PaperID AU205

Author **Arvind Kumar , Schlumberger , India**

Co-Authors **Siddhanta Batshas, Suraj Singh, Shivam Sharma, Shaktim Dutta**

A new workflow to model vertical interference test using petrophysical & image based rock types & flow units

Abstract

Vertical Interference tests have been used to determine the hydraulic connectivity between the formation sand intervals. Conventionally, during the interpretation of these tests, a section of reservoir sand is taken as homogenous and then properties are fed to the interference modeling, leading to over estimation or underestimation of vertical permeabilities. This paper showcases an entirely new and innovative workflow of using the petrophysical and image log attributes to characterize a heterogeneous reservoir sand by making use of ANN/SMLP based rock typing techniques as well as image based advanced sand layer computation techniques. These outputs are then fed into a vertical interference test model to determine the accurate vertical permeability values. The paper demonstrated the entire workflow through several stages of the modeling part for different geologically complex environments like channel sands, faults, naturally occurring fractures and low resistivity contrast sands. Once, this workflow has been validated on all these geological features, the impact of vertical permeability on the total oil recovery factor in a 3D numerical reservoir model has been established through a series of sensitivity analysis.

Introduction

Interference tests along with other pressure transient tests are performed in both exploratory as well as development fields in order to determine the reservoir parameters like horizontal permeability, vertical permeability, distance to boundaries, fault distances and type of reservoir. Vertical interference test is one of the pressure transient analysis which is performed mainly to confirm the hydraulic connectivity between the sand intervals and to determine the vertical permeability. This is mainly performed using a wireline formation testing tool with multiple flow probes deployed in a vertical sequence at desired depth points on the borehole wall (as shown below in Fig.1).

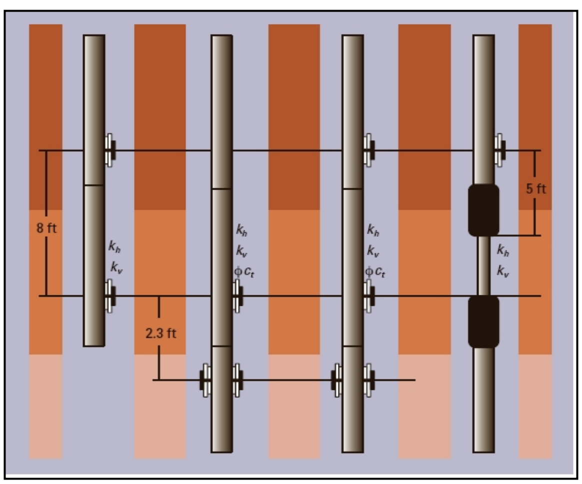

Figure 1: Formation testing: multiprobe configurations vertical interference testing.

To model the Vertical Interference Tests, a formation model with the initial estimates of the petrophysical properties like horizontal permeability, vertical permeability, porosity, sand thickness along with the fluid properties like viscosity, GOR etc. are given to the software. Based on these inputs, the software generates a pressure model curve which is then matched with the pressure transient recorded during these tests. The values corresponding to the best fit model gives the final value of all these properties.

Traditionally, the formation model being used here is considered as a homogenous model with uniform/constant petrophysical properties distributed over the entire thickness of reservoir. This conventional approach has a lot of limitations attached with it, since it didn't address the vertical heterogeneity within the reservoir thickness. Hence, overestimating the vertical permeability values since the model considers an NTG of one.

However, in cases of thin sand-shale sequences or heterogeneous reservoirs mainly in complex geological settings like channel sands, near to faults, pinch outs etc., this effect becomes critically important. In these cases a heterogeneous formation model would yield better results in comparison to the uniform, homogenous formation model (as explained in fig 2).

Sand A	**Sand A1**
	Sand A2
	Sand A3
	Shale A1
Sand B	**Shale B1**
	Sand B1
	Sand B2
	Shale B2

Fig2: A) Homogenous formation model with 2 broad sand intervals defined.; B) A fully layered heterogeneous model addresses all the available heterogeneities present within the reservoir thickness.

Rock Typing based on Petrophysical and Image logs

Rock typing is essentially a process which classifies a combined unit of formation rock into different sub-units based on their several petrophysical attributes, each of those sub-units would have been deposited under similar geological conditions and undergone similar diagenetic alterations within (Gunter et al. 1997). Each of the rock type empirically has similar porosity-permeability relationship, capillary pressure profile and saturation height models.

Different type of rock type classification workflows are available in the industry. The Artificial Neural Net and SMLP based rock typing workflows have been used in this workflow. The open hole logs required at this stage are permeability curve (from magnetic resonance logs), total and effective porosity curves, water saturation and other advanced lithology logs if available.

Amefule et.al correlated the modified Kozeny-Carmen equation and permeability-porosity relationship with the concept of mean hydraulic radius of pore throats to generate a Flow Zone indicator.

Equation 1: Reservoir Quality Index (RQI) = $0.0314 \sqrt{(K/Ø_e)}$,

Here $Ø_e$ is the effective porosity.

The reservoir quality index is plotted versus a Normalized Porosity Index (NPI) denoted as $Ø_z$, which is the ratio of pore volume to grain volume, described as below by equation 2.

Equation 2: Normalized Porosity Index, NPI ($Ø_z$) = $Ø_e/(1- Ø_e)$

A log-log plot of RQI vs NPI yields a straight line with unit slope and the intercept of the unit slope line with $Ø_z$ =1, gives the "Flow Zone Indicator" also known as FZI as described below with equation 3.

Equation 3: $\log(RQI) = \log(Ø_z) + \log(FZI)$

FZI is unique for every hydraulic flow unit. The FZI is then correlated with other petrophysical logs like saturation or core data to compute the final rock types using one of the two techniques discussed here- Artificial Neural Net based or Stratigraphic Modified Lorenz (SMLP) plot based. The minimum thickness of rock types and number of rock types are generally controlled by the user based on the model complexities or heterogeneities available in the reservoir sand.

Artificial Neural Net based Rock typing

In this technique, a regression algorithm runs which correlates the FZI plot with the other available petrophysical inputs like Water saturation, lithology information etc. to define different rock types that have similar characteristics. The distribution is mainly based on statistical distribution of input parameters analyzed in order to come up with an output i.e., rock types in this case. Once the rock types are generated, a quality check is being performed based on the petrophysical attributes like GR, Lithology curves, Image logs and saturation distribution.

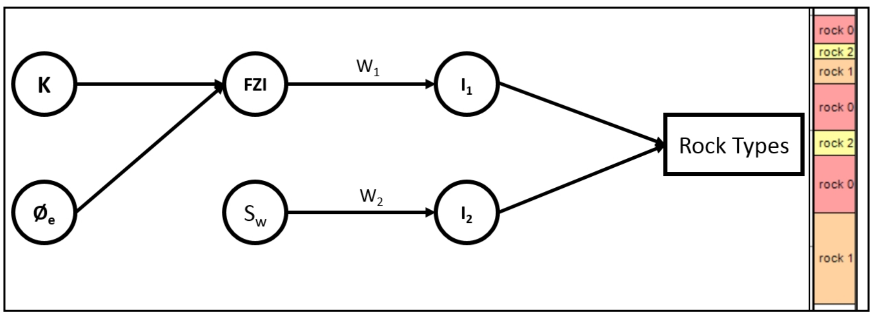

Figure 3: ANN based rock typing workflow

The rock type is then validated by studying the permeability-porosity crossplots for each rock type. In cases where a uniform relationship between the two is not observed, the rock typing process is revised by changing the weights for each of the input.

Stratigraphic Modified Lorenz (SMLP)

This technique utilizes a plot of percent flow capacity (%KH) versus percent storage capacity (% ØH) arranged in stratigraphic sequence. Flow capacity is defined as the product of permeability and thickness (KH) and the storage capacity is defined as the product of porosity and thickness. The shape of the flow capacity versus storage capacity curve indicates the flow performance of the reservoir.

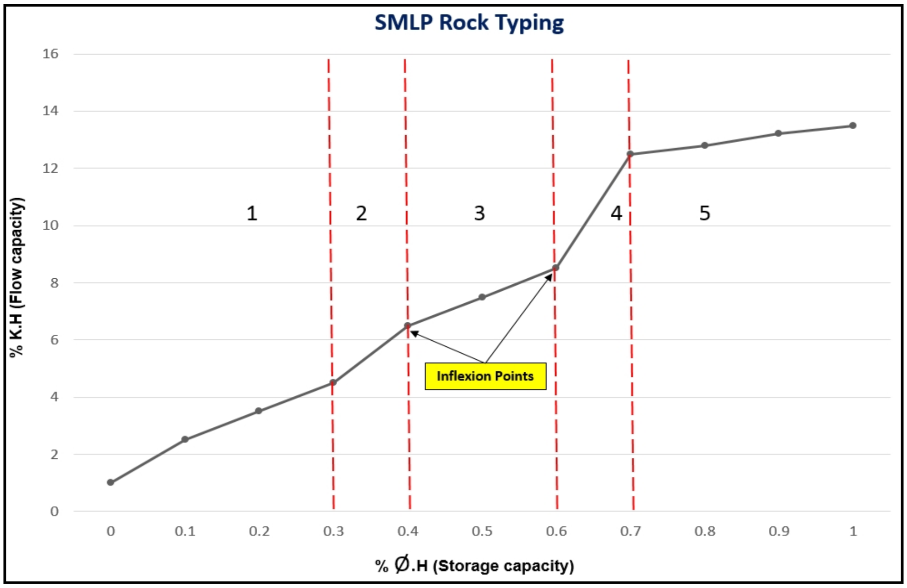

Fig 4: SMLP technique (variations in slopes correspond to different rock types)

Parts of the curve with steeper slopes indicates a greater flow capacity compared to the storage capacity, and hence a more mobile formation. These are good reservoirs compared to those reservoirs that lie in the flat part of the curve where the storage capacity is higher than the flow capacity. Sections having similar slopes are considered as single rock type, where as there is a big change of slope is considered as the boundary of two rock types.

Complex geological settings

The process was implemented for different complex geological settings like channel sands, near to fault, pinch outs, high sand-shale laminations etc.

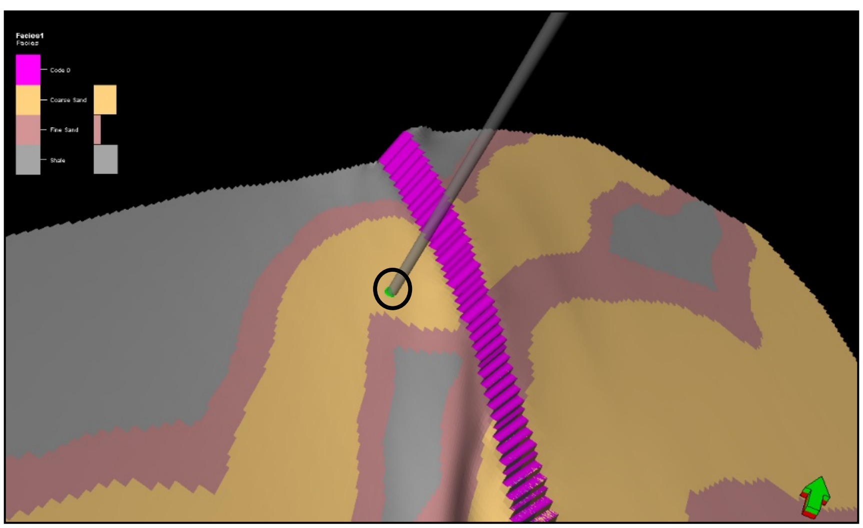

Fig 5: Lateral variations being observed in a 3D reservoir model (channel sand, near to fault)

Formation Model as an input to Vertical Interference Test Model

After the rock types have been prepared, a formation model corresponding to these rock types are prepared. The formation model contains the rock and fluid properties corresponding to each rock type which can be used as an initial estimate for the Pressure Transient Analysis (PTA) modeling.

Rock Type	Horizontal Permeability (K_h), mD	Vertical Permeability (K_v), mD	Thickness ft	Porosity	Viscosity cP	Wellbore storage coefficient (C)	Skin (S)
1	120	36	3	0.21	5.2	5 E-6	-2
2	23	2.3	4	0.19	5.1	4 E-6	-1
3	39	1.3	2	0.15	5.2	5 E-6	0
4	43	8.4	3	0.25	5.3	3 E-6	-1

Table 1: Formation model as an input for VIT modeling

Vertical Interference Tests

These tests are essentially performed to check the hydraulic connectivity within a given formation unit. It is permed using the multi-probe or packer probe configurations (Fig 1), where the pressure transients are recorded at 2 places- one at the source probe and other at the observation probe.

These pressure transients are then analyzed together with inputs from the formation mode (Table 1). A typical response of pressure transients and their derivatives are shown here in figure 6.

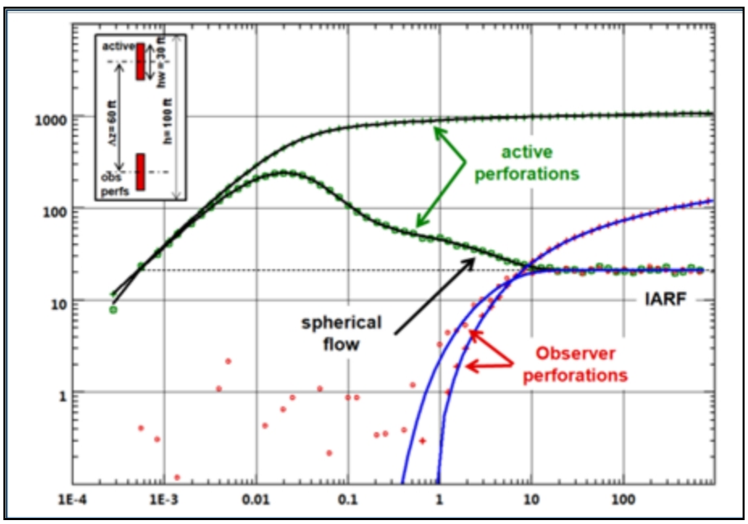

Figure 6: Typical Pressure transient signature for vertical interference tests

In the above plot, the green dots represents the pressure recorded at source probe and the green solid line shows the model fit on it. Similarly, the red dots represent the pressure recorded art observation probe and the blue solid line represents the model fit on it.

A robust formation model helps achieve a good model match and also accurate estimation of the reservoir parameters.

These parameters were then fed into the reservoir model for total oil recovery factor estimation. Also a sensitivity study has been performed to showcase the impact of variations in vertical permeability on the total oil recovery factor for different geological settings.

Conclusions, Results and Observations

Based on the study, following were the key observations and conclusions:

1) The rock type based formation model gives relatively more robust and accurate reservoir parameters for each layer and hence addresses the heterogeneity within the reservoir sands.
2) Both ANN and SMLP techniques have been described and used, depending on the reservoir behavior anyone of these can be used.
3) This approach is important to use especially in reservoirs lying in complex geological settings like channel sand, near to faults, pinch outs and thin sand-shale laminations
4) Impact of Kv/Kh on recovery factor has been studied. With the help of a sensitivity analysis, the variations in recovery factor due to a variation in Kv/Kh has been showcased.

References:

Amaefule, J. O., Altunbay, M., Tiab, D., Kersey, D. G., & Keelan, D. K. (1993). Enhanced Reservoir Description: Using Core and Log Data to Identify Hydraulic (Flow) Units and Predict Permeability in Uncored Intervals/Wells. *SPE Annual Technical Conference and Exhibition*, (c). https://doi.org/10.2118/26436-MS

Gunter, G. W., Finneran, J. M., Hartmann, D. J., & Miller, J. D. (1997). Early Determination of Reservoir Flow Units Using an Integrated Petrophysical Method. *SPE Annual Technical Conference and Exhibition*, (1), 1–8. https://doi.org/10.2118/38679-MS