CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

June 14, 1954

05 59A

The California Standard Company
Medical Arts Building
Calgary, Alberta, Canada

Attention: Mr. J. F. Ross

11-4-10-28

Subject: Reservoir Fluid Study
California Standard Scallion No. 4-11 Well
North Virden ~~Roselea~~-Field
Manitoba, Canada

Gentlemen:

Presented in this report are the results of laboratory studies performed using subsurface samples collected from the subject well.

The saturation pressure of the fluid was found to be 156 psig at the measured temperature of 84° F. Comparison of this value with the reservoir pressure makes it apparent that the reservoir exists in an undersaturated condition.

The fluid yielded 74 standard cubic feet of vapor per barrel of residual liquid. The corresponding formation volume factor was found to be 1.0528 barrels of saturated fluid per barrel of residual liquid. The viscosity of the liquid phase varied from a value of 3.81 centipoises at saturation pressure to a maximum value of 5.31 centipoises at zero pressure. The various measurements performed evidence very limited changes at pressures in excess of 20 to 30 psig.

The separator tests indicate a limited response to variations in operating pressure. The gas-oil ratios again show a marked change at pressures in excess of approximately 30 psig.

The reservoir fluid composition substantiates the somewhat unusual behavior. A very low methane content with a high concentration of intermediate material are the required factors for behavior of this type.

Thank you for this opportunity to be of service. If we may be of further assistance, please call upon us.

Very truly yours,

Core Laboratories, Inc.

F. O. Reudelhuber

F. O. Reudelhuber,
Division Manager

FOR:ma

Form 69355

CORE LABORATORIES, Inc.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 332

Company The California Standard Company Date Sampled April 19, 1954

Well California Standard Scallion No. 4-11 County

Field North Virden Roselea State Manitoba, Canada

FORMATION CHARACTERISTICS

Formation Name	Mississippian
Date First Well Completed	December, 1953
Original Reservoir Pressure	870 PSI @ 2010 ft.
Original Produced Gas-Oil Ratio	cu. ft./bbl.
Production Rate	bbl./d.
Separator Pressure and Temperature	PSI, ° F.
Oil Gravity at 60° F.	34 ° API
Datum	518 ft. subsea
Original Gas Cap	

WELL CHARACTERISTICS

Elevation	1492 Feet K. B.
Total Depth	2062 K. B. ft.
Completion Depth	2005-07, 11-12, 17-19, 24-26 ft.
Tubing Size and Depth	2.0 in. to 2059 ft.
Productivity Index	bbl./d./PSI @ bbl./d.
Last Reservoir Pressure	665 PSI @ 2010 ft.
Date	April 19, 1954
Reservoir Temperature	84 ° F. @ 2010 ft.
Status of Well	Shut-In 147 Hours
Pressure Gauge	Amerada (CLI)
Normal Production Rate	70 bbl./d.
Gas-Oil Ratio	cu. ft./bbl.
Separator Pressure and Temperature	PSI, ° F.
Base Pressure	PSI Abs.
Well Making Water	% Cut

SAMPLING CONDITIONS

Sampled at	2010 Feet K. B.
Status of Well	Shut-In 147 Hours
Gas-Oil Ratio	cu. ft./bbl.
Separator Pressure and Temperature	PSI, ° F.
Tubing Pressure	60 PSI
Casing Pressure	60 PSI
Core Laboratories Engineer	N. I. C.
Type Sampler	Perco

REMARKS:

Form 54891

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 332

Well California Standard
Scallion No. 4-11

VOLUMETRIC DATA OF Reservoir Fluid SAMPLE

1. Saturation pressure (bubble-point pressure) 156 PSI @ 84 °F.
2. Thermal expansion of saturated oil @ 5000 PSI = $\frac{V @ 84\ °F.}{V @ 75\ °F.}$ = 1.00370
3. Compressibility of saturated oil @ reservoir temperature: Vol./Vol./PSI:

   From 5000 PSI to 3000 PSI = 4.91×10^{-6}

   From 3000 PSI to 1500 PSI = 5.48×10^{-6}

   From 1500 PSI to 156 PSI = 6.82×10^{-6}
4. Specific volume at saturation pressure: cu. ft./# 0.01925 @ 84 °F.

Form 50870

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 332

Well California Standard
Scallion No. 4-11

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATIONS @ 84 °F., RELATIVE VOLUME OF OIL AND GAS, V/Vs	VISCOSITY OF OIL @ 84 °F., CENTIPOISES	DIFFERENTIAL VAPORIZATION @ 84 °F. LIBERATED GAS SCF PER BARREL OF RESIDUAL OIL	SOLUTION GAS SCF PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/Vr
5000	0.9730				1.0244
4500	0.9758				1.0273
4000	0.9777				1.0293
3500	0.9802				1.0320
3000	0.9827				1.0346
2500	0.9854				1.0374
2000	0.9881				1.0403
1990		4.56			
1530		4.36			
1500	0.9908				1.0431
1200	0.9926				1.0450
1025		4.15			
1000	0.9938				1.0463
800	0.9950				1.0475
600	0.9964				1.0490
505		3.95			
500	0.9970				1.0496
400	0.9978				1.0505
300	0.9986				1.0513
255		3.86			
200	0.9996				1.0524
156	1.0000	3.81	0	74	1.0528
141	1.0100				
135		3.81			
130	1.0257				
122			3	71	1.0524
120	1.0470				
113	1.0647				
100		3.83			
92	1.1245				
90			6	68	1.0518
78	1.2326				
65		3.91			

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

Form 50870

CORE LABORATORIES, Inc.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 332

Well California Standard
Scallion No. 4-11

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATIONS @ 84 °F., RELATIVE VOLUME OF OIL AND GAS, V/Vs	VISCOSITY OF OIL @ 84 °F., CENTIPOISES	DIFFERENTIAL VAPORIZATION @ 84 °F. LIBERATED GAS SCF PER BARREL OF RESIDUAL OIL	SOLUTION GAS SCF PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/Vr
62	1.3866				
58			10	64	1.0510
50	1.6202				
40	2.0077				
35	2.3237				
31			20	54	1.0480
28	3.0608	4.06			
0		5.31	74	0	1.0108

@ 60° F. = 1.0000

Gravity of Residual Oil =

34.4° API @ 60° F.

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

Form 54868

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 332

Well California Standard
Scallion No. 4-11

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	76		34.2	0.9355	1.069	1.4108
10	74	56	8	34.6	0.9425	1.061	
20	74	41	16	34.8	0.9488	1.054	
50	74	12	53	35.1	0.9542	1.048	

(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 @ 156 PSI gauge and 84 ° F.

(3) Formation Volume Factor: $V_{SAT.}/V_R$ is barrels of saturated oil @ 156 PSI gauge and 84 °F. per barrel of stock tank oil @ 60° F.

Form 35349

CORE LABORATORIES, INC.

Petroleum Reservoir Engineering

DALLAS, TEXAS

File RFL 332

Company The California Standard Company Formation Mississippian

Well California Standard Scallion No. 4-11 County

Field North Virden Roselea State Manitoba, Canada

HYDROCARBON ANALYSIS OF Reservoir Fluid SAMPLE

COMPONENT	WEIGHT %	MOL %	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Methane	0.10	1.18			
Ethane	0.72	4.44			
Propane	1.86	7.83			
Iso-butane	0.63	2.03			
N-butane	1.89	6.04			
Iso-pentane	1.28	3.30			
N-pentane	1.12	2.89			
Hexanes	2.96	6.37			
Heavier	89.44	65.92	0.8747	30.1	252
	100.00	100.00			

Core Laboratories, Inc.

F. O. Reudelhuber

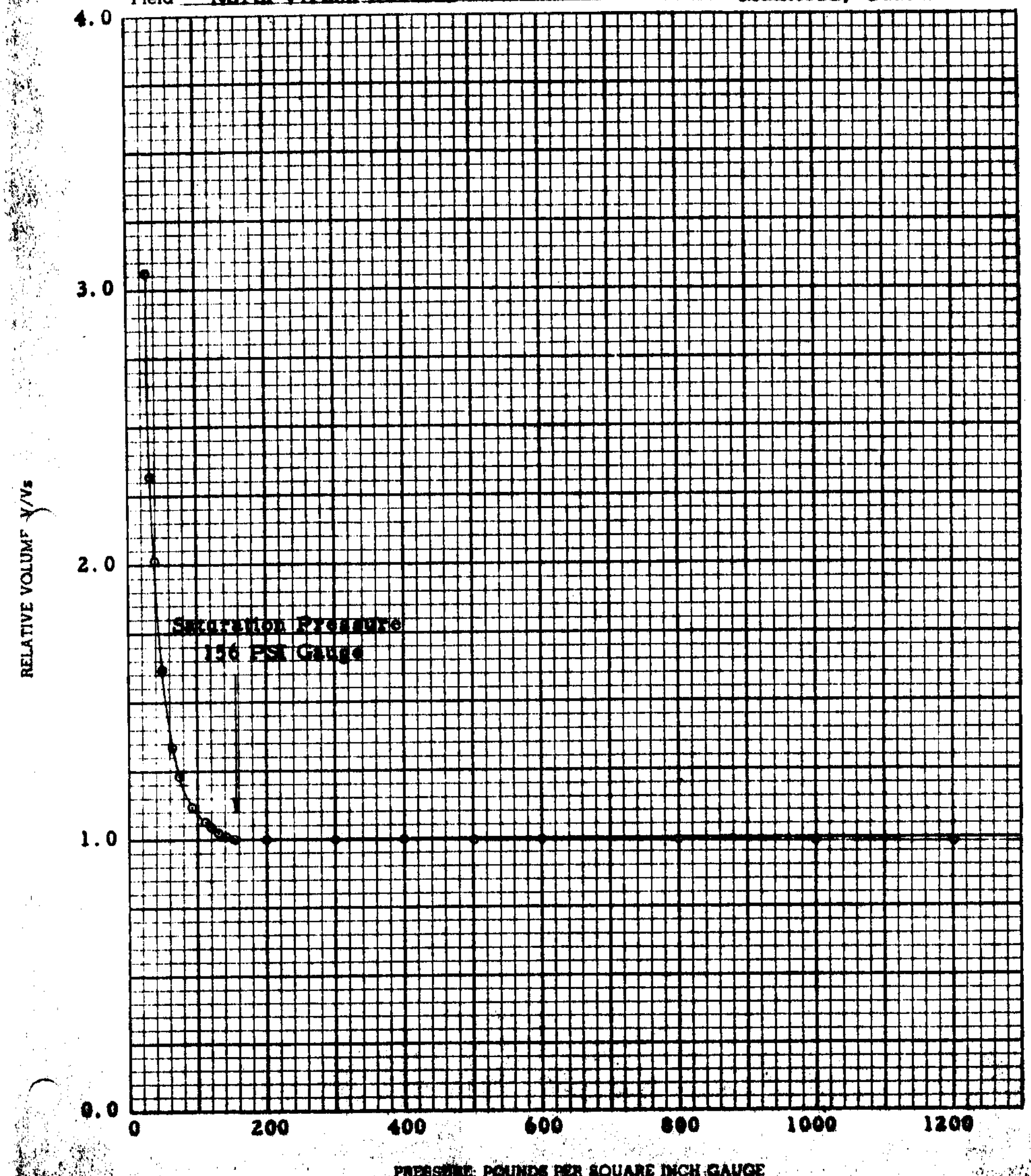
F. O. Reudelhuber

File RFL 332

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

PRESSURE-VOLUME RELATIONS OF RESERVOIR FLUID

Company The California Standard Company Formation Mississippian
Well California Standard Scallion No. 4-11 County
Field North Virden Roselea State Manitoba, Canada

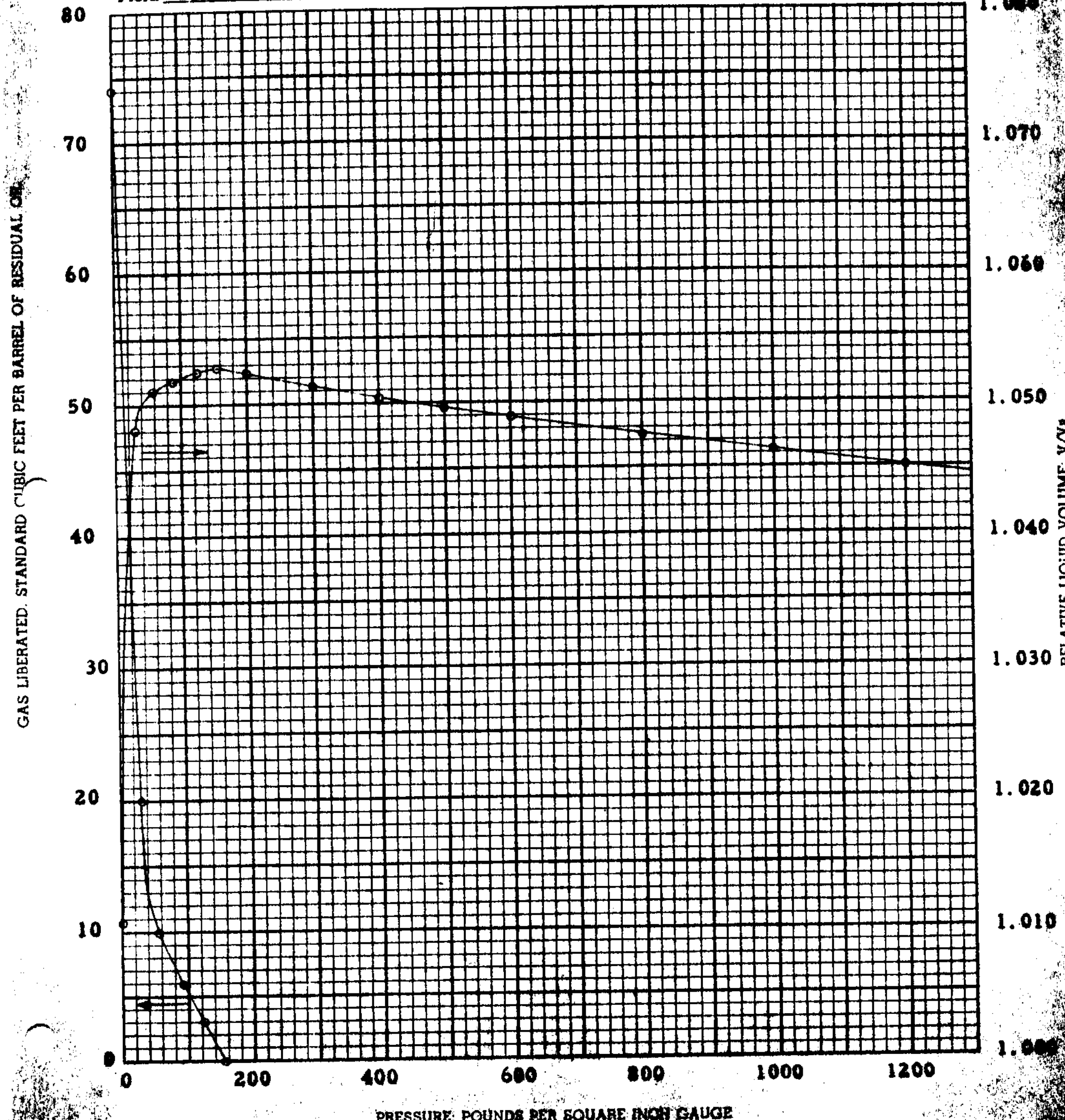


CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 332

DIFFERENTIAL VAPORIZATION OF RESERVOIR FLUID

Company The California Standard Company Formation Mississippian
Well California Standard Scallion No. 4-11 County
Field North Virden Roselea State Manitoba, Canada

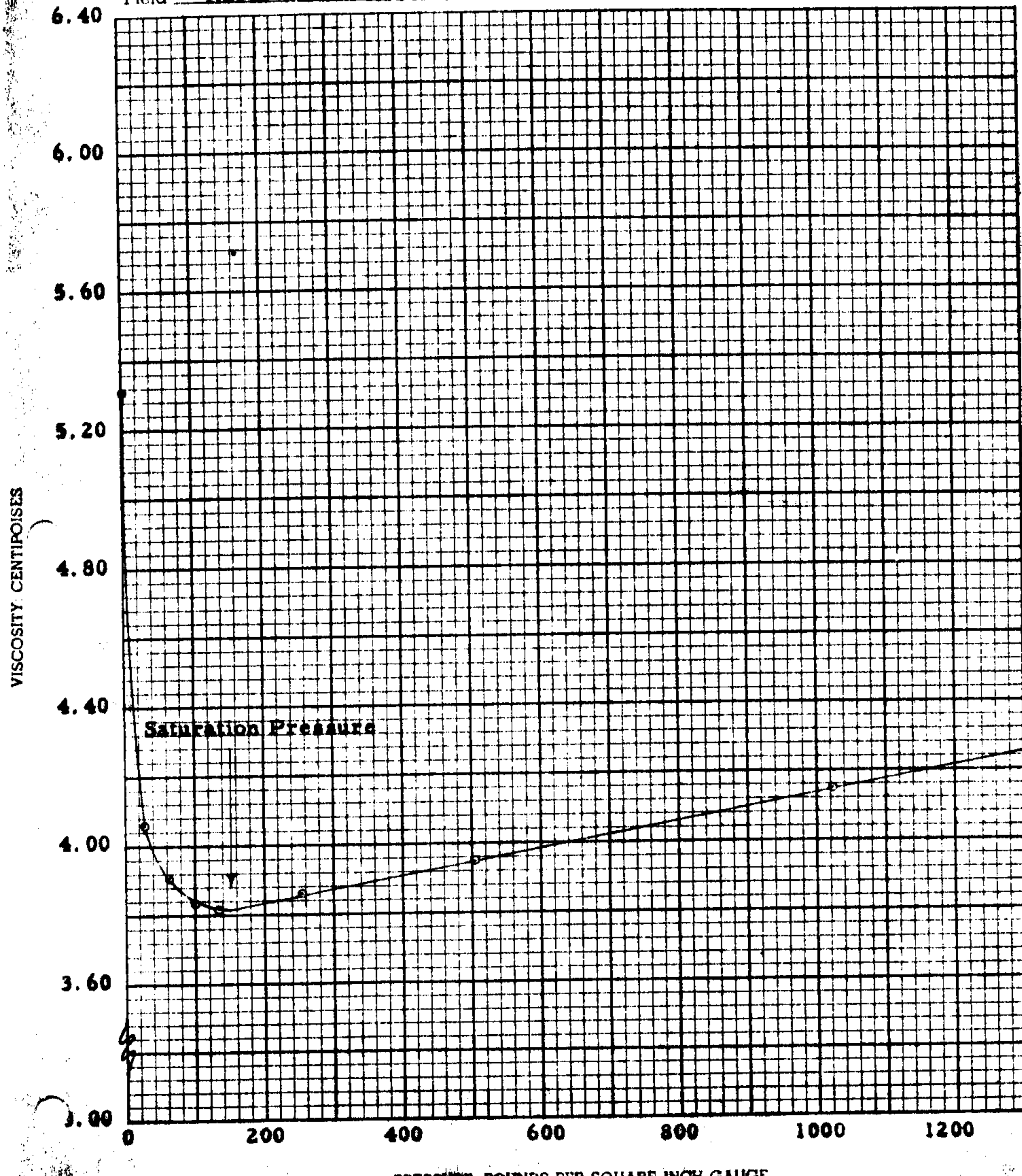


CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

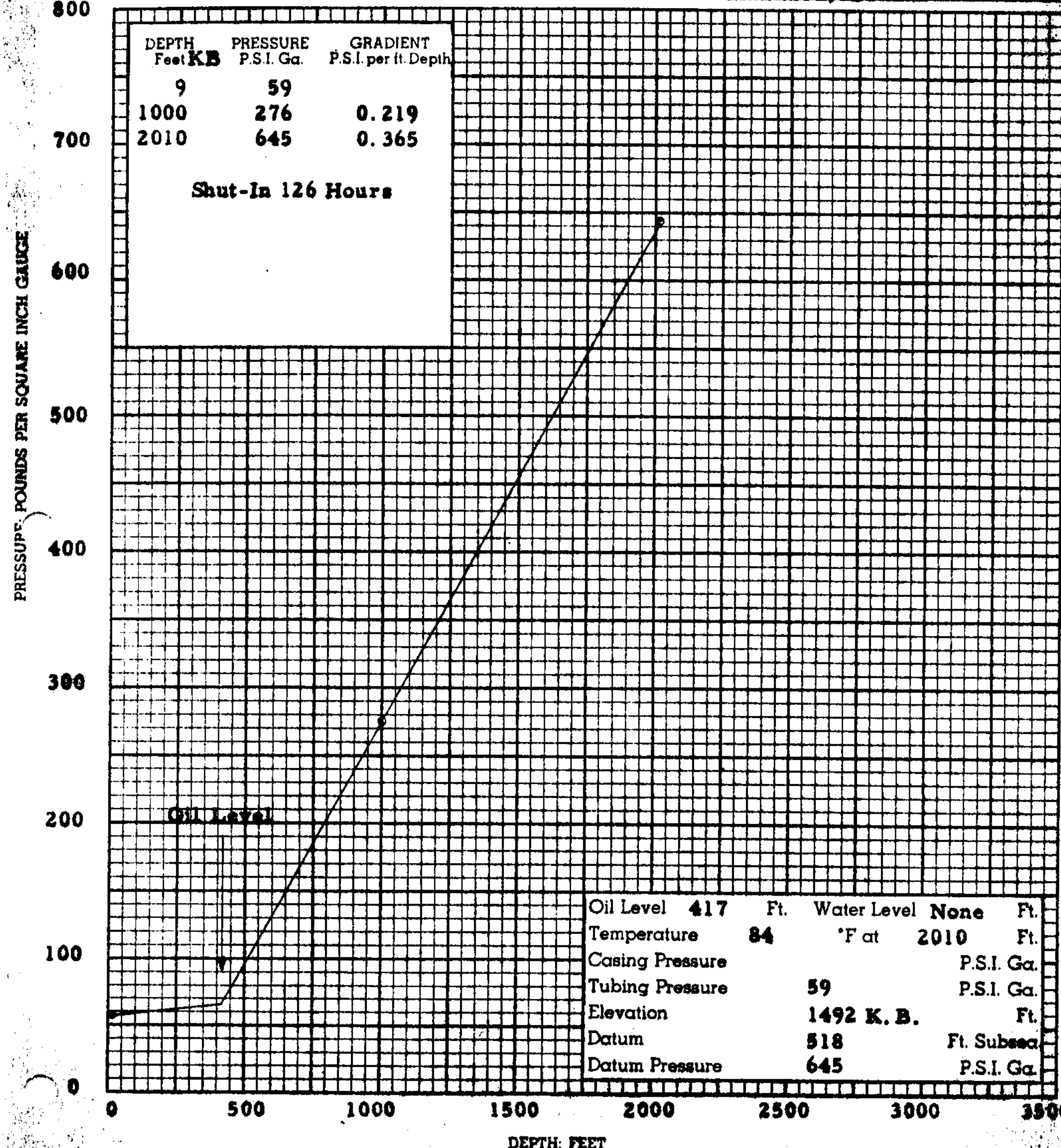
File RFL 332

VISCOSITY OF RESERVOIR FLUID

Company The California Standard Company Formation Mississippian
Well California Standard Scallion No. 4-11 County
Field North Virden Roselea State Manitoba, Canada



Company The California Standard Company Formation Mississippian
Well California Standard Scallion No. 4-11 County
Field North Virden Roselea State Manitoba, Canada



DEPTH Feet KB	PRESSURE P.S.I. Ga.	GRADIENT P.S.I. per ft. Depth
9	59	
1000	276	0.219
2010	645	0.365

Shut-In 126 Hours

Oil Level	417 Ft.	Water Level	None Ft.
Temperature	84 °F at	2010	Ft.
Casing Pressure			P.S.I. Ga.
Tubing Pressure		59	P.S.I. Ga.
Elevation		1492 K. B.	Ft.
Datum		518	Ft. Subsea
Datum Pressure		645	P.S.I. Ga.

[illegible]

SUN OIL COMPANY

CANADIAN PRODUCTION DIVISION

805 - 8TH AVE. W.
P.O. DRAWER 39
CALGARY, ALBERTA
CANADA

G. E. DUNLAP
MANAGER

L. E. MILLER
ASSISTANT MANAGER

M. E. AUSTIN
SUPT. OPERATING DEPT.

March 3rd, 1958

Mr. M. J. Gobert
Senior Petroleum Engineer
Department of Mines & Minerals
Province of Manitoba
WINNIPEG, Manitoba

Dear Sir:

Enclosed herewith is one copy of the Water-Oil Relative Permeability Measurements taken in the North Virden field of Manitoba, as prepared for Sun Oil Company by Core Laboratories, Inc.

Yours very truly,

SUN OIL COMPANY

A. D. Brown per jhm.

A. D. Brown

ADB/jhm
Encl.(1)

Stone

G. E. DUNLAP
MANAGER

SUN OIL COMPANY

CANADIAN PRODUCTION DIVISION

805 - 8TH AVE. W.
P.O. DRAWER 39
CALGARY, ALBERTA
CANADA

L. E. MILLER
ASSISTANT MANAGER

M. E. AUSTIN
SUPT. OPERATING DEPT.

February 5th, 1958.

Mr. M. J. Gobert
Senior Petroleum Engineer
Department of Mines & Mineral Resources
Government of the Province of Manitoba
WINNIPEG, Manitoba

Dear Sir:

Re: Radial Flow Calculations:
E. Hutchinson #4-23 - Lsd 4-23-11-26 WPM
C. Nichol #10-20 - Lsd 10-20-11-26 WPM
G. Clarke #8-20 - Lsd 8-20-11-26 WPM

Enclosed herewith for your information and file is one copy of the injection rate calculations which you requested at the hearing held on January 16th, 1958, regarding the injection of salt water into the Cherty zone of E. Hutchinson #4-23, C. Nichol #10-20 and G. Clarke #8-20. These calculations are based on the method employed by Suder and Calhoun in the 1949 issue of the American Petroleum Institute's "Drilling and Production Practices".

If there are any other questions regarding this matter, please advise.

Yours very truly,

SUN OIL COMPANY

V F Zubko

V. F. Zubko.

VFZ:iw
Enclosures

Lease - G. Clarke

Computation of Water Injection

A single homogeneous bed of 19.8 feet thick and 14.56 md was chosen in the Cherty Zone of the Lodgepole to represent an average for the purpose of injection calculations. For this average bed the following conditions were found:-

1. Sw = 30%. Average water saturation of the Cherty Zone in this area.

2. So = 60%. Oil saturation at start of flood, found by subtracting oil produced during primary operations from original oil in place all on a stock basis. It could be anticipated that the reverse of the injection rates may occur, that is the injection rate may start at the steady state and reversal phenomena will be encountered. Since the Cherty and Crinoidal are produced simultaneously and no segregation test had been conducted. It is assumed that only 10% of the oil from the Cherty has been produced.

3. ϕ = 11.7%. Average porosity found in the same manner as average permeability.

In order to calculate water rates, the following operating conditions were known or assumed:-.

? 4. rw Kw = 0.328, the radius of the 7 7/8" hole used for the input well.

5. W = 1,320'. The water to oil well distance.

6. P = 400 p.s.i. The pressure difference between the sand face and the reservoir during flow, the formation at well bore being assumed to be originally at atmospheric pressure.

7. $\frac{Kw}{k = 14.56}$ = 0.4 or Kw = 0.4 x 14.56 (md) = 5.82 = relative permeability to water.

8. Sor = 30%. Residual oil saturation.

9. Mu = 1 centipoise. The viscosity of the injected fluid.

With the foregoing information, the water injection rate was computed for the average bed in three steps:-

1. For the original period of water encroachment.

2. For the steady-state period after all space was filled with water.

3. For the period in between these two phases.

The period of radial encroachment was assumed to last until sufficient water has been injected to fill the bed completely with liquid to a point half-way between the input and producing wells

This limit is based on electrolytic studies reported by Muskat in which he shows departure from a radial encroachment at this point in the 5-spot system. The total water in barrels injected to the end of radial encroachment was computed from:-

$$Vi = 0.178 \pi \frac{W^2}{4} h \phi (1-Sw-So)$$

Where:-

0.178 converts from cubic feet to barrels, h is the thickness of the bed, and the other quantities are as previously defined.

The rate of water injected in barrels per day during the radial encroachment phase was computed from:-

$$Q = \frac{0.00308\ KwhP}{Mu \log \frac{re}{rw}}$$

Where re = the position of the pressured radius given in the equation

$$V = 0.178 \pi re^2 h \phi (1-Sw-So)$$

in which V is the cumulative water injection at the instant that radial encroachment has reached the radius re.

To find the time at which a given radius of injection has been reached, it was assumed that the gas space volume between two successive values of re was filled at a rate equal to the average injection rate between the two limits chosen.

In this manner water input rates and total input volumes at a given time were calculated up to the limit of radial encroachment. These values are given in a tabulated form and plotted.

The steady-state flow phase was assumed to have begun at the time when the formation was completely filled with liquid. Although this is not strictly true, the object is to keep these techniques simplified as much as possible. At the beginning of steady-state flow the total volume of water injected was computed from:-

$$Vii = 0.723 W^2 h \phi (1-Sw-So) 0.178$$

where the factor 0.723 is that portion of the 5-spot assumed to be flooded.

The following formula was used to compute the steady-state rate:-

$$Q = \frac{0.00154\ KwhP}{mu (\log \frac{W}{rw} - 0.470)}$$

Reservoir Characteristics - G. Clarke Lease

Well No.	Interval	Feet Rep.	Average Wt. Porosity	Average Rad. Permeability	Sw %	Formation
G. Clarke 1-20	2096.0-2116.0	20.0	14.60	23.1	30	Cherty
" " 2-20	2076.6-2098.7	22.1	10.60	20.9	30	Cherty
" " 4-21	2068.4-2085.2	16.8	8.45	5.1	30	Cherty
" " 5-21	2078.0-2098.0	20.0	12.92	8.4	30	Cherty
" " 7-20	2090.0-2110.0	20.0	11.33	21.5	30	Cherty
" " 8-20	2141.6-2161.5	19.9	12.31	8.4	30	Cherty
TOTAL		118.8	70.21	87.4	180	
AVERAGE		19.80	11.70	14.56	30	

Water Injection Calculation

A. Radial encroachment phase:

re (Feet)	Q Barrels/day	V Barrels	t Months
10	75.6	13.0	0
25	65.2	81.3	0.042
50	60.2	325.0	0.17
75	57.3	732.0	0.43
100	55.1	1,300.0	0.79
125	53.4	2,032.0	1.28
150	52.2	2,925.0	1.88
175	51.1	3,982.0	2.60
200	51.0	5,200.0	3.40
225	50.0	6,582.0	4.40
250	48.0	8,125.0	5.70
300	47.5	11,700.0	8.22
350	47.0	15,925.0	11.30
400	46.3	20,800.0	14.98
450	45.3	26,325.0	19.38
500	44.5	32,500.0	24.35
550	44.1	39,325.0	29.72
600	43.5	46,800.0	35.62
660	43.0	56,630.0	43.90

Steady-State Flow:-

$$Q = \frac{0.00154 \; Kw \; h \;\; P}{Mu \; (\log \frac{W}{rw} - 0.420)}$$

$$= \frac{0.00154 \times 5.82 \times 19.8 \times 400}{3.19} \; (3/2)$$

$$= 33.38 \text{ barrels/day}$$

$$Vii = 0.723 \; W2 \; h \; \phi \; (1\text{-}Sw\text{-}So) \; 0.178$$

$$= 0.723 \times 1320 \times 1320 \times 19.8 \times .1 \times .178 \times .117$$

$$= 51{,}800$$

Intermediate phase:-

$$\text{Average Rate} = \frac{43 + 33.38}{2} = 38.2$$

Interim Cumulative:-

$$56{,}700 - 51{,}800 = 4{,}900$$

Interim Time:-

$$4{,}900 : 38.2 = 4.3 \text{ months}$$

Remarks:-

Since these reservoirs have been partially depleted the water injection method discussed above may reverse its course, that is the water injected may start at steady-state conditions, thru the intermediate phase and finally to the radial encroachment conditions. It could be, however, anticipated that the radial encroachment duration will be proportional to the amount of oil produced. Bottom hole pressure maintenance will avail the three wells G. Clarke 1-20, 2-20 and 7-20, the immediate neighbouring wells, to the proposed injection one. Pressure maintenance data and calculations are not available at the present time and a thorough analysis of this process can't be traced. Communication of the three zones (Crinoidal, Cherty and Oolites) make computations more difficult.

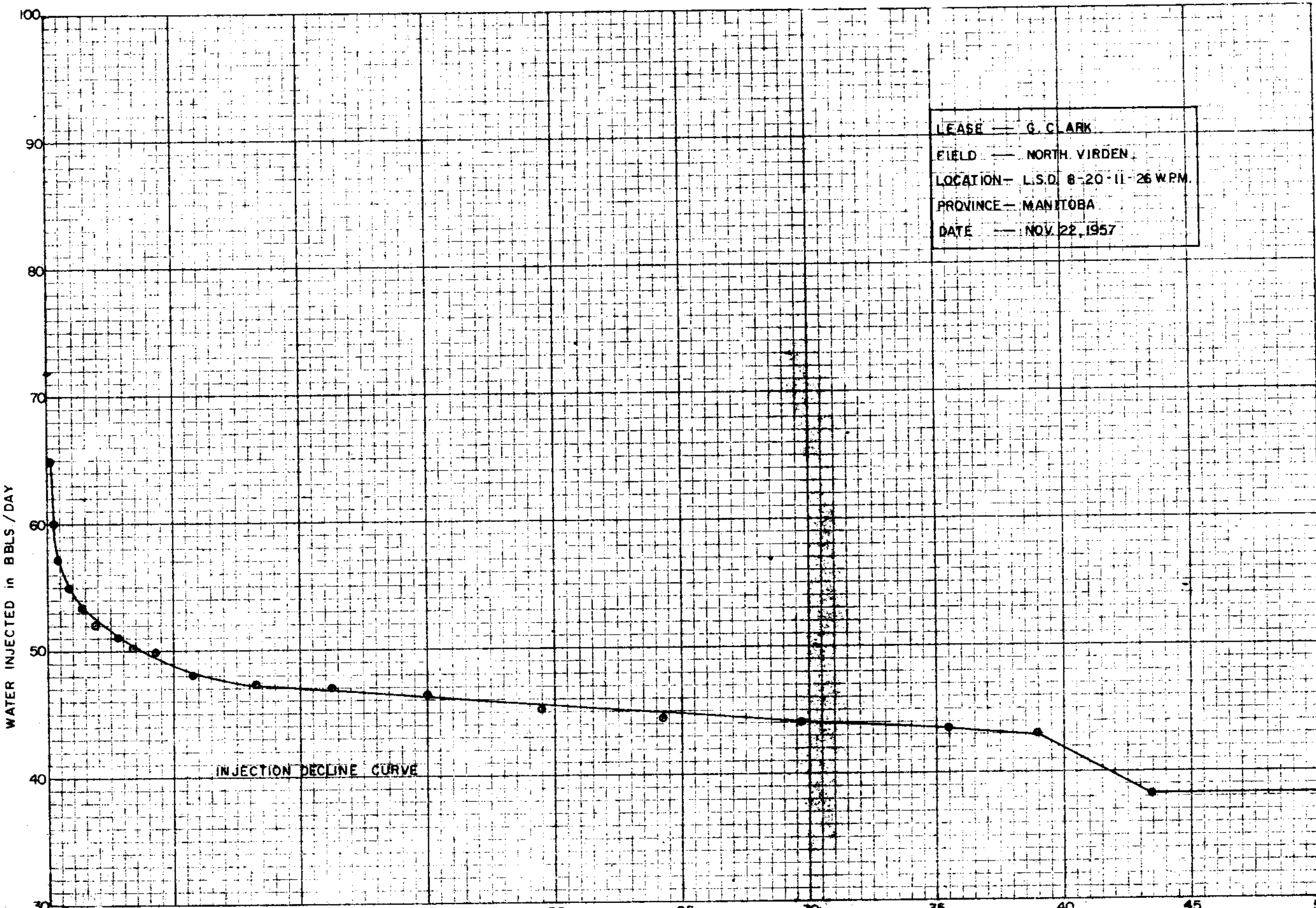

LEASE — G. CLARK
FIELD — NORTH. VIRDEN
LOCATION — L.S.D. 8-20-11-26 W.P.M.
PROVINCE — MANITOBA
DATE — NOV. 22, 1957
INJECTION DECLINE CURVE
WATER INJECTED in BBLS./DAY
100
90
80
70
60
50
40
30
0
5
10
15
20
25
30
35
40
45
50

FIGURE 4

Lease - C. Nichol

Computation of Water Injection

A single homogeneous bed of 20 feet and of 15.72 md was chosen to present an average for the purpose of injection calculations. For this average bed, the following conditions were found:-

1. Sw = 43.33%.

2. So = 49%. Oil saturation at start of flood, found by subtracting oil produced during primary operations from original oil in place.

3. ϕ = 11.66%. Average porosity found in the same manner as average permeability.

In order to calculate water rates, the following operating conditions were known:-

4. rw = 0.328'. The radius of 7 7/8" hole used for input well. rw 0.3275

5. W = 1,320'.

6. P = 400 p.s.i. The pressure difference between the sand face and the reservoir during flow, the formation being assumed to be originally at atmospheric pressure.

7. $\frac{Kw}{k}$ = 0.6 assumed.

8. Sor = 30% assumed.

9. Mu = 1 centipoise. The viscosity of the injected fluid.

The total volume of water in barrels injected to the end of radius encroachment was computed from:-

$$Vi = 0.178\ \pi\ \frac{W2}{4}\ h\ \phi\ (1\text{-}Sw\text{-}So)$$

Where 0.178 converts from cubic feet to barrels, h is the thickness of the bed and the other quantities as previosly defined.

The rate of water injection in barrels per day during the radial encroachment phase was computed from:-

$$Q = \frac{0.00308\ KwhP}{Mu\ \log \frac{re}{rw}}$$

Where re is the position of the pressured radius given in the equation

$$V = 0.178\ \pi\ re^2\ h\ \phi\ (1\text{-}Sw\text{-}So)$$

in which the cumulative water injection at the instant that radial encroachment has reached the radius re.

Since very little oil has been produced, the main state of affairs will be the steady-state flow phase. It is assumed to have begun at the time the formation was completely filled with liquid. At the beginning of steady-state flow the total volume of water injected was computed from:-

$$Vii = 0.723\ W^2\ h\ \phi\ (1\text{-}Sw\text{-}So)\ 0.178$$

The following formula was used to compute the steady-state rate:-

$$Q = \frac{0.00154\ Kw \times h \times P}{Mu\ (\log \frac{W}{rw} - 0.420)}$$

By substitution:-

$$Q = \frac{0.00154 \times 9.43 \times 20 \times 400}{1\ (\log \frac{1,320}{.328} - .420)} = 36.5 \text{ bbls./day}$$

re (Feet)	Q Barrels/day	V Barrels	t Months
10	158.06	10.5	0
25	123.60	65.2	0.017
50	106.60	261.0	0.08
75	98.90	585.0	0.197
100	93.70	1,045.0	0.372
125	90.10	1,630.0	0.62
150	87.40	2,350.0	0.90
175	85.40	3,200.0	1.24
200	84.60	4,180.0	1.65
225	83.80	5,750.0	2.3
250	82.30	6,540.0	2.65
275	79.90	7,900.0	3.30
300	78.50	9,400.0	4.0
325	77.80	11,000.0	4.72
350	77.10	12,800.0	5.53
375	76.20	14,600.0	6.40
400	75.50	16,700.0	7.40
450	74.50	21,150.0	9.5
500	73.10	26,100.0	11.9
550	72.40	31,600.0	14.5
600	71.30	37,600.0	17.6
660	70.40	45,500.0	21.6

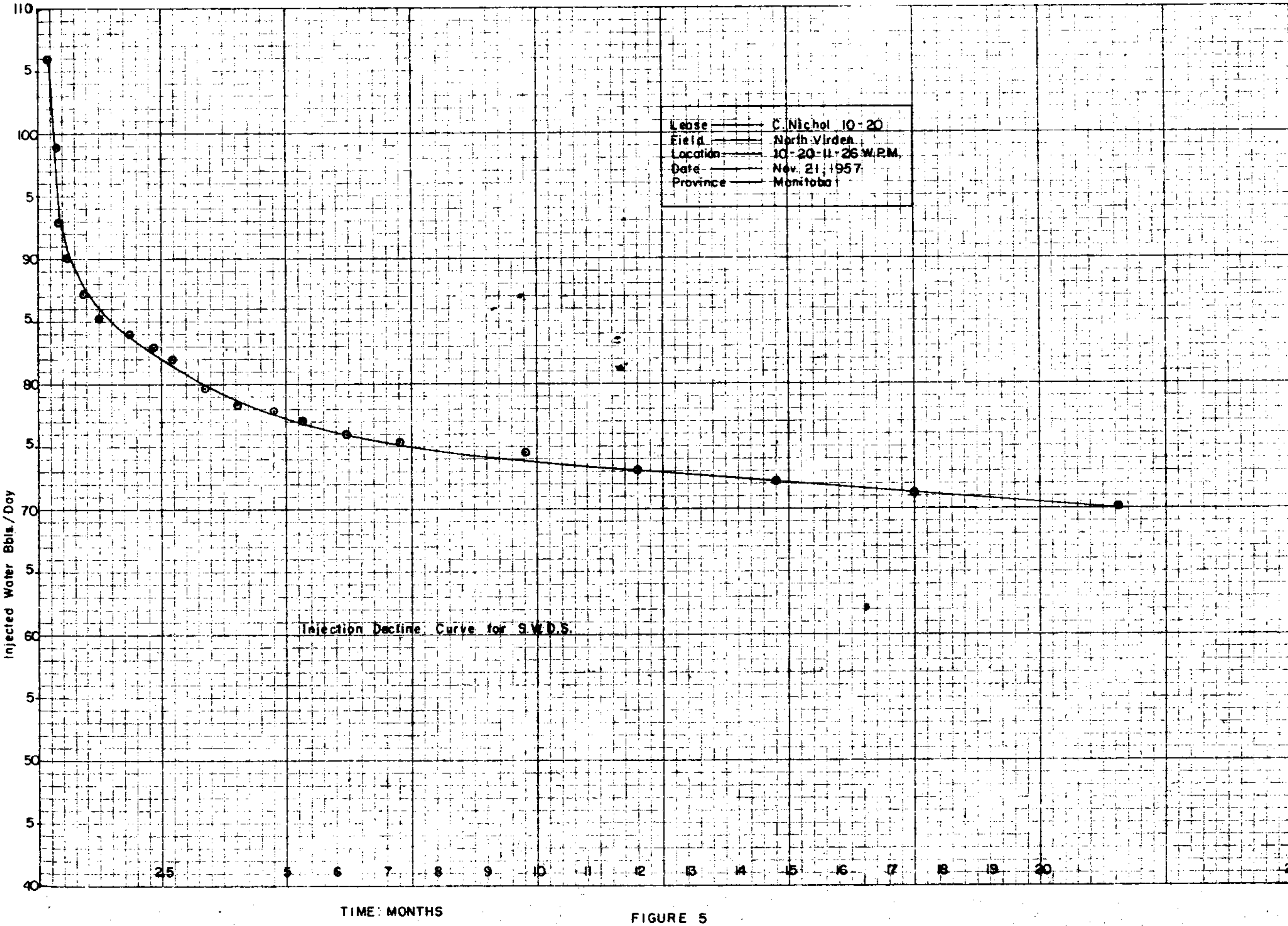

Lease — C. Nichol 10-20
Field — North Virden
Location — 10-20-11-26 W.P.M.
Date — Nov. 21, 1957
Province — Manitoba
Injection Decline Curve for S.W.D.S.
Injected Water Bbls./Day
TIME: MONTHS

FIGURE 5

Lease - E. Hutchinson

Assumptions made:-

1. Determination of porosity from RA-log is reliable.

2. Since core analysis was not available, a direct relationship between porosity and permeability was assumed. This is however not true. If mathematical approach is to be used, calculations will be lengthy and very complicated.

3. Relative permeability to water as taken is 60% of the total.

4. The 5-spot system as described by Muskat was considered to apply in this case.

5. Specific gravity of injected water was taken as .45#/in^2-ft.

6. Viscosity of the injected water was assumed 1 centipoise.

Lease - E. Hutchinson

Computation of Water Injection

A single homogeneous bed 22.25 feet thick and of 22.3 md was chosen, therefore to represent an average for the purpose of injection calculations. For this average bed, the following conditions were found:-

1. $S_w = 36\%$. Water saturation at start of flood, found by averaging individual well water saturations.

2. $S_o = 52\%$. Oil saturation at start of flood, found by subtracting oil produced during primary operations from original oil in place, all on a stock tank basis.

3. $\phi = 0.26\%$. Average porosity found in the same manner as average permeability.

In order to calculate water rates, the following operating conditions are known:-

4. $r_w = 0.328'$. The radius of the 7 7/8" hole used for input wells.

5. $W = 1{,}320'$. The radius of flow from water input well to surrounding oil wells.

6. $P = 350$ p.s.i. The pressure difference between the formation face and the reservoir during flow, the formation being assumed to be originally at atmospheric pressure.

The following data was assumed in order to permit calculations:-

7. $\frac{K_w}{k} = 0.6$ relative permeability to water at 8.26% porosity for unconsolidated formation.

8. $S_{or} = 30\%$. Residual oil saturation assumed.

With the foregoing information, the water injection rate will be computed for the average bed in three steps:-

1. For the original period of radial water encroachment from the input well.

2. For the steady-state period after all space was filled with liquid.

3. For the period in between these two phases.

The period of radial encroachment was assumed to last until sufficient water has been injected to fill the bed completely with liquid to a point half-way between the input and producing wells. The limit is based on electrolytic studies reported by Muskat in which he showed departure curve from radial encroachment at this point in the five-spot system.

The total volume of water in barrels injected to the end of radial encroachment was computed from:-

$$Vi = 0.178 \pi \frac{W^2}{4} h \phi (1-Sw-So)$$

Where:-

0.178 = converts from feet to barrels
h = the thickness of the bed and other quantities are as previously defined.

The rate of water injection, in barrels per day, during the radial-encroachment phase was computed from:-

$$Q = \frac{0.00308 \times Kw \times h \times P}{Mu \log \frac{re}{rw}}$$

Where mu = 1 centipoise - viscosity of the injected fluid.
Where re = the position of the pressured radius given in the equation.

$$V = 0.178 \pi re^2 h \phi (1-Sw-So)$$

in which V is the cumulative water injection at the instant that radial encroachment has reached the radius re.

To find the time at which a given radius of injection has been reached, it was assumed that the gas-space volume between two successive values of re was filled at a rate equal to the average injection rate between the two limits chosen.

In this manner water input rates and total input volume at a given time were calculated up to the limit of radial encroachment. The values are given in the attached table and graph.

Reservoir Characteristics and Data
E. Hutchinson Lease

Well No.	Interval	Feet Repr.	Average Permeability	Average Wt. Porosity %
E. Hutchinson 4-23	2040-2073	26.36	26.06 ?	9.57
E. Hutchinson 5-23	1998-2018	20.00	18.74 ?	6.80
E. Hutchinson 6-23	2035-2055.4	20.40	23.20	8.42
TOTAL		66.76	68.00	24.79
AVERAGE		22.25	22.30	8.26

re (Feet)	Q Barrels/day	V Barrels	t Months
10	214.20	12.0	0
25	168.60	75.0	0.015
45	148.20	243.0	0.055
70	136.00	598.0	0.15
95	128.80	1,083.0	0.28
115	124.30	1,587.0	0.43
140	120.50	2,352.0	0.65
165	117.00	3,267.0	0.93
185	115.20	4,107.0	1.18
210	112.50	5,292.0	1.55
235	110.90	6,627.0	2.0
250	110.80	7,500.0	2.26
275	108.50	9,075.0	2.79
300	107.00	10,800.0	3.34
350	105.00	14,700.0	4.7
400	103.30	19,200.0	6.2
450	101.00	24,300.0	7.1
500	99.40	30,000.0	9.1
550	98.50	36,300.0	12.3
600	96.90	43,200.0	14.9
660	95.80	52,300.0	18.2

FORM 0-8633

WATER SATURATION CALCULATION

FROM MLL (NEUTRON) AND LATEROLOG (GUARD RING)

WELL E. Hutchinson #4-23

LOCATION Lsd. 4-23-11-26 WPM

FIELD North Virden

PROVINCE Manitoba

Rm 1.22 at 67 F.

Rmf 0.82 at 73 F.

Rm 0.97 at 84 F.

Rmf 0.72 at 84 F.

Rmc 1.56 at 73 F.

Rmc 1.35 at 84 F.

Formation Oolites and Cherty

Interval 2040 - 2073

BH Temp. 84 °F ROS=10 %

Rw at BHT 0.097 @ 84° F.

ROS, 2010

Interval	Feet	~~R1"x1"~~ RMLL	R2"	Rxo	Rxo/Rmc	P%	% Ft	Ro	Rt	Sw	Remarks
2040-42	2	25		25		17.0					
2042-43	1	100		100		8.8					
2043-46	3	15		15		21.5					
2046-48	2	110		110		8.5					
2048-51	3	35		35		14.6					
2051-52	1	300		300		5.2					
2052-53	1	105		105		8.7					
2053-54	1	75		75		10.6					
2054-55	1	250		250		5.8					
2055-60	5	25		25		17.0					
2060-62	2	175		175		6.8					
2062-64	2	150		150		7.3					
2064-66	2	200		200		6.5					
2066-69	3	250		250		5.8					
2069-70	1	100		100		8.8					
2070-73	3	60		60		11.5					
Av. Poro.						9.57	315.7				

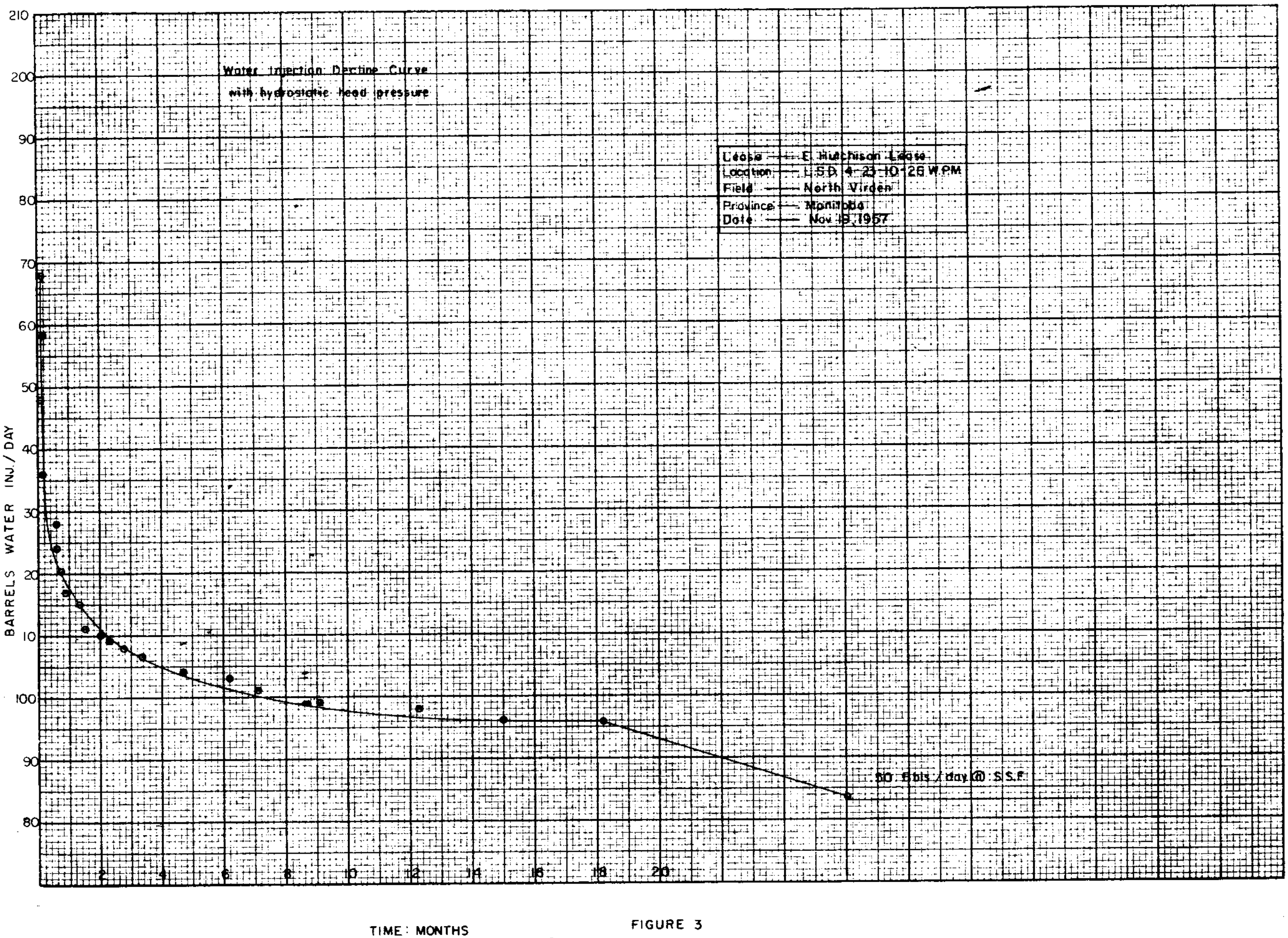

Water Injection Decline Curve
with hydrostatic head pressure
Lease — E. Hutchison Lease
Location — L.S.D. 4-23-10-26 W.P.M.
Field — North Virden
Province — Manitoba
Date — Nov 19, 1957
50 Bbls / day @ S.S.F.
BARRELS WATER INJ./DAY
TIME: MONTHS

FIGURE 3

DOWELL SCHLUMBERGER
CANADA

Laboratory report

SOLUBILITY REPORT

CHEVRON CANADA RESOURCES LTD.

THREE WELLS FROM EACH:
DALY FIELD;
NORTH VIRDEN STALLION UNIT;
ROSELEA FIELD; AND,
ROUTLEDGE FIELD

MISSISSIPPIAN FORMATION

ART UNGER, ESTEVAN
TECHNICAL REPRESENTATIVE

HARLEY FEAR
LABORATORY REPRESENTATIVE

CALGARY LABORATORY
C.L. NO.: 86-138

MARCH 13, 1986

DOWELL SCHLUMBERGER CANADA

SOLUBILITY REPORT
FOR
CHEVRON CANADA RESOURCES LTD.

Laboratory report

WELL DATA

THREE WELLS FROM EACH:
DALY FIELD, NORTH VIRDEN STALLION UNIT; ROSELEA FIELD; AND, ROUTLEDGE FIELD.
FORMATION: MISSISSIPPIAN

B.H.S.T. 32°C

INFORMATION REQUIRED

Solubility tests from samples from twelve different wells.
Scanning Electron Microscope Analysis.

TYPE OF SAMPLE SUBMITTED

Well Name	Locations	Depth
Cal Stan Daly	11-12-10-28-W1M	2324.5 metres
Canadian Superior Haskett	15-2-10-28-W1M	2306.5 metres
Cal Stan Daly	15-13-10-28-W1M	2394.5 metres
Cal Stan Stallion	4-27-11-26-W1M	2037.5 metres
Canadian Devonian Hepburn	15-23-10-26-W1M	2013.0 metres
Cal Stan Scallion	16-15-11-26-W1M	2041.5 metres
Canadian Prospects Roselea	10-30-10-25-W1M	1904.0 metres
Canadian Prospect Roselea	1-30-10-25-W1M	1784.5 metres
Cal Stan South Virden Prov.	4-11-10-26-W1M	2031.0 metres
Halliburton Vanderschaeghe	13-17-9-25-W1M	2110.5 metres
Cal Stan Routledge	16-21-9-25-W1M	2072.5 metres
Cal Stan Routledge	12-22-9-25-W1M	2068.0 metres

SOLUBILITY REPORT
RESULTS

SOLUBILITY TESTS

A portion of each sample was ground up into a fine powder, weighed and placed in 15% HCl. These solutions were then placed in a 66°C hot bath for one hour, after which time they were filtered, dried, re-weighed and the solubilities calculated.

Well Location	Solubility in 15% HCl
11-12-10-28-W1M	97%
15-2-10-28-W1M	71%
15-13-10-28-W1M	95%
4-27-11-26-W1M	100%
15-23-10-26-W1M	92%
16-15-11-26-W1M	97%
10-30-10-25-W1M	99%
1-30-10-25-W1M	99%
4-11-10-26-W1M	99%
13-17-9-25-W1M	97%
16-21-9-25-W1M	99%
12-22-9-25-W1M	100%

SCANNING ELECTRON MICROSCOPE AND ENERGY DISPERSIVE X-RAY ANALYSIS

In these analyses, small core chips were placed in the SEM chamber and visual examination under high magnification (220 times up to 231 times) was conducted. In conjunction with this, the core chips were subjected to an electron beam (EDX), which produced X-rays which were analyzed to give a semi-quantitative elemental analysis.

SOLUBILITY REPORT
RESULTS

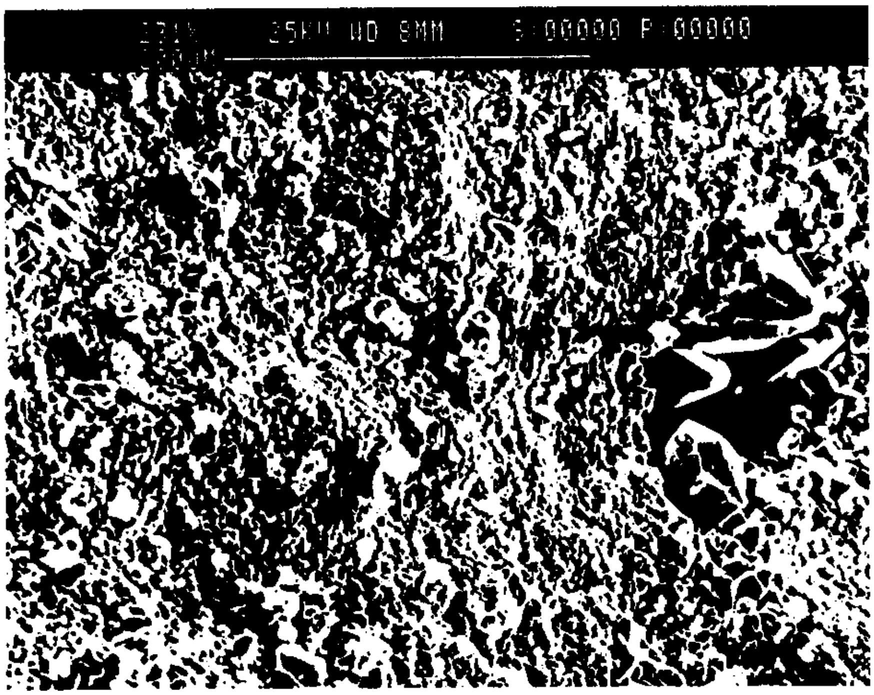


Figure	1
Formation	Mississippian
Depth	2041.5 metres
Magnification	231X
Stub No.	86-17
Location:	16-15-11-26-W1M

This photomicrograph shows well developed Calcite cubes as well as larger Calcite cubes surrounding a pore throat. EDX Analysis gave Ca as the major element present. A small amount of Si was also detected, form chert nodules. The bar at the top measures 200 microns long.

SOLUBILITY REPORT
RESULTS

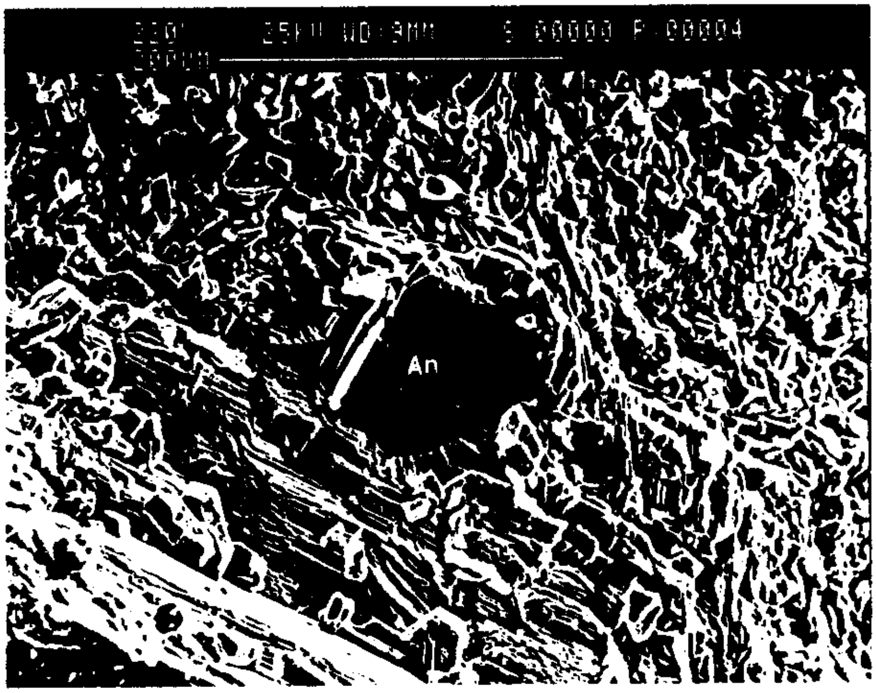


Figure	2
Formation	Mississippian
Depth	2306 metres
Magnification	220X
Stub No.	86-18
Location:	15-2-10-28-W1M

This photomicrograph shows well developed Calite (Ca) and massive, blockly Anhydrite (An). EDX Analysis gave Ca and S as the major elements present. The bar at the top measures 200 microns long.

HARLEY FEAR
Telephone No.: (403) 250-7891
cc: Al McCallum, Calgary, Alberta
Julie Ferriman, Tulsa, Oklahoma

WATER-OIL RELATIVE PERMEABILITY MEASUREMENTS

FOR

SUN OIL COMPANY

North Virden Field

~~HARMS WORTH AREA~~

MANITOBA, CANADA

CORE

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS
February 25, 1958

Sun Oil Company
P. O. Drawer 39
Calgary, Alberta, Canada

Attention: Mr. A. D. Brown

Subject: Water-Oil Relative Permeability Measurements
~~Harms Worth~~ Area North Virden
Manitoba, Canada
Our File Number: SCAL 57205

Gentlemen:

This is to present the results of water-oil relative permeability relationships measured on samples recovered from the subject area. The cores used in making this study are identified as to well and depth on page one of this report.

In preparation for this study, a number of large cylindrical plugs, one and one-half inches in diameter, were cut from the whole-core samples submitted to this laboratory. These plugs were thoroughly extracted and dried. Their air permeabilities were then measured. Based on this permeability data and a visual inspection of the samples, five were selected for further testing. These five were evacuated and saturated under 2000 PSI pressure with brine prepared as instructed. A portion of this brine was displaced in a capillary pressure cell until the water saturation anticipated in the reservoir had been reached. The pores voided by this capillary desaturation were then saturated with a refined mineral oil. Effective permeabilities to oil were measured and the samples were flooded with the prepared brine solution until a water cut in excess of 99.9 per cent was reached. Volumes and rates of flow of both oil and water were measured continuously during this displacement. At the completion of the flood, effective permeabilities to brine were measured and the residual fluid saturations determined. From these laboratory data, the water-oil relative permeability relationships were calculated using a digital computer.

A summary of the basic flood results is presented on page two of this report. The calculated relative permeability relationships are shown tabularly on pages three through five and graphically on pages six through fourteen.

Upon calculation of the results, it was observed that a large increase in permeability had occurred during flood. In view of this, the samples were thoroughly cleaned and dried and their air permeabilities remeasured. Results of this second set of air permeability measurements are shown on page two and indicate an increase in specific permeability ranging from roughly five to fifteen hundred per cent. A thorough study of the core samples indicated them to contain an anhydrite cementation which was partially removed by the flood water thereby increasing the permeability. Similar performance in the reservoir would increase significantly the effective permeability in the vicinity of the injection wells. It might not significantly influence the productive behavior of the reservoir, however, since the water at the flood front would be saturated with the anhydrite. In applying the relative permeability data presented here, this change in physical properties during testing must be considered.

It should be noted that approximately two hundred pore volumes of brine were flooded through these test samples. Roughly half of this volume of water was injected between the last two measured points. Similarly, half of the remaining water, or one-fourth of the total, occurred between the next to last two points. Since the rate of change of effective permeability would, presumably, be proportional to the amount of water throughput, most of the change in permeability should have occurred during the latter phases of the testing. Effects of this change in pore geometry should not have significantly changed the laboratory results in the low water saturation range. Of note, is the performance of the Kw/K curves for samples numbered 1 and 4. These curves appear normal over a large range of water saturation. At the high water saturation, however, they become very steep, indicating the permeability to be changing very rapidly in the latter stages of the flood. Samples number two and three showed the least change in specific permeability. The relative permeability curves, Kw/K and Ko/K for these two samples have been calculated twice; one set of data being based on the air permeability measured prior to flood and one set based on the air permeability obtained after flood. The performance observed on sample number five was extremely erratic and the individual curves have not been presented.

We are pleased to be of service.

Very truly yours,

Core Laboratories, Inc.

W. R. Aufricht, Engineer in Charge
Special Core Analysis Laboratory

WRA:ds
7 cc. - Addressee

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File SCAL 57205

Company Sun Oil Company
Number of Wells Four
Field Harms Worth Area
Formation
County
State Manitoba, Canada

Identification of Samples

Sample Number	Company	Well		Depth, Feet
1	Sun Oil Company	H. McLaren 6-20	CRINOIDAL	2044.0-2045.0
2		T. L. Tapp 16-22	cherty	1987.0-1988.0
3		H. McLaren 6-20	cherty	2096.0-2097.0
4		W. C. Tapp 9-27	cherty	2003.0-2004.0
5		Sun McLaren 4-20	cherty	2081.7-2082.5

Summary of Water Flood Data

Sample Number	Permeability, Millidarcys: To Air, Before Flood	To Air, After Flood	To Oil With Connate Water Present	To Water At Residual Oil Saturation	Porosity, Per Cent	Connate Water, Per Cent Pore Space	Oil in Place, Per Cent Pore Space	Residual Oil Saturation, Per Cent Pore Space	Oil Recovered, Per Cent Oil in Place
1	1.9	21	1.73	4.6	11.3	18.7	81.3	15.2	81.4
2	4.4	7.9	4.3	0.32	14.0	7.8	92.2	32.8	64.4
3	5.0	10	8.0	1.9	14.1	19.4	80.6	17.2	78.6
4	5.4	88	6.4	13.3	11.1	8.1	91.9	32.2	66.0
5	8.4	9.3	6.3	0.52	10.7	16.1	83.9	29.7	64.6

Flood data

Summary of Water Flood Data

Sample Number	Permeability, Millidarcys: To Air, Before Flood	To Air, After Flood	To Oil With Connate Water Present	To Water At Residual Oil Saturation	Porosity, Per Cent	Connate Water, Per Cent Pore Space	Oil in Place, Per Cent Pore Space	Residual Oil Saturation, Per Cent Pore Space	Oil Recovered, Per Cent Oil in Place
1	1.9	21	1.73	4.6	11.3	18.7	81.3	15.2	81.4
2	4.4	7.9	4.3	0.32	14.0	7.8	92.2	32.8	64.4
3	5.0	10	8.0	1.9	14.1	19.4	80.6	17.2	78.6
4	5.4	88	6.4	13.3	11.1	8.1	91.9	32.2	66.0
5	8.4	9.3	6.3	0.52	10.7	16.1	83.9	29.7	64.6

Flood data 273.6 / 4 = 68.4% of OIP

Summary of Water Flood Data

Sample Number	Permeability, Millidarcys: To Air, Before Flood	Permeability, Millidarcys: To Air, After Flood	Permeability, Millidarcys: To Oil With Connate Water Present	Permeability, Millidarcys: To Water At Residual Oil Saturation	Porosity, Per Cent	Connate Water, Per Cent Pore Space	Oil in Place, Per Cent Pore Space	Residual Oil Saturation, Per Cent Pore Space	Oil Recovered, Per Cent Oil in Place
1	1.9	21	1.73	4.6	11.3	18.7	81.3	15.2	81.4
2	4.4	7.9	4.3	0.32	14.0	7.8	92.2	32.8	64.4
3	5.0	10	8.0	1.9	14.1	19.4	80.6	17.2	78.6
4	5.4	88	6.4	13.3	11.1	8.1	91.9	32.2	66.0
5	8.4	9.3	6.3	0.52	10.7	16.1	83.9	29.7	64.6

Flood Clarity $\frac{273.6}{4} = 68.4\%$ of OIP

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

Water-Oil Relative Permeability Data

Sample Number:	1	2	3	4	5	
Air Permeability, Md.:	1.9	4.4	5.0	5.4	8.4	
Porosity, Per Cent Bulk:	11.3	14.0	14.1	11.1	10.7	
Initial Water Saturation, Per Cent Pore Space:	18.7	7.8	19.4	8.1	16.1	
Water Saturation, Per Cent Pore Space	**Water-Oil Relative Permeability Ratio**					[illegible]
15				.045		
20		.033		.142	.122	
25		.130		.305	.345	
30	.021	.239	.048	.575	.64	.231
35	.081	.415	.147	1.01	1.14	.679
40	.261	.740	.305	1.830	2.050	1.231
45	.71	1.41	.56	3.50	3.75	2.305
50	1.55	3.05	1.10	7.00	7.30	4.618
55	3.4	8.5	2.1	15.3	15.0	10.225
60	7.8	36.00	4.25	42.50	38.00	30.18
65	18		9.7	285	195	[illegible]
70	44.5		26.0			
75	119		79.0			
80	370		280.0			

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File SCAL 57205

Water-Oil Relative Permeability Data

Relative Permeability to Oil

Sample Number:	1	2	3	4	5
Air Permeability, Md.:	1.9	4.4	5.0	5.4	8.4
Porosity, Per Cent Bulk:	11.3	14.0	14.1	11.1	10.7
Initial Water Saturation, Per Cent Pore Space:	18.7	7.8	19.4	8.1	16.1

Water Saturation, Per Cent Pore Space	Relative Permeability to Oil, Fraction				
15		.418		.465	
20		.260		.305	
25	.710	.182	.460	.223	
30	.196	.134	.332	.170	
35	.115	.100	.260	.129	
40	.069	.074	.193	.090	
45	.044	.048	.147	.058	
50	.029	.027	.107	.035	
55	.018	.012	.073	.019	
60	.010	.003	.045	.010	
65	.006		.023	.003	
70	.004		.011		
75			.004		
80			.001		

All data relative to measured air permeability.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File SCAL 57205

Water-Oil Relative Permeability Data

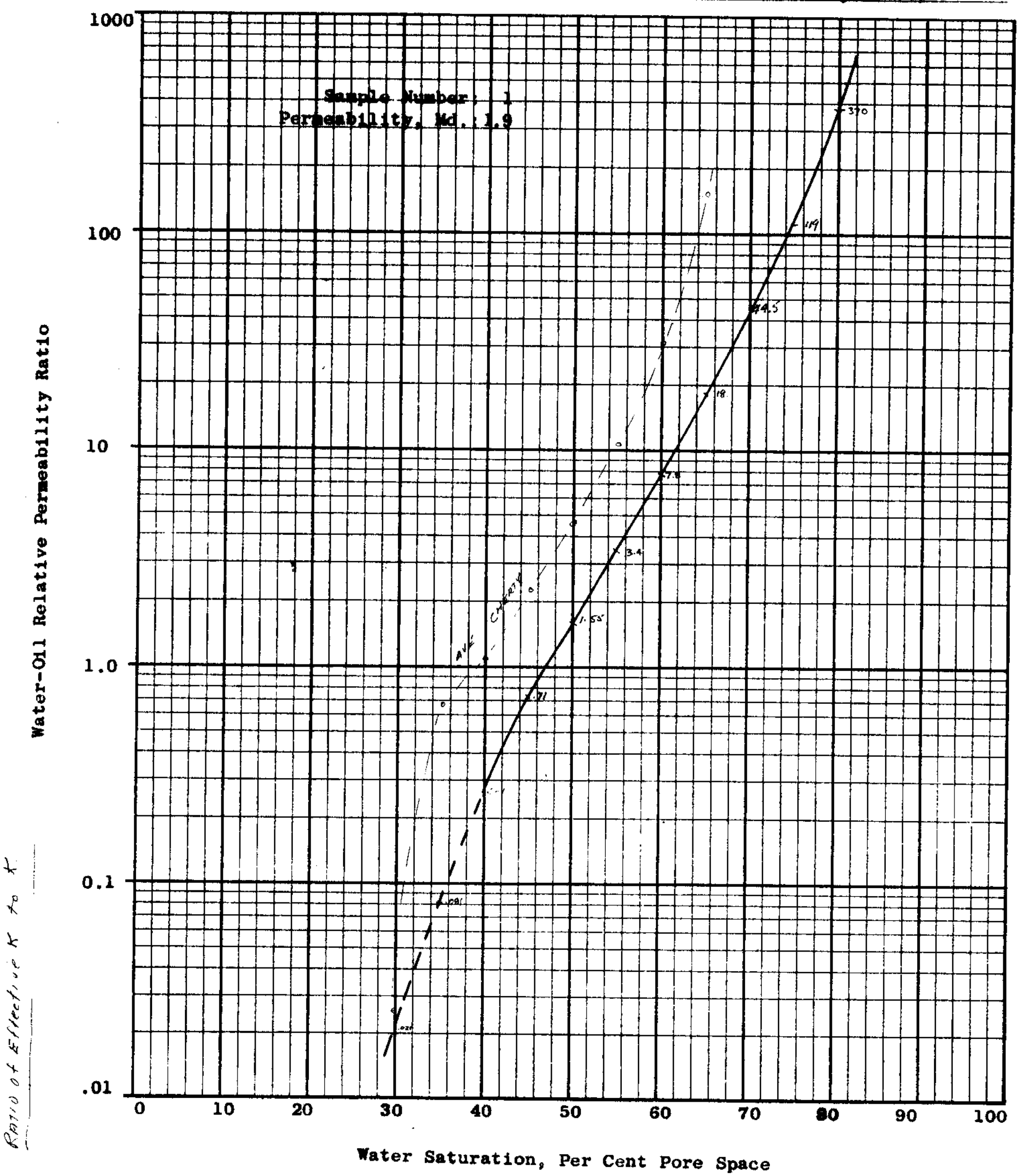
Relative Permeability to Water

Sample Number:	1	2	3	4	5
Air Permeability, Md.:	1.9	4.4	5.0	5.4	8.4
Porosity, Per Cent Bulk:	11.3	14.0	14.1	11.1	10.7
Initial Water Saturation, Per Cent Pore Space:	18.7	7.8	19.4	8.1	16.1

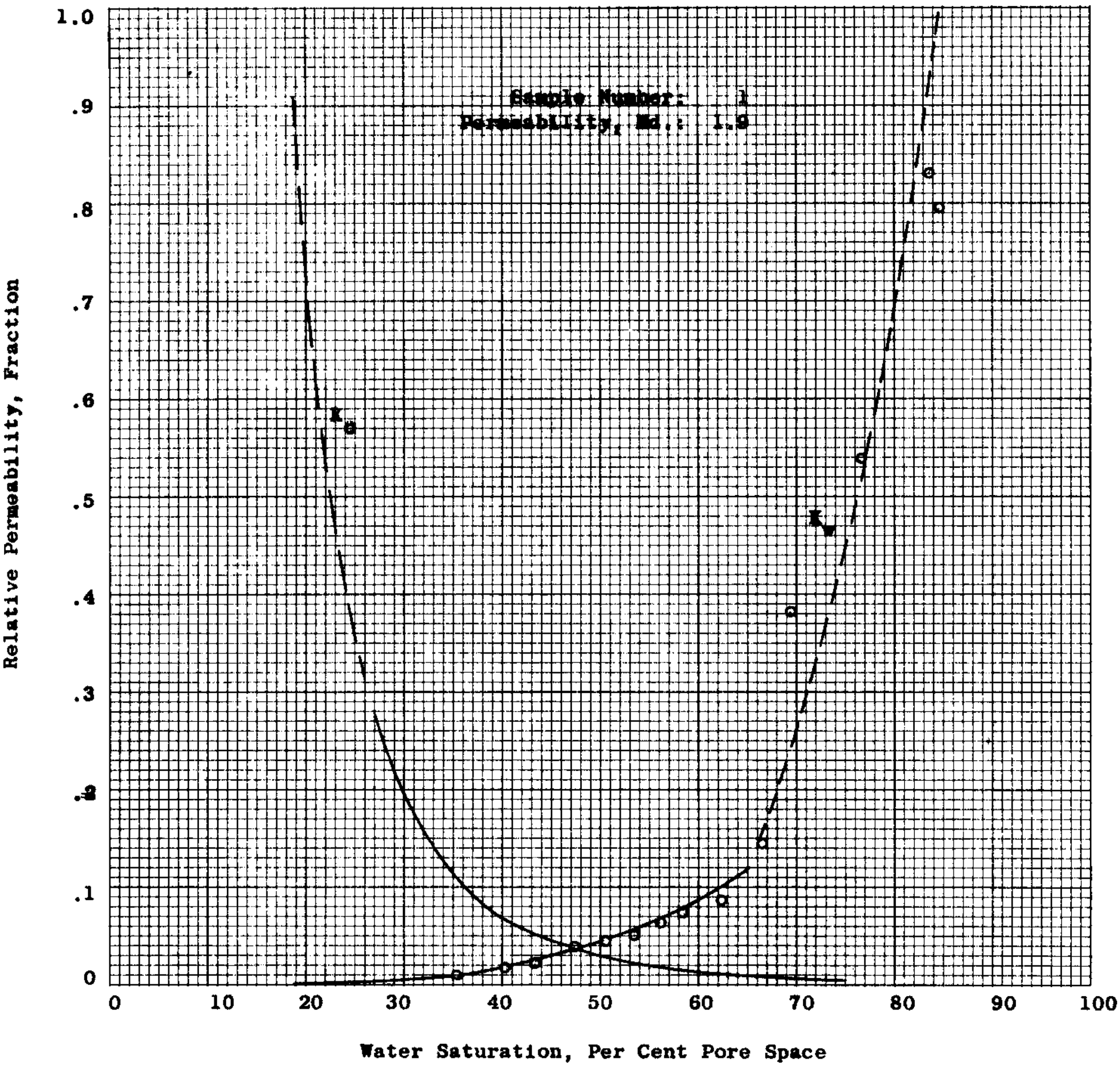
Water Saturation, Per Cent Pore Space	Relative Permeability to Water, Fraction				
15				.021	
20		.014		.043	
25	.001	.024		.068	
30	.004	.032	.016	.098	
35	.008	.043	.038	.130	
40	.018	.055	.059	.165	
45	.031	.068	.089	.202	
50	.045	.082	.118	.241	
55	.062	.094	.150	.290	
60	.087	.110	.191	.420	
65	.115		.230	.910	
70	.260		.273		
75	.450		.316		
80	.680		.360		

All data relative to measured air permeability.

Company Sun Oil Company
Well H. McLaren 6-20
Field Harms Worth Area
Formation
County
State Manitoba, Canada



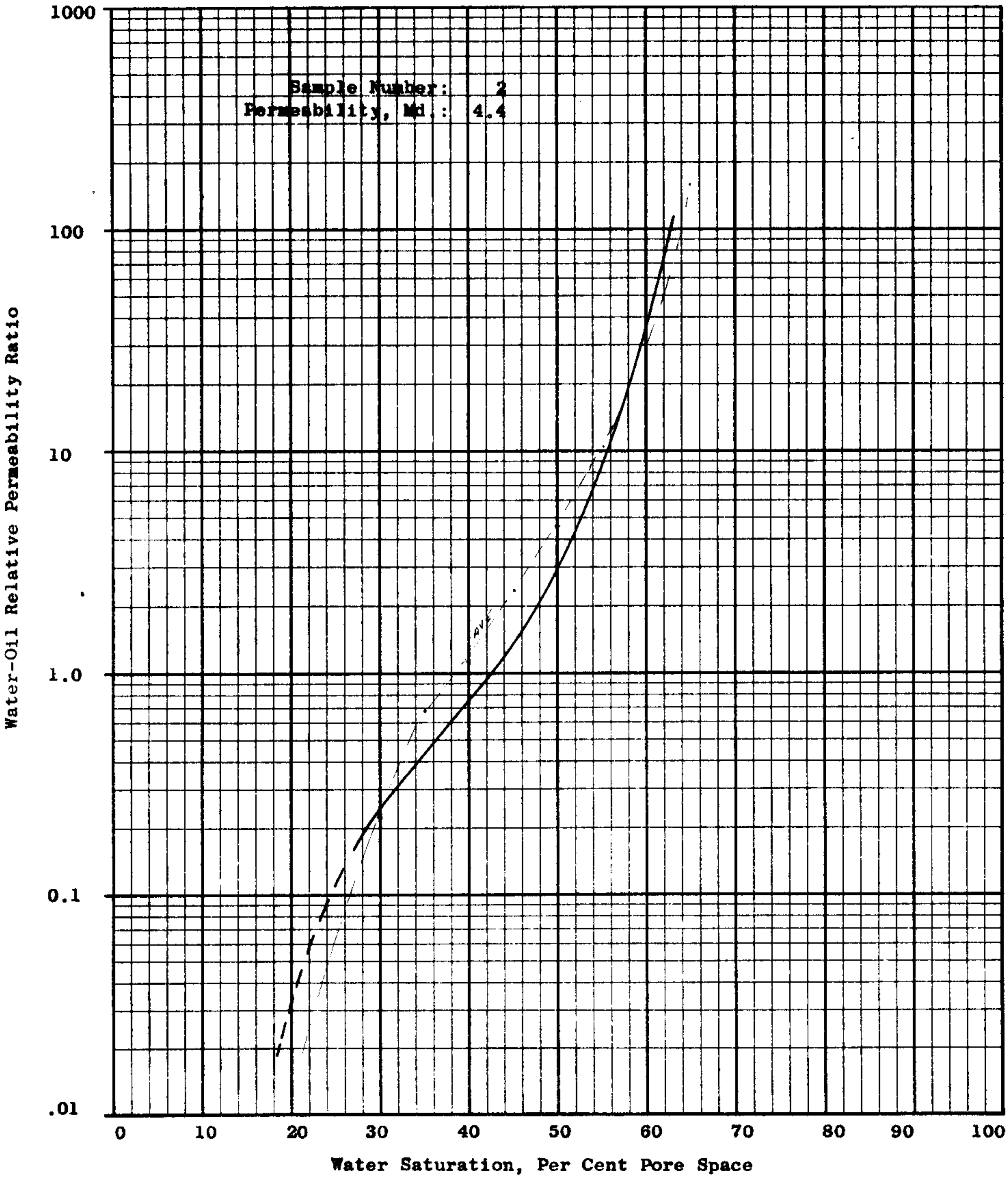
Company	Sun Oil Company	Formation	
Well	H. McLaren 6-20	County	
Field	Harms Worth Area	State	Manitoba, Canada



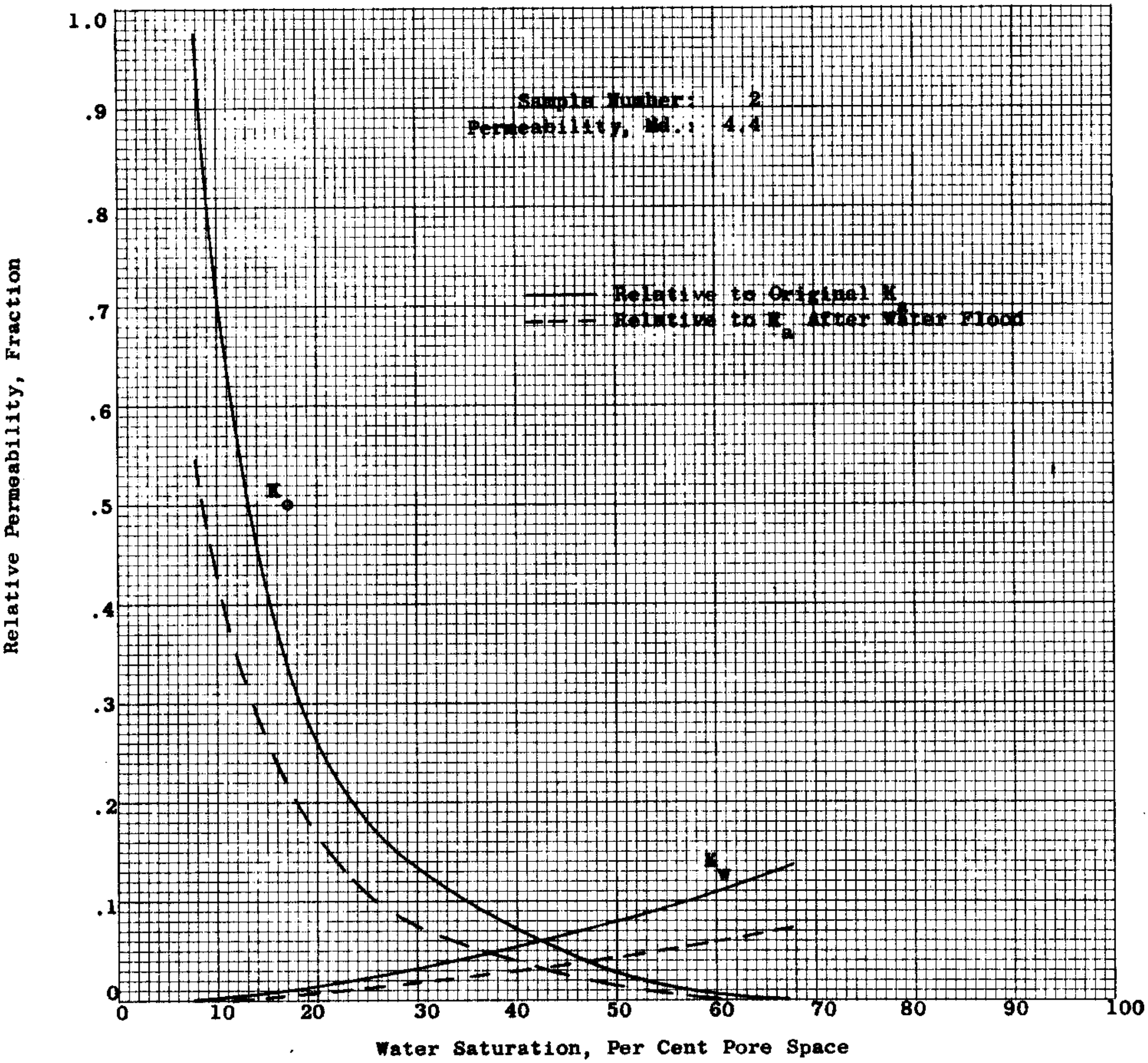
CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File SCAL-57205

Company Sun Oil Company Formation
Well T. L. Tapp 16-22 County
Field Harms Worth Area State Manitoba, Canada



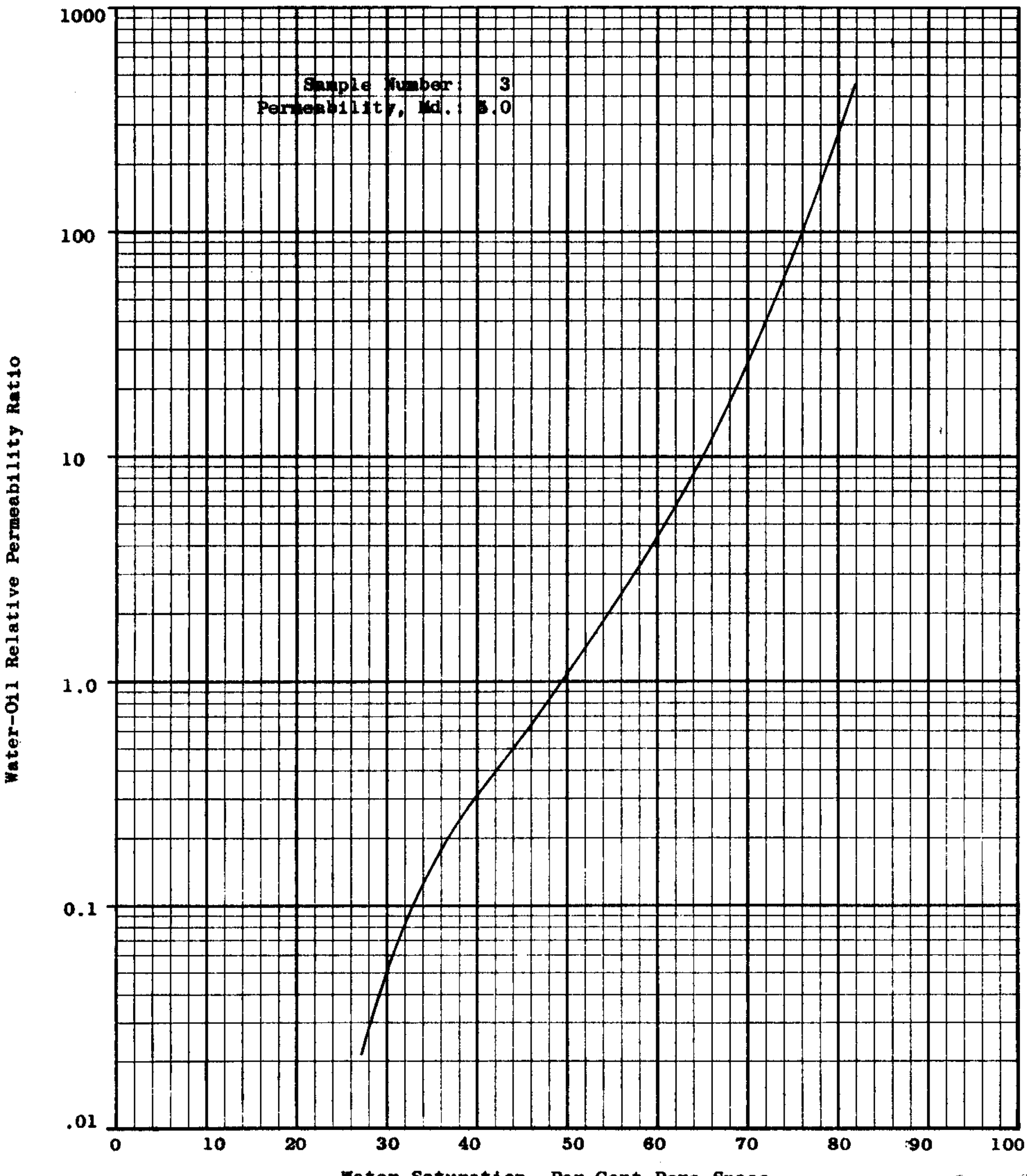
Company Sun Oil Company
Well T. L. Tapp 16-22
Field Harms Worth Area
Formation
County
State Manitoba, Canada



CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

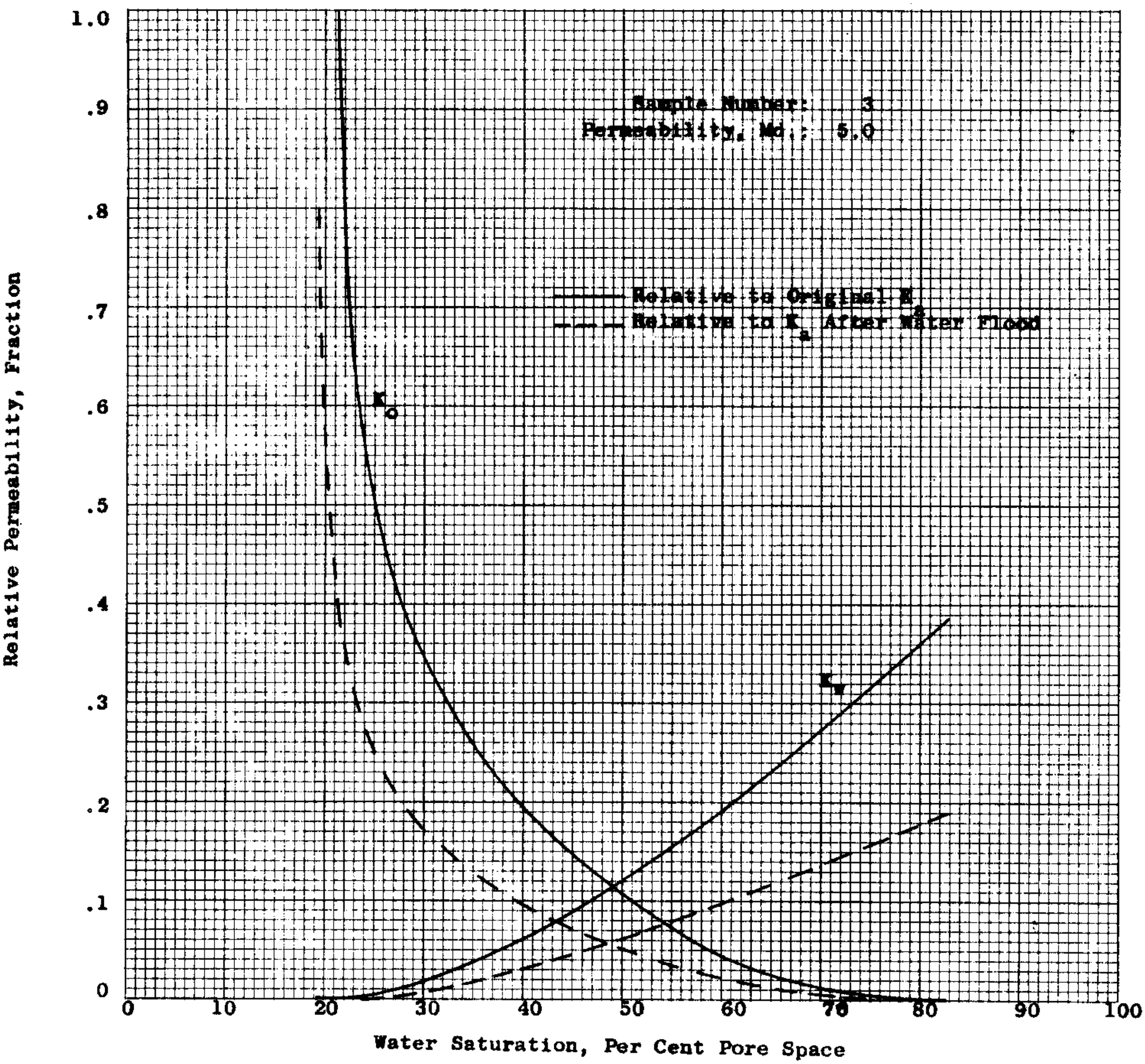
File SCAL-57205

Company Sun Oil Company
Formation
Well H. McLaren 6-20
County
Field Harms Worth Area
State Manitoba, Canada

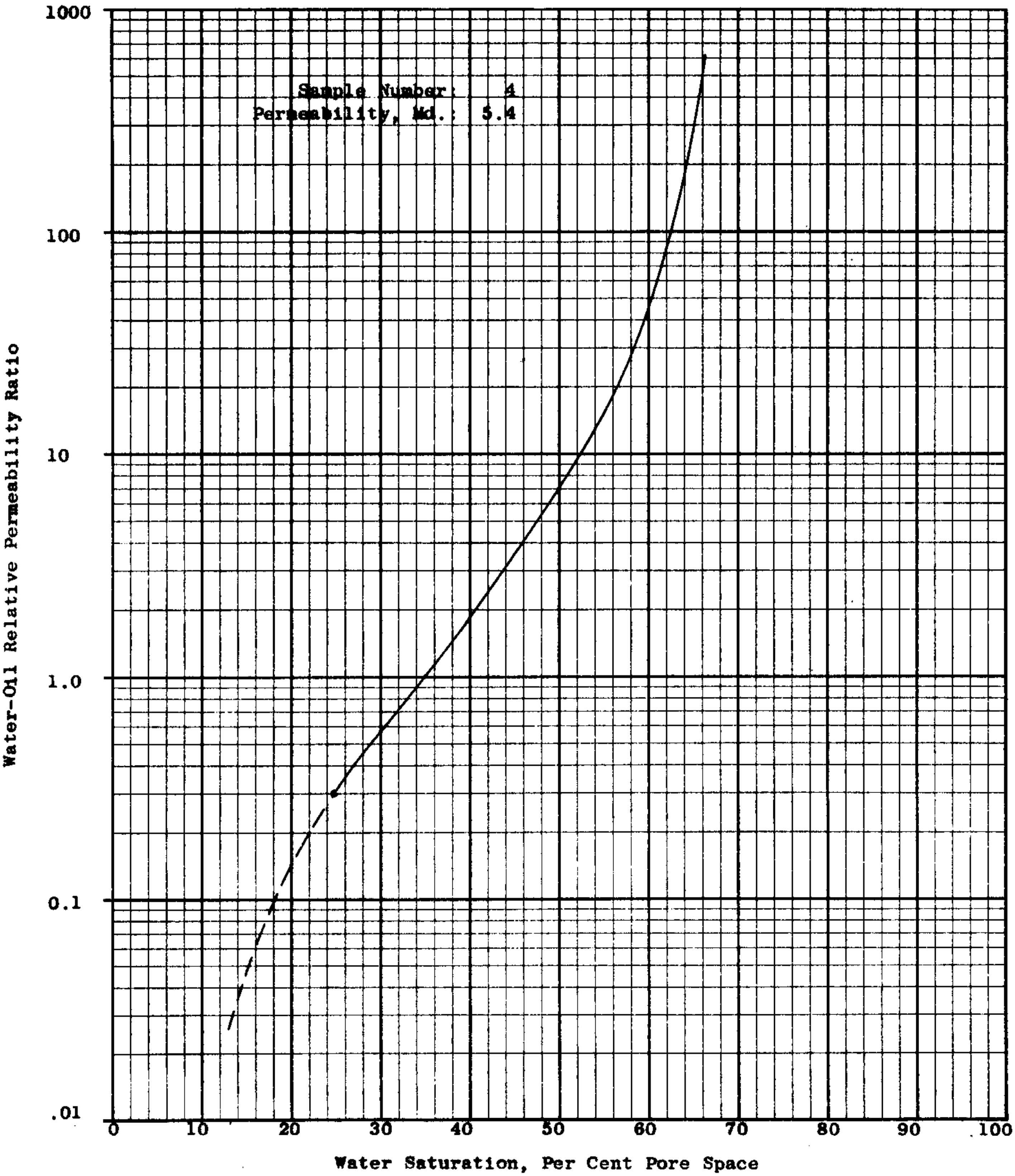


percentage of Total Pore Volume -

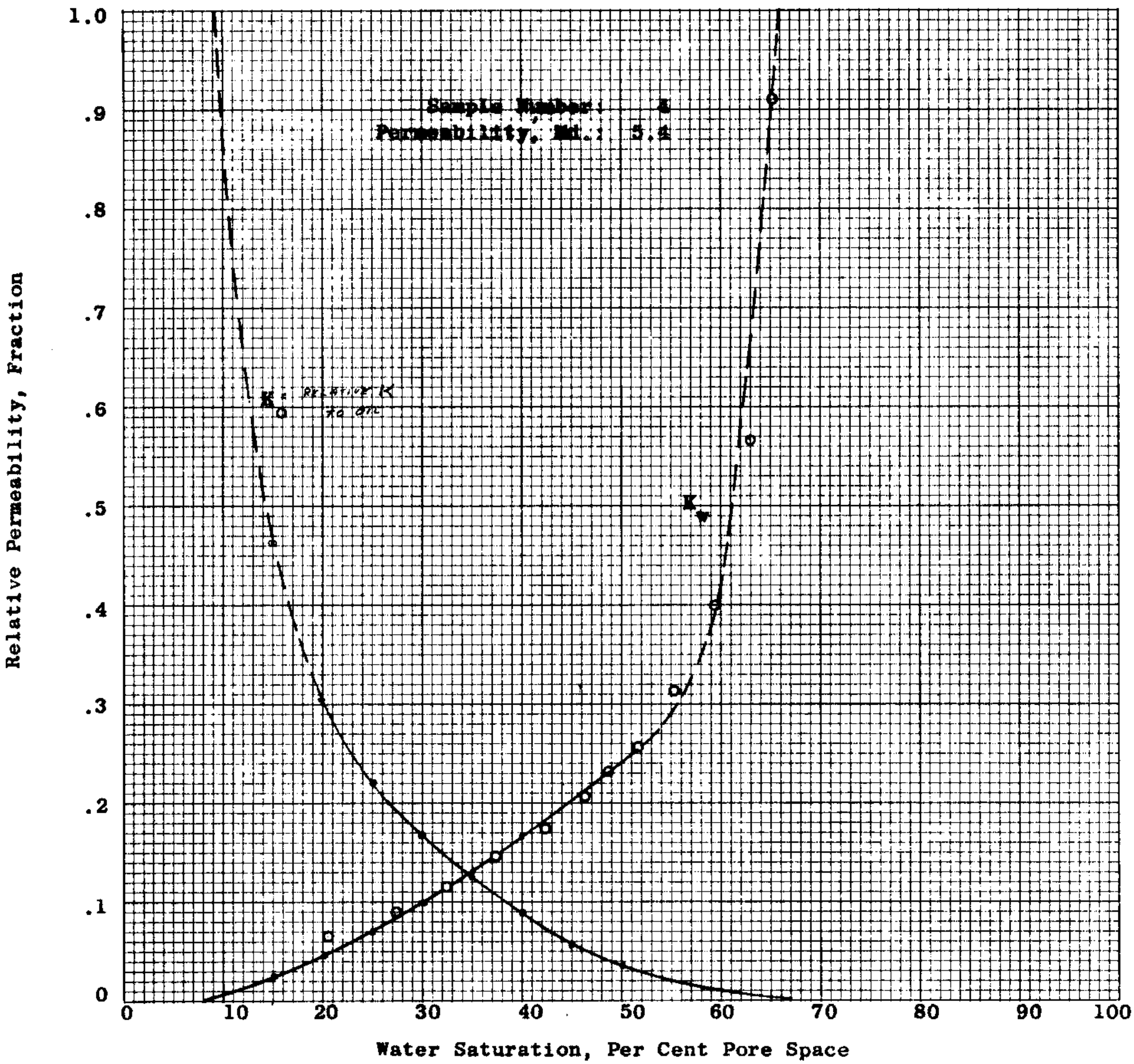
Company **Sun Oil Company** Formation
Well **H. McLaren 6-20** County
Field **Harms Worth Area** State **Manitoba, Canada**



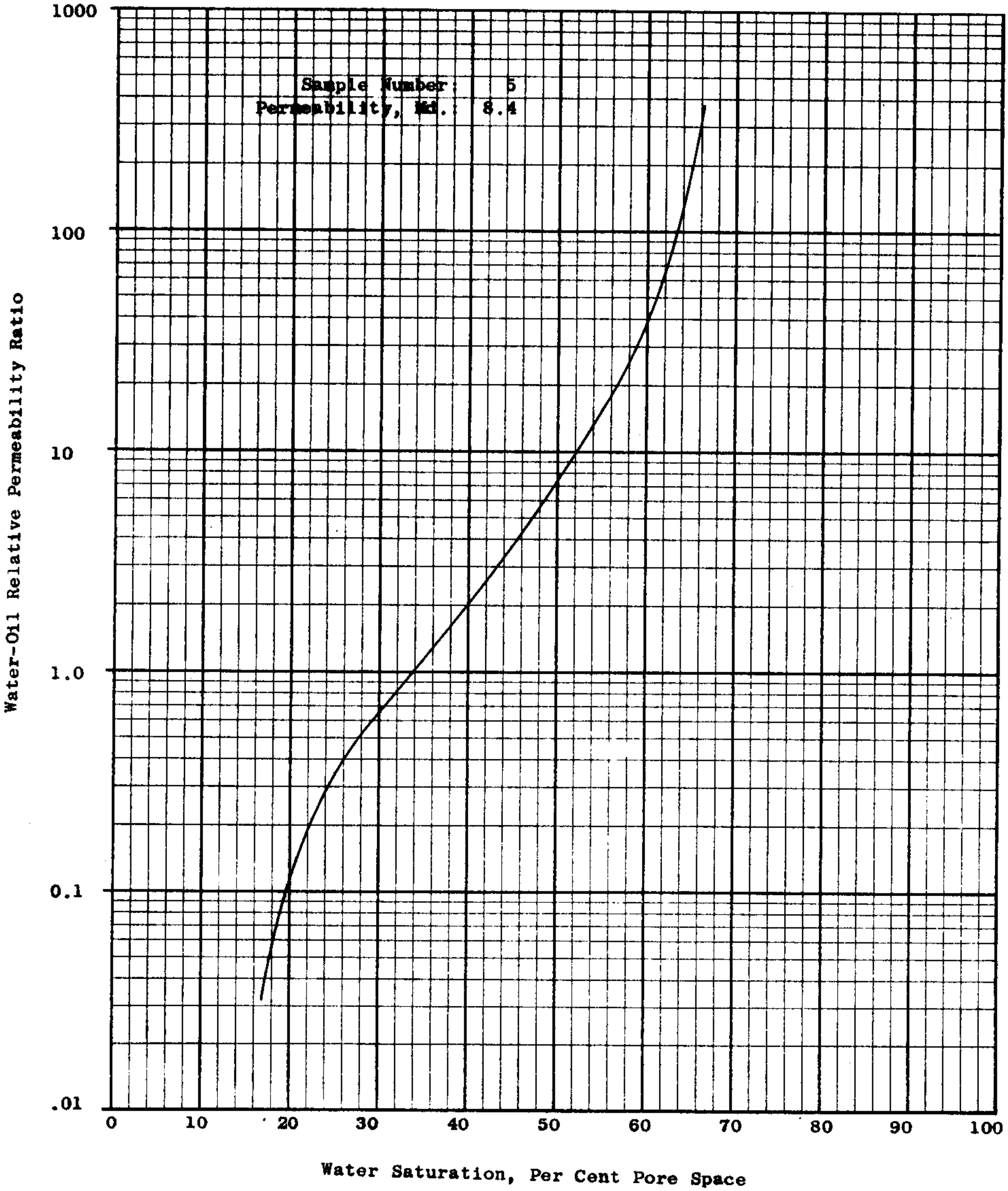
Company Sun Oil Company
Well W. C. Tapp 9-27
Field Harms Worth Area
Formation
County
State Manitoba, Canada



Company **Sun Oil Company** Formation
Well **W. C. Tapp 9-27** County
Field **Harms Worth Area** State **Manitoba, Canada**



Company Sun Oil Company
Well Sun McLaren 4-20
Field Harms Worth Area
Formation
County
State Manitoba, Canada



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CAPILLARY PRESSURE - SATURATION RELATIONSHIPS

FOR

SUN OIL COMPANY

SCALLION FIELD

MANITOBA, CANADA

2-20-11-26

CORE

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

May 22, 1957

Sun Oil Company
2041 Hamilton Street
Regina, Saskatchewan, Canada

Attention: Mr. J. W. Crate

Subject: Capillary Pressure-Saturation Relationships
Scallion Field
Manitoba, Canada
Our File No. SCAL-5745

2-20-11-26

Gentlemen:

Presented herewith are the results of mercury injection capillary pressure tests performed on samples of formation recovered from the subject field. The cores used in making this study were taken from the Sun Clarke No. 2-20 Well and are identified as to depth on page one of the attached report.

Large cylindrical plugs, an inch and one-half in diameter and approximately two inches long, were cut from the whole core samples forwarded to this laboratory. The cylindrical plugs were extracted, leached, and dried, and their air permeabilities and porosities were measured. Mercury injection capillary pressure measurements were then made by first evacuating the samples and then injecting mercury at increasing pressure increments from zero to 1800 PSIA.

The results obtained are recorded tabularly on page two of this report in which the wetting phase saturation (equivalent to water saturation in a water-wet reservoir) are shown as a function of absolute pressure. A graphical presentation of these data from zero to 1000 PSIA is shown on pages three through eight.

We are pleased to be of service.

Very truly yours,

Core Laboratories, Inc.

W.R. Aufricht

W. R. Aufricht, Engineer in Charge
Special Core Analysis Laboratory

WRA:sw
7 cc. - Addressee

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File SCAL 5745

Company Sun Oil Company
Number of Wells One
Field Scallion
Formation
County
State Manitoba, Canada

Identification of Samples

Sample Number	Company	Well	Depth, Feet
1	Sun Oil Company	Sun Clarke No. 2-20	6710
2			6834
3			? 6705
4			6827
5			6713
6			6831

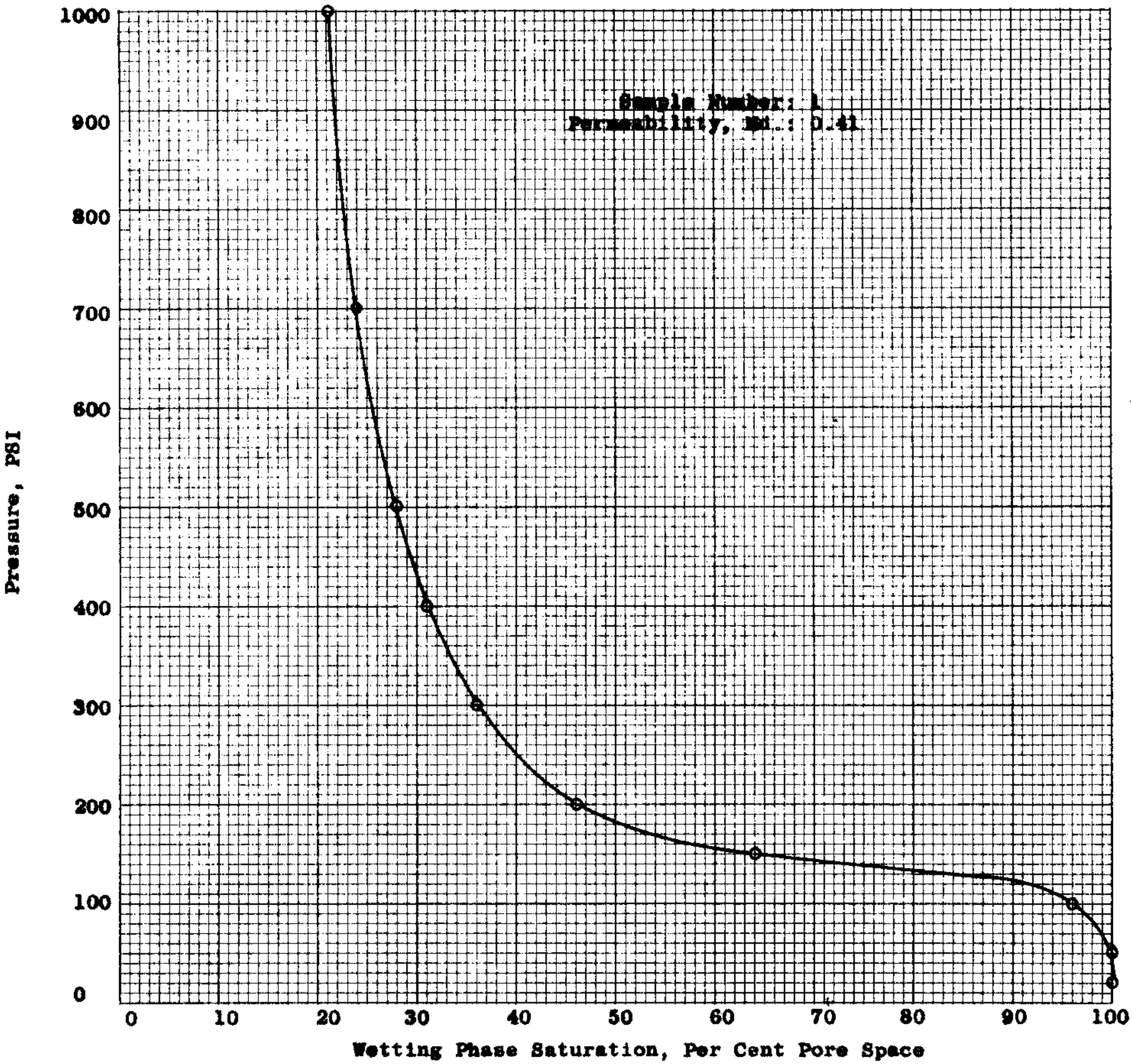
Mercury Injection Capillary Pressure Data

Sample Number:	1	2	3	4	5	6
Permeability, Md.:	0.41	0.44	0.57	0.67	1.0	9.3
Porosity, Per Cent:	6.6	5.9	7.1	9.4	12.5	12.6
Injection Pressure, PSIA	**Wetting Phase Saturation, Per Cent Pore Space**					
20	100	100	100	100	100	88
50	100	99	94	98	100	62
100	96	95	63	69	73	39
150	64	89	44	56	39	29
200	46	82	34	47	29	24
300	36	67	25	38	20	19
400	31	57	20	34	16	17
500	28	50	18	31	13	15
700	24	41	15	28	10	13
1000	21	32	12	24	8	11
1400	18	25	9	21	6	8
1800	16	20	7	19	5	7

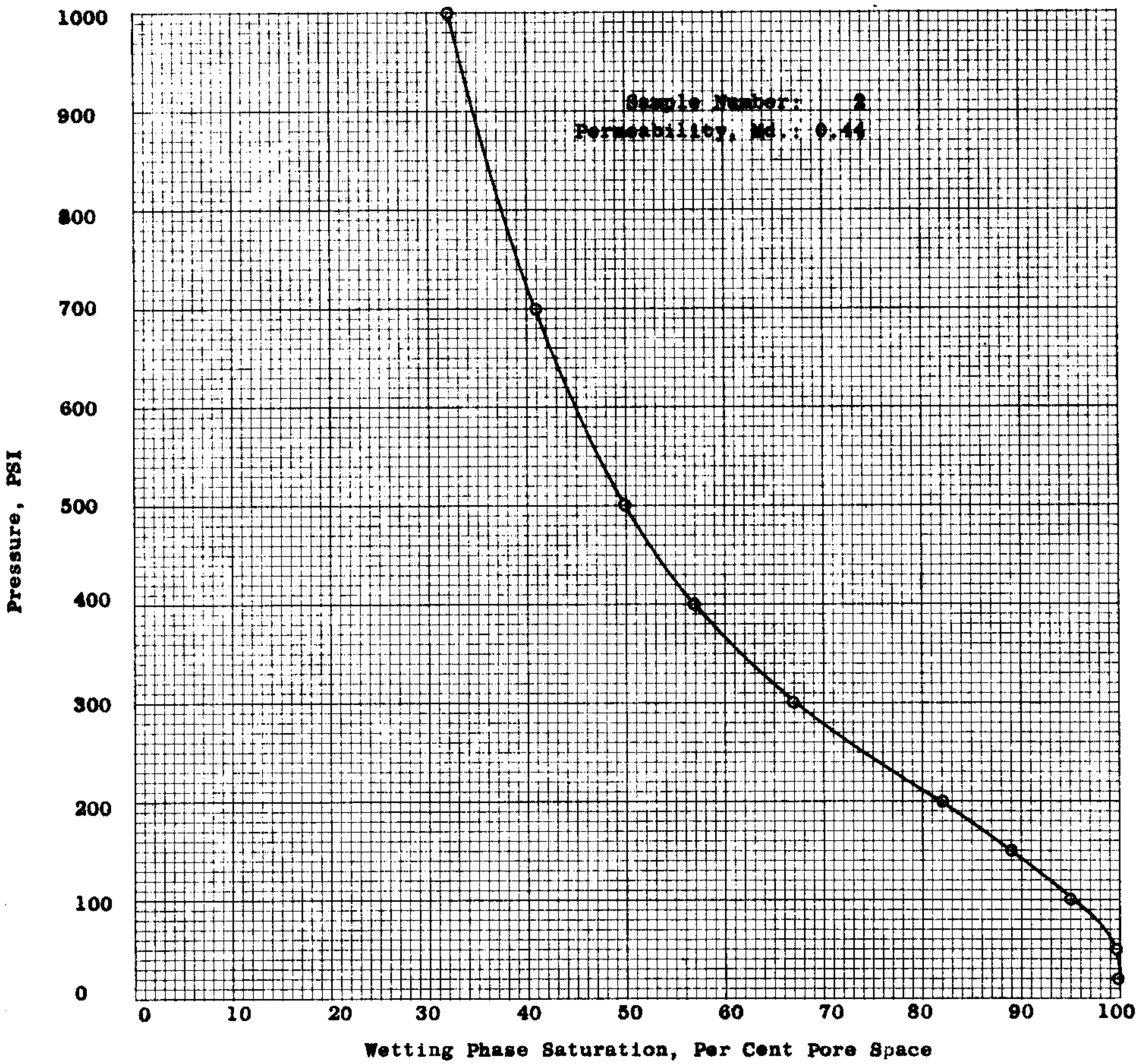
CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File SCAL-5745

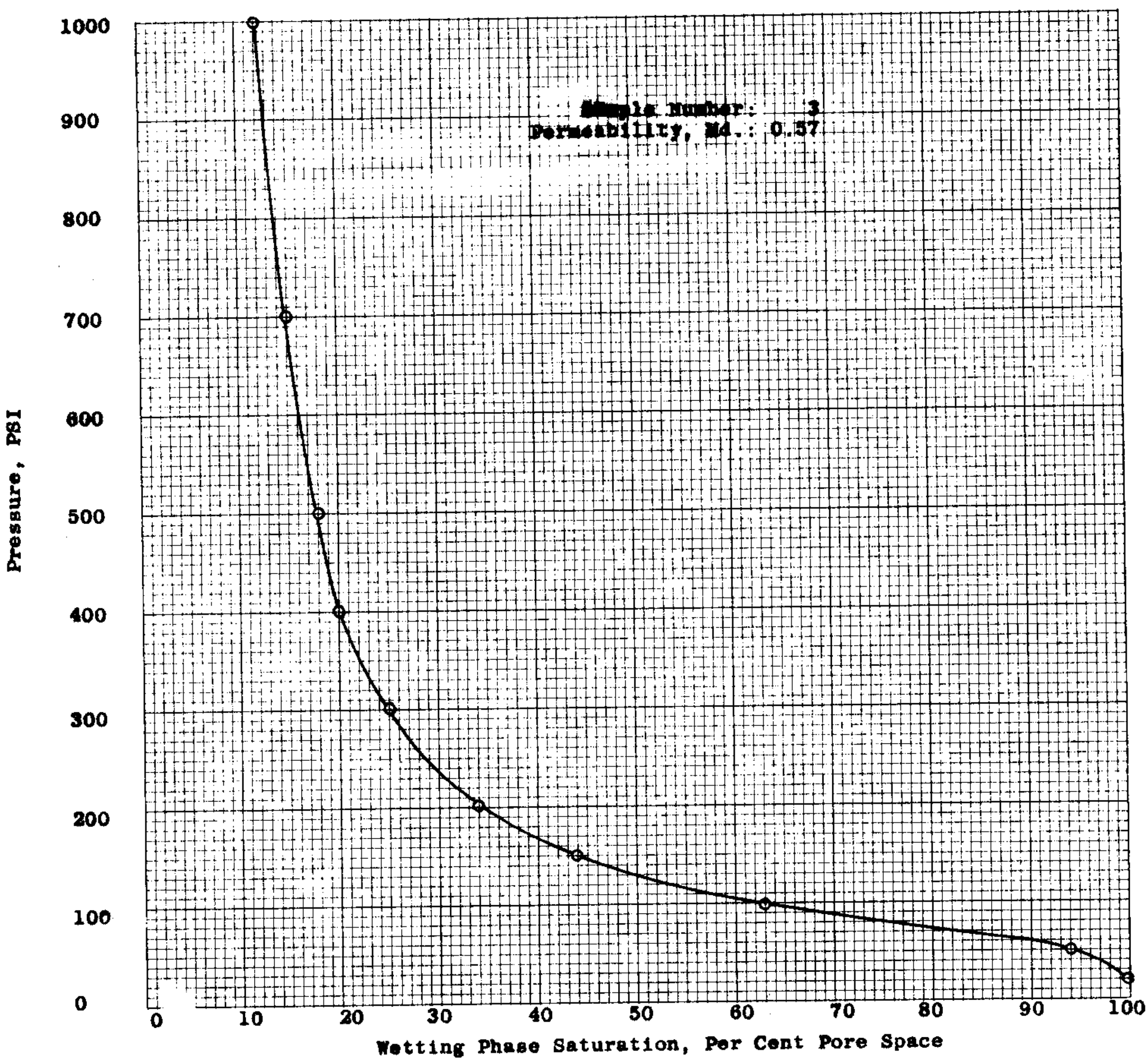
Company Sun Oil Company
Well Sun Clarke #2-20
Field Scallion
Formation -
County -
State Manitoba, Canada



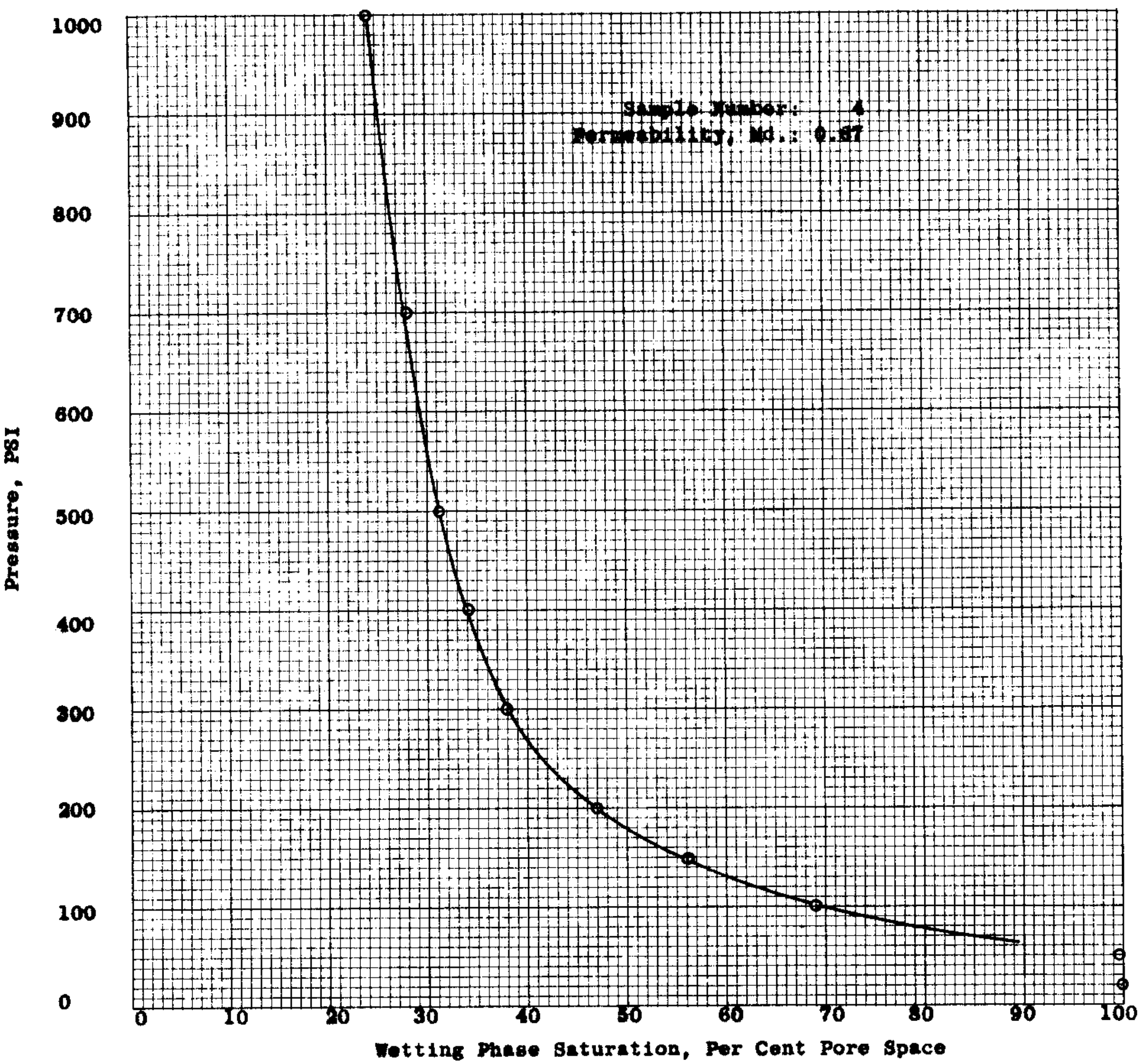
Company Sun Oil Company
Well Sun Clarke #2-20
Field Scallion
Formation -
County -
State Manitoba, Canada



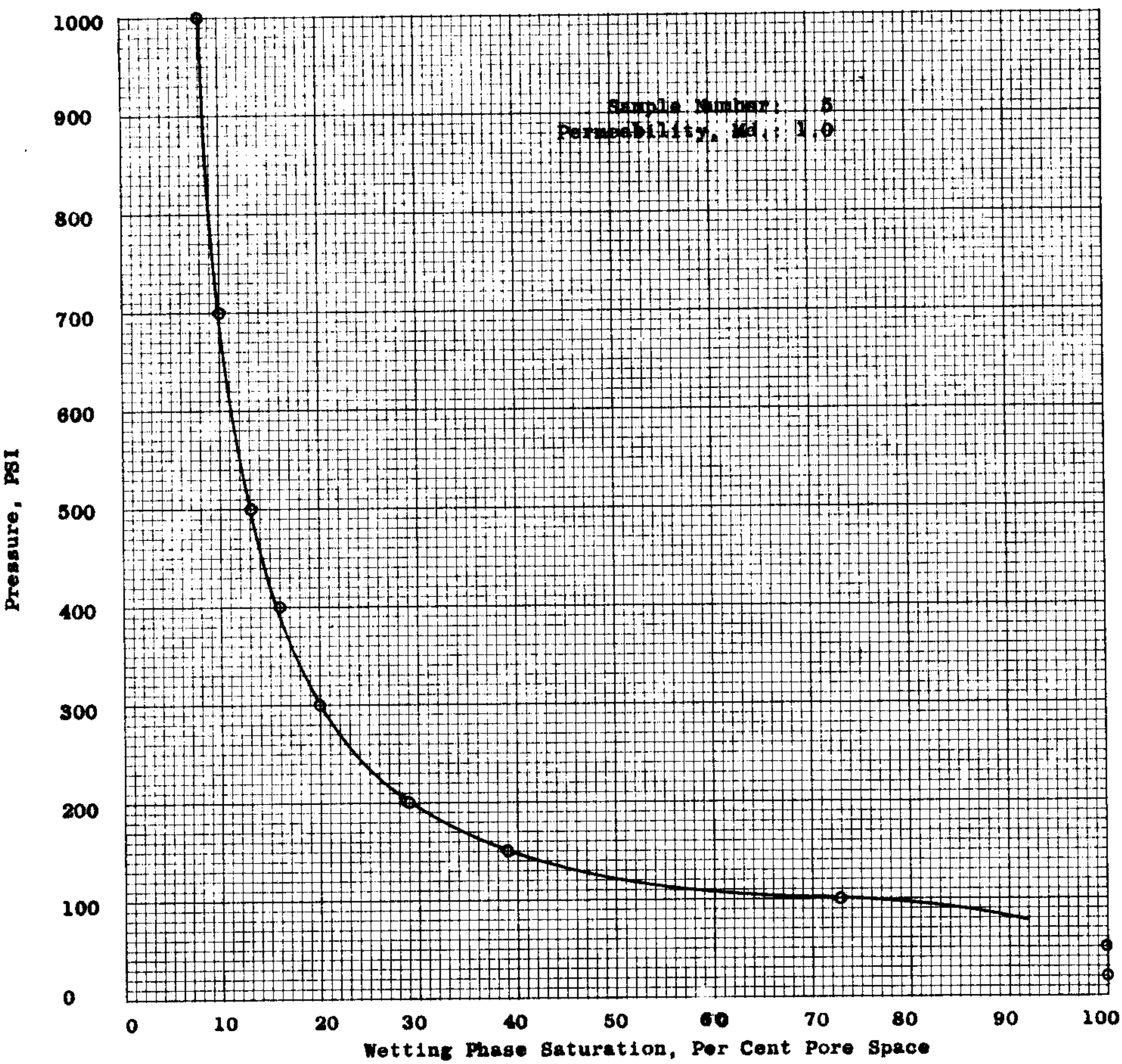
Company Sun Oil Company
Well Sun Clarke #2-20
Field Scallion
Formation -
County -
State Manitoba, Canada



Company **Sun Oil Company** Formation -
Well **Sun Clarke #2-20** County -
Field **Scallion** State **Manitoba, Canada**



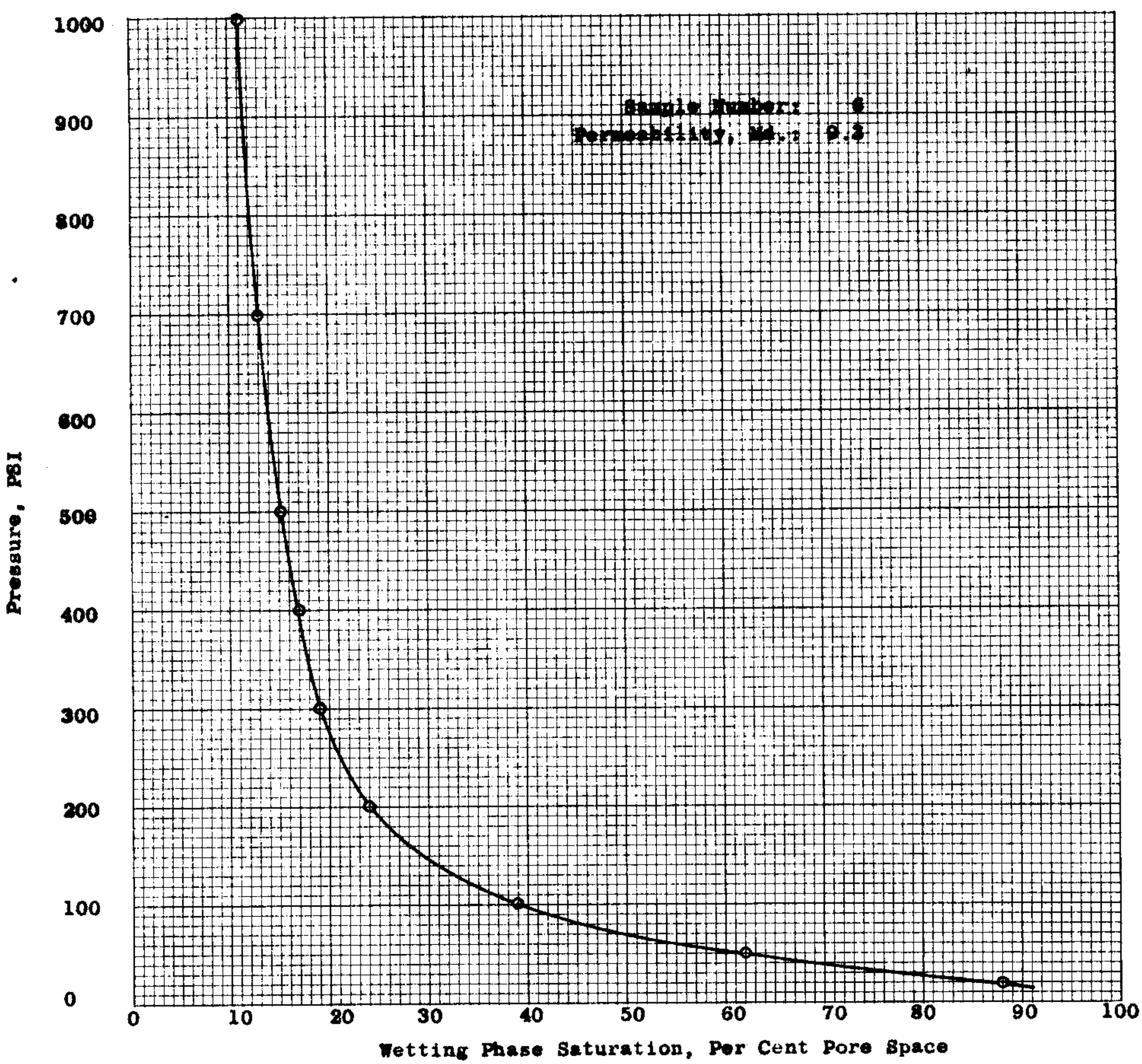
Company Sun Oil Company
Well Sun Clarke #2-20
Field Scallion
Formation -
County -
State Manitoba, Canada



CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File SCAL-5745

Company Sun Oil Company
Well Sun Clarke #2-20
Field Scallion
Formation -
County -
State Manitoba, Canada



Dup

RESERVOIR FLUID STUDY

FOR

THE CALIFORNIA STANDARD COMPANY

SCALLION NO. 3-21 WELL -11-26

NORTH VIRDEN FIELD

MANITOBA, CANADA

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

July 9, 1956

RESERVOIR FLUID DIVISION

The California Standard Company
Medical Arts Building
Calgary, Alberta, Canada

Subject: Reservoir Fluid Study
Scallion No. 3-21 Well
North Virden Field
Manitoba, Canada

Gentlemen:

This report presents the results of fluid studies performed using subsurface samples collected from the subject well by a representative of Core Laboratories, Inc.

The saturation pressure of the fluid was measured to be 135 psig at the reservoir temperature of 83° F. The static reservoir pressure, measured prior to sampling, was 768 psig. Comparison of these two pressure values indicates that the reservoir presently exists in a highly undersaturated condition.

A sample of the fluid was subjected to differential pressure depletion at the reservoir temperature of 83° F. Under these conditions, the fluid evolved 67 standard cubic feet of gas per barrel of residual oil with an attendant formation volume factor of 1.049 barrels of saturated fluid per barrel of residual oil. Under similar depletion conditions, the viscosity of the fluid was measured at pressures exceeding reservoir pressure to atmospheric pressure and varied from a minimum of 3.220 centipoises at saturation pressure to 6.165 centipoises at atmospheric pressure.

Low temperature fractional distillation of the fluid indicated less than one mol per cent of methane with a very substantial quantity of the components ethane through hexanes. The effects of this unusual distribution may be seen in the differential vaporization curves and the viscosity curve. As pressure was reduced, the fluid was comparatively inactive until pressures of approximately 30 psig were reached. Below this pressure, much larger quantities of gas were evolved resulting in a greater shrinkage and increased viscosity.

It was a pleasure to cooperate with you in performing this study. If we may be of further assistance, please do not hesitate to notify us.

Very truly yours,

Core Laboratories, Inc.
Reservoir Fluid Division

P L Moses

P. L. Moses,
Operations Supervisor

PLM:dd
12cc. - Addressee

Form 69385

CORE LABORATORIES, Inc.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 696

Company	The California Standard Company	Date Sampled	May 29, 1956
Well	Scallion No. 3-21	County	
Field	North Virden	State	Manitoba, Canada

FORMATION CHARACTERISTICS

Formation Name	Mississippian - Cherty Zone
Date First Well Completed	December, 1953
Original Reservoir Pressure	860 PSI @ - 520 ft.
Original Produced Gas-Oil Ratio	cu. ft./bbl.
Production Rate	bbl./d.
Separator Pressure and Temperature	PSI, ° F.
Oil Gravity at 60° F.	° API
Datum	490 ft. subsea
Original Gas Cap	

WELL CHARACTERISTICS

Elevation	1507 Feet Gnd., 1518 Feet KB
Total Depth	2078 ft.
Completion Depth	2070 PB ft.
Tubing Size and Depth	2 in. to 2066 ft.
Productivity Index	bbl./d./PSI @ bbl./d.
Last Reservoir Pressure	768 PSI @ 1997 ft.
Date	May 29, 1956
Reservoir Temperature	83 ° F. @ 1997 ft.
Status of Well	Shut-In 13 Days
Pressure Gauge	Amerada (CLI)
Normal Production Rate	75 bbl./d.
Gas-Oil Ratio	80 (Est) cu. ft./bbl.
Separator Pressure and Temperature	10 PSI, 140 ° F.
Base Pressure	PSI Abs.
Well Making Water	0.2 % Cut

SAMPLING CONDITIONS

Sampled at	2008 Feet KB
Status of Well	Shut-In 13 Days
Gas-Oil Ratio	cu. ft./bbl.
Separator Pressure and Temperature	PSI, ° F.
Tubing Pressure	40 PSI
Casing Pressure	PSI
Core Laboratories Engineer	CPG
Type Sampler	Perco

REMARKS:

Form 54001

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 696

Well Scallion No. 3-21

VOLUMETRIC DATA OF Reservoir Fluid SAMPLE

1. Saturation pressure (bubble-point pressure) 135 PSI @ 83 °F.

2. Thermal expansion of saturated oil @ 5000 PSI = $\frac{V @ 83\ °F}{V @ 76\ °F}$ = 1.00297

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

   From 5000 PSI to 3000 PSI = 4.59×10^{-6}

   From 3000 PSI to 1500 PSI = 5.18×10^{-6}

   From 1500 PSI to 135 PSI = 6.00×10^{-6}

4. Specific volume at saturation pressure: cu. ft./# 0.01923 @ 83 °F.

Form 50870

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 696

Well Scallion No. 3-21

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 83 °F., RELATIVE VOLUME OF OIL AND GAS, V/Vsat.	VISCOSITY OF OIL @ 83 °F., CENTIPOISES	DIFFERENTIAL LIBERATION @ 83 °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	0.9750				1.023
4000	0.9794				1.027
3000	0.9840				1.032
2000	0.9890				1.037
1500	0.9918				1.040
1400	0.9924				1.041
1300	0.9929				1.042
1200	0.9935				1.042
1100	0.9941				1.043
1005		3.532			
1000	0.9947				1.043
900	0.9954				1.044
855		3.484			
800	0.9960				1.045
715		3.434			
700	0.9966				1.045
600	0.9972				1.046
565		3.389			
500	0.9977				1.047
400	0.9983				1.047
385		3.321			
300	0.9990				1.048
270		3.283			
200	0.9995	3.263			1.048
135	1.0000	3.220	0	67	1.049
130	1.0025				
128	1.0050				
124	1.0086				
120	1.0123				
116	1.0160				
114	1.0230				
110			2	65	1.049

V — Volume at given pressure
$V_{SAT.}$ — Volume at saturation pressure at the specified temperature.
V_R — Residual Oil Volume at 14.7 PSI absolute and 60° F.

Form 50870

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 696

Well Scallion No. 3-21

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 83 °F., RELATIVE VOLUME OF OIL AND GAS, V/VSAT.	VISCOSITY OF OIL @ 83 °F., CENTIPOISES	DIFFERENTIAL LIBERATION @ 83 °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
103	1.0414				
100		3.333			
91	1.0783				
80	1.1274		4	63	1.048
70	1.1889				
62	1.2627				
61			7	60	1.047
60		3.337			
55	1.3612				
50	1.4720				
45	1.6320				
40	1.7977				
37			13	54	1.045
30	2.3479				
25			20	47	1.041
20		3.500			
0		6.165	67	0	1.010
				@ 60° F. =	1.000

Gravity of Residual Oil = 34.5°API @ 60° F.
Specific Gravity of Liberated Gas = 1.4629

V — Volume at given pressure
$V_{SAT.}$ — Volume at saturation pressure at the specified temperature.
V_R — Residual Oil Volume at 14.7 PSI absolute and 60° F.

Form 54802

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 696

Well Scallion No. 3-21

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	76	81		33.8	0.9398	1.064	1.4975
10	76	59	12	34.3	0.9470	1.056	
30	76	27	34	34.5	0.9542	1.048	
50	76	8	50	34.4	0.9542	1.048	

(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 @ 135 PSI gauge and 83 ° F.

(3) Formation Volume Factor: $V_{SAT.}/V_R$ is barrels of saturated oil @ 135 PSI gauge and 83 °F. per barrel of stock tank oil @ 60° F.

Form 55849

CORE LABORATORIES, INC.

Petroleum Reservoir Engineering

DALLAS, TEXAS

File RFL 696

Company The California Standard Company Formation Mississippian - Cherty Zone

Well Scallion No. 3-21 County

Field North Virden State Manitoba, Canada

HYDROCARBON ANALYSIS OF Reservoir Fluid SAMPLE

COMPONENT	WEIGHT %	MOL %	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Nitrogen	0.07	0.47			
Methane	0.07	0.75			
Ethane	0.79	4.74			
Propane	1.70	6.99			
Iso-butane	0.66	2.06			
N-butane	1.79	5.55			
Iso-pentane	1.31	3.28			
N-pentane	1.11	2.78			
Hexanes	2.93	6.15			
Heavier	89.57	67.23	0.8764	29.8	241
	100.00	100.00			

Core Laboratories, Inc.
Reservoir Fluid Division

P L Moses (f)

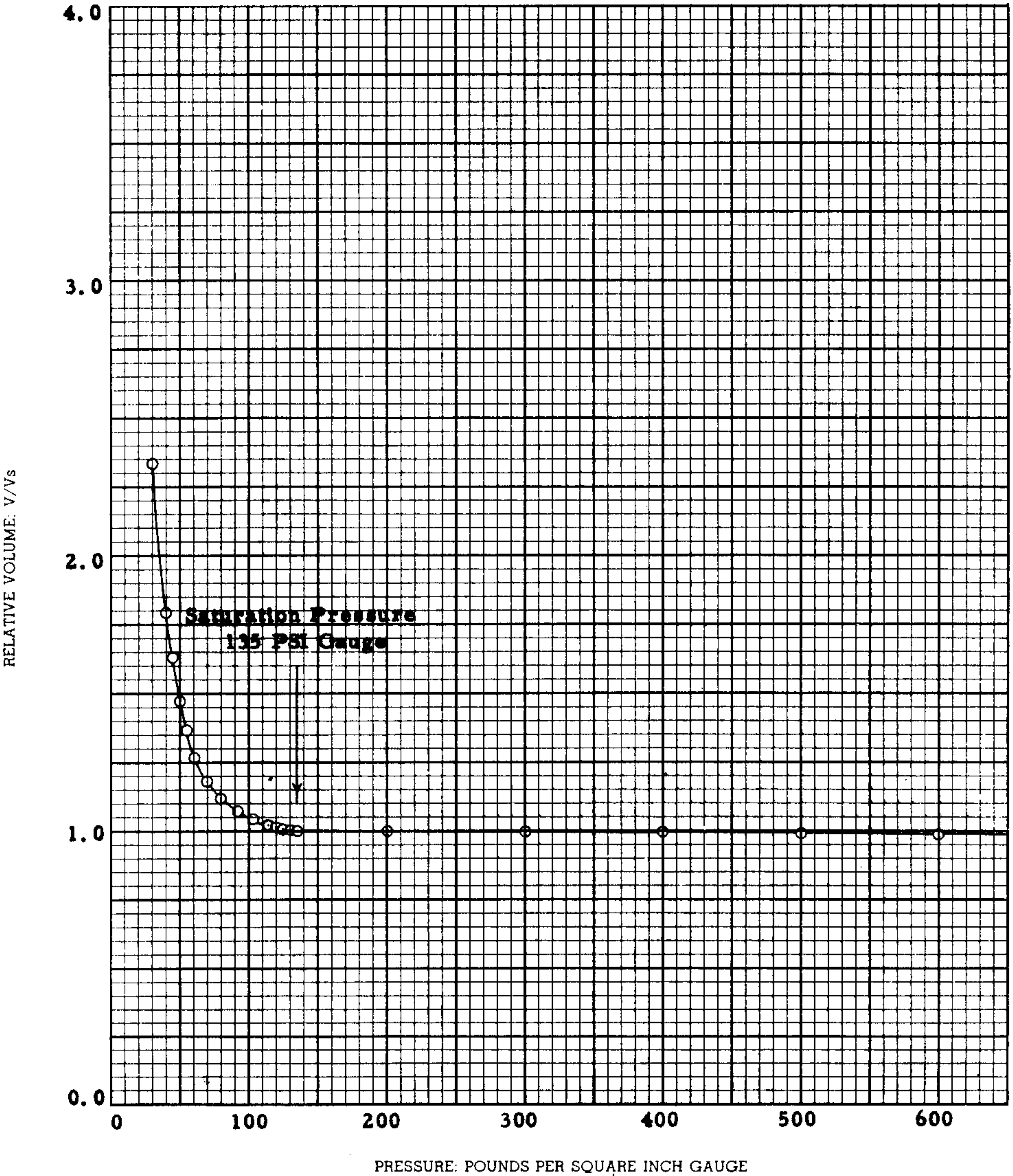
P. L. Moses,
Operations Supervisor

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 696

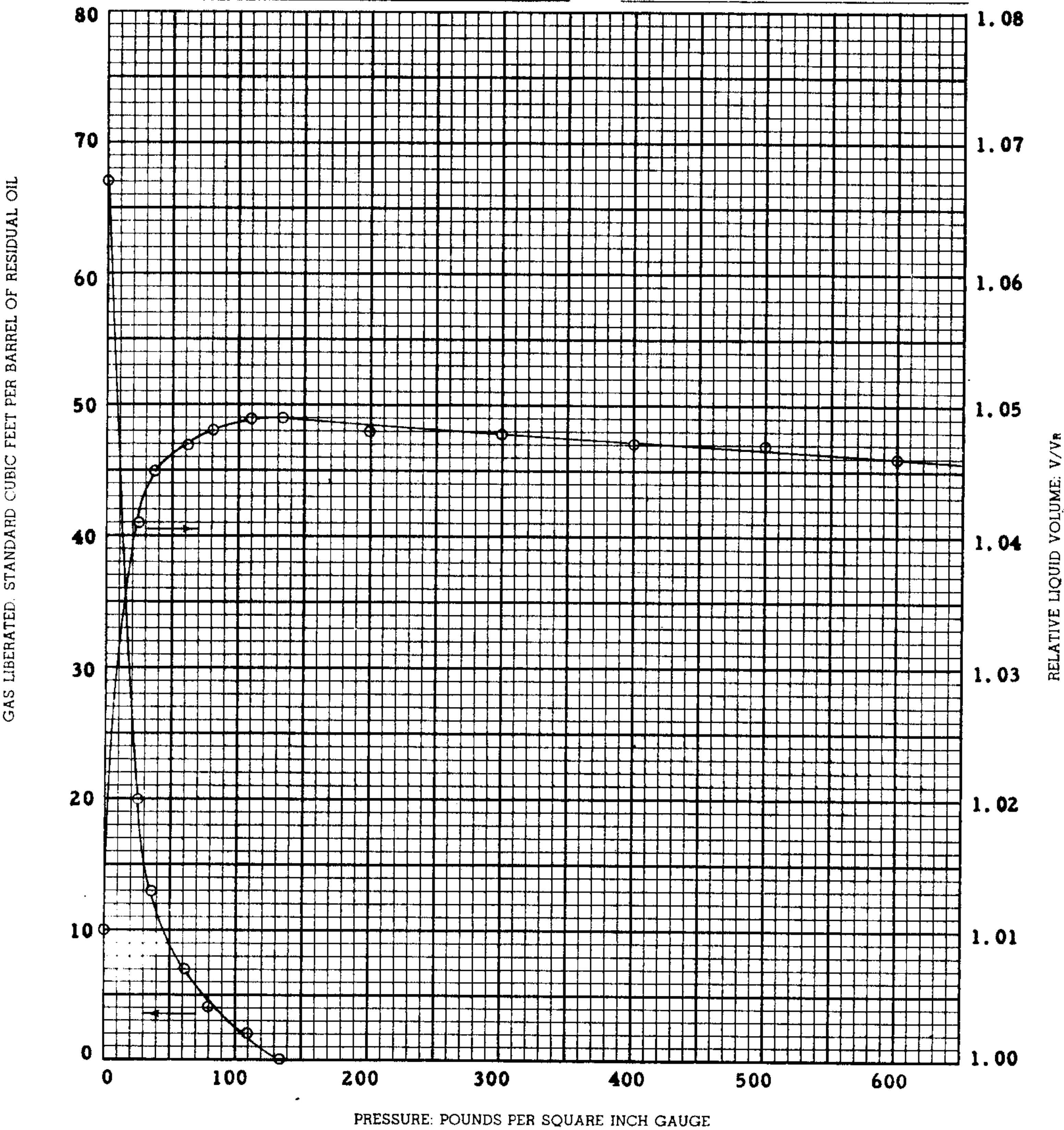
PRESSURE-VOLUME RELATIONS OF RESERVOIR FLUID

Company **The California Standard Company** Formation **Mississippian - Cherty Zone**
Well **Scallion No. 3-21** County
Field **North Virden** State **Manitoba, Canada**



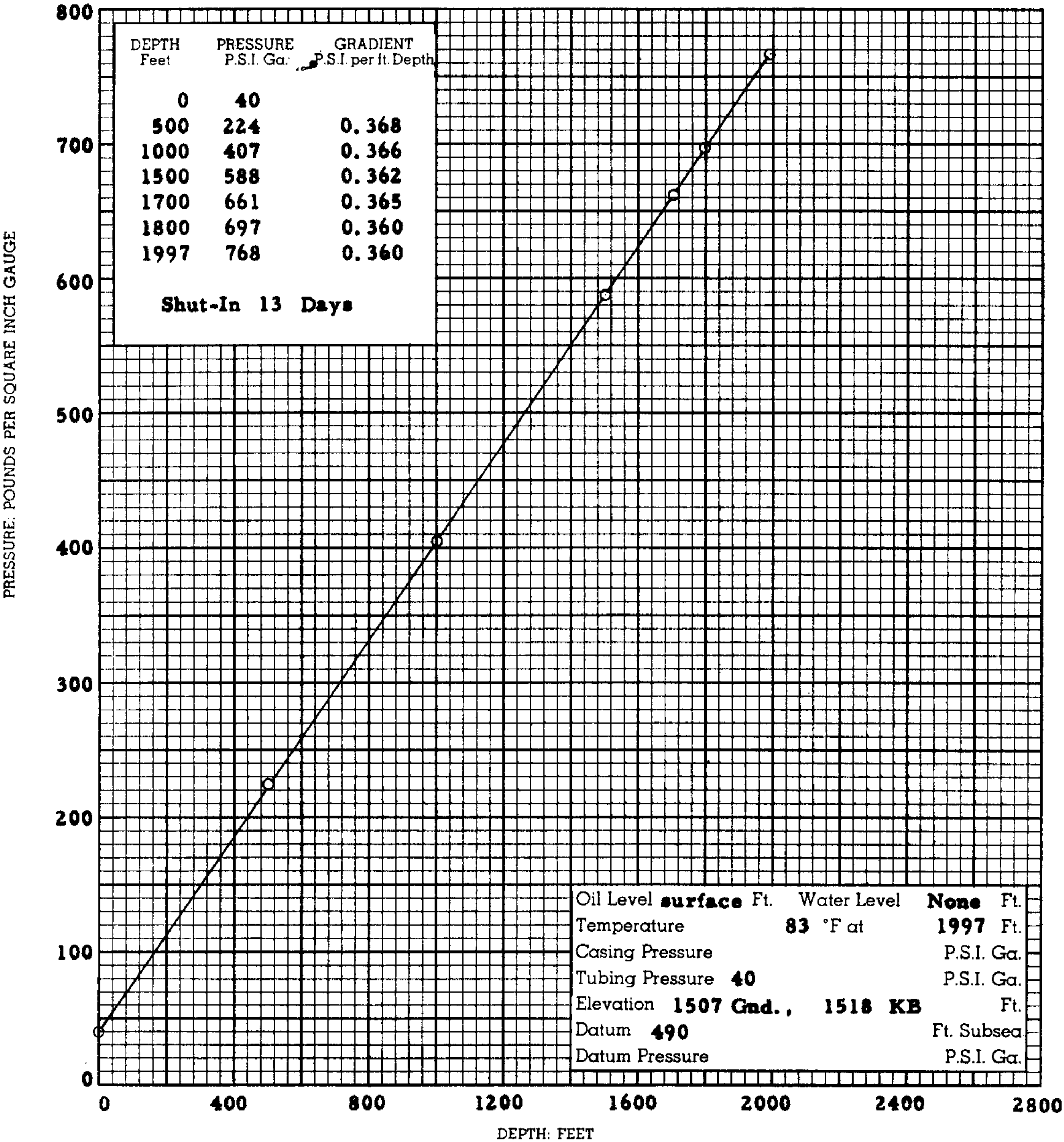
DIFFERENTIAL VAPORIZATION OF RESERVOIR FLUID

Company The California Standard Company Formation Mississippian - Cherty Zone
Well Scallion No. 3-21 County
Field North Virden State Manitoba, Canada



CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

Company **The California Standard Company** Formation **Mississippian - Cherty Zone**
Well **Scallion No. 3-21** County
Field **North Virden** State **Manitoba, Canada**



DEPTH Feet	PRESSURE P.S.I. Ga.	GRADIENT P.S.I. per ft. Depth
0	40	
500	224	0.368
1000	407	0.366
1500	588	0.362
1700	661	0.365
1800	697	0.360
1997	768	0.360

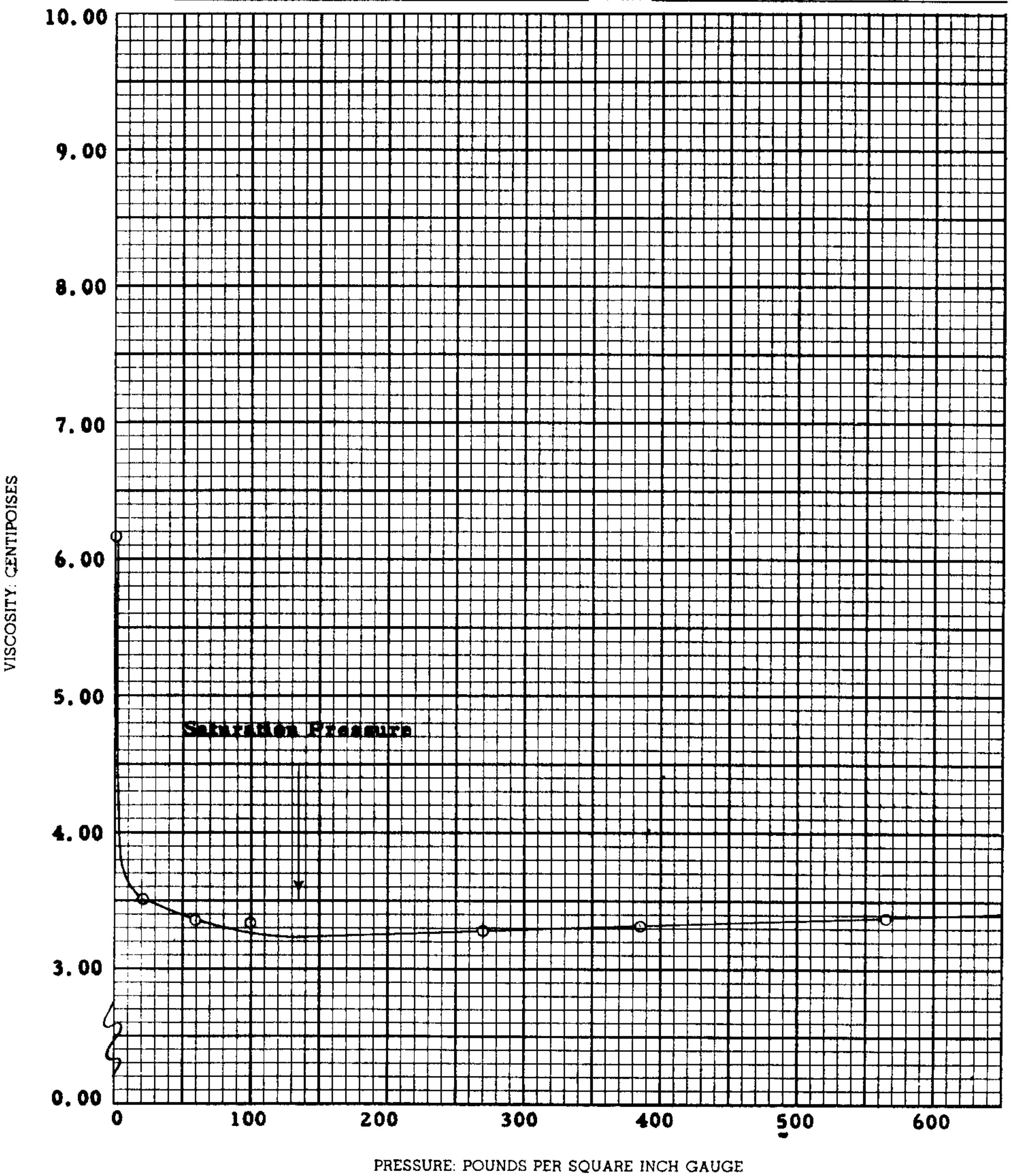
Shut-In 13 Days

Oil Level **surface** Ft.		Water Level **None**	Ft.
Temperature	**83** °F at	**1997**	Ft.
Casing Pressure			P.S.I. Ga.
Tubing Pressure **40**			P.S.I. Ga.
Elevation **1507 Gnd.,**	**1518 KB**		Ft.
Datum **490**			Ft. Subsea
Datum Pressure			P.S.I. Ga.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

VISCOSITY OF RESERVOIR FLUID

Company **The California Standard Company** Formation **Mississippian - Cherty Zone**
Well **Scallion No. 3-21** County
Field **North Virden** State **Manitoba, Canada**



Dup

RESERVOIR FLUID STUDY

FOR

THE CALIFORNIA STANDARD COMPANY

SCALLION NO. 10-16 WELL

VIRDEN FIELD

MANITOBA, CANADA

10-16-11-26

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

March 16, 1956

RESERVOIR FLUID DIVISION

The California Standard Company
Medical Arts Building
Calgary, Alberta, Canada

Subject: Reservoir Fluid Study
Scallion No. 10-16 Well
North Virden Field
Manitoba, Canada

Gentlemen:

Presented in the following report are the results of fluid studies performed using subsurface fluid samples collected from the subject well at a depth of 1991 feet.

The fluid exhibited a saturation pressure of 118 psig when examined at the reservoir temperature of 80° F. This value is considerably below the static reservoir pressure and is good indication that the reservoir presently exists in an undersaturated condition.

Differential pressure depletion of the fluid evolved 58 standard cubic feet of gas per barrel of residual oil with a corresponding formation volume factor of 1.032 barrels of saturated fluid per barrel of residual oil. Under these conditions, the viscosity of the liquid phase was measured from pressures exceeding reservoir pressure to atmospheric pressure and varied from a minimum of 4.350 centipoises at saturation pressure to 6.535 centipoises at atmospheric pressure.

Flash vaporization tests were performed at four operating pressures and atmospheric temperature to determine the effects of changes in separation pressure upon the produced fluid. The fluid showed very little response to changes in separation pressure and the tests indicate that only very slight benefit may be obtained by operation of field separators above atmospheric pressure.

It was a pleasure to perform this study for you. If we may assist you further in any manner, please do not hesitate to call.

Very truly yours,

Core Laboratories, Inc.
F. O. Reudelhuber

P. L. Moses,
Senior Engineer

PLM:ir

Form 69585

CORE LABORATORIES, Inc.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 647

Company	The California Standard Company	Date Sampled	February 7, 1956
Well	Scallion No. 10-16	County	
Field	North Virden	State	Manitoba, Canada

FORMATION CHARACTERISTICS

Formation Name	Mississippian Cherty Zone and Oolitic Zone
Date First Well Completed	December, 1954
Original Reservoir Pressure	PSI @ ft.
Original Produced Gas-Oil Ratio	cu. ft./bbl.
Production Rate	70 bbl./d.
Separator Pressure and Temperature	11 PSI, 140 ° F.
Oil Gravity at 60° F.	34.5 ° API
Datum	490 ft. subsea
Original Gas Cap	

WELL CHARACTERISTICS

Elevation	1511 Feet KB, 1501 Feet Gnd.
Total Depth	2081 ft.
Completion Depth	2075 PB ft.
Tubing Size and Depth	2 in. to 2073 KB ft.
Productivity Index	bbl./d./PSI @ bbl./d.
Last Reservoir Pressure	830 PSI @ -490 ft.
Date	February 6, 1956
Reservoir Temperature	80 ° F. @ -490 ft.
Status of Well	Shut-In 21.3 Hours
Pressure Gauge	Johnston
Normal Production Rate	bbl./d.
Gas-Oil Ratio	cu. ft./bbl.
Separator Pressure and Temperature	11 PSI, 140 ° F.
Base Pressure	13.8 PSI Abs.
Well Making Water	0.2 % Cut

SAMPLING CONDITIONS

Sampled at	1991 Feet
Status of Well	Shut-In 2 Days
Gas-Oil Ratio	cu. ft./bbl.
Separator Pressure and Temperature	PSI, ° F.
Tubing Pressure	100 PSI
Casing Pressure	Packer PSI
Core Laboratories Engineer	CPG, NJC
Type Sampler	Perco

REMARKS:

Form 54801

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 647

Well Scallion No. 10-16

VOLUMETRIC DATA OF Reservoir Fluid SAMPLE

1. Saturation pressure (bubble-point pressure) 118 PSI @ 80 °F.
2. Thermal expansion of saturated oil @ 5000 PSI = $\frac{V @ 80\ °F.}{V @ 75\ °F.}$ = 1.00210
3. Compressibility of saturated oil @ reservoir temperature: Vol./Vol./PSI:

   From 5000 PSI to 3000 PSI = 4.56×10^{-6}

   From 3000 PSI to 1000 PSI = 5.08×10^{-6}

   From 1000 PSI to 118 PSI = 5.81×10^{-6}
4. Specific volume at saturation pressure: cu. ft./# 0.01894 @ 80 °F.

Form 50870

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 647

Well Scallion No. 10-16

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 80 °F. RELATIVE VOLUME OF OIL AND GAS, V/VSAT.	VISCOSITY OF OIL @ 80 °F. CENTIPOISES	DIFFERENTIAL LIBERATION @ 80 °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	0.9757				1.007
4000	0.9801				1.011
3000	0.9847				1.016
2500	0.9871				1.019
2000	0.9896	5.254			1.021
1700		5.119			
1500	0.9922				1.024
1400		4.987			
1100		4.801			
1000	0.9948				1.027
900		4.689			
800	0.9959	4.645			1.028
700	0.9965	4.625			1.028
600	0.9971	4.574			1.029
500	0.9977	4.530			1.030
400	0.9983	4.486			1.030
300	0.9989	4.435			1.031
200	0.9994	4.391			1.031
120		4.436			
118	1.0000	4.350	0	58	1.032
115	1.0022				
111	1.0042				
108	1.0093				
105	1.0147				
100	1.0215				
91	1.0431				
83			2	56	1.032
80	1.0843	4.431			
60	1.2166		5	53	1.031
51	1.3149				
50		4.451			
45	1.4256				
40	1.5641				

V — Volume at given pressure
$V_{SAT.}$ — Volume at saturation pressure at the specified temperature.
V_R — Residual Oil Volume at 14.7 PSI absolute and 60° F.

Form 50870

CORE LABORATORIES, Inc.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 647

Well Scallion No. 10-16

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 80 °F., RELATIVE VOLUME OF OIL AND GAS, V/Vsat.	VISCOSITY OF OIL @ 80 °F., CENTIPOISES	DIFFERENTIAL LIBERATION @ 80 °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
35	1.7505				
30	2.1081		13	45	1.027
24	2.5744				
21			19	39	1.025
20		4.554			
0		6.535	58	0	1.009
				@ 60°F. =	1.000

Gravity of Residual Oil = 34.0° API @ 60° F.

Specific Gravity of Liberated Gas = 1.4580

V — Volume at given pressure
Vsat. — Volume at saturation pressure at the specified temperature.
Vr — Residual Oil Volume at 14.7 PSI absolute and 60° F.

Form 54802

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 647

Well Scallion No. 10-16

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, VR/VSAT. *See Foot Note (2)*	FORMATION VOLUME FACTOR, VSAT./VR *See Foot Note (3)*	SPECIFIC GRAVITY OF FLASHED GAS
0	77	70		33.4	0.9470	1.056	1.5363
10	77	50	11	34.0	0.9497	1.053	
20	78	34	25	34.0	0.9515	1.051	
50	79	6	52	33.9	0.9542	1.048	

(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: VR/VSAT. is barrels of stock tank oil @ 60° F. per barrel of saturated oil @ 118 PSI gauge and 80 ° F.

(3) Formation Volume Factor: VSAT./VR is barrels of saturated oil @ 118 PSI gauge and 80 °F. per barrel of stock tank oil @ 60° F.

Form 55849

CORE LABORATORIES, Inc.
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DALLAS, TEXAS

File RFL 647

Company The California Standard Company Formation Mississippian Cherty Zone and Oolitic Zone

Well Scallion No. 10-16 County

Field North Virden State Manitoba, Canada

HYDROCARBON ANALYSIS OF Reservoir Fluid SAMPLE

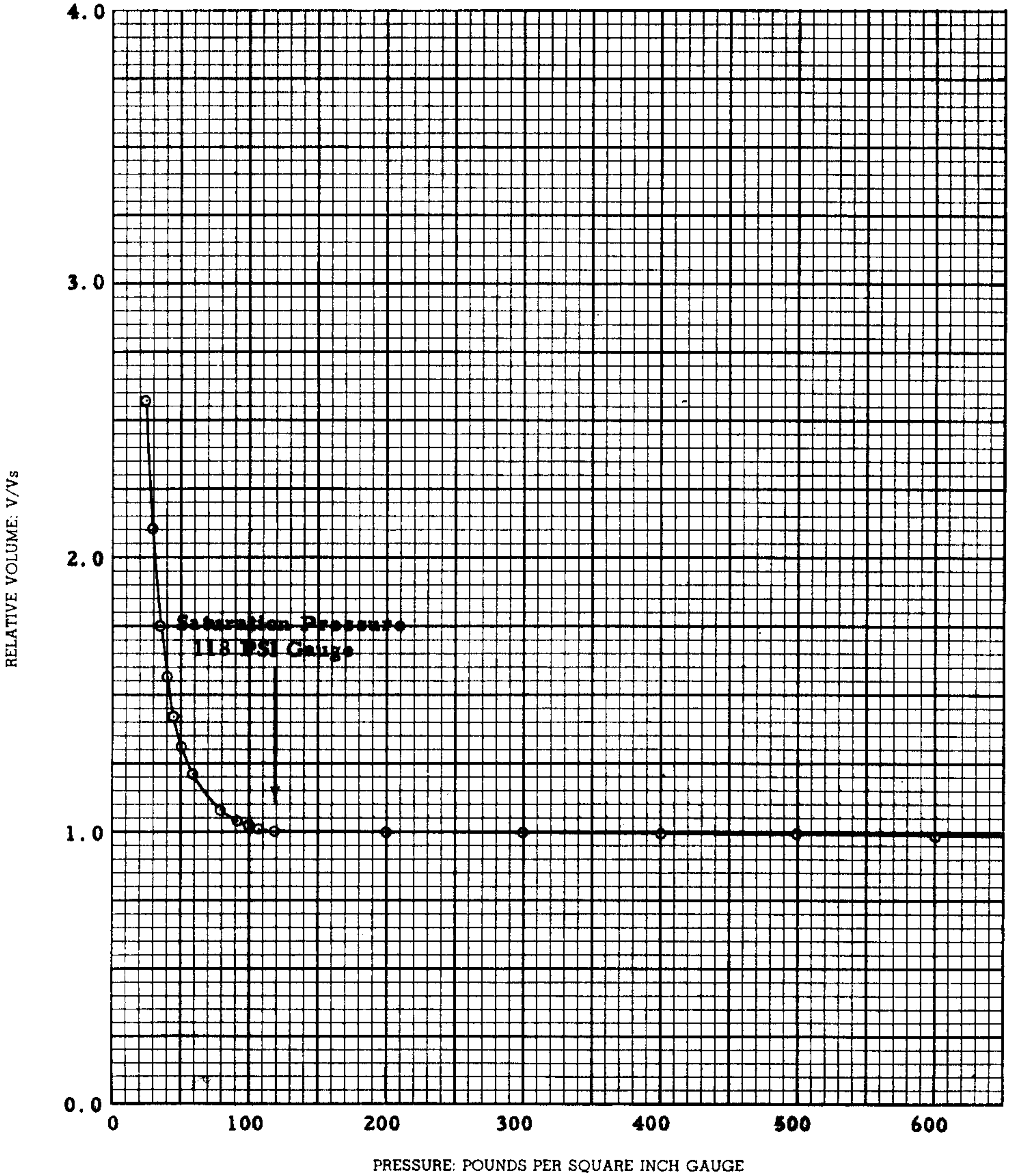
COMPONENT	WEIGHT %	MOL %	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Methane	0.07	0.86			
Ethane	0.64	4.01			
Propane	1.58	6.75			
Iso-butane	0.64	2.08			
N-butane	1.71	5.54			
Iso-pentane	1.28	3.33			
N-pentane	0.81	2.10			
Hexanes	3.23	7.05			
Heavier	90.04	68.28	0.8785	29.4	248
	100.00	100.00			

Core Laboratories, Inc.
F. O. Reudelhuber

P. L. Moses

PRESSURE-VOLUME RELATIONS OF RESERVOIR FLUID

Company **The California Standard Company** Formation **Mississippian Cherty Zone and Oolitic Zone**
Well **Scallion No. 10-16** County
Field **North Virden** State **Manitoba, Canada**

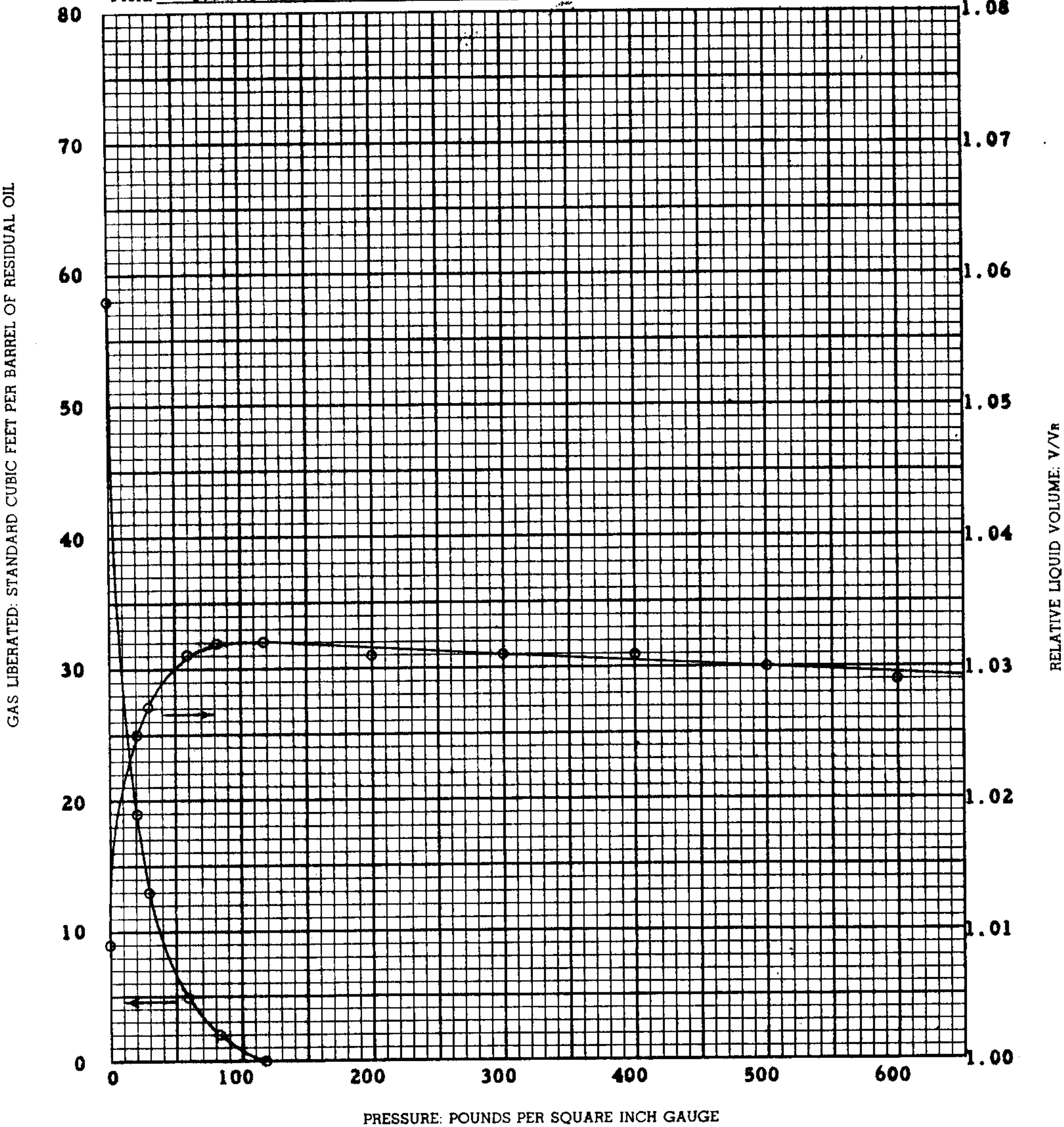


CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 647

DIFFERENTIAL VAPORIZATION OF RESERVOIR FLUID

Company The California Standard Company
Formation Mississippian Cherty Zone and Oolitic Zone
Well Scallion No. 10-16
County
Field North Virden
State Manitoba, Canada



CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

VISCOSITY OF RESERVOIR FLUID

Company **The California Standard Company** Formation **Mississippian Cherty Zone and Oolitic Zone**
Well **Scallion No. 10-16** County
Field **North Virden** State **Manitoba, Canada**