Improving the accuracy of determining the character saturation reservoirs on the results of log interpretation in the oil field "K"(Tomsk region)

A A Rogov[1,2]

[1] Department of Geophysics, National Research Tomsk Polytechnic University, 30 Lenin Ave., Tomsk, 634050, Russia
[2] Department of Geology, Tomsk Research and Design Institute of Oil and Gas, National Research Tomsk Polytechnic University, 30 Lenin Ave., Tomsk, 634050, Russia

E-mail: RogovAA@nipineft.tomsk.ru

Abstract. Log interpretation has revealed a number of factors that have a significant impact on the determination of reservoir fluid content (oil saturation factor). The presented research paper is focused on the analysis of petrophysical properties of reservoir fluids considering laboratory studies of core samples. Based on core sample analysis, data of laboratory studies have been correlated to estimates of radioactive logging and high-frequency induction logging. To determine the oil saturation factor a method which considers the effect of mixed clay on reservoir fluid saturation has been proposed.

1. Introduction

Field K is located in Pudinsk oil and gas province in Western Siberia. Commercial oil content is associated with sand J_1^1 formation confined to Callovian-Oxfordian J_1 horizon of Vasyugan suite. The deposit is a complex, lithologically sealed structure located at the anticline flank. According to facies classification pay zone is related to coastal bar.

In a number of well cores from the field K the discrepancies between predicted log-derived water cut and actual water cut for tested wells have been revealed, with predicted water cut being higher than the actual one by 10% average.

The relevance of the research is that, in some cases, the current petrophysical model of field K does not determine water saturation coefficient (S_w) and reservoir fluid content (figure 1). In this respect, to refine the petrophysical model, new core sample analysis has been conducted which revealed the peculiarities of non-homogeneous field K reservoir. This data has proved the consistency of water saturation estimates and, consequently, reservoir fluid content.

The purpose of this research is to identify the factors which distort water saturation coefficient and reservoir fluid content estimates and their effects on well log interpretation.

The research target is J_1^1 reservoir rock within which reservoir properties are non-uniformly distributed from the roof to the bottom [1].

Content from this work may be used under the terms of the Creative Commons Attribution 3.0 licence. Any further distribution of this work must maintain attribution to the author(s) and the title of the work, journal citation and DOI.
Published under licence by IOP Publishing Ltd

2. Selection of reference wells

Based on the comparison of predicted and actual water cut, seven wells located in the same area of the field have been selected as water cut is higher than the initial one by approximately 5-15 % (table 1).

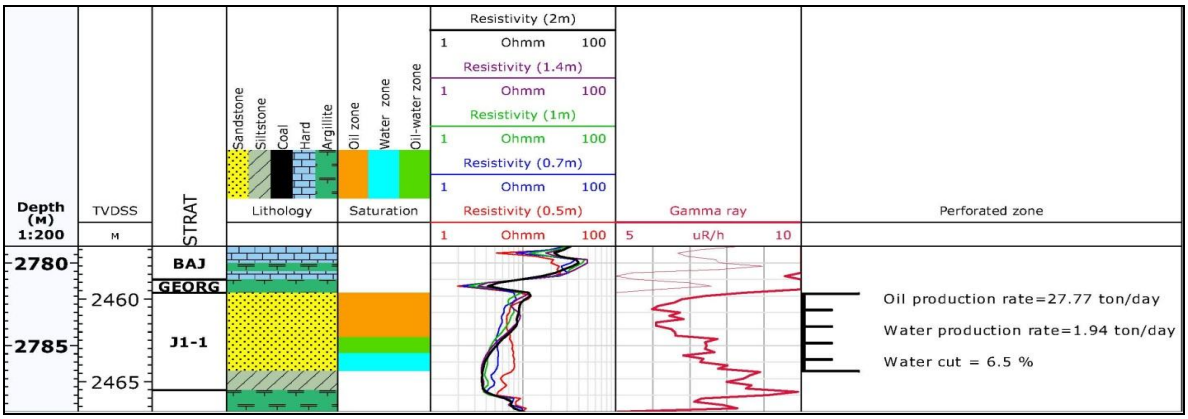


Figure 1. Ambiguity of reservoir fluid content estimates.

Table 1. Comparison of predicted and actual water cut.

Well number	Predicted water cut, %	Initial water cut, %
204	15.8	7.5
301	19.4	6.5
304	20.9	6.3
403	15.3	8.0
405	21.1	6.5
406	13.1	6.7
501	9.2	2.6

The wells are located within the zone which is not affected by production operations, as during drilling no production and injection wells were found. All the wells are located in the northeastern part of field K forming an anomalous zone on the areal map.

3. Log analysis

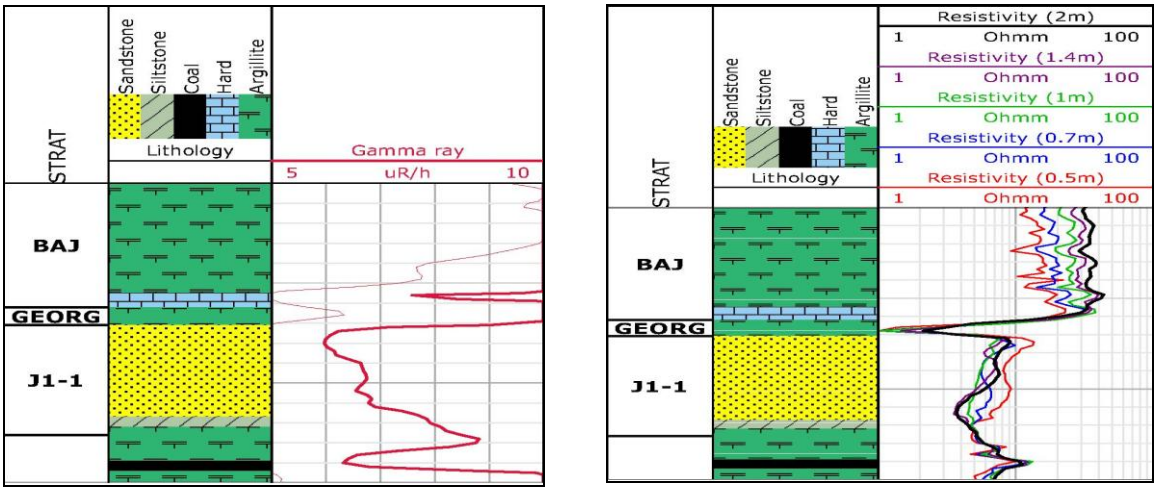
Well-logging suite implemented in field K involved basic methods which are used in production well testing, and included such methods as spontaneous potential log, gamma-ray logging, neutron logging, gamma-gamma density logging, lateral logging, high frequency induction logging. [5]. Such a combination makes it possible to define reservoir zones, their reservoir properties, electrical resistivity and fluid content with sufficient accuracy. It should be noted that pay zone SP curve does not indicate bottom reservoir boundary due to its regressive structure. Therefore, in the present petrophysical model, selection of effective thickness and porosity calculation was based on calculated gamma-ray relative amplitude curve; whereas porosity calculation, according to gamma-gamma density logs, has not been performed for all reference wells because of partial log recordings.

The analysis of well logs from reference wells has indicated the following effects:

1) increased shaliness of reservoir bottom according to gamma-ray logs (figure 2a);
2) high-frequency induction log inversion (figure 2b) .

Though high-frequency induction log inversion implies the presence of oil-water contact within reservoir zone, well operation tests have indicated that fluid inflow water cut does not exceed 10%, which, in its turn, provides evidence of pure oil content.

Based on qualitative analysis of well log behavior, it can be concluded that reservoir properties of J_1^1 formation bottom zone are derated. Low resistivity is probably due to overall high bulk-volume fraction of shale in the bottom zone.



a) b)

Figure 2. Anomalous behavior of well logs (Well № 403).

4. Porosimetry, granulometry and thin section analysis

Core samples from three wells were used in analyzing reservoir properties. Porosity measurements, particle size and thin section analysis were performed to determine the lithologic composition of reservoir rocks, void pattern and mineral composition of pore-filling cement in the above-described reservoir.

According to mineralogical composition J_1^1 sandstones include greywacke-feldspar-quartz variety; rock matrix also contains mica aggregates, single grains of glauconite, as well as chlorite as pseudomorph glauconite.

Cement content in the rock is 9-18%. Cement is basically of polymineral composition, predominantly hydromica, chlorite, kaolinite and mica aggregates, and in some areas calcite, siderite and pyrite. Chlorite is a common cement constituent. Cementation is of membrane-pore type.

In terms of particle size, sandstones are fine-medium-grained; in the layer bottom where fine-grained sandstones (0.25-0.1 mm) and fine-grained siltstones (0.1-0.01 mm) are interbedded.

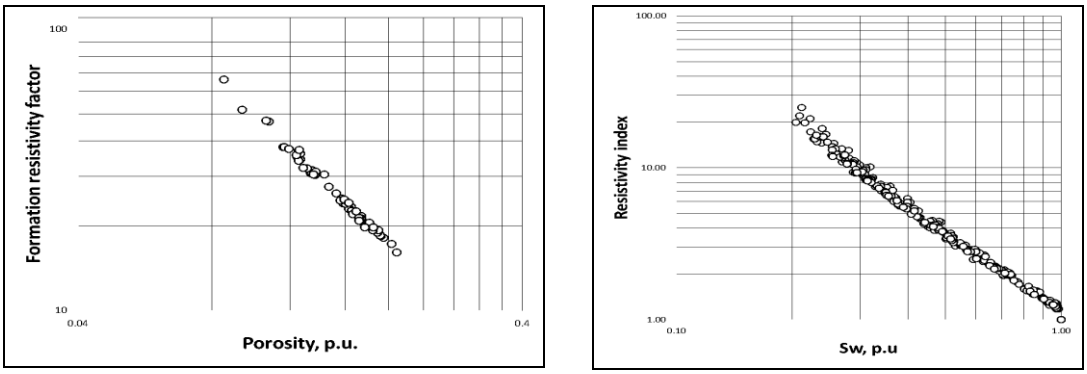
It can also be noted that pyrite (6-30% content) is distinguished in the mineralogical composition of the cement, which in glauconite-chlorite mineral association of cement increases the electrical conductivity, and, thereby, causes electrical resistivity decrease. Additional correction for pyritization was not applied as pyrite content was calculated on the basis of formation resistivity vs. porosity coefficient.

Porosity measurements have also been performed based on the analysis of core samples from two wells. Correlation of sampling intervals with modal pore distribution has indicated that bottom reservoir rocks are non-homogeneous and contain small-size pores with average radius of 1-2 mm [7].

5. Petrophysical properties of reservoir rocks

Considering the fact that log-derived porosity is the same as laboratory-measured formation porosity, it has been concluded that the algorithm used for calculating porosity is reliable. Consequently, the error in determination of fluid content regarding this petrophysical parameter has not been considered.

As a result of the analysis of petrophysical relationships $F_R = f(\varphi)$ and $I_R = f(Sw)$ based on core sample studies, no definite petrophysical type for clay-abundant bottom reservoir rock has been distinguished (figure 3) which, in its turn, suggests that the mineral matrix within the entire reservoir column is composed of a single rock.



а) б)

Figure 3. Petrophysical dependency of formation resistivity factor (a) and resistivity index (b) for the studied reservoir rock.

6. Analysis of challenging factors

The study of open-hole logs, cased hole logs and core analysis has indicated that shaliness bottom J_1^1 reservoir rocks has the greatest effect on oil saturation determination. This factor causes overestimation of electrical conductivity, which, in its turn, has a significant impact on the determination of water saturation coefficient, resulting in overestimation as well.

According to facies classification, the reservoir is a regressive bar, bottom clays tend to be of a mixed type (they are mainly laminar and, to a lesser extent, structured). Therefore, to estimate its effect volumetric clay index calculated by Ellansky formula is used [2]:

$$Vcl = 1.055 - \sqrt{1.14 - 1.111 \cdot \Delta I\gamma},$$

where,

Vcl – clay volume (factor), $\Delta I\gamma$ – gamma ray delta.

To eliminate the influence of this factor the reservoir rock was divided into two types, and these types do not correspond to existing petrophysical reservoir rock types but they have been distinguished based on lithotypes that differ in void space internal arrangement and clay cement distribution. However, material which constitutes these reservoir types is the same.

Lithological types (lithotypes) are differentiated according to the following characteristic criteria:

1 type - pure medium-grained sandstone characterized by the lowest natural radioactivity, AGR> 0.90 unit fraction (figure 4)

2 type - clayey, medium-grained sandstone characterized by increased natural radioactivity, AGR≤0.90 unit fraction (figure 4), and the inversion of induction logs.

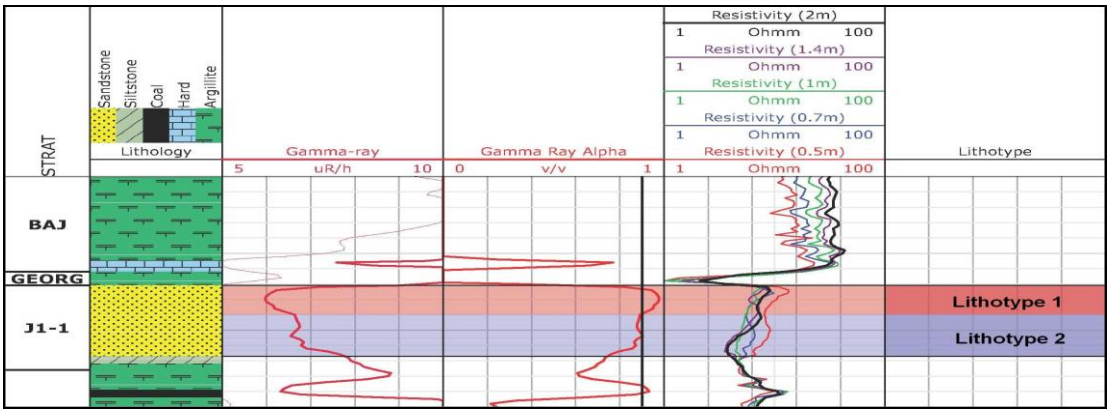


Figure 4. Well № 403 summary plot indicating lithotype classification.

7. Methods for water saturation coefficient calculation

The standard petrophysical model of water saturation coefficient calculation (Archie-Dakhnov method) is applied to homogeneous reservoirs. Provided that clay material is non-uniformly distributed within the reservoir rock, the standard method of calculation is not reliable. Calculation of water saturation coefficient using j-function is difficult, in this case, since there are no reliable data on oil-water contact in the field.

The analysis of in the laboratory core samples provides evidence of different relationships between particular mineral presence in the clay material and rock porosity. Vasyugan suite porosity factor is dependent on chlorite content. Its presence in reservoir pore-filling cement reduces effective porosity, resulting in a felted structure, and therefore, increasing the specific surface area of pore channels and amount of bound water [7].

Taking into account the regressive reservoir structure, being of mixed clay type, and the fact that cross-plots used in the interpretation were produced for cores composed of pure sandstone, a correction has been introduced into the calculation of formation resistivity factor to identify the effect of complex shaliness.

Water saturation coefficient calculation for lithotype 1 was made according to approved cross-plots for the reservoir rock composed of pure sandstone. Calculation of water saturation coefficient for lithotype 2 involved a correction for formation resistivity factor which was calculated as follows [6]:

$$F_R = \frac{a \cdot (1 - Vsh)^m}{\varphi^m},$$

where a – lithological factor,
m – cementation factor,
Vsh – shale volume factor,
φ – porosity factor.

8. Results and discussion

Based on the applied method, for wells with high predicted water cut, water saturation coefficient has been recalculated for intervals which correspond to reservoir rock lithotype 2. Recomputation of water saturation coefficient for intervals corresponding to lithotype 1 has not been performed (table. 2).

Table 2. Comparison of weighted average water saturation coefficients before and after application of the recommended method.

Well number	Sw (Archie), p.u.	Sw (Corrected), p.u.	Relative difference, %
204	0.61	0.56	-9.3
301	0.61	0.56	-7.3
304	0.60	0.54	-10.8
403	0.53	0.51	-3.7
405	0.62	0.53	-14.7
406	0.51	0.49	-3.2
501	0.64	0.57	-9.5

Recomputation of predicted water cut has also been carried out. The estimates turned out to be fairly coincident to the actual values (table 3). Prediction of water cut was carried out on the basis of capillarimetry studies of core samples. To calculate the water cut fractional flow vs. normalized water saturation coefficient cross-plot has been produced FF = f (Sw^{norm}).

Table 3. Comparison of weighted average values of predicted and initial water cut estimates before and after application of the recommended methods.

Well number	Predicted water cut, %	Inintial water cut, %	Predicted water cut including shaliness, %
204	15.8	7.5	9.4
301	19.4	6.5	13.5
304	20.9	6.3	12.5
403	15.3	8.0	13.2
405	21.1	6.5	9.9
406	13.1	6.7	8.6
501	9.2	2.6	4.8

Discrepancies of predicted and initial water cut estimates are due to log measurement error.

9. Conclusion

The analysis conducted for field K wells with high predictive water cut has identified the factor which causes errors in water saturation coefficient calculation, which, in its turn, results in misleading conclusions about fluid content in a reservoir.

To eliminate this factor effect, the method of water saturation coefficient calculation considering reservoir shale index has been applied in this field for the first time.

As a result of this technique application and based on new core data, the petrophysical model has been improved making it more reliable.

The presented method is recommended in log interpretation for step-out wells in this field, as well as in deposits with similar reservoirs. Application of this method improves the accuracy of determination of water saturation coefficient and fluid content, as well as a more accurate prediction of initial water cut.

References

[1] Dakhnov B 1985 *Geofizicheskie metody opredeleniya kollektorskikh svojstv i neftegazonasyscheniya gornykh porod* (Moscow: Nedra) (in Russian)

[2] Dobrynin B, Vendelshteyn B, Kozhevnikov D 2004 *Petrofizika* (Moscow: State University of Oil and Gas) (in Russian)

[3] Kosarev B 2009 *Kontrol za razrabotkoj neftegazovykh mestorozhdenij* (Kazan: KFU) p 145 (in Russian)

[4] Petersile B, Poroskuna B, Yatsenko G 2003 *Metodicheskie recomendatsyi po podschetu zapasov nefti i gaza objemnym metodom* (Moscow – Tver: VNIGNI, SPC "Tvergeofizika") (in Russian)

[5] Rukobodjaschij dokument №153-39.0-072-01 2001 *Tekhnicheskaya instruktsyya po provedeniju geofizicheskikh issledovanij i rabot priborami na kabele v neftyanykh i azobykh skwazhinakh* (Moscow: SSC VNIGIK VNIIgeosystem) (in Russian)

[6] Djebbar Tiab and Erle C. Donaldson 2004 *Petrophysics: theory and practice of measuring reservoir rock and fluid transport properties* (Gulf Professional Publishing is an imprint of Elsevier 200 Wheeler Road, Burlington, MA 01803, USA Linacre House, Jordan Hill, Oxford OX2 8DP, UK)

[7] Birukova L, Kolmaberg N, Loganova S 1988 *Kompleksirovanie metodov issledovaniya pri razrabotke mestorozhdenij nefti i gaza Zapadnoj Sibiri* (Tyumen: ZapSibNIGNI) (in Russian)