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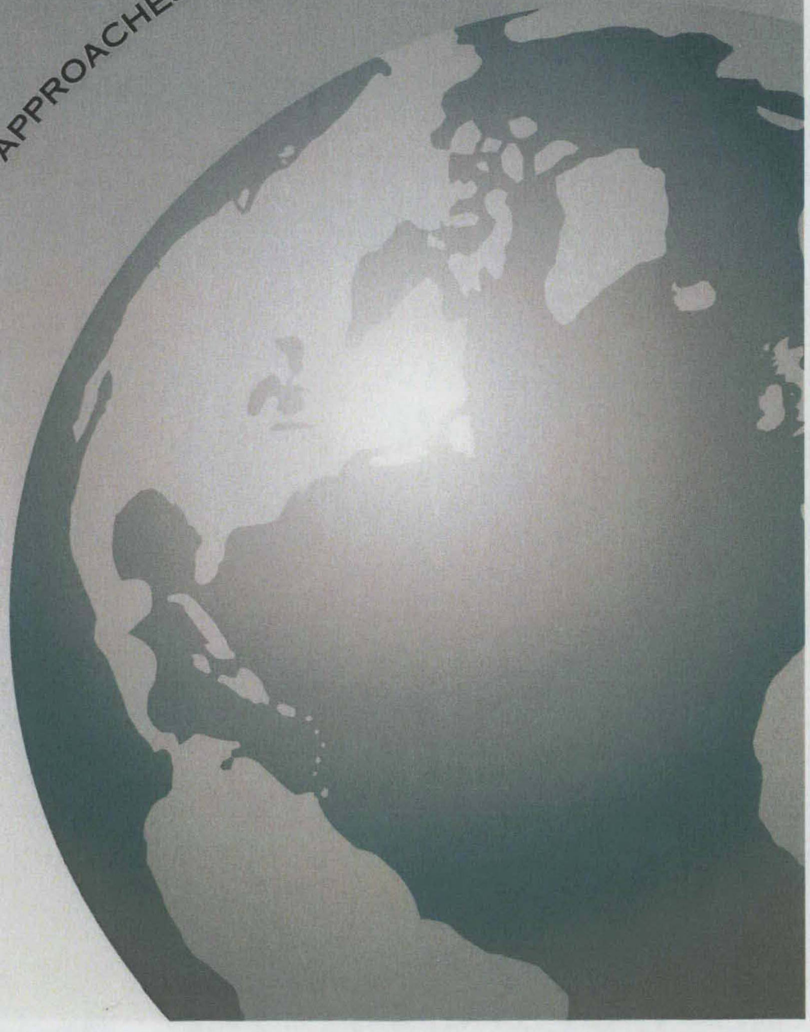
PETRO-CANADA OIL AND GAS
TWEED LAKE, MOUNT CLARK FORMATI

FORMATION DAMAGE STUDY

WORLD LEADERS IN INNOVATIVE APPROACHES TO RESERVOIR MANAGEMENT



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PETRO-CANADA OIL AND GAS
TWEED LAKE, MOUNT CLARK FORMATION

FORMATION DAMAGE STUDY

Prepared for

PETRO-CANADA

Prepared by

Hycal Energy Research Laboratories Ltd.

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SUMMARY

SUMMARY

Study Objective

At the request of Petro-Canada Oil and Gas (Petro-Canada), Hycal Energy Research Laboratories Ltd. conducted a formation damage study using core material from well Tweed Lake A-67 in the Tweed Lake field. The study was initiated to optimize the hydraulic fracturing program in the said area. The objective of this study was to evaluate fracture fluid systems by investigating their leakoff characteristics and regain permeability performance. The tests were conducted at the test temperature of 12°C, reservoir pressure of 13,000 kPa, net fracture pressure of 11,550 kPa, and net confining pressure of 16,225 kPa. Mercury injection capillary pressure tests were also conducted in the aid of reservoir quality assessment.

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 Hycal's interpretation as to possible mechanisms and physical phenomena that may be occurring within the laboratory models that have been studied. These laboratory experiments are micro scale representations of the field scenario; however, macro scale 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. Mercury injection results showed a high ratio of micropores (pore throat diameter of less than 1.0 microns), indicating the probability of liquid phase trapping if the formation is at sub-irreducible saturation levels. The estimated irreducible water saturation ranges from 18 to 52%, and median pore throat diameter ranges from 0.591 and 1.68 microns for all the samples.

2. The gelled Rimbey platinum system performed better than the FX2 fluid tested. The fluid regained 93% at the pressure drawdown of 4000 kPa. The fluid leakoff volume was very minimal, about 1.7 ml of filtrate was recorded during the leakoff test.

3. The carbon dioxide miscible Rimbey platinum fracture fluid did not perform well. At the threshold pressure of 14 kPa, the regain permeability to gas was 19%, at subsequent pressure drawdown increments, the regain permeability declined rapidly. At maximum pressure drawdown of 13,000 kPa, the regain permeability was 3%. The permeability

behaviour is typical of particulate migration within the pore system. The CO_2 might have caused significant velocity within the pore system, thereby mobilizing rock particulates.

4. The FX2 fracture fluid also caused the significant permeability impairment. At the threshold pressure of 1172 kPa, the regain permeability to gas was 7%, at maximum pressure drawdown of 13,000 kPa, the regain permeability was 15%. The core was shut in for 24 hours longer, and the threshold pressure regain permeability was measured again. The threshold pressure was much lower than before, it was 55 kPa with a 21% regain in permeability. At maximum pressure drawdown, the regain permeability was 24%. It was thought that CO_2 injection might help. About 2 pore volumes of CO_2 were injected, and regain permeability measured. There was permeability reduction following the CO_2 injection, with a maximum regain permeability of 15%. The increase in reservoir temperature from 12°C to 16°C did not cause an increase in gas permeability.

DISCUSSION

DISCUSSION

Core Sample Preparation

Hycal drilled 1-inch OD core plugs taken from one-third portion of the core slab in the Tweed Lake A-67 well, Mt. Clark formation. Core samples were subjected to azeotropical cleaning at a low temperature, using a combination of methanol/chloroform and toluene for 72 hours and then conventionally-oven dried at 120°C for 36 hours. The dried clean samples were subjected to routine core analysis consisting of air permeability, porosity and grain density measurements using a Hassler type coreholder and helium Boyle's law porosimeter. The measured basic routine core data of the samples are presented in Table 1. The cross plot of porosity versus air permeability is presented in Figure 1.

For baseline permeability measurements, the core samples were restored to an initial water saturation of approximately 30%, using a synthetic formation brine solution based on a compositional analysis of the Mt. Clark formation brine contained in Appendix A.

Capillary Pressure by Mercury Injection Test

Four samples were selected for mercury injection testing, samples 4A, 13B, 27C, and 36A. The selected core samples were cleaned using toluene and methanol to remove any residual hydrocarbon. The pore volume of each core sample was measured to facilitate "penetrometer" selection for the mercury injection tests. Detailed tabular and graphical results of the mercury injection tests are presented for each tested sample in Tables 2 through 9 and in Figures 2 through 21, and include:

(1) Air-mercury capillary pressure curve
(2) Derived air-water capillary pressure curve
(3) Pore throat size distribution profile
(4) Pore throat size classification
(5) Derived transition zone height for an air-water system

A summary of mercury injection capillary pressure data for the two tested core samples is presented in the table below.

SUMMARY OF MERCURY INJECTION RESULTS

Sample I.D.	Sample Depth (m)	Routine Air Permeability (mD)	Helium Porosity (fraction)	* Median Pore Throat Size (μm)	Pore Throat Types: *Micropores* Pore Dia < 1 micron	*Mesopores* Pore Dia 1-3 micron	*Macropores* Pore Dia >3 micron	‡ Threshold Intrusion Pressure (kPa)	Estimated Swir (percent)
Well: Tweed Lake A-67									
4A	1279.14	6.0	0.127	0.591	54.2%	12.2%	33.6%	21.0	52.0%
13B	1282.34	0.95	0.110	0.972	64.2%	35.8%	0.0%	632	19.0%
27C	1292.25	11.50	0.134	0.737	56.4%	20.0%	23.6%	14.2	48.0%
36A	1296.37	2.72	0.115	1.68	30.1%	68.2%	1.7%	286	18.0%

Note:
* Median Pore Throat Size: Pore throat diameter at 50% mercury saturation of pore volume.
‡ Threshold pressures are converted from air/mercury to air/water system using published values of air/water interfacial tension.

The mercury injection data summary presents the median pore throat sizes and pore throat types, as determined by the mercury injection capillary pressure tests. The median pore throat size is defined as the pore throat diameter at 50% of mercury intrusion during the experiment. The pore throat types are divided into the following categories: Micropores: less than 1 micron in diameter, Mesopores: between 1 to 3 microns in diameter and Macropores: greater than 3 microns in diameter.

The mercury injection data summary clearly shows that Samples 4A, and 27C exhibited a similar pore size distribution; they indicate over 50% micro-porosity, 10 to 20% meso-porosity, and 20 to 30 % macro-porosity. Samples 13B and 36A have no macro-porosity; 64% of the pore sizes in sample 13B are less than 1 micron. This high percentage of micropores requires higher pressures to remove liquid phase fluids. If the rock matrix was sub-irreducible and were to come into contact with any extraneous fluids such as mud filtrates or fracture fluids, it would have a strong tendency to retain some of these fluids and thus reduce the available conduit for hydrocarbon flow. Median pore throat diameters were estimated to range from 0.591 to 1.68 microns.

Irreducible water saturations were estimated from the derived air-water mercury injection curves using the graphical method. The estimated irreducible water saturations were 52%, 19, 48, and 18% in samples 4A, 13B, 27C, and 36A respectively.

Samples 27B, 27C: Fracture Fluid Evaluation with Gelled Rimbey Platinum (Oil base)

Table 10 provides a summary of pertinent core and test parameters as well as the permeability summary for samples 27B, 27C. The plugs were mounted as a stack in order to increase the pore volume and length of the core material. Initial harmonic average air permeability for the core stack is 10.36 mD, with average porosity of 16.4%. The core material was saturated with formation water to 30% of pore volume.

The core was initially flooded with synthesized reservoir gas to establish baseline permeability to gas. Initial permeability to gas for the core was measured to be 2.92mD. The reservoir gas was used as a permeability gas in order to observe the formation of hydrates, if the conditions exist.

The fracture fluid leakoff test was conducted by circulating gelled fracture fluid across the simulated fracture sandface of the core (in the reverse direction to initial gas flood). The fracture fluid overbalance pressure into the core was maintained at a constant value of 11,550 kPa (calculated using fracture gradient of 19 kPa/m) during this process. Table 11 contains summaries of pertinent leakoff data for the test. A total invasion depth of 2.2 cm was invaded by 1.7 ml of filtrate during the half-hour overbalance exposure period (assuming the pore space is 100% swept).

A series of regain displacements was conducted in the original flow direction with nitrogen gas (to simulate inflow clean-up from the reservoir after fracturing) at various drawdown clean-up pressures.

Inflow was first achieved at 276 kPa drawdown pressure with a stabilized permeability to gas of 0.263 mD. This represents 9% regain in permeability relative to the baseline value at the same pressure drawdown. Incremental increases in drawdown pressures (Table 10) yielded a marginal increase in permeability, with a maximum regain permeability of 35% at 4,000 kPa pressure drawdown; the gas permeability at this pressure drawdown was 1.03 mD. At a maximum pressure drawdown of 13,000 kPa, the gas permeability was 1.04 mD, a regain of 35%. The regain permeability results of the test are illustrated in Figure 22.

The core stack was re-mounted following the regain permeability measurement. Several additional pore volumes of the reservoir gas were flowed through the core to measure threshold pressure regain permeability. At 276 kPa drawdown pressure, stabilized gas permeability was 1.84 mD, representing a regain of 63% relative to the baseline value of 2.92 mD. At maximum pressure drawdown of 13,000 kPa, the gas permeability was 2.71 mD, a regain of 93%. The subsequent increase in gas permeability might be due to desiccation of the connate water saturation following dismount and re-mount of the core plugs. Nevertheless, the appreciable increase in gas permeability was very encouraging.

Samples 27D, 27J: Fracture Fluid Evaluation with Gelled FX2 (Oil base)

Table 12 provides a summary of pertinent core and test parameters as well as the permeability summary for samples 27D, 27J. The plugs were mounted as a stack in order to increase the pore volume and length of the core material. Initial harmonic average air permeability for the core stack is 10.7 mD, with an average porosity of 13.3%. The core material was saturated with formation water to 30% of pore volume.

The core was initially flooded with synthesized reservoir gas to establish baseline permeability to gas. Initial permeability to gas for the core was measured to be 2.92mD.

The fracture fluid leakoff test was conducted by circulating gelled fracture fluid across the simulated fracture sandface of the core (in the reverse direction to initial gas flood). The fracture fluid overbalance pressure into the core was maintained at a constant value of 11,550 kPa (calculated using a fracture gradient of 19 kPa/m) during this process. Table 13 contains summaries of pertinent leakoff data for the test. A total invasion depth of 1.27 cm was invaded by 0.8 ml of filtrate during the half-hour overbalance exposure period (assuming the pore space is 100% swept).

A series of regain displacements was conducted in the original flow direction with nitrogen gas (to simulate inflow clean-up from the reservoir after fracturing) at various drawdown clean-up pressures.

Inflow was first achieved at 1172 kPa drawdown pressure with a stabilized permeability to gas of 0.241 mD. This represents a 7% regain in permeability relative to the baseline value at the same pressure drawdown. Incremental increases in drawdown pressures (Table 12) yielded a marginal increase in permeability, with a maximum regain permeability of 15% at 13,000 kPa pressure drawdown; the gas permeability at this pressure drawdown was 0.497 mD. The regain permeability results of the test are illustrated in Figure 23.

The core stack was shut in over a 24-hour period to allow the gels to break following the regain permeability measurement. Several additional pore volumes of the reservoir gas were flowed through the core to measure threshold pressure regain permeability. At 55 kPa drawdown pressure, stabilized gas permeability was 0.685 mD, representing a regain of 21% relative to the baseline value of 3.25 mD. At a maximum pressure drawdown of 13,000 kPa, the gas permeability was 0.786 mD, a regain of 24%.

The core stack was further stimulated with liquid CO_2 injection. About two pore volumes (about 4 ml) were injected into, and produced from the core. Threshold pressure regain

permeability measurements were conducted to observe the effects of the CO_2 injection. At 55 kPa pressure drawdown, stabilized gas permeability was 0.460 mD, representing a regain of 14% relative to the baseline value. At a maximum pressure drawdown of 13,000 kPa, the gas permeability was 0.480 mD, a regain of 15%. The reduction in gas permeability might suggest that the CO_2 might have caused significant velocity within the pore system, thereby mobilizing rock particulates.

The reservoir temperature was increased from 12°C to 16°C; there was no appreciable increase in gas permeability following the temperature increase.

Samples 27F, 27G: Fracture Fluid Evaluation with CO_2 Miscible Rimbey Platinum

Table 14 provides a summary of pertinent core and test parameters as well as the permeability summary for samples 27F, 27G. The plugs were mounted as a stack in order to increase the pore volume and length of the core material. Initial harmonic average air permeability for the core stack is 27.5 mD, with average porosity of 11.7%. The core material was saturated with formation water to 30% of pore volume.

The core was initially flooded with synthesized reservoir gas to establish baseline permeability to gas. Initial permeability to gas for the core was measured to be 11.6 mD. The reservoir gas was used as a permeability gas in order to observe the formation of hydrates, if the conditions existed.

The fracture fluid leakoff test was conducted by co-injecting gelled fracture fluid and liquid CO_2 (40% CO_2) across the simulated fracture sandface of the core (in the reverse direction to initial gas flood). The fracture fluid overbalance pressure into the core was maintained at a constant value of 11,550 kPa (calculated using a fracture gradient of 19 kPa/m) during this process. Table 15 contains summaries of pertinent leakoff data for the test. There was no filtrate produced during the 30-minute leakoff test.

A series of regain displacements was conducted in the original flow direction with nitrogen gas (to simulate inflow clean-up from the reservoir after fracturing) at various drawdown clean-up pressures.

Inflow was first achieved at 14 kPa drawdown pressure with a stabilized permeability to gas of 2.17 mD. This represents a 19% regain in permeability relative to the baseline value at the same pressure drawdown. Incremental increases in drawdown pressures (Table 14) yielded a significant reduction in permeability, with a regain permeability of 3% at 13,000 kPa pressure drawdown; the gas permeability at this pressure drawdown was 0.374 mD. The regain permeability results of the test are illustrated in Figure 24. The permeability behaviour is typical of particulate migration within the pore system. The CO_2 might have caused significant velocity within the pore system, thereby mobilizing rock particulates.

Samples 27B, 27C: Fracture Fluid Evaluation with Gelled Rimbey Platinum (Oil base)

Table 16 provides a summary of pertinent core and test parameters as well as the permeability summary for samples 27B, 27C. The plugs were cleaned following a previous test, and were mounted as a stack in order to increase the pore volume and length of the core material. Initial harmonic average air permeability for the core stack is 10.54 mD, with average porosity of 13.5%. The core material was saturated with formation water to 30% of pore volume.

The core was initially flooded with synthesized reservoir gas to establish baseline permeability to gas. Initial permeability to gas for the core was measured to be 2.1 mD.

The fracture fluid leakoff test was conducted by circulating gelled fracture fluid across the simulated fracture sandface of the core (in the reverse direction to initial gas flood). The fracture fluid overbalance pressure into the core was maintained at a constant value of 11,550 kPa (calculated using a fracture gradient of 19 kPa/m) during this process. Table 17 contains summaries of pertinent leakoff data for the test. A total invasion depth of 1.57 cm was invaded by 1.0 ml of filtrate during the half-hour overbalance exposure period (assuming the pore space is 100% swept).

A series of regain displacements was conducted in the original flow direction with nitrogen gas (to simulate inflow clean-up from the reservoir after fracturing) at various drawdown clean-up pressures.

Inflow was achieved at 55 kPa drawdown pressure with a stabilized permeability to gas of 0.816 mD. This represents a 39% regain in permeability relative to the baseline value at the same pressure drawdown. Incremental increases in drawdown pressures (Table 16) yielded a significant increase in permeability, with a maximum regain permeability of 60% at 13,000 kPa pressure drawdown; the gas permeability at this pressure drawdown was 1.25 mD. The regain permeability results of the test are illustrated in Figure 25.

Based on the relatively good performance of the Rimbey platinum, we recommend it as the fluid for use in the Mt. Clark formation, in the Tweed Lake area.

PROCEDURES &
EQUIPMENT

PROCEDURES AND EQUIPMENT

Saturation Restoration (Brine Only)

The core samples used in this study were extracted and cleaned cores. In preparation for testing, the core samples are restored to a target initial water saturation of 30% to simulate the initial water saturation existing in the reservoir. The brine saturation is instituted by slowly adding small amounts of brine to the core and then weighing the core until the appropriate target mass is attained. Humidified nitrogen is displaced at a high rate through the core in both directions in an attempt to evenly distribute the brine in the rock matrix by both physical displacement and spontaneous imbibitions mechanisms. The saturation is checked gravimetrically and the above process is repeated until saturation equilibrium is obtained. The core samples are then stored in a humidity-controlled environment until subsequent testing can be performed.

Laboratory Net Overburden Pressure

Tests performed in the laboratory are subjected to a hydrostatic stress loading rather than uni-axial (lithostatic) loading as in the field. Because the hydrostatic (tri-axial) loading results in more strain than reservoir loading conditions, the following equation is used to obtain a hydrostatic net confining pressure that is equivalent to the reservoir loading conditions:

$$\textit{Laboratory Net Overburden Pressure} = \left[\frac{1}{3}+\frac{2}{3}\left(\frac{\mu}{1-\mu}\right)\right] * \left[\left(\textit{Depth} * \textit{Press. Gradient}\right) - \textit{Res. Press}\right]$$

Where:	Depth	=	Reservoir True Vertical Depth in feet	
	Pressure Gradient	=	1.0 psi/ft (22.62kPa/meter)	
	Res. Pressure	=	Reservoir Pressure in Psig	
	μ	=	Poisson's Ratio	(0.26 for Sandstone)
				(0.35 for Carbonate)

Mercury Injection Capillary Pressure

Air-mercury capillary pressure tests were performed using an automated Micromeritics Autopore 9220 instrument with a maximum mercury intrusion pressure of 414 MPa (60,000 psia). The cleaned and dried samples were placed in a specially designed penetrometer and evacuated using a high efficiency vacuum pump. Mercury was then injected at multiple pre-determined pressure levels up to 414 MPa as presented in column (1). At each equilibrium pressure level, the volume of mercury intrusion is determined by the change in capacitance of the penetrometer reference cell. At each successful pressure step, the final volume of mercury intrusion was then converted to a fraction of the wetting phase saturation, column (3). Figure 26 is a schematic of the Micromeritics Autopore 9220 instrument.

The air-water capillary pressure data, column (2), was then derived from the air-mercury capillary pressure data in column (1) to scale back to more representative reservoir conditions. The conversion factor utilizes the difference in mercury and water surface tension as follows:

$$\text{Conversion factor} = (\text{Air-Mercury Pc}) / (\text{Air-Water Pc})$$
$$= \sigma m \cos\theta m / \sigma w \cos\theta w$$

where:

σm = Surface tension of mercury

σw = Surface tension of water

θm = Contact angle of mercury against solid

θw = Contact angle of water against solid

Data from the mercury injection apparatus is also used to calculate the pore entry radius, column (4), using the following equation:

$$Ri = \frac{2T \bullet \cos\theta \bullet C}{Pc}$$

where:

Ri	= Pore radius, microns
Pc	= Capillary pressure in laboratory, psi
T	= Interfacial Tension, Dynes/cm
θ	= Contact angle, degrees
C	= Conversion constant = 0.145

For the air-mercury data directly from the laboratory:

The contact angle θ = 130 degrees

The interfacial tension T = 485 dynes/cm

For the derived air-water data:

The contact angle θ = 0.0 degrees

The interfacial tension T = 72 dynes/cm

The height of the transition zone (h), column (5), represents the equilibrium between the capillary pressure forces and the formation water hydrostatic head weight explained by the Leverett equation:

$$Pc = \Delta\rho_{air-water}\, gh$$

Fracture Fluid Leakoff Procedure

1. Displace inert gas or oil through the core (Direction 1) at the specified reservoir conditions to determine the initial effective permeability to gas and /or oil at immobile water saturation. This displacement is conducted at minimum pressure of 689 kPa to avoid turbulent flow regime.

2. Circulate supplied fracture fluid across the simulated sandface (Direction 2) at representative field overbalance conditions. Leakoff volume is monitored as a function of circulation time.

3. Displace gas in the original flow direction (Direction 1) at incrementally increasing drawdown pressures and measure stabilized permeabilities at each pressure. This "threshold pressure" regain technique is used to determine the minimum pressure range at

which the rock begins to flow. By comparing pre and post leakoff permeability values, the relationship between drawdown cleanup pressure and permeability impairment is defined relative to the specific test fluid attributes, overbalance conditions, and reservoir rock quality utilized.

4. If applicable, a specified volume of stimulation fluid (CO_2) can be injected into the fracture face (Direction 2). After injection, the system will be shut up for six hours. This will again be followed with regain permeabilities measured at incrementally increasing drawdown pressures as in the previous step. In this fashion, the effectiveness of the stimulation can be assessed.

Description of Test Equipment

Equipment that is used in conventional displacement experiments is common to most core flow evaluation techniques. A detailed schematic of the specific apparatus configuration is provided in Figure 27 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 a non-damaging mineral oil. The annular fluid is then compressed with a hydraulic pump to obtain the desired overburden pressure. The coreholder ends each contain two ports to facilitate fluid displacement and pressure measurements at each end of the core.

High Capacity Core Flow Heads

For experiments which utilize highly viscous fluids and/or which contain a significant suspended solids load, specially designed high capacity core flow heads are used to conduct fluid with solids or additives to the rock face to minimize the potential for flow impedance in the apparatus. Conventional 316 SS is used to fabricate this equipment for applications where reservoir-operating conditions are not extreme.

Pressure Measurement

Pressure differential is monitored using Yokogawa 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 from 0 to 2 psig and 0 to 4000 psig and are 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 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 coreholder 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.

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.

Gas Displacement

A regulated high-pressure gas source is used to conduct gas into the porous media at a constant pressure. For systems where displacement gas composition is specifically designed for the experiment, buffer fluids are placed between the test gas and the drive gas sample as to maintain compositional integrity.

TABLES

TABLE 1
PHYSICAL CORE PARAMETERS

Sample I.D.	Well Location	Depth (m)	Air Permeability (mD)	Porosity (fraction)	Grain Density (kg/m3)
4A	Tweed Lake A-67	1279.14	5.97	0.125	2740
4B	Tweed Lake A-67	1279.17	3.48	0.130	2690
4C	Tweed Lake A-67	1279.22	1.81	0.112	2670
4D	Tweed Lake A-67	1279.26	1.07	0.104	2660
13A	Tweed Lake A-67	1282.3	0.91	0.113	2660
13B	Tweed Lake A-67	1282.34	0.95	0.111	2660
13C	Tweed Lake A-67	1282.38	0.87	0.103	2660
13D	Tweed Lake A-67	1282.43	0.88	0.108	2660
13E	Tweed Lake A-67	1282.47	0.30	0.105	2660
27A	Tweed Lake A-67	1292.16	1.0	0.133	2750
27B	Tweed Lake A-67	1292.21	9.42	0.178	2700
27C	Tweed Lake A-67	1292.25	11.5	0.149	2670
27D	Tweed Lake A-67	1292.3	10.7	0.147	2670
27E	Tweed Lake A-67	1292.51	15.3	0.11	2650
27F	Tweed Lake A-67	1292.54	26.7	0.121	2660
27G	Tweed Lake A-67	1292.58	28.4	0.112	2660
27H	Tweed Lake A-67	1292.62	76.1	0.106	2680
27I	Tweed Lake A-67	1292.66	133.0	0.288	2680
27J	Tweed Lake A-67	1293.00	10.7	0.119	2640
27K	Tweed Lake A-67	1293.04	30.1	0.134	2640
27L	Tweed Lake A-67	1293.08	104.5	0.18	2660
36A	Tweed Lake A-67	1296.37	2.72	0.112	2670
36B	Tweed Lake A-67	1296.42	1.88	0.094	2650
36C	Tweed Lake A-67	1296.46	0.86	0.093	2650

TABLE 2
MERCURY INJECTION CAPILLARY PRESSURE TEST SUMMARY

Well Location: Tweed Lake A-67
Core I.D.: 4A
Core Depth: 1279.14 m

Routine Core Analysis Air Permeability : 5.97 mD
Routine Core Analysis Porosity (fraction): 0.127

Mercury Injection Test Sample Data	
Sample Weight (g):	11.364
Corrected sample porosity (fraction):	0.114
Grain Density (g/cc):	2.66
Conformance Correction Vol. (cc):	0.031
Total Pore Surface Area (m^2):	55.72
Median Pore Diameter (micron):	0.591
Conformance Correction (percent of P.V.):	5.3%
* Threshold Pressure (kPa):	21.0
Pore throat size distribution:	
Macropores (pore throat dia. > 3.0 microns):	33.6%
Mesopores (pore throat dia. 1.0 - 3.0 microns):	12.2%
Micropores (pore throat dia. < 1.0 microns):	54.2%

Conversion Factors for Data Calculation	
Mercury Density (g/cc):	13.5335
Air / Mercury Interfacial Tension (dynes/cm):	485
Air / Mercury Contact Angle (degree):	130
Air / Water Interfacial Tension (dynes/cm):	72
Air / Water Contact Angle (degree):	0.0
Water Density for transitional height calculation (kg/m^3):	1000
Air Density for transitional height calculation (kg/m^3):	0.0010

* Threshold pressure - pressure at which mercury first enters the pore system.

TABLE 3
MERCURY INJECTION CAPILLARY PRESSURE DATA

Well Location: Tweed Lake A-67
Core I.D.: 4A
Core Depth: 1279.14 m

Air Permeability : 5.97 mD
Porosity (fraction): 0.127

Air/Mercury Capillary Pressure (MPa)	Derived Air / Water Capillary Pressure (MPa)	Wetting Phase Saturation (fraction)	Pore Throat Diameter (Microns)	Height of Transition (m)
0.021	0.005	1.0000	73.68	0.00
0.028	0.006	0.9959	52.00	0.16
0.038	0.009	0.9897	38.66	0.40
0.042	0.010	0.9877	31.29	0.49
0.052	0.012	0.9836	26.94	0.73
0.059	0.014	0.9692	22.59	0.89
0.073	0.017	0.9589	19.19	1.21
0.090	0.021	0.9425	15.54	1.62
0.110	0.025	0.9220	12.60	2.10
0.138	0.032	0.8891	10.17	2.75
0.172	0.040	0.8378	8.146	3.56
0.193	0.045	0.8049	6.854	4.04
0.283	0.065	0.7536	5.437	6.17
0.356	0.082	0.7043	3.957	7.87
0.426	0.098	0.6694	3.219	9.53
0.530	0.122	0.6345	2.641	12.0
0.627	0.145	0.6099	2.170	14.3
0.805	0.186	0.5832	1.769	18.4
0.961	0.222	0.5647	1.423	22.1
1.201	0.277	0.5462	1.168	27.8
1.519	0.351	0.5298	0.930	35.3
1.874	0.433	0.5175	0.743	43.6
2.281	0.527	0.5051	0.606	53.2
2.890	0.668	0.4949	0.489	67.6
3.593	0.830	0.4867	0.389	84.1
4.415	1.020	0.4764	0.315	103
5.523	1.276	0.4661	0.254	130
6.845	1.581	0.4559	0.204	161
8.337	1.925	0.4435	0.166	196
10.40	2.403	0.4271	0.135	244
13.10	3.026	0.4025	0.108	308
16.37	3.780	0.3737	0.0857	385
20.01	4.621	0.3450	0.0693	471
24.80	5.728	0.3142	0.0563	583
30.93	7.144	0.2813	0.0453	728
38.49	8.889	0.2485	0.0364	906
47.39	10.94	0.2156	0.0294	1115
59.13	13.66	0.1786	0.0237	1392
73.02	16.86	0.1437	0.0191	1719
90.58	20.92	0.1109	0.0154	2132
113.1	26.12	0.0801	0.0124	2662
137.7	31.80	0.0575	0.0100	3241
171.9	39.69	0.0370	0.0082	4046
206.0	47.57	0.0267	0.0067	4848
240.8	55.61	0.0185	0.0056	5668
275.5	63.61	0.0123	0.0049	6484
310.0	71.60	0.0082	0.0043	7298
344.5	79.57	0.0041	0.0038	8111
378.5	87.41	0.0021	0.0035	8910
409.0	94.46	0.0000	0.0032	9628

TABLE 4
MERCURY INJECTION CAPILLARY PRESSURE TEST SUMMARY

Well Location: Tweed Lake A-67

Core I.D.: 13B

Core Depth: 1282.34 m

Routine Core Analysis Air Permeability : 0.95 mD

Routine Core Analysis Porosity (fraction): 0.11

Mercury Injection Test Sample Data	
Sample Weight (g):	18.404
Corrected sample porosity (fraction):	0.104
Grain Density (g/cc):	2.65
Conformance Correction Vol. (cc):	0.055
Total Pore Surface Area (m^2):	9.00
Median Pore Diameter (micron):	0.972
Conformance Correction (percent of P.V.):	6.4%
* Threshold Pressure (kPa):	631.7
Pore throat size distribution:	
Macropores (pore throat dia. > 3.0 microns):	0.0%
Mesopores (pore throat dia. 1.0 - 3.0 microns):	35.8%
Micropores (pore throat dia. < 1.0 microns):	64.2%

Conversion Factors for Data Calculation	
Mercury Density (g/cc):	13.5335
Air / Mercury Interfacial Tension (dynes/cm):	485
Air / Mercury Contact Angle (degree):	130
Air / Water Interfacial Tension (dynes/cm):	72
Air / Water Contact Angle (degree):	0.0
Water Density for transitional height calculation (kg/m^3):	1000
Air Density for transitional height calculation (kg/m^3):	0.0010

* Threshold pressure - pressure at which mercury first enters the pore system.

TABLE 5
MERCURY INJECTION CAPILLARY PRESSURE DATA

Well Location: Tweed Lake A-67
Core I.D.: 13B
Core Depth: 1282.34 m

Air Permeability : 0.95 mD
Porosity (fraction): 0.11

Air/Mercury Capillary Pressure (MPa)	Derived Air / Water Capillary Pressure (MPa)	Wetting Phase Saturation (fraction)	Pore Throat Diameter (Microns)	Height of Transition (m)
0.632	0.146	1.0000	2.154	0.0
0.810	0.187	0.9864	1.757	4.2
0.966	0.223	0.9299	1.416	7.9
1.202	0.278	0.6448	1.164	13.4
1.517	0.350	0.4253	0.930	20.8
1.871	0.432	0.3281	0.744	29.2
2.278	0.526	0.2624	0.607	38.7
2.886	0.667	0.2036	0.490	53.1
3.588	0.829	0.1629	0.390	69.6
4.410	1.018	0.1335	0.315	89
5.518	1.274	0.1086	0.254	115
6.840	1.580	0.0882	0.204	146
8.332	1.924	0.0747	0.166	181
10.40	2.401	0.0588	0.135	230
13.10	3.025	0.0452	0.108	293
16.36	3.779	0.0339	0.0857	370
20.00	4.620	0.0249	0.0693	456
24.80	5.727	0.0181	0.0563	569
30.93	7.143	0.0136	0.0453	713
38.48	8.888	0.0090	0.0364	891
47.39	10.94	0.0068	0.0294	1101
59.13	13.66	0.0045	0.0237	1377
73.02	16.86	0.0023	0.0191	1704
90.58	20.92	0.0000	0.0154	2118
113.1	26.12	0.0000	0.0124	2648
137.7	31.80	0.0000	0.0100	3227
171.9	39.69	0.0000	0.0082	4031
206.0	47.57	0.0000	0.0067	4834
240.8	55.61	0.0000	0.0056	5653
275.5	63.61	0.0000	0.0049	6470
310.0	71.60	0.0000	0.0043	7283
344.5	79.57	0.0000	0.0038	8096
378.5	87.41	0.0000	0.0035	8896
409.0	94.46	0.0000	0.0032	9614

TABLE 6
MERCURY INJECTION CAPILLARY PRESSURE TEST SUMMARY

Well Location: Tweed Lake A-67
Core I.D.: 27C
Core Depth: 1292.25 m

Routine Core Analysis Air Permeability : 11.5 mD
Routine Core Analysis Porosity (fraction): 0.134

Mercury Injection Test Sample Data	
Sample Weight (g):	15.221
Corrected sample porosity (fraction):	0.121
Grain Density (g/cc):	2.64
Conformance Correction Vol. (cc):	0.026
Total Pore Surface Area (m^2):	48.63
Median Pore Diameter (micron):	0.737
Conformance Correction (percent of P.V.):	3.1%
* Threshold Pressure (kPa):	14.2
Pore throat size distribution:	
Macropores (pore throat dia. > 3.0 microns):	23.7%
Mesopores (pore throat dia. 1.0 - 3.0 microns):	20.0%
Micropores (pore throat dia. < 1.0 microns):	56.4%

Conversion Factors for Data Calculation	
Mercury Density (g/cc):	13.5335
Air / Mercury Interfacial Tension (dynes/cm):	485
Air / Mercury Contact Angle (degree):	130
Air / Water Interfacial Tension (dynes/cm):	72
Air / Water Contact Angle (degree):	0.0
Water Density for transitional height calculation (kg/m^3):	1000
Air Density for transitional height calculation (kg/m^3):	0.0010

* Threshold pressure - pressure at which mercury first enters the pore system.

TABLE 7
MERCURY INJECTION CAPILLARY PRESSURE DATA

Well Location: Tweed Lake A-67
Core I.D.: 27C
Core Depth: 1292.25 m

Air Permeability : 11.5 mD
Porosity (fraction): 0.134

Air/Mercury Capillary Pressure (MPa)	Derived Air / Water Capillary Pressure (MPa)	Wetting Phase Saturation (fraction)	Pore Throat Diameter (Microns)	Height of Transition (m)
0.014	0.003	1.0000	220.0	0.00
0.021	0.005	0.9924	73.68	0.16
0.028	0.006	0.9885	52.00	0.32
0.038	0.009	0.9809	38.66	0.57
0.042	0.010	0.9771	31.29	0.65
0.052	0.012	0.9676	26.94	0.89
0.059	0.014	0.9618	22.59	1.05
0.073	0.017	0.9504	19.19	1.37
0.090	0.021	0.9370	15.54	1.78
0.110	0.025	0.9237	12.60	2.26
0.138	0.032	0.9084	10.17	2.91
0.172	0.040	0.8893	8.146	3.72
0.193	0.045	0.8760	6.854	4.20
0.285	0.066	0.8473	5.424	6.37
0.359	0.083	0.8149	3.929	8.11
0.429	0.099	0.7882	3.192	9.77
0.519	0.120	0.7576	2.654	11.9
0.619	0.143	0.7252	2.207	14.2
0.797	0.184	0.6737	1.789	18.4
0.965	0.223	0.6298	1.429	22.4
1.202	0.278	0.5821	1.165	28.0
1.520	0.351	0.5363	0.929	35.4
1.872	0.432	0.5019	0.743	43.7
2.272	0.525	0.4790	0.608	53.2
2.884	0.666	0.4542	0.491	67.6
3.600	0.831	0.4351	0.389	84.4
4.397	1.015	0.4179	0.315	103
5.494	1.269	0.3969	0.255	129
6.813	1.573	0.3779	0.205	160
8.375	1.934	0.3531	0.166	197
10.38	2.397	0.3225	0.135	244
13.04	3.011	0.2824	0.108	307
16.36	3.779	0.2462	0.0859	385
19.98	4.613	0.2156	0.0693	470
24.75	5.715	0.1889	0.0564	582
31.54	7.284	0.1603	0.0450	742
38.45	8.879	0.1393	0.0360	905
47.50	10.97	0.1183	0.0293	1118
59.11	13.65	0.0992	0.0237	1391
72.77	16.81	0.0782	0.0191	1713
90.56	20.92	0.0573	0.0155	2132
112.8	26.05	0.0401	0.0124	2656
137.6	31.78	0.0267	0.0101	3240
171.7	39.66	0.0172	0.0082	4042
206.5	47.69	0.0095	0.0067	4861
240.5	55.54	0.0057	0.0056	5661
276.0	63.75	0.0038	0.0049	6498
309.7	71.52	0.0019	0.0043	7290
344.5	79.56	0.0000	0.0038	8110
378.7	87.45	0.0000	0.0035	8914
409.0	94.46	0.0000	0.0032	9629

TABLE 8
MERCURY INJECTION CAPILLARY PRESSURE TEST SUMMARY

Well Location: Tweed Lake A-67

Core I.D.: 36A

Core Depth: 1296.37 m

Routine Core Analysis Air Permeability : 2.72 mD

Routine Core Analysis Porosity (fraction): 0.115

Mercury Injection Test Sample Data	
Sample Weight (g):	12.589
Corrected sample porosity (fraction):	0.100
Grain Density (g/cc):	2.64
Conformance Correction Vol. (cc):	0.040
Total Pore Surface Area (m^2):	9.11
Median Pore Diameter (micron):	1.676
Conformance Correction (percent of P.V.):	7.0%
* Threshold Pressure (kPa):	286.2
Pore throat size distribution:	
Macropores (pore throat dia. > 3.0 microns):	1.6%
Mesopores (pore throat dia. 1.0 - 3.0 microns):	68.2%
Micropores (pore throat dia. < 1.0 microns):	30.1%

Conversion Factors for Data Calculation	
Mercury Density (g/cc):	13.5335
Air / Mercury Interfacial Tension (dynes/cm):	485
Air / Mercury Contact Angle (degree):	130
Air / Water Interfacial Tension (dynes/cm):	72
Air / Water Contact Angle (degree):	0.0
Water Density for transitional height calculation (kg/m^3):	1000
Air Density for transitional height calculation (kg/m^3):	0.0010

* Threshold pressure - pressure at which mercury first enters the pore system.

TABLE 9
MERCURY INJECTION CAPILLARY PRESSURE DATA

Well Location: Tweed Lake A-67
Core I.D.: 36A
Core Depth: 1296.37 m

Air Permeability : 2.72 mD
Porosity (fraction): 0.115

Air/Mercury Capillary Pressure (MPa)	Derived Air / Water Capillary Pressure (MPa)	Wetting Phase Saturation (fraction)	Pore Throat Diameter (Microns)	Height of Transition (m)
0.286	0.066	1.0000	5.412	0.00
0.360	0.083	0.9953	3.909	1.75
0.431	0.100	0.9859	3.177	3.41
0.521	0.120	0.9485	2.643	5.5
0.618	0.143	0.7073	2.205	7.8
0.792	0.183	0.4145	1.796	11.9
0.960	0.222	0.3513	1.437	15.9
1.196	0.276	0.3021	1.171	21.4
1.514	0.350	0.2623	0.933	28.9
1.866	0.431	0.2272	0.746	37.2
2.267	0.523	0.1991	0.609	46.6
2.879	0.665	0.1686	0.492	61.0
3.594	0.830	0.1452	0.390	77.9
4.391	1.014	0.1265	0.316	97
5.488	1.267	0.1077	0.256	122
6.807	1.572	0.0937	0.205	154
8.369	1.933	0.0820	0.166	190
10.37	2.396	0.0703	0.135	237
13.03	3.010	0.0609	0.108	300
16.36	3.778	0.0539	0.0860	378
19.97	4.612	0.0468	0.0693	463
24.74	5.714	0.0398	0.0564	576
31.54	7.283	0.0351	0.0450	736
38.44	8.878	0.0304	0.0360	898
47.50	10.97	0.0258	0.0293	1111
59.11	13.65	0.0211	0.0237	1385
72.77	16.81	0.0187	0.0191	1706
90.56	20.91	0.0141	0.0155	2125
112.8	26.05	0.0094	0.0124	2649
137.6	31.78	0.0070	0.0101	3233
171.7	39.66	0.0047	0.0082	4036
206.5	47.69	0.0023	0.0067	4854
240.5	55.54	0.0023	0.0056	5655
276.0	63.75	0.0023	0.0049	6492
309.7	71.52	0.0000	0.0043	7284
344.5	79.56	0.0000	0.0038	8103
378.7	87.45	0.0000	0.0035	8908
409.0	94.46	0.0000	0.0032	9622

TABLE 10
FRACTURE FLUID EVALUATION WITH GELLED RIMBEY PLATINUM

CORE & TEST PARAMETERS			
Gas Viscosity (cP):	0.01643	**Length (cm):**	2.42
Plug I.D. (Inlet to Outlet):	27B,27C	**Diameter (cm):**	2.45
Depth (m):	1292.20	**Pore Volume (cm³):**	1.86
Porosity (fraction):	0.164	**Fracture Pressure (kPa):**	11550
Air Permeability (mD):	10.36	**Pore Pressure (kPa):**	13000
Test Temperature (°C):	12	**Net Overburden Pressure (kPa):**	16225

PERMEABILITY SUMMARY

Test Phase	Permeability (mD)	Regain Permeability (%)
Initial Permeability to Synthesized Gas @ 30% Swi (Forward Direction)	2.92	Baseline Permeability
Fracture Fluid Circulation with **GELLED RIMBEY PLATINUM** (Reverse Direction)	--	--
Regain Permeability to Synthesized Gas (Forward Direction)		
At 276 kPa	0.263	9%
Post 1172 kPa	0.937	32%
Post 4000 kPa	1.03	35%
Post 13000 kPa	1.04	35%
RERUN Regain Permeability to Synthesized Gas (Forward Direction)		
At 276 kPa	1.84	63%
Post 1172 kPa	1.85	63%
Post 4000 kPa	2.71	93%
Post 13000 kPa	2.71	93%

TABLE 11
FRACTURE FLUID EVALUATION WITH GELLED RIMBEY PLATINUM

CORE & TEST PARAMETERS			
Gas Viscosity (cP):	0.01643	**Length (cm):**	2.42
Plug I.D. (Inlet to Outlet):	27B,27C	**Diameter (cm):**	2.45
Depth (m):	1292.20	**Pore Volume (cm³):**	1.86
Porosity (fraction):	0.164	**Fracture Pressure (kPa):**	11550
Air Permeability (mD):	10.36	**Pore Pressure (kPa):**	13000
Test Temperature (°C):	12	**Net Overburden Pressure (kPa):**	16225

SUMMARY of FLUID LEAKOFF	
Leakoff Exposure Time	30 minutes
Total Leakoff Volume after 30 minutes	1.7 cc
Leakoff Fluid Linear Penetration Depth	2.21 cm*

* Assuming 100% Filtrate Sweep Efficiency

TABLE 12
FRACTURE FLUID EVALUATION WITH GELLED FX2

CORE & TEST PARAMETERS			
Gas Viscosity (cP):	0.01643	**Length (cm):**	3.02
Plug I.D. (Inlet to Outlet):	27D,27J	**Diameter (cm):**	2.46
Depth (m):	1292.20	**Pore Volume (cm³):**	1.91
Porosity (fraction):	0.133	**Fracture Pressure (kPa):**	11550
Air Permeability (mD):	10.7	**Pore Pressure (kPa):**	13000
Test Temperature (°C):	12	**Net Overburden Pressure (kPa):**	16225

PERMEABILITY SUMMARY

Test Phase	Permeability (mD)	Regain Permeability (%)
Initial Permeability to Synthesized Gas @ 30% Swi (Forward Direction)	3.25	Baseline Permeability
Fracture Fluid Circulation with **GELLED FX2** (Reverse Direction)	--	--
Regain Permeability to Synthesized Gas (Forward Direction)		
At 1172 kPa	0.241	7%
Post 4000 kPa	0.396	12%
Post 13000 kPa	0.497	15%
Core Shut in for over 24 hours.	--	--
Regain Permeability to Synthesized Gas (Forward Direction)		
At 55 kPa	0.685	21%
Post 276 kPa	0.708	22%
Post 1172 kPa	0.738	23%
Post 4000 kPa	0.781	24%
Post 13000 kPa	0.786	24%
Liquid CO2 Injection (2 Pore Volumes)	--	--
Regain Permeability to Synthesized Gas (Forward Direction)		
At 55 kPa	0.460	14%
Post 276 kPa	0.450	14%
Post 1172 kPa	0.410	13%
Post 4000 kPa	0.450	14%
Post 13000 kPa	0.480	15%

TABLE 12 Cont'd.
FRACTURE FLUID EVALUATION WITH GELLED FX2

CORE & TEST PARAMETERS			
Gas Viscosity (cP):	0.01643	**Length (cm):**	3.02
Plug I.D. (Inlet to Outlet):	27D,27J	**Diameter (cm):**	2.46
Depth (m):	1292.20	**Pore Volume (cm³):**	1.91
Porosity (fraction):	0.133	**Fracture Pressure (kPa):**	11550
Air Permeability (mD):	10.7	**Pore Pressure (kPa):**	13000
Test Temperature (°C):	12	**Net Overburden Pressure (kPa):**	16225

PERMEABILITY SUMMARY		
Test Phase	**Permeability (mD)**	**Regain Permeability (%)**
Initial Permeability to Synthesized Gas @ 30% Swi (Forward Direction)	3.25	Baseline Permeability
Fracture Fluid Circulation with **GELLED FX2** (Reverse Direction)	--	--
Liquid CO2 Injection (2 Pore Volumes)		
Regain Permeability to Synthesized Gas (Forward Direction)		
At 55 kPa	0.460	14%
Post 276 kPa	0.450	14%
Post 1172 kPa	0.410	13%
Post 4000 kPa	0.450	14%
Post 13000 kPa	0.480	15%
Heat Oven to 16 °C		
Regain Permeability to Synthesized Gas (Forward Direction)		
At 55 kPa	0.440	14%
Post 276 kPa	0.44	14%
Post 1172 kPa	0.41	13%
Post 4000 kPa	0.47	14%
Post 13000 kPa	0.52	16%

TABLE 13
FRACTURE FLUID EVALUATION WITH GELLED FX2

CORE & TEST PARAMETERS			
Gas Viscosity (cP):	0.01643	**Length (cm):**	3.02
Plug I.D. (Inlet to Outlet):	27D,27J	**Diameter (cm):**	2.46
Depth (m):	1292.20	**Pore Volume (cm³):**	1.91
Porosity (fraction):	0.133	**Fracture Pressure (kPa):**	11550
Air Permeability (mD):	10.7	**Pore Pressure (kPa):**	13000
Test Temperature (°C):	12	**Net Overburden Pressure (kPa):**	16225

SUMMARY of FLUID LEAKOFF	
Leakoff Exposure Time	30 minutes
Total Leakoff Volume after 30 minutes	0.8 cc
Leakoff Fluid Linear Penetration Depth	1.27 cm*

* Assuming 100% Filtrate Sweep Efficiency

TABLE 14
FRACTURE FLUID EVALUATION WITH CO2 MISCIBLE RIMBEY PLATINUM

CORE & TEST PARAMETERS			
Gas Viscosity (cP):	0.01643	**Length (cm):**	2.87
Plug I.D. (Inlet to Outlet):	27F,27G	**Diameter (cm):**	2.58
Depth (m):	1292.00	**Pore Volume (cm³):**	1.75
Porosity (fraction):	0.117	**Fracture Pressure (kPa):**	11550
Air Permeability (mD):	27.5	**Pore Pressure (kPa):**	13000
Test Temperature (°C):	16	**Net Overburden Pressure (kPa):**	16225

PERMEABILITY SUMMARY

Test Phase	Permeability (mD)	Regain Permeability (%)
Initial Permeability to Synthesized Gas @ 30% Swi (Forward Direction)	11.56	Baseline Permeability
Fracture Fluid Circulation with **CO2 PAD &** **CO2 MISCIBLE RIMBEY PLATINUM** (Reverse Direction)	--	--
Regain Permeability to Synthesized Gas (Forward Direction)		
At 14 kPa	2.170	19%
Post 28 kPa	0.568	5%
Post 55 kPa	0.933	8%
Post 276 kPa	0.643	6%
Post 1172 kPa	0.410	4%
Post 4000 kPa	0.330	3%
Post 13000 kPa	0.374	3%
At 14 kPa	2.20	19%

PETRO-CANADA

TABLE 15
FRACTURE FLUID EVALUATION WITH CO2 MISCIBLE RIMBEY PLATINUM

CORE & TEST PARAMETERS			
Gas Viscosity (cP):	0.01643	**Length (cm):**	2.87
Plug I.D. (Inlet to Outlet):	27F,27G	**Diameter (cm):**	2.58
Depth (m):	1292.00	**Pore Volume (cm^3):**	1.75
Porosity (fraction):	0.117	**Fracture Pressure (kPa):**	11550
Air Permeability (mD):	27.5	**Pore Pressure (kPa):**	13000
Test Temperature (°C):	16	**Net Overburden Pressure (kPa):**	16225

SUMMARY of FLUID LEAKOFF	
Leakoff Exposure Time	30 minutes
Total Leakoff Volume after 30 minutes	0 cc
Leakoff Fluid Linear Penetration Depth	0.00 cm*
* Assuming 100% Filtrate Sweep Efficiency	

TABLE 16
FRACTURE FLUID EVALUATION WITH GELLED RIMBEY PLATINUM

CORE & TEST PARAMETERS			
Gas Viscosity (cP):	0.01643	**Length (cm):**	2.42
Plug I.D. (Inlet to Outlet):	27B,27C	**Diameter (cm):**	2.45
Depth (m):	1292.20	**Pore Volume (cm³):**	1.54
Porosity (fraction):	0.135	**Fracture Pressure (kPa):**	11550
Air Permeability (mD):	10.54	**Pore Pressure (kPa):**	13000
Test Temperature (°C):	16	**Net Overburden Pressure (kPa):**	16225

PERMEABILITY SUMMARY

Test Phase	Permeability (mD)	Regain Permeability (%)
Initial Permeability to Synthesized Gas @ 30% Swi (Forward Direction)	2.1	Baseline Permeability
Fracture Fluid Circulation with **GELLED RIMBEY PLATINUM** (Reverse Direction)	--	--
Regain Permeability to Synthesized Gas (Forward Direction)		
At 55 kPa	0.816	39%
Post 276 kPa	0.966	46%
Post 1172 kPa	0.988	47%
Post 4000 kPa	1.03	49%
Post 13000 kPa	1.25	60%

TABLE 17
FRACTURE FLUID EVALUATION WITH GELLED RIMBEY PLATINUM

CORE & TEST PARAMETERS			
Gas Viscosity (cP):	0.01643	**Length (cm):**	2.42
Plug I.D. (Inlet to Outlet):	27B,27C	**Diameter (cm):**	2.45
Depth (m):	1292.20	**Pore Volume (cm³):**	1.54
Porosity (fraction):	0.135	**Fracture Pressure (kPa):**	11550
Air Permeability (mD):	10.54	**Pore Pressure (kPa):**	13000
Test Temperature (°C):	16	**Net Overburden Pressure (kPa):**	16225

SUMMARY of FLUID LEAKOFF	
Leakoff Exposure Time	30 minutes
Total Leakoff Volume after 30 minutes	1.0 cc
Leakoff Fluid Linear Penetration Depth	1.57 cm*

* Assuming 100% Filtrate Sweep Efficiency

FIGURES

FIGURE 1
PERMEABILITY vs. POROSITY CROSSPLOT

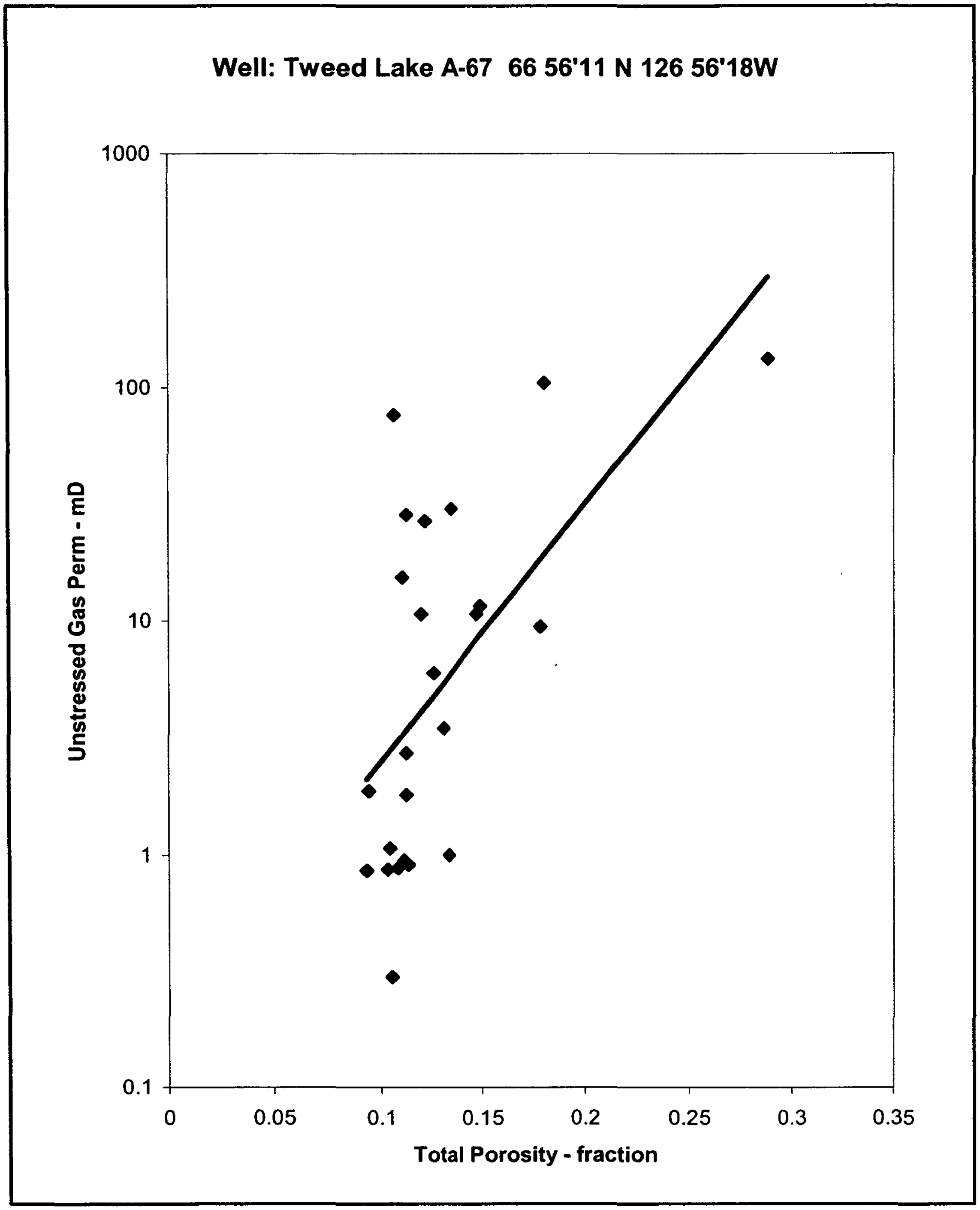


FIGURE 2
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 4A
Core Depth: 1279.14 m

Air Permeability : 5.97 mD
Porosity (fraction): 0.127

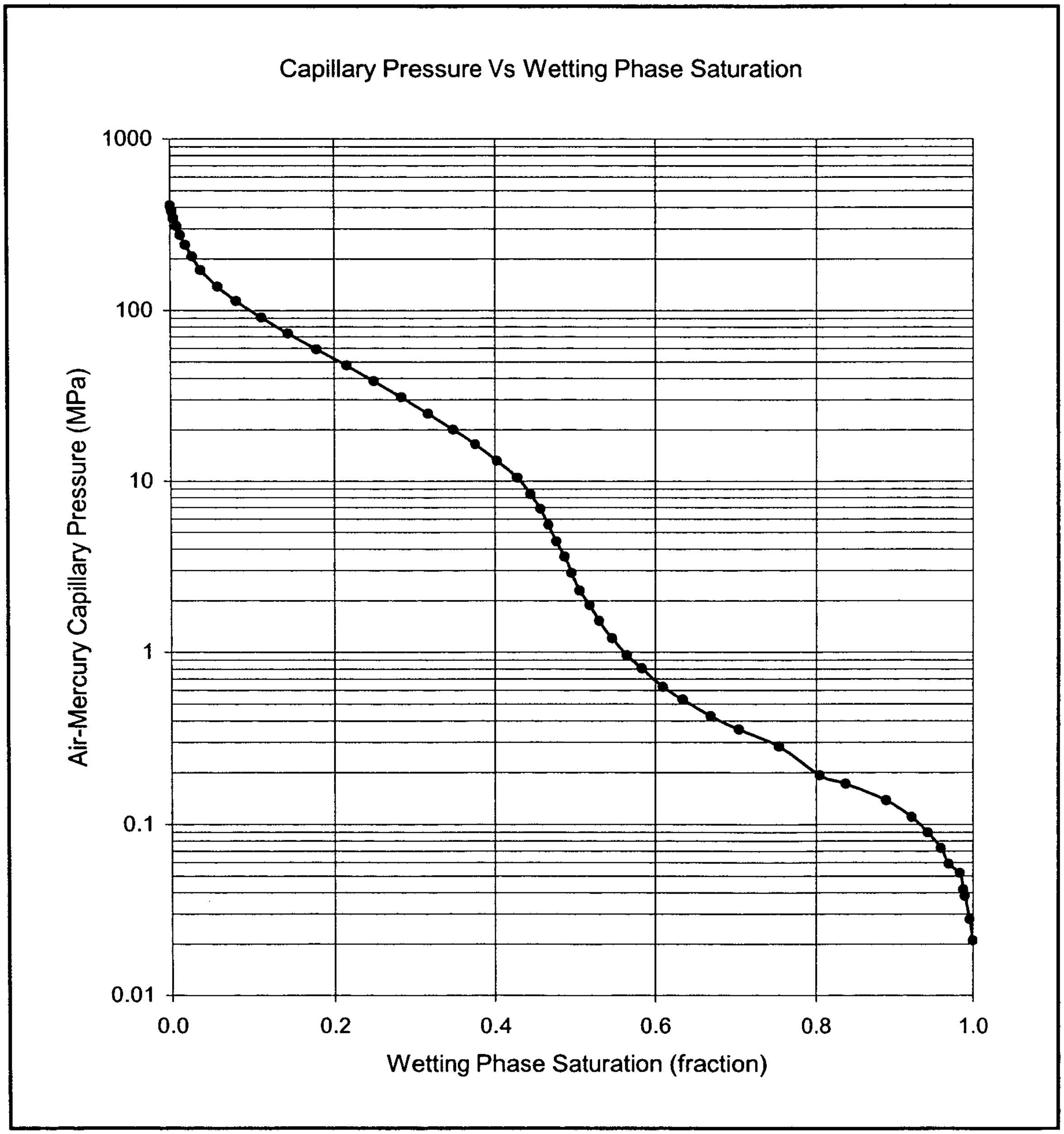


FIGURE 3
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 4A
Core Depth: 1279.14 m

Air Permeability : 5.97 mD
Porosity (fraction): 0.127

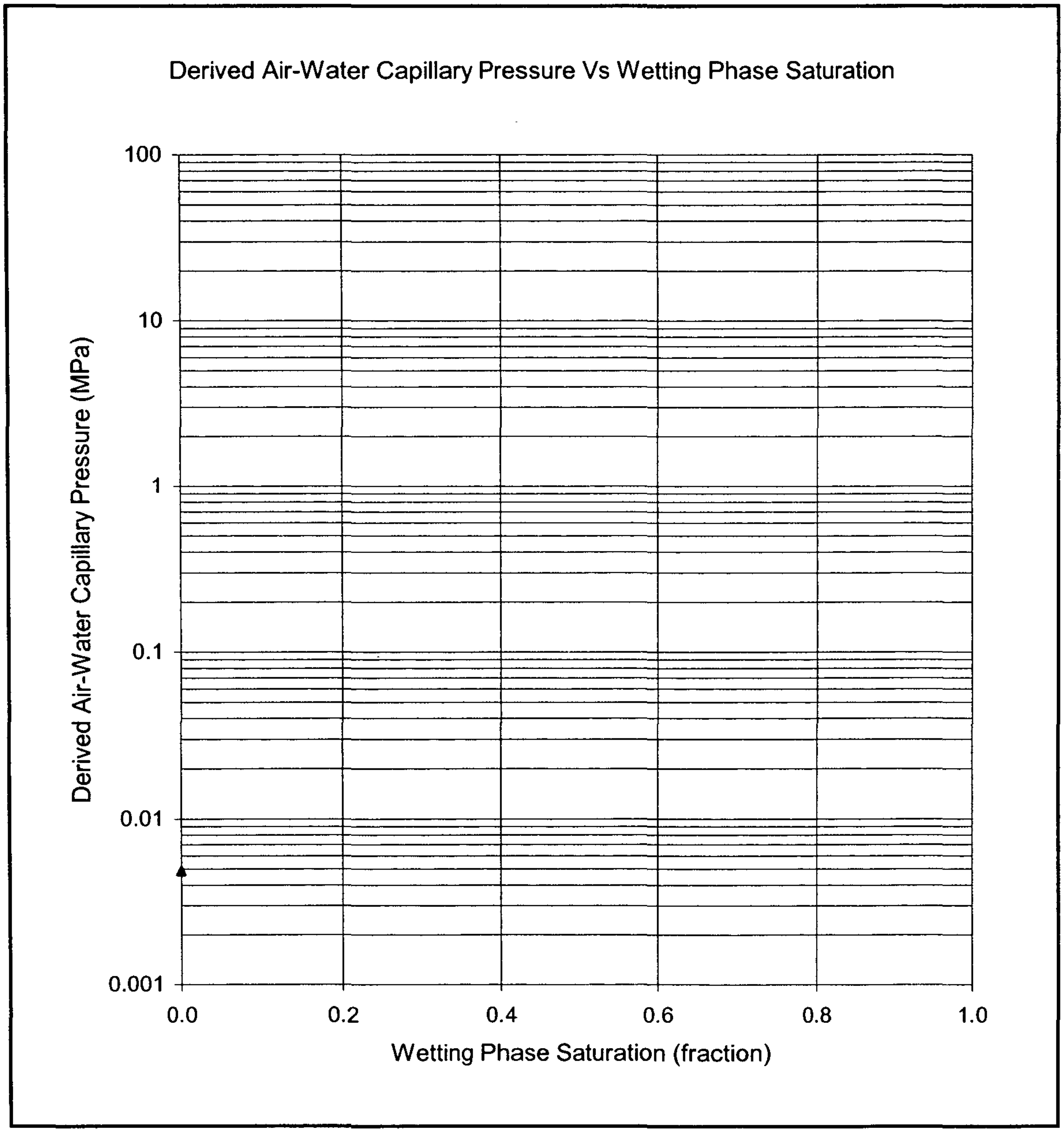


FIGURE 4
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67

Core I.D.: 4A

Core Depth: 1279.14 m

Air Permeability : 5.97 mD

Porosity (fraction): 0.127

Pore Throat Types:	Macropores (> 3 micron diameter) =	33.6%
	Mesopores (1 - 3 micron diameter) =	12.2%
	Micropores (< 1 micron diameter) =	54.2%

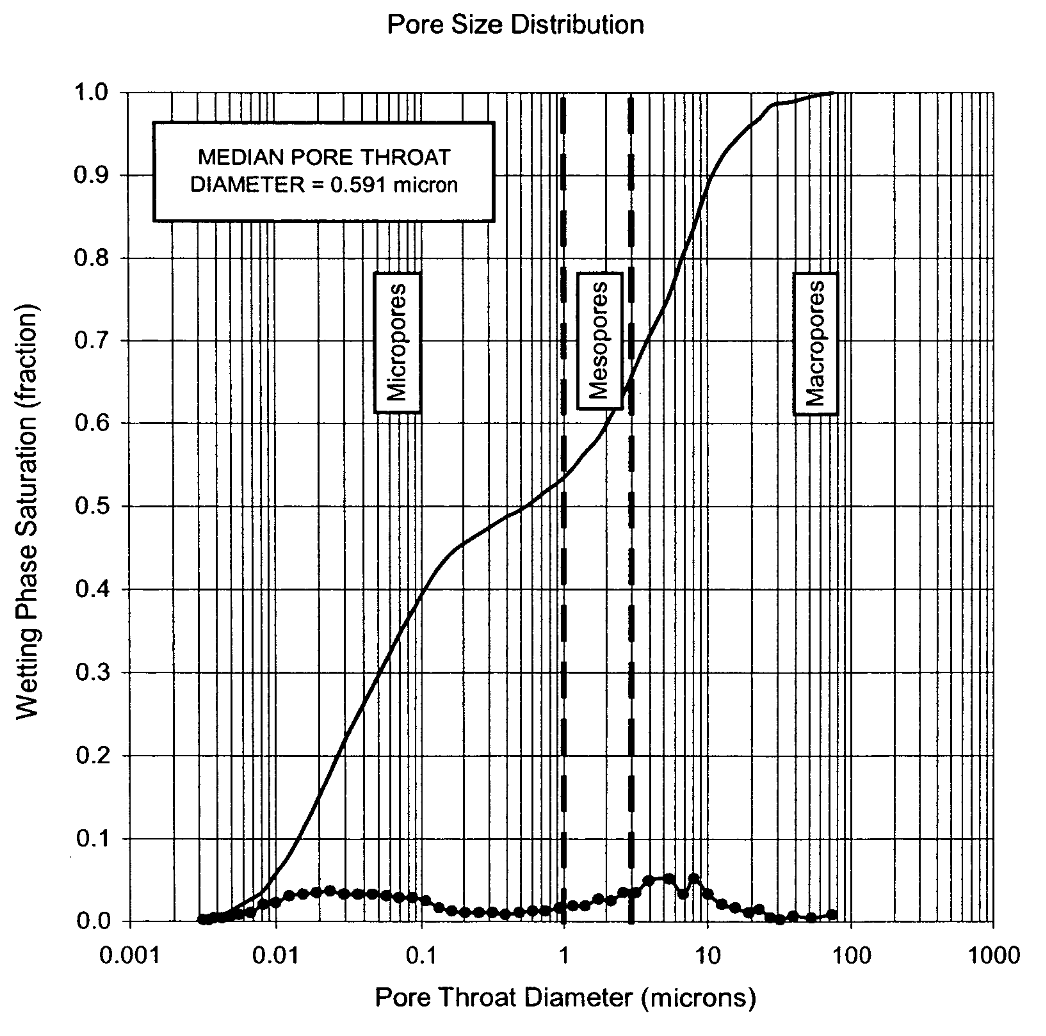


FIGURE 5
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 4A
Core Depth: 1279.14 m

Air Permeability : 5.97 mD
Porosity (fraction): 0.127

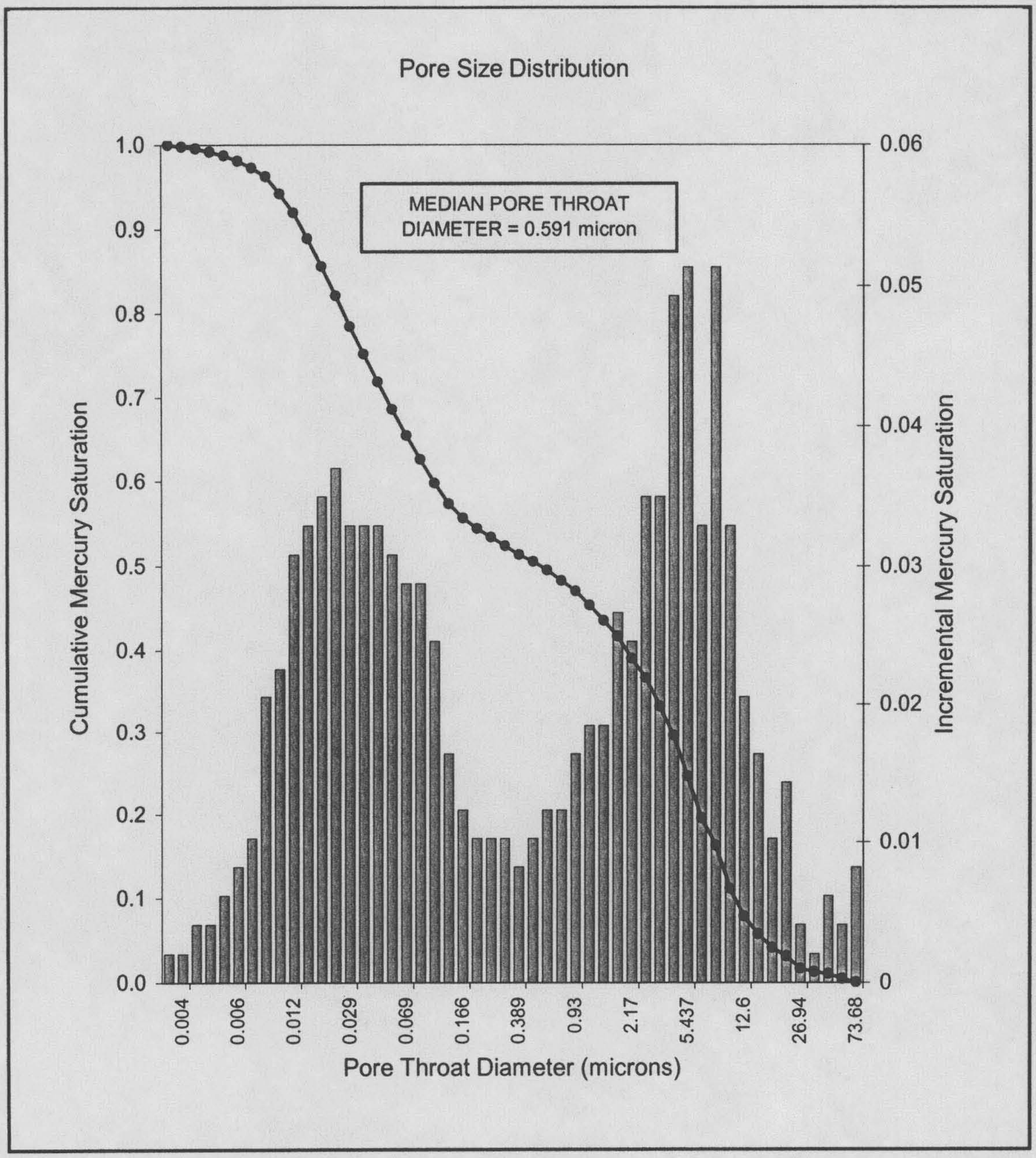


FIGURE 6
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67

Core I.D.: 4A

Core Depth: 1279.14 m

Air Permeability : 5.97 mD

Porosity (fraction): 0.127

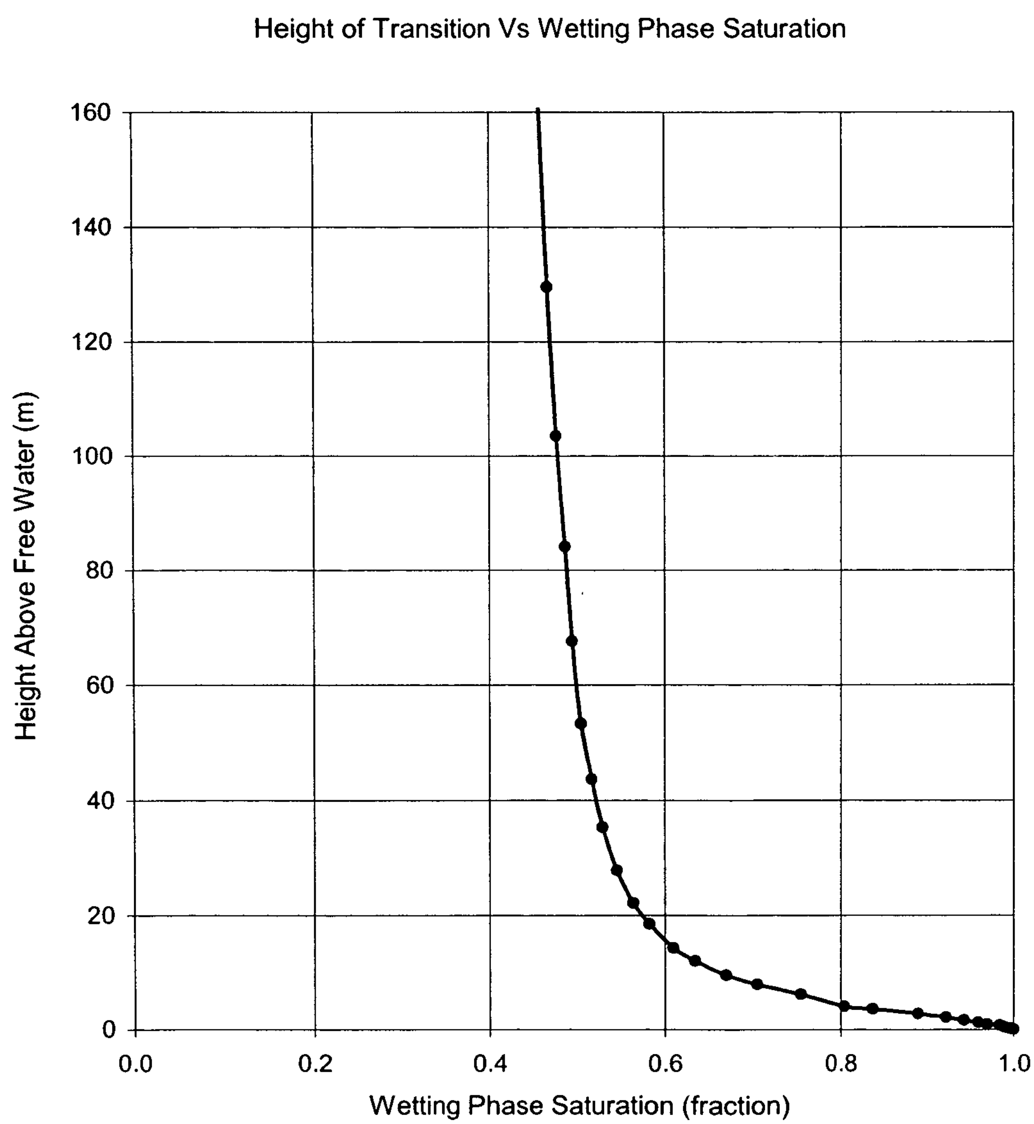


FIGURE 7
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 13B
Core Depth: 1282.34 m

Air Permeability : 0.95 mD
Porosity (fraction): 0.11

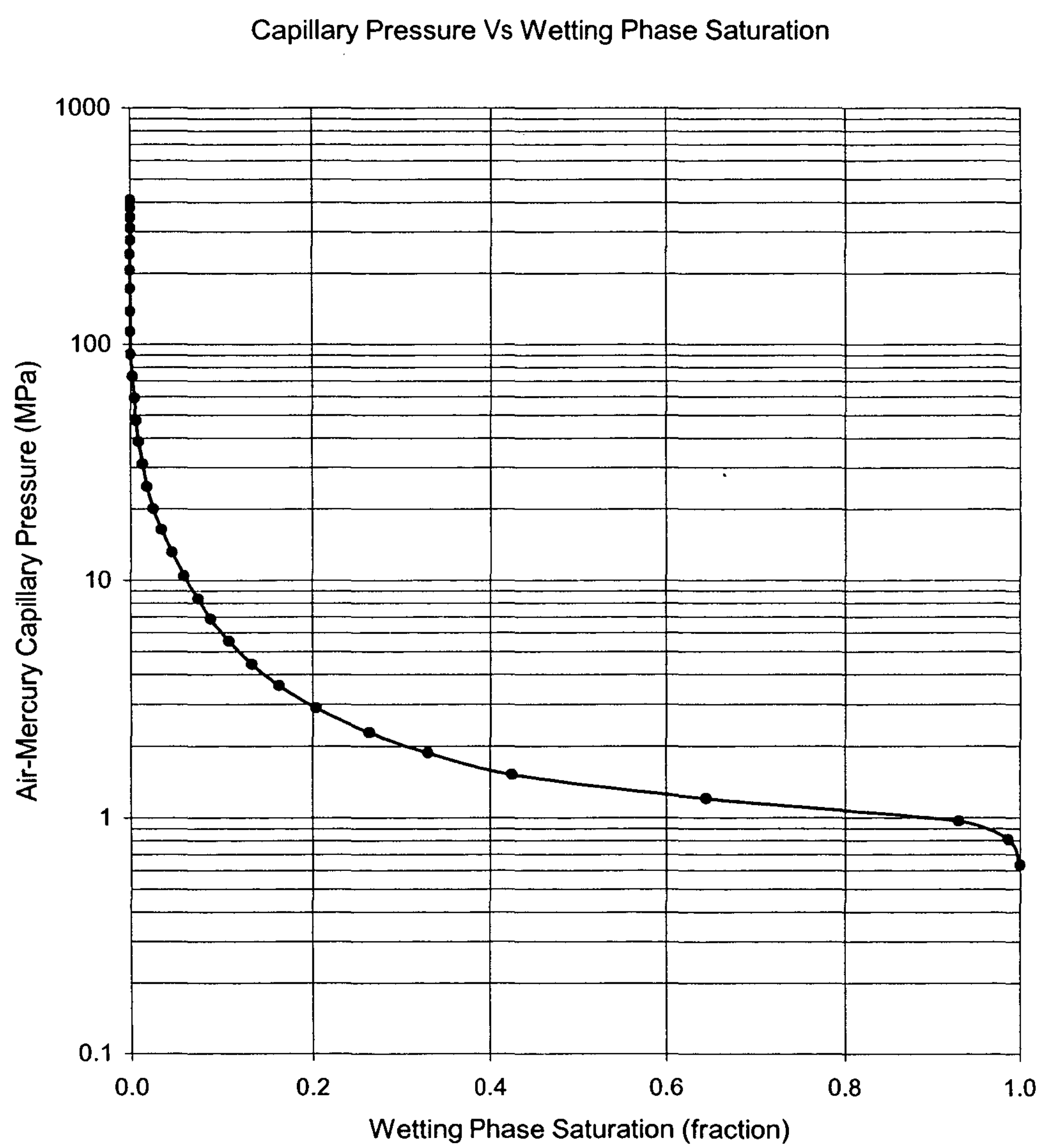


FIGURE 8
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 13B
Core Depth: 1282.34 m

Air Permeability : 0.95 mD
Porosity (fraction): 0.11

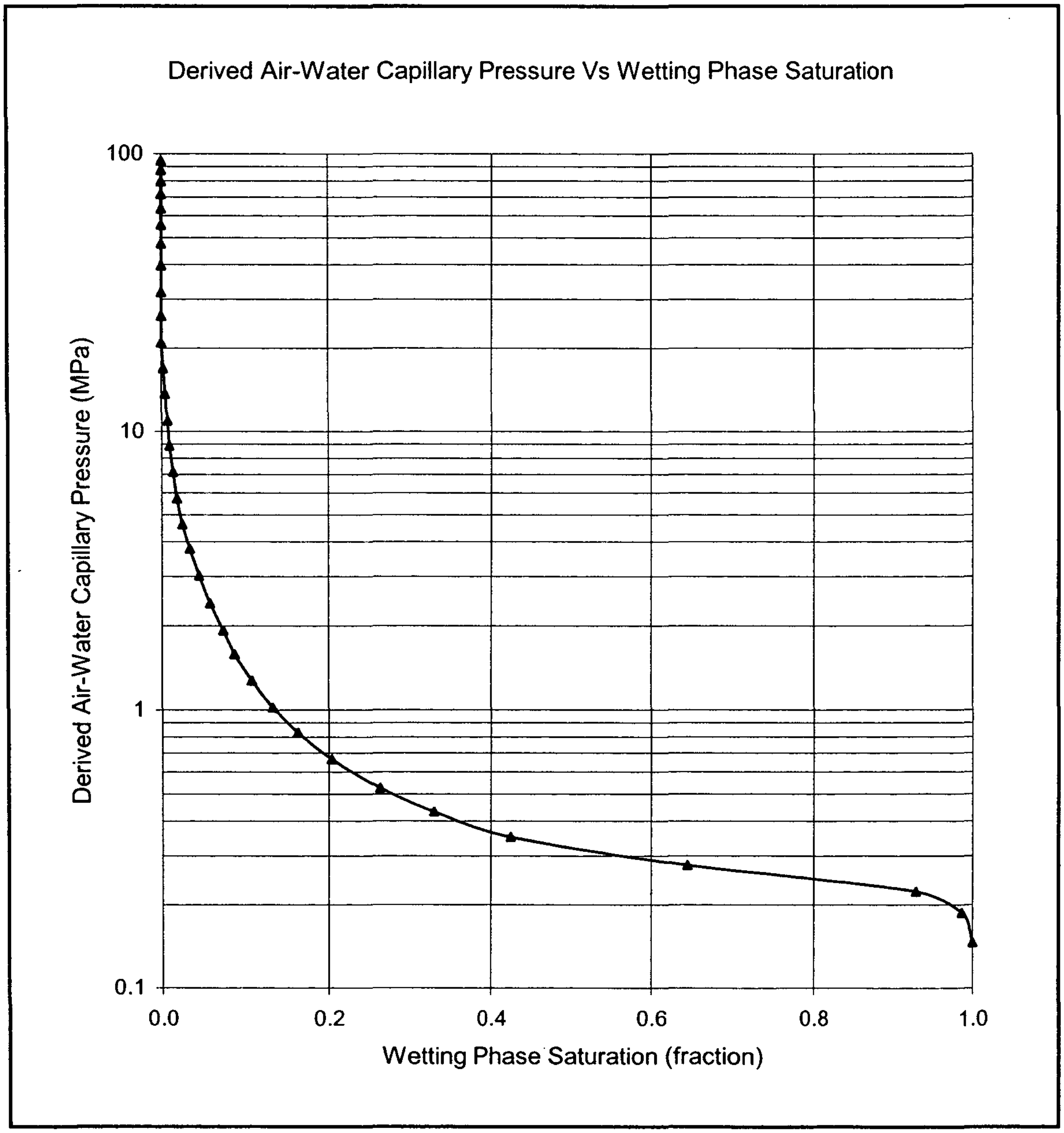


FIGURE 9
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 13B
Core Depth: 1282.34 m

Air Permeability : 0.95 mD
Porosity (fraction): 0.11

Pore Throat Types:		
	Macropores (> 3 micron diameter) =	0.0%
	Mesopores (1 - 3 micron diameter) =	35.8%
	Micropores (< 1 micron diameter) =	64.2%

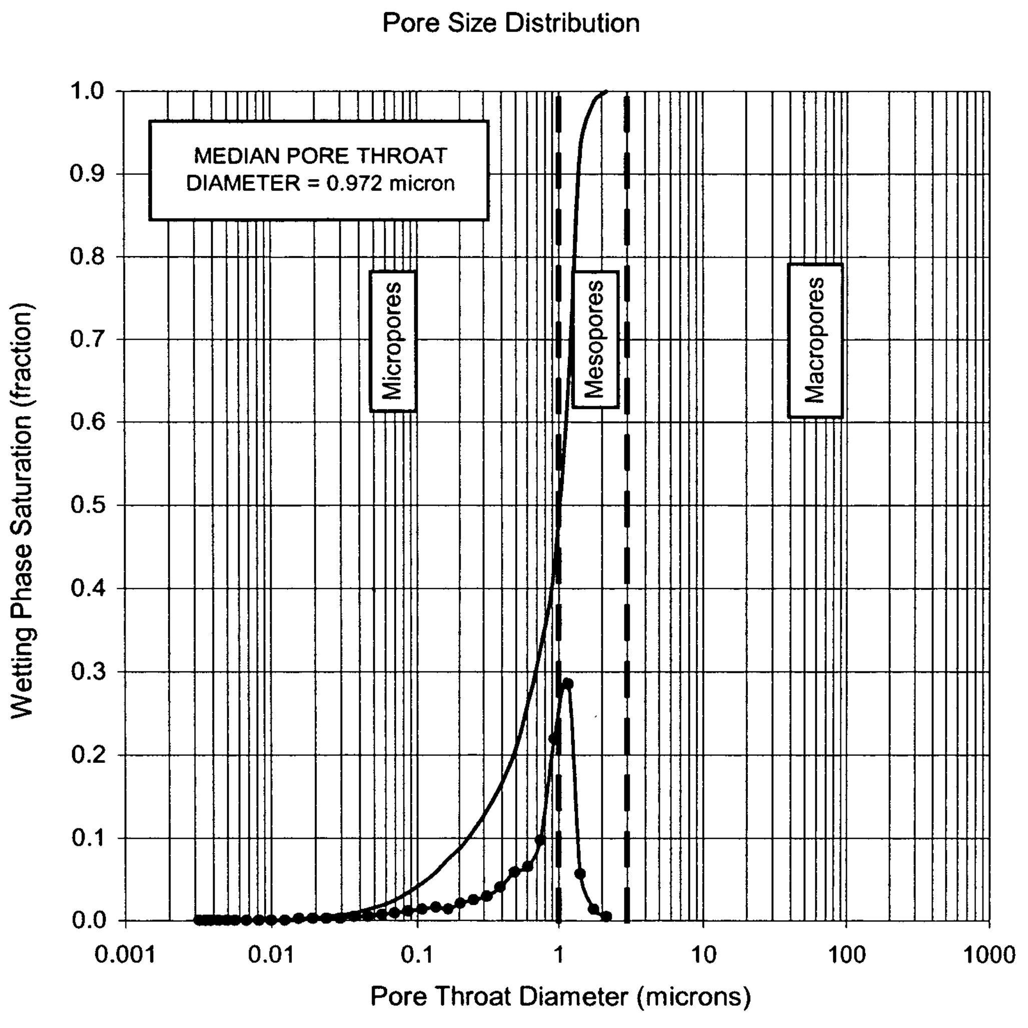


FIGURE 10
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 13B
Core Depth: 1282.34 m

Air Permeability : 0.95 mD
Porosity (fraction): 0.11

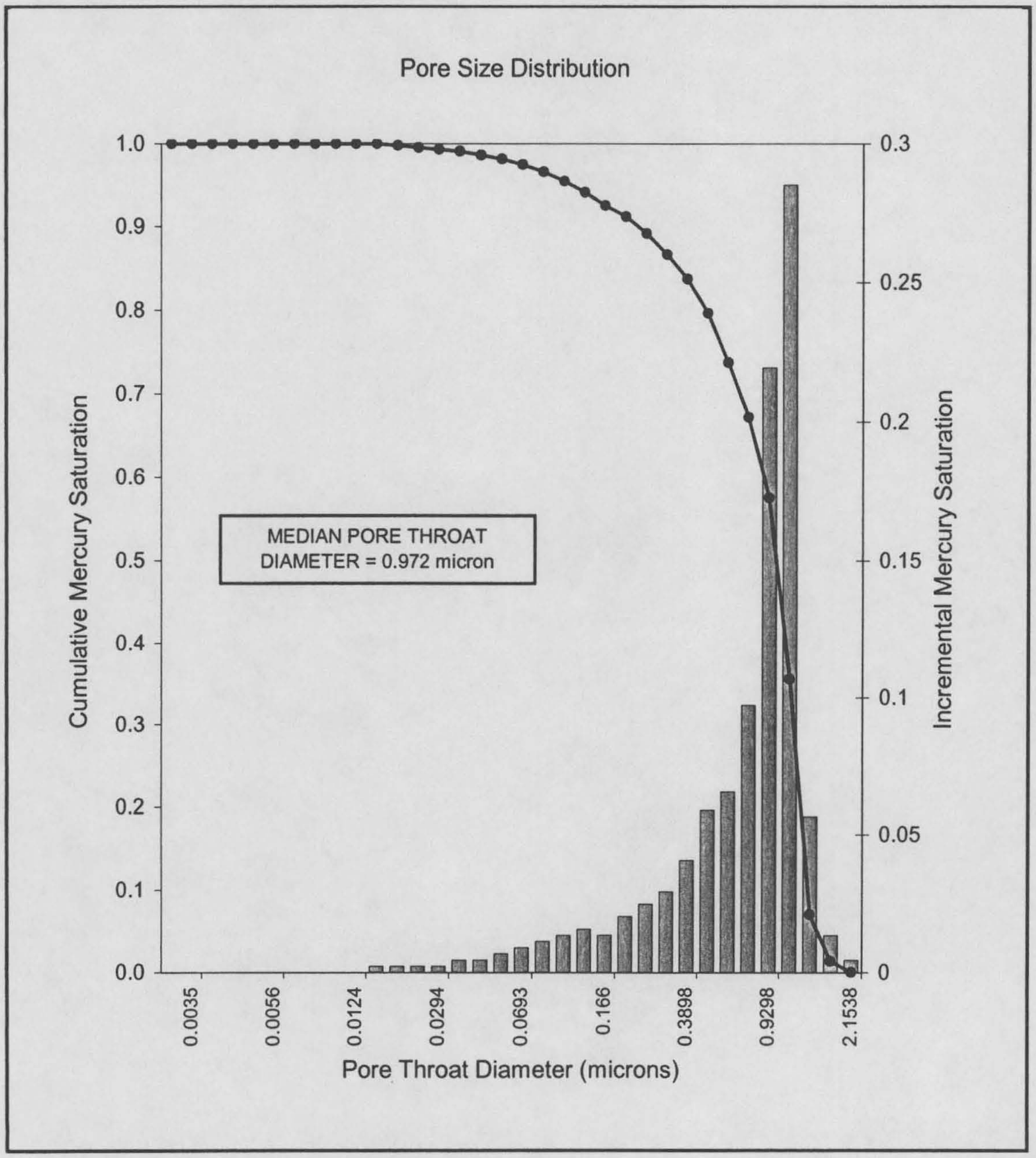


FIGURE 11
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 13B
Core Depth: 1282.34 m

Air Permeability : 0.95 mD
Porosity (fraction): 0.11

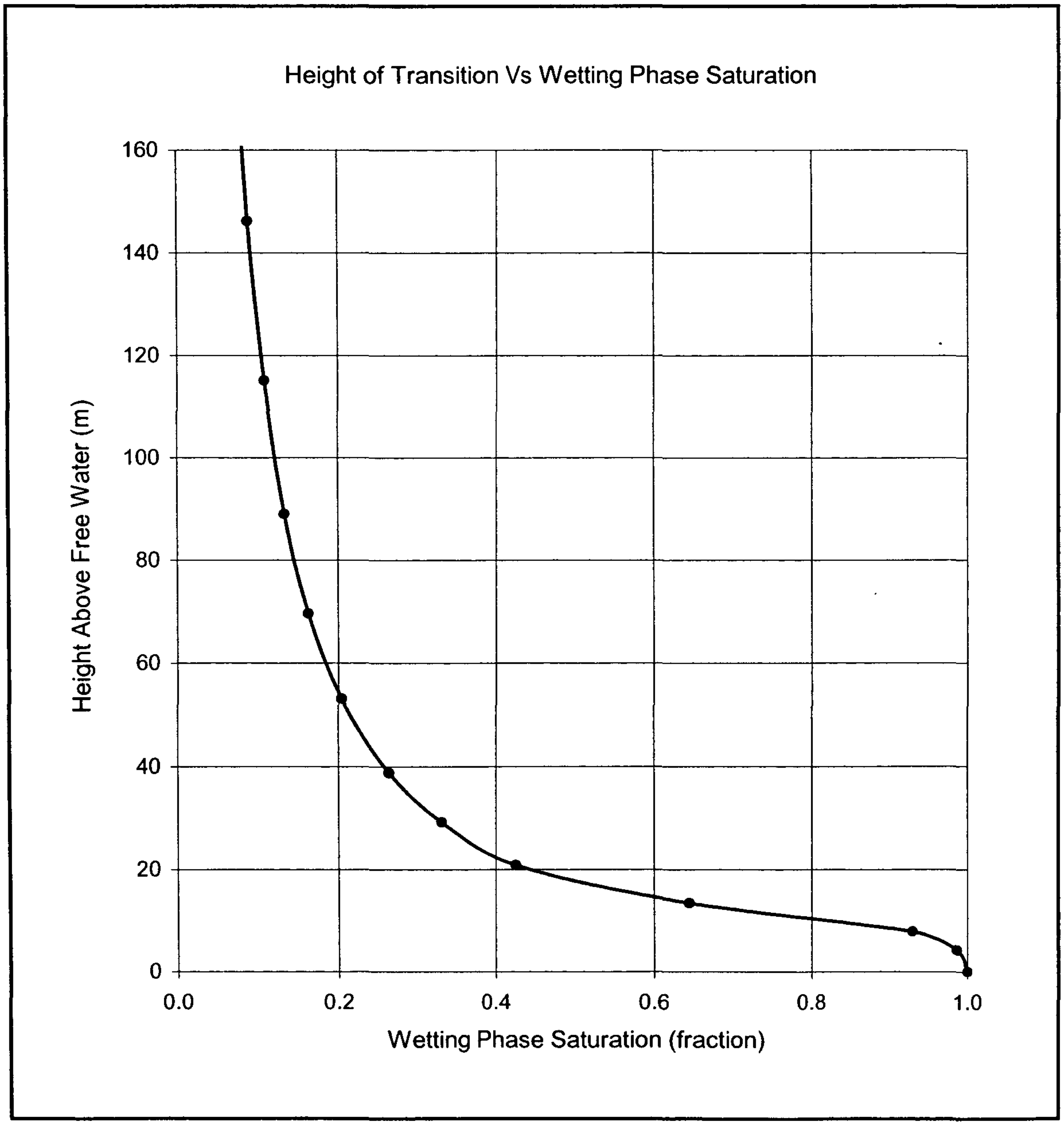


FIGURE 17
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 36A
Core Depth: 1296.37 m

Air Permeability : 2.72 mD
Porosity (fraction): 0.115

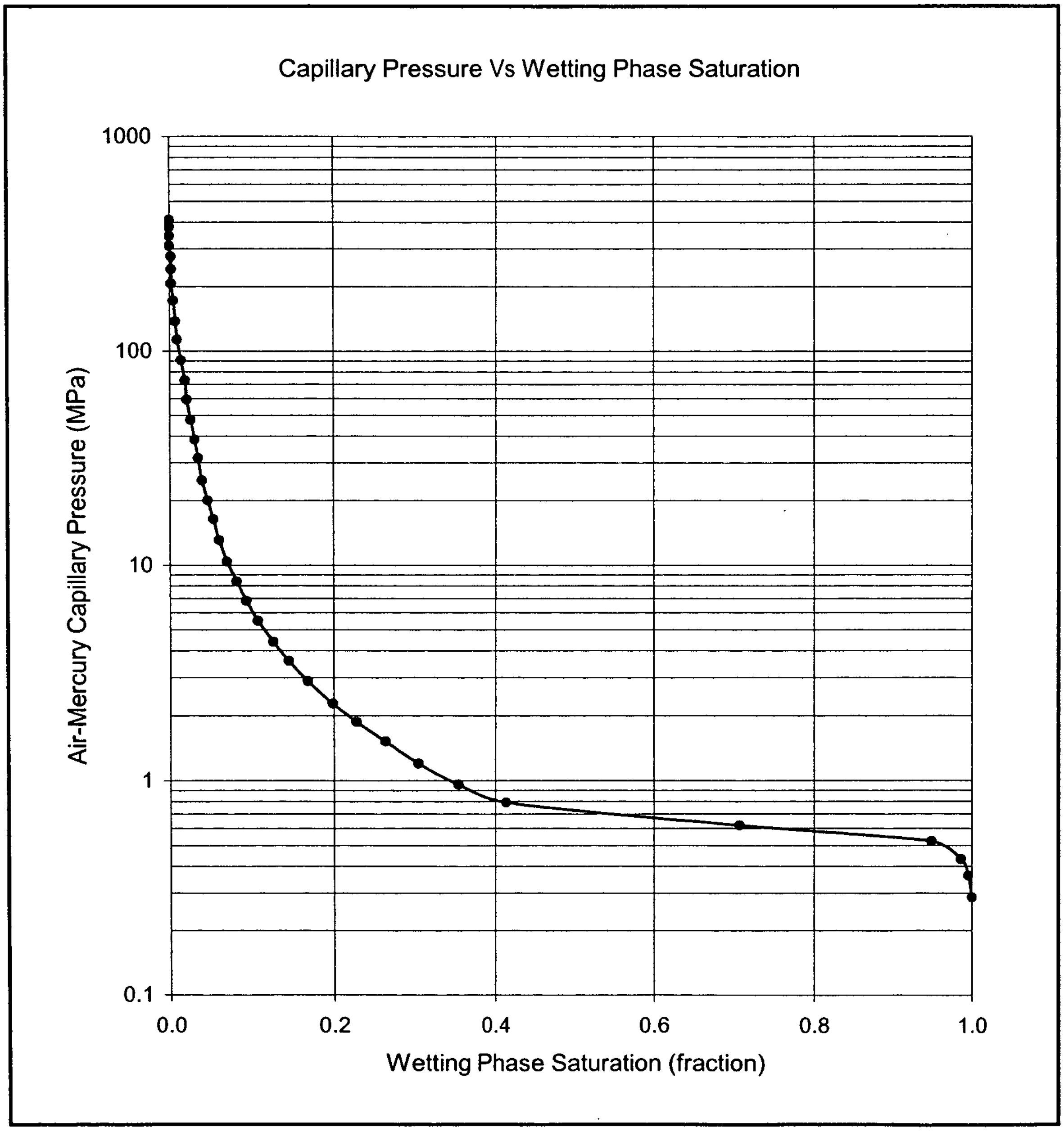


FIGURE 18
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 36A
Core Depth: 1296.37 m

Air Permeability: 2.72 mD
Porosity (fraction): 0.115

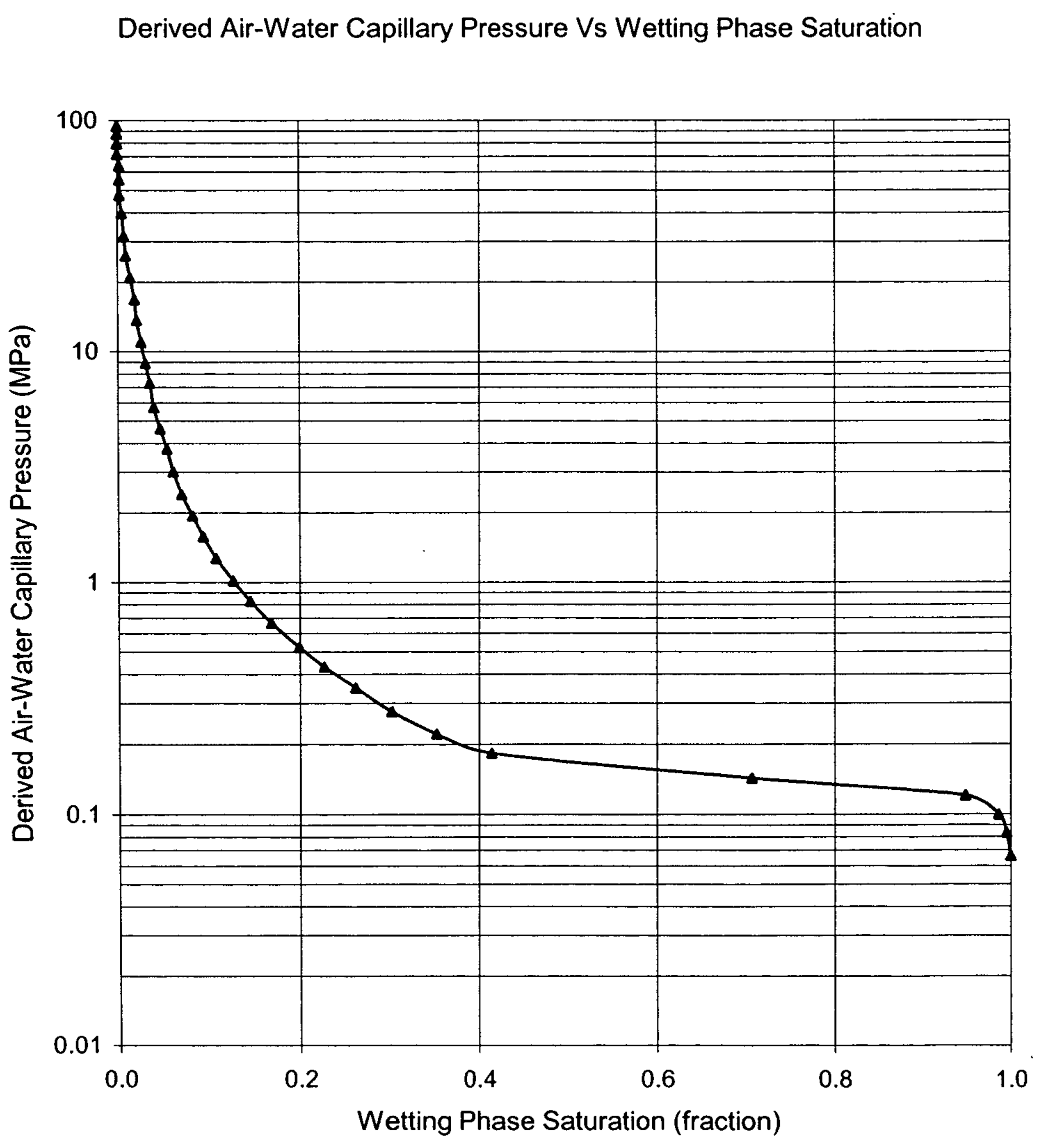


FIGURE 19
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 36A
Core Depth: 1296.37 m

Air Permeability : 2.72 mD
Porosity (fraction): 0.115

Pore Throat Types:		
	Macropores (> 3 micron diameter) =	1.6%
	Mesopores (1 - 3 micron diameter) =	68.2%
	Micropores (< 1 micron diameter) =	30.1%

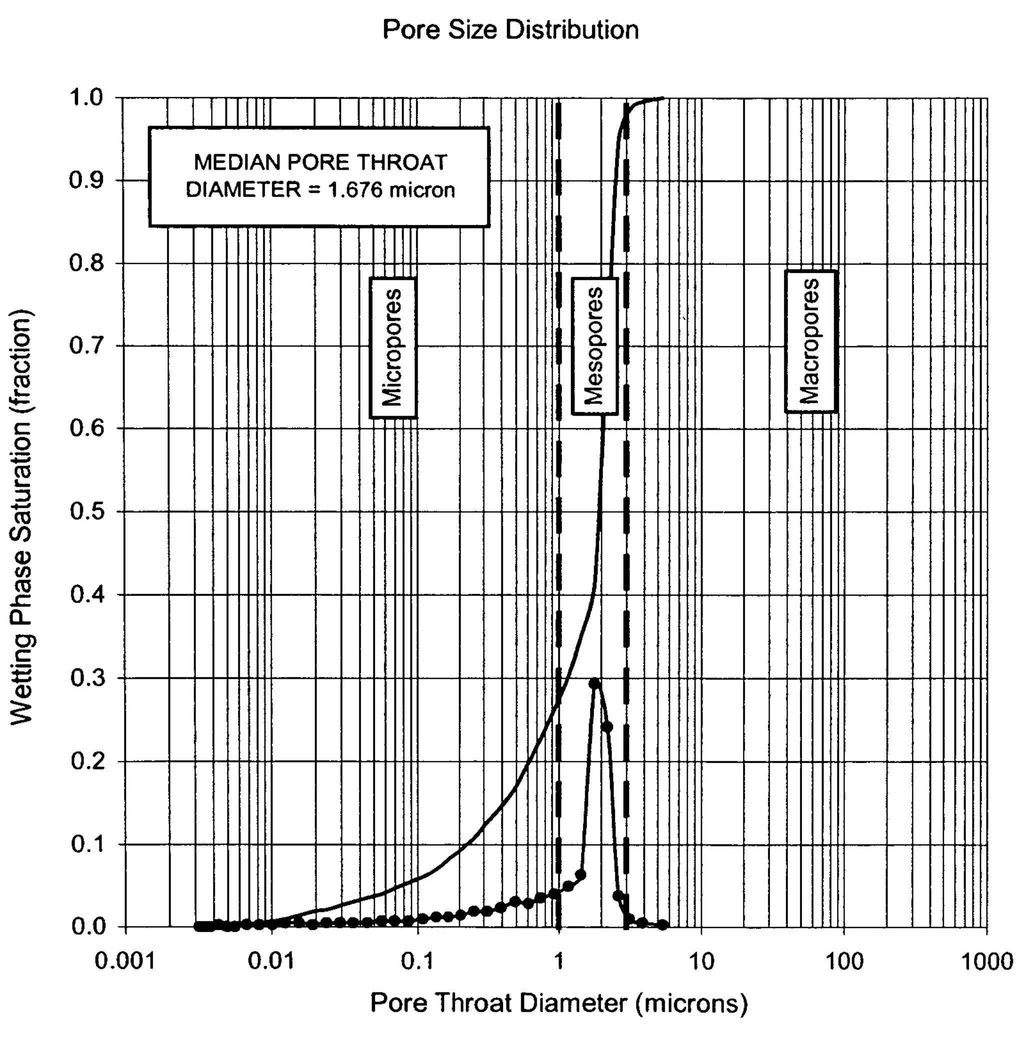


FIGURE 20
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 36A
Core Depth: 1296.37 m

Air Permeability : 2.72 mD
Porosity (fraction): 0.115

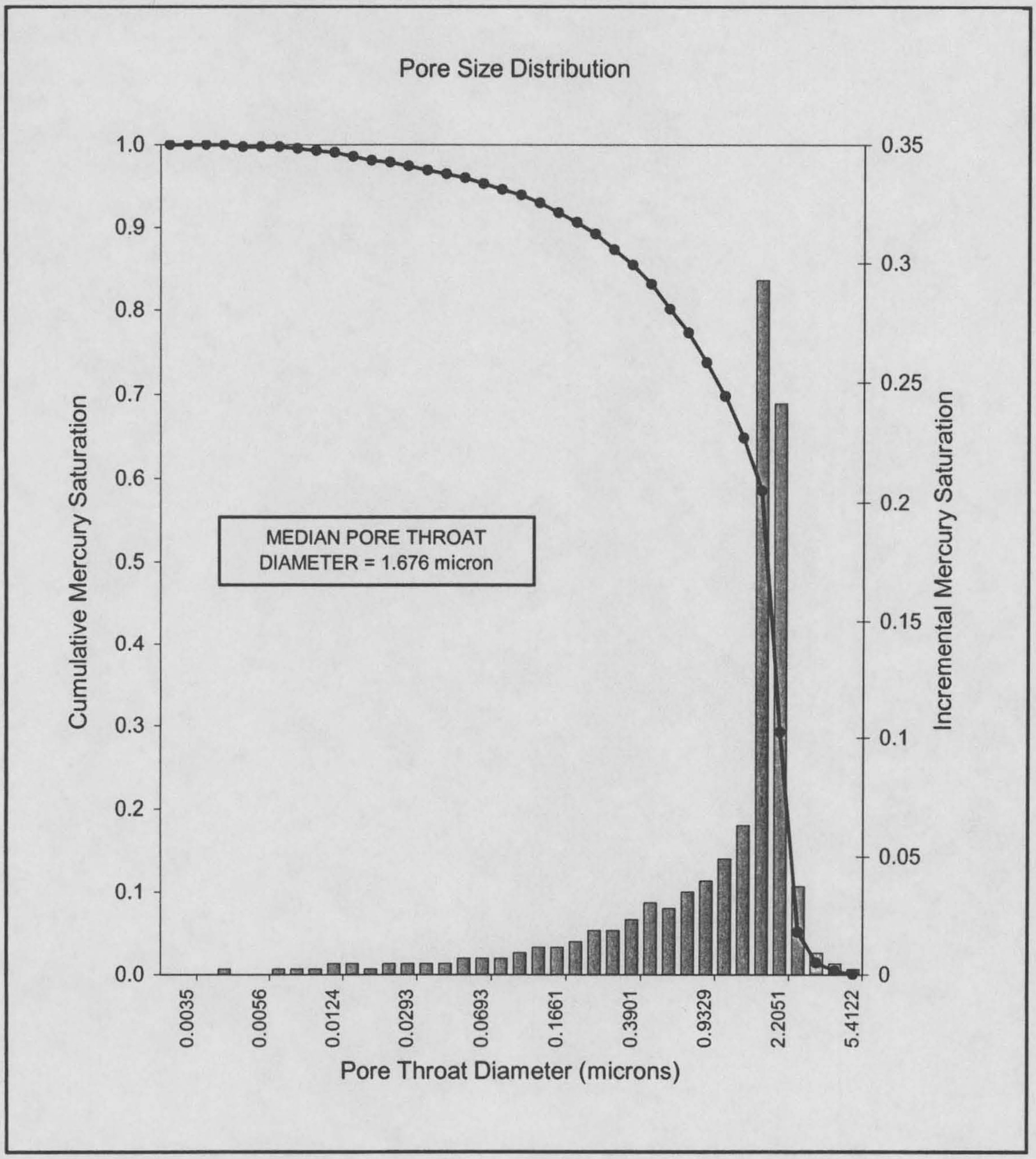


FIGURE 21
MERCURY INJECTION CAPILLARY PRESSURE

Well Location: Tweed Lake A-67
Core I.D.: 36A
Core Depth: 1296.37 m

Air Permeability : 2.72 mD
Porosity (fraction): 0.115

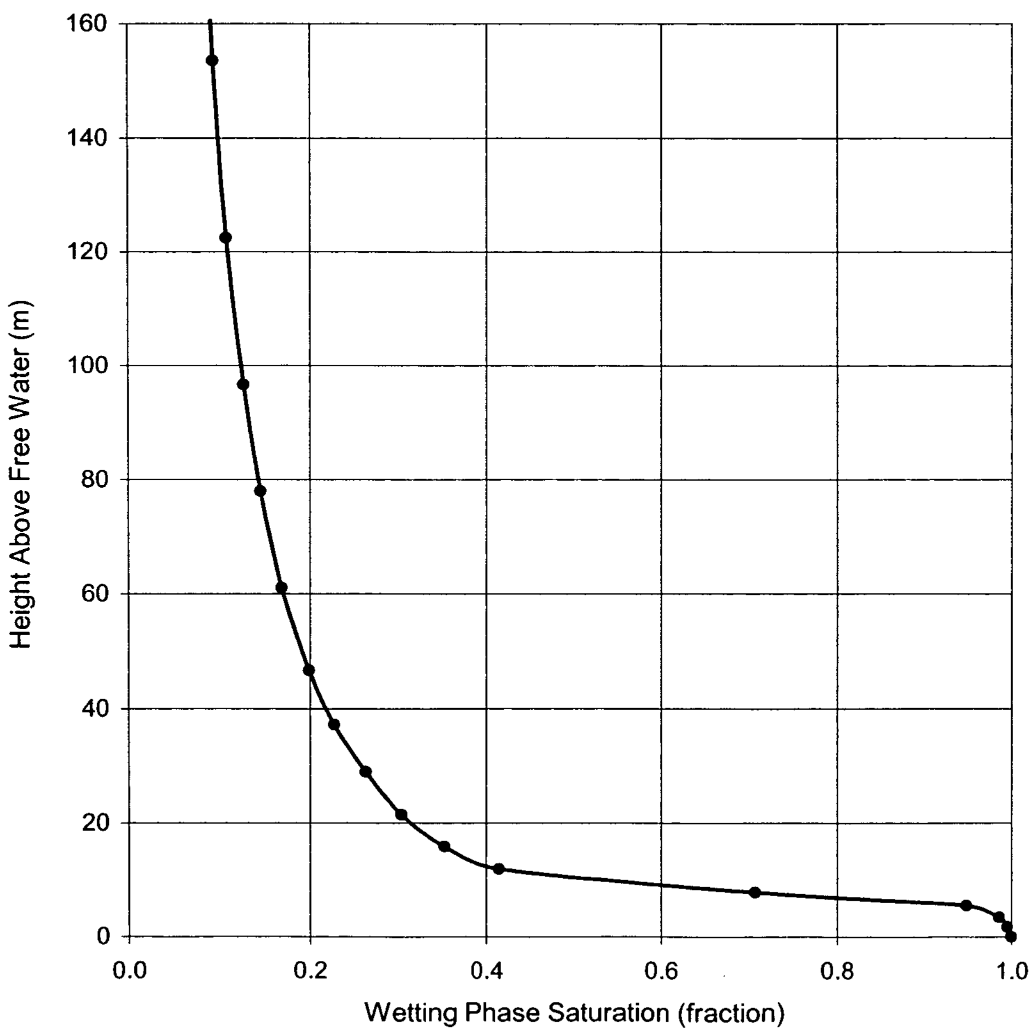


FIGURE 22
FRACTURE FLUID EVALUATION WITH GELLED RIMBEY PLATINUM

Well Location:	TWEED LAKE A-67		
Core Number:	27B,27C	**Porosity (fraction):**	0.164
Depth (m):	1292.20	**Air Permeability (mD):**	10.36

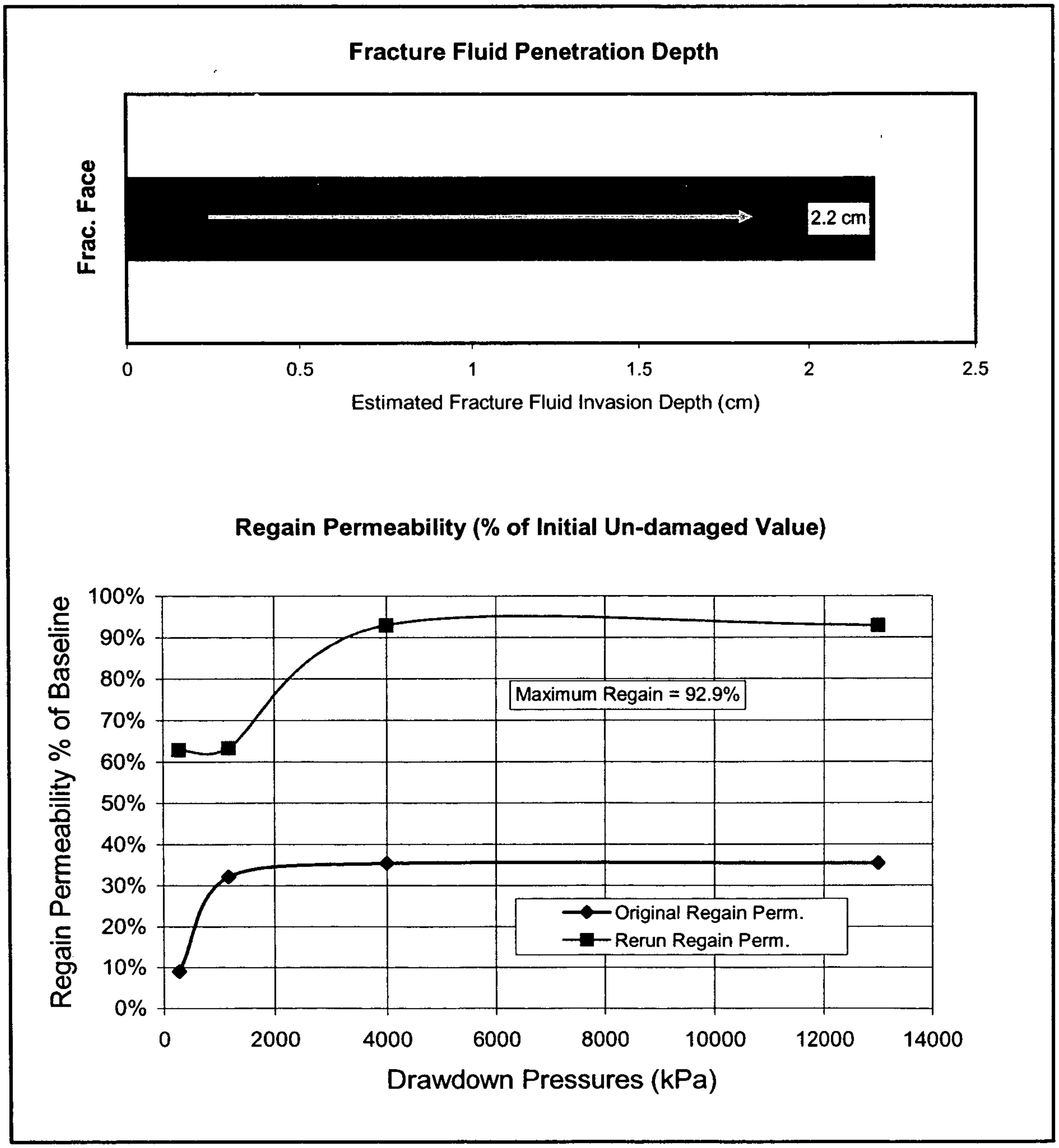
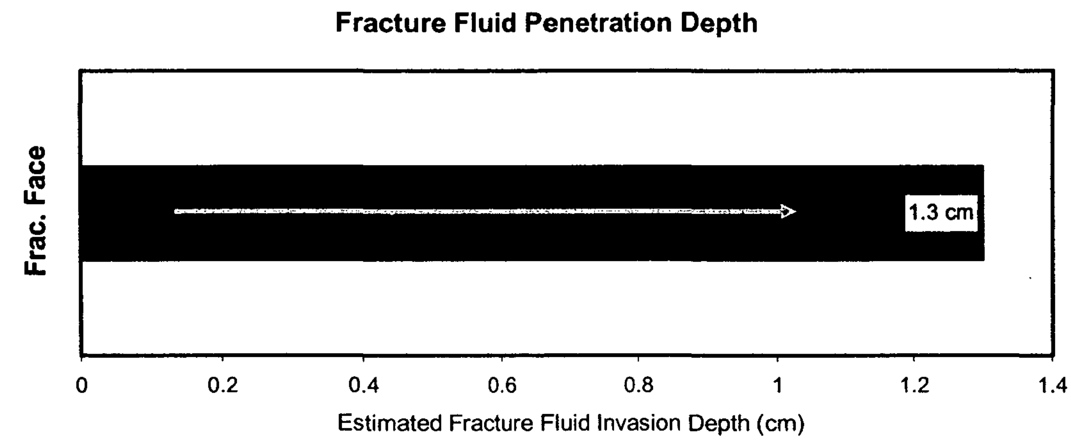


FIGURE 23
FRACTURE FLUID EVALUATION WITH GELLED FX2

Well Location:	TWEED LAKE A-67		
Core Number:	27D,27J	**Porosity (fraction):**	0.133
Depth (m):	1292.20	**Air Permeability (mD):**	10.7



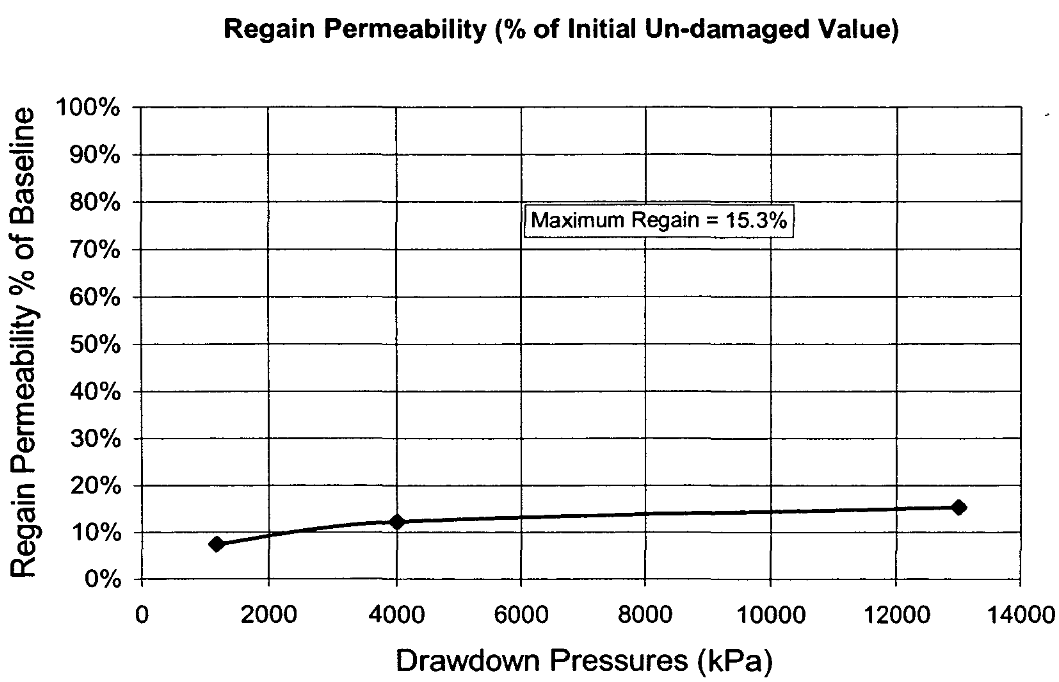
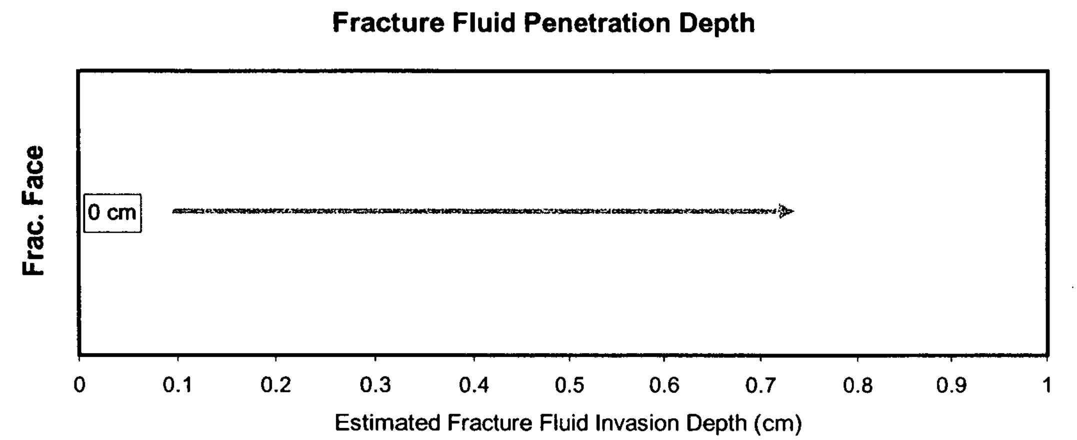


FIGURE 24
FRACTURE FLUID EVALUATION WITH CO2 MISCIBLE RIMBEY PLATINUM

Well Location:	TWEED LAKE A-67		
Core Number:	27F,27G	**Porosity (fraction):**	0.117
Depth (m):	1292.00	**Air Permeability (mD):**	27.5



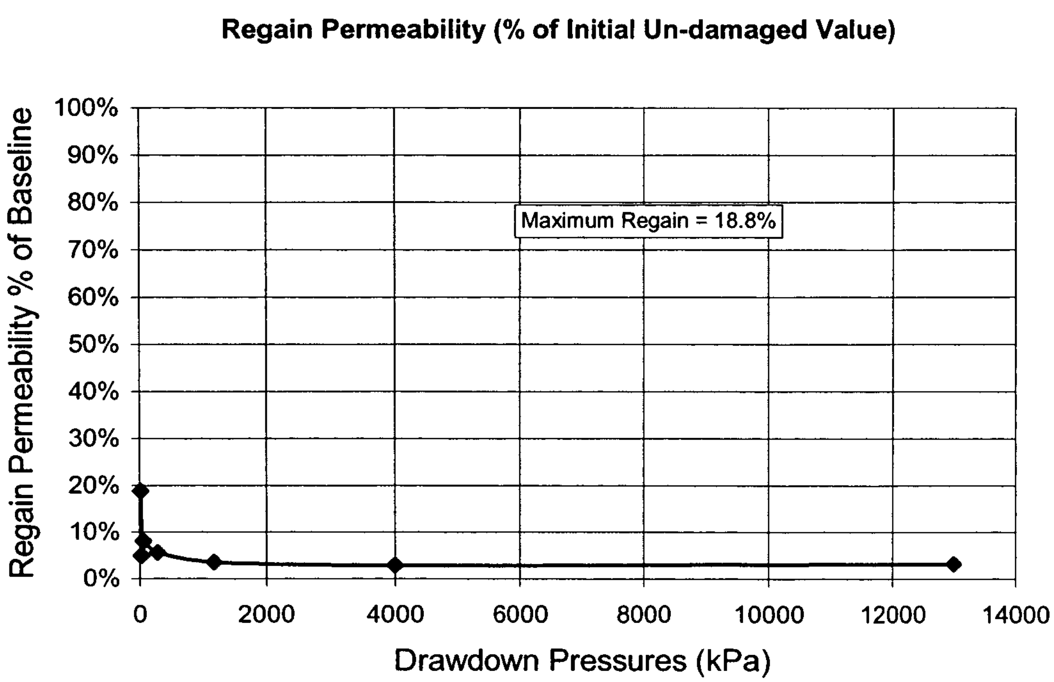
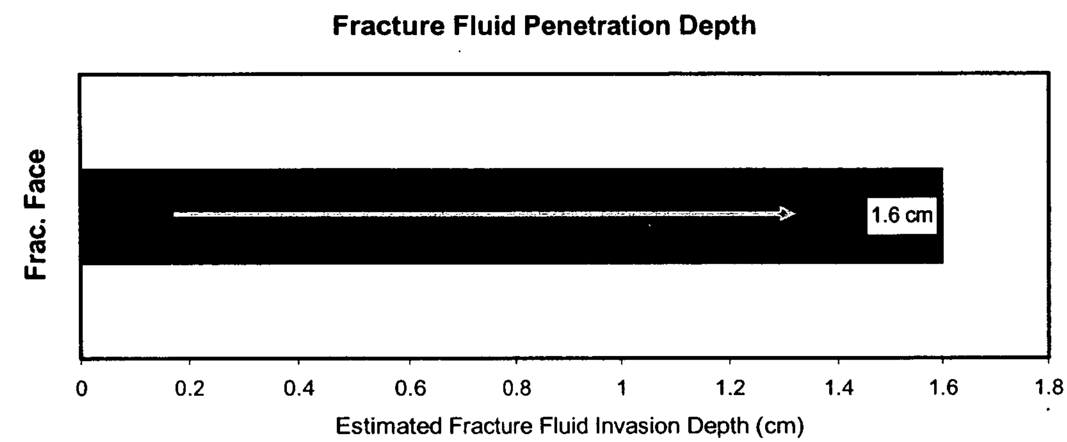


FIGURE 25
FRACTURE FLUID EVALUATION WITH GELLED RIMBEY PLATINUM

Well Location:	TWEED LAKE A-67		
Core Number:	27B,27C	**Porosity (fraction):**	0.135
Depth (m):	1292.20	**Air Permeability (mD):**	10.54



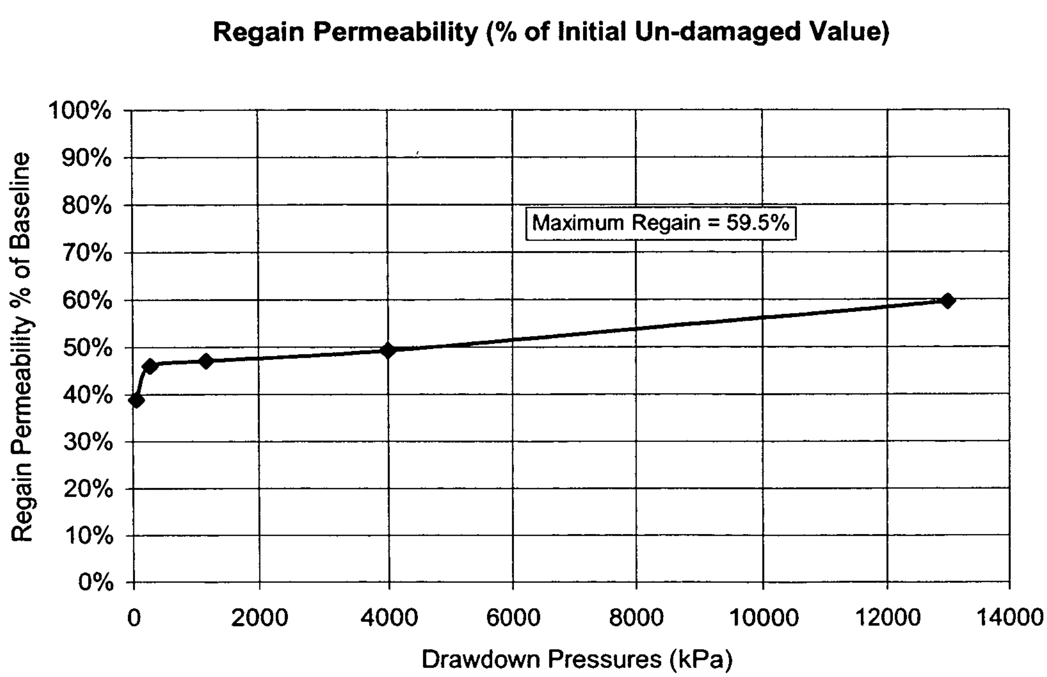


FIGURE 26

AUTOPORE III ANALYZER

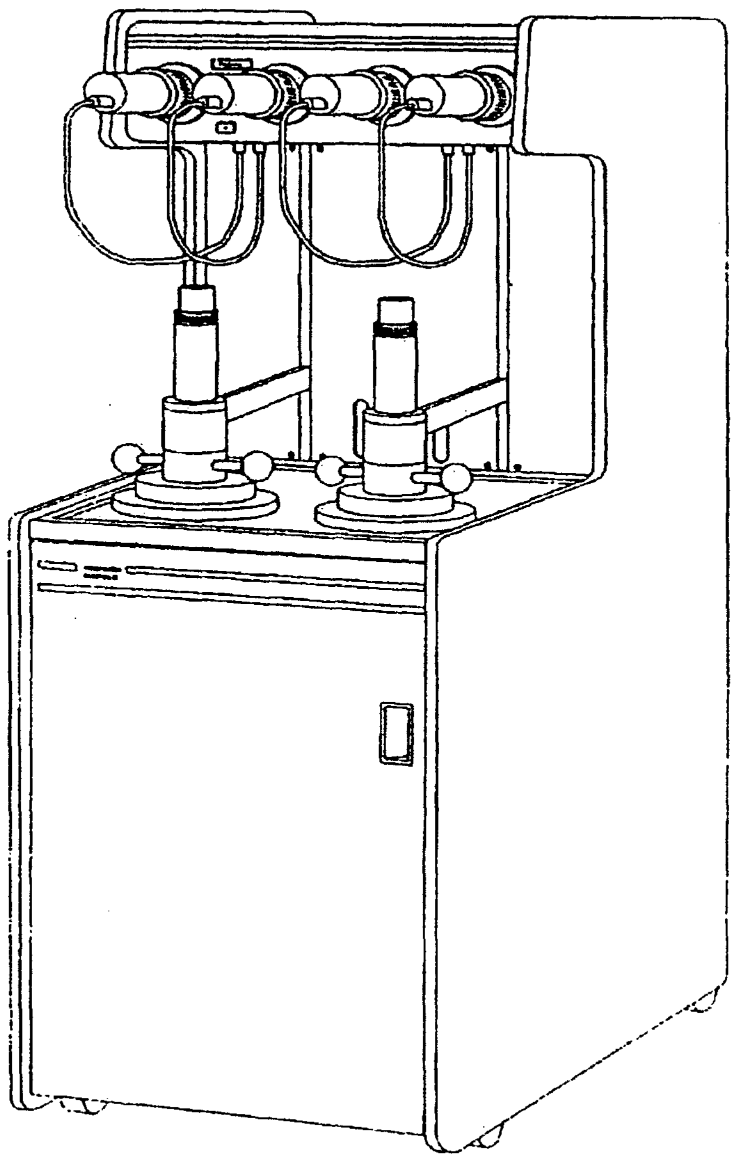
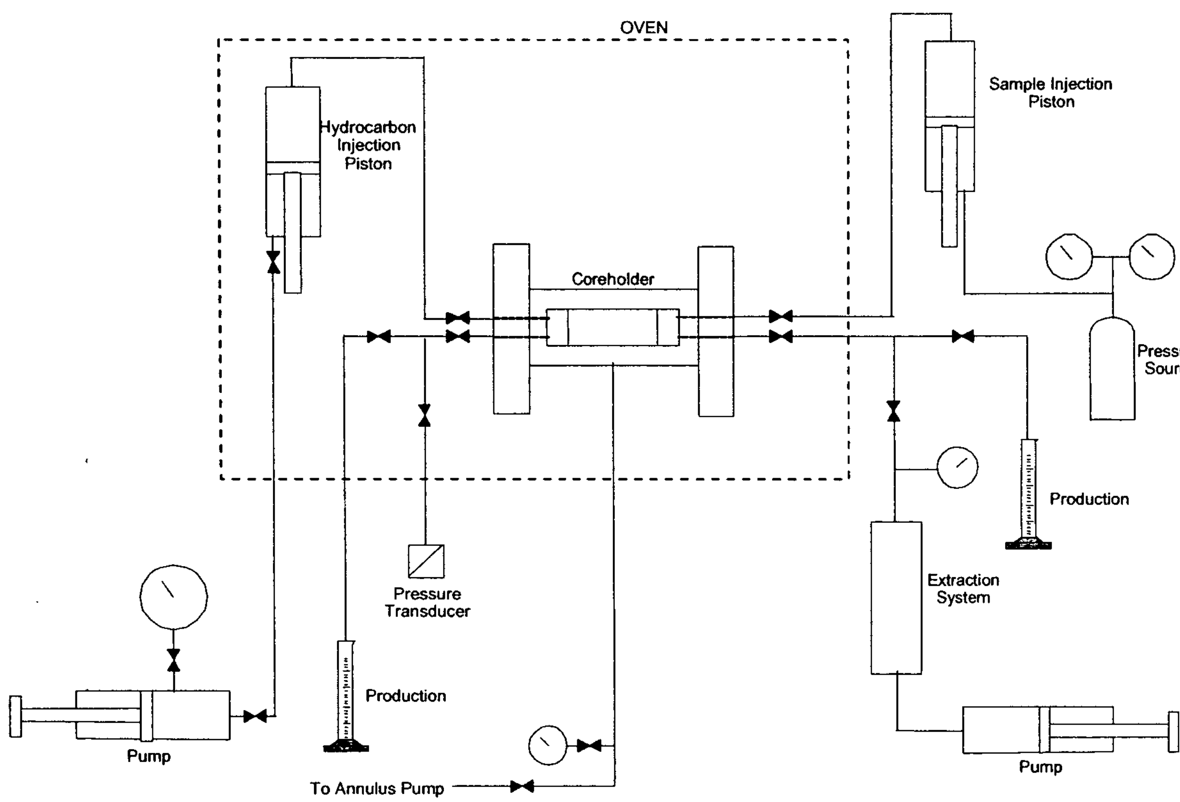


FIGURE 27
OVERBALANCED DRILLING/FRACTURE FLUID LEAKOFF APPARATUS



APPENDICES

APPENDIX A

Water Compositional Analysis – Mount Clark Formation

APPENDIX A
WATER COMPOSITIONAL ANALYSIS

Operator:	Petro-Canada Oil and Gas		
Well Name:	PCI Canterra Tweed Lake A-67	File # :	L156NE
Field:	Tweed Lake	Formation:	Mount Clark Formation
Sample Point:	Separator	Date sampled:	Feb. 23 1986
Container I.D.:	Plastic	Analysis Lab:	Core Lab

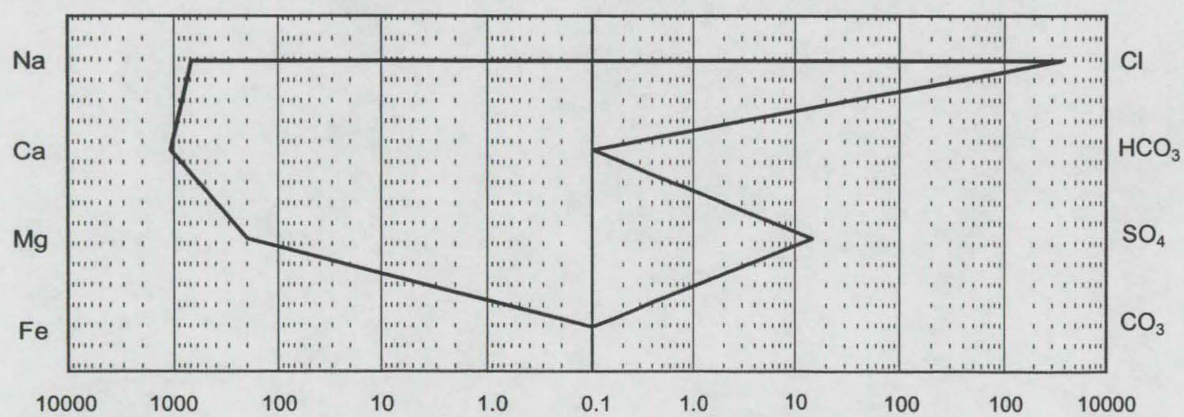
CATIONS		
Ion	**mg/L**	**meq/L**
Na^{+}	15540	675.95
K^{+}	10980	280.89
Ca^{+2}	21600	1077.84
Mg^{+2}	2409	198.23
Ba^{+2}	0	0.00
Sr^{+2}	0	0.00
Fe^{+3}	0	0.00
B^{+3}	0	0.00
Mn^{+3}	0	0.00

ANIONS		
Ion	**mg/L**	**meq/L**
Cl^{-}	133003	3751.53
Br^{-}	0	0.00
I^{-}	0	0.00
HCO_3^{-}	0	0.00
SO_4^{-2}	715	14.89
CO_3^{-2}	0	0.00
OH^{-}	0	0.00
H_2S	Absent	---

Total Dissolved Solid (mg/L)

	184247
Evaporated @ 110°C	Calculated
Total suspended solids (mg/L)	Oil & Grease Content (mg/L)
1.0964	1.3813 @ 25°C
Relative Density	Refractive Index
1 @ 18 °C	0.053
Observed pH	Resistivity ohm.m @25°C
Total Hardness As $CaCO_3$ (mg/L)	Total Alkalinity As $CaCO_3$ (mg/L)

Logarithmic Pattern of Dissolved Ions, meq/L



Remarks:

APPENDIX B

Halliburton - Fracture Fluids Composition

1. Rimbey Platinum

   1 L –Rimbey Platinum base oil

   MO-85 @ 3 l/m^3

   MO-IV @ 4 kg/m^3

   MO-86 @ 3 l/m^3

2. FX2

   1 L – FX2 base oil

   MO-85 @ 3 l/m^3

   MO-IV @ 4 kg/m^3

   MO-86 @ 3 l/m^3

3. CO_2 Miscible Rimbey Platinum

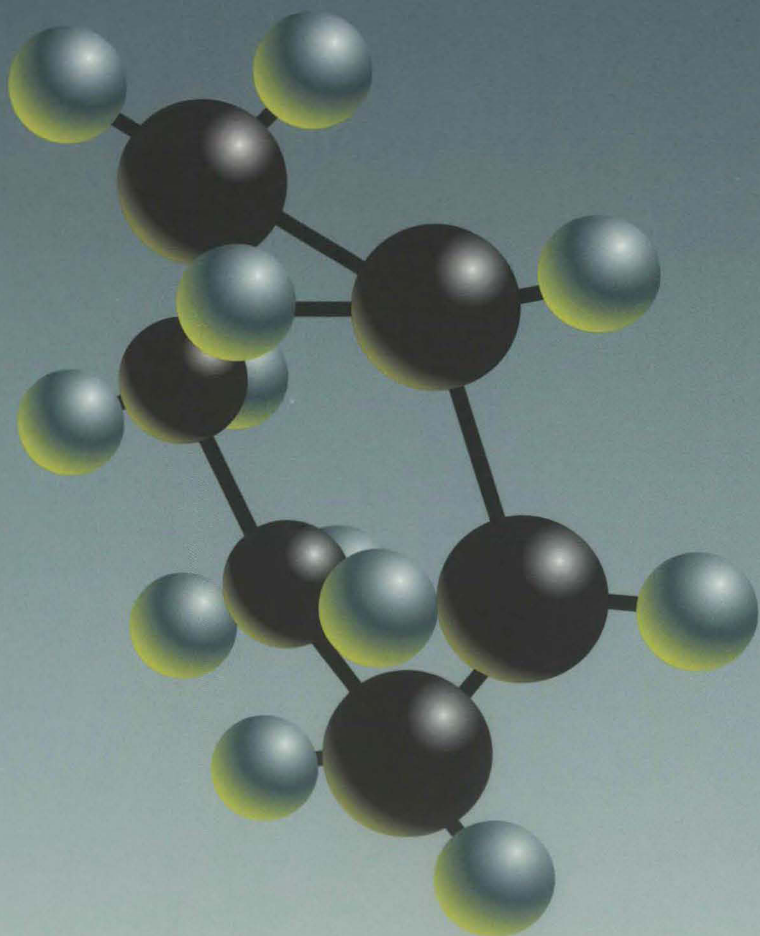
   1 L –Rimbey Platinum base oil

   MO-85 @ 7 l/m^3

   MO-IV @ 7 kg/m^3

   MO-86 @ 7 l/m^3

   40% CO_2 co-injection with gelled oil



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