BUILDING OF A GEOLOGIC MODEL OF A FIELD IN THE SLAUGHTER AREA, WEST TEXAS

Rajesh Ramachandran, Teddy Oetama, George Asquith,
Seguntayo Ogunsanya and Lloyd Heinze
Texas Tech University

ABSTRACT

Detailed study of a field in the Slaughter area of Hockley County resulted in increased original-oil-in-place (OOIP) as compared to an earlier estimate from an internal company report (1975). An important aspect of the study was the inclusion of well logs drilled after the earlier estimate of OOIP. Log-core transforms for Compensated Neutron Logs (CNL) and Sidewall Neutron Logs (SNP) and Sonic logs were constructed. Three Old Neutron (ON) logs were normalized to improve the spatial control of the field. The normalization of the ON logs involved the correlating of the ON log data to a modern neutron log (CNL/SNP). Availability of more data made it feasible to obtain more accurate reservoir parameters for the field that was developed in 1930's.

This paper describes the methodology involved in the construction of the geologic model to calculate the net pay, average reservoir porosity, permeability and water saturation. The OOIP was calculated using the isovolume and parametric averaging methods. The OOIP was increased by two folds from the earlier estimate but only 63% of the OOIP was movable.

INTRODUCTION

The field is located in the Slaughter area of Hockley County, Texas. The area of interest comprises of approximately 2,000 acres and produces from the San Andres formation. The field has been producing from 1939 with a dominant solution gas drive. The field is currently on waterflood after 30 years of primary production. Reservoir parameters were calculated for 21 wells with SNP, 18 wells with CNL, 3 wells with ON logs normalized to modern neutron logs, and 2 Sonic logs (SL).

GEOLOGIC MODEL

Correlation of Producing Zones

A type log was selected in the middle of the field. The tops for the producing zones were correlated using the type log. All the wells showed excellent stratigraphic correlations. A grid of eight North-South (N-S) and East-West (E-W) cross-sections was constructed for the entire field. Three main producing zones: Zone 1, 2, and 3, were identified (see Fig.1).

CNL, SNP, Sonic Log to Core Porosity Transform

Log porosity-core porosity transforms were constructed for CNL, SL and SNP logs. Core porosity data was plotted versus log porosity for wells having core data. Depth shifting of core data to match the log data was done electronically. The data was shifted up to ± 7 ft and the best fit (i.e., the highest coefficient of correlation, R^2) was selected to construct the transforms. Depth shifting was done within intervals of a well so as to match the data as accurately as possible. Before using the log porosity to core porosity transforms, anhydrite zones were examined on hard copies of the logs for each well, and if the log porosity was not 0%, the log data was shifted to 0%. Three-foot running average was used for both log and core porosities. The transforms and the R^2-values for the CNL, SL and SNP logs are shown in Figs. 2, 3, and 4.

Normalization of ON Logs to Modern Logs

Three wells with ON logs were normalized to modern neutron logs to obtain additional map control. Wells with the modern neutron logs near to the ON logs were used for the normalization.

The casing point was obtained for the ON log well. The maximum and minimum neutron counts above and below the casing were read from the well log. The corresponding maximum and minimum porosity readings above and below the casing were determined from the modern log well. The normalized porosity is then calculated from the equation,

$$\phi_N = [m \cdot \log(NEU)] \pm B \qquad \text{..... (1)}$$

The values for m and B were determined from the equations,

$$m = \frac{\phi_{N\,\max} - \phi_{N\,\min}}{\log(NEU_{\min}) - \log(NEU_{\max})} \qquad \text{..... (2)}$$

$$B = \phi_{N\,\max} - [m \cdot \log(NEU_{\min})] \qquad \text{..... (3)}$$

The normalized Old Neutron logs were then calibrated to core data using the log porosity to core porosity transforms.

Permeability Determination

Wells with core data were studied for developing the porosity-permeability correlations. The well data were separated by zones identified from the tops correlated for each well. The core data was combined for the wells selected and the core porosity was plotted versus the core permeability. Fig. 5 shows the porosity-permeability plot by zone. The transform equations obtained from the plot are as follows:

Zone 1: $k = 0.0452\ e^{0.2588\,\phi_k}$ .... (4)

Zone 2: $k = 0.0591\ e^{0.2654\,\phi_k}$ ....(5)

Zone 3: $k = 0.0519\ e^{0.2781\,\phi_k}$ ….(6)

Net Pay Calculation

The porosity cutoff to calculate the net pay was selected from the core porosity-permeability correlations. In the Slaughter area, the minimum permeability for the flow of oil is 0.3 md[1]. So the porosity corresponding to the 0.3 md permeability was selected as the porosity cutoff. From the core porosity-core permeability transforms a porosity cutoff of 6% was selected. From Fig. 5 it can be observed that for Zone 2 the porosity cutoff is 6% and for Zone 1 the porosity cutoff is 7%. Since Zone 3 also is closer to 6%, a porosity cutoff of 6% was then chosen for all the zones. Bureau of Economic Geology (1983)[1] in a study of Northern Shelf Permian Carbonate used a similar porosity cutoff value.

Determination of Water Saturation

From the logs, it was determined that zones 1 and 2 were at irreducible water saturation. So the average Bulk Volume Water (BVW) method was used to calculate the water saturation using the equation,

$$S_w = \frac{BVW}{\phi} \cdot 100 \qquad \text{... (7)}$$

The value of BVW of 0.029 for the Slaughter area was obtained from Galloway and others[1]. The water saturation was calculated using the core calibrated porosity at every half-foot interval.

A subsea depth of the Oil-Water Contact (OWC) in the field was indicated to be -1450 ft on several well logs. The OWC is in Zone 3 and the water saturation was determined by Lucia[2] method for this zone. Based on the porosity-permeability cross-plots of the core data, Zone 3 was classified as Class 2 carbonate (crystal size 20µm – 100µm). The Lucia water saturation equation for the Class 2 carbonate requires the values for the height above free water level and porosity. The water saturation was calculated from the equation,

$$S_w = 100 \cdot (0.1404 \cdot H^{-0.407}) \cdot \phi^{-1.44} \qquad \text{... (8)}$$

To justify the use of the Lucia Class 2 method for water saturation calculations in Zone 3, the average permeability calculated for the Zone 3 was compared to the estimated permeability using the Lucia - Class 2 permeability equation (see Equation 9) and the same porosity value, i.e., the average Zone 3 porosity.

$$k = 2.04 \cdot 10^6 \cdot \phi^{6.38} \qquad \ldots (9)$$

The core analysis of Zone 3 data yields 0.1133 average porosity and 1.86 md average permeability. Using the average porosity value the corresponding permeability calculated from the Equation 9 is 1.89 md, which is in agreement with the core average permeability. Therefore, the Zone 3 has to be a Class 2 carbonate reservoir with crystal size of 20 – 100 μm.

CALCULATION OF ORIGINAL OIL IN PLACE

The average net pay, porosity, permeability and water saturation was calculated for each zone. All average reservoir parameters were calculated based on a porosity cutoff of 6%. Geologic maps for the average reservoir parameters and structure maps were constructed using the APPRENTICE software. The software uses the kriging method to construct the maps. ϕh -, *kh*- and $S_o\phi h$ - maps were also constructed for each zone.

The equations used to calculate the reservoir parameters are given below.

Average net pay, $$\bar{h} = \frac{\sum h}{n} \qquad \ldots..(10)$$

Average porosity, $$\bar{\phi} = \frac{\sum \phi h}{\sum h} \qquad \ldots. (11)$$

Average permeability, $$\bar{k} = \frac{\sum kh}{\sum h} \qquad \ldots. (12)$$

Average water saturation, $$\overline{S_w} = 100 - \frac{\sum S_o\phi h}{\sum \phi h} \qquad \ldots..(13)$$

Volumetric method was used to calculate the OOIP. Two different averaging methods were used: Isovolume and Parametric Averaging. In the Isovolume method, $S_o\phi h$ - maps were constructed for each zone. The OOIP was then calculated from the equation,

$$OOIP = \sum_{j=1}^{n} \frac{\left(x \cdot y \cdot S_o\phi h\right)_j}{5.615 B_o} \qquad \ldots. (14)$$

In the Parametric Averaging method, the average reservoir parameters were calculated for each zone. The OOIP was calculated from the equation,

$$OOIP = \frac{7758 \cdot A\bar{h}\bar{\phi} \cdot (1 - \bar{S}_w)}{B_o} \qquad .... (15)$$

Zone 3 includes the oil in the transition zone and the residual oil. The OOIP calculated from Equation 14 is 79 MMSTB and from Equation 15 is 81 MMSTB (see Table 1). The values are in close comparison.

From the earlier study of this field, the OOIP was estimated approximately 40 MMstb. But the number of wells used in the study was half the number used for the current study. From this study the OOIP has been increased by two folds. From the core data the residual oil saturation (S_{or}) was determined to be 37%. Thus, the calculated moveable oil is only 50 MMstb which is 63% of the OOIP. Also, by having more wells the accuracy of the geologic model is increased. This is especially important in carbonate reservoirs because of extreme heterogeneity.

Conclusions

The tops of the three main producing zones were correlated and eight N-S and E-W cross-sections were constructed throughout the field. All the wells showed excellent stratigraphic correlations. To obtain additional well control three ON logs were normalized to modern neutron log data. The minimum permeability required for the flow of oil in the Slaughter area is 0.3 md[1]. A net pay porosity cutoff of 6% was selected based on the minimum permeability value. For Zones 1 and 2, the average BVW method was used to calculate water saturation. For Zone 3, Lucia Class 2 carbonate method was used.

The current study has more well controls; therefore, a better reservoir description. The OOIP increased by two folds from the 1975 study of the field. However, only 63% of the OOIP is moveable. With a more accurate geologic model, re-completion/drilling can be recommended for wells that are not drilled or completed in the proper zones. Also, the data generated from this study can be input to a numerical simulation model that will be used to locate in-fill drilling and define depletion strategies.

Nomenclature

$\phi_{N\max}$ = Maximum porosity from the modern log, fraction

$\phi_{N\min}$ = Minimum porosity from the modern log, fraction

$NEU_{\max}$ = Maximum neutron count from the ON log, counts

$NEU_{\min}$ = Minimum neutron count from the ON log, counts

k = Permeability, md

ϕ_k = Log porosity calibrated to core data, %

S_w = Water saturation, %

BVW = Bulk volume of water in the Slaughter area, fraction

ϕ = Log porosity calibrated to core data, fraction

H = Height above free water level, ft

$\bar{h}$ = Average net pay, ft

$\sum h$ = Sum of all cell net-pay values, ft

n = Number of cells in the geologic model

$\bar{\phi}$ = Average porosity for each zone, %

$\sum \phi h$ = Sum of all cell ϕh -values, ft

$\bar{k}$ = Average permeability, md

$\sum kh$ = Sum of all cell kh –values, md.ft

$\overline{S_w}$ = Average water saturation, %

$\sum S_o \phi h$ = Sum of all cell $S_o \phi h$ -values, ft

x, y = Cell dimensions, ft

$S_o \phi h$ = Cell $S_o \phi h$ - value, ft

B_o = Formation Volume Factor of oil, rb/stb

h = Net pay, ft

S_{wfr} = Average water saturation, fraction

A = Area, acres

REFERENCES

1. Galloway, W.E., *et.al.*, *Atlas of Major Texas Oil Reservoirs*, Bureau of Economic Geology, 1983.
2. Lucia, F.J., “Rock-fabric/Petrophysical Classification of Carbonate Pore Space for Reservoir Characterization,” *AAPG* Bulletin, 1995, v.79, no.9, 1275-1300.

Table 1
Original Oil-in-Place (OOIP) Comparison

Year	OOIP (MMstb)		Source
	Isovolume	Parametric	
1975		40	Internal company report
2003	79	81	TTU PE – Study

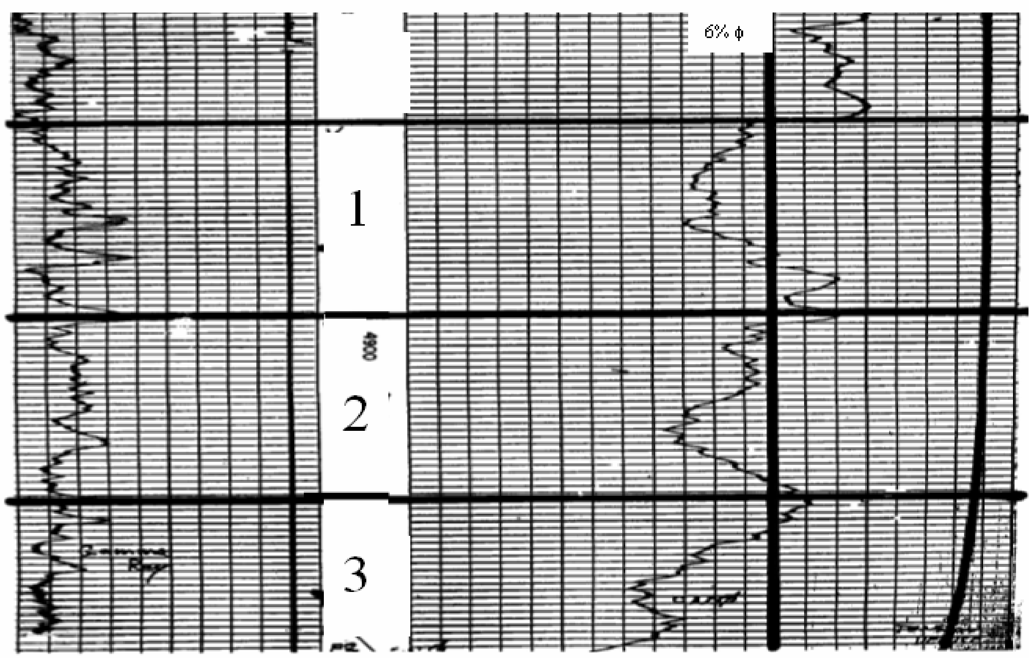

Figure 1 - Tops Correlated for the Three Main Producing Zones

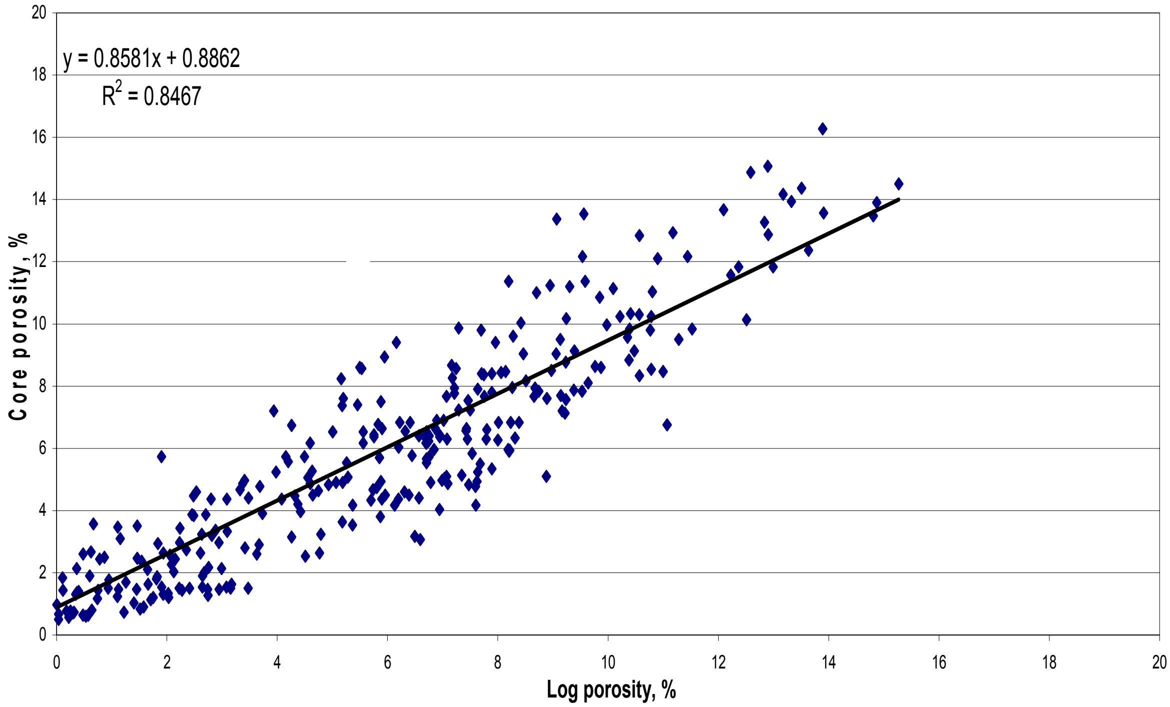

Figure 2 - Log Porosity to Core Porosity Transform, CNL Data

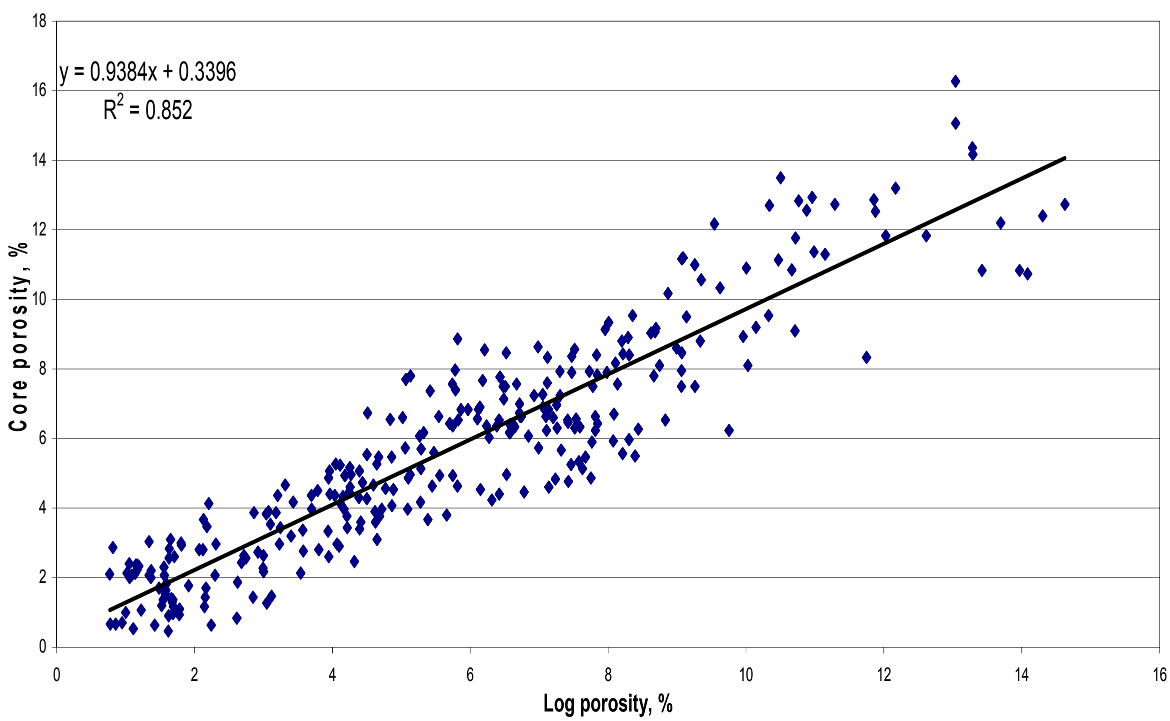

Figure 3 - Log Porosity to Core Porosity Transform, SNP Log Data

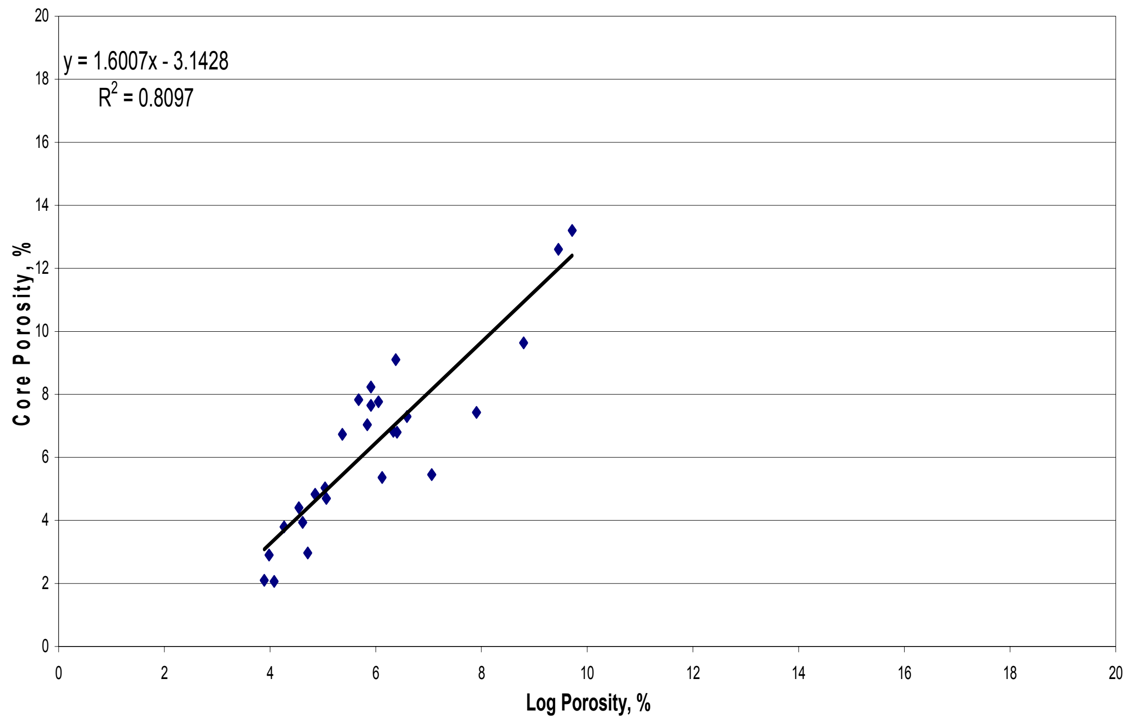

Figure 4 - Log Porosity to Core Porosity Transform, Sonic Log Data

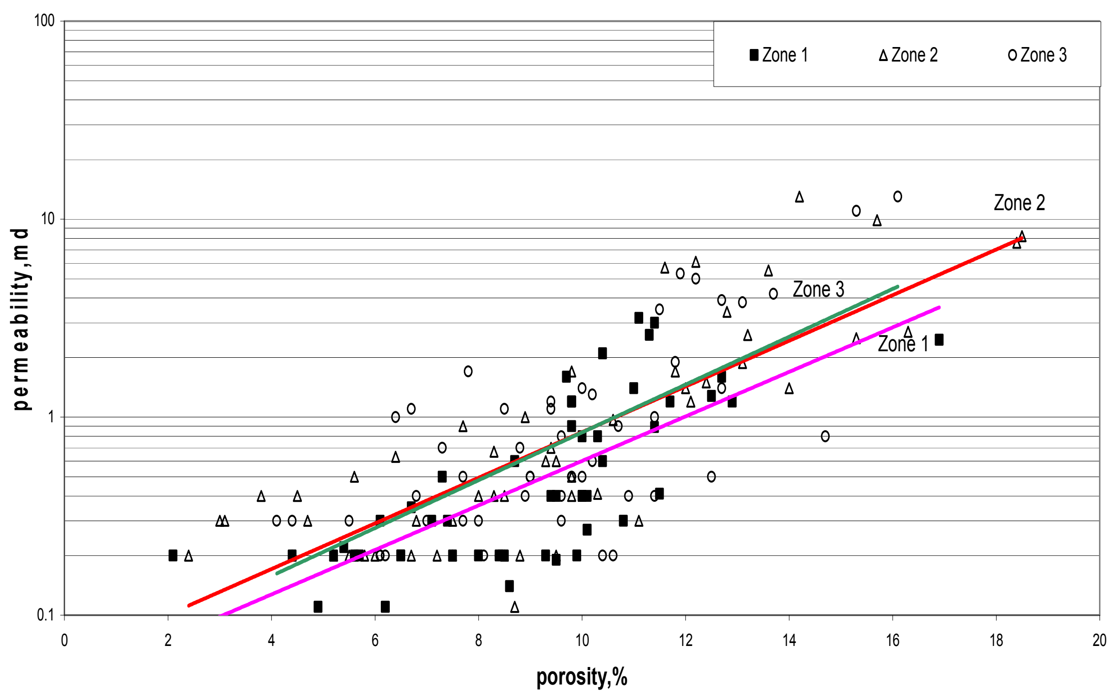

Figure 5 - Porosity-Permeability Transforms by Zone