Tundra oil and gas ltd.

November 8, 1996

Manitoba Energy and Mines
Petroleum Branch
1395 Ellice Avenue, Suite 360
Winnipeg, Manitoba
R3G OG3

NOV 18 1996

Attention: **Mr. J. Fox, P.Eng.**
Chief Petroleum Engineer

Dear John,

RE: Deloraine 8-31-2-23 Coreflood Study

Please find attached the referenced study for your departmental records.

If you have any questions, I can be reached at 934-5853.

Yours truly,

TUNDRA OIL AND GAS LTD.

George Czyzewski, P.Eng.
General Manager

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J.

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TUNDRA - DELORAINE
WATERFLOOD STUDY

Prepared For

Tundra Oil & Gas Ltd.

Prepared By

Hycal Energy Research Laboratories Ltd.

November 7, 1996

96-131-A

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SUMMARY

Study Objective

At the request of George Czyzewski of Tundra Oil and Gas Ltd., Hycal Energy Research Laboratories Ltd. conducted a waterflood study on core and fluid material from the Deloraine area. The objective of the study was evaluate the quality of the oil reservoir as a candidate for possible waterflood recovery.

A laboratory scale dead-oil/water relative permeability test was conducted to estimate initial water saturation in the reservoir, to evaluate potential waterflood recovery and to determine the water/oil relative permeability profiles.

Conclusions

The following conclusions are provided to enhance understanding of the laboratory data and to offer additional insight relative to Hycal's experience with laboratory and field processes. They represent our interpretation as to possible mechanisms and physical phenomena that may be occurring within the laboratory models that have been studied. However, these laboratory experiments are microscale representations of the field scenario and macroscale phenomena may override behaviour exhibited in the laboratory. A more thorough development of these conclusions is presented in the Discussion section of this report.

1. Initial absolute permeabilities were measure on the core stack with formation brine prior to attempting to restore the wettability. Absolute permeability to brine for the stack was 11.9 mD.

2. Initial water saturations on the composite core stack after the six week wettability restoration period was estimated to be 29.7% (based on post-test material balance calculations).

3. The initial permeability to oil after wettability restoration was 0.21 mD which is significantly lower than would normally be expected for this quality of rock based on the

routine gas permeabilities and absolute permeability to brine. Heating the core material and crude oil to 40°C prior to running the test appeared to have no significant effect on the resulting permeability (which suggests that paraffins are not the cause of the problem). Therefore, the low oil permeability appears to be inherent with the fluid/rock system possibly associated with either strongly oil wet or mixed wettability behaviour. Other factors that may result in lower than expected permeability are associated with relative permeability effects, the application of full net overburden pressure and the absence of gas slippage effects.

4. The laboratory waterflood test conducted on the core stack indicates an ultimate oil recovery of 47.7% of the original oil-in-place (OOIP) after 2.28 pore volume of water injection. Breakthrough occurred at approximately 0.24 pore volumes of water injection with significant oil production occurring after water breakthrough. Endpoint permeability to water at the end of the waterflood was 0.11 mD.

DISCUSSION

The dead-oil/water relative permeability study was conducted using restored state core material from the Tilston formation of the Deloraine area. The test simulated the reservoir conditions of 30°C with 10235 kPag of net overburden pressure and no backpressure and utilized dead field crude and formation brine as displacing fluids. The major results of this study are discussed in the following sections.

1. The routine analyses conducted on the core plugs drilled from the parent core material are summarized in Table 1. As a result of these analyses, 4 plugs were selected to be used in a composite core stack to represent core material in the waterflood test. Initial absolute permeabilities were measure on the core stack with formation brine once the core stack had been mounted and prior to attempting to restore the wettability. Absolute permeability to brine for the stack was 11.9 mD. This is the absolute liquid permeability used in the relative permeability test.

2. Initial water saturations on the composite core stack after the six week wettability restoration period was estimated to be 29.7% (based on post-test material balance calculations).

3. The results of the water-oil relative permeability test are summarized in Tables 2 through 5 and Figures 2 through 4. The initial permeability to oil after wettability restoration was only 0.21 mD which is significantly lower than would normally be expected for this quality of rock based on the routine gas permeabilities and absolute permeability to brine. Heating the core material and crude oil to 40°C prior to running the test appeared to have no significant effect on the resulting permeability (which suggests that paraffins are not the cause of the problem). Therefore, the low oil permeability appears to be inherent with the fluid/rock system possibly associated with either strongly oil wet or mixed wettability behaviour. Other factors that may result in lower than expected permeability are associated with relative permeability effects, the application of full net overburden pressure and the absence of gas slippage effects.

4. The laboratory waterflood test conducted on the core stack indicates an ultimate oil recovery of 47.7% of the original oil-in-place (OOIP) after 2.28 pore volume of water injection. Breakthrough occurred at approximately 0.24 pore volumes of water injection with significant oil production occurring after water breakthrough. Endpoint permeability to water at the end of the waterflood was 0.11 mD. The relative permeability profiles for this waterflood displacement are typical for oil-wet porous media in that the endpoint water relative permeability is similar in magnitude to the initial oil relative permeability. This can be explained by considering the orientation of each phase in the pore space. As

the flood front advances, the immobile residual oil phase adheres to the pore walls while the water phase occupies a central channel in the pore. This acts to lower the frictional forces of the displacing phase by isolating it from the static boundary at the rock surface and reducing turbulence caused by pore space particulates, clays and other pore features which are encapsulated by the residual oil film. These effects result in a water relative permeability profile which favours the conductivity of the water phase through the pore system and the propensity for early flood front breakthrough and water coning tendencies.

PROCEDURES & EQUIPMENT

Core Handling and Preparation

Full diameter core material supplied by Tundra Oil and Gas Ltd. was utilized as the test matrix for the study. The core material was taken from the 820.75 to 822.22 m interval of well 8-31-2-23 W1M in the Deloraine area.

A total of 6 plugs were drilled from the full diameter core samples to obtain small plug samples with a maximum diameter of 3.81 cm. All small plugs were drilled using 3% KCl as a lubricating fluid to minimize the potential for damage of in situ clay mineralogy and prevent any other damage to the core during drilling.

Routine air permeability and helium expansion porosity were conducted on the samples to aid in the selection of representative core material for testing. Table 1 summarizes the routine analysis for the samples.

Sufficient volumes of dead crude oil and produced water were supplied by Tundra to act as displacing fluids for the test series.

Wettability Restoration

Core samples used in this study were in a non-preserved state, and a wettability restoration procedure was utilized to attempt to restore the rock wettability to original in-situ conditions. Since all reservoirs initially exist in a water-wet state, with oil migration occurring into the reservoir following deposition and hydration, the restoration procedure is conducted to simulate the actual field scenario.

The cores to be restored are mounted in lead sleeves, evacuated and then saturated with formation brine (hydration stage). This brine is circulated in the core for one week to re-establish an ionic equilibrium condition and to rehydrate any desiccated in-situ clays. This brine circulation is followed by the displacement of supplied unoxidized dead crude oil (migration stage) at reservoir temperature for a recommended period of six weeks (1100 hours) as discussed in the literature. At the beginning of each week a fresh supply of oil is circulated through the core followed by a static interval to allow the wettability transformation reaction to occur (if the tendency exists).

This wettability restoration procedure is important if the rock has a natural tendency to become less water-wet (i.e. neutral- to oil-wet) as normal extraction procedures tend to remove the polar and asphaltic components which cause an oil-wetted pore surface to be established. The long term exposure of the virgin unoxidized crude generally allows an equilibrium concentration of these polar and asphaltic constituents to be re-adsorbed on the rock surface allowing the samples to revert to their natural in-situ wettability. Restoring the correct wettability condition is significant to experimentation because the wetting phase contacting the rock matrix acts as the conduit (or barrier) between invading fluids and rock mineralogy thereby controlling the propensity for rock-fluid interactions. Wettability can also have a profound influence on the efficiency of immiscible displacement processes.

Ambient Condition Water-Oil Relative Permeability Tests

Ambient pressure (i.e. dead oil) relative permeability experiments are not typically recommended for coreflood testing. The viscosity of the dead crude oil is usually significantly higher than the viscosity of the live crude oil, and this has an adverse affect on mobility and consequently on the displacement efficiency of the rock/fluid system. In particular, the viscosity ratio term (μ_o/μ_w) within the mobility ratio can be increased by as much as 200 to 300% (i.e. larger is more adverse), due to the more viscous dead crude oil phase and the affect of adverse mobility is well documented in the literature.

In spite of the concerns over the mobility of the dead crude system, it was decided to continue with the experiments in this manner because there is very little gas produced with this oil and therefore the difference between live and dead oil systems should not be as great.

The core samples to be tested were mounted using the equipment outlined in the Description of Equipment section of this report. Core samples were maintained at the specified reservoir temperature and a net overburden pressure was applied to simulate the net effective pore pressure in the reservoir. The laboratory net overburden stress was Poisson's ratio corrected to account for the tri-axial stress condition exerted on the sample in the core holder. This correction ensures that field stress load conditions are emulated to yield representative rock compression and realistic absolute permeability values.

The following procedure was utilized for each of the ambient condition water-oil relative permeability tests conducted as a portion of the test program.

Relative Permeability Procedure

1. Composite core samples are mounted using specified conditions.
2. Initial effective permeability to crude oil is measured to establish the initial permeability endpoint value for the relative permeability relationship.
3. Injection formation brine at a low rate until no additional oil is produced. During this displacement, measure the pressure drop across the core and record the water and oil production rates to facilitate the calculation of the saturation and permeability values.
4. Measure several endpoint waterflood permeabilities at higher rates to ensure that the endpoint water permeability data are representative.
5. At the conclusion of the test, dismount and subject the core to Dean-Stark extraction to measure exact in-situ residual fluid saturations to obtain material balance closure.
6. Evaluate endpoint permeability data and develop production and pressure history profiles to facilitate the execution of the history match numerical simulation technique to obtain relative permeability profiles.

General Displacement Test Equipment

Equipment that is used in conventional displacement experiments is common to most core flow evaluation techniques. Detailed schematics of the specific apparatus configuration are provided in Figure 1 of this report. General descriptions of the laboratory equipment utilized for these tests appear in the following paragraphs.

Core Mounting

The core sample to be tested is placed in a 3.81 cm ID flexible confining sleeve. The ductility of the sleeve allows a confining external overburden pressure to be transferred to the core in a radial and axial mode to simulate reservoir pressure. The core, mounted within the sleeve, is placed inside a 7.5 cm ID steel core holder that can simulate reservoir pressures of up to 68.9 MPa. This pressure is applied by filling the annular space between the core sleeve and the core holder with non-damaging mineral oil. The annular fluid is then compressed with a hydraulic pump to obtain the desired overburden pressure. The core holder ends each contain two ports to facilitate fluid displacement and pressure measurements at each end of the core.

Stacked Core

Stacked (composite) cores are constructed to reduce experimental error by increasing the pore volume of the porous media utilized for the experiment. End effect errors can also be reduced by increasing the amount of rock volume which possesses stabilized saturation apart from the inlet and outlet phenomena. The longer core composed of several shorter samples is constructed by mounting the core samples end to end and placing wafers of thin porous fibre between the samples to ensure capillary continuity between the rock faces. The stacked core technique has application for both secondary waterflood displacement experiments as well as enhanced displacement where mixing zone length or chemical adsorption is of concern.

Conventional Core Flow Heads

The portions of the core holder directly adjacent to the injection and production ends of the core are equipped with radial distribution plates to ensure that fluid flow is uniformly distributed into and out of the core sample. These heads are used for experiments which involve fluids that are prefiltered to remove large suspended solids which could entrain in the flow ports. All wetted surfaces of the flow equipment use conventional 316 SS.

Pressure Measurement

Pressure differential is monitored using Validyne pressure transducers. The transducers are mounted directly across the core and measure the pressure differential between the injection and production ends. The pressure transducers have ranges of sensitivity ranging from 0 to 14 and 0 to 26000 kPa and is rated as accurate to 0.01% of the full scale value. The appropriate transducer size is selected based upon the expected permeability and associated range of accompanying differential pressures for a given core sample. The signal from the pressure transducer appears on a multi-channel digital Validyne terminal from which the test operator records pressure readings during the displacement processes. The signal can also be downloaded to a computerized continuing data acquisition system for long term runs.

Temperature Control

The core holder and associated injection fluids are contained in a temperature controlled air bath to simulate reservoir temperature. The oven contains a circulating air system to eliminate internal temperature gradients and can control at temperatures from 20 to 200°C with a rated accuracy of ±1°C.

Filtration

All injection fluids are filtered to 0.5 microns before use to remove any potentially plugging suspended particles (unless unfiltered fluids are requested). An in-line 0.5 micron filter is also present directly before the core as a backup filtration system (removable if unfiltered fluids are desired).

Fluid Displacement

A highly accurate positive displacement pump is used to inject fluids into the core. The pump can inject fluids at rates from 0.6 to 8200 cm^3/hr and at pressures of up to 68.9 MPa, with an accuracy of ± 0.01 cm^3. The pump is filled with distilled water that displaces hydrocarbon fluid, test fluid or immiscible buffer fluid which in turn displaces test fluid into the core relative to the specific application. The experimental system has been designed to minimize dead volumes and to ensure that the entire system is at pressure equilibrium prior to any fluid change. Backpressure on the system (for full reservoir condition tests) is controlled using a 316 SS controlling backpressure regulator rated accurate to 0.5% of the setpoint value. This regulator allows for the smooth production of fluids from the system at any required flowrate and setpoint pressure.

TABLE 1
TUNDRA - DELORAINE
WATERFLOOD STUDY
ROUTINE CORE ANALYSIS

Sample No.	Depth (m)	Permeability (mD)	Porosity (fraction)	Grain Density (kg/m^3)
32	820.75	14.60	0.213	2800
33	820.98	20.70	0.215	2850
34	821.27	26.50	0.225	2860
36	821.68	29.00	0.271	2820
37	821.98	4.30	0.223	2820
38	822.22	3.70	0.183	2830

TABLE 2
TUNDRA - DELORAINE
WATERFLOOD STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
CORE AND TEST PARAMETERS

Core Stack Number	1
Core Stack Configuration (from inlet)	32, 33, 34, 36
Depth (m)	820.75 - 821.68
Field Name	Deloraine
Well Location	8-31-2-23 W1M
Stack Length (cm)	23.53
Diameter (cm)	3.80
Effective Flow Area (cm^2)	11.34
Bulk Volume (cm^3)	266.86
Porosity (fraction)	0.230
Pore Volume (cm^3)	61.46
Test Temperature (°C)	30.0
Water Viscosity @ 30°C (mPa•s)	0.831
Oil Viscosity @ 30°C (mPa•s)	5.71
Displacement Rate (cc/hr)	5.0
Backpressure (kPag)	0
Net Overburden Pressure (kPag)	10235

TABLE 3
TUNDRA - DELORAINE
WATERFLOOD STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
SATURATION AND PERMEABILITY SUMMARY

Test Phase	So	Sw	Permeability (mD)	Relative Permeability
Absolute Liquid Permeability	1.000	0.000	11.9	1.000
Initial Oil Permeability (@ Sw_i)	0.703	0.297	0.21	0.018
Final Water Permeability (@ So_r)	0.368	0.632	0.11	0.009
Waterflood recovery based on total pore volume (%)				33.5
Waterflood oil recovery based on initial hydrocarbon pore volume (%)				47.7
Absolute permeability is determined by extrapolating the k_{ro} curve to 1.0 at Sw = 0.0				

TABLE 4
TUNDRA - DELORAINE
WATERFLOOD STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
DIFFERENTIAL PRESSURE & PRODUCTION

Cuml Injection (PV)	Cuml Production (PV)	Pressure (MPa)
0.000	0.000	6.9502
0.081	0.081	6.2197
0.225	0.225	3.3462
0.244	0.240	3.1041
0.325	0.259	2.8774
0.488	0.282	2.6891
0.651	0.294	2.6201
0.814	0.303	2.5512
1.139	0.316	2.4822
1.464	0.324	2.4133
1.790	0.327	2.3404
2.278	0.334	2.2097

TABLE 5
TUNDRA - DELORAINE
WATERFLOOD STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
RELATIVE PERMEABILITY DATA

Water Saturation	Relative Permeability	
	k_{rw}	k_{ro}
0.297	0.00000	0.01780
0.314	0.00009	0.01687
0.330	0.00025	0.01595
0.347	0.00047	0.01502
0.364	0.00074	0.01410
0.381	0.00105	0.01319
0.397	0.00140	0.01227
0.414	0.00178	0.01136
0.431	0.00220	0.01045
0.448	0.00265	0.00954
0.464	0.00312	0.00864
0.481	0.00363	0.00774
0.498	0.00416	0.00685
0.515	0.00472	0.00596
0.531	0.00530	0.00507
0.548	0.00591	0.00419
0.565	0.00654	0.00332
0.582	0.00720	0.00246
0.598	0.00788	0.00161
0.615	0.00858	0.00078
0.632	0.00930	0.00000

FIGURE 1
TUNDRA - DELORAINE
WATERFLOOD STUDY
LOW PRESSURE RELATIVE PERMEABILITY APPARATUS

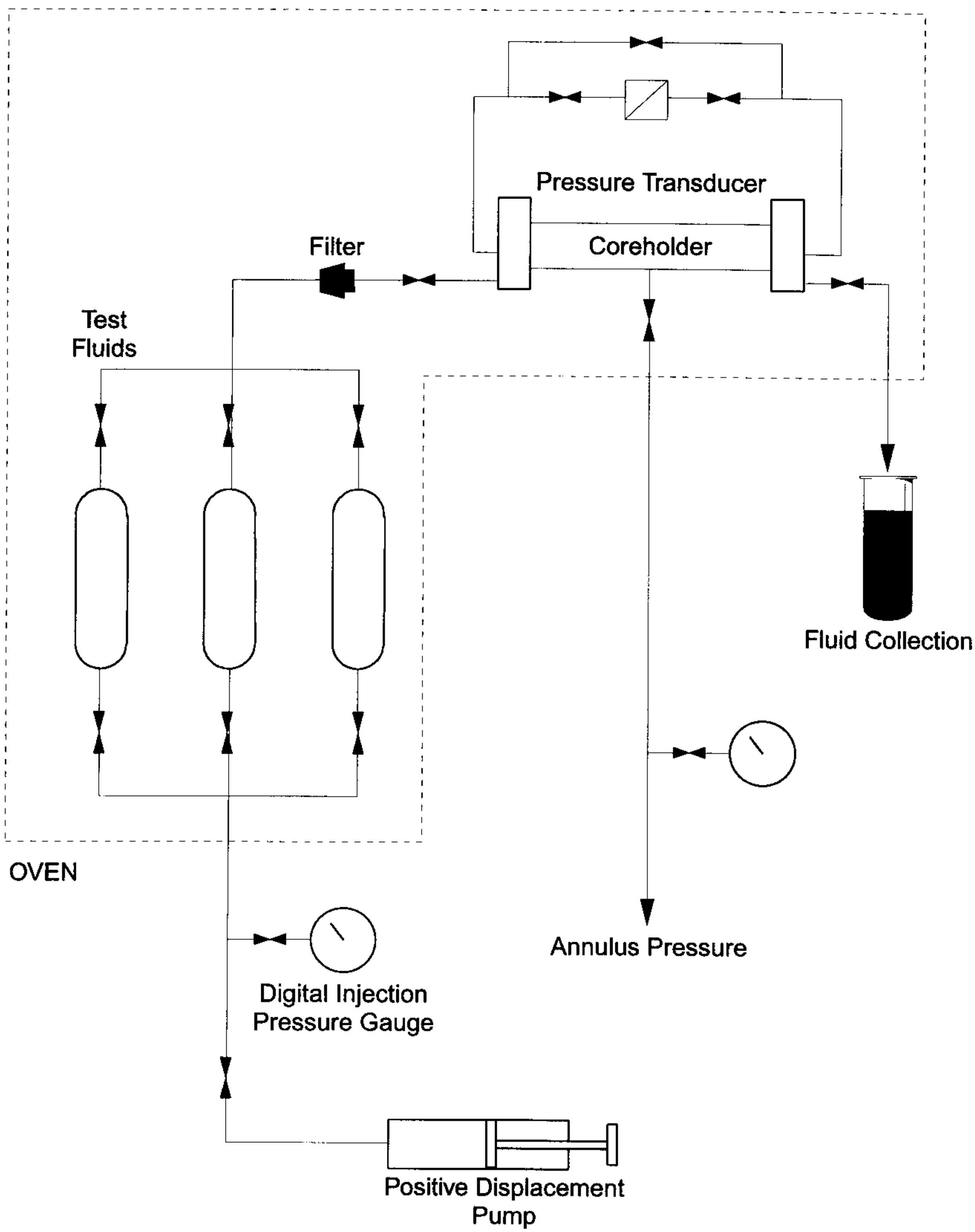

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FIGURE 2
TUNDRA - DELORAINE
WATERFLOOD STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
CUML PRODUCTION vs CUML INJECTION

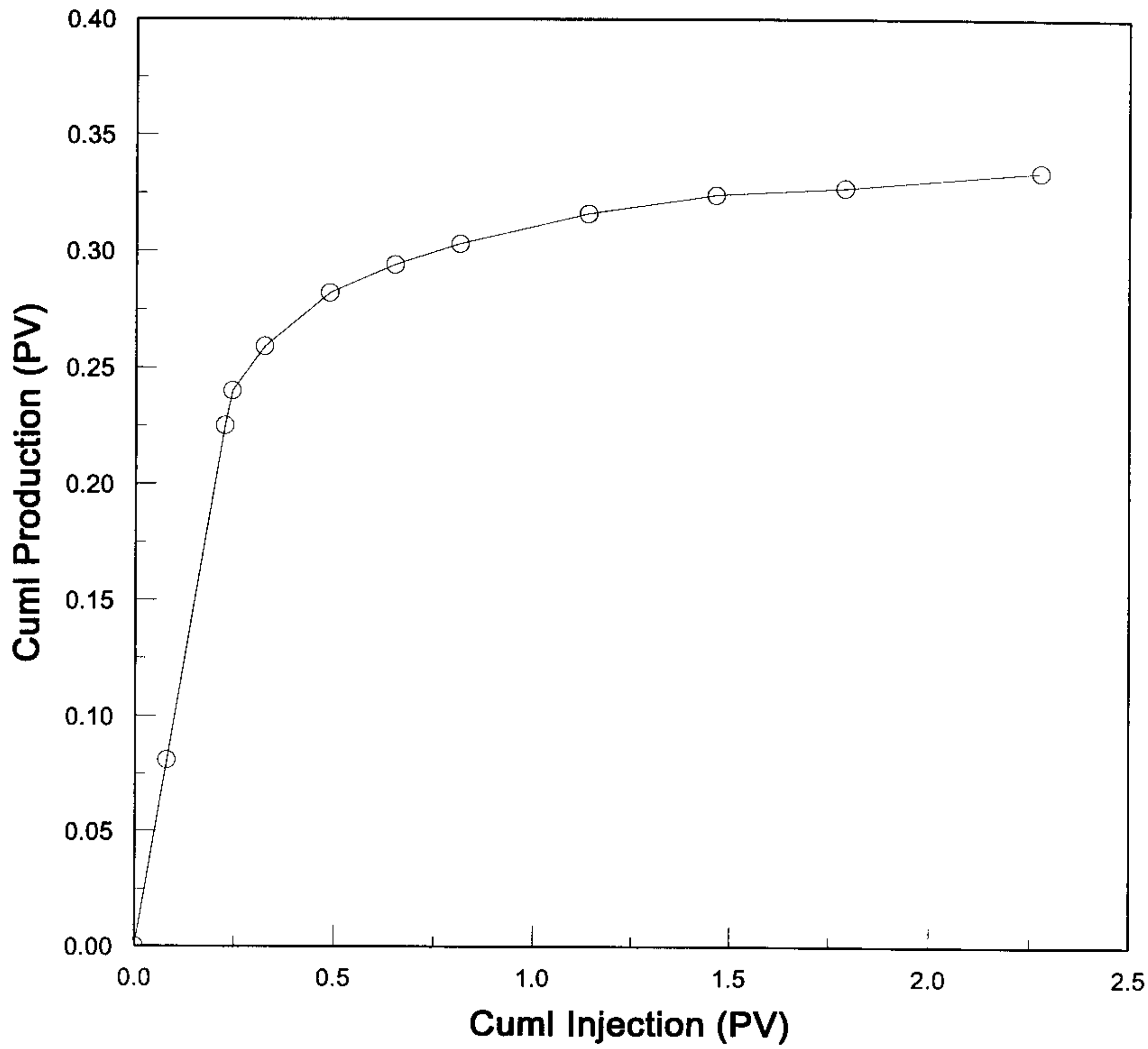

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FIGURE 3
TUNDRA - DELORAINE
WATERFLOOD STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
PRESSURE vs CUML INJECTION

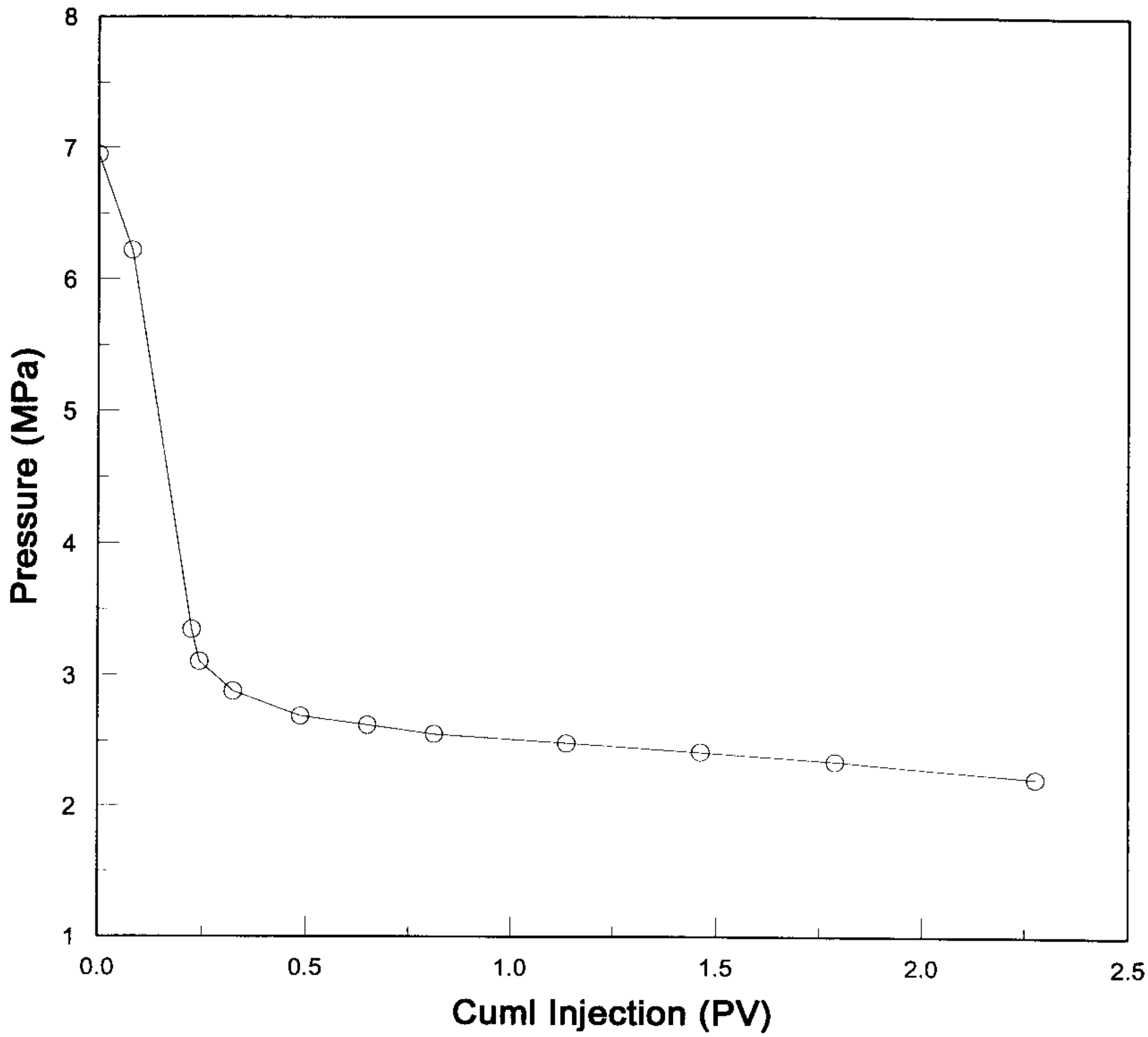
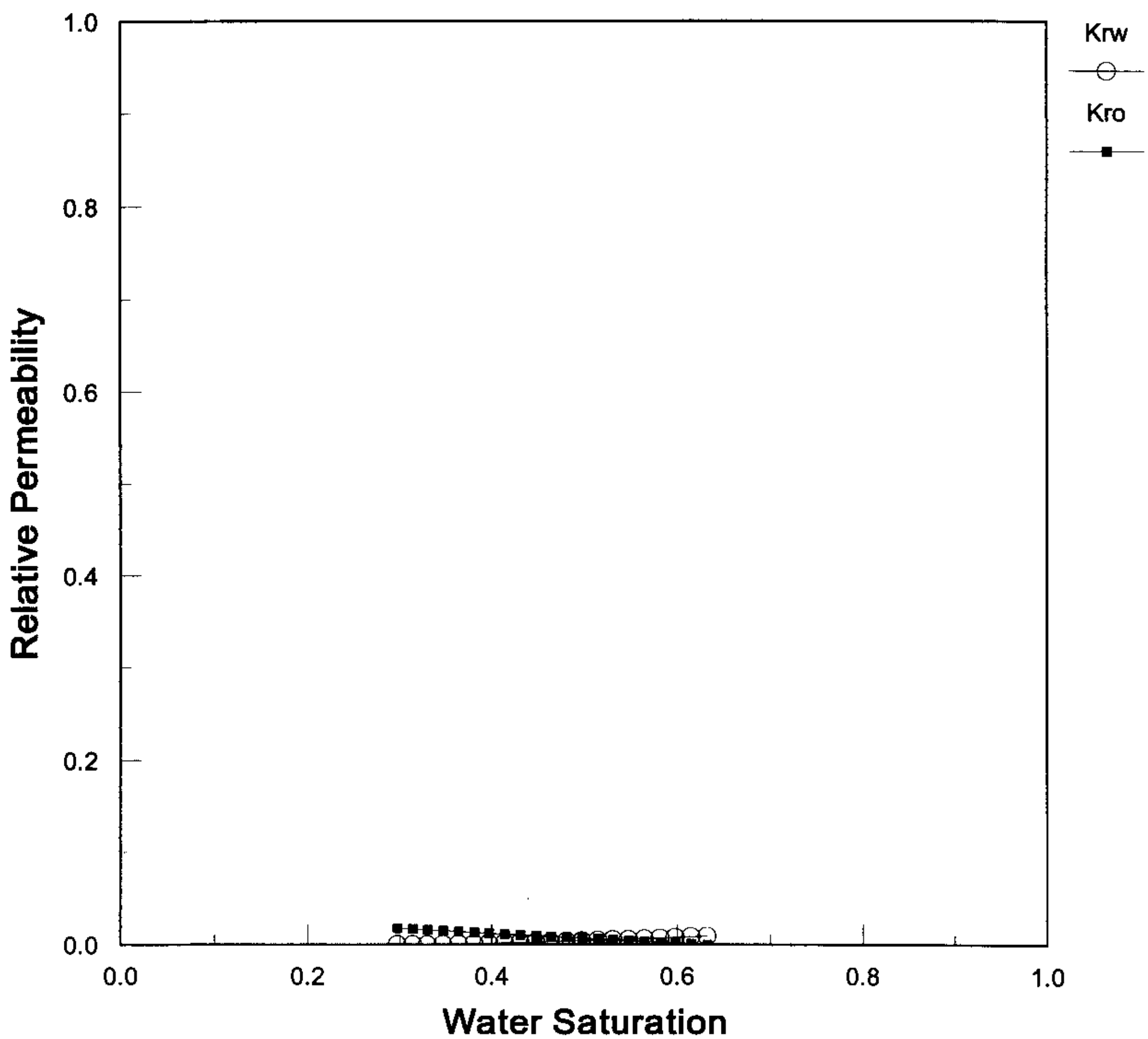


FIGURE 4
TUNDRA - DELORAINE
WATERFLOOD STUDY
CORE STACK #1 - WATER-OIL RELATIVE PERMEABILITY
RELATIVE PERMEABILITY vs WATER SATURATION



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