Integrated Reservoir Characterization from Core to Geomodel: Example of a Cretaceous Mixed Clastic/Carbonate Oil Field, West Africa*

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Abstract

A cretaceous mixed clastic/carbonate oil field is described throughout an integrated study from sedimentary context to static reservoir model. Core data understanding of field sedimentary and diagenesis evolution is integrated with petrophysics and log responses to provide Petro-Geological Groups (PGG). These PGG are to be relevant both for electro-facies modeling from logs and for geological facies maps and trends used to populate the geomodels. On the other hand, Petrophysical Groups (PG), strictly relying on petrophysical properties, appear to be more pertinent for petrophysical parameters distribution. Regarding saturation laws, several approaches were attempted to model them from PC data (Wooddy-Wright-Johnson; J Leverett function, Sw as function of height above free water level), the last one being finally selected for geomodeling purposes. Petrophysics (porosity, permeability, saturation) will be consequently propagated into the geological model through a relationship between PGG and PG. To establish this relationship was a key issue for geomodeling. A supervised model of PGG provides a good result in terms of petrophysical characterization and propagation for most of the studied wells. The vertical sequences and lateral evolutions on maps validate their geological consistency. The Similarity Threshold Method (STM) computed for this supervised model highlights the good reliability of the propagation with regards to the log responses. This propagation on all wells is the base for sedimentary and diagenesis maps and evolution trends. In such a heterogeneous carbonate field, the comparison between small scale permeability derived from cores and logs and larger scale permeability derived from well test demonstrates upscaling rules which are consequently implemented to improve the reservoir

models. This integrated study provides geological and petrophysical guidelines to populate the reservoir model and improve its overall consistency.

Introduction

Reservoir characterization is an important step for the building of a geological model. Anticipation in data acquisition and integration of all available data, from different scales and different sources, request an integrated workflow to achieve a geologically and petrophysically consistent reservoir characterization.

A Cretaceous carbonate oil field from West Africa is presently described throughout an integrated study from sedimentary context to static reservoir model.

Petro-Geological Groups (PGG)

Core data understanding of field sedimentary and diagenesis evolution is approached through the Petro-Geological Groups (PGG) concept. PGG is based on the reconciliation between (1) depositional, (2) diagenetic, (3) petrophysical and (4) wireline log data (Figure 1). Points (1) and (2) are mandatory for the definition of vertical and lateral distribution rules of each PGG. Input data are the detailed core and thin section observations. Point (3) aims at providing PGG with a coherent set of associated poro-perm properties to ensure the most relevant relationships with Petrophysical Groups.

The consistency with wireline log data (4) is essential to allow a good propagation of PGG to other wells and non cored intervals through electro-facies modeling. For the present study, 15 PGG were defined as below. (Figure 2)

As each PGG presents a strong sedimentological meaning, they provide a powerful tool for the propagation into the reservoir through depositional and diagenetic conceptual models (Figure 3). Petrophysical Groups (PG), strictly relying on petrophysical properties, appear to be more pertinent for petrophysical parameters distribution.

Petrophysical Groups (PG)

Eight Petrophysical Groups have been defined with five parameters: porosity, permeability, grain density (from CCA) and Sw at Pc max and Sw at transition zone (from Pc data). Distribution of petrophysical properties for each PG is illustrated in Figure 4. Distribution of Φ, K can be displayed for each Petrophysical Group (Figure 5).

Relationship between Geology (PG) and Petrophysics (PGG)

Petrophysics (porosity, permeability, saturation) will be consequently propagated into the geological model through a relationship between PGG and PG. Trying to find this relationship is a key problem for geomodeling. Petrophysics is not a correlatable parameter. In order to be able to populate geological model with petrophysical properties, a simple and consistent relationship between PGG and PG must be defined.

This relationship is provided through a contingency analysis based on a Kohonen map neural-network approach. A statistical parameter (V of Cramer, varying from 0 to 1) estimates the strength of the statistical relationship between the two parameters (PGG and PG). The contingency table, as evidenced on Figure 6, leads to a simple relationship between geology and petrophysics, using cut-offs in order to consider the two dominant PG for each PGG (Figure 7).

Saturation Laws

A core driven saturation law can be subsequently proposed for each PG. Different approaches have been tested: Wooddy-Wright-Johnson, J Leverett function, SW as function of height above free water level (FWL). The last one has finally been selected for geomodeling issue. Figure 8 displays the regression law for each PG.

Facies Modeling

In order to propagate the PGG into the non-cored intervals, a facies modeling has been realized. From GR, Density, Neutron and PEF logs. All these logs have been normalized, corrected from hydrocarbon content and compaction effect. Figure 9 displays the effect of hydrocarbon correction. To calibrate the method, blind tests are applied. PGG supervised modeling (integrating core data within the training set) provides good results in terms of petrophysical characterization and propagation for most of the studied wells (Figure 10). This propagation on all wells is the base for sedimentary and diagenesis maps and evolution trends. The Similarity Threshold Method

(STM) computed for this supervised model highlights the good reliability of the propagation with regards to the log responses (Figure 11).

Permeability Modeling

Permeability modeling relies on permeability petrophysical logs, generated from an interpolation of core data. A training set is built with the Permeability Petrophysical log and the conventional logs (GR, Density, Neutron and PEF). Predicted permeabilities (KARI for arithmetic average permeability and KGEO for geometric average permeability) are calculated along the well study interval using nearest neighbor method (Figure 12). In such heterogeneous carbonate fields, permeability modeling at small scales can be compared with larger scale well test data. This permeability prediction provides guideline for geomodeling upscaling. Such an integrated study (with geological, Petrophysical and dynamic data) allows to emphasize the field geomodel coherency and provides strong geological and petrophysical guidelines in such a complex environment.

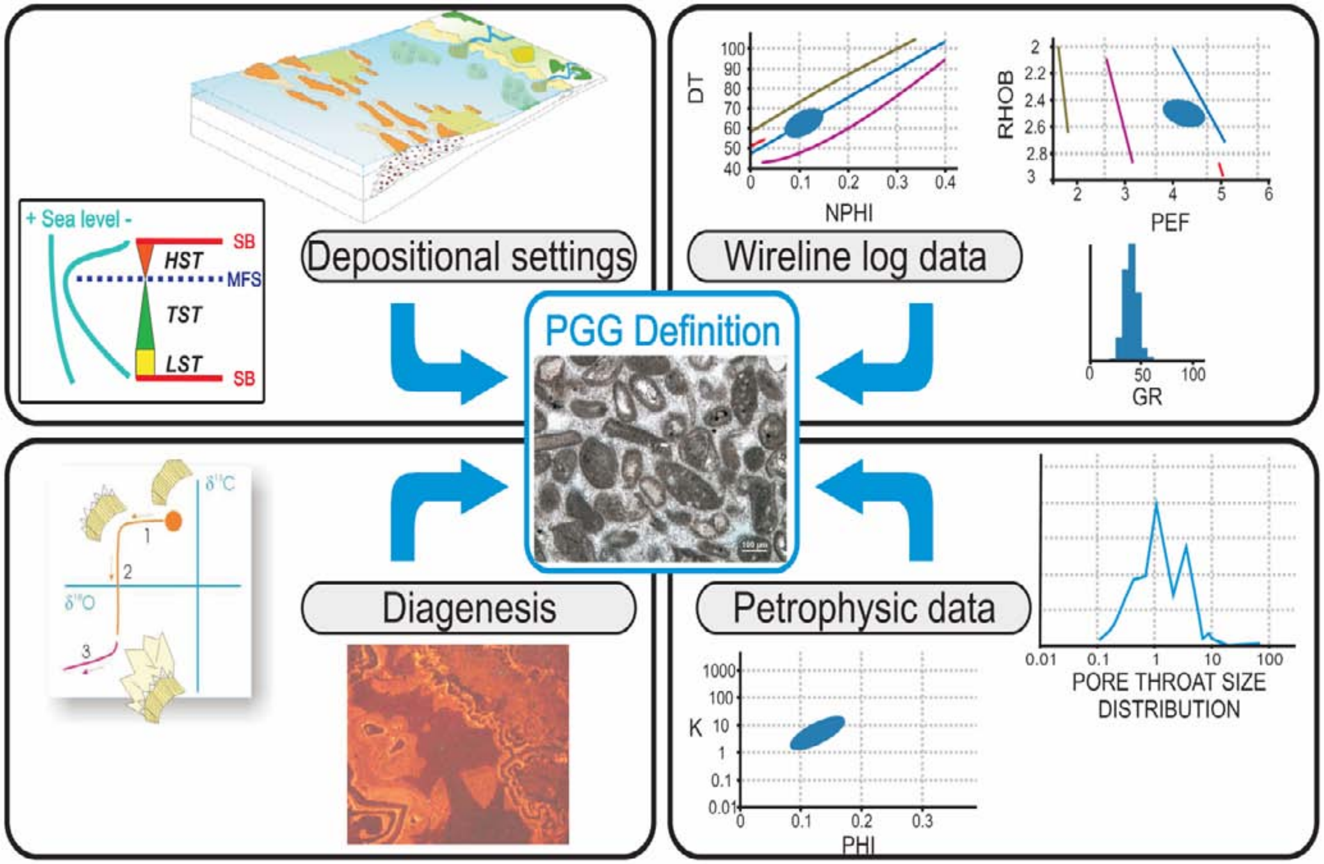
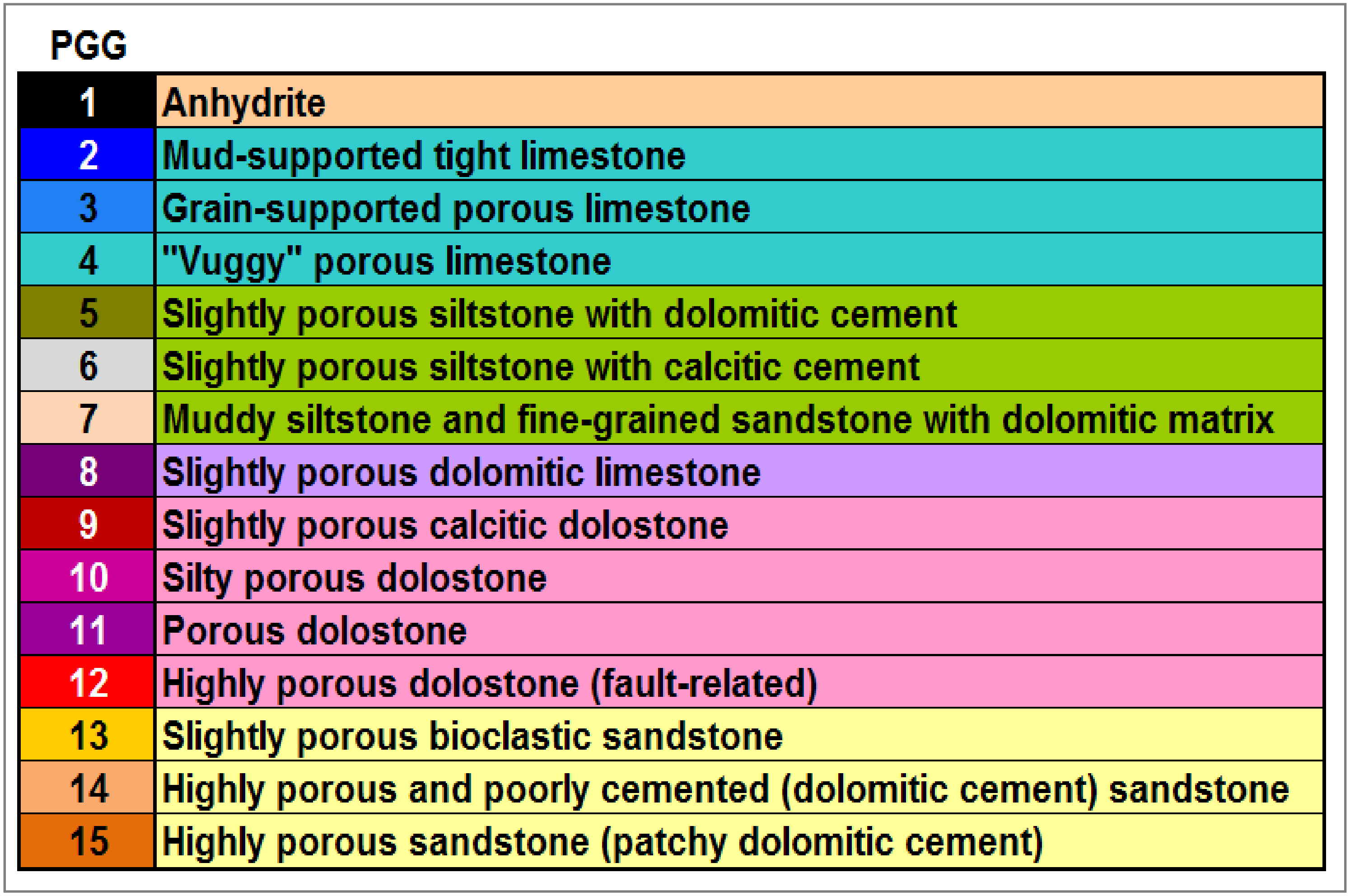


Figure 1. Definition of Petro-Geological Groups (PGG).



PGG	
1	Anhydrite
2	Mud-supported tight limestone
3	Grain-supported porous limestone
4	"Vuggy" porous limestone
5	Slightly porous siltstone with dolomitic cement
6	Slightly porous siltstone with calcitic cement
7	Muddy siltstone and fine-grained sandstone with dolomitic matrix
8	Slightly porous dolomitic limestone
9	Slightly porous calcitic dolostone
10	Silty porous dolostone
11	Porous dolostone
12	Highly porous dolostone (fault-related)
13	Slightly porous bioclastic sandstone
14	Highly porous and poorly cemented (dolomitic cement) sandstone
15	Highly porous sandstone (patchy dolomitic cement)

Figure 2. Geological description of the 15 PGG.

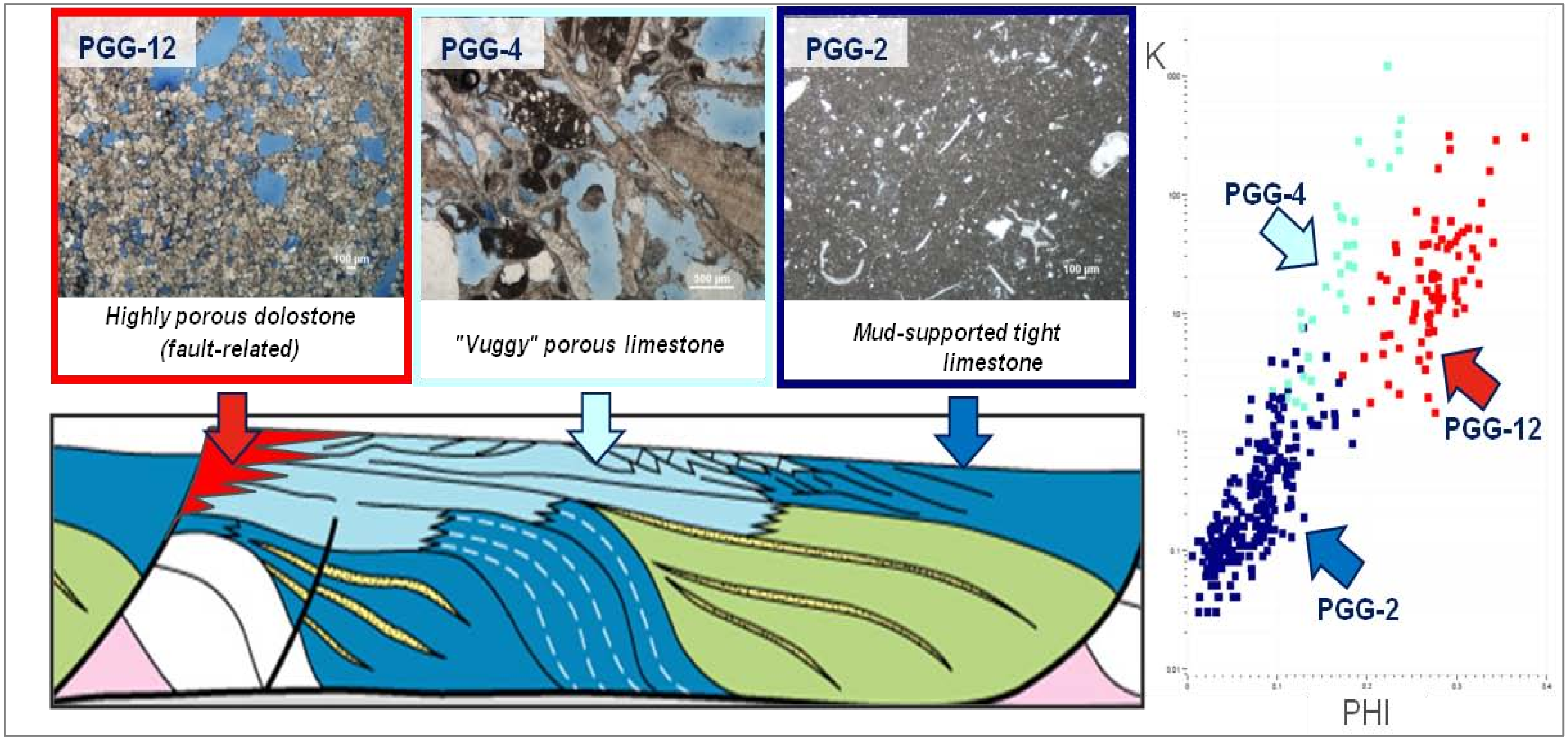


Figure 3. Depositional and diagenetic conceptual model.

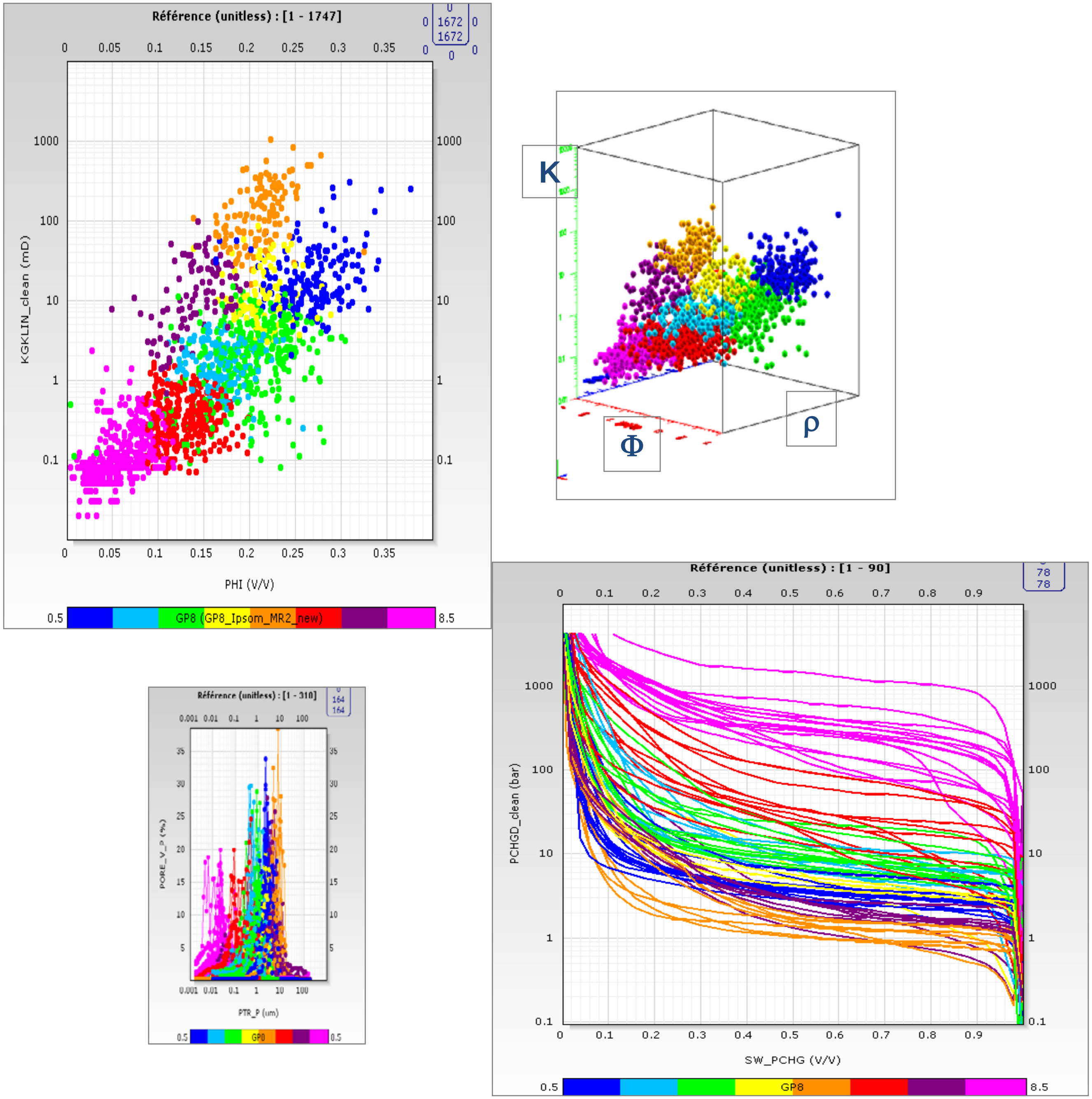


Figure 4. PG Petrophysical properties. Upper left: K vs. Φ; Upper right: K vs. Φ vs. ρ; Lower left: PTR distribution; Lower right: MICP curves.

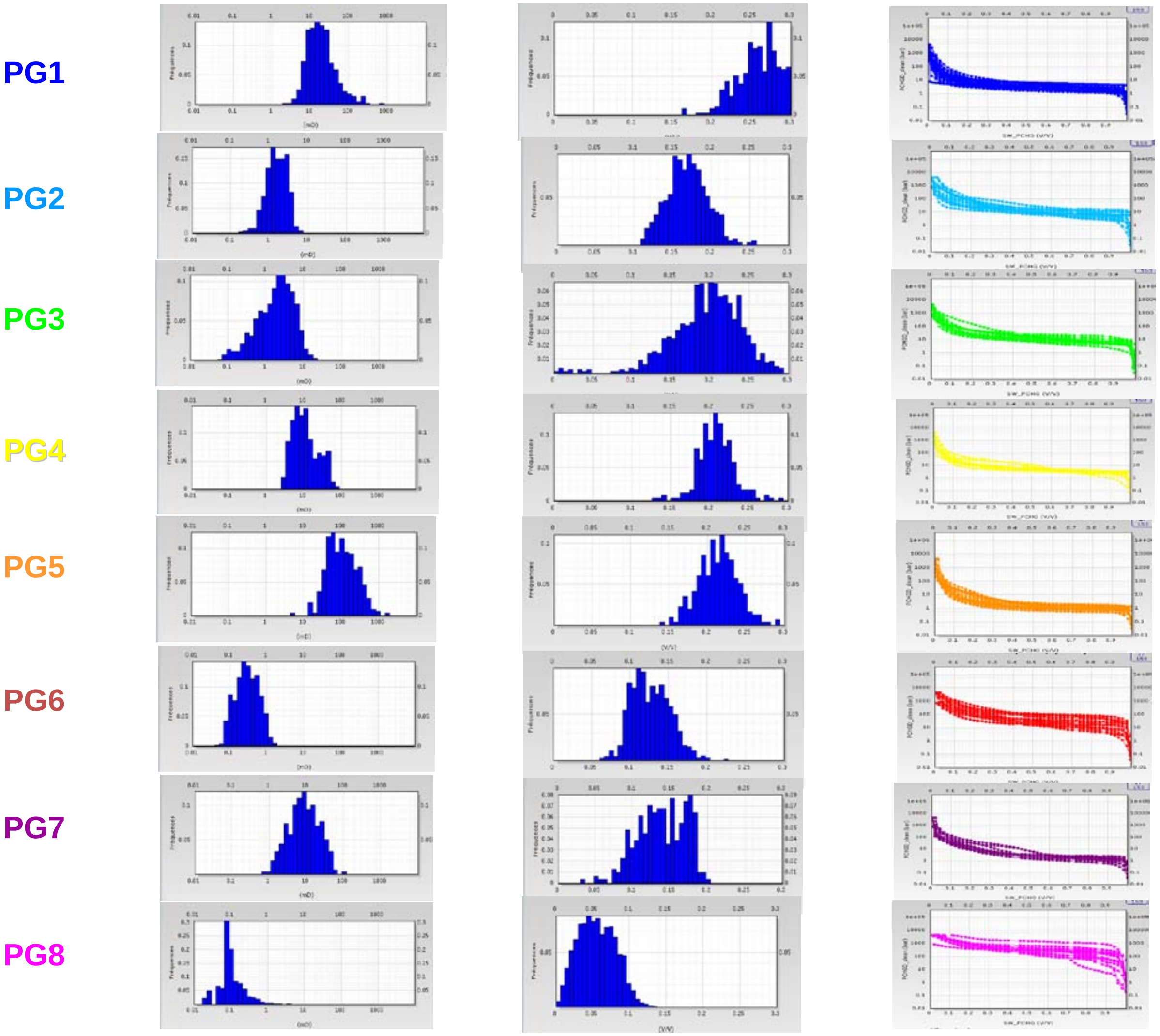
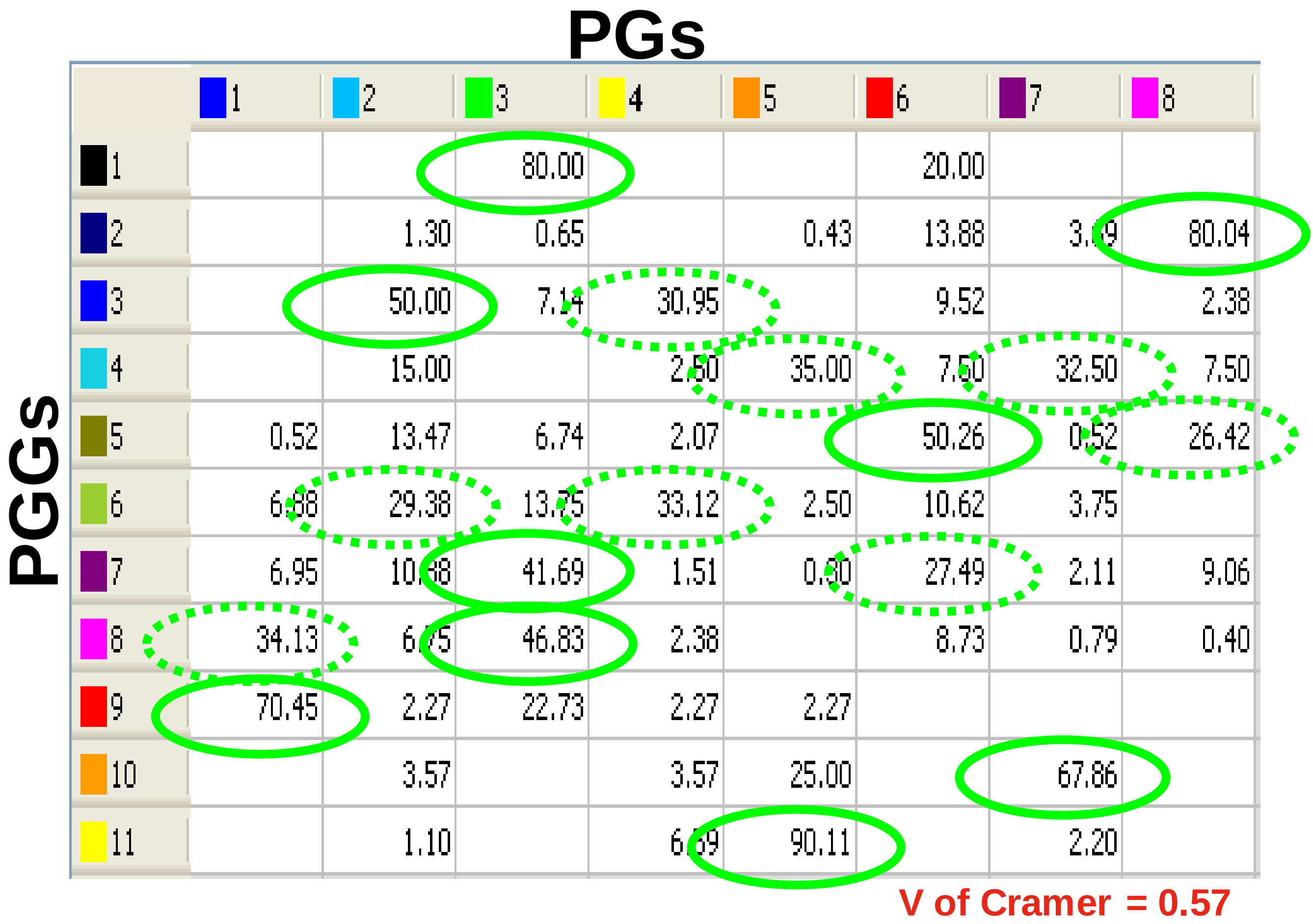


Figure 5. Permeability (left), porosity (middle) and Pc (right) distribution per PG.



PGs

PGGs

	🟦 1	🟦 2	🟩 3	🟨 4	🟧 5	🟥 6	🟪 7	🟪 8
⬛ 1			80.00			20.00		
🟦 2		1.30	0.65		0.43	13.88	3.69	80.04
🟦 3		50.00	7.14	30.95		9.52		2.38
🟦 4		15.00		2.50	35.00	7.50	32.50	7.50
🟫 5	0.52	13.47	6.74	2.07		50.26	0.52	26.42
🟩 6	6.88	29.38	13.75	33.12	2.50	10.62	3.75	
🟪 7	6.95	10.88	41.69	1.51	0.30	27.49	2.11	9.06
🟪 8	34.13	6.75	46.83	2.38		8.73	0.79	0.40
🟥 9	70.45	2.27	22.73	2.27	2.27			
🟧 10		3.57		3.57	25.00		67.86	
🟨 11		1.10		6.59	90.11		2.20	

V of Cramer = 0.57

Figure 6. Contingency table relating PGG with PG.

PGG	Lithology		PG
1	Anhydrite		8
2	Tight limestones		8
3	Porous limestones	$\Phi<20\%$	2
		$\Phi>20\%$	4
4	Vuggy limestones	$\Phi<19\%$	7
		$\Phi>19\%$	5
5	Siltites		6
6	Very fine sandstones	$\Phi<19\%$	2
		$\Phi>19\%$	4
7	Fairly porous dolomites	$\Phi<16\%$	6
		$\Phi>16\%$	3
8	Porous dolomites	$\Phi<24\%$	3
		$\Phi>24\%$	1
9	Highly porous dolomites		1
10	Fairly porous sandstones		7
11	Highly porous sandstones		5

Figure 7. Simple relationship between PGG and PG.

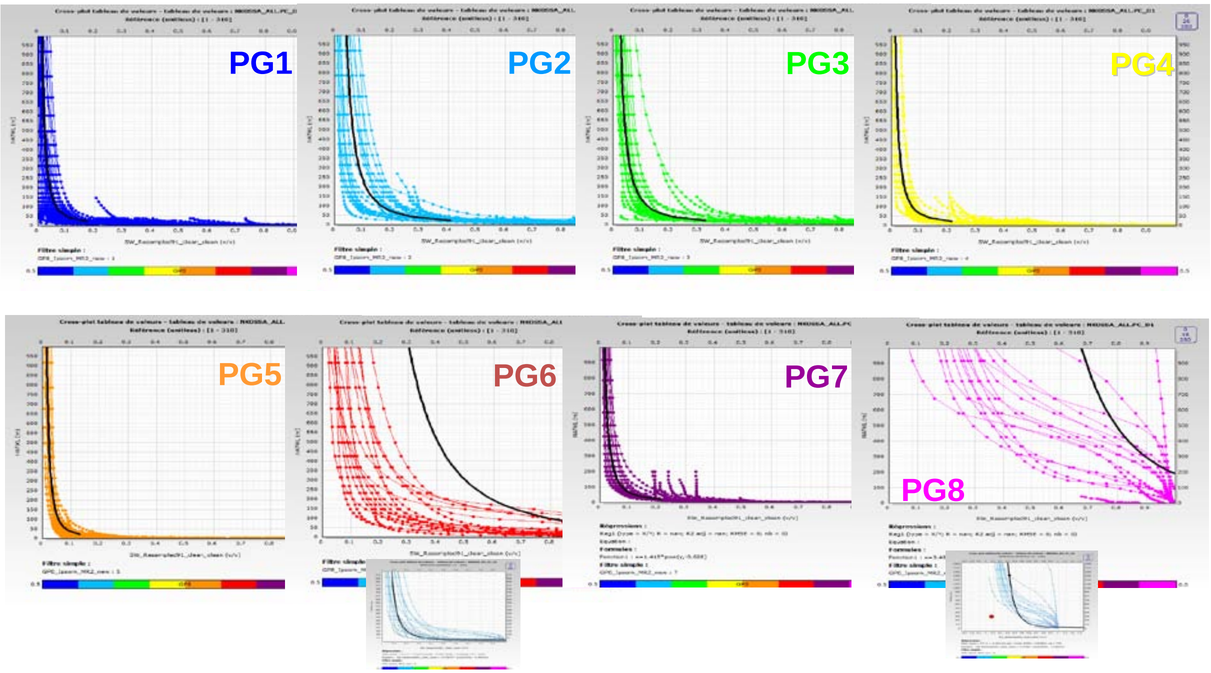


Figure 8. Sw=f(H_FWL) core driven saturation law for each PG.

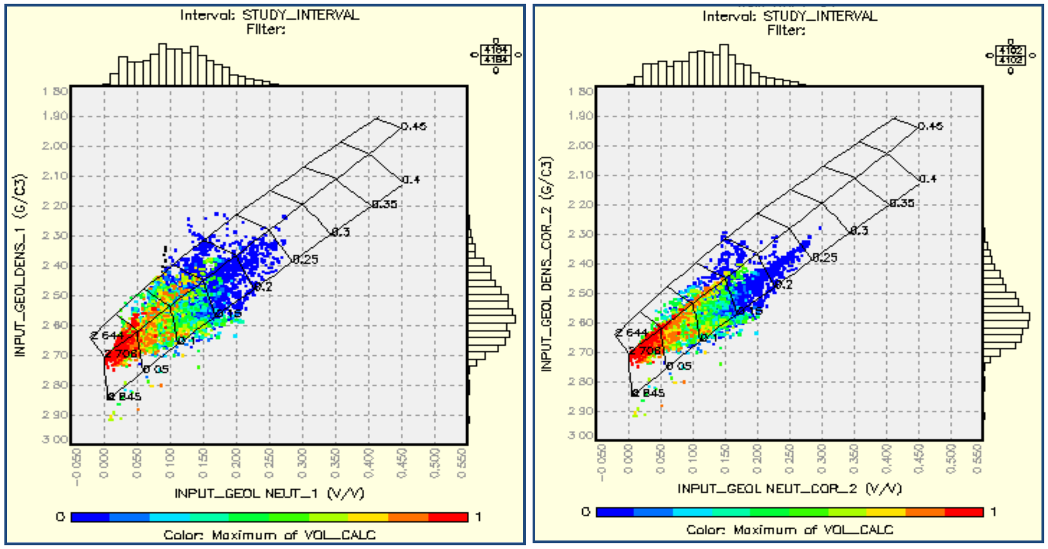


Figure 9. Hydrocarbon correction effect on a Density vs. Neutron cross-plot (left: before, right: after).

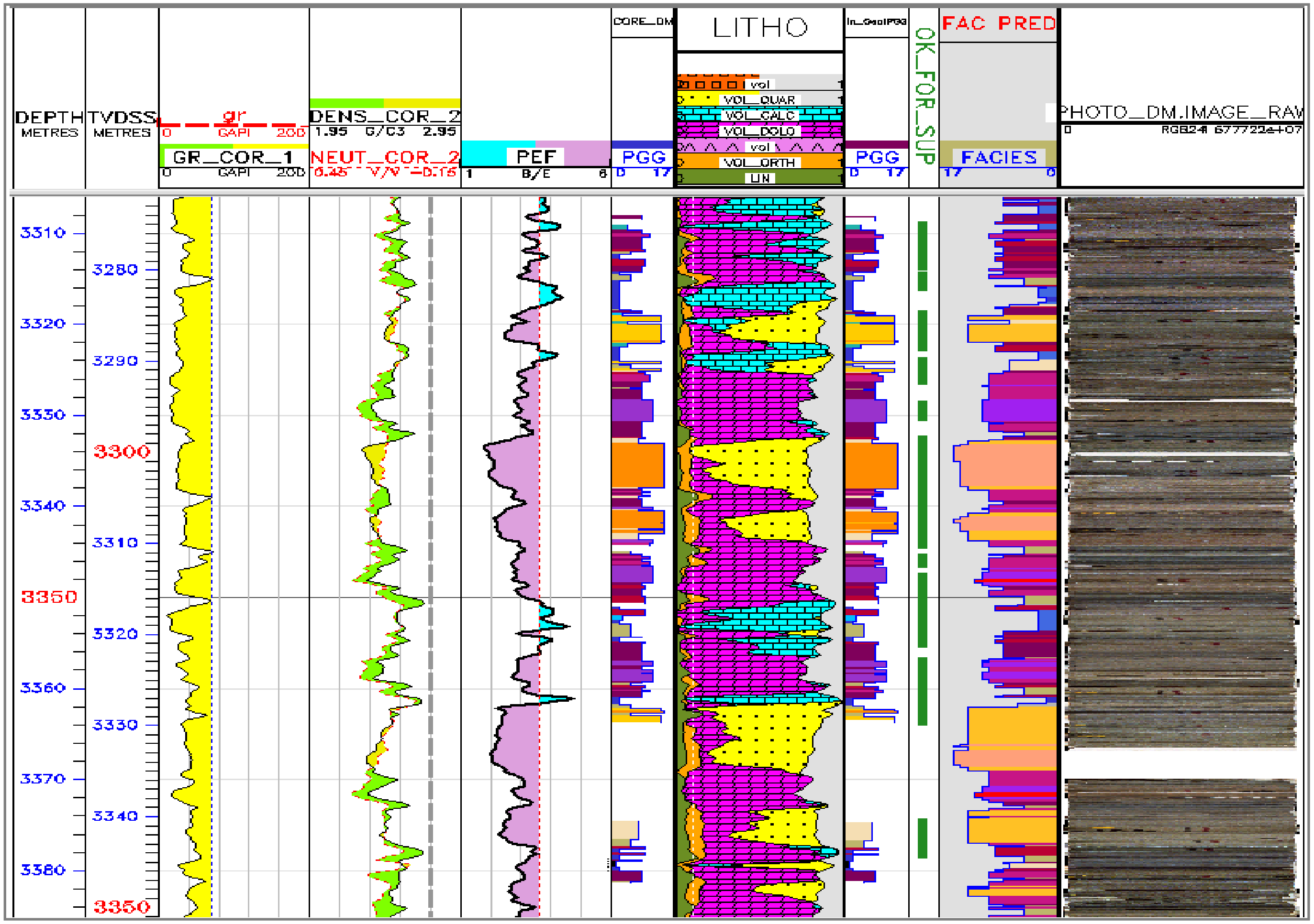


Figure 10. Example of PGG modeling throughout a well.

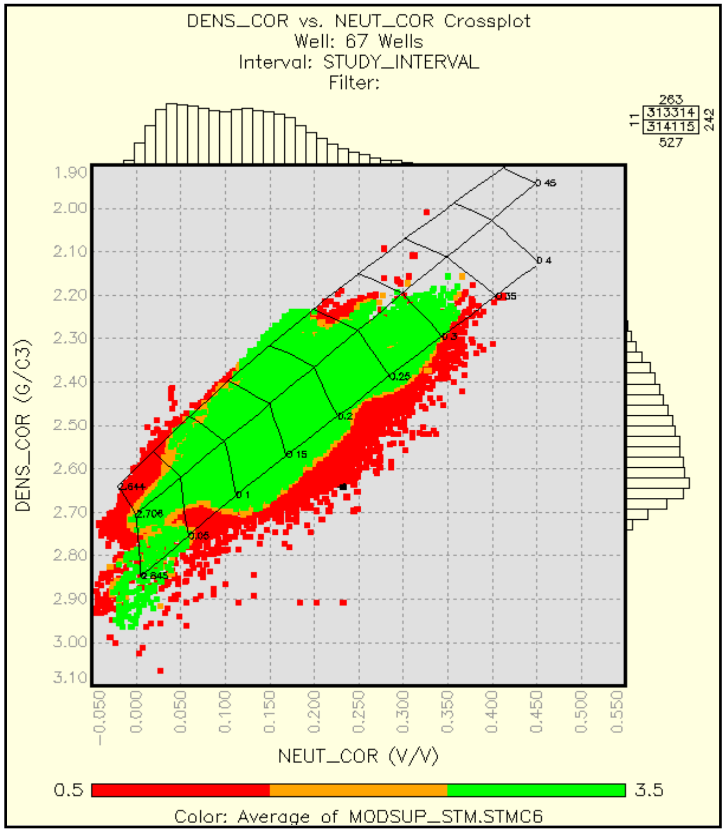


Figure 11. Facies prediction evaluation using STM method (green for OK, orange for ambiguous, red for discarded).

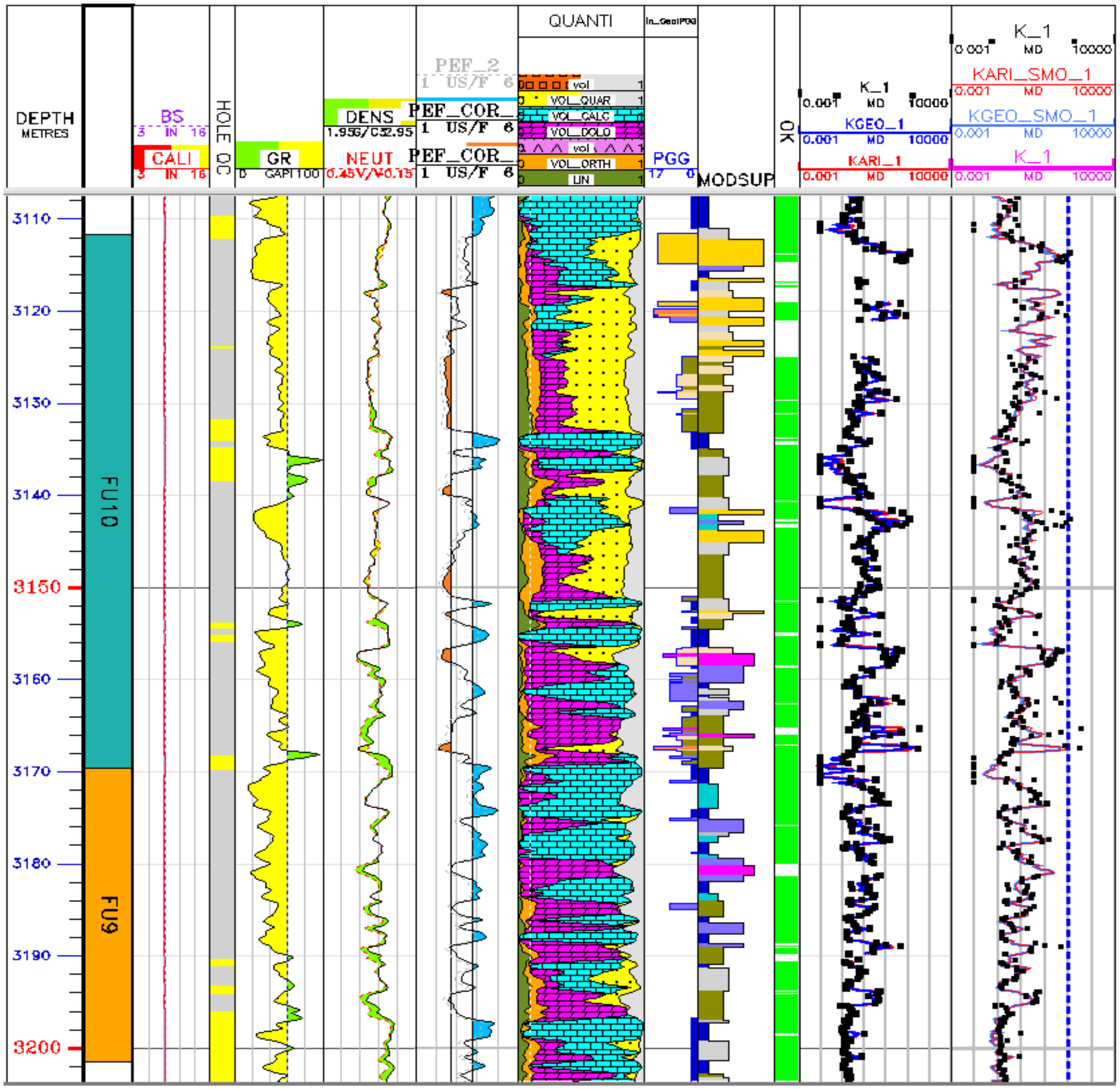


Figure 12. Permeability modeling results compared with plug data.