Analysis of Core Data—Kinder Morgan SU 228-4A (2011)

F. Jerry Lucia
Bureau of Economic Geology

The Kinder Morgan SU 228-4A well, located in the south part of Sacroc field, Scurry County, Texas, was cored between the depths of 6,989 and 7,009 ft. The basic objective for this study is to describe the saturation profile in the bottom Sacroc reservoir. In other words, is there a transition zone or a residual oil zone (ROZ) at the base?

Core Analysis

Porosity and permeability were measured on core plugs, and a cross-plot of the results is illustrated in figure 1. The core was slabbed and a basic core description prepared (fig. 2). The core is mainly a fossil wackestone with two thick beds and one thin bed of grain-dominated packstone (gdp) and one debris-flow interval. Some of the wackestone is highly stylolitized with associated tension gashes. Gdp beds are interpreted to be grain flows into deep-water muddy sediment. Thin sections were prepared from the ends of the core plugs; however, they are of poor quality and only a basic description was done to validate the core description.

The porosity permeability cross-plot (fig. 1) shows that permeable class 2 gdp's plot in the class 2 field, but permeable class 3 fossil wackestones plot in and to the left of the class 1 field. The presence of tension gashes and stylolites provides the permeability that results in class 3 wackestones plotting in the class 1 rather than in the class 3 field. Samples of the gdp's and most of the samples from the debris flow either plot in the class 2 field or have less than 0.1 md permeability.

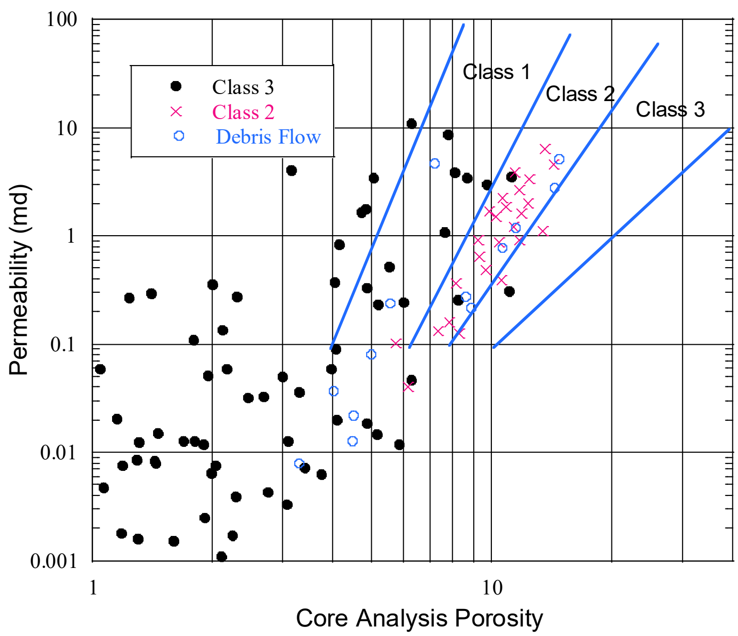

Figure 1. Cross-plot of porosity and permeability showing petrophysical class fields and rock fabric petrophysical class of samples.

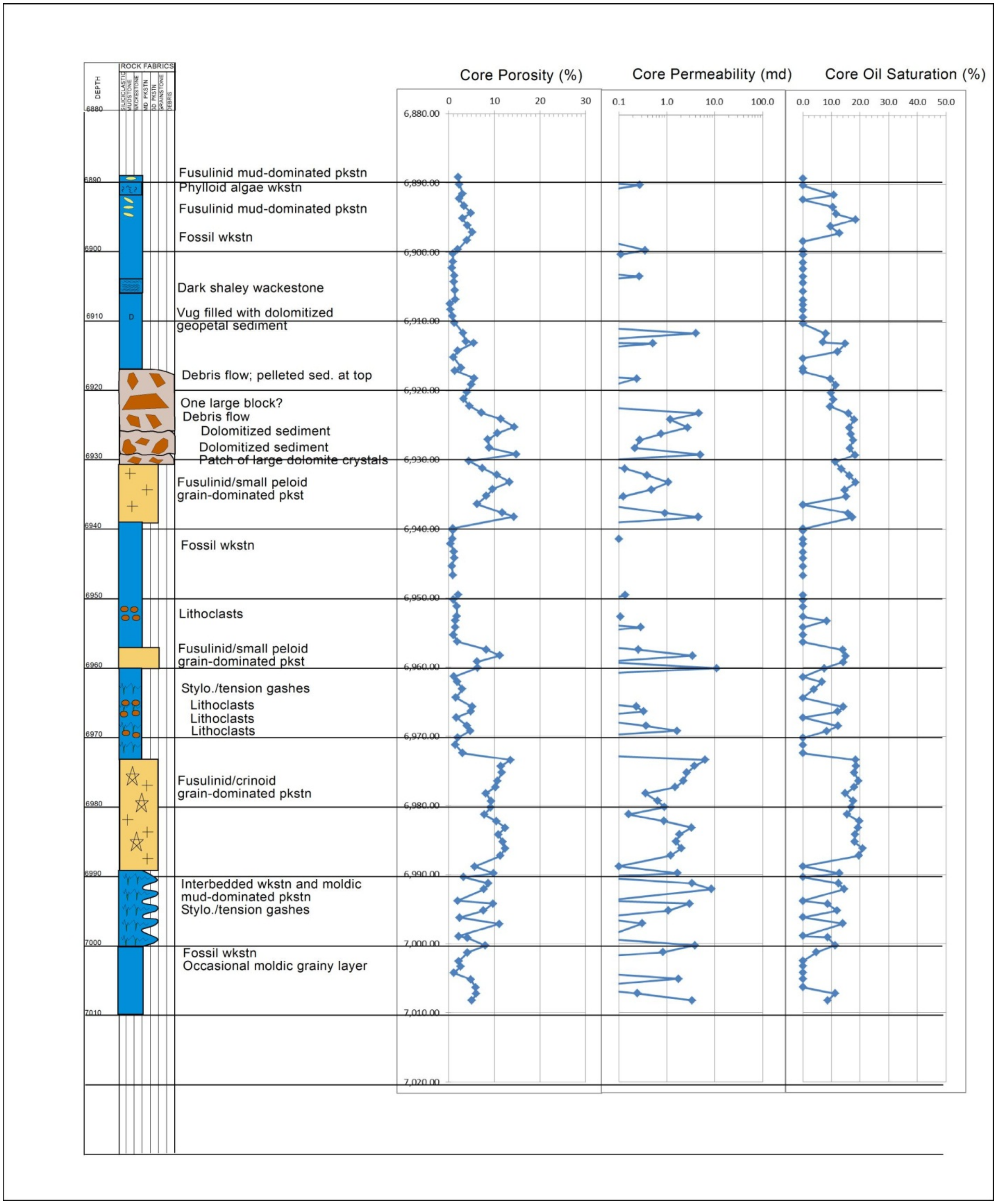

Figure 2. Geologic core description and plot of core analysis data.

Mercury Capillary-Pressure Analysis

Capillary-pressure measurements were made on selected samples to aid in determining whether the base of the reservoir is a transition zone or an ROS. Permeable samples that plot in the class 2 and 1 fields were selected for analysis. Core and thin-section observations show that samples plotting in the class 2 field are mostly class 2, gdp's. Six samples were selected, three from each thick, porous interval with high and low porosity (table 1).

Table 1. Samples that plot in the class 2 field.

Depth	*KH*	*Porosity*	*So*	*Rock*
ft	*mD*	*%*	*%*	*Fabric*
Upper Porous Zone				
6926.2	0.7694	10.63	16.8	Gdp (debris flow)
6935.2	0.1248	8.29	15.1	Gdp
6938.3	4.54	14.31	17.3	Gdp
Lower Porous Zone				
6976.5	2.24	10.65	19.4	Gdp
6978.2	0.3592	8.14	14.8	Gdp
6983.2	3.32	12.41	19.3	Gdp

Similarly, four samples were selected that plot in the class 1 field, two from an upper interval with low porosity and two from a lower interval with high porosity (table 2). Core and thin-section observations show these samples to be fossil wackestones with thin beds of moldic grain- to mud-dominated packstones, stylolites, and tension-gash fractures.

Table 2. Samples that plot in the class 1 field.

Depth ft	*KH mD*	*Porosity %*	*So %*	*Rock Fabric*
Upper Stylolitic Zone				
6966.4	0.3291	4.88	12.2	Sty wkstn
6968.5	0.375	4.05	12.3	Sty wkstn
Lower Stylolitic Zone				
6991.2	3.4	8.69	12.5	Sty wkstn
7000.2	3.89	8.07	11.3	Sty wkstn

The two sets of mercury injection capillary pressure data (MICP) are distinctly different because the fabrics are distinctly different. Samples plotting in the class 1 field are fractured, moldic, class 3 wackestones. The MICP curves have a nonmatrix character with high water saturation despite acceptable permeability values (fig. 3). Permeability is related to stylolites and open tension-gash fractures. The high porosity is related to grain molds. There is no apparent relationship between porosity and saturation. Importantly, the curves show no traditional transition zone but a gradual decrease in water saturation (Sw) with increasing pressure.

Samples plotting in the class 2 field are class 2, grain-dominated packstones. One sample is from debris flow. The curves are typical for matrix porosity (fig. 4). The highest porosity samples (average 12% porosity) have lower entry pressures than the lowest porosity samples (average 9% porosity), indicating a direct relationship between porosity and saturation.

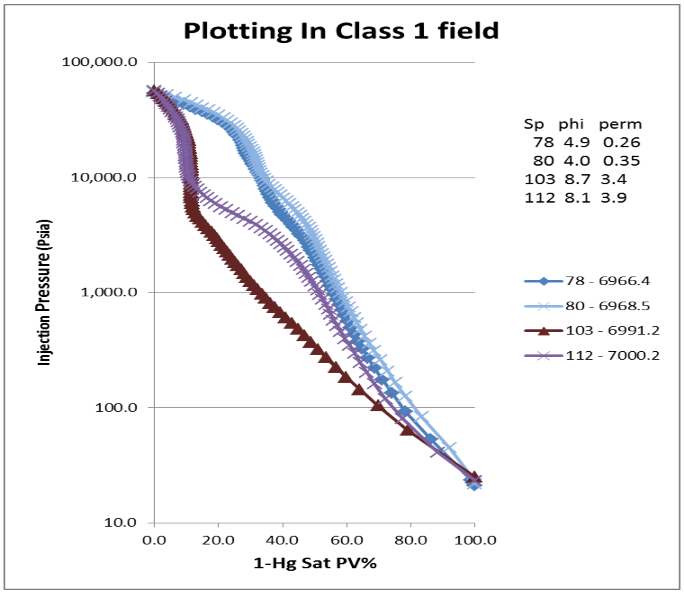

Figure 3. Mercury injection capillary pressure curves for class 3, fractured and moldic wackestones that plot in the class 1 field.

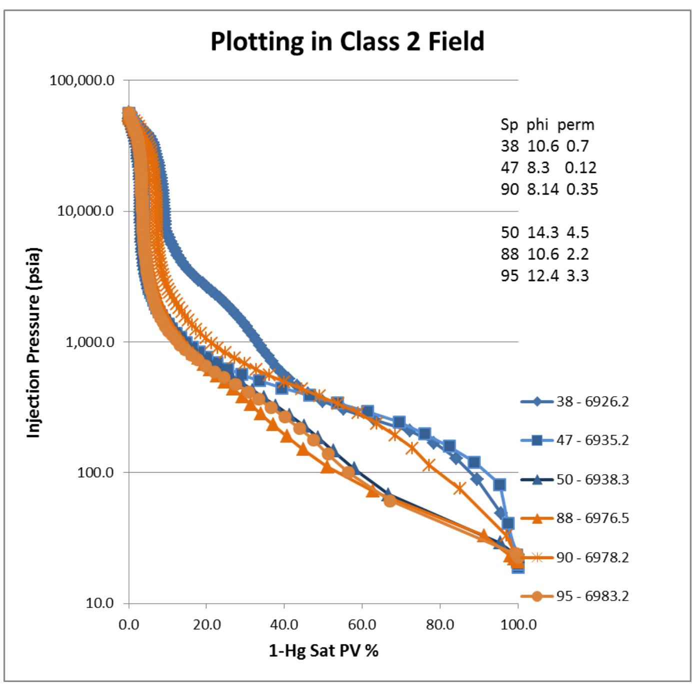

Figure 4. Mercury injection capillary pressure curves for class 2, grain-dominated packstones that plot in the class 2 field.

Water Saturation from Wireline Logs

Water saturation (Sw) was calculated from wireline logs by Jeff Kane of Kinder Morgan (fig. 5). The lower porosity zone has an average Sw of about 80%. Oil saturation from core analysis averages 18%, suggesting that it is in the oil zone (fig. 2). Water saturation in the upper zone is split into an upper interval with an average Sw of about 50% and a lower interval with an Sw of about 80%, although the porosity is higher. Oil saturation from core analysis is constant over the interval and averages 14% (fig. 2). The sharp change in Sw from 50% to 80% is not consistant with the gradual changes observed in the capillary-pressure curves and cannot be explained by a reduction in porosity or a change in rock fabric.

MICP curves were compared with Sw from wireline logs. Injection pressure was converted to reservoir height by Weatherford using fluid densities, surface tension, and contact angle similar to field values (table 3). Three height curves from the lower porous interval are displayed in figure 6. They vary according to porosity, and the more porous samples display a traditional transition zone. However, the Sw from log analysis is relatively constant at 80%, suggesting no systematic change in Sw, as expected from a traditional transition zone. Similarly, the three curves from the upper porous zone vary according to porosity, and the more porous samples again display traditional transition zones (fig. 7). These data do not support the abrupt change in Sw calculated by log analysis.

Table 3. Conversion data used by Weatherford to convert MICP to reservoir height.

System Tested:	**Air-Mercury**		Conversion System :	**Water-Oil**	
Interfacial Tension:	480	dyne/cm.	Interfacial Tension:	30	dyne/cm.
Contact Angle:	140	deg.	Contact Angle:	30	deg.
Water Density:	65.6	lbs/ft3	Conversion Constant (Pc):	14.15	Plab/Pres
Oil Density:	41.9	lbs/ft3	Conversion Constant (h):	6.10	

Conclusions

These observations can best be explained by imbibition curves rather than drainage curves. Unfortunately, no imbibition curves are available for this core. Imbibition curves, however, typically have an abrupt change in saturation at zero capillary pressure (zcp), with an interval of residual oil beneath. It is suggested that the abrupt Sw change in the upper porous zone at a subsea depth of –4,569 ft most likely marks the current zcp level, and oil saturation found in the core and calculated from wireline logs below this level is residual oil (fig. 8).

The location of the original zcp level is difficult to determine from these core data because of the lack of significant matrix porosity below the lower porous zone. However, the presence of oil saturation at the base of the core suggests an original zcp level below the base of the core. Capillary-pressure curves are not definitive because only about 15 ft of 50% Sw is available for comparison.

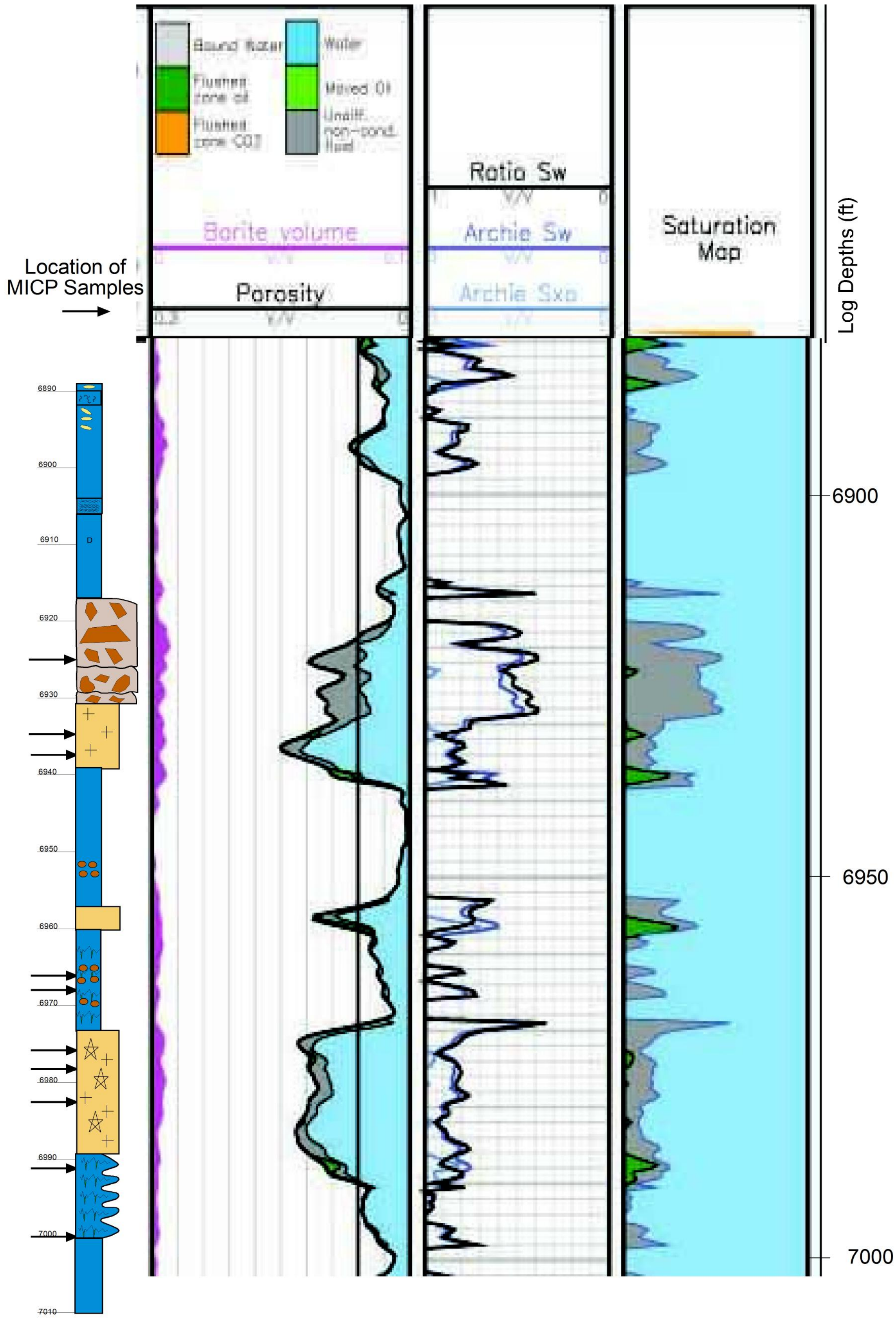

Figure 5. Log-calculated water saturation by Jeff Kane, Kinder Morgan, and core description showing an abrupt increase in Sw within the upper porous zone.

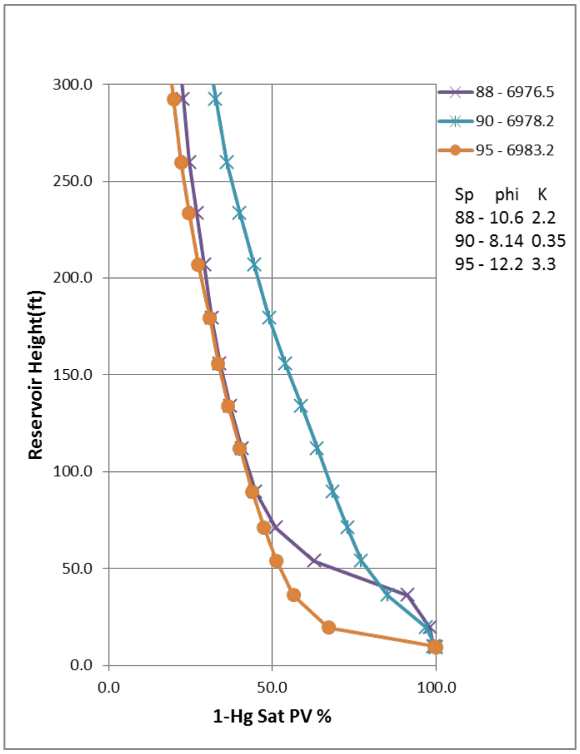

Figure 6. MICP curves for lower porous interval converted to reservoir height.

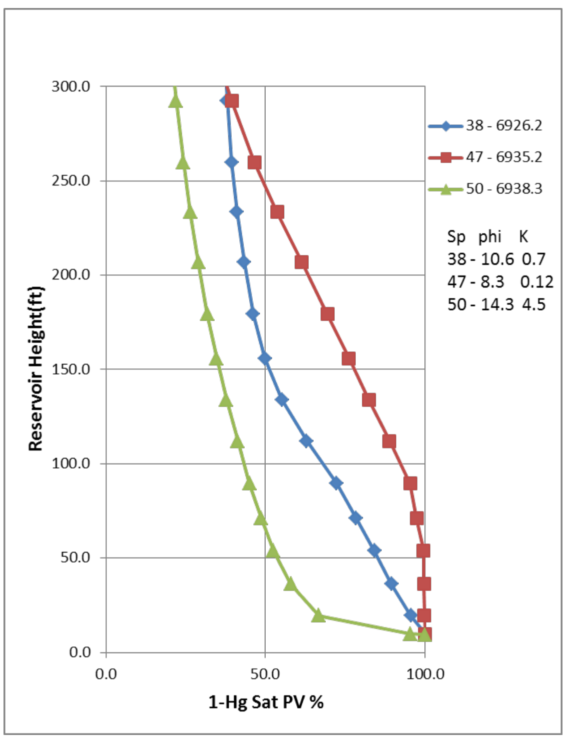

Figure 7. MICP curves for upper porous interval converted to reservoir height. Sample 38 at 6,926.2 ft depth is from the debris flow.

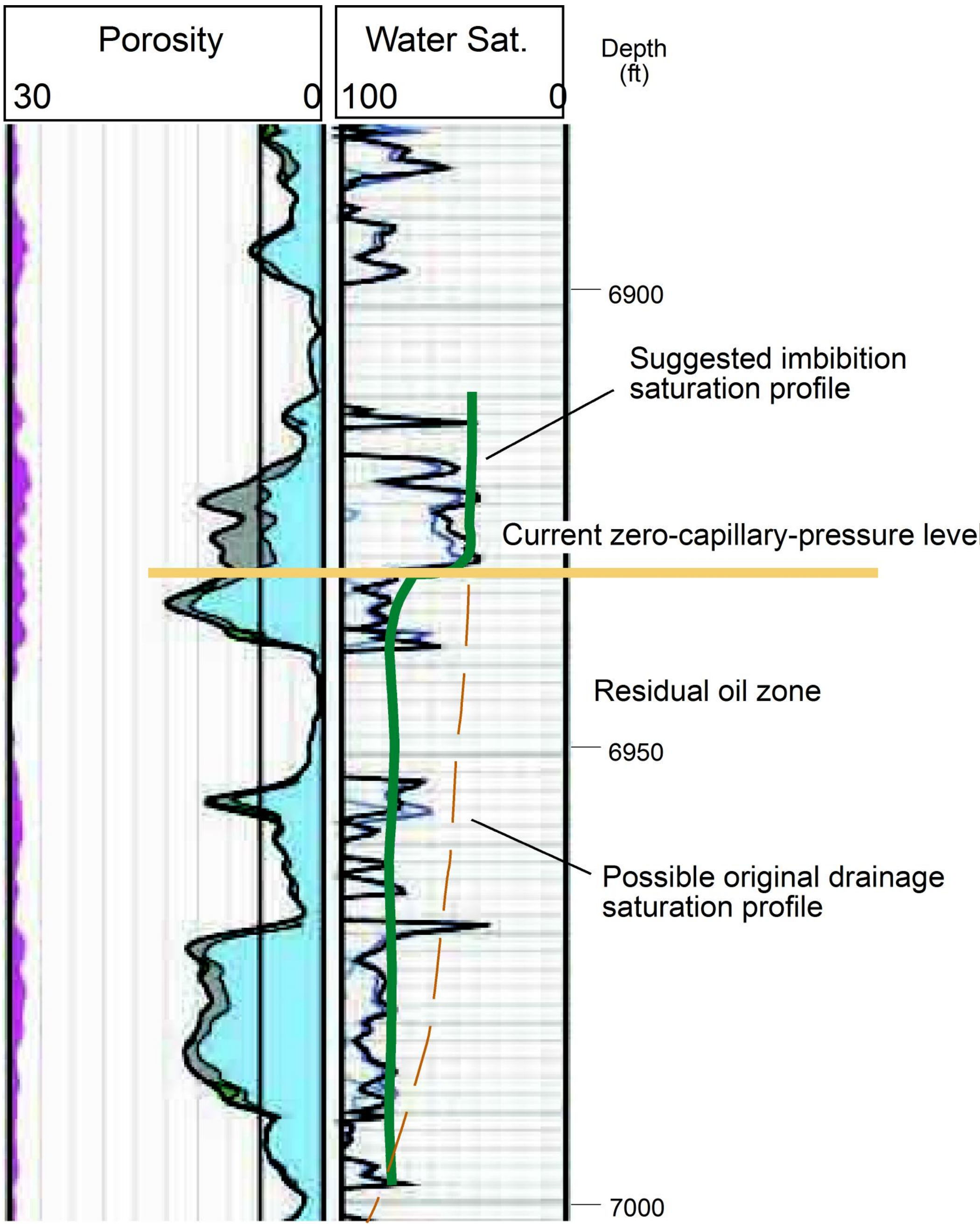

Figure 8. Suggested saturation model.