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ESSO EXPLORATION
NORWAY INC.

EXXON PRODUCTION RESEARCH COMPANY

Research Application

CORE ANALYSIS REPORT

NORWAY WELL 34/10-3

10 MAR 1981

L. H. Jenks

Reservoir Division

January, 1980

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EPR.21PS.80

CONFIDENTIAL

EXXON PRODUCTION RESEARCH COMPANY

CORE ANALYSIS REPORT

NORWAY WELL 34/10-3

L. H. Jenks

Reservoir Division

January, 1980

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FOR ESSO EXPLORATION & PRODUCTION NORWAY INC. USE ONLY

EXXON PRODUCTION RESEARCH COMPANY
POST OFFICE BOX 2189 • HOUSTON, TEXAS 77001

RESERVOIR DIVISION
C. C. MATTAX
MANAGER

January 29, 1980

Esso Exploration & Production Norway, Inc.
P.O. Box 560
4001 Stavanger
Norway

Attn: Mr. G. J. Lookabaugh

Dear Mr. Lookabaugh:

EPR.21TS.80 - Core Analysis Report
Norway Well 34/10-3

This report contains the results of all special core analysis tests performed on core material from Norway well 34/10-3, in the Ness, Etine and Rannach formations. A total of 10 core plugs were cut from the 2-1/2 feet of core material furnished. The work reported herein was authorized by a letter of May 30, 1979 from Mr. L. T. Barron of Esso Norway to Drs. C. C. Mattax and R. H. Rossen of EPRCo.

These tests included water-oil relative permeability by waterflood, oil relative permeability by centrifuge, gas-oil relative permeability by gas-flood, and both water-oil imbibition and gas-oil drainage capillary pressure measurements by centrifuge.

Very truly yours,

C. C. Mattax

By Clay Gruesbeck
C. Gruesbeck

LIJ:taw

cc: Mr. G. H. Sawyer

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INTRODUCTION

This report presents the results of a core analysis study of core material cut from Norway Well 34/10-3. Except for one piece, the furnished material appeared to be well preserved. This work was authorized in a letter dated May 30, 1979 from Mr. L. T. Barron of Esso Norway to Drs. C. C. Mattax and R. H. Rossen of EPRCo.

A summary of the tests performed is shown below:

Type of Test	Number of Tests Planned	Number of Tests Completed
Water-oil relative permeability by waterflood of composite core at reservoir conditions	1	1
Gas-oil relative permeability by gasflood of the same composite	1	1
Oil relative permeability by centrifuge at 160°F and atmospheric pressure	4	4
Water-oil imbibition capillary pressure by centrifuge at 160°F and atmospheric pressure	4	4
Air-Kerosene drainage capillary pressure by centrifuge at room conditions	4	4

DISCUSSION

Core Material

A total of ten usable samples were cut from approximately 2.5 feet of core material furnished by Exploresso Stavanger. The cylindrical samples were approximately 6 cm. long and 3.8 cm. in diameter. Due to its extremely friable nature, some of the core material disintegrated under the sampling bit. This condition was remedied by freezing the more friable sections in liquid nitrogen prior to being plugged. Except for one section, (1937.75-37.85 m) the core material upon receipt was well-wrapped and sealed, and appeared to be preserved. The unpreserved piece arrived wrapped loosely in a polyethylene bag but was not sealed.

Preliminary Sample Data

Where possible, preliminary porosity and permeability measurements were made, these to be used as a basis for selecting samples for the various tests. Approximate porosities were measured by the nuclear magnetic resonance (NMR) procedure, and permeability by flowing brine through the core sample in "as received" condition (prior to any cleanup measures). Table I lists the core sections and samples, preliminary data, and sample selections for further testing.

Water-oil Relative Permeability by Waterflood

A composite core, consisting of four butted preserved core plugs enclosed under triaxial stress within a steel cell was waterflooded in order to measure oil and water relative permeabilities. The core was prepared for flooding by establishing a minimum water saturation with a viscous white oil flush at 3000 psi differential pressure, and then displacing the white oil with a reconstituted live crude from the Norway reservoir. During the test a synthetic brine (60 grams NaCl and 20 grams KCl per liter)(See Appendix A) was injected at a constant rate to displace oil from the core. Oil production rates and differential pressures across the core were continuously monitored during the flood. Test temperature was 163°F. Brine injection was continued until oil production ceased. A system pressure of several hundred psi greater than the saturation pressure of the oil was employed throughout.

Results of the waterflood test, analyzed by the Johnson-Bossler-Naumann procedure[1], are presented in Table II and in Figures 1-3.

Oil Relative Permeability by Gasflood

The same composite was subjected to a gasflood in order to measure relative permeabilities to gas and oil. The core initially contained a minimum water saturation, established as described above, and a 2.5 cp white oil. During the test helium gas displaced the white oil at essentially a constant differential pressure. Gas flow and oil production rates were monitored throughout, providing data for the relative permeability computations using the Johnson-Bossler-Naumann procedure. Test data and results are presented in Table III and Figures 4 and 5.

Oil Relative Permeability by Centrifuge

Four core samples, subjected to about 3500 psi overburden pressure in triaxial cells, were used in the centrifuge tests for relative permeability to oil. The samples were prepared by using a refined white oil flush for cleaning and later for establishing irreducible water saturations. Prior to the test, the white oil was replaced by degassed crude oil from the Norway reservoir. Tests were performed in the centrifuge at 160°F and with atmospheric pressure on the fluids in the samples. The centrifuge speed was held constant at about 2400 RPM. Oil production vs. time data collected during the approximately 24 hours of the test period were analyzed for relative permeability behavior, with data and computed results being shown in Table IV and in Figures 6-9. Relative permeabilities were corrected for capillary end effects (See Appendix B), although these effects were essentially insignificant.

Water-oil Imbibition Capillary Pressure by Centrifuge

Imbibition capillary pressure tests were performed on the same samples used in the above relative permeability tests. Preparations for the tests were the same in both cases.

This test is started by allowing the samples, containing degassed crude oil and irreducible water saturations, to stand in contact with brine for approximately a week to permit spontaneous imbibition of the brine. At the end of this period, the samples are placed in the centrifuge and spun at a low speed for production of oil until equilibrium is established. Centrifuge speeds are increased incrementally (with each held long enough to achieve saturation equilibrium) to apply a range of capillary pressures. Results of these tests are shown in Table V and in Figures 10-13. Capillary pressure curves are based on calculated face saturations of the water phase [2], [3].

Air-Kerosene Drainage Capillary Pressure by Centrifuge

The same set of samples was saturated with a 2.5 centipoise white oil, and subjected to drainage capillary pressure tests in the centrifuge. In this test the oil is displaced by air at a series of centrifuge speeds, with oil saturation brought to equilibrium at each speed. Results of these tests are shown in Table VI and in Figures 14-17, with capillary pressure curves being based on calculated face saturations of the displaced phase.

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[1] Johnson, E.F.; Bossler, D.P.; and Naumann, V.O.: "Calculation of Relative Permeability from Displacement Experiments," Trans. AIME (1959), 216,370.

[2] Hassler, G.L.; and Brunner, E.: "Measurement of Capillary Pressure in Small Core Samples," Trans. AIME (1945), 160, 114-123.

[3] Slobod, R.L.; Chambers, A.; Phren, W.L. Jr.: "Use of Centrifuge for Determining Connate Water, Residual Oil, and Capillary Pressure Curves for Small Core Samples," Trans. AIME (1951), 192, 127-134.

APPENDIX A

USE OF A SYNTHETIC BRINE

The water phase used in all tests was a solution containing 60 grams of sodium chloride and 20 grams of potassium chloride per liter. It has been determined in core analysis tests made over a long period of time that brine composition within a wide saturation range has no measurable effect on water-oil displacement test results. The mixture that was used in tests reported here is one that was developed in our laboratories to minimize the possibility of loss of permeability in brine sensitive cores.

The use of reservoir brine samples or close simulations of reservoir brine compositions has proved to be undesirable for a number of reasons.

1. It is often difficult to secure a large volume of uncontaminated reservoir brine.

2. Reservoir brines are unstable and tend to form precipitates when subjected to changes in pressure or temperature or to slight contact with air.

3. Even when formation of precipitate is not apparent, reservoir brine may cause serious loss of permeability in test cores.

4. It is often impossible to make a stable brine to match the analysis of a reservoir brine by starting with pure salts and distilled water.

APPENDIX B

CORRECTION OF CENTRIFUGE RELATIVE PERMEABILITY FOR CAPILLARY PRESSURE

The procedure used for measuring relative permeability to oil in the centrifuge is based in part on an assumption that the capillary pressure gradient in the direction of flow is negligible compared to the gravity potential gradient. As the brine saturation increases this assumption is subject to increasing error.

The gravity potential difference is equal to the expression

$$\left(\frac{2\pi N}{60}\right)^2 \times \frac{(\rho_w - \rho_o) r \times 14.7 \times L}{1.0133 \times 10^6}, \text{ psi}$$

N = centrifuge speed, rpm

ρ_w = density of water phase, gm/cc

ρ_o = density of oil phase, gm/cc

r = distance between pivot point of the centrifuge arm and the midpoint of the sample, cm

L = sample length, cm

Early in the displacement of oil from a core, the capillary pressure, $p_o - p_w$, is small and the permeability to oil calculated by using the gravity gradient as the pressure term gives an accurate relative permeability value. As the oil saturation is lowered, the capillary pressure retarding the production of oil increases and the gravity gradient must be corrected for the capillary pressure to obtain an accurate measure of permeability to oil. When relative permeability and capillary pressure data are available for the test sample, an approximate correction can be made.

A plot of the capillary pressure data showing average water saturation, % PV, versus calculated capillary pressure, $p_o - p_w$, psi, is used to determine the capillary pressure at any selected water saturation. The gravity gradient calculated for the k_{ro} test in the centrifuge must be decreased by the capillary pressure to obtain a corrected driving pressure at any saturation. Because the corrected pressure gradient is less than the total gravity gradient, the corrected permeability and the relative permeability to oil are higher than uncorrected values. The correction is made to all calculated points based on average saturation values for both relative permeability and capillary pressure data.

This type of correction can be made with acceptable accuracy to a saturation at which the corrected k_{ro} is about twice the uncorrected value. If greater accuracy is required or if extension of the relative permeability curve to a lower oil saturation is necessary, these data must be obtained from a simulator study of the system.

TABLE I

Core Samples Properties and Selection for Testing

Core Depth, Meters	Sample Depth, Meters	Preliminary Data Used as Basis for Selection		Test Use	
		NMR Porosity	Permeability $**k_{bro}$, md	Centrifuge	Composite
1931.31-31.46	1931.4	--	0.45		
*1937.75-37.85	*1937.78	26.4	53.4	X	
	*1937.81	22.6	18.7		
1963.30-63.39	1963.33	30.9	78.0	X	
	1963.36	26.1	45.1	X	
1997.78-97.89	1997.85	--	51.8	X	
2023.97-24.29	2023.99	--	323		X
	2024.01	--	301		X
	2024.08	--	315		X
	2024.15	--	194		X

* Unpreserved

** Permeability in brine in "as received" condition

TABLE IIA

EPRCO WATERFLOOD CALCULATION, SAMPLE COMPOSITE CONDITION - PRESERVED DATE 11-16-79

COMPANY	RESERVOIR	WELL NO.	DEPTH FT.	SAMPLE NO.	WATERFLOOD NUMBER	TOT. TIME INCREMENTS IN FLOOD
EXPL.NORWAY		34/10-3	6640.000	COMPOSITE	1	13

CORE LENGTH, CM	24.500	
CROSS-SECTIONAL AREA OF CORE, SQ CM	10.860	
BULK VOLUME, CC	266.070	
PORE VOLUME OF CORE, CC	80.500	
HYDROCARBON VOLUME, CC	71.600	
OIL VISCOSITY IN TEST, CP	1.500	
FLOODING BRINE VISCOSITY IN TEST, CP	0.430	
VISCOSITY RATIO	3.488	
POROSITY, PCT. BULK VOLUME	30.255	
SCALING FACTOR, LVMUB	2.307	
KOCW, PREDETERMINED PERMEABILITY TO OIL IN PRESENCE OF CONNATE WATER, MD	302.000	$K_o(S_{wc})$
KBRO, BRINE PERMEABILITY AT RESIDUAL OIL SATURATION	36.113	$K_w(S_{or})$
FLOW VELOCITY IN CORE, INCHES/DAY	410.310	
TIME CONVERSION FACTOR, UNITS/MINUTE	0.133	
TIME UNITS AT FLOOD START	0.0	
PRESSURE CONVERSION FACTOR, UNITS/PSI	4.000	
PRESSURE UNITS AT ZERO PRESSURE	0.0	
TEMPERATURE OF CORE DURING FLOOD, DEG F	163.000	
CORE OUTFLOW FACE PRESSURE, PSIG	3635.000	
INITIAL OIL IN PLACE, PCT. PV	88.944	
CONNATE WATER, INITIAL WATER IN PLACE, PCT. PV	11.056	S_{wc}
OIL DISPLACED DURING FLOOD, PCT. PV	57.574	

RELATIVE PERMEABILITY CALCULATION METHOD - SMOOTHED (5 POINT, LEAST SQUARES, BOSSLER)

COMMENTS

RESERVOIR CONDITIONS WATERFLOOD

INLET 2023.99, 2024.15, 2024.08, 2024.01 (METERS)

TABLE IIB

EPRCO WATERFLOOD CALCULATION, SAMPLE COMPOSITE   CONDITION - PRESERVED   DATE 11-16-79

CONTINUOUS CHART TYPE FLOOD
DISPLACED OIL RECORDED FROM SEPARATOR TRANSDUCER OUTPUT

INPUT DATA

READING OF OIL RECOVERY SYSTEM AT FLOOD START, UNITS	10.0000
OIL RECOVERY VOLUME FACTOR, CC/UNIT	1.3300
BRINE HOLDUP, CC. (VOLUME OF SYSTEM BETWEEN CORE OUTLET AND OIL COLLECTOR)	1.0000
OIL HOLDUP, CC. (VOLUME OF OIL IN INLET AND OUTLET LINES OF CORE HOLDER, NOT PART OF HV)	1.4000
BRINE INJECTION RATE, CC/MIN	2.3780
COMPUTED TIME TO PRODUCE OIL PLUS WATER HOLDUP, MIN	1.0093

STEP NO.	CUMULATED TIME FROM START OF FLOOD TIME UNITS	PRESSURE DROP ACROSS CORE PRESSURE UNITS	PRODUCED OIL READING CHART UNITS
1	0.8750	39.0000	21.0000
2	1.8310	53.0000	33.8000
3	2.4950	60.1000	42.7000
4	4.0000	61.7000	44.1000
5	6.0000	63.6000	44.7000
6	8.0000	65.0000	45.0000
7	11.0000	65.9000	45.2000
8	16.0000	65.8000	45.5000
9	20.0000	65.3000	45.8000
10	26.0000	64.5000	45.8500
11	32.0000	63.6000	45.9000
12	38.0000	63.0000	45.9000
13	42.0000	62.2000	45.9000

CHECK VOLUMES AT STEP 1.

TABLE IIC

EPRCO WATERFLOOD CALCULATION, SAMPLE COMPOSITE   CONDITION - PRESERVED   DATE 11-16-79

STEP NO.	AVG. OIL SAT. PERCENT PV	OIL DISPLACED PERCENT PV	OIL DISPLACED PERCENT HV	VOLUME BRINE INJECTED, PV	VOLUME OIL PRODUCED, CC	TOTAL FLUID PRODUCED, CC
1	72.5093	16.4348	18.4776	0.1641	13.2300	13.2095
2	51.3615	37.5825	42.2541	0.3760	30.2540	30.2640
3	36.6572	52.2869	58.7862	0.5231	42.0910	42.1094
4	34.3441	54.5999	61.3868	0.8566	43.9530	68.9576
5	33.3528	55.5912	62.5013	1.2998	44.7510	104.6367
6	32.8572	56.0869	63.0586	1.7431	45.1500	140.3156
7	32.5267	56.4173	63.4301	2.4079	45.4160	193.8340
8	32.0311	56.9130	63.9874	3.5159	45.8150	283.0313
9	31.5354	57.4086	64.5446	4.4023	46.2140	354.3892
10	31.4528	57.4912	64.6375	5.7320	46.2805	461.4258
11	31.3702	57.5738	64.7304	7.0616	46.3470	568.4626
12	31.3702	57.5738	64.7304	8.3913	46.3470	675.4990
13	31.3702	57.5738	64.7304	9.2777	46.3470	746.8572

TABLE IID

EPRCO WATERFLOOD CALCULATION, SAMPLE COMPOSITE CONDITION - PRESERVED DATE 11-16-79

RELATIVE PERMEABILITIES

STEP NO.	CALC. OIL SAT. AT OUTLET CORE FACE PCT. HV	CALC. OIL SAT. AT OUTLET CORE FACE PCT. PV	CALC. WATER SAT. AT OUTLET CORE FACE PCT. PV	RELATIVE PERMEABILITY TO BRINE PCT.	RELATIVE PERMEABILITY TO OIL PCT.	RELATIVE PERMEABILIT RATIO
1	*******	92.2422	7.7578	-4.3190	89.4483	-0.0482
2	79.9316	71.0945	28.9055	10.1309	39.0418	0.2594
3	63.3995	56.3901	43.6099	13.2792	28.0593	0.4732
4	49.8973	44.3807	55.6193	12.8945	5.9696	2.1600
5	40.5004	36.0228	63.9772	12.5781	0.9202	13.6695
6	38.7329	34.4506	65.5494	12.3313	0.3969	31.0716
7	38.1566	33.9380	66.0620	11.8219	0.2431	48.6235
8	37.4440	33.3042	66.6958	11.4287	0.1449	78.8783
9	36.7090	32.6505	67.3495	11.1306	0.0986	112.8971
10	36.1328	32.1380	67.8620	11.0132	0.0460	239.5329
11	35.5328	31.6043	68.3957	11.0027	0.0127	864.5244
12	35.5328	31.6043	68.3957	11.0033	0.0107	1027.3618
13	35.5328	31.6043	68.3957	11.0036	0.0097	1135.9206
				Krw	Kro	

TABLE IIE

EPRCO WATERFLOOD CALCULATION, SAMPLE COMPOSITE   CONDITION - PRESERVED   DATE 11-16-79

RELATIVE INJECTIVITY

STEP NO.	BRINE INJECTED, PV	RELATIVE INJECTIVITY
1	0.1641	0.6696
2	0.3759	0.4927
3	0.5231	0.4345
4	0.8566	0.4232
5	1.2998	0.4106
6	1.7431	0.4017
7	2.4079	0.3963
8	3.5159	0.3969
9	4.4023	0.3999
10	5.7320	0.4049
11	7.0616	0.4106
12	8.3913	0.4145
13	9.2777	0.4198

TABLE IIIA

EPRCO GASFLOOD CALCULATION, SAMPLE COMPOSITE CONDITION - PRESERVED DATE NOV26,'79

COMPANY	RESERVOIR	WELL NO.	DEPTH FT.	SAMPLE NO.	GASFLOOD NUMBER	TIME INCREMENTS IN FLOOD
EXPOR.NORWAY		34/10-3	6640.000	COMPOSITE	1	15

CORE LENGTH, CM	24.500
CROSS-SECTIONAL AREA OF CORE, SQ CM	10.860
BULK VOLUME, CC	266.070
PORE VOLUME OF CORE, CC	80.500
HYDROCARBON VOLUME, CC	71.200
OIL VISCOSITY IN TEST, CP	2.500
GAS VISCOSITY IN TEST, CP	0.018
POROSITY, PCT. BULK VOLUME	30.255
KOCW, PREDETERMINED PERMEABILITY TO OIL IN PRESENCE OF CONNATE WATER, MD	414.000
KGRO, GAS PERMEABILITY AT RESIDUAL OIL SATURATION, MD	229.361
COMPUTED TIME FOR PRODUCED OIL TO REACH COLLECTOR, MIN	0.200
TIME CONVERSION FACTOR, UNITS/MINUTE	0.133
TIME UNITS AT FLOOD START	0.0
PRESSURE CONVERSION FACTOR, UNITS/PSI	10.000
PRESSURE UNITS AT ZERO PRESSURE GRADIENT	0.0
INITIAL OIL IN PLACE, PCT. PV	88.447
INITIAL WATER SATURATION, PCT. PV	11.553

RELATIVE PERMEABILITY CALCULATION METHOD - SMOOTHED (5 POINT,LEAST SQUARES,BOSSLER)

COMMENTS

GASFLOOD OF COMPOSITE - HELIUM DISPLACING WHITE OIL

INLET 2023.99,2024.15,2024.08,2024.01 OUTLET (METERS)

EPRCO GASFLOOD CALCULATION, SAMPLE COMPOSITE   CONDITION - PRESERVED   DATE NOV26,'79

READING OF OIL RECOVERY SYSTEM AT FLOOD START, UNITS	10.0000
OIL RECOVERY VOLUME FACTOR, CC/UNIT	0.5040
OIL HOLDUP, CC. (VOLUME OF OIL IN INLET AND OUTLET LINES OF CORE HOLDER , NOT PART OF HV)	1.4000
INITIAL READING - WET TEST METER	0.3300
CORE OUTLET FACE PRESSURE, PSI	236.0000

** BACK PRESSURE HELD CONSTANT **

STEP NO.	CUMULATED TIME FROM START OF FLOOD TIME UNITS	PRESSURE DROP ACROSS CORE PRESSURE UNITS	PRODUCED OIL READING CHART UNITS	PRODUCED GAS LITERS AT ATM. PRESSURE
1	1.0000	82.0000	43.2000	1.0
2	2.0000	81.9000	56.9000	4.0
3	5.0000	82.6000	72.5000	18.2
4	10.0000	79.9000	82.5000	61.0
5	20.0000	77.8000	91.2000	181.5
6	30.0000	75.5000	96.0000	331.0
7	40.0000	77.1000	101.0000	498.0
8	50.0000	79.0000	102.8000	682.0
9	60.0000	77.7000	104.5000	884.0
10	70.0000	76.9000	106.0000	1091.0
11	80.0000	72.2000	106.9000	1308.0
12	90.0000	74.7000	107.6000	1525.0
13	100.0000	73.1000	108.3000	1740.0
14	105.0000	72.9000	108.6000	1848.5
15	110.0000	70.2000	108.9000	1955.5

TABLE IIIC

EPRCO GASFLOOD CALCULATION, SAMPLE COMPOSITE CONDITION - PRESERVED DATE NOV26,'79

STEP NO.	AVG. OIL SAT. PERCENT PV	OIL PRODUCED PERCENT PV	OIL PRODUCED PERCENT HV	VOLUME GAS INJECTED, CC	VOLUME OIL PRODUCED, CC
1	69.40	19.05	21.53	37.5	15.33
2	60.82	27.62	31.23	210.7	22.24
3	51.06	37.39	42.28	1030.0	30.10
4	44.80	43.65	49.35	3500.3	35.14
5	39.35	49.10	55.51	10458.0	39.52
6	36.34	52.10	58.91	19094.1	41.94
7	33.21	55.23	62.45	28738.0	44.46
8	32.09	56.36	63.72	39359.6	45.37
9	31.02	57.43	64.93	51023.3	46.23
10	30.08	58.37	65.99	62977.6	46.98
11	29.52	58.93	66.63	75520.9	47.44
12	29.08	59.37	67.12	88058.1	47.79
13	28.64	59.81	67.62	100483.6	48.14
14	28.45	59.99	67.83	106754.4	48.29
15	28.27	60.18	68.04	112941.8	48.45

TABLE IIID

EPRCO GASFLOOD CALCULATION. SAMPLE COMPOSITE   CONDITION - PRESERVED   DATE NOV26.'79

RELATIVE PERMEABILITIES

STEP NO.	CALC. OIL SAT. AT OUTLET CORE FACE PCT. HV	CALC. OIL SAT. AT OUTLET CORE FACE PCT. PV	LIQUID SAT. AT OUTLET CORE FACE PCT. PV	Sg=1-SL	RELATIVE PERMEABILITY TO GAS PCT.	RELATIVE PERMEABILTIY TO OIL PCT.	RELATIVE PERMEABILTIY RATIO
1	84.7732	74.9795	86.5323	13.47	2.1458	31.7768	0.06753
2	75.0755	66.4021	77.9549	22.05	4.5376	17.0261	0.26651
3	64.0328	56.6352	68.1879	31.8	9.1914	6.1767	1.48806
4	56.5111	49.9825	61.5352	38.47	14.9240	2.6689	5.59174
5	50.2406	44.4364	55.9892	44.	23.4338	1.3348	17.55542
6	46.9462	41.5226	53.0753	46.93	29.3110	0.9078	32.28641
7	43.5218	38.4938	50.0466	49.96	34.3994	0.7103	48.43269
8	41.9361	37.0913	48.6441	51.38	37.7812	0.5378	70.25349
9	39.5036	34.9398	46.4926	53.51	38.6854	0.3340	115.81802
10	38.3100	33.8840	45.4368	54.57	40.6581	0.2755	147.59047
11	37.2423	32.9397	44.4925	55.51	44.6039	0.2272	196.33316
12	36.3431	32.1444	43.6972	56.31	47.4196	0.1853	255.91022
13	35.8732	31.7288	43.2815	56.72	48.8522	0.1680	290.74048
14	35.6608	31.5409	43.0937	56.91	49.3579	0.1596	309.24146
15	35.4484	31.3531	42.9059	57.1	50.0731	0.1527	327.97681

RELATIVE PERMEABILITY TO OIL DATA
WATER-OIL SYSTEM

FIELD: RESERVOIR: 34-10
WELL: 3 CENTRIFUGE @ 160

CORE NO.	1937.78	1963.33	1963.36	1997.85
DEPTH, FT	6357.9	6441.7	6441.8	6554.9
PERMEABILITY (KOCW), MD	19.2	239.0	186.0	2078.0
POROSITY, % BV	24.4	31.2	30.5	27.8
PORE VOLUME, CC	15.4	19.7	19.3	13.2
CONNATE WATER, % PV	13.0	12.2	20.2	15.9
LENGTH, CM	5.82	5.82	5.82	4.80
GRAVITY GRADIENT, PSI	15.13	15.13	15.13	12.07

CFG.* TIME MINUTES	OIL** PROD. % HV	CFG.* TIME MINUTES	OIL** PROD. % HV	CFG.* TIME MINUTES	OIL** PROD. % HV	CFG.* TIME MINUTES	OIL** PROD. % HV
0.20	0	0.45	16.8	0.54	10.1	0.65	55.0
0.78	0.4	0.88	20.2	0.98	13.3	1.07	56.8
1.26	3.4	1.50	29.5	1.75	29.5	1.99	59.5
2.12	4.1	2.33	39.9	2.54	35.4	2.75	64.9
3.14	6.7	3.48	46.0	3.71	41.9	3.97	67.6
4.70	11.2	4.96	49.4	5.29	47.7	5.47	68.5
6.60	13.4	6.85	50.6	7.39	49.4	7.70	69.4
9.10	19.4	9.60	54.9	10.00	54.2	10.30	71.2
13.20	26.1	13.50	58.4	13.90	58.4	18.60	73.4
17.70	29.9	18.00	60.7	18.30	62.3	26.6	75.7
25.8	37.3	25.8	63.9	22.3	64.6	34.1	77.5
33.7	42.5	33.3	65.6	30.5	68.2	52.3	77.7
44.7	49.6	45.0	67.1	38.9	69.2	63.9	78.0
58.7	53.4	58.7	68.1	50.9	72.1	83.4	78.4
71.7	55.2	71.7	68.8	63.7	73.4	110.7	78.8
96.2	56.7	96.2	70.2	83.0	75.0	138.7	80.2
121.7	57.1	121.7	71.4	109.7	75.8	221.0	81.1
157.7	57.5	157.7	72.0	137.7	76.6	324.0	81.7
195.7	60.4	220.0	73.1	196.7	78.6	693	82.9
270.0	61.9	293.0	74.9	270.0	81.2	1267	82.9
322.0	64.2	692	75.4	323.0	82.1		
692	65.7	1266	77.2	693	82.8		
1266	67.9			1266	83.8		

* EARLY TIME DATA HAVE BEEN DECREASED 0.30 MINUTES TO ACCOUNT FOR CENTRIFUGE STARTUP.
** OIL VOLUMES HAVE BEEN CONVERTED TO PERCENT HYDROCARBON VOLUME.

TABLE V

Water-Oil Imbibition Capillary Pressure Data
in Centrifuge at 160°F
Esso Expro Norway 34/10-3

Core Name, (depth in meters)	1937.78	1963.33	1963.36	1997.85
Core Depth, feet	6357.9	6441.7	6441.8	6554.9
Permeability, $k_{o(cw)}$, md	19.2	239	186	2078
Porosity, % BV	24.4	31.2	30.5	27.8
Pore Volume, cc	15.4	19.7	19.3	13.2
Connate Water, % PV	11.0	11.2	15.0	14.4
Length, cm	5.8	5.8	5.8	4.8

Cap Pressure (Po-Pw) psi	Average Brine Sat. Pct PV	Cap Pressure (Po-Pw) psi	Average Brine Sat. Pct PV	Cap Pressure (Po-Pw) psi	Average Brine Sat. Pct PV	Cap Pressure (Po-Pw) psi	Average Brine Sat. Pct PV
0	12.3	0	13.2	0	17.6	0	68.9
-0.37	60.8	-0.37	73.6	-0.37	72.5	-0.29	87.2
-1.07	65.6	-1.07	79.7	-1.07	80.3	-0.86	89.4
-2.05	69.5	-2.05	82.8	-2.05	83.4	-1.64	89.4
-4.3	72.1	-4.3	84.8	-4.3	86.0	-3.4	89.4
-8.2	74.0	-8.2	85.0	-8.2	87.1	-6.5	89.4
-14.6	74.0	-14.6	85.0	-14.6	87.8	-11.7	89.4

AIR-KEROSENE DRAINAGE CAPILLARY PRESSURE DATA

IN CENTRIFUGE AT 75°F

34/10 WELL 3

CORE NAME	1937.78	1963.33	1963.36	1997.85
PERMEABILITY, KO, MD				
POROSITY, PCT. BULK VOLUME	24.4	31.2	30.5	27.8
PORE VOLUME, PV, CC	15.4	19.7	19.3	13.2
INITIAL OIL SAT., PCT. PV	100.0	100.0	100.0	100.0
LENGTH, CM	5.82	5.82	5.82	4.80

CAP. PRESSURE (PA-PO), PSI	AVERAGE LIQUID SAT., PCT. PV	CAP. PRESSURE (PA-PO), PSI	AVERAGE LIQUID SAT., PCT. PV	CAP. PRESSURE (PA-PO), PSI	AVERAGE LIQUID SAT., PCT. PV	CAP. PRESSURE (PA-PO), PSI	AVERAGE LIQUID SAT., PCT. PV
2.11	100.0	2.11	81.7	2.11	66.8	1.80	38.6
4.40	98.7	4.40	73.6	4.40	56.0	3.76	31.1
8.44	69.5	8.44	39.1	8.44	45.1	7.21	25.8
17.6	55.8	17.6	29.9	17.6	33.7	15.0	20.5
33.8	44.8	33.8	25.4	33.8	26.4	28.8	18.2
60.0	37.7	60.0	23.9	60.0	22.3	51.3	16.7

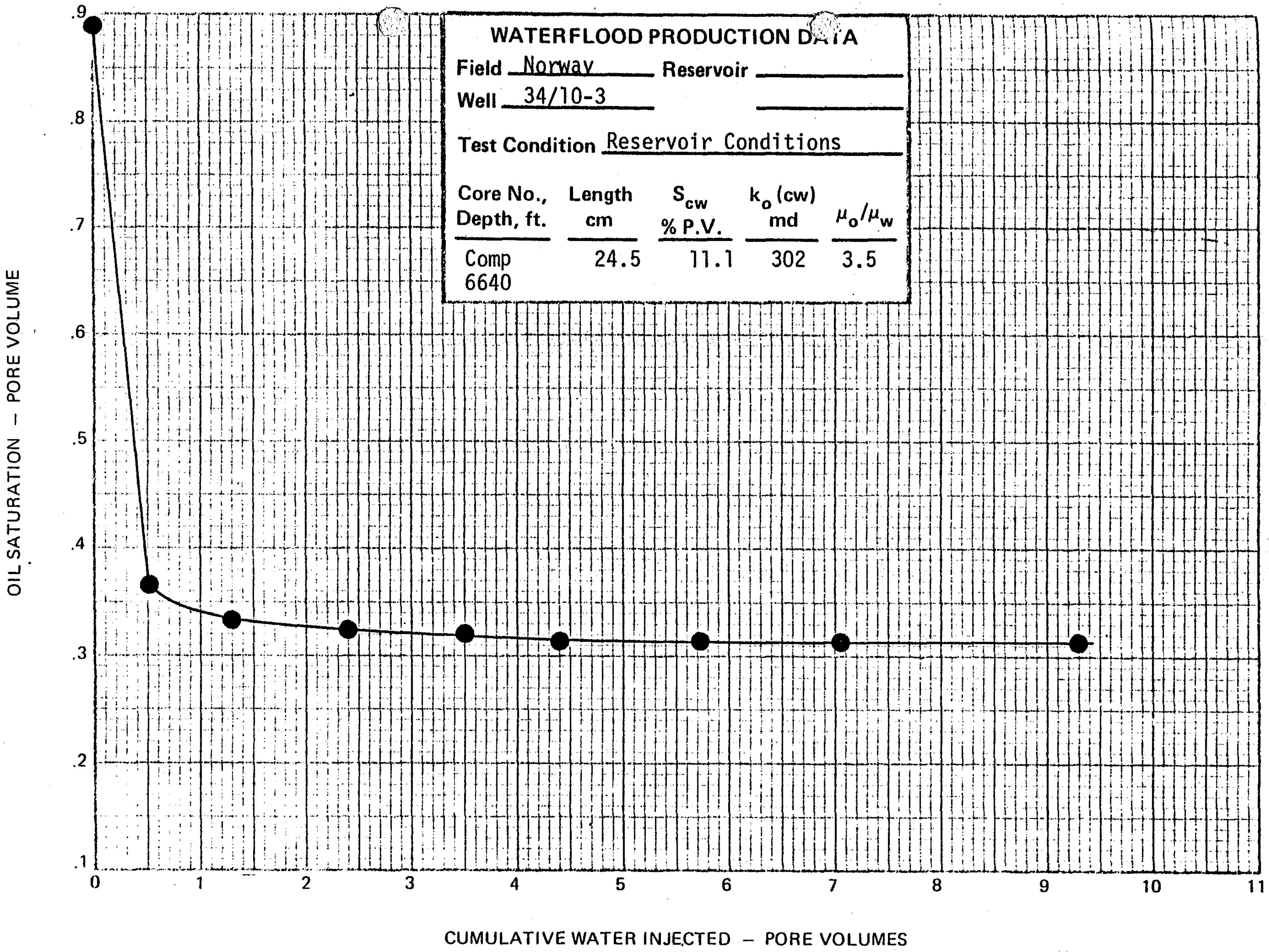

WATERFLOOD PRODUCTION DATA
Field Norway Reservoir
Well 34/10-3
Test Condition Reservoir Conditions
Core No., Depth, ft. | Length cm | Scw % P.V. | ko (cw) md | μo/μw
Comp 6640 | 24.5 | 11.1 | 302 | 3.5
OIL SATURATION – PORE VOLUME
.9
.8
.7
.6
.5
.4
.3
.2
.1
0
1
2
3
4
5
6
7
8
9
10
11
CUMULATIVE WATER INJECTED – PORE VOLUMES

FIGURE 1

FIGURE 2

OIL-WATER RELATIVE PERMEABILITY BY WATERFLOOD

Field Norway Reservoir

Well 34/10-3

Core Composite

Depth, ft. 6640

Permeability, k_o (cw), md 302

Connate Water, % P.V. 11.1

Porosity, % B.V. 30.3

Oil Viscosity, cp 1.5

Brine Viscosity, cp 0.43

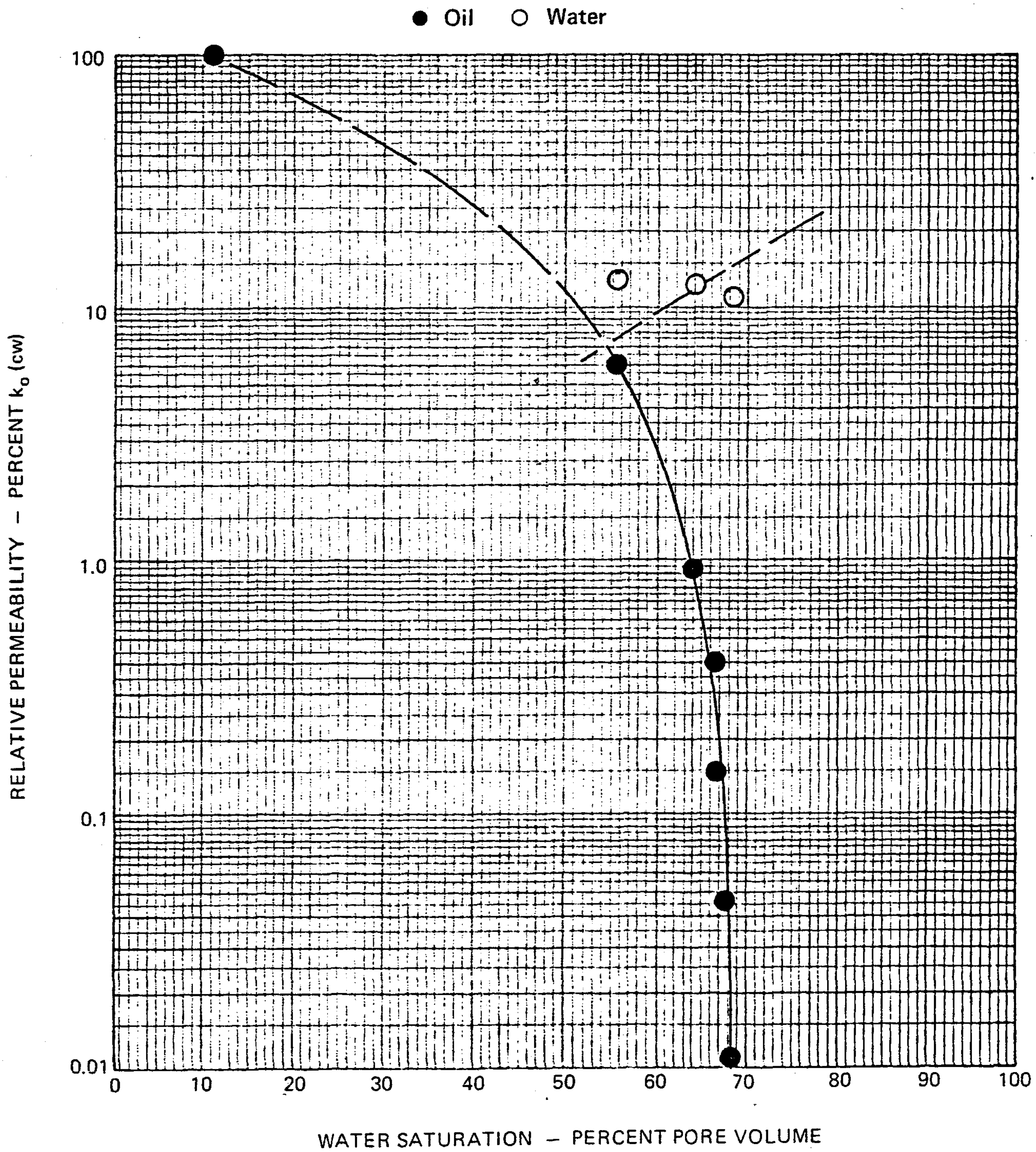


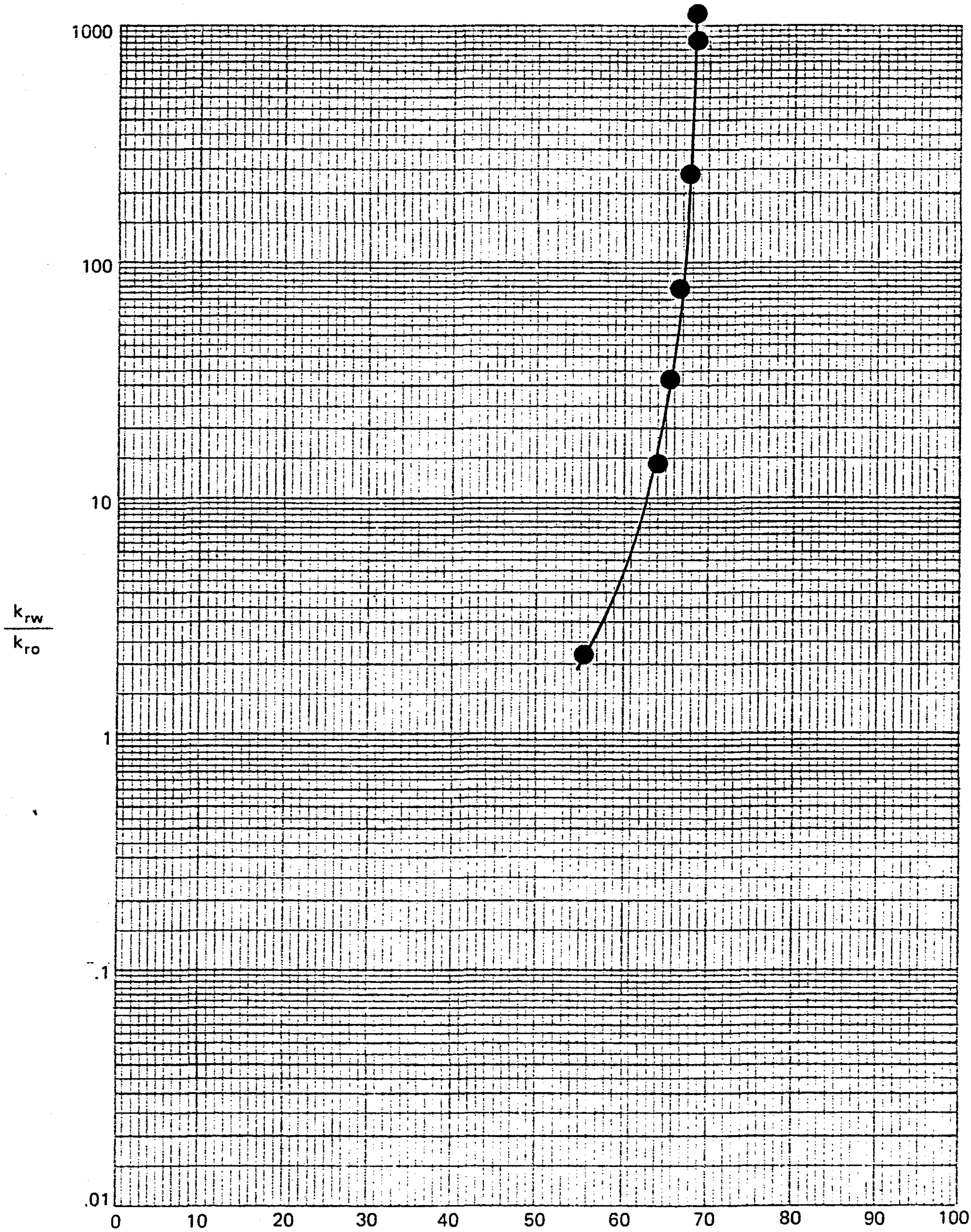
FIGURE 3

OIL-WATER RELATIVE PERMEABILITY RATIO

Field Norway Reservoir

Well 34/10-3

Symbol	Core No., Depth, ft.	Permeability k_o (cw), md	Connate Water % P.V.
	Composite 6640	302	11.1



WATER SATURATION – PERCENT PORE VOLUME

FIGURE 4

GAS-OIL RELATIVE PERMEABILITY BY GASFLOOD

Field Norway Reservoir

Well 34/10-3

Core Composite

Depth, ft. 6640

Permeability, k_o (cw), md 414

Connate Water, % P.V. 11.6

Porosity, % B.V. 30.3

Oil Viscosity, cp 2.5

Gas Viscosity, cp 0.018

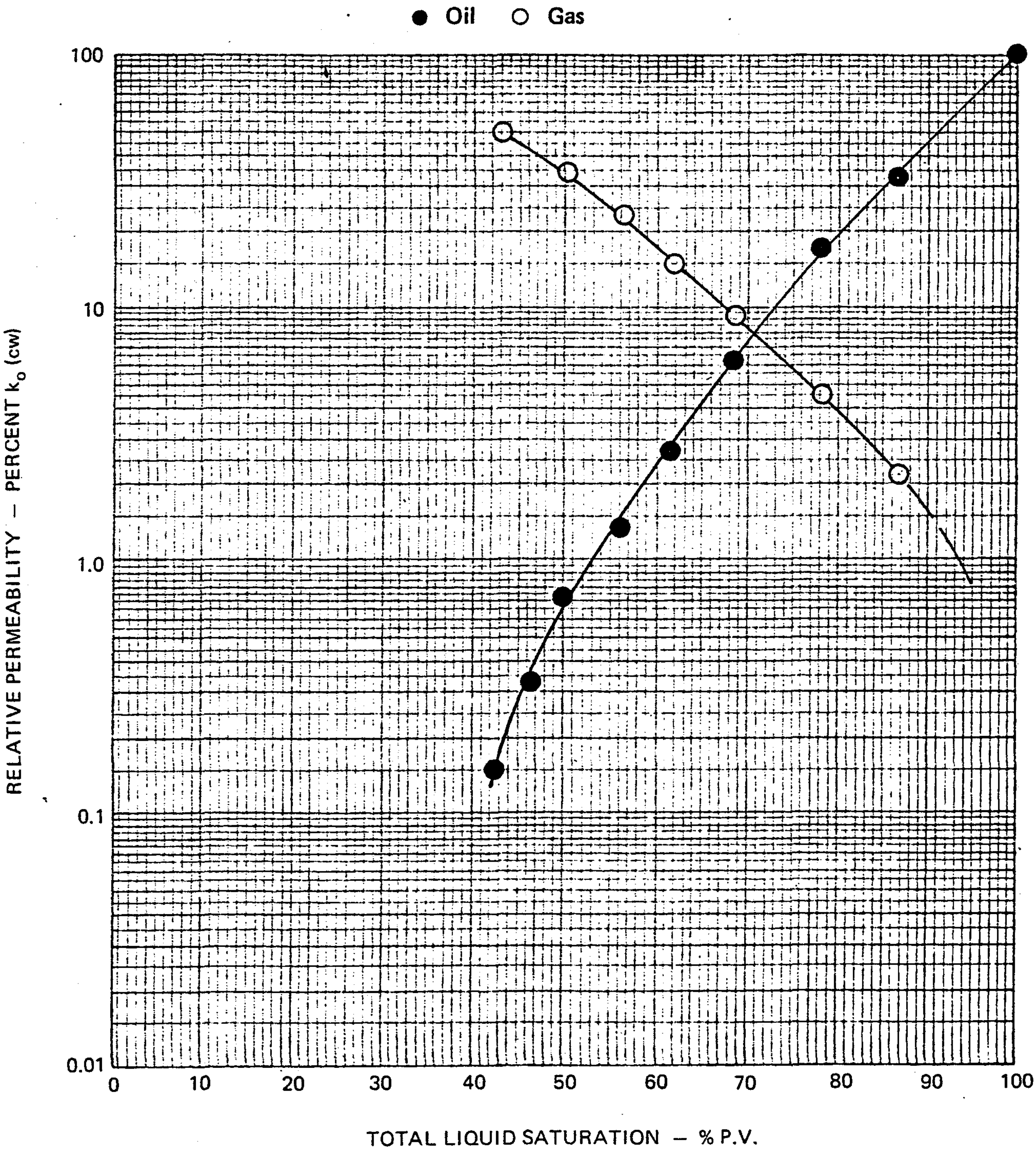


FIGURE 5

GAS-OIL RELATIVE PERMEABILITY RATIO

Field Norway Reservoir

Well 34/10-3

Symbol	Core No., Depth, ft.	Permeability k_o (cw), md	Connate Water % P.V.
	Composite 6640	414	11.6

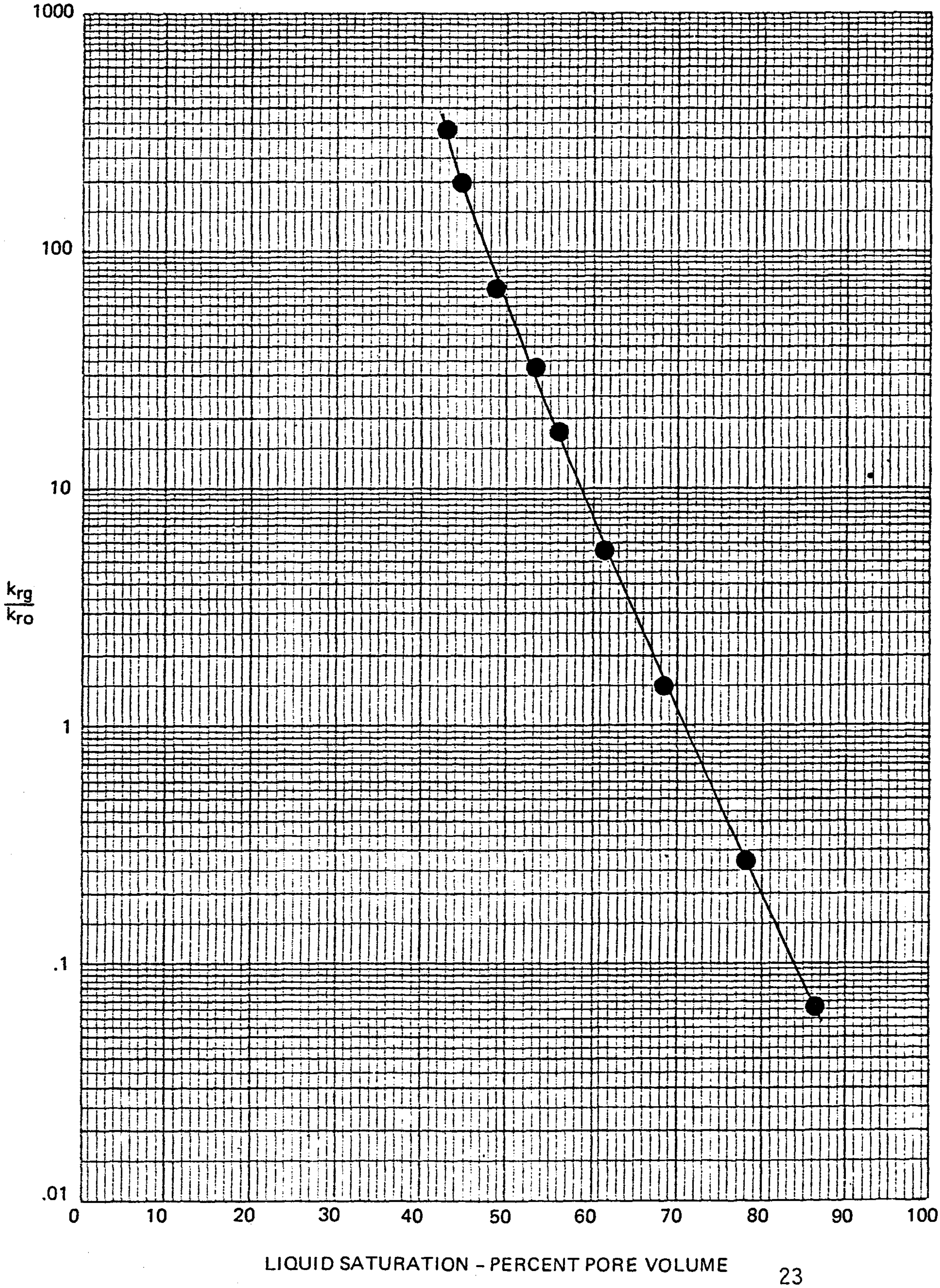


FIGURE 6

RELATIVE PERMEABILITY TO OIL BY CENTRIFUGE
WATER-OIL SYSTEM

Field Norway Reservoir

Well 34/10-3

Core 1937.78 Porosity, % B.V. 24.4
Depth, ft. 6357.9 Oil Viscosity, cp 4.4
Permeability, k_o (cw), md 19.2 Brine Viscosity, cp 9.43
Connate Water, % P.V. 13.0

O Uncorrected for capillary end effects

• Corrected

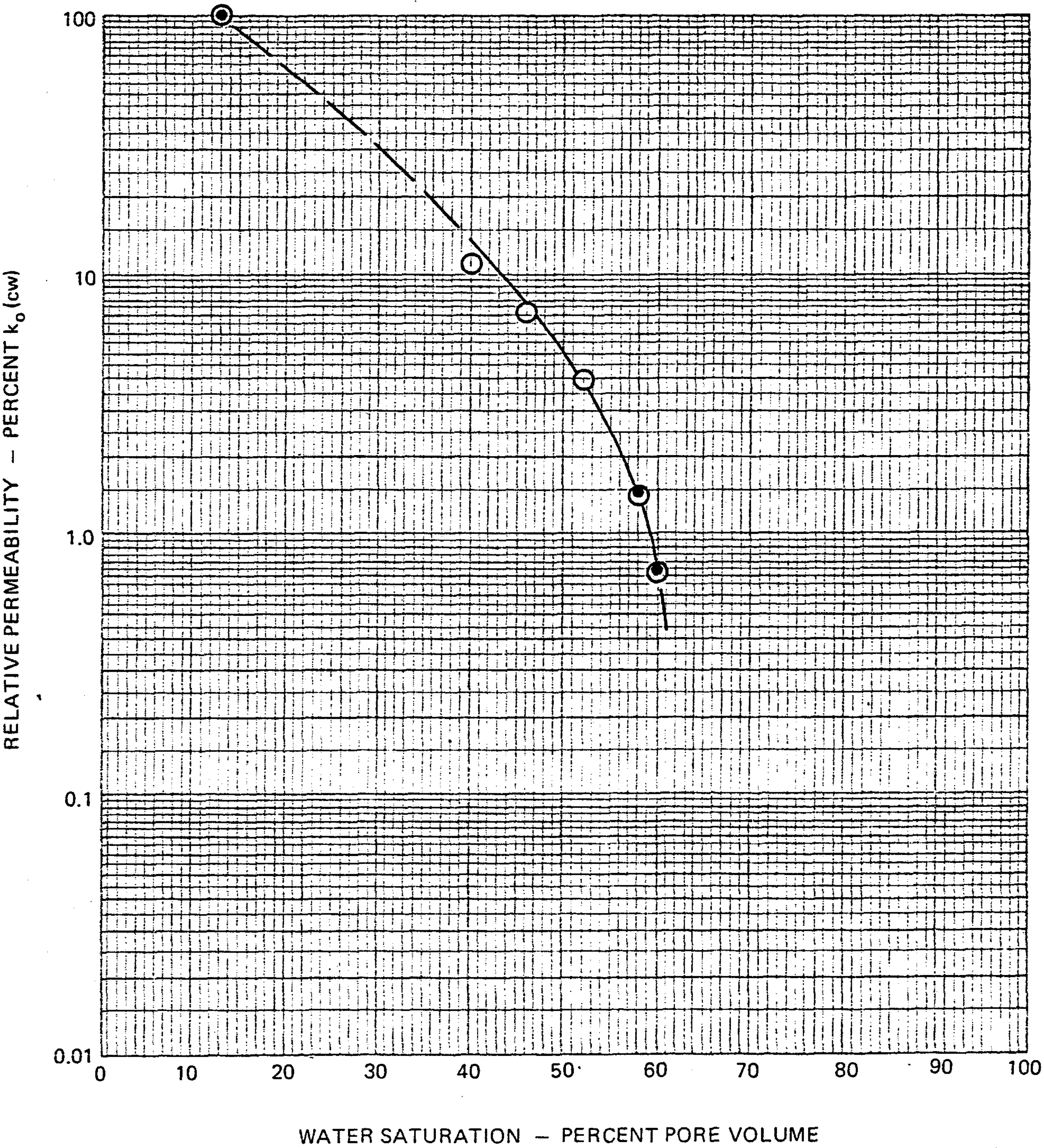


FIGURE 7

RELATIVE PERMEABILITY TO OIL BY CENTRIFUGE
WATER-OIL SYSTEM

Field Norway Reservoir

Well 34/10-3

Core	1963.33	Porosity, % B.V.	31.2
Depth, ft.	6441.7	Oil Viscosity, cp	4.4
Permeability, k_o (cw), md	239	Brine Viscosity, cp	0.43
Connate Water, % P.V.	12.2		

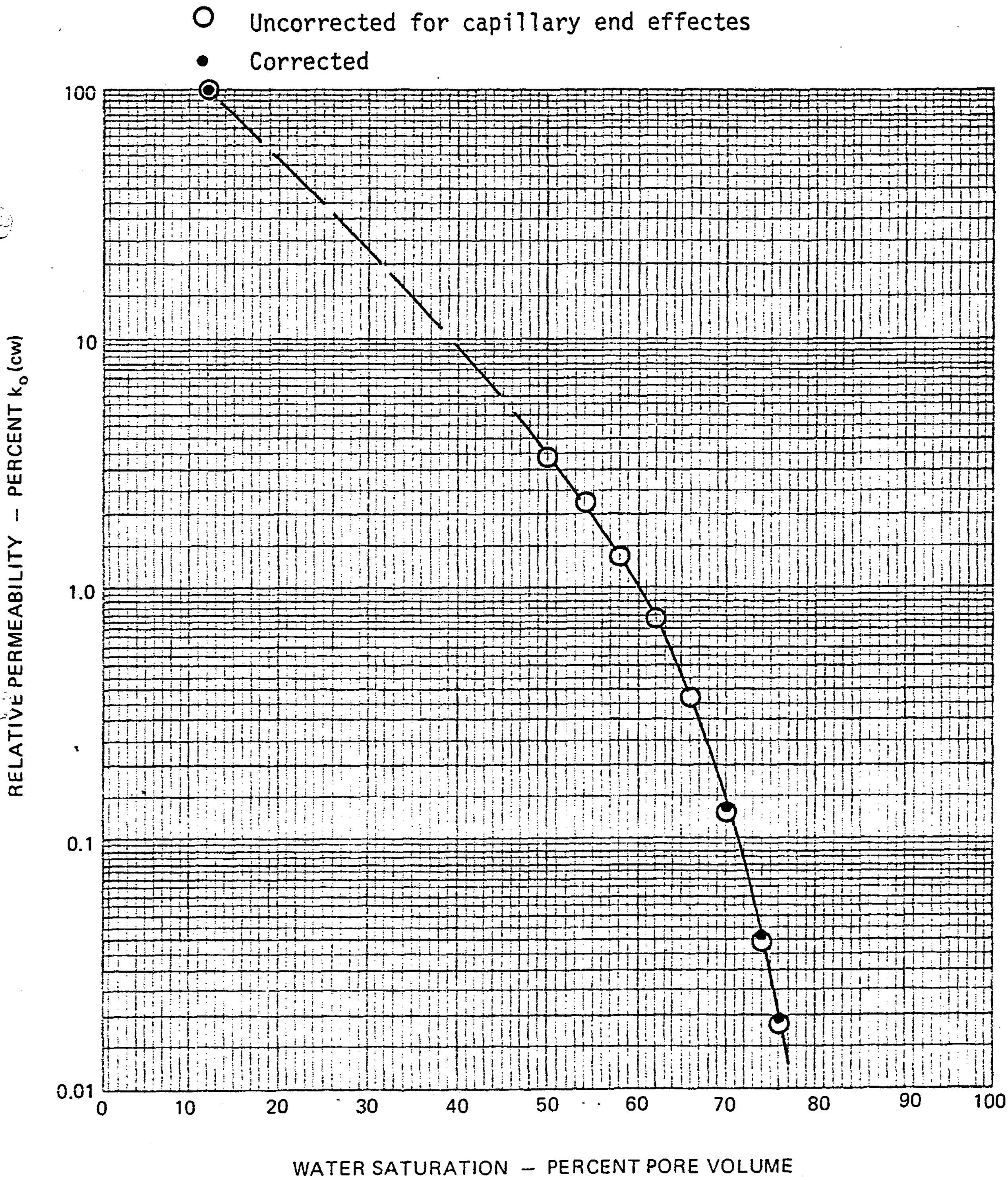


FIGURE 8

RELATIVE PERMEABILITY TO OIL BY CENTRIFUGE
WATER-OIL SYSTEM

Field Norway Reservoir

Well 34/10-3

Core 1963.36 Porosity, % B.V. 30.5

Depth, ft. 6441.8 Oil Viscosity, cp 4.4

Permeability, k_o (cw), md 186 Brine Viscosity, cp 0.43

Connate Water, % P.V. 20.2

O Uncorrected for capillary end effects

●—● Corrected

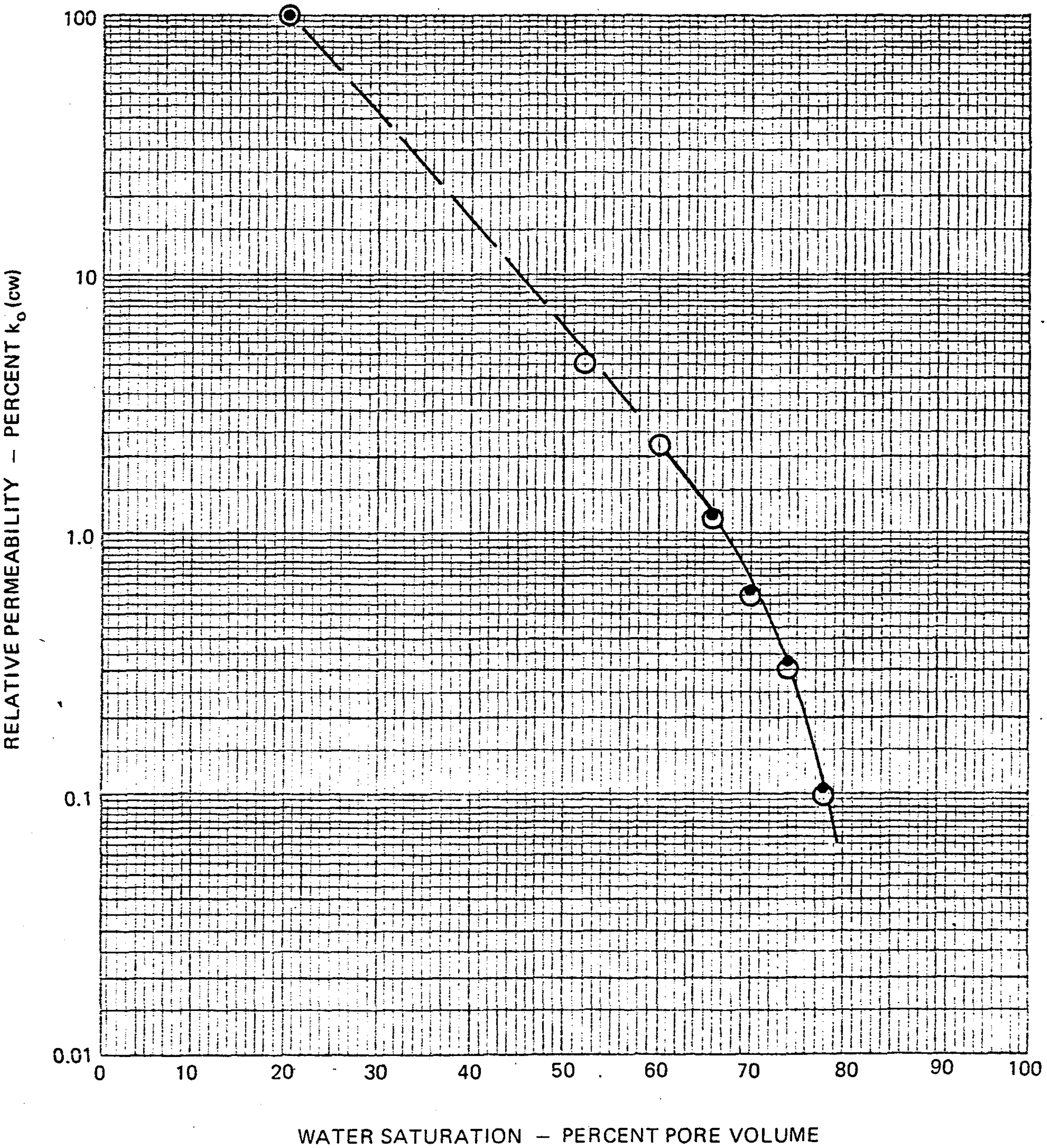


FIGURE 9

RELATIVE PERMEABILITY TO OIL BY CENTRIFUGE
WATER-OIL SYSTEM

Field Norway Reservoir

Well 34/10-3

Core 1997.8
Depth, ft. 6554.9
Permeability, k_o (cw), md 2078
Connate Water, % P.V. 15.9

Porosity, % B.V. 27.8
Oil Viscosity, cp 4.4
Brine Viscosity, cp 0.43

Capillary end effects nil

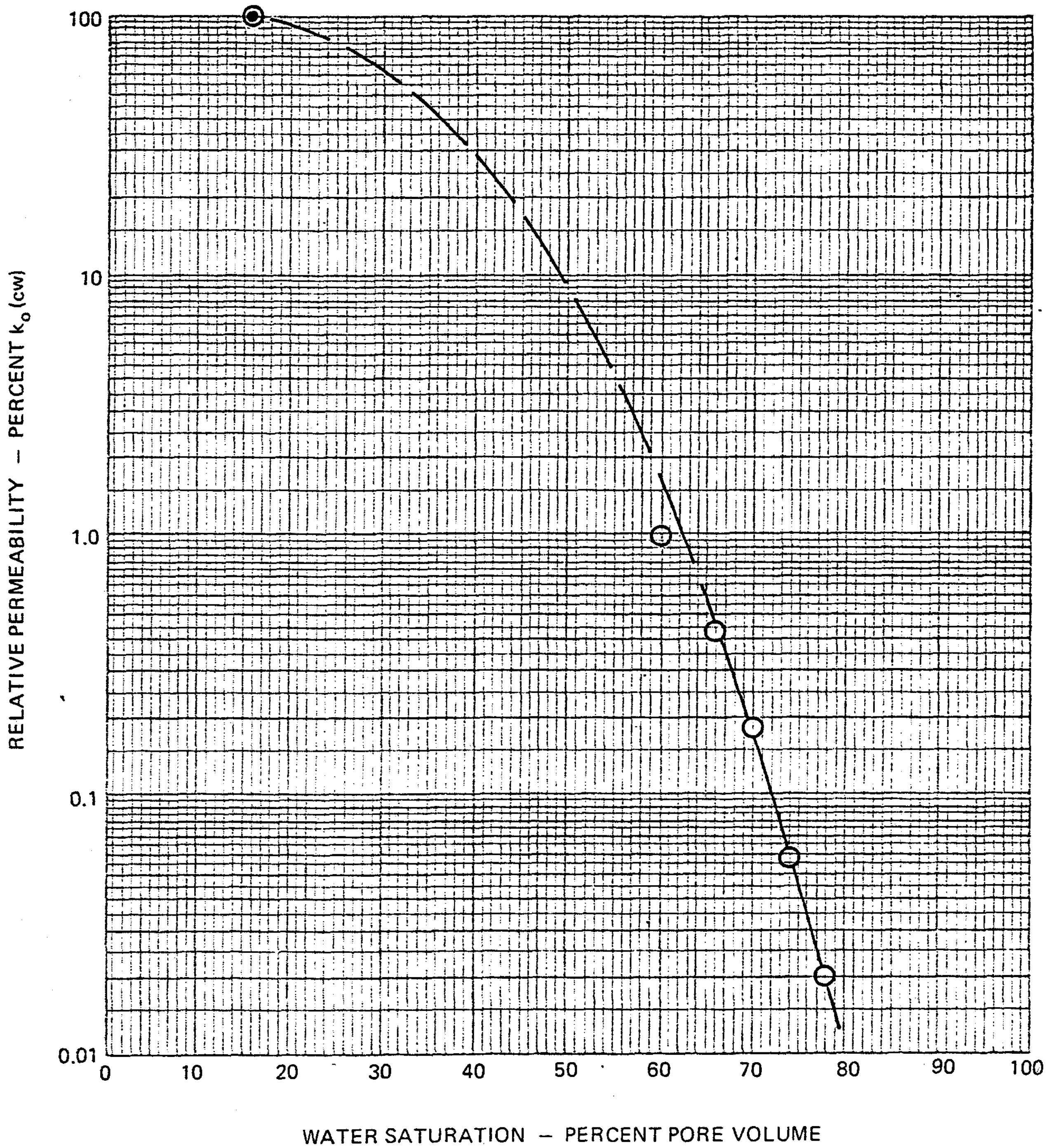


FIGURE 10

WATER-OIL IMBIBITION CAPILLARY PRESSURE BY CENTRIFUGE

Field Norway Reservoir

Well 34/10-3

Core No., Depth, ft.	Permeability, k_o (cw), md	Porosity, % B.V.	Connate Water, % P.V.
1937.78 6357.9	19.2	24.4	11.0

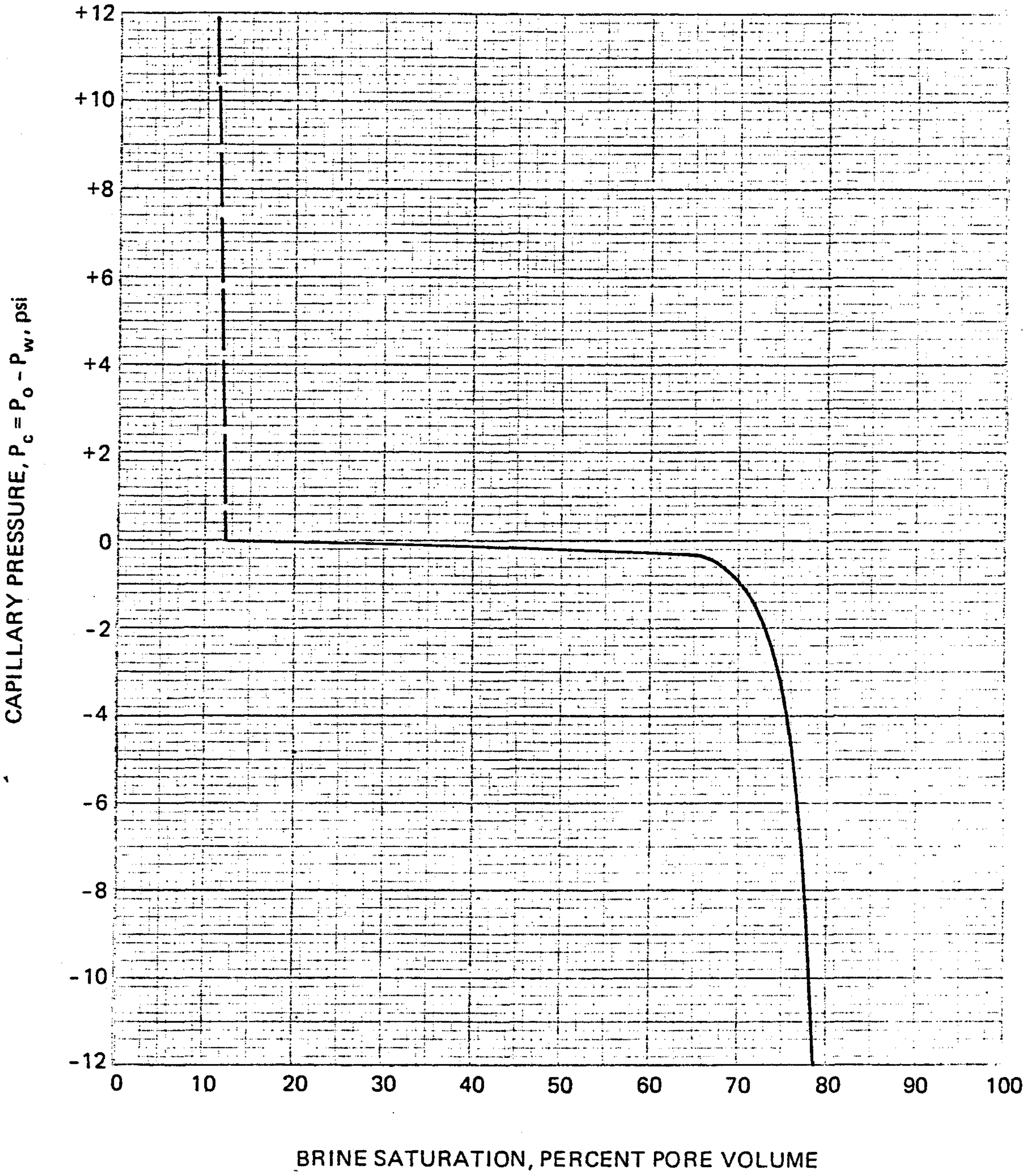


FIGURE 11

WATER-OIL IMBIBITION CAPILLARY PRESSURE BY CENTRIFUGE

Field Norway Reservoir

Well 34/10-3

Core No., Depth, ft.	Permeability, k_o(cw), md	Porosity, % B.V.	Connate Water, % P.V.
1963.33 6441.7	239	31.2	11.2

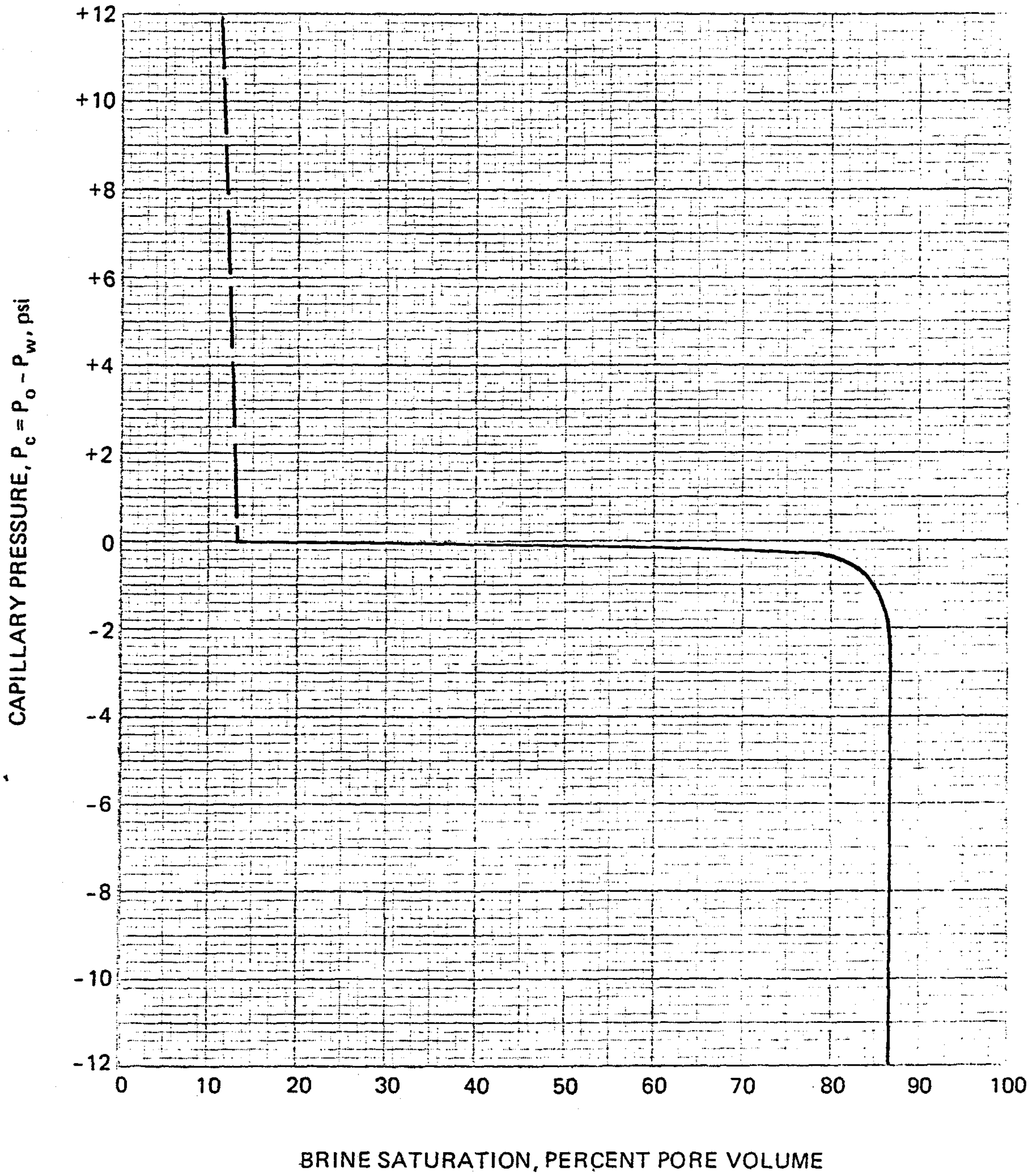


FIGURE 12

WATER-OIL IMBIBITION CAPILLARY PRESSURE BY CENTRIFUGE

Field Norway Reservoir

Well 34/10-3

Core No., Depth, ft.	Permeability, k_o(cw), md	Porosity, % B.V.	Connate Water, % P.V.
1963.36 6441.8	186	30.5	15.0

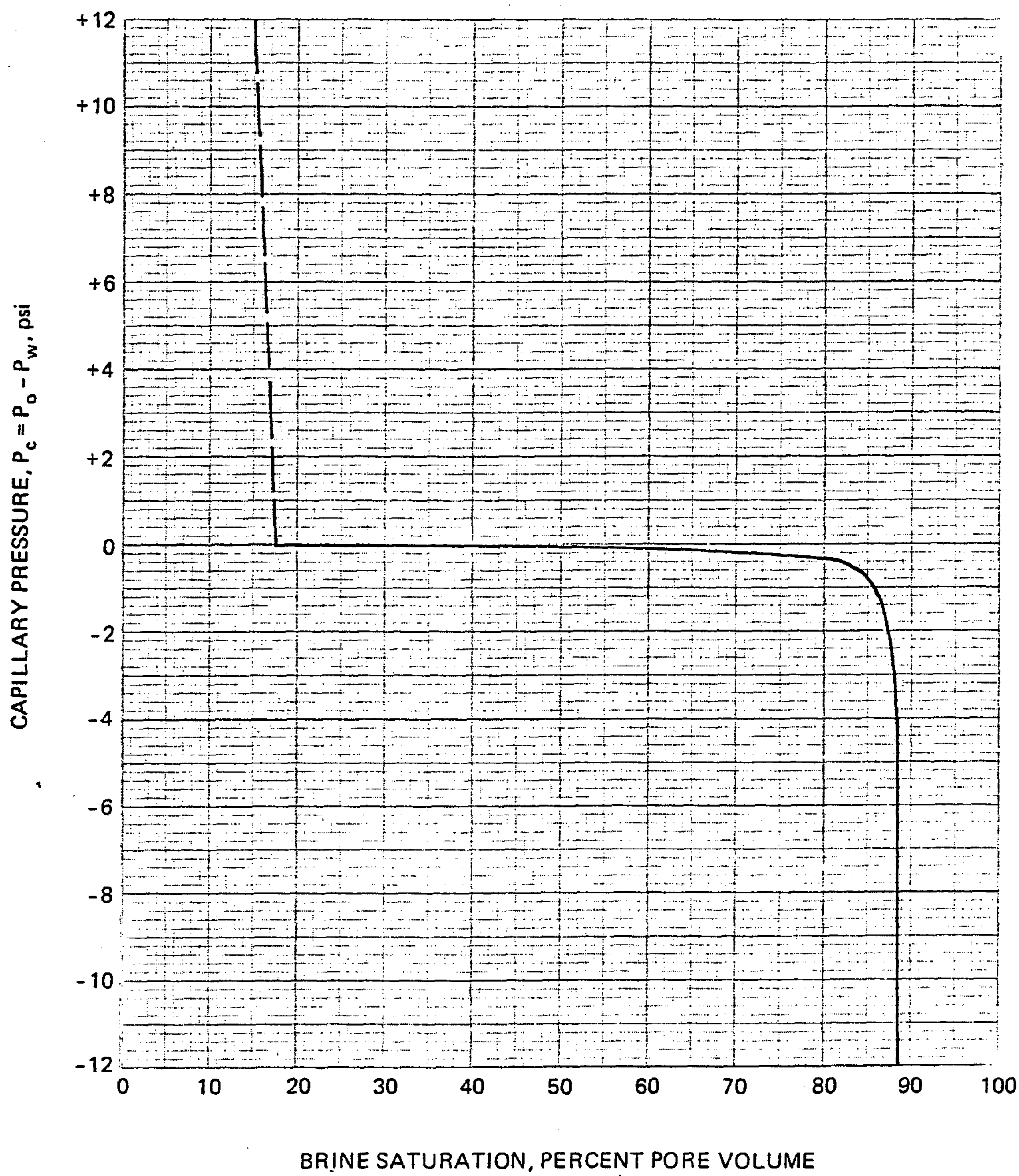


FIGURE 13

WATER-OIL IMBIBITION CAPILLARY PRESSURE BY CENTRIFUGE

Field Norway Reservoir

Well 34/10-3

Core No., Depth, ft.	Permeability, k_o (cw), md	Porosity, % B.V.	Connate Water, % P.V.
1997.87 6554.9	2078	27.8	14.4

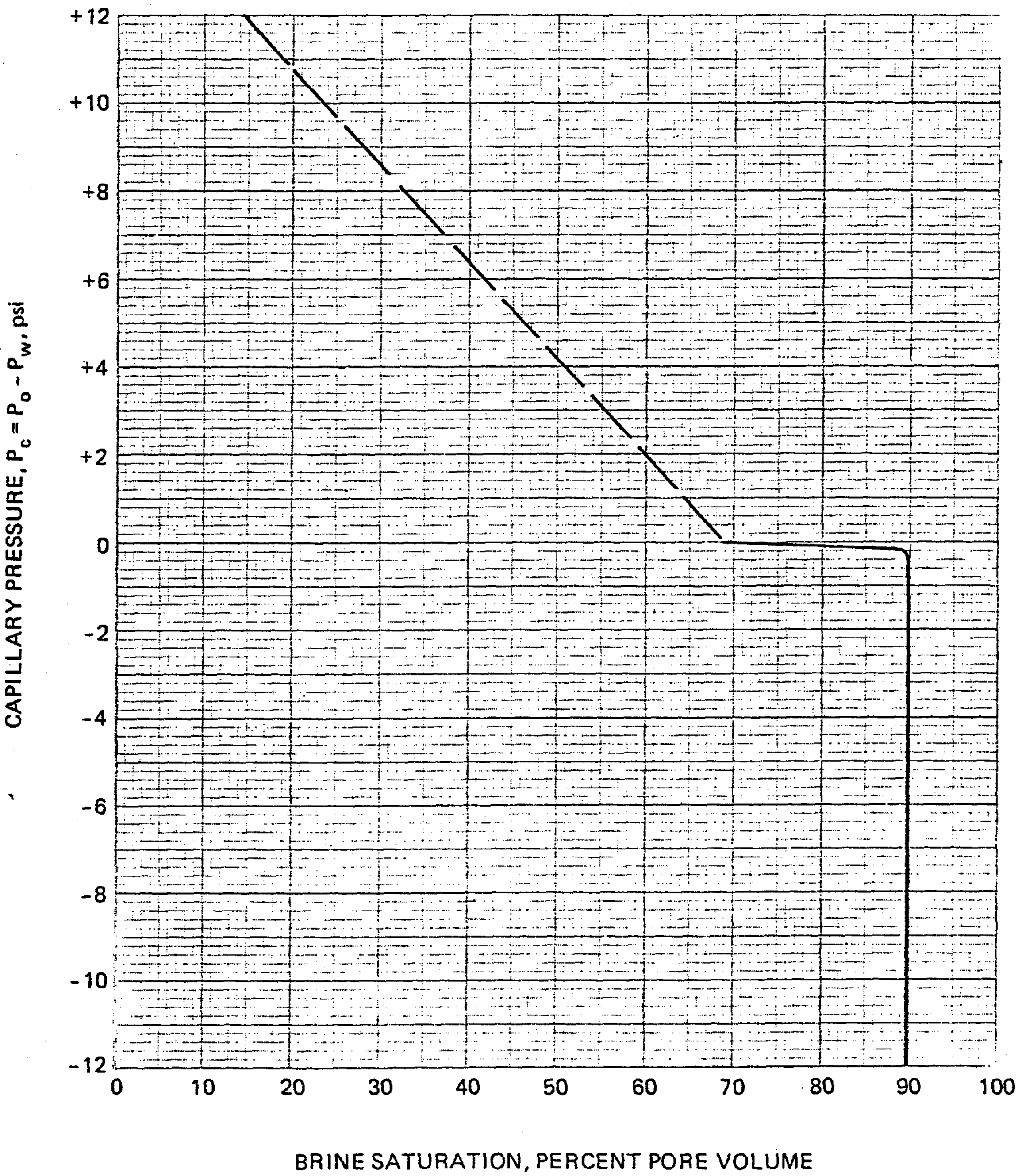


FIGURE 14

CAPILLARY PRESSURE CURVE

FIELD Norway 34/10	CORE 1937-78
RESERVOIR	PERMEABILITY, md
WELL 3	POROSITY,% 24.4
DEPTH, ft 6357.5	METHOD Air-Kerosene Drainage

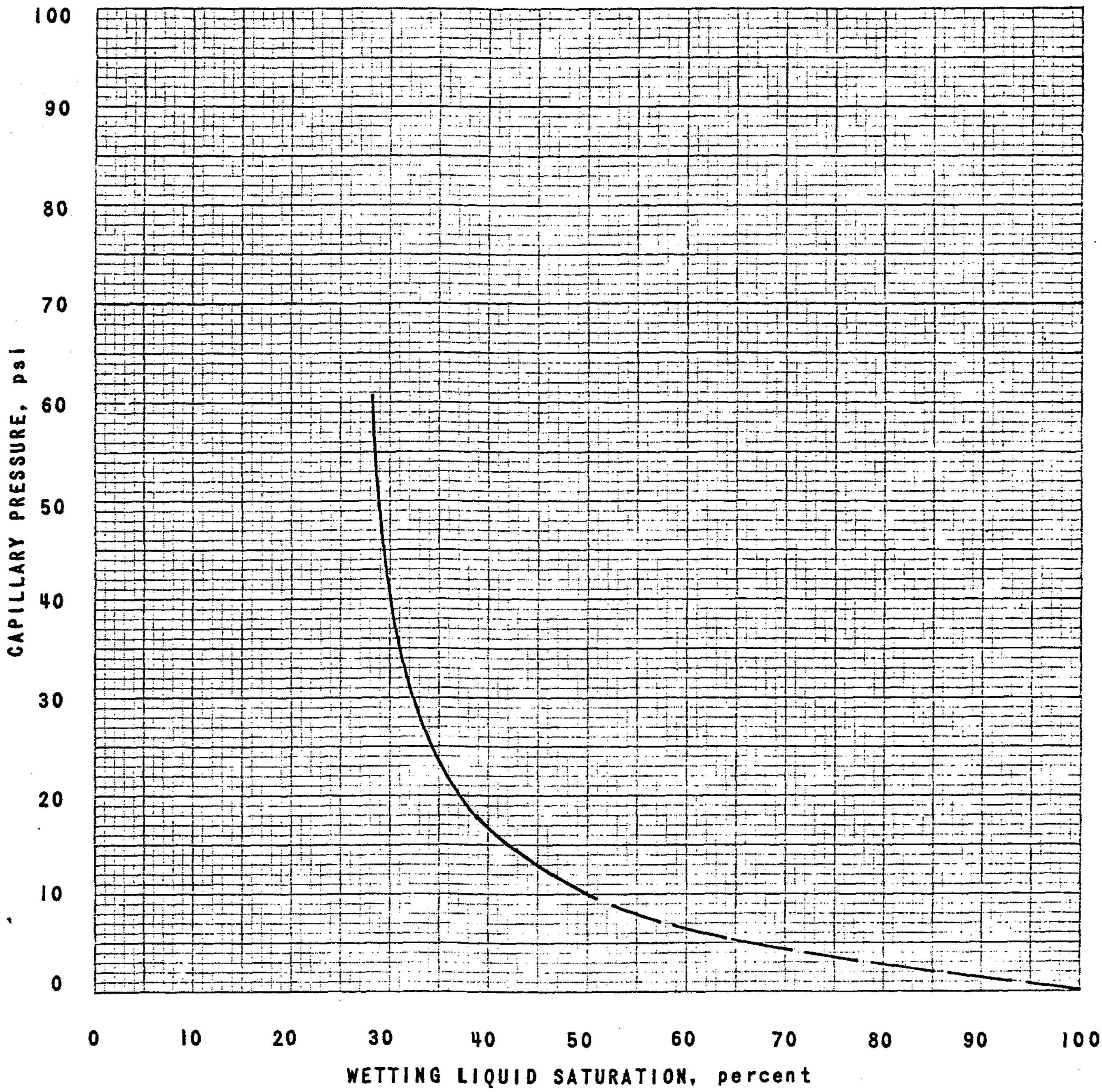


FIGURE 15

CAPILLARY PRESSURE CURVE

FIELD	Norway 34/10	CORE	1963.33
RESERVOIR		PERMEABILITY, md	
WELL	3	POROSITY,%	31.2
DEPTH, ft	6441.4	METHOD	Air-Kerosene Drainage

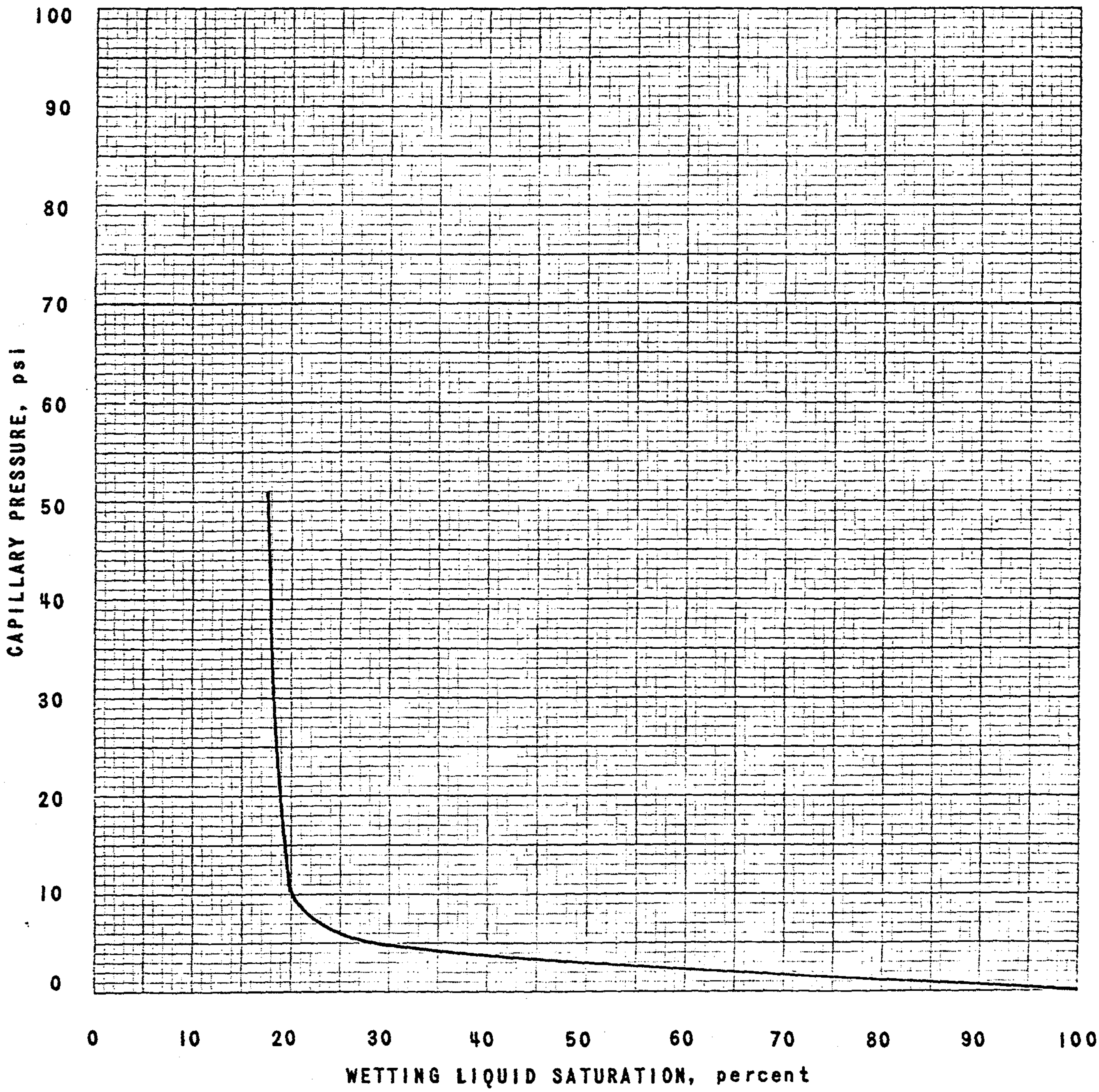


FIGURE 16

CAPILLARY PRESSURE CURVE

FIELD Norway 34/10

RESERVOIR

WELL 3

DEPTH, ft 6441.5

CORE 1963.36

PERMEABILITY, md

POROSITY,% 30.5

METHOD Air-Kerosene Drainage

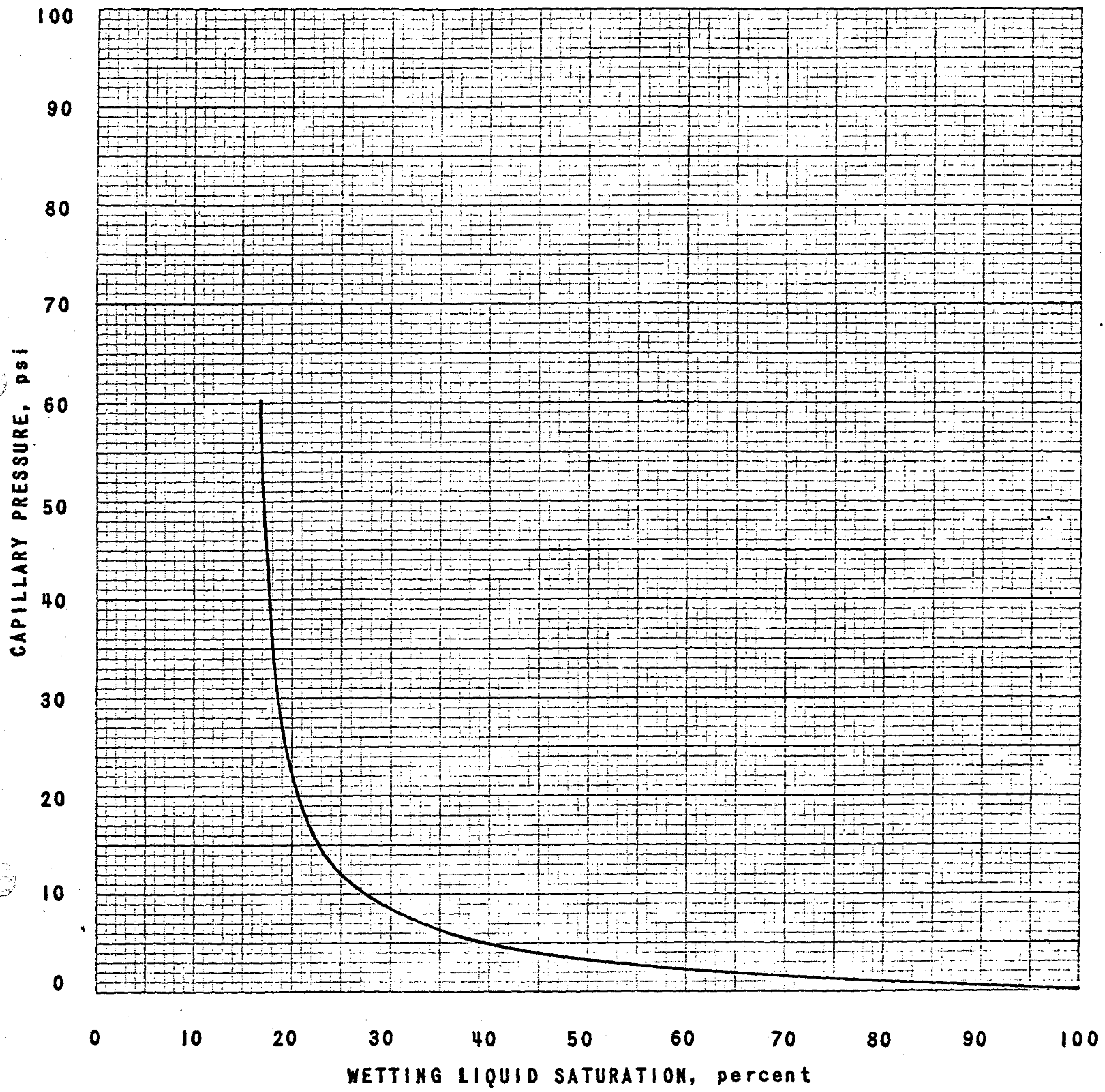


FIGURE 17

CAPILLARY PRESSURE CURVE

FIELD Norway 34/10
RESERVOIR
WELL 3
DEPTH, ft 6554.6

CORE 1997.85
PERMEABILITY, md
POROSITY,% 27.8
METHOD Air-Kerosene Drainage