_f)]\,du}{u^2[J_1^2(ur_f) + Y_1^2(ur_f)]}. \tag{3}$$

[1] The solution for this problem, applying to the special case of Eq. (3), has been derived by J. C. Jaeger in an unpublished manuscript.

[2] These functions are treated exhaustively by G. N. Watson, "The Theory of Bessel Functions," Cambridge University Press, 1922. Most of the properties required in developing the analysis given in this chapter are briefly outlined in M. Muskat, "The Flow of Homogeneous Fluids through Porous Media," Sec. 10.2, McGraw-Hill Book Company, Inc., 1937.

$at/r_f^2 = \frac{kt}{f\kappa\mu r_f^2}$ to convert $\frac{(60\times60\times24)\ \text{sec/day}}{(14.696\ \#/\text{atmos})(30.48\ \text{cm/ft})^2}$ →

$\left(\frac{\pi^3 k\Delta p}{2Q\mu}\right.$ per unit $\Big)$ to convert $(1/14.696\ \#/\text{atmos})(\pi^3)\ 30.48\ \text{cm/ft}$ →
1,840 cc/bbl/day × 2

At the field boundary r_f, γ will therefore have the value

$$\gamma_f = \gamma_i - \frac{2q_o}{\pi^3 a f r_f^2} \int_0^\infty \frac{(1 - e^{-au^2 t})\,du}{u^3[J_1^2(ur_f) + Y_1^2(ur_f)]}. \tag{4}$$

On translating the decline in density $\gamma_i - \gamma_f$ to the corresponding pressure drop $\Delta p = p_i - p_f$ and introducing the dimensionless time variable $\bar{t}$, Eq. (4) becomes

$$\Delta p = \frac{2Q\mu}{\pi^3 k} \int_0^\infty \frac{(1 - e^{-z^2 \bar{t}})\,dz}{z^3[J_1^2(z) + Y_1^2(z)]}; \qquad \bar{t} = \frac{at}{r_f^2}, \tag{5}$$

where Q represents the volumetric outflow per unit thickness at r_f, but measured at the surface,[1] that is, q_o/γ_o. In Fig. 11.4 a graphical evaluation

per unit of pay thickness

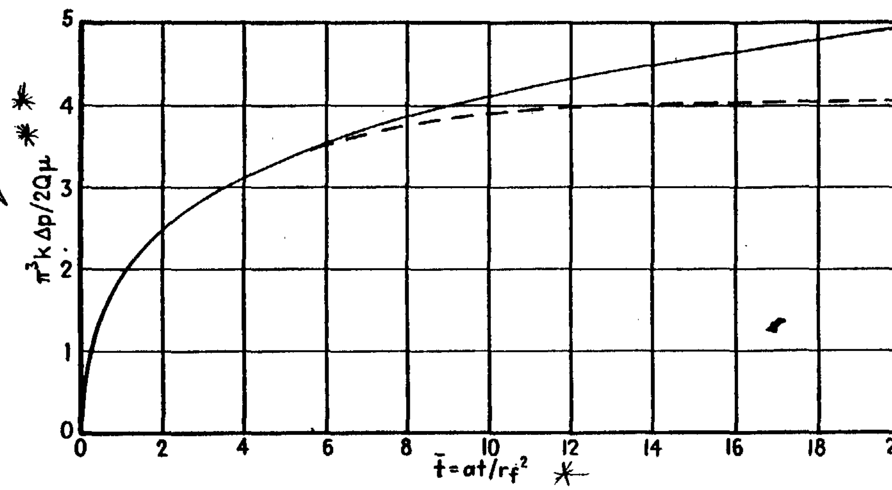


FIG. 11.4. The calculated pressure drop Δp vs. the time t plotted in dimensionless form, at the internal boundary of water reservoirs, with constant water-withdrawal rate Q per unit thickness. Internal-boundary radius $= r_f$; permeability of water reservoir $= k$; μ = viscosity of water; κ = compressibility of water; f = porosity; $a = k/f\kappa\mu$. Solid curve refers to an infinite water reservoir. Dashed curve applies to a finite water reservoir with the pressure kept fixed at an external radius that is 6.3 times r_f.

of Eq. (5) is plotted as the solid curve in dimensionless form, as $\pi^3 k\,\Delta p/2Q\mu$ vs. $\bar{t}$. As may be shown by an analysis of Eq. (5), Δp initially rises as $\sqrt{\bar{t}}$ and asymptotically assumes a logarithmic variation with $\bar{t}$. Thus in contrast to the steady-state approximation treated in the last section there

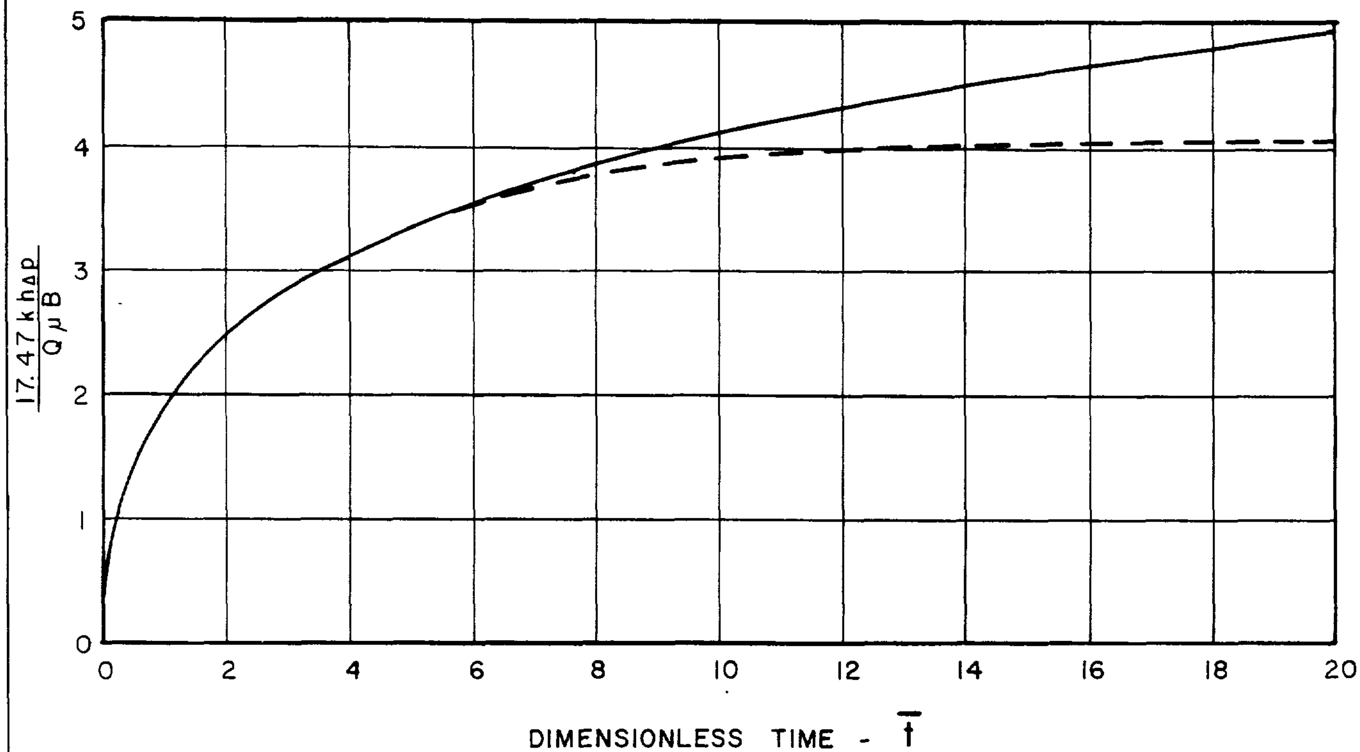
[1] To second-order terms in κ, the conversion between $\Delta\gamma$ and Δp can be made using any convenient value of γ [cf. Eq. 11.3(11)]. The values of flux represented by Q in this and the following sections refer to complete cylindrical systems. If the reservoirs are more appropriately described by sectors of angular width w, the equations relating pressure drops to flux will still remain valid provided that the values of Q used in the equations are the actual values multiplied by $2\pi/w$.

* $\bar{t} = \frac{6.328\,k\,t}{f\,c\,\mu\,r_f^2}$ where $\left\{\begin{array}{l} k = \text{darcys} \quad t = \text{days} \\ f = \text{fraction} \quad r_f = \text{feet} \\ \mu = \text{cp} \quad c = \text{vol/vol/\#} \end{array}\right.$

** $\frac{1.747\,k\,h\,\Delta p}{\mu\,Q\,B_o}$ where k = darcys μ = cp, h = feet Q = B/D

PRESSURE DECLINE AT THE INTERNAL BOUNDARY OF LARGE RESERVOIRS SUBJECT TO CONSTANT WITHDRAWAL RATE

AFTER MUSKAT, PHYSICAL PRINCIPLES OF OIL PRODUCTION, 543



$$\bar{t} = \frac{6.328\ kt}{\phi c \mu\ r_f^2} = \frac{\eta t}{r_f^2} \qquad \eta = \frac{6.328k}{\phi c \mu}$$

where:

$\bar{t}$ = dimensionless time

k = permeability, darcys

t = producing time, days

ϕ = porosity, fraction

c = system compressibility, $\Delta V/V$/psi

μ = viscosity, centipoises

r_f = internal boundary radius, feet

Q = constant withdrawal rate, bbls/day

μ = viscosity, centipoises

B = formation volume factor, reservoir bbls per surface barrel

ΔP = pressure drop from static at time t, at internal boundary

SOLID CURVE REFERS TO AN INFINITE RESERVOIR
DASHED CURVE APPLIES TO A FINITE RESERVOIR WITH THE PRESSURE KEPT FIXED AT AN EXTERNAL RADIUS THAT IS 6.3 TIMES r_f

FIGURE NO. 22

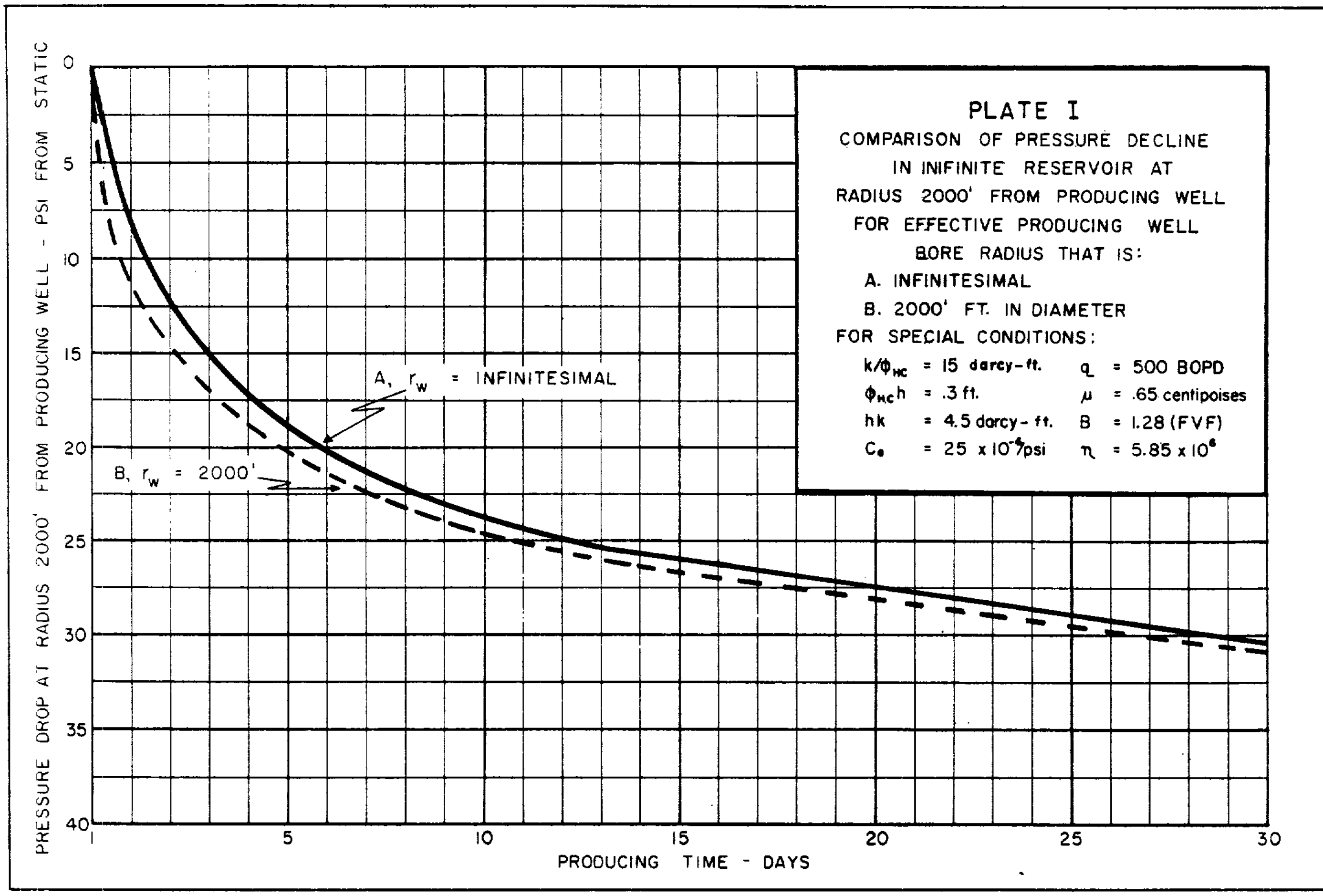


PLATE I
COMPARISON OF PRESSURE DECLINE
IN INIFINITE RESERVOIR AT
RADIUS 2000' FROM PRODUCING WELL
FOR EFFECTIVE PRODUCING WELL
BORE RADIUS THAT IS:
A. INFINITESIMAL
B. 2000' FT. IN DIAMETER
FOR SPECIAL CONDITIONS:
k/ϕ_{HC} = 15 darcy-ft.
$\phi_{HC}h$ = .3 ft.
hk = 4.5 darcy-ft.
C_e = 25 x 10^{-6}/psi
q = 500 BOPD
μ = .65 centipoises
B = 1.28 (FVF)
η = 5.85 x 10^{6}
A, r_w = INFINITESIMAL
B, r_w = 2000'
PRESSURE DROP AT RADIUS 2000' FROM PRODUCING WELL - PSI FROM STATIC
PRODUCING TIME - DAYS

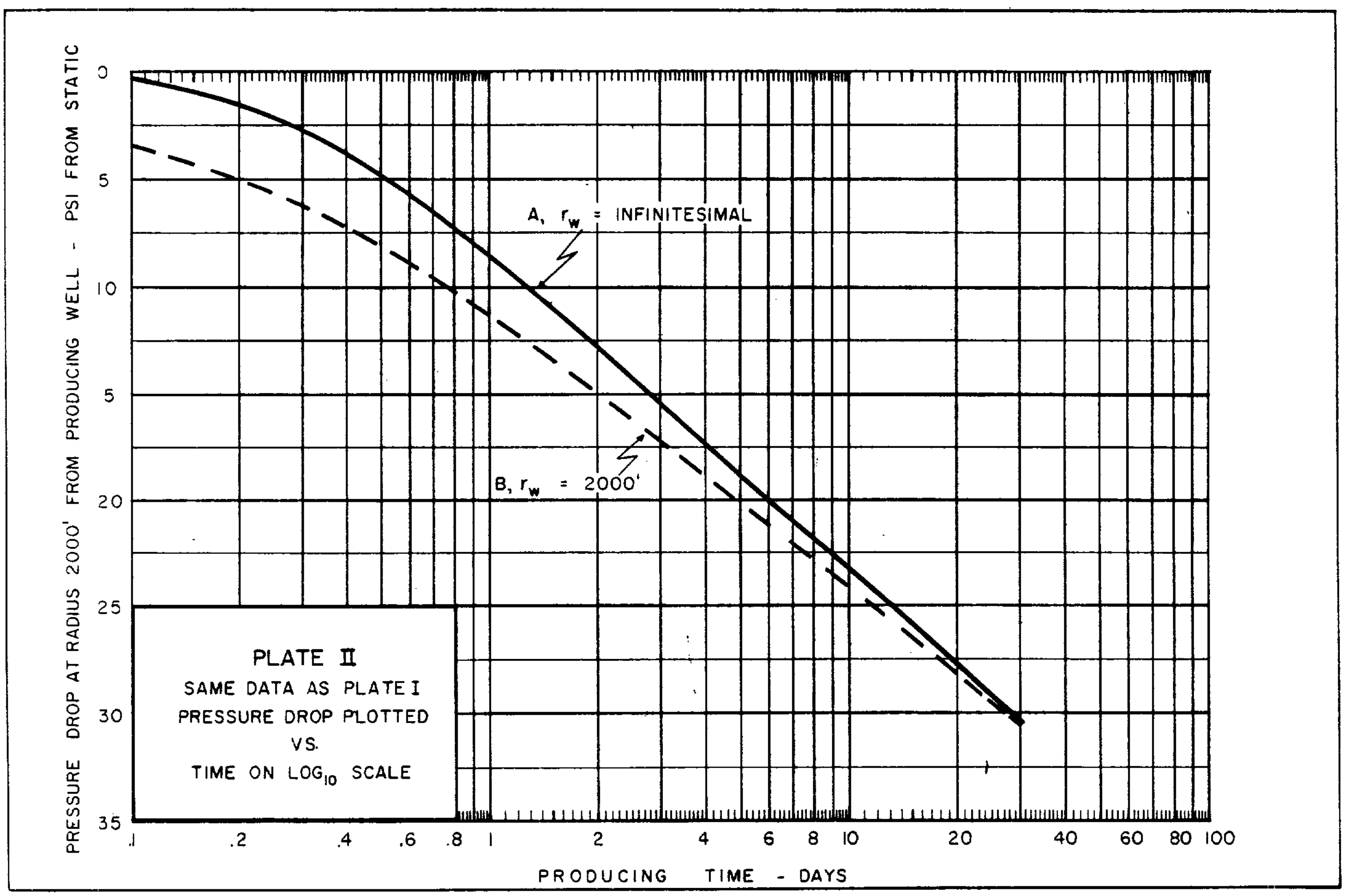
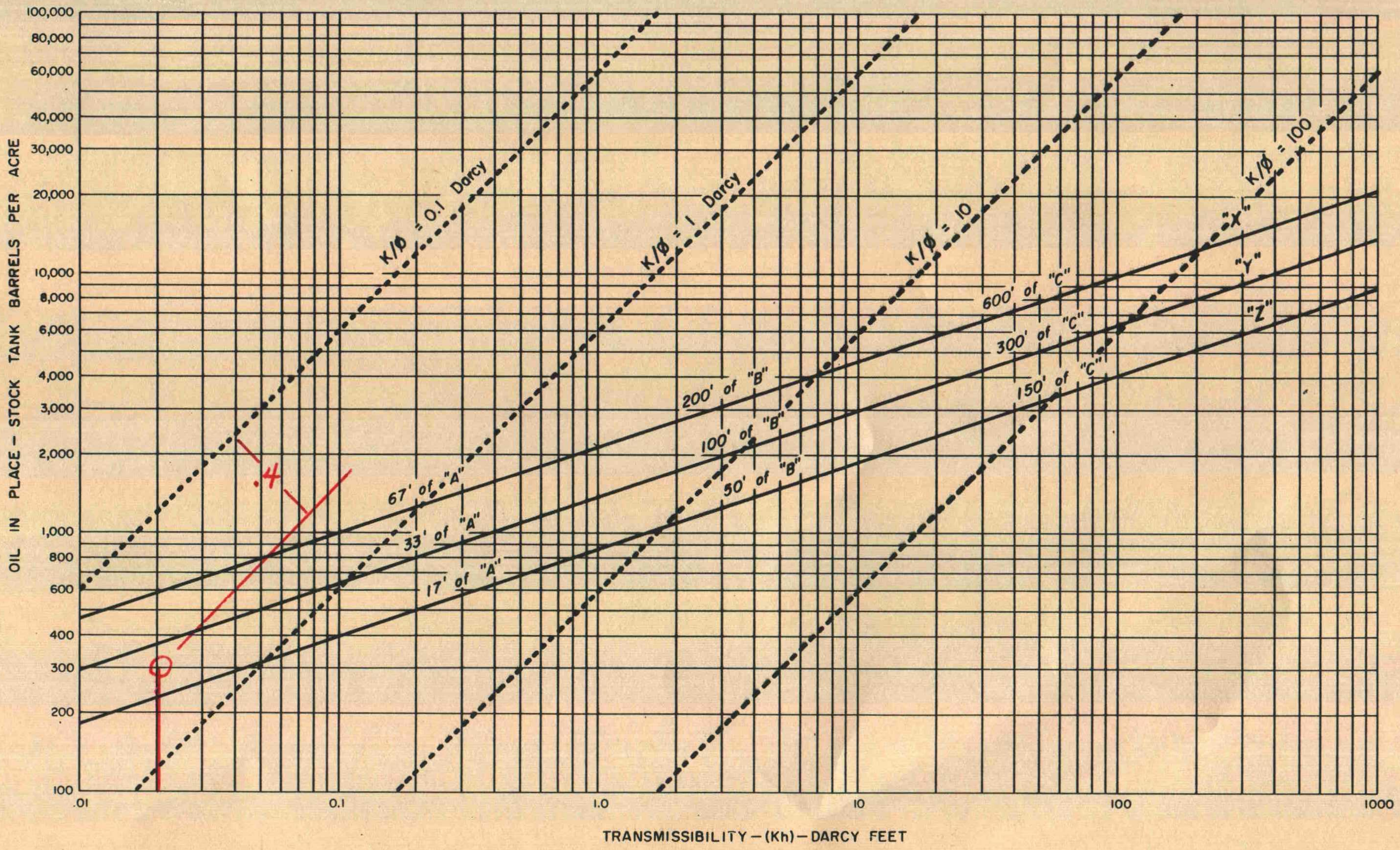


PLATE II
SAME DATA AS PLATE I
PRESSURE DROP PLOTTED
VS.
TIME ON LOG_{10} SCALE
A, r_w = INFINITESIMAL
B, r_w = 2000'
PRESSURE DROP AT RADIUS 2000' FROM PRODUCING WELL - PSI FROM STATIC
PRODUCING TIME - DAYS

FIGURE NO. 23

C

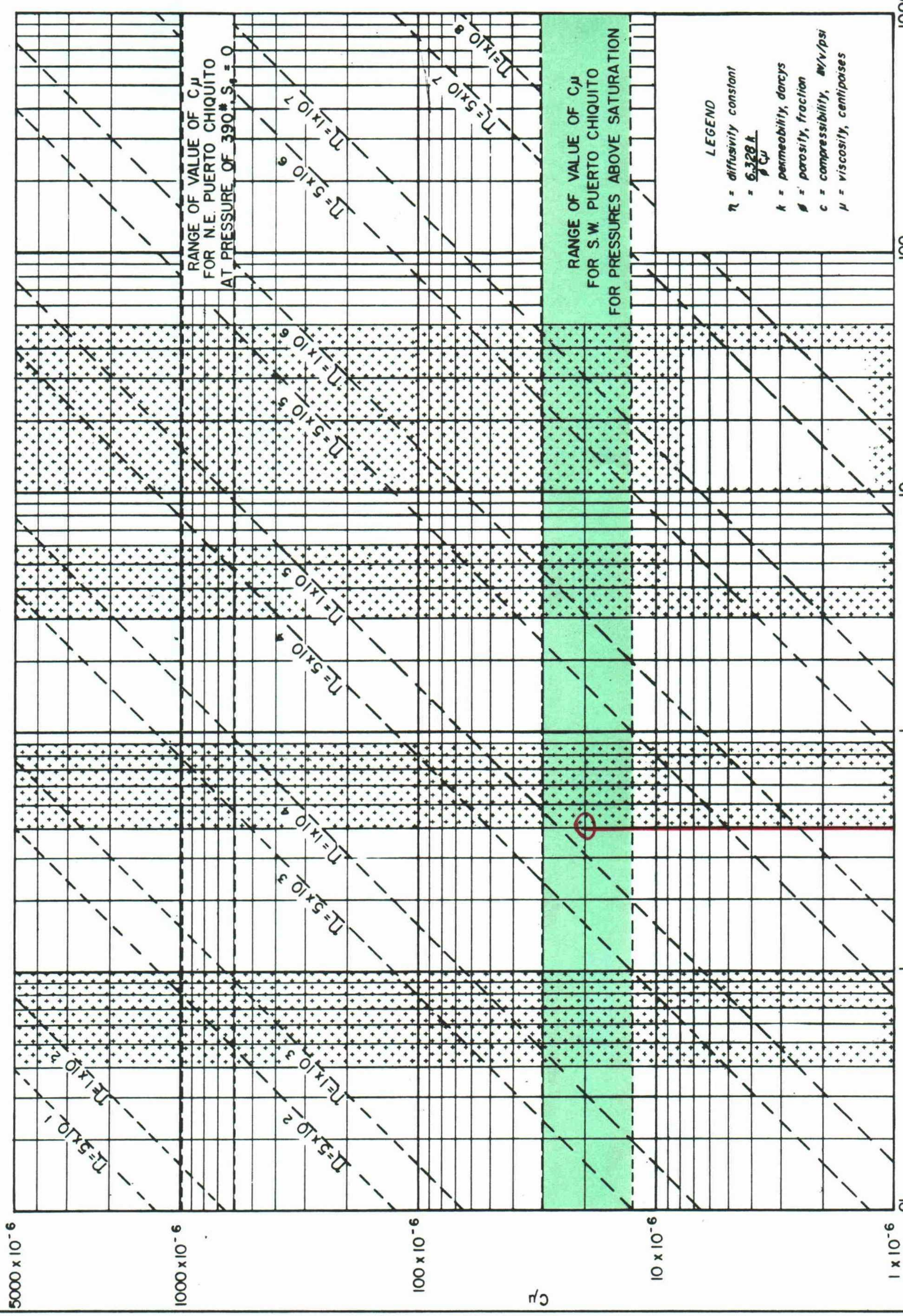
RELATION OF OIL IN PLACE
TO
TRANSMISSIBILITY
FOR
POROSITY-PERMEABILITY RELATIONS
"A", "B" & "C"
AND FOR
RESERVOIR THICKNESSES SHOWN
F.V.F. = 1.29



FILE: 13A

APPENDIX III FIGURE NO. III-5

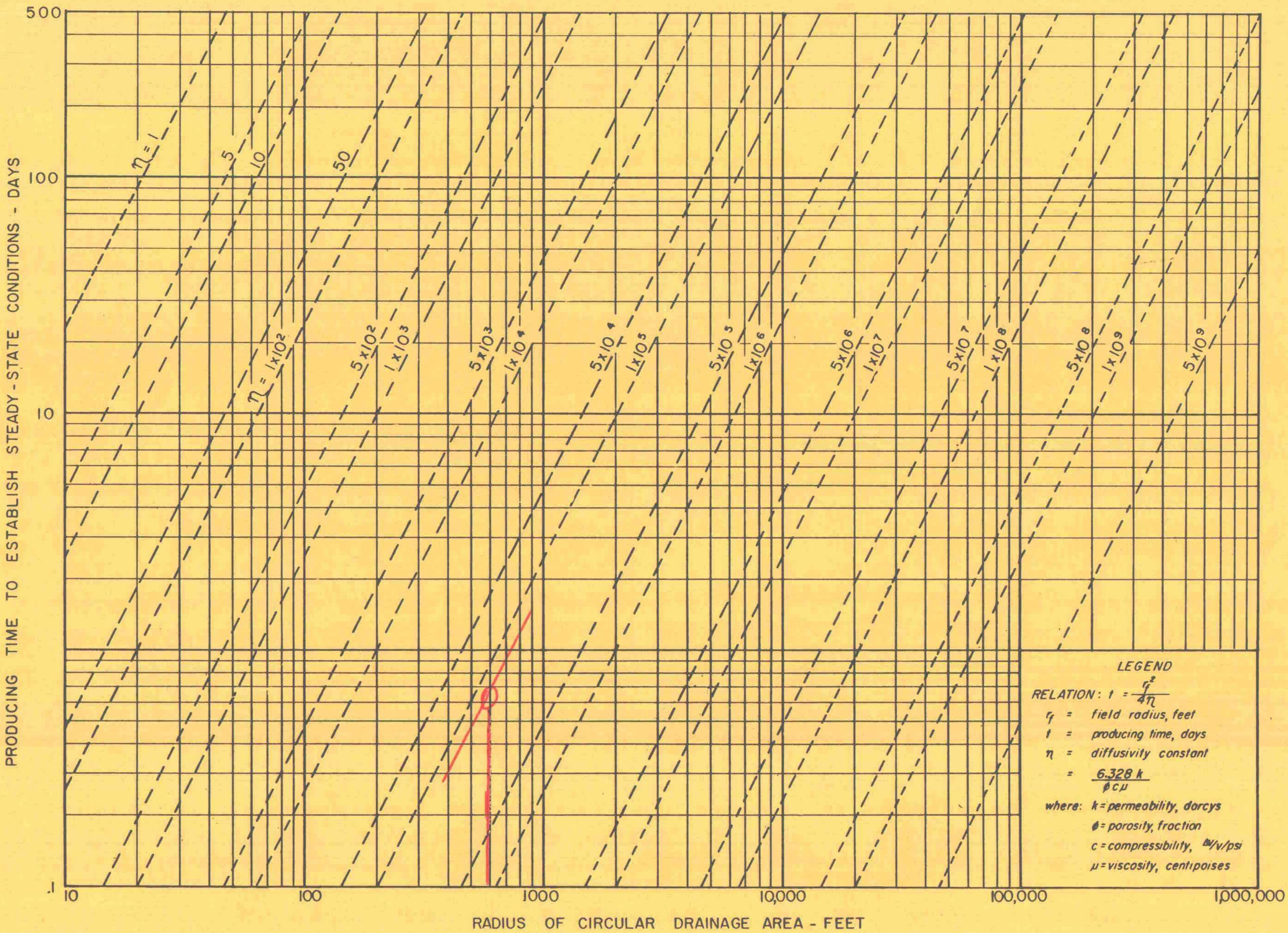
VALUE OF DIFFUSIVITY CONSTANT AS FUNCTION OF K/φ VS. Cμ



Rev. 8/86

FIGURE NO. 10

TIME REQUIRED TO ESTABLISH STEADY-STATE CONDITIONS FOR CIRCULAR DRAINAGE AREAS OF UNIFORM PROPERTIES



MR. STAMETS

BENSON-MONTIN-GREER DRILLING CORP.
EXHIBITS IN CASE NOS. 8946 & 8950
BEFORE THE OIL CONSERVATION DIVISION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

AUGUST 7, 1986

NMOCC/NMOCD Case No. 8950
Hearing Date 8/21/86
Benson-Montin-Greer

Exhibit No. 8

Geologic Analysis of Naturally Fractured Reservoirs

Ronald A. Nelson

A

Effect of Variation in Fracture Spacing

Variation in fracture spacing can have a dramatic effect on both fracture porosity and permeability (Figures 1-55 and 1-56). The combined effect of both fracture width and spacing on these reservoir parameters is shown in Figures 1-55 and 1-56. A good qualitative feeling for the effect of outcrop or core observations of fracture spacing at an assumed fracture width, or vice versa, can be derived from these diagrams.

Techniques for Calculating Fracture Spacing

In simple fracture networks of regular, closely spaced fractures, fracture spacing is easily calculated in core or outcrop provided the sampling area or volume is large with respect to fracture spacing. This is accomplished by counting the number of fractures encountered along a line of some given length perpendicular to the fracture set of interest, for each of the fracture sets present and dividing the length of measurement line.

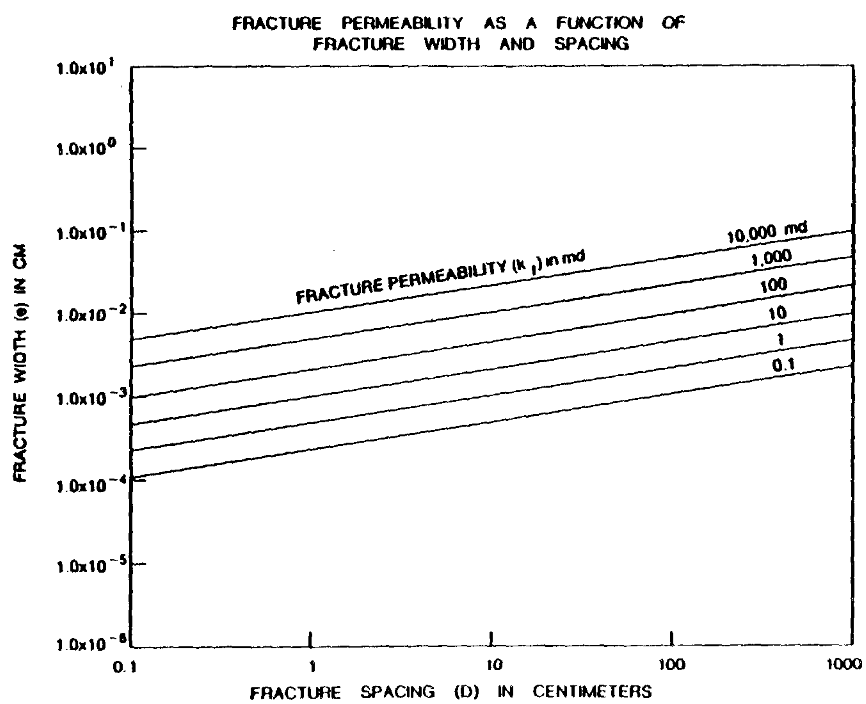


Figure 1-55. Fracture permeability as a function of fracture width and fracture spacing

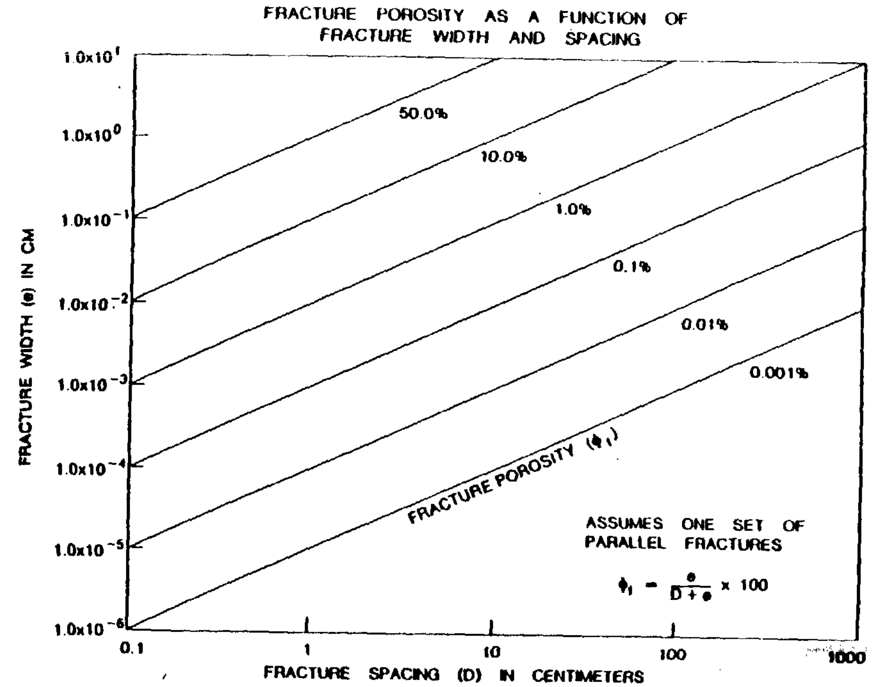


Figure 1-56. *Fracture porosity as a function of fracture width and fracture spacing.*

In more complex fracture systems, workers have gone to similar determinations along lines in specific directions. This author has often used two perpendicular measurement directions with one parallel to bedding strike and one parallel to bedding dip. Others have tried to reconstruct the entire vector/spacing distribution (at least in a plane) by measuring along three specific directions (120° apart) and statistically manipulating the data into a full 360° distribution. Hudson and Priest (1983) present an excellent statistical technique for determining the entire 2-D array of spacing vectors present in a rock. Narr and Lerche (1984) present a statistical/geometric method for accurately depicting fracture spacing from core data.

Utilization of Laboratory Data

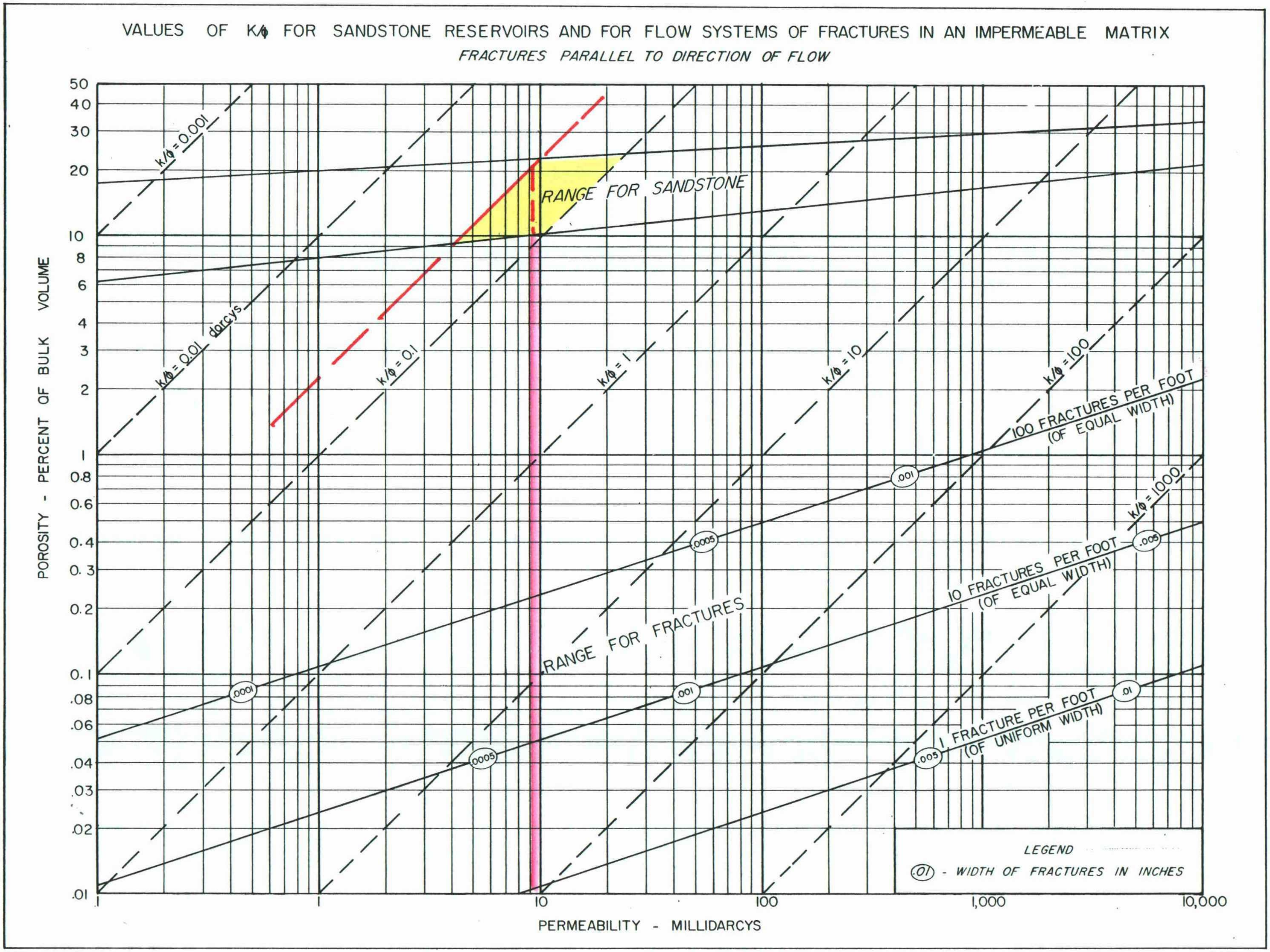
Laboratory data can be quite useful in quantifying reservoir properties in fractured reservoirs. However, the extrapolation of these data to sub-

METHODS OF INTERPRETATION OF PRESSURE BEHAVIOR IN THE OIL PRODUCING FRACTURED SHALE RESERVOIRS OF THE PUERTO CHIQUITO POOL RIO ARRIBA COUNTY, NEW MEXICO

November 1, 1966

EXHIBIT NO. 1
NMOCD CASE NO. 3455
November 16, 1966

B



APPENDIX III FIGURE NO. III-3

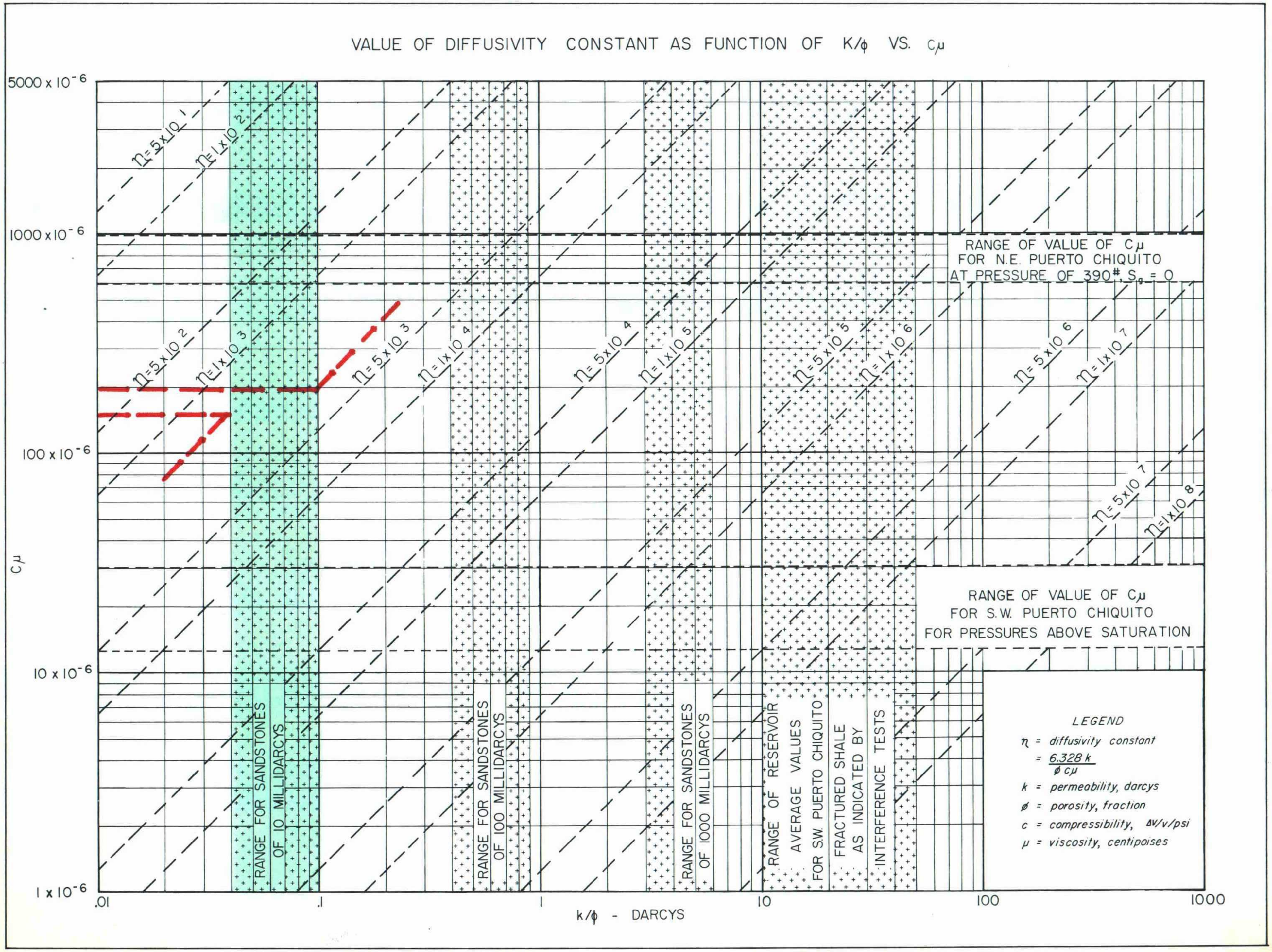
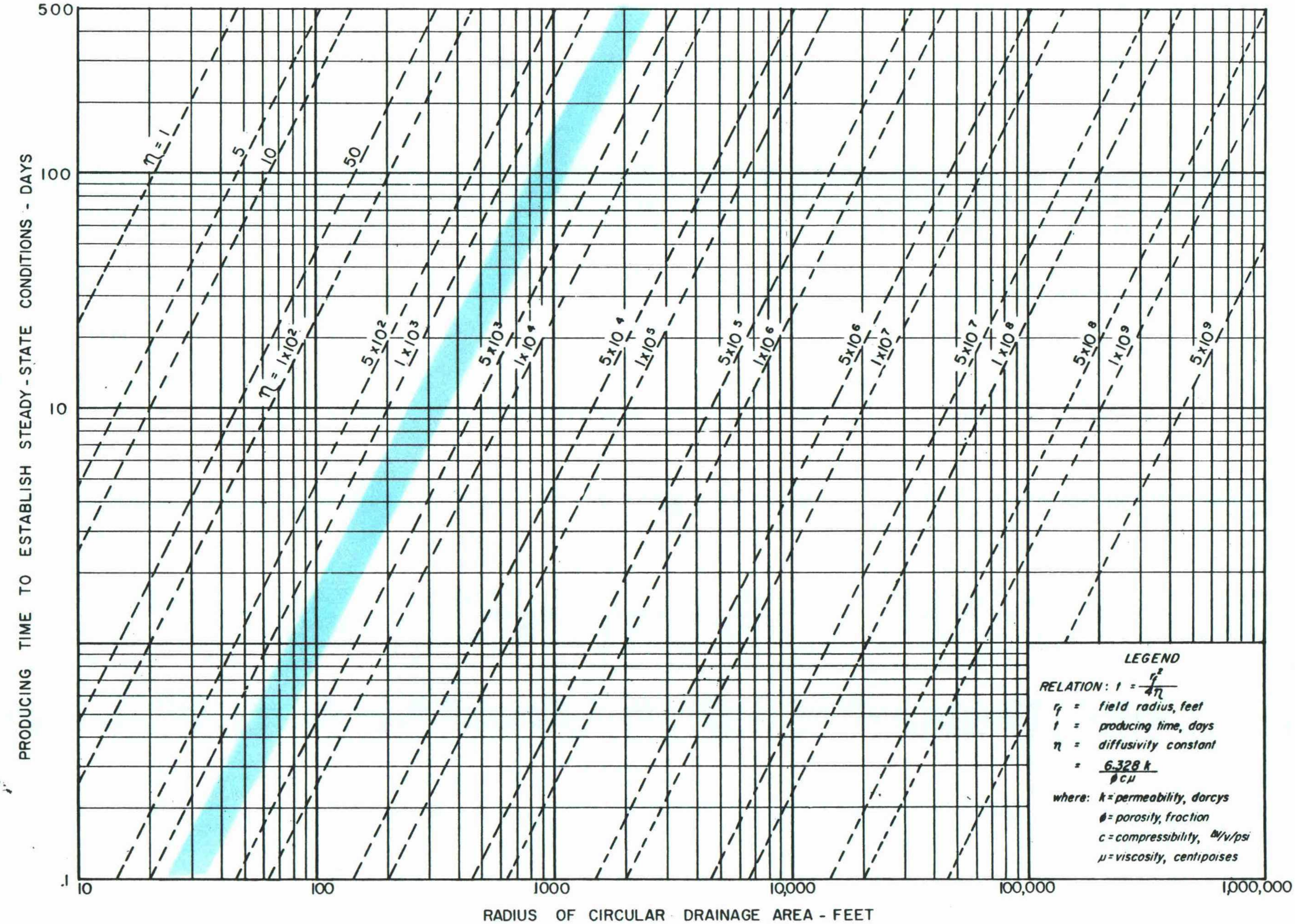

VALUE OF DIFFUSIVITY CONSTANT AS FUNCTION OF K/ϕ VS. Cμ
5000 x 10⁻⁶
1000 x 10⁻⁶
100 x 10⁻⁶
10 x 10⁻⁶
1 x 10⁻⁶
Cμ
.01
.1
1
10
100
1000
k/ϕ - DARCYS
η = 5 x 10 1
η = 1 x 10 2
η = 5 x 10 2
η = 1 x 10 3
η = 5 x 10 3
η = 1 x 10 4
η = 5 x 10 4
η = 1 x 10 5
η = 5 x 10 5
η = 1 x 10 6
η = 5 x 10 6
η = 1 x 10 7
η = 5 x 10 7
η = 1 x 10 8
RANGE FOR SANDSTONES OF 10 MILLIDARCYS
RANGE FOR SANDSTONES OF 100 MILLIDARCYS
RANGE FOR SANDSTONES OF 1000 MILLIDARCYS
RANGE OF RESERVOIR AVERAGE VALUES FOR S.W. PUERTO CHIQUITO
FRACTURED SHALE AS INDICATED BY INTERFERENCE TESTS
RANGE OF VALUE OF Cμ FOR N.E. PUERTO CHIQUITO AT PRESSURE OF 390#, Sg = 0
RANGE OF VALUE OF Cμ FOR S.W. PUERTO CHIQUITO FOR PRESSURES ABOVE SATURATION
LEGEND
η = diffusivity constant
= 6.328 k / ϕ cμ
k = permeability, darcys
ϕ = porosity, fraction
c = compressibility, ΔV/V/psi
μ = viscosity, centipoises

FIGURE NO. 10

TIME REQUIRED TO ESTABLISH STEADY-STATE CONDITIONS FOR CIRCULAR DRAINAGE AREAS OF UNIFORM PROPERTIES



The Behavior of Naturally Fractured Reservoirs

J. E. WARREN
P. J. ROOT
MEMBERS AIME

GULF RESEARCH & DEVELOPMENT CO.
PITTSBURGH, PA.

ABSTRACT

An idealized model has been developed for the purpose of studying the characteristic behavior of a permeable medium which contains regions which contribute significantly to the pore volume of the system but contribute negligibly to the flow capacity; e.g., a naturally fractured or vugular reservoir. Unsteady-state flow in this model reservoir has been investigated analytically. The pressure build-up performance has been examined in some detail; and, a technique for analyzing the build-up data to evaluate the desired parameters has been suggested. The use of this approach in the interpretation of field data has been discussed.

As a result of this study, the following general conclusions can be drawn:

1. *Two parameters are sufficient to characterize the deviation of the behavior of a medium with "double porosity" from that of a homogeneously porous medium.*
2. *These parameters can be evaluated by the proper analysis of pressure build-up data obtained from adequately designed tests.*
3. *Since the build-up curve associated with this type of porous system is similar to that obtained from a stratified reservoir, an unambiguous interpretation is not possible without additional information.*
4. *Differencing methods which utilize pressure data from the final stages of a build-up test should be used with extreme caution.*

INTRODUCTION

In order to plan a sound exploitation program or a successful secondary-recovery project, sufficient reliable information concerning the nature of the reservoir-fluid system must be available. Since it is evident that an adequate description of the reservoir rock is necessary if this condition is to be fulfilled, the present investigation was undertaken for the purpose of improving the fluid-flow characterization, based on normally available data, of a particular porous medium.

DISCUSSION OF THE PROBLEM

For many years it was widely assumed that, for the purpose of making engineering studies, two parameters were sufficient to describe the single-phase flow properties of a producing formation, i.e., the absolute permeability and the effective porosity. It later became evident that the concept of directional permeability was of more than academic interest; consequently, the degree of permeability anisotropy and the orientation of the principal axes of permeability were accepted as basic parameters governing reservoir performance.[1,2] More recently,[3-6] it was recognized that at least one additional parameter was required to depict the behavior of a porous system containing regions which contributed significantly to the pore volume but contributed negligibly to the flow capacity. Microscopically, these regions could be "dead-end" or "storage" pores or, macroscopically, they could be discrete volumes of low-permeability matrix rock combined with natural fissures in a reservoir. It is obvious that some provision for the inclusion of all the indicated parameters, as well as their spatial variations, must be made if a truly useful, conceptual model of a reservoir is to be developed.

A dichotomy of the internal voids of reservoir rocks has been suggested.[7,8] These two classes of porosity can be described as follows:

a. *Primary porosity* is intergranular and controlled by deposition and lithification. It is highly interconnected and usually can be correlated with permeability since it is largely dependent on the geometry, size distribution and spatial distribution of the grains. The void systems of sands, sandstones and oolitic limestones are typical of this type.

b. *Secondary porosity* is foramenular and is controlled by fracturing, jointing and/or solution in circulating water although it may be modified by infilling as a result of precipitation. It is not highly interconnected and usually cannot be correlated with permeability. Solution channels or vugular voids developed during weathering or burial in sedimentary basins are indigenous to carbonate rocks such as limestones or dolomites. Joints or fissures which occur in massive, extensive formations composed of shale, siltstone, schist, limestone or dolomite are generally vertical, and they are ascribed to tensional failure during mechanical deformation (the permeability associated with this type of void system is often anisotropic). Shrinkage cracks are the result

Original manuscript received in Society of Petroleum Engineers office Aug. 17, 1962. Revised manuscript received March 21, 1963. Paper presented at the Fall Meeting of the Society of Petroleum Engineers in Los Angeles on Oct. 7-10, 1962.

[1] References given at end of paper.

C

4
Formation Evaluation By Well Testing

Various theories have evolved regarding pressure behavior in naturally fractured reservoirs. Since all naturally fractured reservoirs are not the same, the following techniques may vary in their application.

Pollard—Pirson Methods

One of the early papers on pressure buildup analysis of fractured reservoirs was published by Pollard in 1959. Pollard considered that the reservoir consisted of three regions: one around the wellbore, one in the fractured system, and one in the matrix. Consequently, he broke the pressure differential into three components: (1) pressure differential across "skin" near the wall of the hole, (2) pressure differential due to flow resistance in the coarse communicating fissures, and (3) pressure differential between the fine voids and the coarse fissures.

Pollard's method

Pollard's method assumes that during a late stage of buildup the flow rate (q_b) from the matrix into the fractures can be described by the equation:

$$q_b = - V_b \, c_b \, \frac{dp_b}{d\Theta} = A_1 \, (p_b - p_f) \tag{4-1}$$

where:

q_b = rate of flow from matrix into fractures
V_b = pore volume of the matrix
c_b = compressibility factor of fluids in the matrix

(Aguilera)

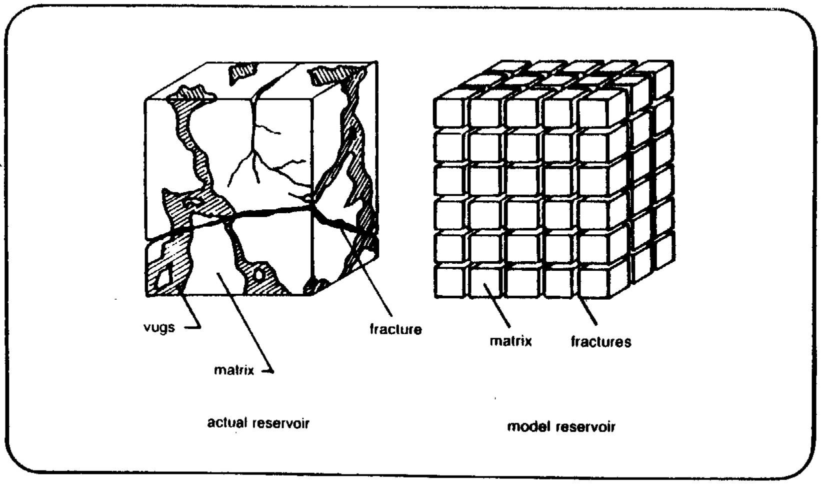


Fig. 4-10 Idealization of the heterogeneous porous medium. (After Warren & Root)

Warren and Root—Kazemi—De Swaan

Warren and Root

They presented a model composed of rectangular parallelopipeds where the blocks represented the matrix and the space in between the fractures (Fig. 4-10).

They evaluated this heterogeneous double-porosity model using as a base the following general assumptions:

1. The primary porosity (matrix) is homogeneous and isotropic, and is made up of identical rectangular parallelopipeds (Fig. 4-10).
2. The secondary porosity is contained within an orthogonal system of continuous, uniform fractures. A different fracture spacing or a different width may exist along each of the axis to simulate the proper degree of anisotropy.
3. Flow can occur between the primary and secondary porosities, but flow to the well can occur only through fractures. Flow through the primary-porosity elements cannot occur.

Warren and Root made an analytical investigation of the unsteady-state of flow in this model. The pressure buildup was analyzed in detail

(Aguilera)

and they found that a conventional buildup plot could result in two parallel straight lines. The vertical separation of the two lines was related to the storage capacity of the fractures.

They concluded that two parameters were enough to characterize the behavior of the double-porosity system. One parameter (ω) represented a measure of the fluid capacitance and the other parameter (λ) was related to the degree of heterogeneity of the system. Mathematically, λ and ω can be written as:

$$\lambda = \frac{\alpha k_1 r_w^2}{\overline{k_2}} \tag{4-23}$$

and

$$\omega = \frac{\phi_2 c_2}{\phi_1 c_1 + \phi_2 c_2} \tag{4-24}$$

where: α = *geometric parameter for hetrogeneous region, $1/L^2$.*
k_1 = *matrix permeability*
r_w = *well bore radius*
$\overline{k_2} = \sqrt{k_{2x} k_{2y}}$, *effective permeability of anisotropic medium, L^2*
ϕ_2 = *secondary porosity*
ϕ_1 = *primary porosity*

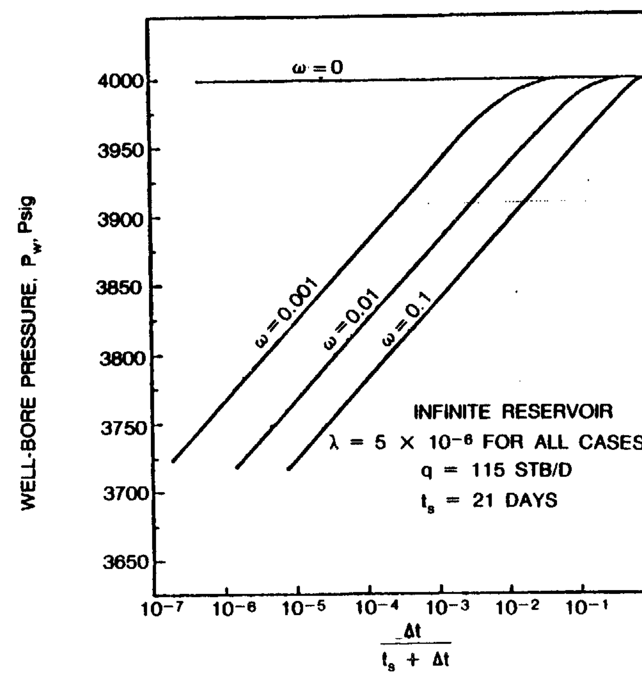


Fig. 4-11 Theoretical buildup curves. (After Warren & Root)

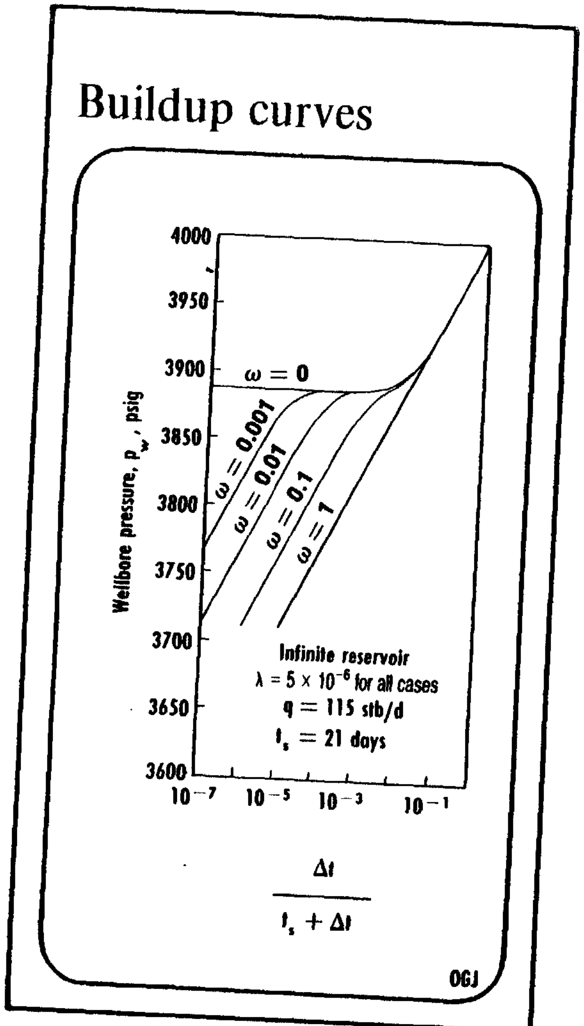


Fig. 4-12 Theoretical buildup curves. (After Warren & Root)

c_2 = *total compressibility in secondary system*
c_1 = *total compressibility in primary system*

Theoretical pressure buildup curves for an *infinite reservoir* and various combinations of λ and ω are shown in Figs. 4-11 and 12. Notice that when there is only primary porosity, ω = 0, the buildup occurs almost instantaneously if λ is very small.

The behavior in Fig. 4-11, where the value of λ is assumed at 5 × 10^{-6}, *implies a reservoir with a closed boundary*. Note also that, if only

the early portion of the curve were recorded, the pressure *p* determined by extrapolations to $\Delta t/(t_s + \Delta t)$ would be in error by an amount equal to m log (1/ω), and the skin resistance (s_d) would be high by an amount equal to 1.15 log (1/ω).

This may lead to error in the interpretation; Warren and Root point out that this is one of the weaknesses of the Pollard method. It is possible to analyze the transitional curve between the initial linear portion and the asymptote just as if the reservoir actually had a finite drainage radius. Fig. 4-12, where the value of λ is assumed at 5 × 10^{-6}, shows the double-slope buildup performance.

Although Warren and Root's method is mathematically more rigorous, Matthews and Russel in SPE Monograph Vol. I indicate that the type of buildup displayed by Pollard and Pirson seems much more common than the one suggested by Warren and Root.

Kazemi

Kazemi studied the transient pressure behavior of naturally fractured reservoirs by means of a model which consisted of a finite circular reservoir with a well located in the center and two distinct porous regions, referred to as matrix and fractures (Fig. 4-13).

Fig. 4-14 depicts a representative section of the Kazemi model, which used as a basis the following assumptions:

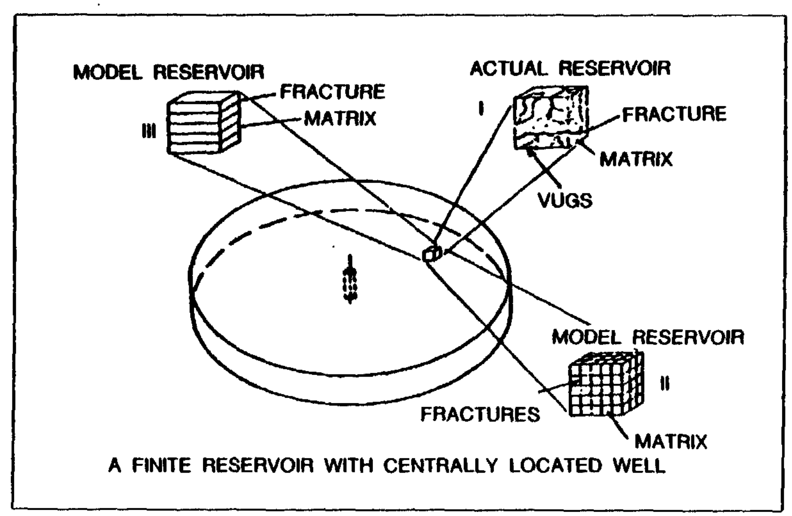


Fig. 4-13 Idealization of naturally fractured porous medium. II, Warren-Root model; III, Kazemi model. (After Kazemi)

(Aguilera)

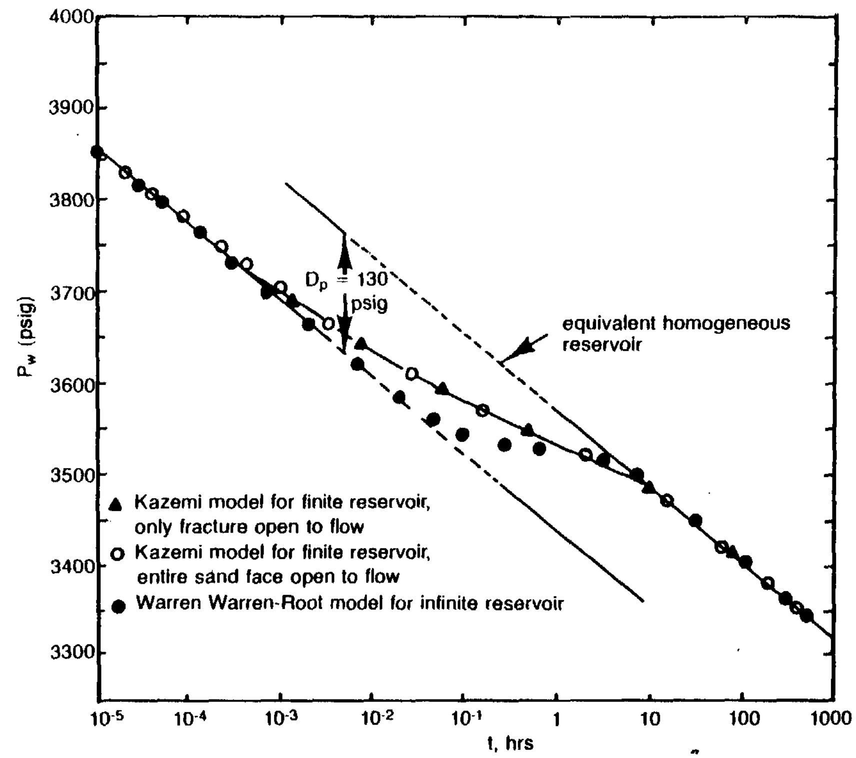


Fig. 4-15 Pressure drawdown for case 1. (After Kazemi)

was uniform, and the contrasts between fracture and matrix flow were large. When this contrast was small, only one straight line was noticeable.

De Swaan

De Swaan presented an excellent analytical approach to the evaluation of naturally fractured reservoirs from pressure drawdown data. His theory is based on the following assumptions:

1. At early times, flow occurs only in the fractures and is described by the approximate solution of the radial infinite reservoir as applied to fracture media:

$$\Delta p_f = \frac{q\mu}{4\pi\, h_f k_f} \ln\left(\frac{4\, \eta_f\, t}{\gamma' r_w^2}\right) \tag{4-31}$$

(Aguilera).

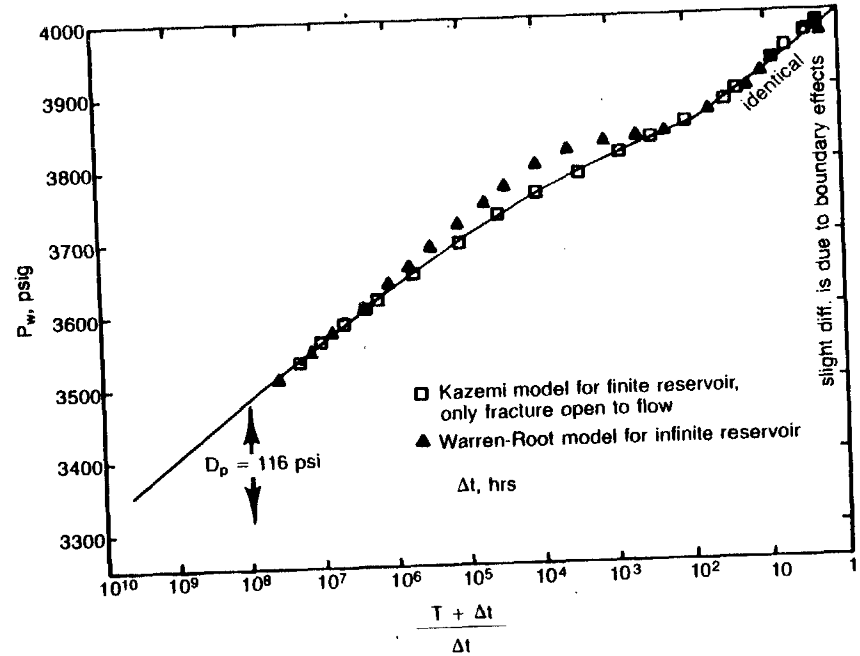


Fig. 4-16 Pressure buildup for case 1. (After Kazemi)

where:
- $p_f = p_i - p$ = *incremental pressure, atm*
- q = *flow rate, cc/sec*
- μ = *viscosity, cp*
- k_f = *fracture permeability, darcys*
- h_f = *fracture thickness, cm*
- η_f = *fracture hydraulic diffusivity—sq cm/sec*
- γ' = *1.78*
- r_w = *well bore radius, cm*
- t = *time, seconds*

2. The matrix blocks represent a source uniformly distributed in the fracture system. Due to the matrix low permeability, the response of the matrix blocks is slower than the fracture media response.
3. Solutions of heat flow problems in solids are applicable to the case in which shape of the matrix block is approximated by regular solids. These solutions are given for solids with unitary pressure (temperature) loss at their surfaces as a boundary condition.
4. The outflow from the blocks is described through a convolution:

CORE DESCRIPTION AND
PETROGRAPHIC ANALYSIS OF
THE GALLUP FORMATION
IN THE
NUMBER 1-11 HOWARD FEDERAL WELL

for

MALLON OIL COMPANY
Denver, Colorado

D

Petrographic Services

DISCUSSION (Continued)

interval. From 7300 to 7280 feet the unit is dark gray in color and exhibits undisturbed, *horizontal planar laminations. Silt laminae are very rare.* Calcareous stringers, silty laminae, and fossil debris are in low abundance in this unit.

Fractures occur throughout the cored interval. They are oriented vertically to approximately 30 degrees from vertical, and spaced at intervals greater than four inches, these fractures are generally mineralized with calcite and pyrite. Fracture sets intersect at angles of ten to fifteen degrees, and commonly terminate one another. The dark gray units typically contain one dominant fracture two to three feet in length, with closely spaced (approx. 1/2 inch) subordinate fractures parallel to it. The gray-black, siltier unit contains a somewhat higher frequency of shorter (six to twelve inch long) fractures.

Thin Section Description

A thin section cut normal to bedding in a silty interval (7322.8 feet) revealed slightly compacted, moderately sorted, wavy laminated, burrowed units of coarse silt within a wavy laminated, silty shale matrix (plate 2A). The silt component is comprised principally of quartz grains, with a lower abundance of feldspar grains, volcanic rock fragments, and mica. Traces of zircon, glauconite, and detrital dolomite are also present. A significant component of both the silty and shaly units is calcareous foraminifer debris. This debris, plus the large bivalve shells, account for the calcareous nature of the entire interval. Carbonaceous matter is abundant in the shaly laminae.

Pyrite is the most abundant authigenic mineral. It has formed in close association with foraminifer tests, and as scattered framboids in both silty and shaly laminae. Calcite is abundant as sparry to poikilotopic, intergranular cement in the silty laminae; very minor dolomite cement has also formed in these units. No porosity is evident in thin section.

Wireline Log Analysis

Figure 1 is a compilation of all wireline log curves plus the measured percent shale curve generated in this study. No log except density porosity exhibits behavior parallel to the percent shale curve. This is a deception, however, as the density porosity reading in the silty zone (log depth 7294 to 7300 feet) indicates high porosity (sandstone matrix), whereas the core analysis from this zone reports porosities around 1 %. The measured grain density of the shale is 2.63 g/cc, which is very close to the assumed matrix

MALLON OIL COMPANY
No. 1-11 Howard Federal Well

File No. PD-85057

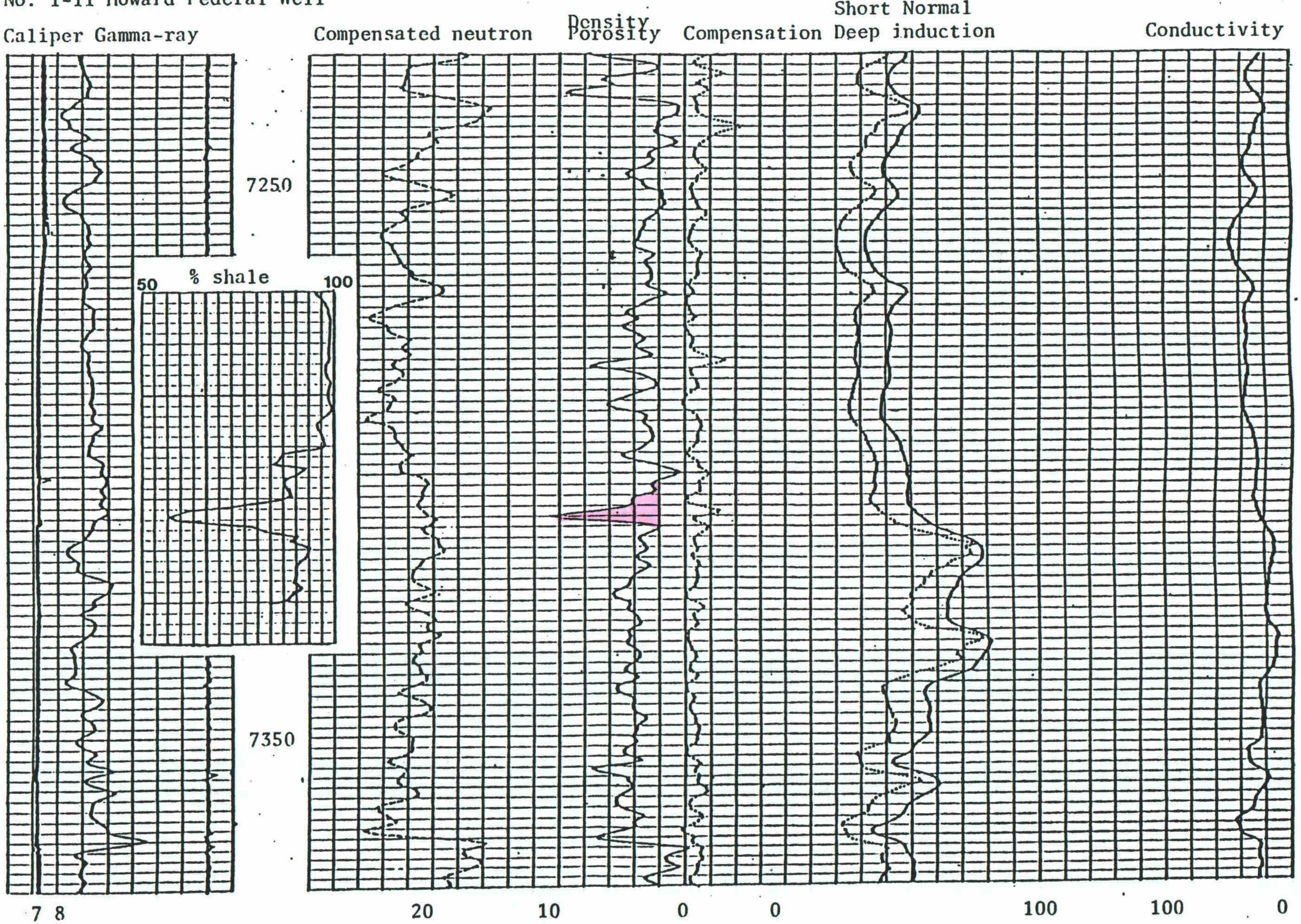


FIGURE 1

Petroleum Reservoir Engineering

DALLAS, TEXAS

MOBIL PRODUCING TX & NM INC.
LINDRITH B UNIT # 38
GAVILAN MANCOS
RIO ARRIBA, N.M.
API # 30-039-70228-85

DATE : 10-DEC-1985
FORMATION : GALLUP
DRLG. FLUID: WBM
LOCATION : NE,SW SEC. 4-T24N-R2W

FILE NO : 38030-3424
ANALYSTS : DS;EV
ELEVATION: 7180 GL

no confining pressure

CONVENTIONAL ANALYSIS-BOYLE'S LAW POROSITY

SAMPLE NUMBER	DEPTH	PERM. TO AIR (MD) MAXIMUM	PERM. TO AIR (MD) 90 DEG	POR. He	FLUID SATS. OIL	FLUID SATS. WTR	GRAIN DEN	DESCRIPTION	
	GALLUP FORMATION CORE # 1 6660-6681								
1	6660.0-61.0	0.01		2.5	39.0	39.0	2.66	SD GRY VFGRN SHY SL/CALC	
2	6661.0-62.0	0.02		2.0	34.6	40.3	2.66	SD GRY VFGRN SHY SL/CALC	
3	6662.0-63.0	<0.01		1.0	39.6	35.2	2.69	SD GRY VFGRN SHY CALC PYR	
4	6663.0-64.0	0.42		0.9	49.5	22.0	2.67	SD GRY VFGRN SHY CALC	**
5	6664.0-65.0	<0.01		0.6	49.8	16.6	2.64	SD GRY VFGRN SHY CALC	
6	6665.0-66.0	<0.01		1.0	52.4	22.1	2.70	SD GRY VFGRN SHY CALC PYR	
7	6666.0-67.0	<0.01		0.9	41.2	34.3	2.63	SD GRY VFGRN SHY CALC	
8	6667.0-68.0	0.02		0.7	45.6	32.9	2.66	SD GRY VFGRN SHY SL/CALC	
9	6668.0-69.0	<0.01		0.5	42.3	35.2	2.65	SD GRY VFGRN SHY SL/CALC	
10	6669.0-70.0	0.02		1.1	38.6	33.1	2.65	SD GRY VFGRN SHY SL/CALC	
11	6670.0-71.0	0.10		0.5	38.8	32.4	2.63	SLTST DRKGRY VFGRN SHY CALC	
12	6671.0-72.0	<0.01		1.7	34.2	34.2	2.69	SD GRY VFGRN SHY CALC PYR	
	6672.0-77.0							SHALE -- NO ANALYSIS	
13	6677.0-78.0	0.02		2.7	24.9	33.1	2.67	SD GRY VFGRN SHY CALC	
14	6678.0-79.0	0.01		2.9	22.5	50.0	2.67	SD GRY VFGRN SHY CALC	
15	6679.0-80.0	0.01		3.5	31.9	31.9	2.66	SD GRY VF-FNGRN SHY CALC	
16	6680.0-81.0	0.01		3.1	30.5	30.5	2.67	SD GRY VF-FNGRN SHY CALC	
	GALLUP FORMATION CORE # 2 6681-6714								
17	6681.0-82.0	0.03		2.3	28.8	38.4	2.67	SD GRY VF-FNGRN SHY SL/CALC	
18	6682.0-83.0	0.14		2.5	19.6	39.2	2.68	SD GRY VF-FNGRN SHY CALC	
19	6683.0-84.0	0.07		2.8	32.0	42.7	2.67	SD GRY VF-FNGRN SHY CALC	
20	6684.0-85.0	0.02		2.2	17.5	60.0	2.68	SD GRY VF-FNGRN SHY PYR	
21	6685.0-86.0	0.16		2.1	24.5	59.9	2.66	SD GRY VF-FNGRN SHY CALC	

MOBIL PRODUCING TX & NM INC.
LINDRITH B UNIT # 38

DATE : 10-DEC-1985
FORMATION : GALLUP

FILE NO : 38030-3424
ANALYSTS : DS;EV

CONVENTIONAL ANALYSIS-BOYLE'S LAW POROSITY

SAMPLE NUMBER	DEPTH	PERM. TO AIR (MD) MAXIMUM	PERM. TO AIR (MD) 90 DEG	POR. He	FLUID SATS. OIL	FLUID SATS. WTR	GRAIN DEN	DESCRIPTION
22	6686.0-87.0	0.06		1.6	21.1	61.0	2.66	SD GRY VF-FNGRN SHY CALC
23	6687.0-88.0	0.12		1.5	16.6	56.8	2.67	SD GRY VFGRN SHY PYR SL/CALC **
24	6688.0-89.0	2.85		2.0	22.3	50.9	2.68	SD GRY VFGRN SHY PYR SL/CALC **
25	6689.0-90.0	11.		2.2	0.0	56.4	2.68	SD DRKGRY VFGRN SHY CALC PYR *
26	6690.0-91.0	0.06		2.6	20.1	57.5	2.67	SD DRKGRY VFGRN SHY CALC PYR
27	6691.0-92.0	0.01		1.8	18.6	47.9	2.67	SD DRKGRY VFGRN SHY CALC PYR
28	6692.0-93.0	0.03		1.9	32.4	36.0	2.67	SD DRKGRY VFGRN SHY CALC PYR
29	6693.0-94.0	0.03		2.4	18.3	52.4	2.67	SD DRKGRY VFGRN SHY CALC PYR
30	6694.0-95.0	0.79		2.0	20.4	52.5	2.66	SD DRKGRY VFGRN SHY CALC **
31	6695.0-96.0	0.02		1.5	23.9	47.9	2.65	SD DRKGRY VFGRN SHY CALC
32	6696.0-97.0	<0.01		1.8	22.5	36.0	2.67	SD DRKGRY VFGRN SHY CALC
33	6697.0-98.0	<0.01		2.5	34.7	30.8	2.67	SD DRKGRY VFGRN SHY CALC
34	6698.0-99.0	0.06		1.5	24.6	49.1	2.65	SD DRKGRY VFGRN SHY CALC
35	6699.0-00.0	0.02		2.2	30.2	51.7	2.68	SD DRKGRY VFGRN SHY CALC PYR
	6700.0-05.0							SHALE SL/SD -- NO ANALYSIS
36	6705.0-06.0	0.36		2.6	21.8	48.5	2.69	SD DRKGRY VFGRN SHY CALC PYR
37	6706.0-07.0	0.01		2.5	26.2	29.9	2.71	SD DRKGRY VFGRN SHY CALC PYR
38	6707.0-08.0	<0.01		2.6	43.6	31.1	2.69	SD DRKGRY VFGRN SHY CALC PYR
39	6708.0-09.0	0.01		2.8	39.3	32.8	2.69	SD DRKGRY VFGRN SHY CALC PYR
40	6709.0-10.0	0.01		2.2	38.5	33.0	2.68	SD DRKGRY VFGRN SHY CALC PYR
41	6710.0-11.0	<0.01		1.3	40.0	26.7	2.66	SD DRKGRY VFGRN SHY CALC
42	6711.0-12.0	<0.01		2.1	39.3	26.2	2.67	SD DRKGRY VFGRN SHY CALC
43	6712.0-13.0	<0.01		1.3	39.1	22.4	2.62	SLTST DRKGRY VFGRN SHY SL/CALC
44	6713.0-14.0	<0.01		1.0	42.8	28.6	2.61	SD GRY VFGRN SHY SL/CALC

GALLUP FORMATION CORE # 3 6714-6720

SAMPLE NUMBER	DEPTH	PERM. TO AIR (MD) MAXIMUM	PERM. TO AIR (MD) 90 DEG	POR. He	FLUID SATS. OIL	FLUID SATS. WTR	GRAIN DEN	DESCRIPTION
45	6714.0-15.0	<0.01		1.3	50.6	25.3	2.61	SD GRY VFGRN SHY SL/CALC
	6715.0-16.0							SHALE -- NO ANALYSIS
46	6716.0-17.0	0.01		2.4	36.2	24.1	2.63	SD GRY VFGRN SHY CALC

Petroleum Reservoir Engineering

DALLAS, TEXAS

MOBIL PRODUCING TX & NM INC.
LINDRITH B UNIT # 38

DATE : 10-DEC-1985
FORMATION : GALLUP

FILE NO : 38030-3424
ANALYSTS : DS;EV

CONVENTIONAL ANALYSIS-BOYLE'S LAW POROSITY

SAMPLE NUMBER	DEPTH	PERM. TO AIR (MD) MAXIMUM	PERM. TO AIR (MD) 90 DEG	POR. He	FLUID SATS. OIL	FLUID SATS. WTR	GRAIN DEN	DESCRIPTION	
	6717.0-18.0							SHALE -- NO ANALYSIS	
47	6718.0-19.0	0.01		2.4	41.7	34.7	2.68	SD GRY VFGRN SHY CALC PYR	
48	6719.0-20.0	0.01		2.0	44.7	31.9	2.68	SD GRY VFGRN SHY CALC PYR	
	GALLUP FORMATION	CORE # 4 6720-6736							
49	6720.0-21.0	0.01		2.2	35.5	31.6	2.67	SD GRY VFGRN SHY CALC PYR	
50	6721.0-22.0	0.01		1.5	26.7	30.6	2.69	SD GRY VFGRN SHY CALC PYR	
51	6722.0-23.0	0.32		2.2	32.8	32.8	2.66	SD GRY VFGRN SHY CALC	
52	6723.0-24.0	<0.01		1.0	10.6	42.4	2.70	SD GRY VFGRN SHY CALC PYR	
53	6724.0-25.0	0.02		1.5	27.1	30.9	2.67	SD GRY VFGRN SHY CALC PYR	
54	6725.0-26.0	<0.01		1.1	30.3	34.6	2.69	SD GRY VFGRN SHY CALC PYR	
55	6726.0-27.0	0.05		1.3	36.2	32.2	2.66	SD GRY VFGRN SHY CALC	
56	6727.0-28.0	0.09		1.8	10.6	42.5	2.64	SD GRY VFGRN SHY CALC	
57	6728.0-29.0	0.01		1.7	44.6	29.8	2.66	SD GRY VFGRN SHY CALC	
	6729.0-31.0							SHALE -- NO ANALYSIS	
58	6731.0-32.0	0.01		1.2	25.8	29.5	2.64	SD GRY VFGRN SHY CALC	
59	6732.0-33.0	0.05		0.8	0.0	35.2	2.64	SD GRY VFGRN SHY CALC	
60	6733.0-34.0	0.08		0.5	30.4	27.1	2.64	SD DRKGRY VFGRN SHY CALC	
61	6734.0-35.0	0.03		0.8	26.0	23.1	2.67	SD GRY VFGRN SHY CALC PYR	
62	6735.0-36.0	0.06		1.0	37.8	31.5	2.65	SD GRY VFGRN SHY CALC	
	GALLUP FORMATION	CORE # 5 6736-6743							
63	6736.0-37.0	0.16		0.8	39.8	33.2	2.61	SD GRY VFGRN SHY CALC	**
	6737.0-39.0							SHALE -- NO ANALYSIS	
64	6739.0-40.0	0.01		0.6	48.8	24.4	2.66	SD GRY VFGRN SHY CALC	
	6740.0-41.0							SHALE -- NO ANALYSIS	
	6741.0-43.0							CORE LOSS	
	GALLUP FORMATION	CORE # 6 6743-6756							

Petroleum Reservoir Engineering

DALLAS, TEXAS

MOBIL PRODUCING TX & NM INC.
LINDRITH B UNIT # 38

DATE : 10-DEC-1985
FORMATION : GALLUP

FILE NO : 38030-3424
ANALYSTS : DS;EV

CONVENTIONAL ANALYSIS-BOYLE'S LAW POROSITY

SAMPLE NUMBER	DEPTH	PERM. TO AIR (MD) MAXIMUM	PERM. TO AIR (MD) 90 DEG	POR. He	FLUID SATS. OIL	FLUID SATS. WTR	GRAIN DEN	DESCRIPTION	
	6743.0-50.0							SHALE -- NO ANALYSIS	
65	6750.0-51.0	0.21		1.6	40.4	26.9	2.64	SD GRY VFGRN SHY CALC	
66	6751.0-52.0	0.01		1.0	42.3	30.2	2.61	SD GRY VFGRN SHY SL/CALC	
	6752.0-56.0							SHALE -- NO ANALYSIS	
	GALLUP FORMATION	CORE # 7 6756-6770							
67	6756.0-57.0	<0.01		0.8	36.3	40.8	2.67	SD GRY VF-FNGRN SHY CALC PYR	
68	6757.0-58.0	0.01		1.0	43.3	37.9	2.65	SD GRY VFGRN SHY SL/CALC	
	6758.0-59.0							SHALE -- NO ANALYSIS	
69	6759.0-60.0	0.01		1.2	32.4	21.6	2.59	SH BLK VFGRN SL/CALC	
	6760.0-70.0							SHALE -- NO ANALYSIS	
	GALLUP FORMATION	CORE # 8 6770-6809							
70	6770.0-71.0	4.16	35	1.0	37.9	52.1	2.59	SH BLK VFGRN SL/CALC	
	6771.0-85.0							SHALE -- NO ANALYSIS	
71	6785.0-86.0	0.65		1.1	28.4	52.1	2.64	SD DRKGRY VFGRN SHY SL/CALC	**
	6786.0-88.0							SHALE -- NO ANALYSIS	
72	6788.0-89.0	0.01	40	1.0	50.6	40.5	2.60	SH BLK VFGRN SL/CALC	
73	6789.0-90.0	0.81		1.1	38.2	38.2	2.70	SD GRY VFGRN SHY CALC PYR	**
	6790.0-91.0							SHALE -- NO ANALYSIS	
74	6791.0-92.0	0.01		0.8	45.3	30.2	2.65	SD GRY VFGRN SHY SL/CALC	
75	6792.0-93.0	0.03		1.0	35.1	40.2	2.63	SD GRY VFGRN SHY SL/CALC	
	6793.0-94.0							SHALE -- NO ANALYSIS	
76	6794.0-95.0	0.01		0.8	48.4	27.6	2.63	SD GRY VFGRN SHY CALC	
	6795.0-98.0							SHALE -- NO ANALYSIS	
77	6798.0-99.0	0.01		1.1	35.0	40.0	2.68	SD GRY VFGRN SHY CALC	
78	6799.0-00.0	0.01		0.4	32.3	35.9	2.64	SD GRY VFGRN SHY CALC	
79	6800.0-01.0	1.21	41	1.2	46.6	39.3	2.63	SD GRY VFGRN SHY CALC	**

MOBIL PRODUCING TX & NM INC. DATE : 10-DEC-1985 FILE NO : 38030-3424
LINDRITH B UNIT # 38 FORMATION : GALLUP ANALYSTS : DS;EV

CONVENTIONAL ANALYSIS-BOYLE'S LAW POROSITY

SAMPLE NUMBER	DEPTH	PERM. TO AIR (MD) MAXIMUM	PERM. TO AIR (MD) 90 DEG	POR. He	FLUID SATS. OIL	FLUID SATS. WTR	GRAIN DEN	DESCRIPTION
80	6801.0-02.0	0.01		0.8	58.6	27.9	2.57	SH BLK VFGRN SL/CALC
81	6802.0-03.0	0.01		1.0	41.7	37.1	2.67	SD GRY VFGRN SHY CALC
	6803.0-09.0							CORE LOSS
	GALLUP FORMATION CORE # 9 6809-6843							
	6809.0-43.0							SHALE -- NO ANALYSIS

** DENOTES FRACTURE PERMEABILITY

INTERPRETATION OF FLUID SATURATIONS
ASSUMING
10% FLUSH AND 20% RECOVERY OF OIL-IN-PLACE
AFTER FLUSH
(FINAL PRESSURE ATMOSPHERIC)

	LABORATORY				CALCULATED SATURATIONS FOR GIVEN CONDITIONS				
Sample Number	Perm (md) (1)	Porosity (2)	Saturations Oil (3)	Water (4)	Initial Reservoir Oil-in-Place (5)	Less 10% Flush (6)	Less 20% "Production" to Atmospheric Pressure (7)	Stock Tank Volume Remaining (8)	Column 8 Minus Column 3 (9)
1	0.01	2.5	39.0	39.0	61.0	54.9	43.9	31.8	(7.2)
2	0.02	2.0	34.6	40.3	59.7	53.7	43.0	31.1	(3.5)
3	<0.01	1.0	39.6	35.2	64.8	58.3	46.7	33.8	(5.8)
4	0.42	0.9	49.5	22.0	78.0	70.2	56.2	40.7	(8.8)
5	<0.01	0.6	49.8	16.6	83.4	75.1	60.0	43.5	(6.3)
6	<0.01	1.0	52.4	22.1	77.9	70.1	56.1	40.6	(11.8)
7	<0.01	0.9	41.2	34.3	65.7	59.1	47.3	34.3	(6.9)
8	0.02	0.7	45.6	32.9	67.1	60.4	48.3	35.0	(10.6)
9	<0.01	0.5	42.3	35.2	64.8	58.3	46.7	33.8	(8.5)
10	0.02	1.1	38.6	33.1	66.9	60.2	48.2	34.9	(3.7)
11	0.10	0.5	38.8	32.4	67.6	60.8	48.7	35.3	(3.5)
12	<0.01	1.7	34.2	34.2	65.8	59.2	47.4	34.3	0.1
13	0.02	2.7	24.9	33.1	66.9	60.2	48.2	34.9	10.0
14	0.01	2.9	22.5	50.0	50.0	45.0	36.0	26.1	3.6
15	0.01	3.5	31.9	31.9	68.1	61.3	49.0	35.5	3.6
16	0.01	3.1	30.5	30.5	69.5	62.6	50.0	36.3	5.8
17	0.03	2.3	28.8	38.4	61.6	55.4	44.4	32.1	3.3
18	0.14	2.5	19.6	39.2	60.8	54.7	43.8	31.7	12.1
19	0.07	2.8	32.0	42.7	57.3	51.6	41.3	29.9	(2.1)
20	0.02	2.2	17.5	60.0	40.0	36.0	28.8	20.9	3.4
21	0.16	2.1	24.5	59.9	40.1	36.1	28.9	20.9	(3.6)
22	0.06	1.6	21.1	61.0	39.0	35.1	28.1	20.3	(0.8)
23	0.12	1.5	16.6	56.8	43.2	30.9	31.1	22.5	5.9
24	2.85	2.0	22.3	50.9	49.1	44.2	35.4	25.6	3.3
25	11.00	2.2	0.0	56.4	43.6	39.2	31.4	22.7	22.7
26	0.06	2.6	20.1	57.5	42.5	38.3	30.6	22.2	2.1
27	0.01	1.8	18.6	47.9	52.1	46.9	37.5	27.2	8.6
28	0.03	1.9	32.4	36.0	64.0	57.6	46.1	33.4	1.0
29	0.03	2.4	18.3	52.4	47.6	42.8	34.3	24.8	6.5
30	0.79	2.0	20.4	52.5	47.5	42.8	34.2	24.8	4.4
31	0.02	1.5	23.9	47.9	52.1	46.9	37.5	27.2	3.3
32	<0.01	1.8	22.5	36.0	64.0	57.6	46.1	33.4	10.9
33	<0.01	2.5	34.7	30.8	69.2	62.3	49.8	36.1	1.4
34	0.06	1.5	24.6	49.1	50.9	45.8	36.6	26.6	2.0
35	0.02	2.2	30.2	51.7	48.3	43.5	34.8	25.2	(5.0)
36	0.36	2.6	21.8	48.5	51.5	46.4	37.1	26.9	5.1
37	0.01	2.5	26.2	29.9	70.1	63.1	50.5	36.6	10.4
38	<0.01	2.6	43.6	31.1	68.9	62.0	49.6	35.9	(7.7)
39	0.01	2.8	39.3	32.8	67.2	60.5	48.4	35.1	(4.2)
40	0.01	2.2	38.5	33.0	67.0	60.3	48.2	35.0	(3.5)
41	<0.01	1.3	40.0	26.7	73.3	66.0	52.8	38.2	(1.8)
42	<0.01	2.1	39.3	26.2	73.8	66.4	53.1	38.5	(0.8)
43	<0.01	1.3	39.1	22.4	77.6	69.8	55.9	40.5	1.4
44	<0.01	1.0	42.8	28.6	71.4	64.3	51.4	37.3	(5.5)
45	<0.01	1.3	50.6	25.3	74.7	67.2	53.8	39.0	(11.6)

INTERPRETATION OF FLUID SATURATIONS
ASSUMING
10% FLUSH AND 20% RECOVERY OF OIL-IN-PLACE
AFTER FLUSH
(FINAL PRESSURE ATMOSPHERIC)

	LABORATORY				CALCULATED SATURATIONS FOR GIVEN CONDITIONS				
Sample Number	Perm (md)	Porosity	Saturations Oil	Saturations Water	Initial Reservoir Oil-in-Place	Less 10% Flush	Less 20% "Production" to Atmospheric Pressure	Stock Tank Volume Remaining	Column 8 Minus Column 3
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
46	0.01	2.4	36.2	24.1	75.9	68.3	54.6	39.6	3.4
47	0.01	2.4	41.7	34.7	65.3	58.8	47.0	34.1	(7.6)
48	0.01	2.0	44.7	31.9	68.1	61.3	49.0	35.5	(9.2)
49	0.01	2.2	35.5	31.6	68.4	61.6	49.2	35.7	0.2
50	0.01	1.5	26.7	30.6	69.4	62.5	50.0	36.2	9.5
51	0.32	2.2	32.8	32.8	67.2	60.5	48.4	35.1	2.3
52	<0.01	1.0	10.6	42.4	57.6	51.8	41.5	30.1	19.5
53	0.02	1.5	27.1	30.9	69.1	62.2	49.8	36.1	9.0
54	<0.01	1.1	30.3	34.6	65.4	58.9	47.1	34.1	3.8
55	0.05	1.3	36.2	32.2	67.8	61.0	48.8	35.4	(0.8)
56	0.09	1.8	10.6	42.5	57.5	51.8	41.4	30.0	19.4
57	0.01	1.7	44.6	29.8	70.2	63.2	50.5	36.6	(8.0)
58	0.01	1.2	25.8	29.5	70.5	63.5	50.8	36.8	11.0
59	0.05	0.8	0.0	35.2	64.8	58.3	46.7	33.8	33.8
60	0.08	0.5	30.4	27.1	72.9	65.6	52.5	38.0	7.6
61	0.03	0.8	26.0	23.1	76.9	69.2	55.4	40.1	14.1
62	0.06	1.0	37.8	31.5	68.5	61.7	49.3	35.7	(2.1)
63	0.16	0.8	39.8	33.2	66.8	60.1	48.1	34.9	(4.9)
64	0.01	0.6	48.8	24.4	75.6	68.0	54.4	39.4	(9.4)
65	0.21	1.6	40.4	26.9	73.1	65.8	52.6	38.1	(2.3)
66	0.01	1.0	42.3	30.2	69.8	62.8	50.3	36.4	(5.9)
67	<0.01	0.8	36.3	40.8	59.2	53.3	42.6	30.9	(5.4)
68	0.01	1.0	43.3	37.9	62.1	55.9	44.7	32.4	(10.9)
69	0.01	1.2	32.4	21.6	78.4	70.6	56.4	40.9	8.5
70	4.16	1.0	37.9	52.1	47.9	43.1	34.5	25.0	(12.9)
71	0.65	1.1	28.4	52.1	47.9	43.1	34.5	25.0	(3.4)
72	0.01	1.0	50.6	40.5	59.5	53.6	42.8	31.0	(19.6)
73	0.81	1.1	38.2	38.2	61.8	55.6	44.5	32.2	(6.0)
74	0.01	0.8	45.3	30.2	69.8	62.8	50.3	36.4	(8.9)
75	0.03	1.0	35.1	40.2	59.8	53.8	43.1	31.2	(3.9)
76	0.01	0.8	48.4	27.6	72.4	65.2	52.1	37.8	(10.6)
77	0.01	1.1	35.0	40.0	60.0	54.0	43.2	31.3	(3.7)
78	0.01	0.4	32.3	35.9	64.1	57.7	46.2	33.4	1.1
79	1.21	1.2	46.6	39.3	60.7	54.6	43.7	31.7	(14.9)
80	0.01	0.8	58.6	27.9	72.1	64.9	51.9	37.6	(21.0)
81	0.01	1.0	41.7	37.1	62.9	56.6	45.3	32.8	(8.9)

Column 1: Permeability, millidarcies.
Column 2: Percent of bulk volume.
Column 3: Percent of pore space.
Column 4: Percent of pore space.
Column 5: Initial oil-in-place, percent of pore space at initial reservoir pressure. 100 minus Column 4.
Column 6: Column 5 x .9 (reservoir volume after flushing, percent of pore space).
Column 7: Column 6 x .8 (reservoir volume after "production" of 20% of oil-in-place after flushing).
Column 8: Stock tank volume remaining in reservoir after "production" and expulsion of flushing water: Column 7 divided by FVF of 1.38.
Column 9: Column 8 minus Column 3, theoretical saturation less laboratory saturation. (Negative figure means sample is suspect - or flushing of less than 10% occurred).

INTERPRETATION OF FLUID SATURATIONS
ASSUMING
0% FLUSH AND 20% RECOVERY OF OIL-IN-PLACE
(FINAL PRESSURE ATMOSPHERIC)

	LABORATORY				CALCULATED SATURATIONS FOR GIVEN CONDITIONS				
Sample Number	Perm (md)	Porosity	Saturations Oil	Saturations Water	Initial Reservoir Oil-in-Place	Less 0% Flush	Less 20% "Production" to Atmospheric Pressure	Stock Tank Volume Remaining	Column 8 Minus Column 3
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	0.01	2.5	39.0	39.0	61.0	61.0	48.8	35.4	(3.6)
2	0.02	2.0	34.6	40.3	59.7	59.7	47.8	34.6	0.0
3	<0.01	1.0	39.6	35.2	64.8	64.8	51.8	37.6	(2.0)
4	0.42	0.9	49.5	22.0	78.0	78.0	62.4	45.2	(4.3)
5	<0.01	0.6	49.8	16.6	83.4	83.4	66.7	48.3	(1.5)
6	<0.01	1.0	52.4	22.1	77.9	77.9	62.3	45.2	(7.2)
7	<0.01	0.9	41.2	34.3	65.7	65.7	52.6	38.1	(3.1)
8	0.02	0.7	45.6	32.9	67.1	67.1	53.7	38.9	(6.7)
9	<0.01	0.5	42.3	35.2	64.8	64.8	51.8	37.6	(4.7)
10	0.02	1.1	38.6	33.1	66.9	66.9	53.5	38.8	0.2
11	0.10	0.5	38.8	32.4	67.6	67.6	54.1	39.2	0.4
12	<0.01	1.7	34.2	34.2	65.8	65.8	52.6	38.1	3.9
13	0.02	2.7	24.9	33.1	66.9	66.9	53.5	38.8	13.9
14	0.01	2.9	22.5	50.0	50.0	50.0	40.0	29.0	6.5
15	0.01	3.5	31.9	31.9	68.1	68.1	54.5	39.5	7.6
16	0.01	3.1	30.5	30.5	69.5	69.5	55.6	40.3	9.8
17	0.03	2.3	28.8	38.4	61.6	61.6	49.3	35.7	6.9
18	0.14	2.5	19.6	39.2	60.8	60.8	48.6	35.2	15.6
19	0.07	2.8	32.0	42.7	57.3	57.3	45.8	33.2	1.2
20	0.02	2.2	17.5	60.0	40.0	40.0	32.0	23.2	5.7
21	0.16	2.1	24.5	59.9	40.1	40.1	32.1	23.2	(1.3)
22	0.06	1.6	21.1	61.0	39.0	39.0	31.2	22.6	1.5
23	0.12	1.5	16.6	56.8	43.2	43.2	34.6	25.0	8.4
24	2.85	2.0	22.3	50.9	49.1	49.1	39.3	28.5	6.2
25	11.00	2.2	0.0	56.4	43.6	43.6	34.9	25.3	25.3
26	0.06	2.6	20.1	57.5	42.5	42.5	34.0	24.6	4.5
27	0.01	1.8	18.6	47.9	52.1	52.1	41.7	30.2	11.6
28	0.03	1.9	32.4	36.0	64.0	64.0	51.2	37.1	4.7
29	0.03	2.4	18.3	52.4	47.6	47.6	38.1	27.6	9.3
30	0.79	2.0	20.4	52.5	47.5	47.5	38.0	27.5	7.1
31	0.02	1.5	23.9	47.9	52.1	52.1	41.7	30.2	6.3
32	<0.01	1.8	22.5	36.0	64.0	64.0	51.2	37.1	14.6
33	<0.01	2.5	34.7	30.8	69.2	69.2	55.4	40.1	5.4
34	0.06	1.5	24.6	49.1	50.9	50.9	40.7	29.5	4.9
35	0.02	2.2	30.2	51.7	48.3	48.3	38.6	28.0	(2.2)
36	0.36	2.6	21.8	48.5	51.5	51.5	41.2	29.9	8.1
37	0.01	2.5	26.2	29.9	70.1	70.1	56.1	40.6	14.4
38	<0.01	2.6	43.6	31.1	68.9	68.9	55.1	39.9	(3.7)
39	0.01	2.8	39.3	32.8	67.2	67.2	53.8	39.0	(0.3)
40	0.01	2.2	38.5	33.0	67.0	67.0	53.6	38.8	0.3
41	<0.01	1.3	40.0	26.7	73.3	73.3	58.6	42.5	2.5
42	<0.01	2.1	39.3	26.2	73.8	73.8	59.0	42.8	3.5
43	<0.01	1.3	39.1	22.4	77.6	77.6	62.1	45.0	5.9
44	<0.01	1.0	42.8	28.6	71.4	71.4	57.1	41.4	(1.4)
45	<0.01	1.3	50.6	25.3	74.7	74.7	59.8	43.3	(7.3)

INTERPRETATION OF FLUID SATURATIONS
ASSUMING
0% FLUSH AND 20% RECOVERY OF OIL-IN-PLACE
(FINAL PRESSURE ATMOSPHERIC)

	LABORATORY				CALCULATED SATURATIONS FOR GIVEN CONDITIONS				
Sample Number	Perm (md) (1)	Porosity (2)	Saturations Oil (3)	Saturations Water (4)	Initial Reservoir Oil-in-Place (5)	Less 0% Flush (6)	Less 20% "Production" to Atmospheric Pressure (7)	Stock Tank Volume Remaining (8)	Column 8 Minus Column 3 (9)
46	0.01	2.4	36.2	24.1	75.9	75.9	60.7	44.0	7.8
47	0.01	2.4	41.7	34.7	65.3	65.3	52.2	37.9	(3.8)
48	0.01	2.0	44.7	31.9	68.1	68.1	54.5	39.5	(5.2)
49	0.01	2.2	35.5	31.6	68.4	68.4	54.7	39.7	4.2
50	0.01	1.5	26.7	30.6	69.4	69.4	55.5	40.2	13.5
51	0.32	2.2	32.8	32.8	67.2	67.2	53.8	39.0	6.2
52	<0.01	1.0	10.6	42.4	57.6	57.6	46.1	33.4	22.8
53	0.02	1.5	27.1	30.9	69.1	69.1	55.3	40.1	13.0
54	<0.01	1.1	30.3	34.6	65.4	65.4	52.3	37.9	7.6
55	0.05	1.3	36.2	32.2	67.8	67.8	54.2	39.3	3.1
56	0.09	1.8	10.6	42.5	57.5	57.5	46.0	33.3	22.7
57	0.01	1.7	44.6	29.8	70.2	70.2	56.2	40.7	(3.9)
58	0.01	1.2	25.8	29.5	70.5	70.5	56.4	40.9	15.1
59	0.05	0.8	0.0	35.2	64.8	64.8	51.8	37.6	37.6
60	0.08	0.5	30.4	27.1	72.9	72.9	58.3	42.3	11.9
61	0.03	0.8	26.0	23.1	76.9	76.9	61.5	44.6	18.6
62	0.06	1.0	37.8	31.5	68.5	68.5	54.8	39.7	1.9
63	0.16	0.8	39.8	33.2	66.8	66.8	53.4	38.7	(1.1)
64	0.01	0.6	48.8	24.4	75.6	75.6	60.5	43.8	(5.0)
65	0.21	1.6	40.4	26.9	73.1	73.1	58.5	42.4	2.0
66	0.01	1.0	42.3	30.2	69.8	69.8	55.8	40.5	(1.8)
67	<0.01	0.8	36.3	40.8	59.2	59.2	47.4	34.3	(2.0)
68	0.01	1.0	43.3	37.9	62.1	62.1	49.7	36.0	(7.3)
69	0.01	1.2	32.4	21.6	78.4	78.4	62.7	45.4	13.0
70	4.16	1.0	37.9	52.1	47.9	47.9	38.3	27.8	(10.1)
71	0.65	1.1	28.4	52.1	47.9	47.9	38.3	27.8	(0.6)
72	0.01	1.0	50.6	40.5	59.5	59.5	47.6	34.5	(16.1)
73	0.81	1.1	38.2	38.2	61.8	61.8	49.4	35.8	(2.4)
74	0.01	0.8	45.3	30.2	69.8	69.8	55.8	40.5	(4.8)
75	0.03	1.0	35.1	40.2	59.8	59.8	47.8	34.7	(0.4)
76	0.01	0.8	48.4	27.6	72.4	72.4	57.9	42.0	(6.4)
77	0.01	1.1	35.0	40.0	60.0	60.0	48.0	34.8	(0.2)
78	0.01	0.4	32.3	35.9	64.1	64.1	51.3	37.2	4.9
79	1.21	1.2	46.6	39.3	60.7	60.7	48.6	35.2	(11.4)
80	0.01	0.8	58.6	27.9	72.1	72.1	57.7	41.8	(16.8)
81	0.01	1.0	41.7	37.1	62.9	62.9	50.3	36.5	(5.2)

Column 1: Permeability, millidarcies.
Column 2: Percent of bulk volume.
Column 3: Percent of pore space.
Column 4: Percent of pore space.
Column 5: Initial oil-in-place, percent of pore space at initial reservoir pressure. 100 Minus Column 4.
Column 6: Same as Column 5 (assumes 0% flush of core by circulating fluid).
Column 7: Column 6 x .8 (reservoir volume after "production" of 20% of oil-in-place).
Column 8: Stock tank volume remaining in reservoir after "production": Column 7 divided by FVF of 1.38.
Column 9: Column 8 minus Column 3, theoretical saturation less laboratory saturation. (Negative figure means sample is suspect.)

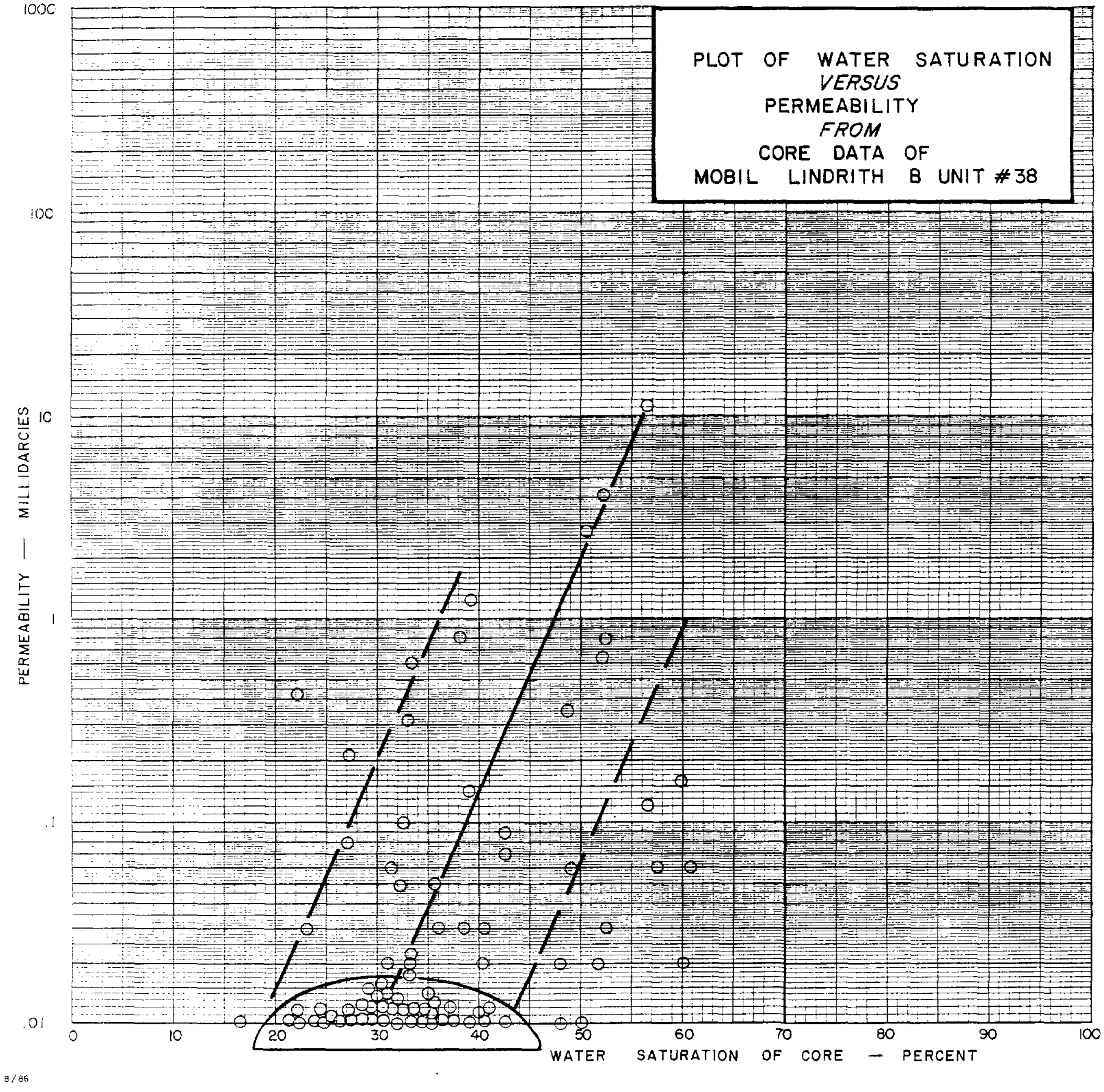
INTERPRETATION OF FLUID SATURATIONS
ASSUMING
0% FLUSH AND "PRODUCTION" REPRESENTED BY DIFFERENCE OF STOCK TANK VOLUMES

	LABORATORY				Initial Oil-in-Place		"Production" to 0# (gauge) Reservoir Pressure (Stock Tank Volumes)	
Sample Number	Perm (md) (1)	Porosity (2)	Saturations Oil (3)	Saturations Water (4)	Reservoir Volume (5)	Stock Tank Volume (6)	"Production" Percent of Pore Space (7)	"Production" Percent of Oil-in-Place (8)
1	0.01	2.5	39.0	39.0	61.0	44.2	5.2	11.8
2	0.02	2.0	34.6	40.3	59.7	43.3	8.7	20.0
3	<0.01	1.0	39.6	35.2	64.8	47.0	7.4	15.7
4	0.42	0.9	49.5	22.0	78.0	56.5	7.0	12.4
5	<0.01	0.6	49.8	16.6	83.4	60.4	10.6	17.6
6	<0.01	1.0	52.4	22.1	77.9	56.4	4.0	7.2
7	<0.01	0.9	41.2	34.3	65.7	47.6	6.4	13.5
8	0.02	0.7	45.6	32.9	67.1	48.6	3.0	6.2
9	<0.01	0.5	42.3	35.2	64.8	47.0	4.7	9.9
10	0.02	1.1	38.6	33.1	66.9	48.5	9.9	20.4
11	0.10	0.5	38.8	32.4	67.6	49.0	10.2	20.8
12	<0.01	1.7	34.2	34.2	65.8	47.7	13.5	28.3
13	0.02	2.7	24.9	33.1	66.9	48.5	23.6	48.6
14	0.01	2.9	22.5	50.0	50.0	36.2	13.7	37.9
15	0.01	3.5	31.9	31.9	68.1	49.3	17.4	35.4
16	0.01	3.1	30.5	30.5	69.5	50.4	19.9	39.4
17	0.03	2.3	28.8	38.4	61.6	44.6	15.8	35.5
18	0.14	2.5	19.6	39.2	60.8	44.1	24.5	55.5
19	0.07	2.8	32.0	42.7	57.3	41.5	9.5	22.9
20	0.02	2.2	17.5	60.0	40.0	29.0	11.5	39.6
21	0.16	2.1	24.5	59.9	40.1	29.1	4.6	15.7
22	0.06	1.6	21.1	61.0	39.0	28.3	7.2	25.3
23	0.12	1.5	16.6	56.8	43.2	31.3	14.7	47.0
24	2.85	2.0	22.3	50.9	49.1	35.6	13.3	37.3
25	11.00	2.2	0.0	56.4	43.6	31.6	31.6	100.0
26	0.06	2.6	20.1	57.5	42.5	30.8	10.7	34.7
27	0.01	1.8	18.6	47.9	52.1	37.8	19.2	50.7
28	0.03	1.9	32.4	36.0	64.0	46.4	14.0	30.1
29	0.03	2.4	18.3	52.4	47.6	34.5	16.2	46.9
30	0.79	2.0	20.4	52.5	47.5	34.4	14.0	40.7
31	0.02	1.5	23.9	47.9	52.1	37.8	13.9	36.7
32	<0.01	1.8	22.5	36.0	64.0	46.4	23.9	51.5
33	<0.01	2.5	34.7	30.8	69.2	50.1	15.4	30.8
34	0.06	1.5	24.6	49.1	50.9	36.9	12.3	33.3
35	0.02	2.2	30.2	51.7	48.3	35.0	4.8	13.7
36	0.36	2.6	21.8	48.5	51.5	37.3	15.5	41.6
37	0.01	2.5	26.2	29.9	70.1	50.8	24.6	48.4
38	<0.01	2.6	43.6	31.1	68.9	49.9	6.3	12.7
39	0.01	2.8	39.3	32.8	67.2	48.7	9.4	19.3
40	0.01	2.2	38.5	33.0	67.0	48.6	10.1	20.7
41	<0.01	1.3	40.0	26.7	73.3	53.1	13.1	24.7
42	<0.01	2.1	39.3	26.2	73.8	53.5	14.2	26.5
43	<0.01	1.3	39.1	22.4	77.6	56.2	17.1	30.5
44	<0.01	1.0	42.8	28.6	71.4	51.7	8.9	17.3
45	<0.01	1.3	50.6	25.3	74.7	54.1	3.5	6.5

INTERPRETATION OF FLUID SATURATIONS
ASSUMING
0% FLUSH AND "PRODUCTION" REPRESENTED BY DIFFERENCE OF STOCK TANK VOLUMES

LABORATORY					Initial Oil-in-Place		"Production" to 0# (gauge) Reservoir Pressure (Stock Tank Volumes)	
Sample Number	Perm (md) (1)	Porosity (2)	Saturations Oil (3)	Saturations Water (4)	Reservoir Volume (5)	Stock Tank Volume (6)	"Production" Percent of Pore Space (7)	"Production" Percent of Oil-in-Place (8)
46	0.01	2.4	36.2	24.1	75.9	55.0	18.8	34.2
47	0.01	2.4	41.7	34.7	65.3	47.3	5.6	11.9
48	0.01	2.0	44.7	31.9	68.1	49.3	4.6	9.4
49	0.01	2.2	35.5	31.6	68.4	49.6	14.1	28.4
50	0.01	1.5	26.7	30.6	69.4	50.3	23.6	46.9
51	0.32	2.2	32.8	32.8	67.2	48.7	15.9	32.6
52	<0.01	1.0	10.6	42.4	57.6	41.7	31.1	74.6
53	0.02	1.5	27.1	30.9	69.1	50.1	23.0	45.9
54	<0.01	1.1	30.3	34.6	65.4	47.4	17.1	36.1
55	0.05	1.3	36.2	32.2	67.8	49.1	12.9	26.3
56	0.09	1.8	10.6	42.5	57.5	41.7	31.1	74.6
57	0.01	1.7	44.6	29.8	70.2	50.9	6.3	12.3
58	0.01	1.2	25.8	29.5	70.5	51.1	25.3	49.5
59	0.05	0.8	0.0	35.2	64.8	47.0	47.0	100.0
60	0.08	0.5	30.4	27.1	72.9	52.8	22.4	42.5
61	0.03	0.8	26.0	23.1	76.9	55.7	29.7	53.3
62	0.06	1.0	37.8	31.5	68.5	49.6	11.8	23.8
63	0.16	0.8	39.8	33.2	66.8	48.4	8.6	17.8
64	0.01	0.6	48.8	24.4	75.6	54.8	6.0	10.9
65	0.21	1.6	40.4	26.9	73.1	53.0	12.6	23.7
66	0.01	1.0	42.3	30.2	69.8	50.6	8.3	16.4
67	<0.01	0.8	36.3	40.8	59.2	42.9	6.6	15.4
68	0.01	1.0	43.3	37.9	62.1	45.0	1.7	3.8
69	0.01	1.2	32.4	21.6	78.4	56.8	24.4	43.0
70	4.16	1.0	37.9	52.1	47.9	34.7	(3.2)	(9.2)
71	0.65	1.1	28.4	52.1	47.9	34.7	6.3	18.2
72	0.01	1.0	50.6	40.5	59.5	43.1	(7.5)	(17.4)
73	0.81	1.1	38.2	38.2	61.8	44.8	6.6	14.7
74	0.01	0.8	45.3	30.2	69.8	50.6	5.3	10.4
75	0.03	1.0	35.1	40.2	59.8	43.3	8.2	19.0
76	0.01	0.8	48.4	27.6	72.4	52.5	4.1	7.7
77	0.01	1.1	35.0	40.0	60.0	43.5	8.5	19.5
78	0.01	0.4	32.3	35.9	64.1	46.4	14.1	30.5
79	1.21	1.2	46.6	39.3	60.7	44.0	(2.6)	(5.9)
80	0.01	0.8	58.6	27.9	72.1	52.2	(6.4)	(12.2)
81	0.01	1.0	41.7	37.1	62.9	45.6	3.9	8.5

Column 1: Permeability, millidarcies.
Column 2: Percent of bulk volume.
Column 3: Percent of pore space.
Column 4: Percent of pore space.
Column 5: Initial oil-in-place, percent of pore space at initial reservoir pressure. 100 minus Column 4.
Column 6: Initial stock tank volume of oil-in-place: reservoir volume divided by FVF.
Column 7: Stock tank volume "production" to 0# (gauge) reservoir pressure, percent of pore space (Column 6 minus Column 3).
Column 8: Stock tank volume "production" to 0# (gauge) reservoir pressure, percent of oil-in-place (Column 7 divided by Column 6 x 100). Low (less than 15 to 20%) means sample is suspect. High (30 to 40% or more) suggests substantial flushing or gas zone or sample is suspect.


PLOT OF WATER SATURATION
VERSUS
PERMEABILITY
FROM
CORE DATA OF
MOBIL LINDRITH B UNIT #38
PERMEABILITY — MILLIDARCIES
1000
100
10
1
.1
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20
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60
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80
90
100
WATER SATURATION OF CORE — PERCENT
8/86

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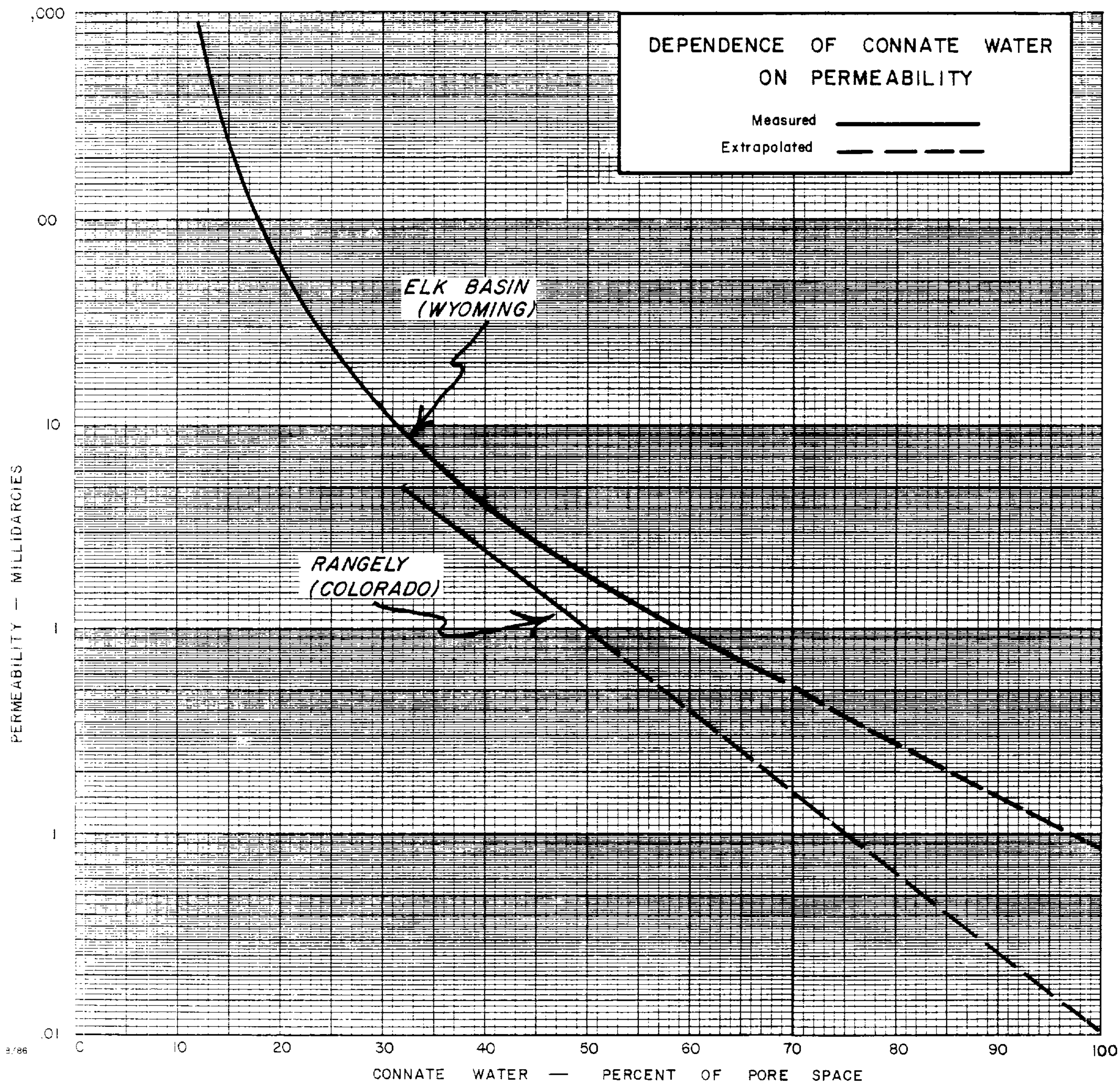
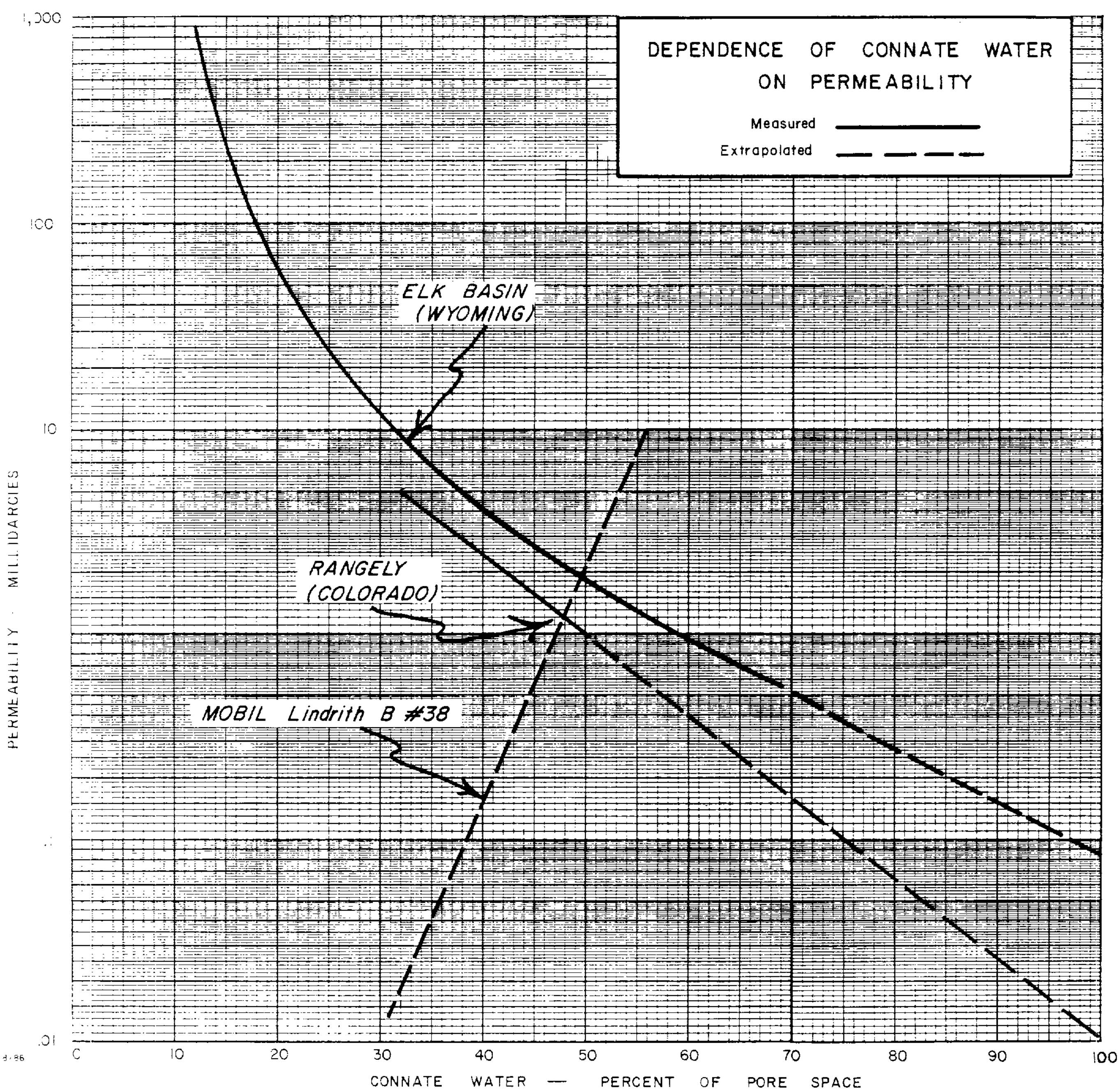


DEPENDENCE OF CONNATE WATER ON PERMEABILITY
Measured
Extrapolated
ELK BASIN (WYOMING)
RANGELY (COLORADO)
,000
00
10
1
1
.01
PERMEABILITY — MILLIDARCIES
C
10
20
30
40
50
60
70
80
90
100
CONNATE WATER — PERCENT OF PORE SPACE



DEPENDENCE OF CONNATE WATER ON PERMEABILITY
Measured
Extrapolated
ELK BASIN (WYOMING)
RANGELY (COLORADO)
MOBIL Lindrith B #38
PERMEABILITY — MILLIDARCIES
CONNATE WATER — PERCENT OF PORE SPACE
1,000
100
10
.01
0
10
20
30
40
50
60
70
80
90
100

CA-20

CORE LABORATORIES, INC.

Petroleum Reservoir Engineering

DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company BENSON-MONTIN-GREER Formation GALLUP File RP-3-2318

Well LA PLATA MANCOS UNIT NO. 3(G-32) Core Type DIAMOND 3.5" Date Report 9-30-68

Field LA PLATA (GALLUP) Drilling Fluid CRUDE OIL Analysts GALLOP

County SAN JUAN State NEW MEX. Elev. 5988'GL Location 1650'FN&EL SEC 32-T32N-R13W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

NOTE: DEDUCT 20' FROM BELOW LISTED DEPTHS TO CORRELATE WITH SCHLUM. IES LOG RUN 10-2-68

(CONVENTIONAL ANALYSIS)

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS K_A	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
1	5075.0-76.0	0.03	5.8	12.1	75.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
2	77.0-78.0	0.30	5.4	13.0	64.9	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
3	79.0-80.0	0.38	5.9	8.5	67.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
4	81.0-82.0	0.66	4.5	11.1	75.5	Sh, Bl, V/Fn Grn, Slty, Frac
5	83.0-84.0	0.17	5.6	8.9	71.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
6	85.0-86.0	0.01	5.3	3.8	75.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
7	87.0-88.0	0.17	5.5	3.6	80.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
8	89.0-90.0	0.02	4.8	4.2	83.4	Sh, Bl, V/Fn Grn, Slty, Frac
9	91.0-92.0	0.01	5.1	9.8	68.6	Sh, Bl, V/Fn Grn, Slty, Frac
10	93.0-94.0	0.01	5.3	13.2	71.7	Sh, Bl, V/Fn Grn, Slty, Frac
11	95.0-96.0	0.04	5.7	8.8	70.7	Sh, Bl, V/Fn Grn, Slty, Frac
12	97.0-98.0	0.02	7.2	29.8	59.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
13	5099.0-00.0	1.12	6.6	39.4	46.9	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
14	5101.0-02.0	0.09	6.2	46.7	43.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
15	03.0-04.0	0.02	6.9	43.5	37.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
16	05.0-06.0	0.01	7.3	46.5	41.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
17	07.0-08.0	0.03	6.7	41.8	44.7	Sh, Bl, V/Fn Grn, Slty, Frac
18	09.0-10.0	0.03	7.8	51.2	35.9	Sh, Bl, V/Fn Grn, Slty, Frac
19	11.0-12.0	0.17	6.7	49.2	40.3	Sh, Bl, V/Fn Grn, Slty, Frac
20	13.0-14.0	0.01	7.5	41.3	44.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
21	15.0-16.0	0.03	6.6	53.0	30.3	Sh, Bl, V/Fn Grn, Slty, Frac
22	17.0-18.0	0.03	6.6	48.5	36.4	Sh, Bl, V/Fn Grn, Slty, Frac
23	19.0-20.0	0.24	6.7	49.2	37.3	Sh, Bl, V/Fn Grn, Slty, Frac
24	21.0-22.0	0.22	5.2	40.3	46.2	Sh, Bl, V/Fn Grn, Slty, Frac
25	23.0-24.0	0.27	5.9	28.8	55.9	Sh, Bl, V/Fn Grn, Slty, Frac
26	25.0-26.0	0.50	4.5	20.0	59.9	Sh, Bl, V/Fn Grn, Slty, Frac
27	27.0-28.0	0.03	6.1	27.8	57.3	Sh, Bl, V/Fn Grn, Slty, Frac
28	29.0-30.0	0.66	6.7	32.8	49.2	Sh, Bl, V/Fn Grn, Slty, Frac
29	31.0-32.0	0.03	6.8	27.9	57.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
30	33.0-34.0	0.04	6.2	27.4	56.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
31	35.0-36.0	0.17	5.2	32.7	44.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
32	37.0-38.0	0.17	5.5	25.5	56.3	Sh, Bl, V/Fn Grn, Slty, Frac
33	39.0-40.0	0.17	5.9	27.1	64.3	Sh, Bl, V/Fn Grn, Slty, Frac
34	41.0-42.0	0.13	5.4	38.9	48.1	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
35	43.0-44.0	0.09	5.6	35.7	44.6	Sh, Bl, V/Fn Grn, Slty, Frac
36	45.0-46.0	0.02	5.3	39.6	51.0	Sh, Bl, V/Fn Grn, Slty, Frac

(Service #1-A)

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CA-20

CORE LABORATORIES, INC.

Petroleum Reservoir Engineering

DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company BENSON-MONTIN-GREER — Formation GALLUP — File RP-3-2318

Well LA PLATA MANCOS UNIT NO. 3(G-32) — Core Type DIAMOND 3.5" — Date Report 9-30-68

Field LA PLATA (GALLUP) — Drilling Fluid CRUDE OIL — Analysts GALLOP

County SAN JUAN — State NEW MEX. — Elev. 5988'GL — Location 1650'FN&EL SEC 32-T32N-R13W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

(CONVENTIONAL ANALYSIS)

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS KA	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE: OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
37	5147.0-48.0	2.80	6.3	33.3	50.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
38	49.0-50.0	0.04	6.2	45.1	35.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
39	51.0-52.0	0.02	6.3	46.0	34.9	Sh, Bl, V/Fn Grn, Slty, Frac
40	53.0-54.0	0.10	5.6	33.9	48.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
41	55.0-56.0	0.30	6.9	50.7	39.1	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
42	57.0-58.0	1.30	5.9	42.4	40.7	Sh, Bl, V/Fn Grn, Slty, Frac
43	59.0-60.0	0.33	6.3	39.7	42.8	Sh, Bl, V/Fn Grn, Slty, Frac
44	61.0-62.0	2.60	6.6	43.9	40.8	Sh, Bl, V/Fn Grn, Slty, Frac
45	63.0-64.0	0.09	5.6	46.1	37.5	Sh, Bl, V/Fn Grn, Slty, Frac
46	65.0-66.0	1.30	6.2	50.0	40.3	Sh, Bl, V/Fn Grn, Slty, Frac
47	67.0-68.0	0.33	6.3	46.0	39.7	Sh, Bl, V/Fn Grn, Slty, Frac
48	69.0-70.0	0.50	4.7	34.0	38.3	Sh, Bl, V/Fn Grn, Slty, Frac
49	71.0-72.0	0.04	6.0	46.7	40.0	Sh, Bl, V/Fn Grn, Slty, Frac
50	73.0-74.0	0.17	7.6	40.8	40.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
51	75.0-76.0	0.19	5.3	13.2	71.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
52	77.0-78.0	0.31	5.7	15.8	73.6	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
53	5180.0-81.0	0.21	5.9	15.2	67.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
54	85.0-86.0	0.02	6.4	14.1	71.9	Sh, Bl, V/Fn Grn, Slty, Frac
55	90.0-91.0	0.01	6.2	14.5	74.2	Sh, Bl, Fn Grn, Slty, Frac
56	95.0-96.0	0.01	5.2	3.8	80.8	Sh, Bl, Fn Grn, Slty, Frac
57	5200.0-01.0	0.01	4.7	4.3	74.4	Sh, Bl, V/Fn Grn, Slty, Frac
58	05.0-06.0	0.02	5.2	3.8	77.0	Sh, Bl, V/Fn Grn, Slty, Frac
59	10.0-11.0	0.01	4.0	5.0	75.0	Sh, Bl, V/Fn Grn, Slty, Frac
60	15.0-16.0	0.04	4.8	10.4	68.8	Sh, Bl, V/Fn Grn, Slty, Frac
61	20.0-21.0	0.32	4.8	10.4	73.0	Sh, Bl, V/Fn Grn, Slty, Frac
62	25.0-26.0	0.09	4.4	11.4	77.2	Sh, Bl, V/Fn Grn, Slty, Frac
63	30.0-31.0	0.01	4.2	11.9	76.2	Sh, Bl, V/Fn Grn, Slty, Frac
64	35.0-36.0	0.01	5.7	3.5	87.8	Sh, Bl, V/Fn Grn, Slty, Frac

CA-20

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company BENSON-MONTIN-GREER Formation GALLUP File RP-3-2326
Well LA PLATA MANCOS UNIT NO. 4(N-31) Core Type DIAMOND 3.5" Date Report 10-25-68
Field LA PLATA (GALLUP) Drilling Fluid CRUDE OIL Analysts GALLOP
County SAN JUAN State NEW MEX. Elev. 6113'GL Location 756'FSL 1208'FWL SEC 31-T32N-R13W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

NOTE: SEE DEPTH CORRELATIONS IN NOTATION ON PAGE 2

(CONVENTIONAL ANALYSIS)

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS KA	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
1	2220.0-21.0	0.20	6.5	44.6	50.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
2	22.0-23.0	0.41	8.3	39.7	56.6	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
3	24.0-25.0	0.20	7.8	41.1	53.8	Sh, Bl, V/Fn Grn, Slty, Frac
4	26.0-27.0	0.20	8.4	48.8	46.4	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
5	28.0-29.0	0.31	8.8	49.8	45.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
6	30.0-31.0	0.08	9.6	45.8	50.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
7	32.0-33.0	0.20	6.8	51.4	42.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
8	34.0-35.0	0.10	8.6	47.7	50.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
9	36.0-37.0	0.01	8.3	54.2	42.2	Sh, Bl, V/Fn Grn, Slty, Frac
10	38.0-39.0	0.02	8.3	49.4	47.0	Sh, Bl, V/Fn Grn, Slty, Frac
11	40.0-41.0	0.05	7.0	47.1	47.1	Sh, Bl, V/Fn Grn, Slty, Frac
12	42.0-43.0	0.01	8.1	50.7	43.1	Sh, Bl, V/Fn Grn, Slty, Frac
13	44.0-45.0	0.01	8.9	43.9	50.5	Sh, Bl, V/Fn Grn, Slty, Frac
14	46.0-47.0	0.02	8.4	34.5	58.5	Sh, Bl, V/Fn Grn, Slty, Frac
15	48.0-49.0	0.01	8.3	45.7	45.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
16	50.0-51.0	0.20	8.9	50.6	41.6	Sh, Bl, V/Fn Grn, Slty, Frac
17	52.0-53.0	0.01	8.1	54.3	35.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
18	54.0-55.0	0.01	7.8	42.3	47.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
19	56.0-57.0	0.04	7.7	45.3	48.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
20	58.0-59.0	0.01	8.2	42.7	47.6	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
21	60.0-61.0	0.62	9.6	40.5	51.0	Sh, Bl, V/Fn Grn, Slty, Frac
22	62.0-63.0	1.20	9.6	41.7	50.0	Sh, Bl, V/Fn Grn, Slty, Frac
23	64.0-65.0	0.04	7.8	37.2	56.4	Sh, Bl, V/Fn Grn, Slty, Frac
24	66.0-67.0	0.08	7.8	37.2	53.8	Sh, Bl, V/Fn Grn, Slty, Frac
25	67.0-68.0	2.10	8.8	29.8	47.7	Sd, Gy, V/Fn Grn, Lmy, W/Shale Strks, Frac
26	68.0-69.0	0.03	4.8	41.6	48.0	Sd, Gy, V/Fn Grn, Lmy, W/Sh Strks, Frac
27	69.0-70.0	0.36	7.7	29.0	41.6	Sd, Gy, V/Fn Grn, Lmy, W/Sh Strks, Frac
28	70.0-71.0	1.60	9.6	44.8	42.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
29	2272.0-73.0	0.17	9.2	48.8	40.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
30	74.0-75.0	0.08	10.3	63.1	32.0	Sh, Bl, V/Fn Grn, Slty, Frac

Service #1-A

CA-20

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company BENSON-MONTIN-GREER
Formation GALLUP
File RP-3-2326
Well LA PLATA MANCOS UNIT NO. 4
Core Type DIAMOND 3.5"
Date Report 10-25-68
Field LA PLATA (GALLUP) (N-31)
Drilling Fluid CRUDE OIL
Analysts GALLOP
County SAN JUAN
State NEW MEX.
Elev. 6113'GL
Location 756'FSL 1208'FWL SEC 31-T32N-R13W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS KA	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	RESIDUAL SATURATION PER CENT PORE TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
31	2276.0-77.0	0.60	8.9	50.5	37.1	Sh, Bl, V/Fn Grn, Slty, Frac
32	78.0-79.0	0.07	9.2	56.5	36.9	Sh, Bl, V/Fn Grn, Slty, Frac
33	80.0-81.0	0.02	8.5	52.8	41.1	Sh, Bl, V/Fn Grn, Slty, Frac
34	82.0-83.0	0.03	8.4	44.1	46.4	Sh, Bl, V/Fn Grn, Slty, Frac
35	84.0-85.0	0.57	7.2	18.1	69.5	Sh, Bl, V/Fn Grn, Slty, Frac
36	86.0-87.0	0.14	7.3	9.6	75.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks
37	88.0-89.0	0.01	5.8	8.6	74.1	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks
38	90.0-91.0	0.02	7.4	6.7	81.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks
39	92.0-93.0	0.03	6.8	3.0	77.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks
40	94.0-95.0	0.11	6.1	3.3	78.7	Sh, Bl, V/Fn Grn, Slty
41	96.0-97.0	0.08	5.7	3.5	82.4	Sh, Bl, V/Fn Grn, Slty

Note: To correspond with Schlumberger log depths:
Add 9' to interval 2220 to 2245 feet
Add 8' to interval 2245 to 2270 feet
Add 7' to interval 2270 to 2297 feet

CA-20

CORE LABORATORIES, INC.

Petroleum Reservoir Engineering

DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company BENSON-MONTIN-GREER Formation GALLUP File RP-3-2312

Well LA PLATA MANCOS UNIT "I" NO. 6 Core Type DIAMOND 3.5" Date Report 8-24-68

Field LA PLATA (GALLUP) Drilling Fluid CRUDE OIL Analysts GALLOP

County SAN JUAN State NEW MEX. Elev. 6015'KB Location SEC 6-T32N-R13W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

(Note: Add 9' to below listed core depths to correspond to depths on Schlumberger log run 8-29-68.)

(CONVENTIONAL ANALYSIS)

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS KA	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
1	3995.0-96.0	0.29	8.3	42.2	46.9	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
2	97.0-98.0	0.11	9.0	41.1	42.2	Sh, Bl, Slty, V/Fn Grn, Frac
3	99.0-00.0	0.10	9.6	38.5	48.9	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
4	4001.0-02.0	0.32	8.7	41.3	43.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
5	03.0-04.0	0.22	9.2	38.0	46.7	Sh, Bl, V/Fn Grn, Slty, Frac
6	05.0-06.0	0.07	8.6	39.5	51.2	Sh, Bl, V/Fn Grn, Slty, Frac
7	07.0-08.0	0.16	9.1	37.4	50.6	Sh, Bl, V/Fn Grn, Slty, Frac
8	09.0-10.0	0.06	9.1	39.5	52.7	Sh, Bl, V/Fn Grn, Slty, Frac
9	11.0-12.0	0.32	9.4	42.6	48.9	Sh, Bl, V/Fn Grn, Slty, Frac
10	13.0-14.0	0.99	8.5	37.7	54.1	Sh, Bl, V/Fn Grn, Slty, Frac
11	15.0-16.0	0.02	8.0	48.7	41.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
12	17.0-18.0	0.02	7.5	52.0	36.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
13	19.0-20.0	0.06	7.5	41.3	49.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
14	21.0-22.0	0.19	7.7	48.2	41.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
15	23.0-24.0	0.11	7.9	44.2	44.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
16	25.0-26.0	0.08	7.5	38.6	49.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
17	27.0-28.0	0.02	7.9	37.9	50.6	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
18	29.0-30.0	0.11	8.6	33.7	54.6	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
19	31.0-32.0	1.70	8.9	39.3	52.7	Sh, Bl, V/Fn Grn, Slty, Frac
20	33.0-34.0	0.07	7.9	36.7	57.0	Sh, Bl, V/Fn Grn, Slty, Frac
21	35.0-36.0	0.14	6.6	49.3	37.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
22	37.0-38.0	0.10	7.9	51.8	39.2	Sh, Bl, V/Fn Grn, Slty, Frac
23	39.0-40.0	0.07	7.0	44.3	47.2	Sh, Bl, V/Fn Grn, Slty, Frac
24	41.0-42.0	0.06	7.4	41.8	52.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
25	43.0-44.0	0.01	7.3	39.7	50.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
26	45.0-46.0	0.13	7.0	44.2	47.2	Sh, Bl, V/Fn Grn, Slty, Frac
27	47.0-48.0	0.02	7.0	40.0	45.7	Sh, Bl, V/Fn Grn, Slty, Frac
28	49.0-50.0	0.03	7.0	41.4	47.1	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
29	51.0-52.0	0.01	7.4	40.6	51.3	Sh, Bl, V/Fn Grn, Slty, Frac
30	53.0-54.0	0.03	8.1	38.3	35.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
31	55.0-56.0	0.06	6.8	30.9	61.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
32	57.0-58.0	0.09	6.3	31.8	55.6	Sh, Bl, V/Fn Grn, Slty, Frac
33	59.0-60.0	0.01	6.5	27.2	61.5	Sh, Bl, V/Fn Grn, Slty, Frac
34	61.0-62.0	2.0	7.2	40.2	48.5	Sh, Bl, V/Fn Grn, Slty, Frac
35	63.0-64.0	4.8	6.7	31.3	61.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
36	65.0-66.0	0.83	7.2	27.7	63.8	Sh, Bl, V/Fn Grn, Slty, Frac

Service #1-A

CA-20

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company BENSON-MONTIN-GREER Formation GALLUP File RP-3-2312
Well LA PLATA MANCOS UNIT "I" NO. 6 Core Type DIAMOND 3.5" Date Report 8-24-68
Field LA PLATA (GALLUP) Drilling Fluid CRUDE OIL Analysts GALLOP
County SAN JUAN State NEW MEX. Elev. 6015'KB Location SEC 6-T32N-R13W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS KA	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
	(CONVENTIONAL ANALYSIS)					
37	4067.0-68.0	0.13	6.0	36.6	48.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
38	69.0-70.0	0.37	4.8	41.7	43.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
39	71.0-72.0	0.10	5.1	43.1	45.1	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
40	73.0-74.0	0.66	6.1	42.6	40.9	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
41	75.0-76.0	0.07	7.1	39.4	45.1	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
42	77.0-78.0	0.40	7.2	40.2	48.6	Sh, Bl, V/Fn Grn, Slty, Frac
43	79.0-80.0	0.13	7.6	32.9	56.5	Sh, Bl, V/Fn Grn, Slty, Frac
44	4150.0-51.0	0.83	5.5	25.4	63.6	Sh, Bl, V/Fn Grn, W/Lmy Slty Strks, Frac
45	52.0-53.0	1.30	5.0	30.0	58.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
46	54.0-55.0	0.83	5.8	27.5	56.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
47	56.0-57.0	5.3	5.1	33.4	52.9	Sh, Bl, V/Fn Grn, S/Lmy Slt Strks, Frac
48	58.0-59.0	0.06	5.7	29.0	54.3	Sh, Bl, V/Fn Grn, S/Lmy Slt Strks, Frac
49	60.0-61.0	<0.01	4.7	25.5	57.4	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
50	62.0-63.0	0.21	5.9	27.2	57.6	Sh, Bl, V/Fn Grn, Slty, Frac
51	64.0-65.0	0.06	5.8	32.8	56.9	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
52	66.0-67.0	0.83	6.1	41.0	49.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
53	68.0-69.0	0.04	6.7	38.8	49.3	Sh, Bl, V/Fn Grn, Slty, Frac
54	70.0-71.0	0.03	6.5	32.3	58.5	Sh, Bl, V/Fn Grn, Slty, Frac
55	72.0-73.0	0.02	6.6	30.3	57.5	Sh, Bl, V/Fn Grn, Slty, Frac
56	74.0-75.0	0.11	6.5	44.6	41.6	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
57	76.0-77.0	0.01	5.9	35.6	52.5	Sh, Bl, V/Fn Grn, Slty, Frac
58	78.0-79.0	5.5	5.9	37.3	42.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
59	80.0-81.0	1.50	7.3	38.3	52.0	Sh, Bl, V/Fn Grn, W/Lmy Slty Strks, Frac
60	82.0-83.0	0.06	8.1	42.0	46.8	Sh, Bl, V/Fn Grn, Slty, Frac
61	84.0-85.0	2.2	7.9	39.2	54.4	Sh, Bl, V/Fn Grn, Slty, Frac
62	86.0-87.0	1.50	5.4	53.6	33.4	Sh, Bl, V/Fn Grn, W/Lm Slty, Strks, Frac
63	88.0-89.0	0.03	7.0	42.8	40.0	Sh, Bl, V/Fn Grn, Slty, Frac
64	90.0-91.0	1.12	5.8	56.9	34.5	Sh, Bl, V/Fn Grn, Slty, Frac
65	92.0-93.0	0.33	6.7	52.2	40.3	Sh, Bl, V/Fn Grn, Slty, Frac
66	94.0-95.0	0.04	7.5	44.0	46.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
67	96.0-97.0	0.33	6.7	49.1	40.3	Sh, Bl, V/Fn Grn, Slty, Frac
68	98.0-99.0	0.83	7.3	43.8	46.5	Sh, Bl, V/Fn Grn, W/Lmy Slty Strks, Frac
69	4200.0-01.0	0.09	6.9	50.7	42.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
70	02.0-03.0	0.50	9.4	41.4	52.0	Sh, Bl, V/Fn Grn, Slty, Frac
71	04.0-05.0	0.08	8.5	43.5	43.5	Sh, Bl, V/Fn Grn, Slty, Frac
72	06.0-07.0	1.30	7.5	49.2	44.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
73	08.0-09.0	0.01	8.2	51.2	34.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac

CA-25

CORE LABORATORIES, INC.

Petroleum Reservoir Engineering

DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company BENSON-MONTIN-GREER Formation GALLUP File RP-3-2312

Well LA PLATA MANCOS UNIT "I" NO. 6 Core Type DIAMOND 3.5" Date Report 8-24-68

Field LA PLATA (GALLUP) Drilling Fluid CRUDE OIL Analysts GALLOP

County SAN JUAN State NEW MEX. Elev. 6015'KB Location SEC 6-T32N-R13W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS KA	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE		SAMPLE DESCRIPTION AND REMARKS
				OIL	TOTAL WATER	
	(CONVENTIONAL ANALYSIS)					
74	4210.0-11.0	0.09	8.5	48.2	41.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
75	12.0-13.0	<0.01	6.9	50.7	42.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
76	14.0-15.0	0.06	8.1	40.7	48.0	Sh, Bl, V/Fn Grn, Slty, Frac
77	16.0-17.0	0.02	8.3	45.7	45.7	Sh, Bl, V/Fn Grn, Slty, Frac
78	18.0-19.0	2.5	7.9	39.2	44.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
79	20.0-21.0	1.80	8.0	41.3	51.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
80	22.0-23.0	0.17	7.3	46.6	41.1	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
81	24.0-25.0	0.10	6.5	49.1	40.0	Sh, Bl, V/Fn Grn, Slty, Frac
82	26.0-27.0	0.10	7.0	55.8	31.4	Sh, Bl, V/Fn Grn, Slty, Frac
83	28.0-29.0	0.02	7.5	50.7	37.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
84	30.0-31.0	8.3	6.6	45.4	39.4	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
85	32.0-33.0	0.37	6.5	47.7	41.6	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
86	34.0-35.0	0.10	7.3	35.6	45.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
87	36.0-37.0	0.06	6.3	33.3	49.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
88	38.0-39.0	0.02	6.0	35.0	45.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
89	40.0-41.0	0.02	7.9	35.4	42.9	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
90	42.0-43.0	0.04	7.0	40.0	48.6	Sh, Bl, V/Fn Grn, Slty, Frac
91	44.0-45.0	<0.01	6.8	17.6	66.2	Sh, Bl, V/Fn Grn, Slty, Frac
92	46.0-47.0	0.83	8.2	36.5	46.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
93	48.0-49.0	0.19	6.2	33.8	48.3	Sh, Bl, V/Fn Grn, Slty, Frac
94	50.0-51.0	0.02	6.6	42.3	39.4	Sh, Bl, V/Fn Grn, Slty, Frac
95	52.0-53.0	0.20	6.2	50.0	35.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
96	54.0-55.0	0.06	7.1	43.6	43.6	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
97	56.0-57.0	0.33	7.0	41.4	41.4	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
98	58.0-59.0	0.17	6.7	43.3	40.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
99	60.0-61.0	0.01	7.6	38.2	40.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
100	62.0-63.0	0.01	6.7	49.2	32.8	Sh, Bl, V/Fn Grn, Slty, Frac
101	64.0-65.0	2.3	5.7	49.1	35.1	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
102	66.0-67.0	0.17	7.4	44.6	44.6	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
103	68.0-69.0	0.07	6.2	50.0	35.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
104	70.0-71.0	0.19	6.3	52.3	34.9	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
105	72.0-73.0	12	6.6	45.4	42.4	Sh, Bl, V/Fn Grn, Slty, Frac
106	74.0-75.0	0.21	6.0	49.3	36.7	Sh, Bl, V/Fn Grn, Slty, Frac
107	76.0-77.0	0.14	6.1	50.8	39.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
108	78.0-79.0	0.66	5.8	46.5	37.9	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
109	80.0-81.0	0.01	7.0	57.1	31.4	Sh, Bl, V/Fn Grn, Slty, Frac
110	82.0-83.0	<0.01	5.6	39.2	48.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
111	84.0-85.0	3.0	6.3	39.7	46.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company BENSON-MONTIN-GREER   Formation GALLUP   File RP-3-2312
Well LA PLATA MANCOS UNIT "I" NO. 6   Core Type DIAMOND 3.5"   Date Report 8-24-68
Field LA PLATA (GALLUP)   Drilling Fluid CRUDE OIL   Analysts GALLOP
County SAN JUAN   State NEW MEX.   Elev. 6015'KB   Location SEC 6-T32N-R13W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS K_A	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE: OIL	RESIDUAL SATURATION PER CENT PORE: TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
	(CONVENTIONAL ANALYSIS)					
112	4286.0-87.0	0.02	6.6	43.9	46.9	Sh, Bl, V/Fn Grn, Slty, Frac
113	88.0-89.0	0.33	6.9	45.9	47.8	Sh, Bl, V/Fn Grn, Slty, Frac
114	90.0-91.0	<0.01	8.2	40.2	47.5	Sh, Bl, V/Fn Grn, Slty, Frac
115	92.0-93.0	<0.01	8.3	42.2	47.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
116	94.0-95.0	0.50	5.1	17.6	68.5	Sh, Bl, V/Fn Grn, V/Slty
117	96.0-97.0	3.3	5.2	13.5	76.8	Sh, Bl, V/Fn Grn, V/Slty
118	98.0-99.0	0.02	7.2	6.9	79.2	Sh, Bl, V/Fn Grn, V/Slty
119	4300.0-01.0	0.01	5.2	13.4	69.2	sh, Bl, V/Fn Grn, V/Slty
120	02.0-03.0	<0.01	4.2	16.6	76.2	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
121	04.0-05.0	0.50	5.0	10.0	84.0	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
122	06.0-07.0	<0.01	5.0	10.0	76.0	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
123	08.0-09.0	0.22	5.4	9.2	77.8	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
124	10.0-11.0	0.09	6.0	8.3	73.3	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
125	12.0-13.0	3.0	6.3	7.9	76.2	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
126	14.0-15.0	<0.01	5.4	9.3	81.5	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
127	16.0-17.0	0.05	6.0	8.3	76.6	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
128	18.0-19.0	0.01	6.3	7.9	69.9	Sh, Bl, V/Fn Grn, V/Slty
129	20.0-21.0	0.07	5.4	9.3	74.0	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
130	22.0-23.0	0.18	5.7	8.7	70.1	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
131	24.0-25.0	<0.01	4.6	10.9	71.7	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
132	26.0-27.0	0.08	5.8	8.6	74.1	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
133	28.0-29.0	0.09	6.2	8.1	77.3	Sh, Bl, V/Fn Grn, V/Slty, W/Lmy Slt Strks
134	30.0-31.0	0.07	6.8	7.3	82.4	Sh, Bl, V/Fn Grn, V/Slty

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company BENSON-MONTIN-GREER Formation GALLUP File RP-3-2312
Well LA PLATA MANCOS UNIT "I" NO. 6 Core Type DIAMOND 3.5" Date Report 8-24-68
Field LA PLATA (GALLUP) Drilling Fluid CRUDE OIL Analysts GALLOP
County SAN JUAN State NEW MEX. Elev. 6015'KB Location SEC 6-T32N-R13W

Lithological Abbreviations

SAND-SD	DOLOMITE-DOL	ANHYDRITE-ANHY	SANDY-SDY	FINE-FN	CRYSTALLINE-XLN	BROWN-BRN	FRACTURED-FRAC	SLIGHTLY-SL/
SHALE-SH	CHERT-CH	CONGLOMERATE-CONG	SHALY-SHY	MEDIUM-MED	GRAIN-GRN	GRAY-GY	LAMINATION-LAM	VERY-V/
LIME-LM	GYPSUM-GYP	FOSSILIFEROUS-FOSS	LIMY-LMY	COARSE-CSE	GRANULAR-GRNL	VUGGY-VGY	STYLOLITIC-STY	WITH-W/

(WHOLE-CORE ANALYSIS)

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS K_A	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
1	4000.0-01.0	**	6.7	19.8	60.3	Sh, Bl, V/Fn Grn, Slty, Frac
2	04.0-05.0	**	6.6	19.4	59.7	Sh, Bl, V/Fn Grn, Slty, Frac
3	10.0-11.0	**	8.3	15.3	66.9	Sh, Bl, V/Fn Grn, Slty, Frac
4	14.0-15.0	*1.12	5.6	22.0	54.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
5	20.0-21.0	**	6.0	19.8	66.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
6	24.0-25.0	**	7.0	17.2	62.2	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
7	30.0-31.0	**	6.9	20.6	57.5	Sh, Bl, V/Fn Grn, Slty, Frac
8	34.0-35.0	**	6.5	13.6	63.3	Sh, Bl, V/Fn Grn, Slty, Frac
9	40.0-41.0	**	5.0	19.4	62.6	Sh, Bl, V/Fn Grn, Slty, Frac
10	44.0-45.0	**	7.0	12.9	71.3	Sh, Bl, V/Fn Grn, Slty, Frac
11	50.0-51.0	*0.01	6.2	21.7	62.2	Sh, Bl, V/Fn Grn, Slty, Frac
12	54.0-55.0	**	8.2	17.8	66.8	Sh, Bl, V/Fn Grn, Slty, Frac
13	60.0-61.0	*0.07	5.9	15.3	62.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
14	64.0-65.0	**	7.0	12.6	72.7	Sh, Bl, V/Fn Grn, Slty, Frac
15	70.0-71.0	*0.99	5.3	20.2	59.4	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
16	74.0-75.0	*0.03	4.4	21.4	55.9	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
17	4155.0-56.0	**	4.7	12.0	78.3	Sh, Bl, V/Fn Grn, Slty, Frac
18	59.0-60.0	*1.8	3.5	12.1	73.5	Sh, Bl, V/Fn Grn, Slty, Frac
19	65.0-66.0	*<0.01	6.0	16.2	62.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
20	69.0-70.0	**	5.1	16.6	74.6	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
21	75.0-76.0	**	5.4	23.9	62.7	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
22	79.0-80.0	**	5.5	22.0	69.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
23	85.0-86.0	**	5.6	20.7	68.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
24	89.0-90.0	**	5.3	26.5	63.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
25	95.0-96.0	*<0.01	5.5	25.7	68.2	Sh, Bl, V/Fn Grn, Slty, Frac
26	4201.0-02.0	*<0.01	5.3	17.7	69.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
27	05.0-06.0	**	5.3	26.9	59.6	Sh, Bl, V/Fn Grn, Slty, Frac
28	09.0-10.0	*<0.01	5.9	25.0	66.6	Sh, Bl, V/Fn Grn, Slty, Frac
29	15.0-16.0	*<0.01	6.3	23.1	66.0	Sh, Bl, V/Fn Grn, Slty, Frac
30	19.0-20.0	*0.01	6.2	22.9	68.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
31	25.0-26.0	**	7.3	23.7	56.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
32	29.0-30.0	**	4.3	22.6	56.4	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
33	35.0-36.0	**	5.1	26.4	54.1	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac

*Indicates Plug Permeability
**Indicates Sample Unsuitable for Permeability Measurement

(Service #5-B)

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

CORE ANALYSIS RESULTS

Company BENSON-MONTIN-GREER Formation GALLUP File RP-3-2312
Well LA PLATA MANCOS UNIT "I" NO. 6 Core Type DIAMOND 3.5" Date Report 6-24-68
Field LA PLATA (GALLUP) Drilling Fluid CRUDE OIL Analysts GALLOP
County SAN JUAN State NEW MEX. Elev. 6015'KB Location SEC 6-T32N-R13W

Lithological Abbreviations

SAND-SD SHALE-SH LIME-LM; DOLOMITE-DOL CHERT-CH GYPSUM-GYP; ANHYDRITE-ANHY CONGLOMERATE-CONG FOSSILIFEROUS-FOSS; SANDY-SDY SHALY-SHY LIMY-LMY; FINE-FN MEDIUM-MED COARSE-CSE; CRYSTALLINE-XLN GRAIN-GRN GRANULAR-GRNL; BROWN-BRN GRAY-GY VUGGY-VGY; FRACTURED-FRAC LAMINATION-LAM STYLOLITIC-STY; SLIGHTLY-SL/ VERY-V/ WITH-W/

(WHOLE-CORE ANALYSIS)

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS K_A	POROSITY PER CENT	RESIDUAL SATURATION PER CENT PORE OIL	TOTAL WATER	SAMPLE DESCRIPTION AND REMARKS
34	4239.0-40.0	*0.02	4.9	20.0	61.4	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
35	45.0-46.0	**	5.2	22.3	60.3	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
36	49.0-50.0	**	3.7	18.5	55.1	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
37	55.0-56.0	*0.01	5.6	18.9	62.0	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
38	59.0-60.0	*0.01	5.9	19.4	57.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
39	65.0-66.0	*0.02	5.1	23.6	59.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
40	69.0-70.0	**	4.1	13.0	52.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
41	75.0-76.0	**	6.9	16.0	62.0	Sh, Bl, V/Fn Grn, Slty, Frac
42	79.0-80.0	*<0.01	5.2	14.9	61.5	Sh, Bl, V/Fn Grn, Slty, Frac
43	85.0-86.0	*<0.01	5.4	22.0	55.8	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
44	89.0-90.0	*0.01	4.7	21.5	61.5	Sh, Bl, V/Fn Grn, W/Lmy Slt Strks, Frac
45	95.0-96.0	*0.01	5.5	4.7	73.0	Sh, Bl, V/Fn Grn, Slty
46	4299.0-00.0	*0.01	4.7	1.5	67.2	Sh, Bl, V/Fn Grn, V/Slty
47	4305.0-06.0	*< 0.01	5.8	1.2	77.7	Sh, Bl, V/Fn Grn, V/Slty
48	09.0-10.0	*< 0.01	5.7	0.9	77.0	Sh, Bl, V/Fn Grn, V/Slty
49	15.0-16.0	*0.01	7.2	1.3	70.5	Sh, Bl, V/Fn Grn, V/Slty
50	19.0-20.0	*<0.01	6.3	1.3	70.2	Sh, Bl, V/Fn Grn, V/Slty
51	25.0-26.0	*0.70	6.9	1.4	73.8	Sh, Bl, V/Fn Grn, V/Slty
52	29.0-30.0	*0.03	7.7	0.9	71.8	Sh, Bl, V/Fn Grn, V/Slty

*Indicates Plug Permeability
**Indicates Sample Unsuitable for Permeability Measurement

LA PLATA MANCOS UNIT I-6

CORE DESCRIPTION

CORE NO. 1 Cored 3995' to 4055'. Cored 60', recovered 60'. Average penetration rate 10 minutes/foot. Bedding plane partings and hairline fractures throughout entire core.

DEPTH	DESCRIPTION	INDICATED VERTICAL FRACTURES	OBSERVED HAIRLINE FRACTURE PATTERN
3995 - 4008'	Black shale		Fair
4008 - 4009'	Black shale	Vertical fracture	Fair
4009 - 4012'	Black shale		Fair
4012 - 4028'	Black shale with limey siltstone laminations		Fair
4028 - 4031'	Black shale with limey siltstone laminations	Vertical fracture	Fair
4031 - 4043'	Black shale with limey siltstone laminations		Poor
4043 - 4046'	Black shale	Vertical fracture	Fair to good
4046 - 4055'	Black shale	Fracture vertical to bedding planes	Good

CORE NO. 2 Cored 4055' to 4080'. Cored 25', recovered 25'. Average penetration rate 9.6 minutes/foot. Bedding plane partings and hairline fractures throughout entire core.

4055 - 4067'	Black shale		Fair
4067 - 4077'	Black shale with limey siltstone laminations		No good
4077 - 4080'	Black shale		Poor to fair

LA PLATA MANCOS UNIT I-[illegible]

CORE DESCRIPTION

CORE NO. 3: Cored 4150' to 4210'. Cored 60', recovered 60'. Average penetration rate 12.2 minutes/foot. Bedding plane partings and hairline fractures throughout entire core. Occasionally throughout core bedding planes are offset.

DEPTH	DESCRIPTION	INDICATED VERTICAL FRACTURES	OBSERVED HAIRLINE FRACTURE PATTERN
4150-4153'	Black shale with limey siltstone laminations		Fair
4154-4155'	" " "	Vertical fracture	Fair
4155-4159'	" " "		Fair to poor
4160-4179'	" " "	Fracture not on bedding plane	Poor to absent
4180-4185'	" " "		Fair to poor
4185-4188'	" " "	Healed fractures at angles to bedding planes	Absent
4189-4191'	" " "		Poor to absent
4192-4197'	" " "		Poor to fair
4197-4200'	" " "		Fair
4201-4203'	" " "	Vertical fracture	Fair
4204-4210'	" " "	Large healed vertical fracture 4005-06'	Good to fair

NOTE: General fracture pattern indicates larger fractures than in La Plata Mancos Unit No. P-31 well for comparative depth interval.

LA PLATA MANCOS UNIT I-6

CORE DESCRIPTION

CORE NO. 4: Cored 4210' to 4265'. Cored 55', recovered 55'. Average penetration rate 13.5 minutes/foot. Bedding plane partings and hairline fractures throughout entire core. Occasionally throughout core bedding planes are offset.

DEPTH	DESCRIPTION	INDICATED VERTICAL FRACTURES	OBSERVED HAIRLINE FRACTURE PATTERN
4210-4212'	Black shale with limey siltstone laminations		Fair
4212-4216'	Black shale with limey siltstone laminations	Vertical fracture	Good
4216-4220'	Black shale		Fair to good
4220-4230'	Black shale with limey siltstone laminations		Good to fair
4230-4238'	Black shale with limey siltstone laminations	All directions	Fair
4238-4242'	Black shale with limey siltstone laminations		Good
4242-4246'	Black shale with limey siltstone laminations		Fair
4246-4249'	Black shale with limey siltstone laminations	Vertical fracture	Fair
4249-4263'	Black shale with limey siltstone laminations		Fair
4263-4265'	Black shale with limey siltstone laminations	Vertical fracture	Fair

NOTE: General fracture pattern indicates larger fractures than in La Plata Mancos Unit No. P-31 well for comparative depth interval.

LA PLATA MANCOS UNIT I-6

CORE DESCRIPTION

CORE NO. 5: Cored 4265' to 4294'. Cored 29', recovered 29'. Average penetration rate 16 minutes/foot. Bedding plane partings and hairline fractures throughout entire core.

DEPTH	DESCRIPTION	INDICATED VERTICAL FRACTURES	OBSERVED HAIRLINE FRACTURE PATTERN
4265-4269'	Black shale with limey siltstone laminations		Fair to good
4269-	Approximately 2" section of slickenside		
4269-4278'	Black shale with limey siltstone laminations		Fair
4278-4281'	Black shale with limey siltstone laminations	Vertical fracture	Good
4281-4288'	Black shale with limey siltstone laminations		Fair
4288-4289'	Black shale with limey siltstone laminations	Vertical fracture	Poor to fair
4289-4292'	Black shale with limey siltstone laminations		Poor
4292-4294'	Black shale with limey siltstone laminations	Vertical fracture	Poor

NOTE: General fracture pattern indicates larger fractures than in La Plata Mancos Unit No. P-31 well for comparative depth interval.

LA PLATA MANCOS UNIT I-6

CORE DESCRIPTION

CORE NO. 6: Cored 4294' to 4334'. Cored 40', recovered 37'. Occasional bedding plane partings and infrequent hairline fractures in part of core as described below. As compared to previous cores, the limey siltstone laminations are more infrequent and thinner.

DEPTH	DESCRIPTION	INDICATED VERTICAL FRACTURES	OBSERVED HAIRLINE FRACTURE PATTERN
4294-4296'	Black shale with limey siltstone laminations	None	Fair
4296-4303'	" "	"	Poor
4303-4305'	" "	"	Fair
4305-4325'	" "	"	Poor to absent
4325-4331'	" "	"	Poor to fair

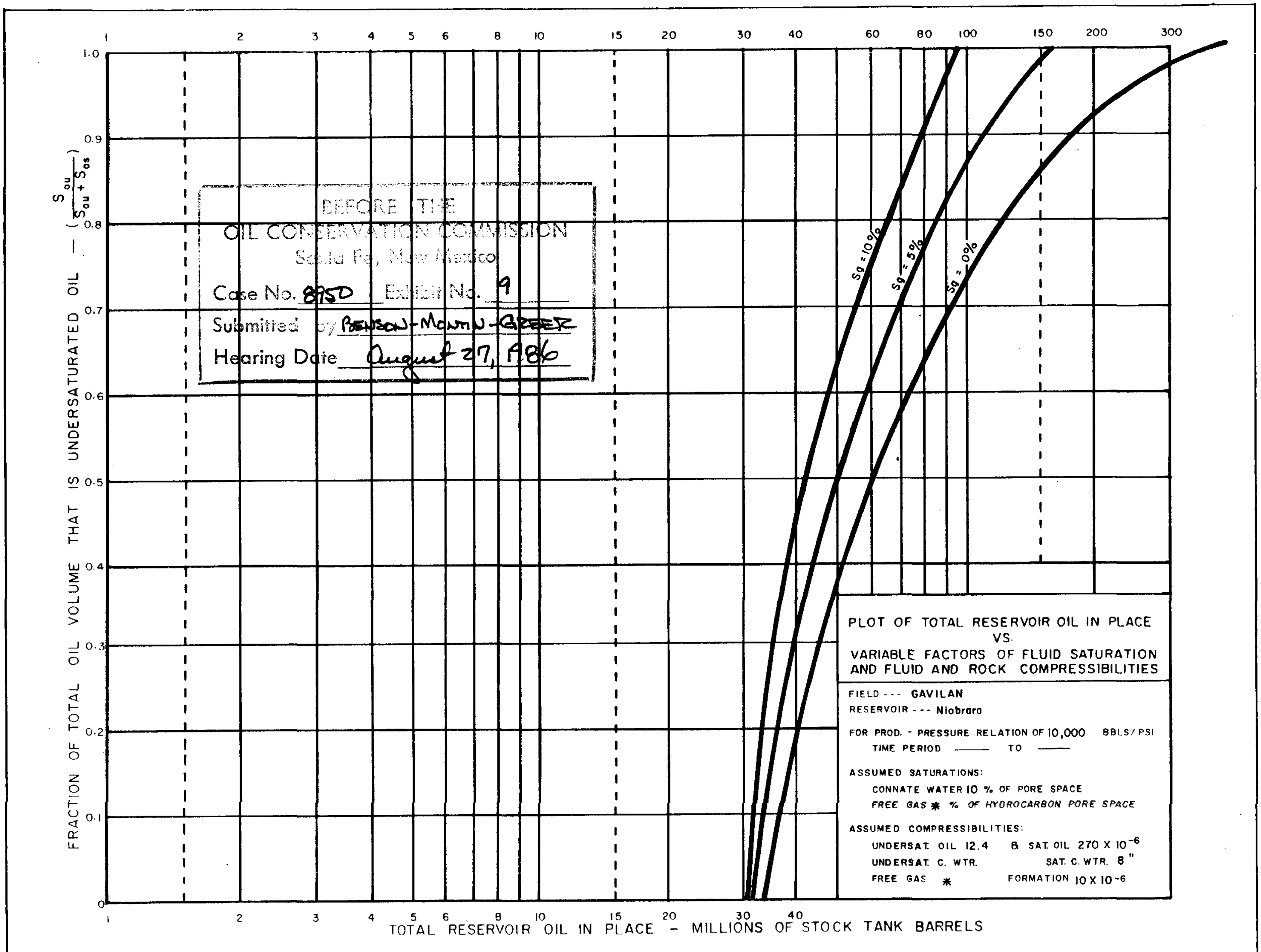
NOTE: Compared to Cores 3, 4 and 5, this core contains less frequent connections of bedding plane partings with hairline fractures at an angle to the bedding planes.

9-25-68 (cont'd) — Pressured up on annulus between tubing on top of packer with tubing open. Pressure held. Did not get any returns through tubing. Swabbed back 12 barrels acid displacement oil.

9-26-68 — Fraced with 6 Dowell Allisons at 625 HHP (total 3750 HHP), 3 Dowell Turbines at 825 HHP (total 2475 HHP) and 1 Dowell Turbine Experimental at 1000 HHP. Total HHP on location 7225. HHP delivered during frac job 6334. Treated with 200,000# 20/40 sand plus estimated 26,000# 10/20 sand, mixed with 3,400 barrels crude oil. Total sand volume 226 barrels. Average overall injection rate 86 BPM. No apparent breakdown pressure. Minimum TP 2900#, maximum 4500#, average 3100#. Well sanded off at 4800#.

1:18 PM — Shut pumpers down at 4800# pressure.

Date	Time	Dowell Gauge	B-M-G Gauge
	1:19 PM	3000#	
	1:20 PM	2300#	
	1:22 PM	1900#	
	1:24 PM	1500#	
	1:26 PM	1300#	
	1:29 PM	1250#	1440#
	1:30 PM		1420#
	1:33 PM		1410#
	1:45 PM		1380#
	2:00 PM		1260#
	2:15 PM		1340#
	2:30 PM		1380#
	2:45 PM		1450#
	3:00 PM		1440#
	3:15 PM		1440#
	3:30 PM		1440#
	3:45 PM		1430#
	4:00 PM		1420#
	4:15 PM		1415#
	4:30 PM		1410#
	4:45 PM		1405#
	5:00 PM		1400#
	5:15 PM		1400#
	5:30 PM		1385#
	5:45 PM		1380#
	6:00 PM		1375#
	6:15 PM		1370#
	6:30 PM		1365#
	6:45 PM		1365#
	7:00 PM		1360#
	7:15 PM		1350#
	7:30 PM		1345#
	7:45 PM		1340#
	8:00 PM		1340#
	9:00 PM		1325#
	10:00 PM		1320#
	11:00 PM		1300#
	Midnight		1290#
9-27-68	1:00 AM		1280#
	2:00 AM		1280#
	3:00 AM		1300#
	4:00 AM		1300#
	5:00 AM		1280#
	6:00 AM		1260#
	7:00 AM		1260#
	8:00 AM		1240#
	9:00 AM		1240#


FRACTION OF TOTAL OIL VOLUME THAT IS UNDERSATURATED OIL — ($\frac{S_{ou}}{S_{ou}+S_{os}}$)
0 0.1 0.2 0.3 0.4 0.5 0.6 0.7 0.8 0.9 1.0
1 2 3 4 5 6 8 10 15 20 30 40 60 80 100 150 200 300
TOTAL RESERVOIR OIL IN PLACE - MILLIONS OF STOCK TANK BARRELS
Sg = 10%
Sg = 5%
Sg = 0%
BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 8950 Exhibit No. 9
Submitted by BENSON-MONTIN-GREER
Hearing Date August 27, 1986
PLOT OF TOTAL RESERVOIR OIL IN PLACE
VS.
VARIABLE FACTORS OF FLUID SATURATION
AND FLUID AND ROCK COMPRESSIBILITIES
FIELD --- GAVILAN
RESERVOIR --- Niobrara
FOR PROD. - PRESSURE RELATION OF 10,000 BBLS/PSI
TIME PERIOD ____ TO ____
ASSUMED SATURATIONS:
CONNATE WATER 10 % OF PORE SPACE
FREE GAS * % OF HYDROCARBON PORE SPACE
ASSUMED COMPRESSIBILITIES:
UNDERSAT. OIL 12.4 & SAT. OIL 270 X 10^-6
UNDERSAT. C. WTR. SAT. C. WTR. 8 "
FREE GAS * FORMATION 10 X 10^-6