PRELIMINARY
Special Core Analysis on the Irene #2-5, Patterson Field Morrow Sandstone Sec.5 T23S R37W Kearny Co., KS

November 20, 2005

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Subject

Forty seven (47) core plugs from Irene #2-5, Patterson Field, Morrow Sandstone, Sec.5 T23S R37W, Kearny Co., KS were obtained from full-diameter core for various special core analysis tests including determination of the following petrophysical properties: routine porosity, grain density, *in situ* Klinkenberg permeability, "critical" brine saturation, mercury intrusion capillary pressure, water-rock sensitivity, effective oil permeability at critical water saturation, effective water permeability at residual oil saturation, and *in situ* formation resistivity factor and cementation exponent analysis.

Experimental Methods

Sample Preparation

Cleaned core plugs measuring approximately 1.0 inch in diameter and 2.0 inches long were cut from full-diamter core using a diamond core drill bit with tap water as a coolant. The samples were dried in a conventional oven at 70 ^{o}C. The samples were then soxhlet extracted with toluene/methyl alcohol to remove any remnant oil and salts. They were then dried in an oven at 70 ^{o}C to a constant weight within ± 0.003 gm. The samples were not humidity oven dried since porosities measured in this fashion do not reflect log measured porosities and are also not suitable for correlation with electrical resistivity measurements.

Porosity

Routine helium porosities were determined using a Boyle's Law technique. Dry sample weights were measured to ±0.001 gm and bulk volume was determined by caliper to an accuracy of ±0.02 cc. Ambient Helium porosity was measured to an accuracy and precision of better than ± 0.1 porosity percent. Porosity data are presented in Table 1

In situ Klinkenberg Permeability

To measure insitu Klinkenberg gas permeabilities, each core was placed in a Hassler type confining pressure cell and subjected to hydrostatic confining stress of 2,300 psi to approximately simulate *insitu* stresses. Klinkenberg permeabilities, which correspond to non-reactive liquid permeabilities or high pressure gas permeabilities, were measured. Permeability data are presented in Table 1.

Mercury Intrusion Capillary Pressure

Subsequent to porosity and permeability analysis select cores were cleaned, dried, and each transferred to the capillary pressure instrument and evacuated to a pressure of less than 0.01 torr for a period of 15 minutes. The sample was then subjected to increasing mercury injection pressures ranging from 2 to 10,000 psia. At each pressure, equilibrium was assumed to have been established when the volume of mercury injected was less than 0.1% of the pore volume for a two minute period. Injected mercury volumes were corrected for system and mercury compressibility effects. Results are presented in tables and figures for each sample. Accuracy and precision vary with sample pore volume and outer pore sizes and surface roughness. Pump injection volumes are readable to 0.001cc. For pore volumes near 1cc, estimated precision for the measurement is better than 0.5% for pore sizes less than 107um.

Electrical Resistivity and Archie Cementation Exponent

Subsequent to vacuum/pressure saturation with a 150,000 ppm NaCl brine (0.0585 ohm-m @ 20 ^{o}C), the cores were allowed to equilibrate with the brine for a period of ten (10) days. After this the *in situ* formation resistivity factor at 2,300 psi confining stress was measured. Electrical resistivity was measured using a two electrode configuration. Resistivity was recorded only after the core had achieved equilibrium with the confining stress as determined by no change in the pore volume over a period of five (5) minutes. Results are presented in Table 2.

Influence of Brine Salinity on Permeability

To evaluate the influence of brine salinity on permeability seven samples were selected for testing. Subsequent to electrical resistivity measurement each caore was placed in a Hassler-type core holder and permeability to 150,000 ppm NaCl brine measured for 100 pore volumes (PV) throughput at flow rates less than 2 cc/min. Following this test, permeability to 30,000 ppm NaCl brine was measured for 100 PV throughput. The cores were then removed from the Core holder, allowed to further equilibrate with the 30,000 ppm brine for a period of approximately 24 hours and the 30,000 ppm NaCl brine permeability remeasured. Results are presented in Table 3.

Effective Oil Permeability at Critical Water Saturation

Each core was placed in a Hassler-type confining pressure cell and subjected to a hydrostatic confining stress of 2,300 psig and the cores flushed to critical water saturation using a 3.1 centipoise isoparaffinic oil. Critical saturation was defined to have been achieved when the oil/water flow ratio exceeded 1,000. This was generally achieved before 60 pore volumes of oil had been flushed through the core. With the cores at critical water saturation the effective oil permeability was measured. Results are presented in Table 4.

Waterflood Susceptibility

Subsequent to effective oil permeability analysis, select cores were waterflooded using a 30,000 ppm NaCl brine to provide an approximate measures of residual oil saturation to waterflood, waterflood recovery efficiency, and effective brine permeability at residual oil saturation. The core were waterflooded at conditions of modified capillary number (Ncam) less than $5x10^{-6}$ and recovery recorded at 2, 5, 10 and 20 pore volumes throughput. Residual oil saturation (Sorw) was defined as the saturation achieved at a water/oil flow rate greater than 1000. With the core at Sorw the effective water permeability to 30,000 ppm NaCl ($k_{ew30K,Sorw}$) was measured. Final oil saturation minus initial oil saturation at critical brine saturation provides a measure of the recovery efficiency. Following the effective brine permeability measurement the cores were flushed with fresh tap water, removed from the Hassler core holder, and allowed to equilibrate for a period of 24 hours. After 24 hours in fresh water the cores were placed back into the core holder and the effective water permeability at Sorw ($k_{ew,Sorw}$) was measured.

Results

Porosity

No statistics were performed to evaluate the nature of the porosity distribution since these were performed in the routine core analysis. Grain density values average 2.655+0.05 g/cc indicating that standard density log interpretation using a 2.65 matrix density should provide porosity values within ±0.002 with 67% of samples within 2 p.u. of true values. Measurements on other Morrow sandstones indicate that the relationship between in situ porosity and routine porosity can be expressed:

$\phi_{insitu}/\phi_{routine}$ (%) = $0.67\ \phi_{routine} + 84.6$

Porosity vs *In situ* Klinkenberg Permeability

In situ Klinkenberg permeability is cross-plotted against routine porosity in Figure 1. An equation that relates *in situ* Klinkenberg permeability (k_{ik}) to porosity (ϕ) for these samples is:

$$k_{ik} = 2.09 \times 10^{-12}\ \phi^{\ 10.38}$$

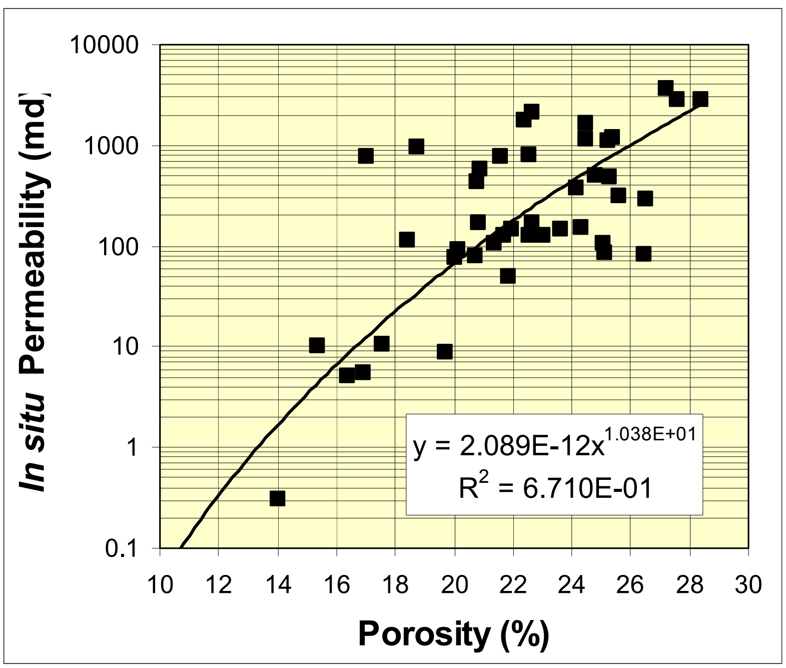


Figure 1. *In situ* Klinkenberg permeability versus routine porosity

The equation presented is for a single population. Though a quantitative relationship is not presented, based on core examination the higher permeability values at any given porosity are associated with medium-coarse grain size whereas the lower permeability values are associated with fine grain size. Based on this association, coarse-grained sandstones exhibit approximately 8X greater permeability than fine grained sandstones at the same porosity for these sandstones.

Mercury Intrusion Capillary Pressure Analysis

Laboratory to Reservoir Capillary Pressure and Height Above Free Water

The laboratory capillary pressure was converted to reservoir oil-brine capillary pressure data using the following equation:

$$Pc_{res} = Pc_{lab}\,(\sigma\cos\theta_{res}/\sigma\cos\theta_{lab})$$

Where Pc_{res} is the oil-brine capillary pressure at reservoir conditions, Pc_{lab} is the laboratory measured air-mercury capillary pressure, and $\sigma\cos\theta$ is the interfacial tension times the cosine of the contact angle at reservoir conditions for gas-brine and at laboratory conditions for air-mercury. Interfacial tension and contact angle values vary with brine and hydrocarbon composition, pressure, and temperature. An approximate interfacial tension * contact angle of 21 dynes/cm was used.

To be able to determine the saturation in any given rock type as a function of height above the free water level, or to be able to determine the saturation at the top of a given structure, it is necessary to convert the capillary pressure data to height above free water level. This was performed using the following relation:

$$\text{Height (ft)} = 0.433\ Pc_{res}/(\rho_{brine}-\rho_{oil})$$

Where H is the height above free water level or above zero capillary pressure (ft), Pc_{res} is the capillary pressure at reservoir conditions (psi), and $P_{b,o}$ is the density gradient of the oil and brine (g/cc). An approximate density assumed for oil was 0.80 g/c and fro the reservoir brine was 1.09 g/cc.

Surface Area Analysis

Surface areas for the samples were calculated using the relation developed by Rootare and Prenzlow (1967):

$$A = \frac{0.0221}{m}\int_0^{V_t} P\,dV$$

Where A is surface area (m^2/g), m is sample weight (g), P is pressure (psia), and V_t is total pore volume (cc).

Surface areas for these samples range from 0.3 to 1 m^2/g, Values near 0.4-0.6 m^2/g are typical of sandstone that contain some pore lining or filling clays but which do not exhibit abundant clay.

Pore Entry Throat Size

Permeability is conventionally shown cross-plotted with porosity. However, other principal variables which exert equal or greater influence on permeability are clay types and distribution (Wilson, 1981) and the pore size and pore throat size distribution. From the mercury injection capillary pressure analysis, pore entry diameters were calculated using the Washburn relation:

$$Pc = 4C\tau\cos\theta/d$$

Where Pc = capillary pressure (psia), C = conversion constant (0.145), θ = contact angle (deg), τ = Interfacial tension (dyne/cm), d = Pore entry diameter (microns). This relation assumes that the mercury is entering cylindrical shaped pores though the pores of rocks can differ considerably from perfect cylinders. In addition, larger pores are frequently "bottle-necked" by smaller pore throats so that the pore size distribution is actually a reflection of the volume accessed by the smaller pore "throats." These "errors" in the operational measurement of pore size as well as variation in the contact angle (120-150 deg) with surface roughness and mineralogy results in pore sizes which can be as much as ± 50% of the pore size derived from the relation above. Based upon the difficulty of adequate topologic description of pore geometry, it is considered sufficient for comparative purposes to present the generalized pore entry throat sizes based upon the original Washburn relation. Figure 2 illustrates the cross-plot between the approximate pore throat diameter (PPTD, microns) and in situ Klinkenberg permeability (md). Linear regression describes the correlation between these variables:

$$PPTD = 1.43\ k_{ik}^{0.54}$$

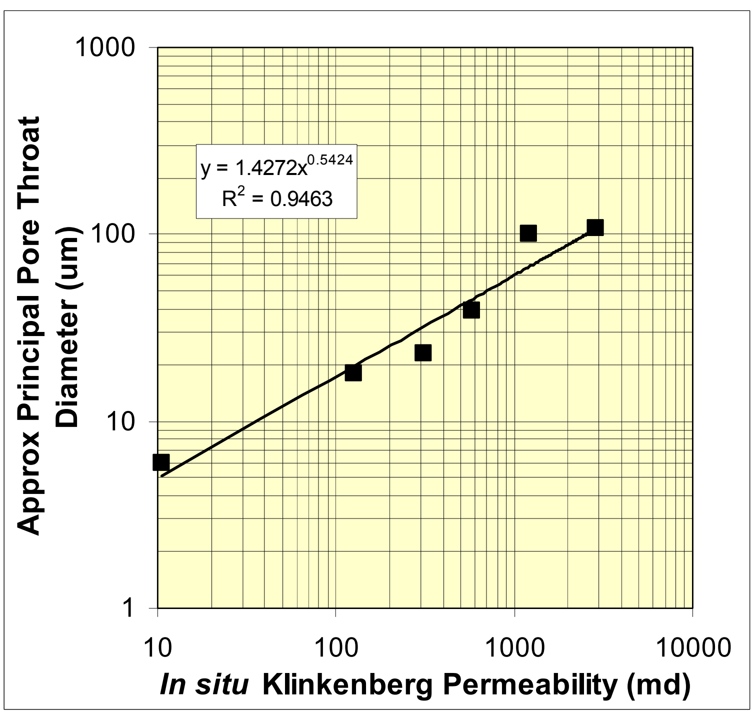


Figure 2. Principal pore throat diameter versus permeability.

Archie Cementation Exponent

Electric logging tools allow the measurement of saturation using the Archie equation or modified Archie equations. To calculate more accurate water saturations from electric logging tools, measurements were performed to determine the cementation exponent, m, and intercept, a. Data are presented in Table 2. The measured Archie cementation exponents can be expressed in two forms: 1) the intercept is assumed to have a value of 1 and the cementation exponent varies, or 2) the data set are treated as a single population and a cementation and intercept are determined for the population.

Figure 3 shows the cross-plot of insitu formation resistivity factor versus porosity. Cementation exponent values can vary depending upon whether the cementation intercept is pinned at 1.0 or is allowed to vary. Using linear regression the following cementation exponent values were obtained:

$m = 1.94$ $\quad$ $a = 1.00$

$m = 1.88$ $\quad$ $a = 1.05$

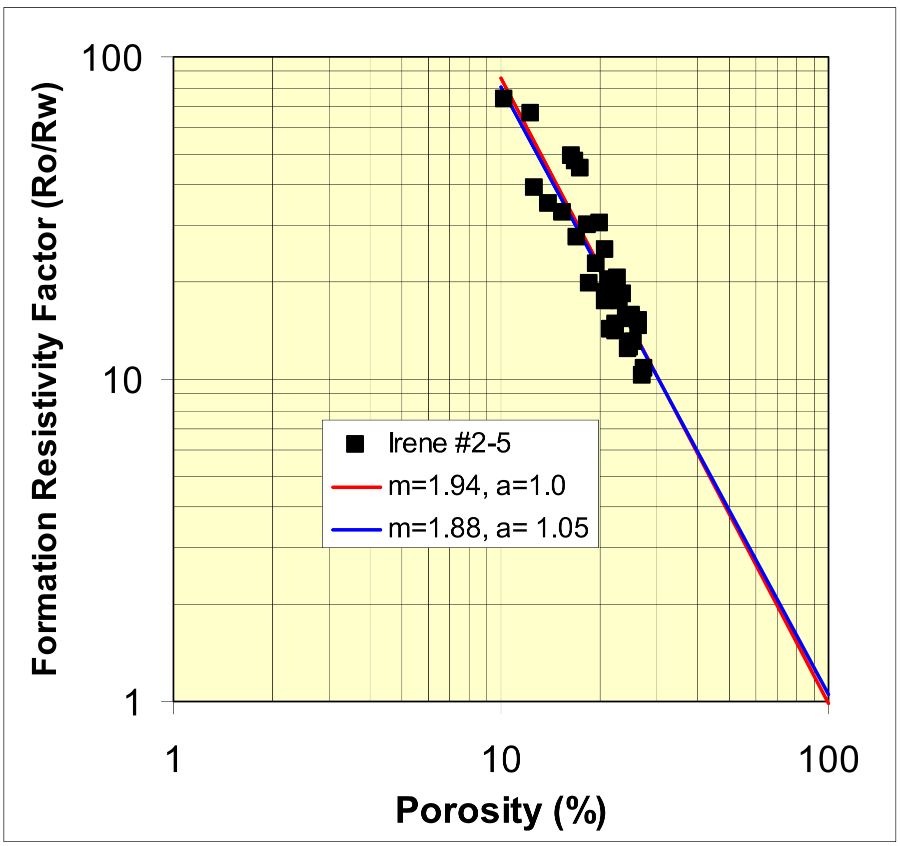


Figure 3. Formation resistivity index versus porosity. The slope and intercept determine the Archie cementation exponent and intercept.

Plotting the cementation exponent versus depth shows that low and high cementation exponents are generally associated with specific intervals in the Irene #2-5 (Figure 4).

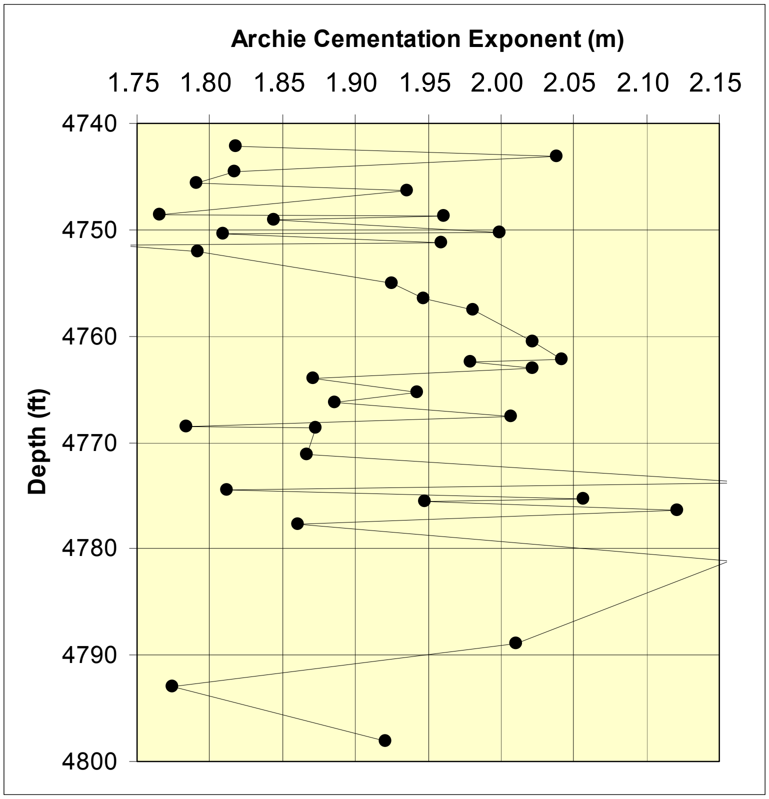


Figure 4. Archie cementation exponent (assuming intercept for each equals 1) versus depth.

A crossplot of the Archie cementation exponent with permeability indicates that the cementation exponent decreases with decreasing permeability.

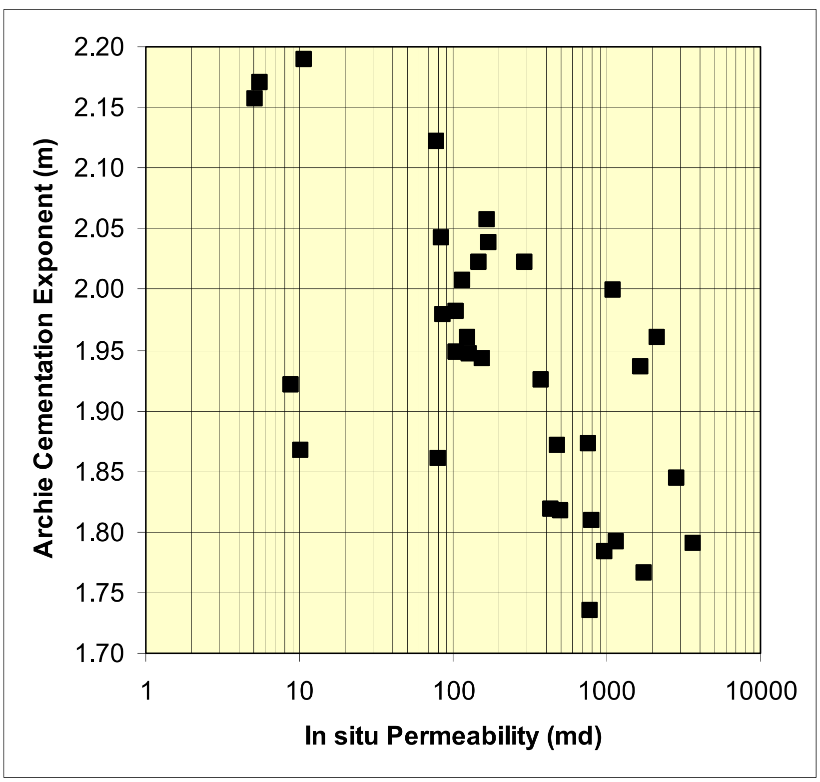


Figure 5. Crossplot of Archie cementation exponent versus permeability.

Influence of Brine Salinity on Permeability

The water sensitivity test shows that 150,000 ppm NaCl brine permeability (measured under a confining stress of 2300 psi) is within 10% of, and for several samples even slightly greater than, *in situ* Klinkenberg Permeability (ideal fluid permeability measured under a confining stress of 2,300 psi) for rocks with permeability greater than 1,000 md (Figures 6 and 7). For rocks with permeability less than this value, brine permeabilities are 50-80% of Klinkenberg values indicating some clay sensitivity to hydration (Figure 6) . Brine permeability decreases by ~5-35% for a brine salinity change from 150,000 ppm NaCl to 30,000 ppm NaCl (Figure). Change in permeability generally occurs within less than 10 pore volumes (PV) throughput and remains relatively stable for many tens of pore volumes throughput. Following flow tests the cores were left in 30,000 ppm NaCl and the brine permeability tested again after 24 hours. Brine permeabilities after 24 hours both increase and decrease from previous values which may be related to minor fines migration or some clay swelling. The observed changes in permeability in response to salinity change can be interpreted to not be sufficient to explain the inferred decrease in permeability observed in the field from well performance.

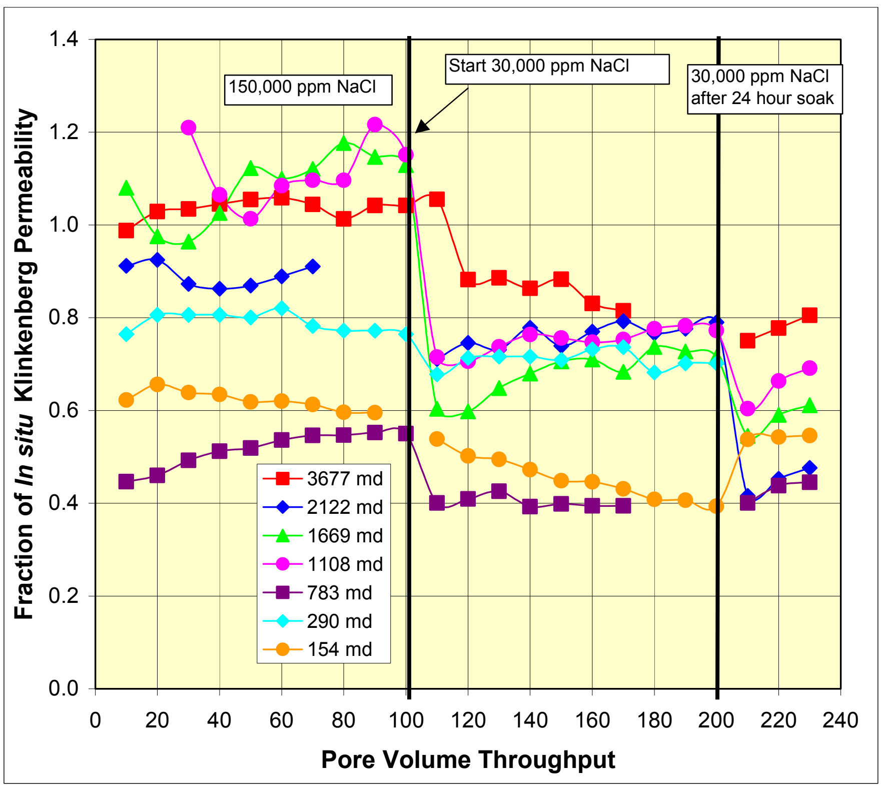


Figure 6. Change in permeability with brine salinity and pore volumes throughput referenced to in situ Klinkenberg permeability.

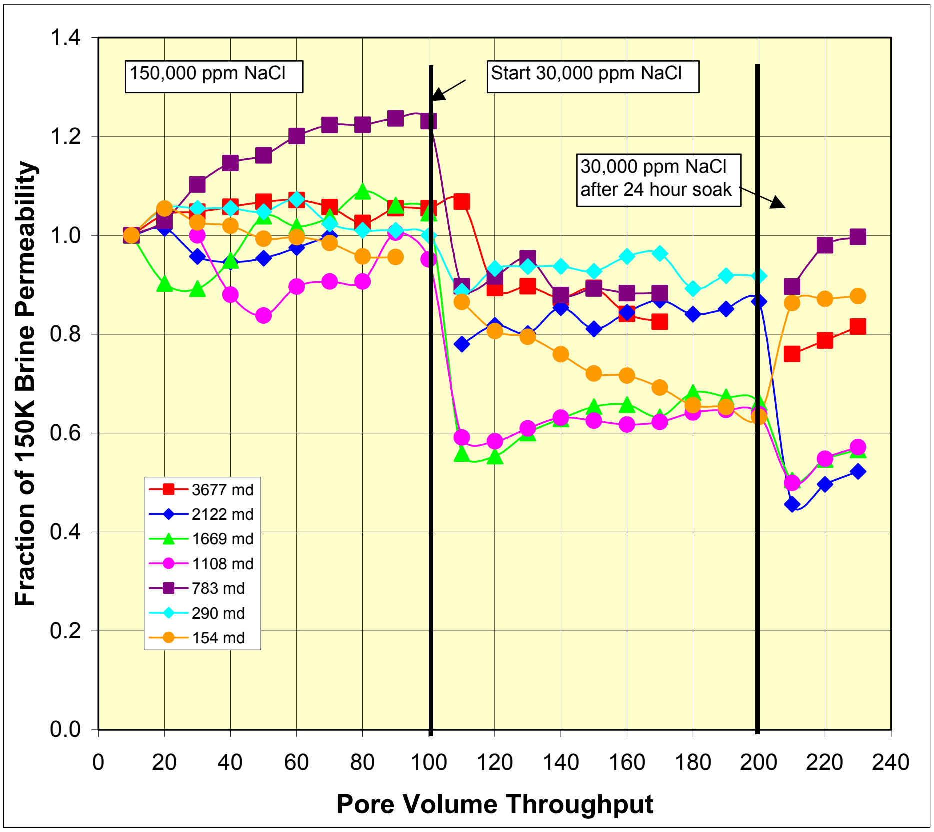


Figure 7. Change in permeability with brine salinity and pore volumes throughput referenced to initial brine permeability.

Effective Oil Permeability at Critical Water Saturation

To evaluate potential oil recovery from waterflood and potential for relative permeability damage selected cores were flooded with a 3 centipoise isoparaffinic oil to critical water saturation (Swc) and the effective oil permeability at Swc measured (keo,Swc). Effective oil permeabilties are less than absolute permeabilities and follow a power-law relationship with in situ Klinkenberg permeability that decreases with decreasing permeability (Figure 8). Critical water saturations range from 30-50% and average 40%. Comparison of Swc with log-measured saturations in the Irene 2-5 (Figure 9) and with capillary pressure curves (worksheets) indicates that Swc is greater than equilibrium capillary pressure saturations and greater than saturations present in the well for depths less than approximately 4750 ft (core depth). This would indicate that formation water in these intervals is effectively immobile. For depths greater than approximately 4760 ft critical water saturations are less than log-measured saturations indicting that a portion of the formation water is mobile.

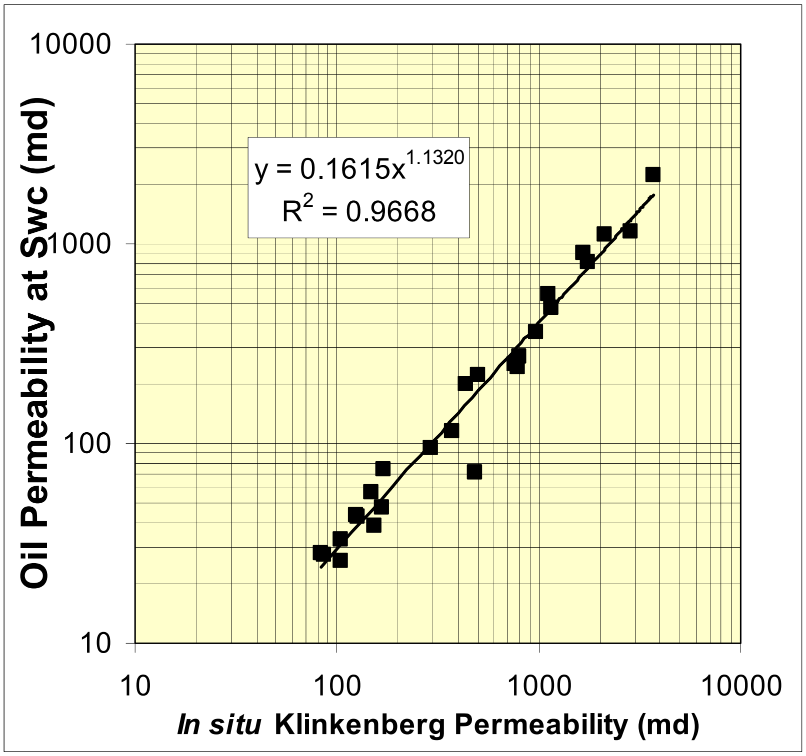


Figure 8. Oil permeability at Swc versus absolute permeability showing power-law relationship.

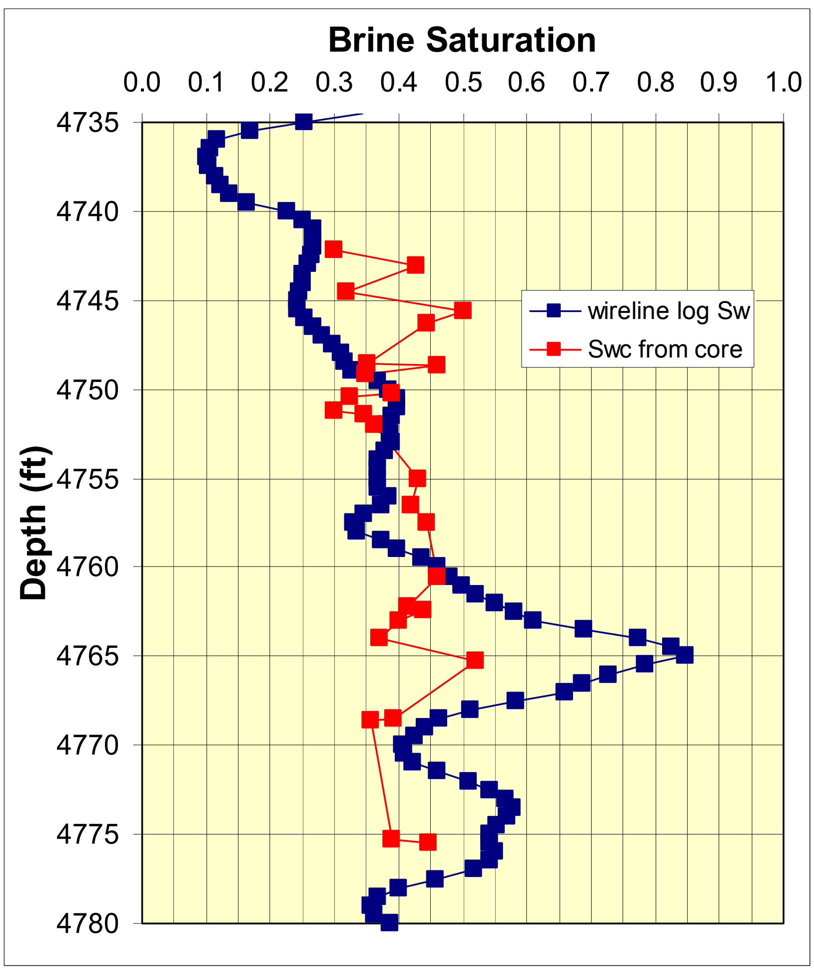


Figure 9. Comparison of core-measured critical water satuation and wireline log-measured formation saturation.

Waterflood Susceptibility

To evaluate potential oil recovery from waterflood and potential for relative permeability damage selected cores were flooded with a 3 centipoise isoparaffinic oil to critical water saturation (Swc) and the effective oil permeability at Swc measured (keo,Swc). Subsequently, the cores were waterflooded with a 30,000 ppm NaCl brine to residual oil saturation to waterflood (Sorw) and the effective brine permeability at residual oil saturation (keb,Sorw) was measured. The cores were then flushed with 10 PV of fresh water and left for a 24 hour period to equilibrate. Following equilibration the effective water permeability to fresh water at residual oil saturation (Kew,Sorw).

For the cores measured, 92±8% of oil recovery from waterflood occurs within 2 PV throughput with residual oil saturation to waterflood (Sorw) generally ranging from 14-27% and averaging 18%. There is a weak correlation of decreasing Sorw with increasing permeability (Figure 10). It is important to not that for the depths where logs indicate initial oil saturations were greater than those in the core measurement, Sorw would be greater than the values obtained from these cores due to trapping of the additional oil in small pores. It is also important to note the very low Sorw of two of the highest permeability samples. These low Sorw values can be attributed to the low Soi values these samples started with prior to waterflood. Oil in these samples occupied only the largest pores. If these samples had been in capillary equilibium and had initial oil saturations greater than 60-70%, as would be anticipated based on the well log response, Sorw would be expected to be greater. Lower Swc values could not be obtained for these samples without increasing the oil visocosity or using capillary pressure methods to achieve higher initial oil saturations. Neither of these methods were used.

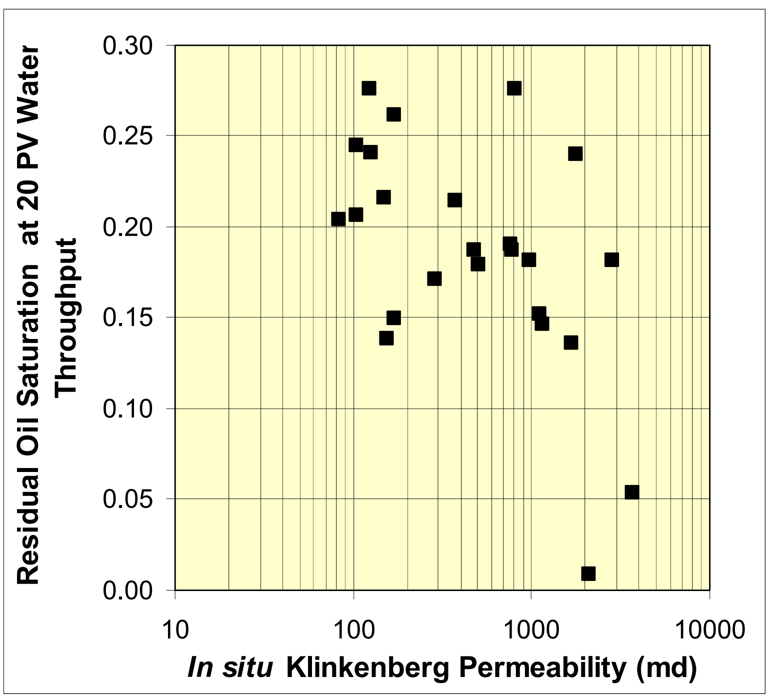


Figure 10. Residual oil saturation to waterflood versus permeability showing weak correlation of decreasing Sorw vs kik for most samples.

Brine relative permeability at Sorw ($k_{rw,Sorw}$) ranges from 8-27% and averages 18% relative to the in situ Klinkenberg Permeability and ranges from 33-117%, averaging 50%, relative to the effective oil permeability at Swc ($k_{eo,Swc}$). Effective brine permeability exhibits a power-law relationship with both in situ Klinkenberg permeability (k_{ik}) and the effective oil permeability at Swc ($k_{eo,Swc}$; Figure 11a and 11b). Relative brine permeability at Sorw exhibits a weak positive correlation with k_{ik} and $k_{eo,Swc}$ (Figures 12 a and 12b).

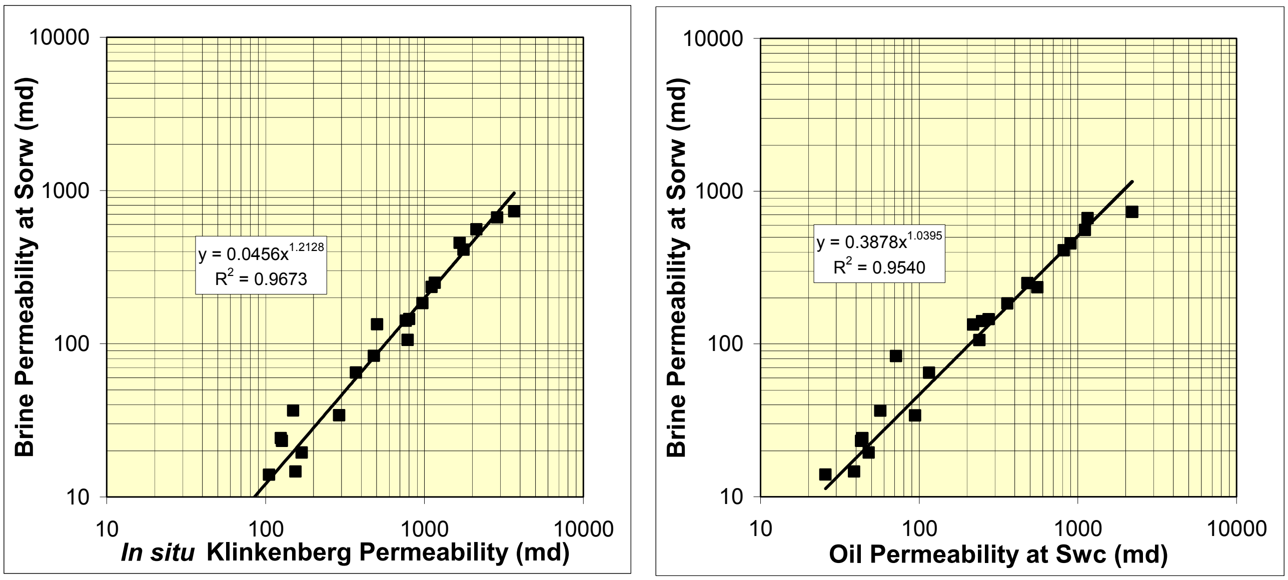


Figure 11a and 11b. Brine permeability at Sorw cross-plotted with *in situ* Klinkenberg permeability and oil permeability at Swc showing power-law relationships.

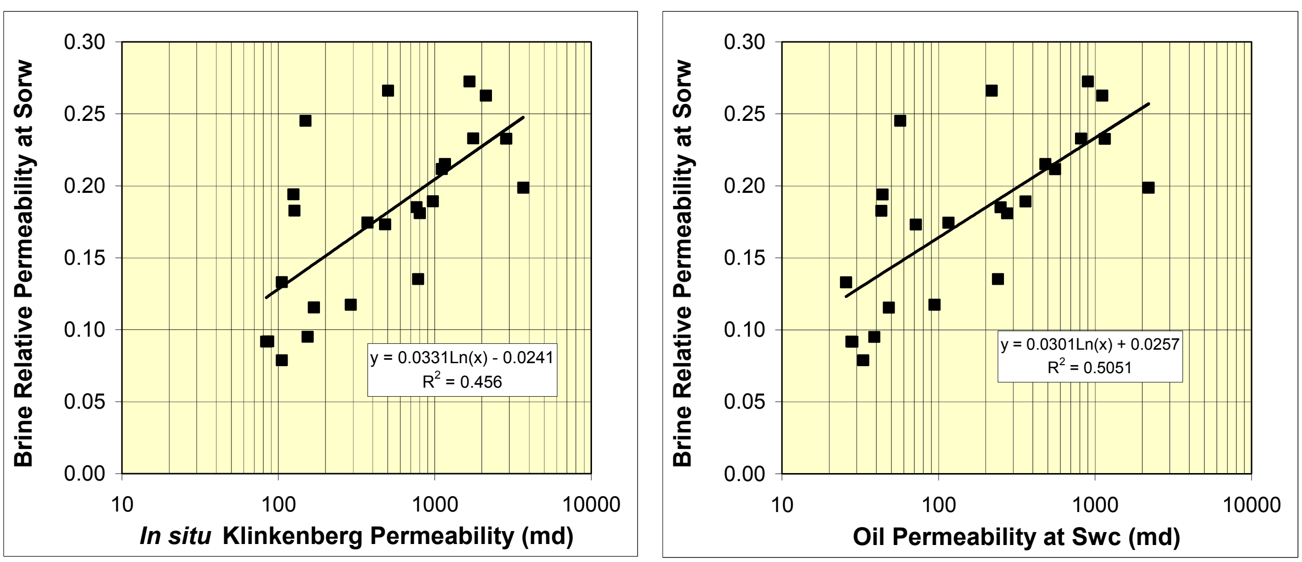


Figure 12a and 12b. Brine relative permeability at Sorw cross-plotted with *in situ* Klinkenberg permeability and oil permeability at Swc showing power-law relationships.

Comparison of fresh water permeability with 30,000 ppm brine permeability indicates that fresh water permeability is generally within 10% of the brine permeability indicating little sensitivity to salinity change from 30,000 ppm to fresh water (Figure 13).

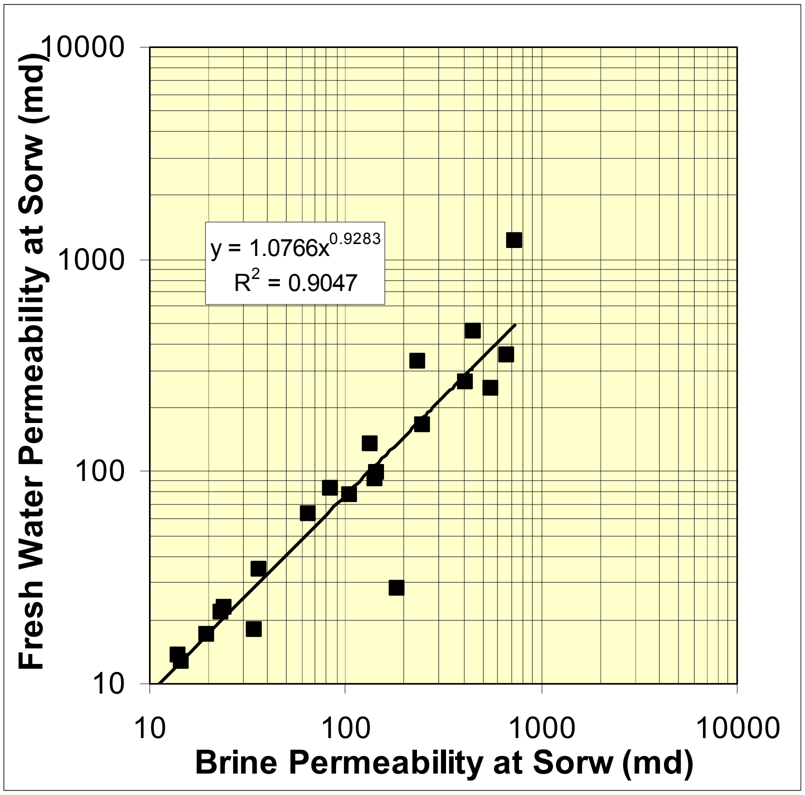


Figure 13. Crossplot of effective fresh water permeability at Sorw versus effective permeability to 30,000 ppm NaCl brine at Sorw.

Table 1.
Berexco Irene #2-5
Summary of Coreplug Petrophysical Properties

Core Depth (ft)	Routine Helium Porosity (%)	*In situ* Klinkenberg Permeability (md)	Grain Density (g/cc)	Archie Cementation Exponent (a=1)	Formation Resistivity Factor @20degC)	Comment
4742.2	20.8	436	2.62	1.82	17.4	
4743.1	22.6	170	2.68	2.04	20.6	
4744.5	24.8	503	2.70	1.82	12.6	
4745.5	28.4	2828	2.66			MICP
4745.6	27.2	3677	2.66	1.79	10.3	
4746.3	24.5	1669	2.69	1.94	15.3	
4748.6	22.4	1763	2.66	1.77	14.1	
4748.7	22.7	2122	2.65	1.96	18.4	
4749.1	27.6	2864	2.65	1.84	10.8	
4749.9	20.9	577	2.61			
4750.2	25.2	1108	2.66	2.00	15.7	
4750.3	25.4	1205	2.66			MICP
4750.4	22.6	802	2.65	1.81	14.8	
4751.2	21.7	125	2.65	1.96	20.0	
4751.4	21.6	784	2.67	1.73	14.3	
4752.0	24.5	1162	2.65	1.79	12.5	
4753.0	25.6	309	2.65			MICP
4755.0	24.2	371	2.65	1.93	15.4	
4756.5	23.0	127	2.63	1.95	17.5	
4757.5	25.1	105	2.65	1.98	15.5	
4760.1	21.9	49.6	2.60			
4760.5	26.5	290	2.65	2.02	14.7	
4761.3	22.5	127	2.63			MICP
4761.3	21.9	148	2.62			
4762.2	26.4	83.6	2.65	2.04	15.1	
4762.4	25.1	86.1	2.64	1.98	15.4	
4763.0	23.6	149	2.63	2.02	18.5	
4764.0	25.3	481	2.66	1.87	13.1	
4765.3	24.3	154	2.65	1.94	15.6	
4766.3	10.2	10.5	2.70	1.89	73.4	
4766.3	10.3	10.3	2.70			MICP
4767.5	18.4	115	2.66	2.01	29.9	
4768.5	18.7	972	2.66	1.78	19.8	
4768.6	17.0	763	2.66	1.87	27.6	
4771.1	15.4	10.3	2.62	1.87	32.9	
4773.7	16.9	5.51	2.65	2.17	47.3	
4773.8	17.5	10.6	2.65	2.19	45.2	
4774.5	14.0	0.310	2.67	1.81	35.1	
4775.3	20.8	169	2.65	2.06	25.2	
4775.5	21.4	105	2.66	1.95	20.2	
4776.4	20.0	77.7	2.66	2.12	30.4	
4776.4	20.1	90.7	2.65			MICP
4777.7	20.7	80.3	2.66	1.86	18.7	
4781.1	16.4	5.15	2.67	2.16	49.5	
4788.9	12.4	0.075	2.68	2.01	66.4	
4793.0	12.7	0.098	2.71	1.77	39.0	
4798.1	19.7	8.76	2.68	1.92	22.7	

Table 2.
Berexco Irene #2-5
Summary of Electrical Properties

Core Depth (ft)	Routine Helium Porosity (%)	Formation Resistivity Factor @20degC)	Archie Cementation Exponent (a=1)
4742.2	20.8	17.4	1.82
4743.1	22.6	20.6	2.04
4744.5	24.8	12.6	1.82
4745.6	27.2	10.3	1.79
4746.3	24.5	15.3	1.94
4748.6	22.4	14.1	1.77
4748.7	22.7	18.4	1.96
4749.1	27.6	10.8	1.84
4750.2	25.2	15.7	2.00
4750.4	22.6	14.8	1.81
4751.2	21.7	20.0	1.96
4751.4	21.6	14.3	1.73
4752.0	24.5	12.5	1.79
4755.0	24.2	15.4	1.93
4756.5	23.0	17.5	1.95
4757.5	25.1	15.5	1.98
4760.5	26.5	14.7	2.02
4762.2	26.4	15.1	2.04
4762.4	25.1	15.4	1.98
4763.0	23.6	18.5	2.02
4764.0	25.3	13.1	1.87
4765.3	24.3	15.6	1.94
4766.3	10.2	73.4	1.89
4767.5	18.4	29.9	2.01
4768.5	18.7	19.8	1.78
4768.6	17.0	27.6	1.87
4771.1	15.4	32.9	1.87
4773.7	16.9	47.3	2.17
4773.8	17.5	45.2	2.19
4774.5	14.0	35.1	1.81
4775.3	20.8	25.2	2.06
4775.5	21.4	20.2	1.95
4776.4	20.0	30.4	2.12
4777.7	20.7	18.7	1.86
4781.1	16.4	49.5	2.16
4788.9	12.4	66.4	2.01
4793.0	12.7	39.0	1.77
4798.1	19.7	22.7	1.92

Table 3.
Berexco Irene #2-5
Summary of Brine Permeability Testing

Core Depth (ft)	Routine Helium Porosity (%)	Meas./Calc. *In situ* Klinkenberg Permeability (md)	Grain Density (g/cc)	150,000 ppm NaCl Brine Permeability 150K 10 (md)	150K 20 (md)	150K 30 (md)	150K 40 (md)	150K 50 (md)	150K 60 (md)	150K 70 (md)	150K 80 (md)	150K 90 (md)	150K 100 (md)	<Brine <PV
4745.6	27.2	3677	2.66	3,633	3,784	3,805	3,843	3,879	3,892	3,841	3,724	3,832	3,832	
4748.7	22.7	2122	2.65	1,935	1,963	1,853	1,831	1,845	1,887	1,932				
4746.3	24.5	1669	2.69	1,803	1,628	1,609	1,712	1,874	1,836	1,871	1,964	1,914	1,885	
4750.2	25.2	1108	2.66			1,341	1,180	1,123	1,202	1,215	1,215	1,348	1,276	
4751.4	21.6	784	2.67	350	360	386	401	407	420	428	428	433	431	
4760.5	26.5	290	2.65	222	234	234	234	232	238	227	224	224	222	
4765.3	24.3	154	2.65	96	101	98	98	95	96	94	92	92		
				Fraction of Insitu Klinkenberg Permeability										
4745.6	27.2	3677	2.66	0.99	1.03	1.03	1.05	1.05	1.06	1.04	1.01	1.04	1.04	
4748.7	22.7	2122	2.65	0.91	0.92	0.87	0.86	0.87	0.89	0.91				
4746.3	24.5	1669	2.69	1.08	0.98	0.96	1.03	1.12	1.10	1.12	1.18	1.15	1.13	
4750.2	25.2	1108	2.66			1.21	1.06	1.01	1.08	1.10	1.10	1.22	1.15	
4751.4	21.6	784	2.67	0.45	0.46	0.49	0.51	0.52	0.54	0.55	0.55	0.55	0.55	
4760.5	26.5	290	2.65	0.76	0.81	0.81	0.81	0.80	0.82	0.78	0.77	0.77	0.76	
4765.3	24.3	154	2.65	0.62	0.66	0.64	0.63	0.62	0.62	0.61	0.60	0.60		
				Fraction of first 150K Brine Permeability										
4745.6	27.2	3677	2.66	1.00	1.04	1.05	1.06	1.07	1.07	1.06	1.03	1.05	1.05	
4748.7	22.7	2122	2.65	1.00	1.01	0.96	0.95	0.95	0.98	1.00				
4746.3	24.5	1669	2.69	1.00	0.90	0.89	0.95	1.04	1.02	1.04	1.09	1.06	1.05	
4750.2	25.2	1108	2.66			1.00	0.88	0.84	0.90	0.91	0.91	1.01	0.95	
4751.4	21.6	784	2.67	1.00	1.03	1.10	1.15	1.16	1.20	1.22	1.22	1.24	1.23	
4760.5	26.5	290	2.65	1.00	1.05	1.05	1.05	1.05	1.07	1.02	1.01	1.01	1.00	
4765.3	24.3	154	2.65	1.00	1.05	1.03	1.02	0.99	1.00	0.98	0.96	0.96		

Core Depth (ft)	Routine Helium Porosity (%)	*In situ* Klinkenberg Permeability (md)	Grain Density (g/cc)	30,000 ppm NaCl Brine Permeability 30K 110 (md)	30K 120 (md)	30K 130 (md)	30K 140 (md)	30K 150 (md)	30K 160 (md)	30K 170 (md)	30K 180 (md)	30K 190 (md)	30K 200 (md)	24 hours later 30K 210 (md)	30K 220 (md)	30K 230 (md)	<B <PV
4745.6	27.2	3677	2.66	3,880	3,244	3,258	3,174	3,247	3,054	2,996				2,760	2,860	2,961	
4748.7	22.7	2122	2.65	1,509	1,583	1,551	1,652	1,569	1,634	1,682	1,627	1,647	1,677	883	961	1,011	
4746.3	24.5	1669	2.69	1,007	998	1,082	1,134	1,178	1,186	1,141	1,230	1,214	1,193	911	986	1,021	
4750.2	25.2	1108	2.66	793	782	817	846	838	828	835	860	867	856	670	735	766	
4751.4	21.6	784	2.67	314	321	334	308	312	309	309				314	343	349	
4760.5	26.5	290	2.65	197	207	208	208	206	212	214	198	204	204				
4765.3	24.3	154	2.65	83	77	76	73	69	69	66	63	63	61	83	84	84	
				Fraction of Insitu Klinkenberg Permeability													
4745.6	27.2	3677	2.66	1.06	0.88	0.89	0.86	0.88	0.83	0.81				0.75	0.78	0.81	
4748.7	22.7	2122	2.65	0.71	0.75	0.73	0.78	0.74	0.77	0.79	0.77	0.78	0.79	0.42	0.45	0.48	
4746.3	24.5	1669	2.69	0.60	0.60	0.65	0.68	0.71	0.71	0.68	0.74	0.73	0.72	0.55	0.59	0.61	
4750.2	25.2	1108	2.66	0.72	0.71	0.74	0.76	0.76	0.75	0.75	0.78	0.78	0.77	0.60	0.66	0.69	
4751.4	21.6	784	2.67	0.40	0.41	0.43	0.39	0.40	0.39	0.39				0.40	0.44	0.45	
4760.5	26.5	290	2.65	0.68	0.71	0.72	0.72	0.71	0.73	0.74	0.68	0.70	0.70				
4765.3	24.3	154	2.65	0.54	0.50	0.49	0.47	0.45	0.45	0.43	0.41	0.41	0.39	0.54	0.54	0.55	
				Fraction of first 150K Brine Permeability													
4745.6	27.2	3677	2.66	1.07	0.89	0.90	0.87	0.89	0.84	0.82				0.76	0.79	0.82	
4748.7	22.7	2122	2.65	0.78	0.82	0.80	0.85	0.81	0.84	0.87	0.84	0.85	0.87	0.46	0.50	0.52	
4746.3	24.5	1669	2.69	0.56	0.55	0.60	0.63	0.65	0.66	0.63	0.68	0.67	0.66	0.50	0.55	0.57	
4750.2	25.2	1108	2.66	0.59	0.58	0.61	0.63	0.62	0.62	0.62	0.64	0.65	0.64	0.50	0.55	0.57	
4751.4	21.6	784	2.67	0.90	0.92	0.95	0.88	0.89	0.88	0.88				0.90	0.98	1.00	
4760.5	26.5	290	2.65	0.89	0.93	0.94	0.94	0.93	0.96	0.96	0.89	0.92	0.92				
4765.3	24.3	154	2.65	0.87	0.81	0.79	0.76	0.72	0.72	0.69	0.66	0.65	0.63	0.86	0.87	0.88	

Table 4.
Berexco Irene #2-5
Waterflood Susceptibility Analysis

Core Depth (ft)	Ambient Porosity	*In situ* Klinkenberg Permeability (md)	Initial Oil Saturation (fraction)	Critical Water Saturation (fraction)	Effective Oil Permeability at Swc keo,Swc (md)	Residual Oil Saturation to waterflood at 2 PV (fraction)	Residual Oil Saturation to waterflood at 5 PV (fraction)	Residual Oil Saturation to waterflood at 10 PV (fraction)	Residual Oil Saturation to waterflood at 20 PV (fraction)	Effective Brine Permeability at Sorw 30K ppm NaCl (md)	Effective Water Permeability at Sorw Fresh Water (md)	Relative Brine Permeability at Sorw 30K ppm NaCl (kew/kik)	Relative Brine Permeability at Sorw 30K ppm NaCl (kew/keo)
4742.2	20.8	436	0.70	0.30	199								
4743.1	22.6	170	0.57	0.43	74	0.21	0.19	0.16	0.15				
4744.5	24.8	503	0.68	0.32	219	0.20	0.20	0.20	0.18	134	134	0.27	0.61
4745.6	27.2	3677	0.50	0.50	2201	0.07	0.06	0.05	0.05	731	1220	0.20	0.33
4746.3	24.5	1669	0.56	0.44	900	0.19	0.16	0.15	0.14	455	455	0.27	0.51
4748.6	22.4	1763	0.65	0.35	814	0.28	0.25	0.24	0.24	411	262	0.23	0.50
4748.7	22.7	2122	0.54	0.46	1110	0.07	0.04	0.03	0.01	557	248	0.26	0.50
4749.1	27.6	2864	0.65	0.35	1154	0.20	0.19	0.19	0.18	666	353	0.23	0.58
4750.2	25.2	1108	0.61	0.39	556	0.21	0.18	0.15	0.15	235	331	0.21	0.42
4750.4	22.6	802	0.68	0.32	274	0.30	0.28	0.28	0.28	145	98	0.18	0.53
4751.2	21.7	125	0.70	0.30	44	0.32	0.29	0.29	0.28	24.2	23.0	0.19	0.55
4751.4	21.6	784	0.65	0.35	240	0.22	0.19	0.19	0.19	106	77	0.14	0.44
4752.0	24.5	1162	0.64	0.36	481	0.18	0.16	0.15	0.15	250	165	0.22	0.52
4755.0	24.2	371	0.57	0.43	116	0.25	0.23	0.21	0.21	64.7	62.7	0.17	0.56
4756.5	23.0	127	0.58	0.42	43	0.28	0.24	0.24	0.24	23.2	21.6	0.18	0.54
4757.5	25.1	105	0.56	0.44	33	0.25	0.25	0.25	0.25	8.3	9.2	0.08	0.25
4760.5	26.5	290	0.54	0.46	94	0.19	0.18	0.17	0.17	34.1	17.9	0.12	0.36
4762.2	26.4	84	0.59	0.41	28	0.21	0.20	0.20	0.20	7.7	6.9	0.09	0.27
4762.4	25.1	86	0.56	0.44	28	0.22	0.22	0.22		7.9	7.4	0.09	0.28
4763.0	23.6	149	0.60	0.40	57	0.26	0.22	0.22	0.22	36.6	34.5	0.25	0.64
4764.0	25.3	481	0.63	0.37	71	0.22	0.19	0.19	0.19	83.3	83.5	0.17	1.17
4765.3	24.3	154	0.48	0.52	39	0.15	0.14	0.14	0.14	14.6	12.7	0.10	0.38
4768.5	18.7	972	0.61	0.39	360	0.22	0.20	0.18	0.18	184	28.2	0.19	0.51
4768.6	17.0	763	0.64	0.36	249	0.17	0.19	0.19	0.19	141	92.8	0.19	0.57
4775.3	20.8	169	0.61	0.39	48	0.27	0.27	0.26	0.26	19.5	17.1	0.12	0.40
4775.5	21.4	105	0.55	0.45	26	0.23	0.22	0.21	0.21	14.0	13.6	0.13	0.55

Mercury Injection Capillary Pressure Analysis
Berexco Irene #2-5 4745.5 ft

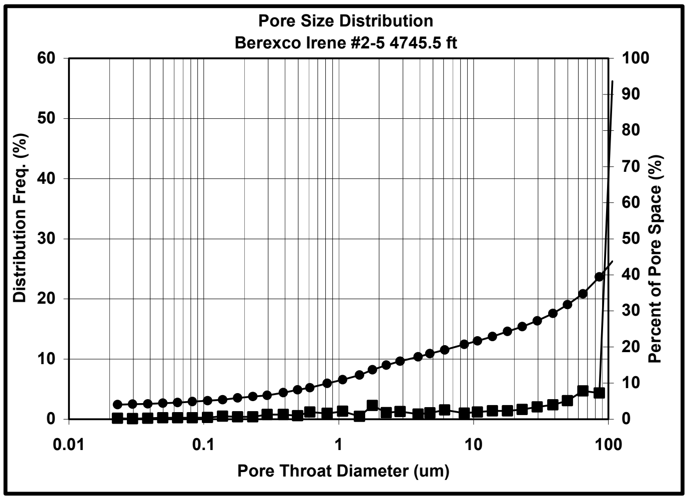
In situ Klinkenberg Permeability = 2857md
In situ Porosity = 27.7%

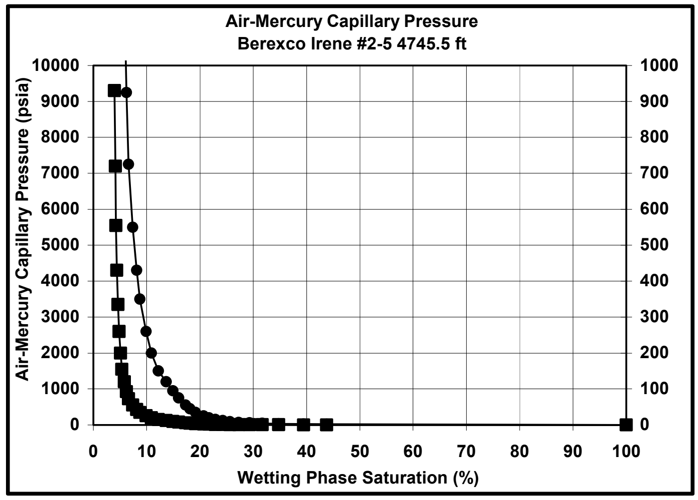
Mercury Injection Capillary Pressure (psia)	Approx. Pore Entry Diameter (um)	Cumulative Wetting Phase Saturation (% pore vol)	Pore Size Distri-bution Fre-quency	Cumula-tive Surface Area (m2/g)	Approx. Gas-Water Height Above Free Water Level (ft)	Approx. Oil-Water Height Above Free Water Level (ft)	Corey-Calculated Drainage: Oil or Gas Relative Permea-bility (%)	Corey-Calculated Drainage: Water Relative Permea-bility (%)	Corey-Calculated Drainage: Log Oil/Brine Kro/Krw Ratio
		100.0	0.0	0.000	0.1	0.1	0.0	100.0	-5.0
2.0	107	43.8	56.2	0.003	0.6	0.9	12.2	2.8	0.6
2.5	86	39.4	4.4	0.003	0.7	1.1	16.4	1.7	1.0
3.3	65	34.8	4.7	0.004	1.0	1.5	22.1	1.0	1.4
4.3	50	31.7	3.1	0.004	1.3	1.9	26.5	0.6	1.6
5.5	39	29.3	2.4	0.005	1.6	2.5	30.4	0.4	1.8
7.2	30	27.3	2.1	0.005	2.2	3.2	34.1	0.3	2.0
9.3	23	25.7	1.6	0.005	2.8	4.2	37.3	0.2	2.2
12.0	18	24.3	1.4	0.006	3.6	5.4	40.1	0.2	2.4
15.5	14	22.9	1.4	0.006	4.6	7.0	43.1	0.1	2.5
20	11	21.7	1.2	0.007	6.0	9.0	45.8	0.1	2.7
25	8.6	20.7	1.0	0.008	7.5	11.3	48.2	0.1	2.8
35	6.1	19.2	1.5	0.009	10	16	52.0	0.1	3.0
45	4.8	18.2	1.0	0.011	13	20	54.8	0.0	3.2
55	3.9	17.3	0.8	0.012	16	25	57.1	0.0	3.3
75	2.9	16.0	1.3	0.014	22	34	60.6	0.0	3.5
95	2.3	14.9	1.1	0.017	28	43	63.8	0.0	3.7
120	1.8	13.7	2.3	0.025	36	54	70.9	0.0	4.2
150	1.4	12.2	0.4	0.019	45	68	72.4	0.0	4.3
200	1.1	10.9	1.3	0.026	60	90	76.9	0.0	4.7
260	0.82	9.9	1.0	0.033	78	117	80.3	0.0	5.0
350	0.61	8.7	1.2	0.045	105	158	84.6	0.0	5.5
430	0.50	8.2	0.6	0.052	128	194	86.8	0.0	5.8
550	0.39	7.4	0.8	0.064	164	248	89.8	0.0	6.2
725	0.30	6.6	0.8	0.079	217	327	92.8	0.0	6.9
925	0.23	6.2	0.4	0.088	276	417	94.3	0.0	7.3
1200	0.18	5.9	0.4	0.101	358	541	95.8	0.0	7.9
1550	0.14	5.3	0.5	0.123	463	699	97.9	0.0	9.1
2000	0.11	5.1	0.3	0.137	597	902	99.0	0.0	10.4
2600	0.08	4.8	0.2	0.155	777	1173	100.0	0.0	15.0
3350	0.06	4.6	0.2	0.175	1001	1511	100.0	0.0	15.0
4300	0.05	4.4	0.2	0.202	1284	1939	100.0	0.0	15.0
5550	0.04	4.2	0.2	0.228	1658	2503	100.0	0.0	15.0
7200	0.03	4.2	0.1	0.241	2151	3247	100.0	0.0	15.0
9300	0.02	4.0	0.2	0.283	2778	4194	100.0	0.0	15.0

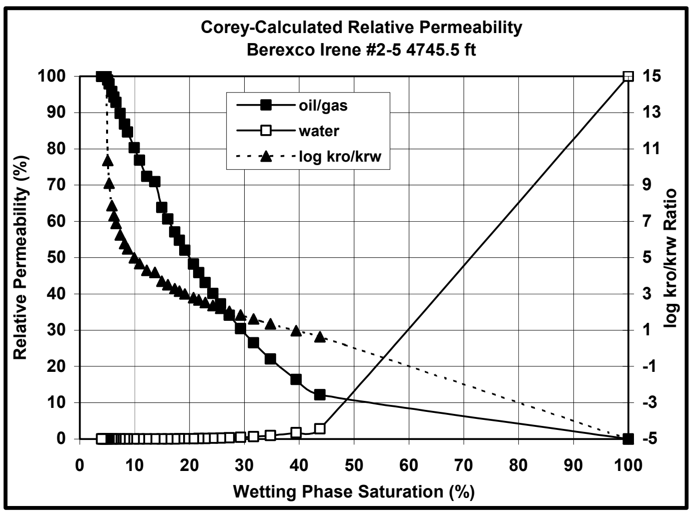
All Hg calculations assume air-mercury T=484 dyne/cm, contact angle=140deg.

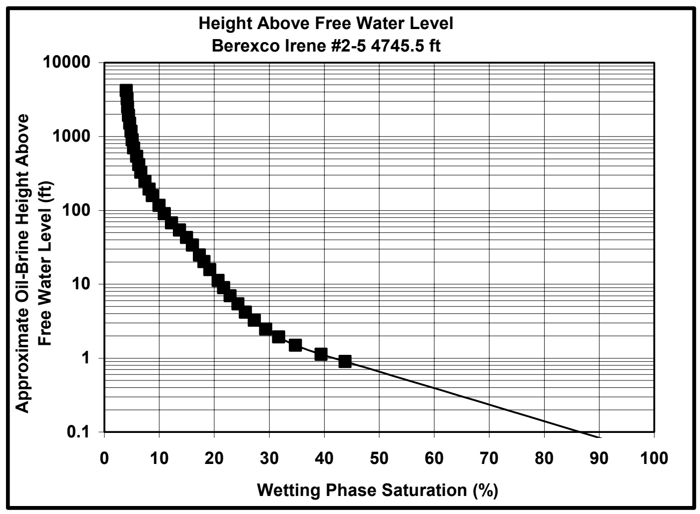
Oil/Gas-Brine Pc assumes insitu o/g-brine Tcos0=	47.00	21.00	dynes/cm
Oil/gas-Brine height assumes o/g density gradient =	0.0476	0.3464	psi/ft
Oil/gas-Brine height assumes brine density gradient =	0.4720	0.4720	psi/ft
Swi assumed for relative permeability =	4.8	4.8	%
In situ Gas/Oil & Brine Density (g/cc)=	0.110/0.80	1.09	g/cc

Mercury Injection Capillary Pressure Analysis
Berexco Irene #2-5 4745.5 ft









Mercury Injection Capillary Pressure Analysis
Berexco Irene #2-5 4750.3 ft

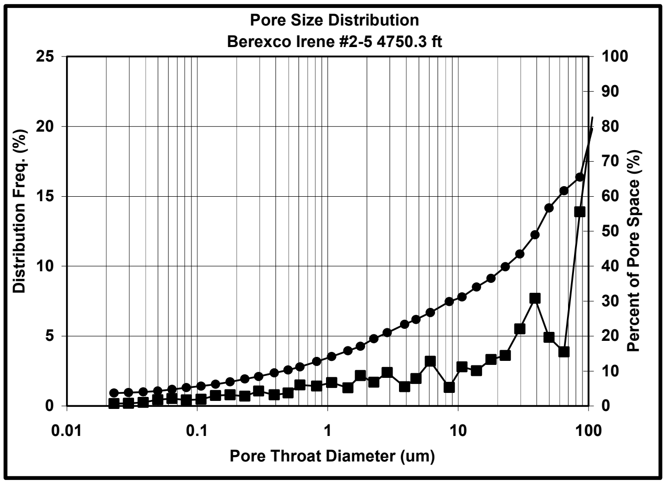
In situ Klinkenberg Permeability = 1205md
In situ Porosity = 25.4%

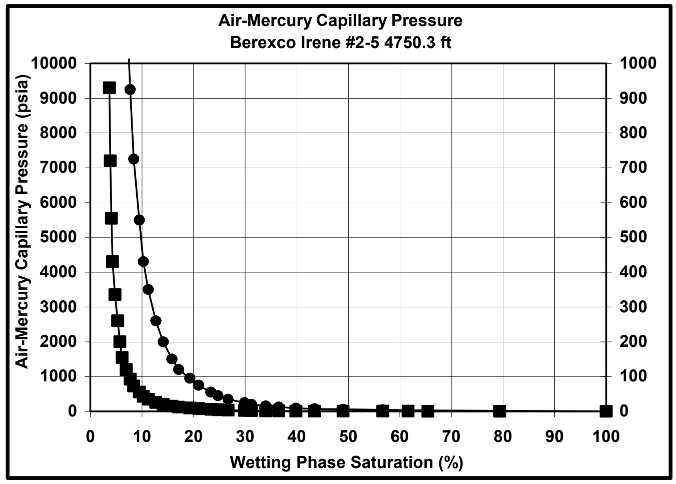
Mercury Injection Capillary Pressure (psia)	Approx. Pore Entry Diameter (um)	Cumulative Wetting Phase Saturation (% pore vol)	Pore Size Distri-bution Fre-quency	Cumula-tive Surface Area (m2/g)	Approx. Gas-Water Height Above Free Water Level (ft)	Approx. Oil-Water Height Above Free Water Level (ft)	Corey-Calculated Drainage		
							Oil or Gas Relative Permea-bility (%)	Water Relative Permea-bility (%)	Log Oil/Brine Kro/Krw Ratio
		100.0	0.0	0.000	0.3	0.4	0.0	100.0	-5.0
2.0	107	79.3	20.7	0.001	0.6	0.9	0.2	37.4	-2.2
2.5	86	65.5	13.9	0.002	0.7	1.1	1.8	16.3	-1.0
3.3	65	61.6	3.9	0.002	1.0	1.5	2.7	12.5	-0.7
4.3	50	56.7	4.9	0.003	1.3	1.9	4.4	8.7	-0.3
5.5	39	49.0	7.7	0.004	1.6	2.5	8.4	4.5	0.3
7.2	30	43.5	5.5	0.005	2.2	3.2	12.7	2.6	0.7
9.3	23	39.8	3.6	0.005	2.8	4.2	16.3	1.8	1.0
12.0	18	36.5	3.3	0.006	3.6	5.4	20.2	1.2	1.2
15.5	14	34.0	2.5	0.007	4.6	7.0	23.6	0.8	1.4
20	11	31.2	2.8	0.009	6.0	9.0	27.8	0.6	1.7
25	8.6	29.9	1.3	0.009	7.5	11.3	30.0	0.5	1.8
35	6.1	26.7	3.2	0.012	10	16	35.9	0.3	2.1
45	4.8	24.7	2.0	0.014	13	20	39.9	0.2	2.4
55	3.9	23.4	1.4	0.016	16	25	42.9	0.1	2.5
75	2.9	21.0	2.4	0.020	22	34	48.5	0.1	2.8
95	2.3	19.3	1.7	0.024	28	43	52.8	0.0	3.0
120	1.8	17.1	2.2	0.030	36	54	58.7	0.0	3.4
150	1.4	15.8	1.3	0.028	45	68	62.4	0.0	3.6
200	1.1	14.1	1.7	0.036	60	90	67.5	0.0	3.9
260	0.82	12.7	1.4	0.045	78	117	72.1	0.0	4.3
350	0.61	11.2	1.5	0.058	105	158	77.2	0.0	4.7
430	0.50	10.3	0.9	0.067	128	194	80.5	0.0	5.0
550	0.39	9.5	0.8	0.077	164	248	83.4	0.0	5.3
725	0.30	8.4	1.1	0.096	217	327	87.4	0.0	5.9
925	0.23	7.7	0.7	0.111	276	417	90.1	0.0	6.3
1200	0.18	6.9	0.8	0.134	358	541	93.2	0.0	7.0
1550	0.14	6.2	0.7	0.161	463	699	96.3	0.0	8.1
2000	0.11	5.7	0.5	0.184	597	902	98.2	0.0	9.4
2600	0.08	5.3	0.4	0.210	777	1173	100.0	0.0	15.0
3350	0.06	4.7	0.5	0.251	1001	1511	100.0	0.0	15.0
4300	0.05	4.3	0.4	0.297	1284	1939	100.0	0.0	15.0
5550	0.04	4.1	0.2	0.330	1658	2503	100.0	0.0	15.0
7200	0.03	3.9	0.2	0.363	2151	3247	100.0	0.0	15.0
9300	0.02	3.7	0.2	0.402	2778	4194	100.0	0.0	15.0

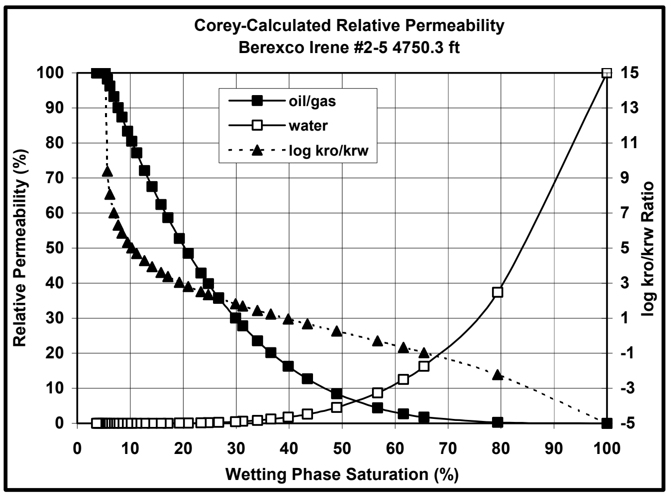
All Hg calculations assume air-mercury T=484 dyne/cm, contact angle=140deg.

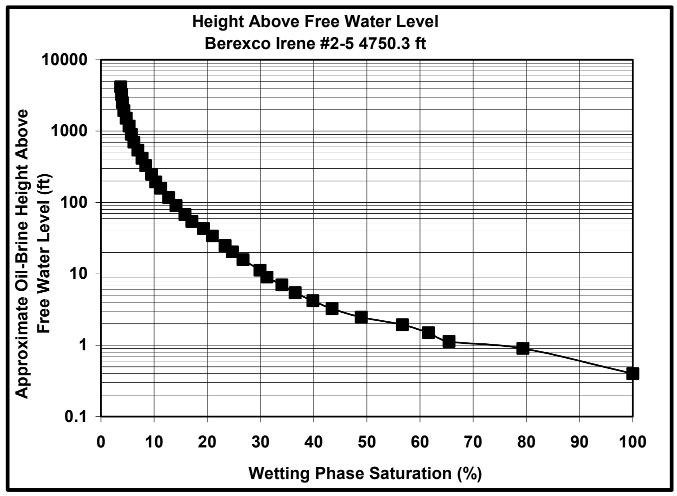
Oil/Gas-Brine Pc assumes insitu o/g-brine Tcos0=	47.00	21.00	dynes/cm
Oil/gas-Brine height assumes o/g density gradient =	0.0476	0.3464	psi/ft
Oil/gas-Brine height assumes brine density gradient =	0.4720	0.4720	psi/ft
Swi assumed for relative permeability =	5.3	5.3	%
In situ Gas/Oil & Brine Density (g/cc)=	0.110/0.80	1.09	g/cc

Mercury Injection Capillary Pressure Analysis
Berexco Irene #2-5 4750.3 ft









Mercury Injection Capillary Pressure Analysis
Berexco Irene #2-5 4749.9 ft

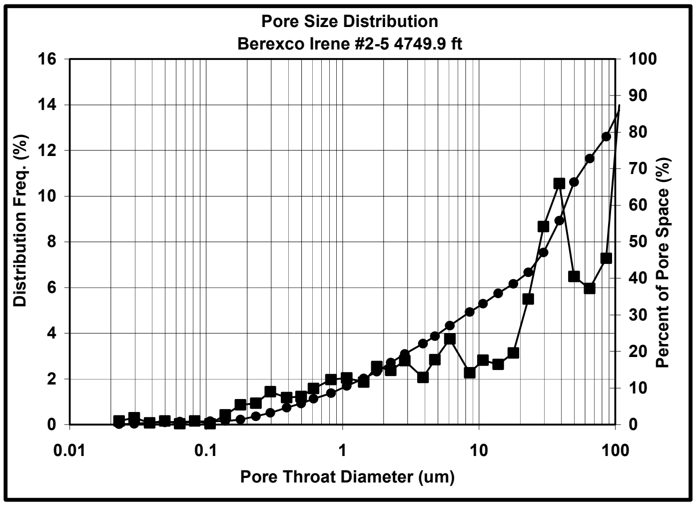
In situ Klinkenberg Permeability = 577md
In situ Porosity = 20.9%

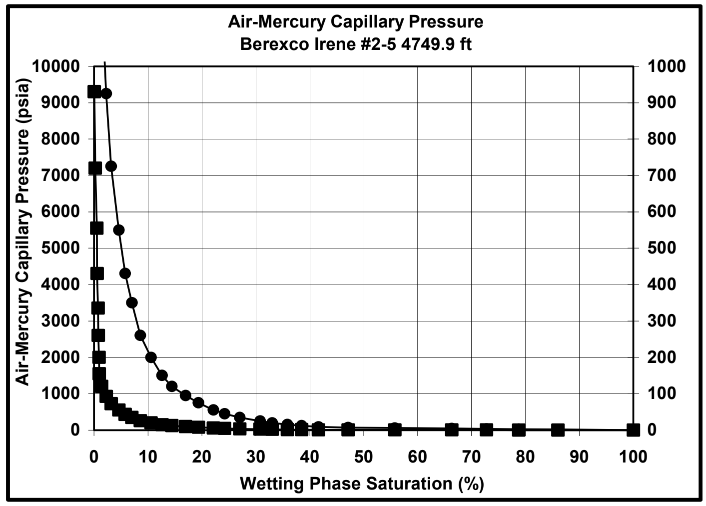
Mercury Injection Capillary Pressure (psia)	Approx. Pore Entry Diameter (um)	Cumulative Wetting Phase Saturation (% pore vol)	Pore Size Distri-bution Fre-quency	Cumula-tive Surface Area (m2/g)	Approx. Gas-Water Height Above Free Water Level (ft)	Approx. Oil-Water Height Above Free Water Level (ft)	Corey-Calculated Drainage: Oil or Gas Relative Permea-bility (%)	Corey-Calculated Drainage: Water Relative Permea-bility (%)	Corey-Calculated Drainage: Log Oil/Brine Kro/Krw Ratio
		100.0	0.0	0.000	0.5	0.5	0.0	100.0	-5.0
2.0	107	86.0	14.0	0.001	0.6	0.9	0.0	54.5	-3.1
2.5	86	78.7	7.3	0.001	0.7	1.1	0.2	38.1	-2.3
3.3	65	72.8	6.0	0.001	1.0	1.5	0.6	27.7	-1.7
4.3	50	66.3	6.5	0.002	1.3	1.9	1.3	19.0	-1.2
5.5	39	55.8	10.6	0.003	1.6	2.5	4.0	9.4	-0.4
7.2	30	47.1	8.7	0.004	2.2	3.2	8.1	4.7	0.2
9.3	23	41.6	5.5	0.005	2.8	4.2	12.0	2.9	0.6
12.0	18	38.5	3.1	0.006	3.6	5.4	14.8	2.1	0.9
15.5	14	35.8	2.6	0.006	4.6	7.0	17.5	1.6	1.0
20	11	33.0	2.8	0.007	6.0	9.0	20.7	1.1	1.3
25	8.6	30.8	2.3	0.009	7.5	11.3	23.7	0.8	1.5
35	6.1	27.0	3.7	0.011	10	16	29.3	0.5	1.8
45	4.8	24.2	2.8	0.013	13	20	34.1	0.3	2.0
55	3.9	22.1	2.1	0.015	16	25	37.9	0.2	2.2
75	2.9	19.3	2.8	0.019	22	34	43.7	0.1	2.6
95	2.3	17.0	2.4	0.024	28	43	49.0	0.1	2.8
120	1.8	14.4	2.5	0.029	36	54	55.3	0.0	3.2
150	1.4	12.6	1.8	0.029	45	68	60.2	0.0	3.5
200	1.1	10.5	2.0	0.036	60	90	66.0	0.0	3.8
260	0.82	8.6	2.0	0.046	78	117	72.1	0.0	4.3
350	0.61	7.0	1.6	0.056	105	158	77.1	0.0	4.7
430	0.50	5.8	1.2	0.066	128	194	81.3	0.0	5.1
550	0.39	4.6	1.2	0.078	164	248	85.4	0.0	5.6
725	0.30	3.2	1.4	0.098	217	327	90.7	0.0	6.4
925	0.23	2.2	0.9	0.114	276	417	94.2	0.0	7.3
1200	0.18	1.4	0.9	0.133	358	541	97.6	0.0	8.9
1550	0.14	1.0	0.4	0.145	463	699	99.2	0.0	10.9
2000	0.11	0.9	0.0	0.146	597	902	99.4	0.0	11.2
2600	0.08	0.8	0.2	0.154	777	1173	100.0	0.0	15.0
3350	0.06	0.7	0.0	0.156	1001	1511	100.0	0.0	15.0
4300	0.05	0.6	0.2	0.169	1284	1939	100.0	0.0	15.0
5550	0.04	0.5	0.1	0.176	1658	2503	100.0	0.0	15.0
7200	0.03	0.2	0.3	0.215	2151	3247	100.0	0.0	15.0
9300	0.02	0.1	0.2	0.242	2778	4194	100.0	0.0	15.0

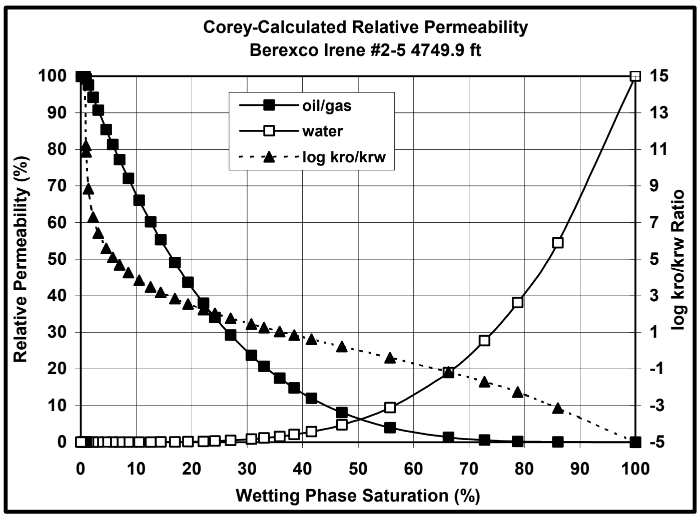
All Hg calculations assume air-mercury T=484 dyne/cm, contact angle=140deg.

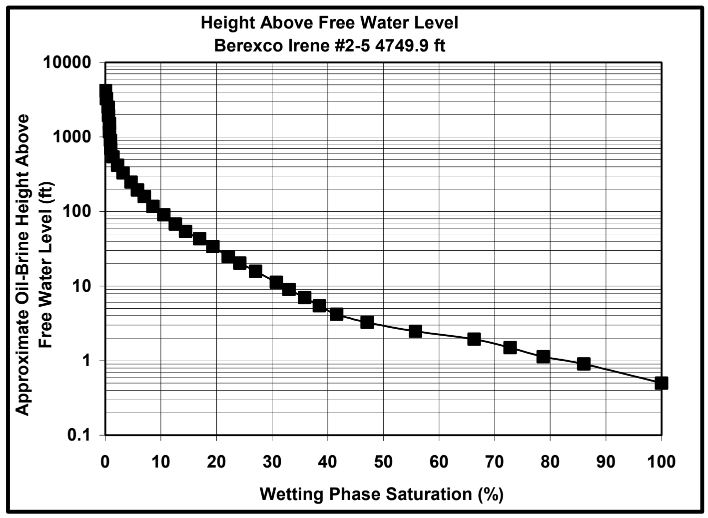
Oil/Gas-Brine Pc assumes insitu o/g-brine Tcos0=	47.00	21.00	dynes/cm
Oil/gas-Brine height assumes o/g density gradient =	0.0476	0.3464	psi/ft
Oil/gas-Brine height assumes brine density gradient =	0.4720	0.4720	psi/ft
Swi assumed for relative permeability =	0.8	0.8	%
In situ Gas/Oil & Brine Density (g/cc)=	0.110/0.80	1.09	g/cc

Mercury Injection Capillary Pressure Analysis
Berexco Irene #2-5 4749.9 ft









Mercury Injection Capillary Pressure Analysis
Berexco Irene #2-5 4753 ft

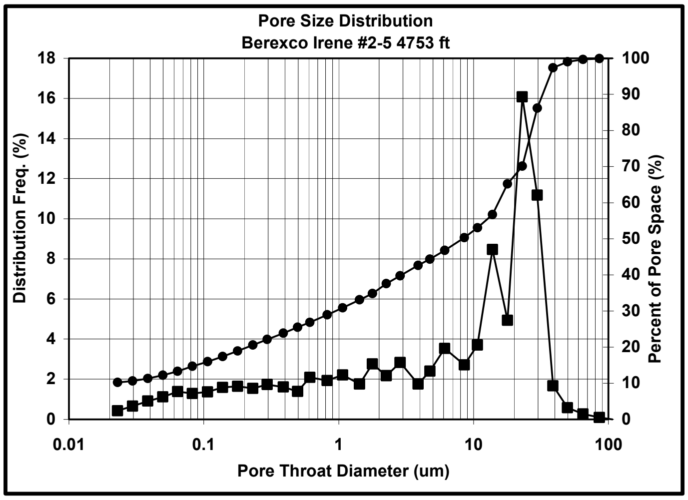
In situ Klinkenberg Permeability = 309md
In situ Porosity = 25.6%

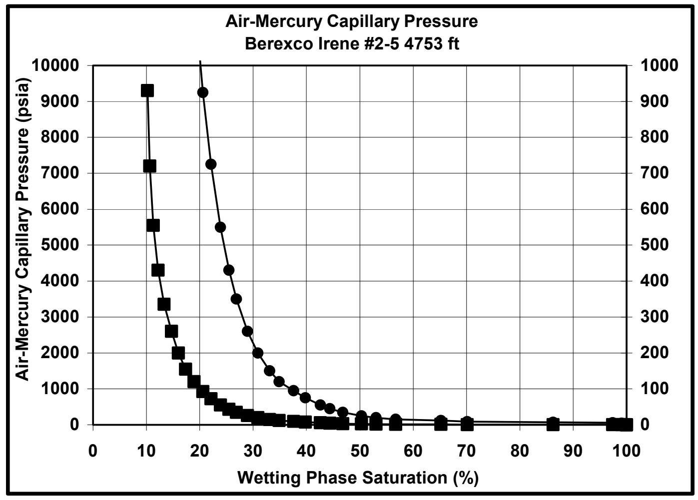
Mercury Injection Capillary Pressure (psia)	Approx. Pore Entry Diameter (um)	Cumulative Wetting Phase Saturation (% pore vol)	Pore Size Distri-bution Fre-quency	Cumula-tive Surface Area (m2/g)	Approx. Gas-Water Height Above Free Water Level (ft)	Approx. Oil-Water Height Above Free Water Level (ft)	Corey Calculated		
							Oil or Gas Relative Permea-bility (%)	Water Relative Permea-bility (%)	Log Oil/Brine Kro/Krw Ratio
		100.0	0.0	0.000	0.1	0.1	0.0	100.0	-5.0
2.0	107	100.0	0.0	0.000	0.6	0.9	0.0	100.0	-5.0
2.5	86	99.9	0.1	0.000	0.7	1.1	0.0	99.6	-5.0
3.3	65	99.7	0.3	0.000	1.0	1.5	0.0	98.4	-5.0
4.3	50	99.1	0.6	0.000	1.3	1.9	0.0	95.7	-5.0
5.5	39	97.4	1.7	0.000	1.6	2.5	0.0	88.4	-6.0
7.2	30	86.2	11.2	0.002	2.2	3.2	0.1	49.4	-2.9
9.3	23	70.1	16.1	0.006	2.8	4.2	1.5	17.8	-1.1
12.0	18	65.2	4.9	0.007	3.6	5.4	2.8	12.3	-0.6
15.5	14	56.7	8.5	0.010	4.6	7.0	6.6	5.9	0.0
20	11	53.0	3.7	0.012	6.0	9.0	9.2	4.1	0.4
25	8.6	50.3	2.7	0.014	7.5	11.3	11.5	3.0	0.6
35	6.1	46.8	3.5	0.017	10	16	15.1	2.0	0.9
45	4.8	44.4	2.4	0.019	13	20	18.1	1.5	1.1
55	3.9	42.6	1.8	0.022	16	25	20.5	1.1	1.3
75	2.9	39.8	2.8	0.027	22	34	24.8	0.7	1.5
95	2.3	37.6	2.2	0.032	28	43	28.6	0.5	1.7
120	1.8	34.9	2.8	0.040	36	54	34.0	0.3	2.0
150	1.4	33.1	1.8	0.038	45	68	37.8	0.2	2.2
200	1.1	30.9	2.2	0.049	60	90	43.1	0.1	2.5
260	0.82	29.0	1.9	0.061	78	117	48.1	0.1	2.8
350	0.61	26.9	2.1	0.078	105	158	54.0	0.0	3.1
430	0.50	25.5	1.4	0.093	128	194	58.3	0.0	3.4
550	0.39	23.9	1.6	0.114	164	248	63.5	0.0	3.7
725	0.30	22.1	1.7	0.144	217	327	69.5	0.0	4.1
925	0.23	20.6	1.5	0.178	276	417	75.1	0.0	4.5
1200	0.18	18.9	1.6	0.226	358	541	81.5	0.0	5.1
1550	0.14	17.4	1.6	0.284	463	699	88.1	0.0	6.0
2000	0.11	16.0	1.4	0.350	597	902	94.1	0.0	7.3
2600	0.08	14.7	1.3	0.431	777	1173	100.0	0.0	15.0
3350	0.06	13.3	1.4	0.541	1001	1511	100.0	0.0	15.0
4300	0.05	12.2	1.1	0.657	1284	1939	100.0	0.0	15.0
5550	0.04	11.3	0.9	0.779	1658	2503	100.0	0.0	15.0
7200	0.03	10.6	0.7	0.892	2151	3247	100.0	0.0	15.0
9300	0.02	10.2	0.4	0.985	2778	4194	100.0	0.0	15.0

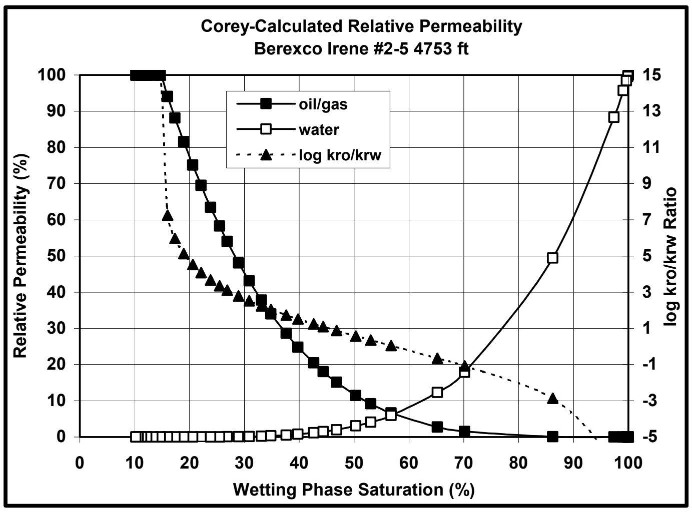
All Hg calculations assume air-mercury T=484 dyne/cm, contact angle=140deg.

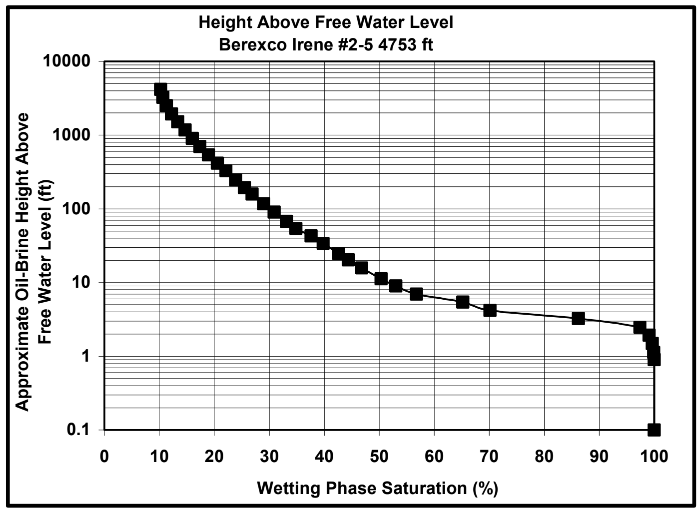
Oil/Gas-Brine Pc assumes insitu o/g-brine Tcos0=	47.00	21.00	dynes/cm
Oil/gas-Brine height assumes o/g density gradient =	0.0476	0.3464	psi/ft
Oil/gas-Brine height assumes brine density gradient =	0.4720	0.4720	psi/ft
Swi assumed for relative permeability =	14.7	14.7	%
In situ Gas/Oil & Brine Density (g/cc)=	0.110/0.80	1.09	g/cc

Mercury Injection Capillary Pressure Analysis
Berexco Irene #2-5 4753 ft









Mercury Injection Capillary Pressure Analysis
Berexco Irene #2-5 4761.3 ft

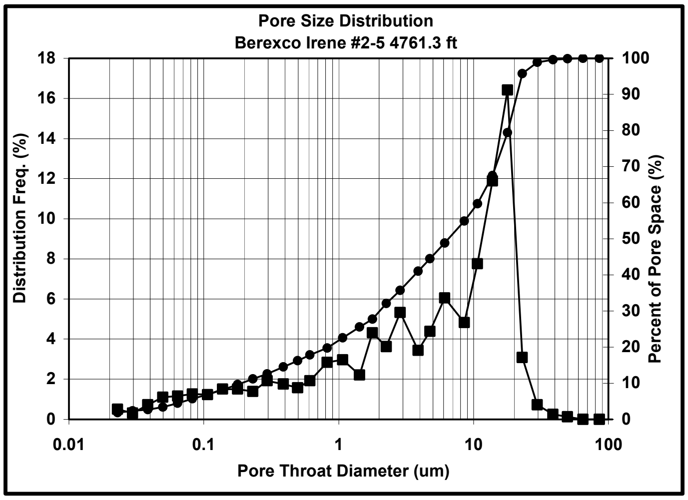
In situ Klinkenberg Permeability = 127md
In situ Porosity = 22.5%

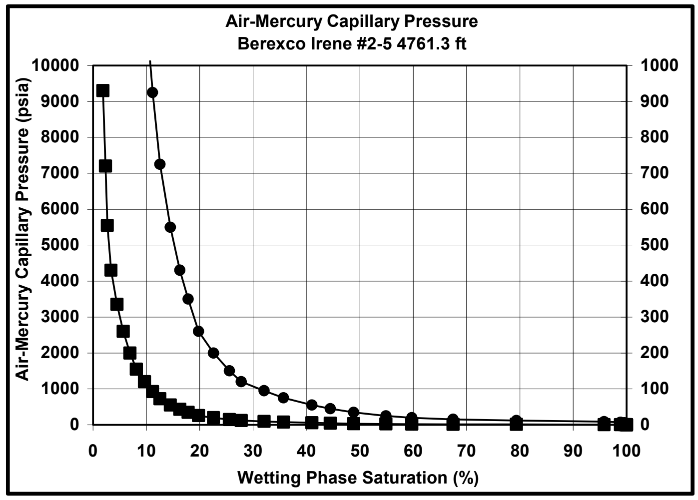
Mercury Injection Capillary Pressure (psia)	Approx. Pore Entry Diameter (um)	Cumulative Wetting Phase Saturation (% pore vol)	Pore Size Distri-bution Fre-quency	Cumula-tive Surface Area (m2/g)	Approx. Gas-Water Height Above Free Water Level (ft)	Approx. Oil-Water Height Above Free Water Level (ft)	Corey-Calculated Drainage: Oil or Gas Relative Permea-bility (%)	Corey-Calculated Drainage: Water Relative Permea-bility (%)	Corey-Calculated Drainage: Log Oil/Brine Kro/Krw Ratio
		100.0	0.0	0.000	0.1	0.1	0.0	100.0	-5.0
2.0	107	100.0	0.0	0.000	0.6	0.9	0.0	100.0	-5.0
2.5	86	100.0	0.0	0.000	0.7	1.1	0.0	100.0	-5.0
3.3	65	100.0	0.0	0.000	1.0	1.5	0.0	100.0	-5.0
4.3	50	99.9	0.1	0.000	1.3	1.9	0.0	99.5	-5.0
5.5	39	99.6	0.3	0.000	1.6	2.5	0.0	98.4	-5.0
7.2	30	98.9	0.7	0.000	2.2	3.2	0.0	95.4	-5.0
9.3	23	95.8	3.1	0.001	2.8	4.2	0.0	83.4	-5.3
12.0	18	79.4	16.4	0.005	3.6	5.4	0.2	37.3	-2.2
15.5	14	67.5	11.9	0.008	4.6	7.0	1.4	18.5	-1.1
20	11	59.7	7.8	0.011	6.0	9.0	3.3	10.8	-0.5
25	8.6	54.9	4.8	0.014	7.5	11.3	5.2	7.4	-0.2
35	6.1	48.9	6.1	0.018	10	16	8.6	4.4	0.3
45	4.8	44.5	4.4	0.022	13	20	12.0	2.9	0.6
55	3.9	41.0	3.4	0.026	16	25	15.3	2.0	0.9
75	2.9	35.7	5.3	0.033	22	34	21.6	1.0	1.3
95	2.3	32.1	3.6	0.040	28	43	26.9	0.6	1.6
120	1.8	27.8	4.3	0.051	36	54	34.4	0.3	2.1
150	1.4	25.6	2.2	0.047	45	68	38.8	0.2	2.3
200	1.1	22.6	3.0	0.059	60	90	45.3	0.1	2.6
260	0.82	19.8	2.8	0.073	78	117	52.3	0.0	3.0
350	0.61	17.8	1.9	0.086	105	158	57.6	0.0	3.3
430	0.50	16.3	1.6	0.100	128	194	62.1	0.0	3.6
550	0.39	14.5	1.8	0.119	164	248	67.5	0.0	3.9
725	0.30	12.6	1.9	0.147	217	327	73.8	0.0	4.4
925	0.23	11.2	1.4	0.172	276	417	78.6	0.0	4.8
1200	0.18	9.7	1.5	0.208	358	541	84.1	0.0	5.4
1550	0.14	8.2	1.5	0.254	463	699	89.8	0.0	6.3
2000	0.11	6.9	1.2	0.303	597	902	94.8	0.0	7.5
2600	0.08	5.7	1.3	0.368	777	1173	100.0	0.0	15.0
3350	0.06	4.5	1.2	0.445	1001	1511	100.0	0.0	15.0
4300	0.05	3.4	1.1	0.539	1284	1939	100.0	0.0	15.0
5550	0.04	2.7	0.7	0.619	1658	2503	100.0	0.0	15.0
7200	0.03	2.4	0.3	0.664	2151	3247	100.0	0.0	15.0
9300	0.02	1.8	0.5	0.756	2778	4194	100.0	0.0	15.0

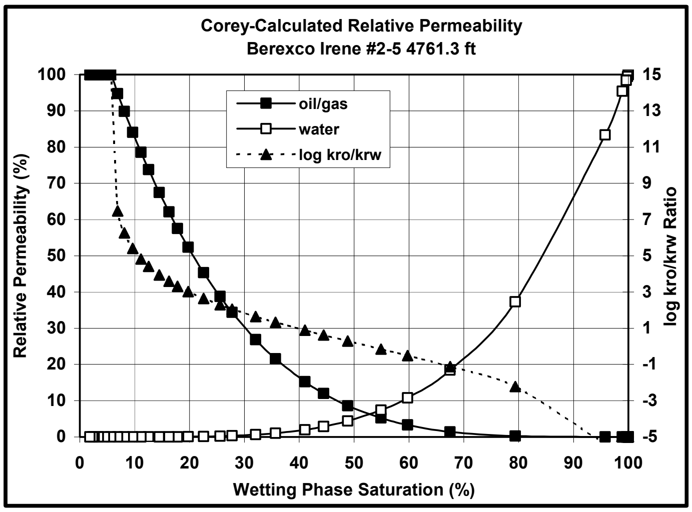
All Hg calculations assume air-mercury T=484 dyne/cm, contact angle=140deg.

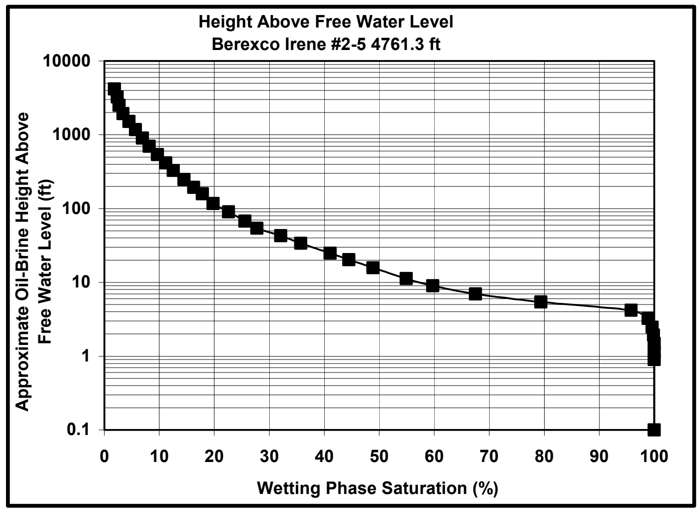
Oil/Gas-Brine Pc assumes insitu o/g-brine Tcos0=	47.00	21.00	dynes/cm
Oil/gas-Brine height assumes o/g density gradient =	0.0476	0.3464	psi/ft
Oil/gas-Brine height assumes brine density gradient =	0.4720	0.4720	psi/ft
Swi assumed for relative permeability =	5.7	5.7	%
In situ Gas/Oil & Brine Density (g/cc)=	0.110/0.80	1.09	g/cc

Mercury Injection Capillary Pressure Analysis
Berexco Irene #2-5 4761.3 ft









Mercury Injection Capillary Pressure Analysis
Berexco Irene #2-5 4766.3 ft

In situ Klinkenberg Permeability = 10.5md
In situ Porosity = 10.3%

Mercury Injection Capillary Pressure (psia)	Approx. Pore Entry Diameter (um)	Cumulative Wetting Phase Saturation (% pore vol)	Pore Size Distri-bution Fre-quency	Cumula-tive Surface Area (m2/g)	Approx. Gas-Water Height Above Free Water Level (ft)	Approx. Oil-Water Height Above Free Water Level (ft)	Corey Calculated: Oil or Gas Relative Permea-bility (%)	Corey Calculated: Water Relative Permea-bility (%)	Corey Calculated: Log Oil/Brine Kro/Krw Ratio
		100.0	0.0	0.000	0.1	0.1	0.0	100.0	-5.0
2.0	107	100.0	0.0	0.000	0.6	0.9	0.0	100.0	-5.0
2.5	86	100.0	0.0	0.000	0.7	1.1	0.0	100.0	-5.0
3.3	65	99.6	0.5	0.000	1.0	1.5	0.0	97.6	-5.0
4.3	50	99.0	0.5	0.000	1.3	1.9	0.0	94.7	-5.0
5.5	39	98.4	0.6	0.000	1.6	2.5	0.0	91.9	-6.7
7.2	30	96.1	2.3	0.000	2.2	3.2	0.0	80.8	-5.0
9.3	23	90.5	5.7	0.001	2.8	4.2	0.0	57.7	-3.3
12.0	18	86.3	4.1	0.001	3.6	5.4	0.1	44.2	-2.6
15.5	14	82.7	3.7	0.001	4.6	7.0	0.3	34.5	-2.1
20	11	79.5	3.2	0.002	6.0	9.0	0.6	27.4	-1.7
25	8.6	76.9	2.6	0.002	7.5	11.3	0.9	22.4	-1.4
35	6.1	72.2	4.7	0.003	10	16	2.0	15.3	-0.9
45	4.8	68.6	3.7	0.005	13	20	3.2	11.0	-0.5
55	3.9	65.9	2.6	0.006	16	25	4.4	8.6	-0.3
75	2.9	61.9	4.0	0.008	22	34	6.9	5.6	0.1
95	2.3	58.6	3.3	0.010	28	43	9.7	3.8	0.4
120	1.8	54.4	4.1	0.014	36	54	14.2	2.2	0.8
150	1.4	52.3	2.1	0.012	45	68	17.0	1.6	1.0
200	1.1	48.7	3.6	0.018	60	90	22.7	0.9	1.4
260	0.82	45.7	3.0	0.023	78	117	28.6	0.5	1.7
350	0.61	42.7	3.0	0.031	105	158	35.5	0.3	2.1
430	0.50	40.6	2.1	0.037	128	194	41.0	0.2	2.4
550	0.39	38.1	2.5	0.047	164	248	48.3	0.1	2.8
725	0.30	35.3	2.8	0.062	217	327	57.7	0.0	3.3
925	0.23	33.0	2.2	0.077	276	417	66.1	0.0	3.8
1200	0.18	30.6	2.5	0.098	358	541	76.3	0.0	4.6
1550	0.14	29.0	1.6	0.116	463	699	83.4	0.0	5.3
2000	0.11	27.5	1.5	0.138	597	902	90.9	0.0	6.5
2600	0.08	25.7	1.8	0.171	777	1173	100.0	0.0	15.0
3350	0.06	24.0	1.7	0.212	1001	1511	100.0	0.0	15.0
4300	0.05	23.0	1.0	0.244	1284	1939	100.0	0.0	15.0
5550	0.04	22.5	0.5	0.264	1658	2503	100.0	0.0	15.0
7200	0.03	21.4	1.1	0.319	2151	3247	100.0	0.0	15.0
9300	0.02	21.2	0.2	0.336	2778	4194	100.0	0.0	15.0

All Hg calculations assume air-mercury T=484 dyne/cm, contact angle=140deg.

Oil/Gas-Brine Pc assumes insitu o/g-brine Tcos0=	47.00	21.00	dynes/cm
Oil/gas-Brine height assumes o/g density gradient =	0.0476	0.3464	psi/ft
Oil/gas-Brine height assumes brine density gradient =	0.4720	0.4720	psi/ft
Swi assumed for relative permeability =	25.7	25.7	%
In situ Gas/Oil & Brine Density (g/cc)=	0.110/0.80	1.09	g/cc

Mercury Injection Capillary Pressure Analysis
Berexco Irene #2-5 4766.3 ft