ID: 930

Mineralogy and Fluid Identification for Shale Oil Evaluation with Combined Advanced Technology in Fukang Sag, Junggar Basin

[1]Hao Zhang, [2]Ni Liping, [3]Liang Cai, [3]Wei Wang, [3]Xianran Zhao, [4]Mu Liwei, [1]Luo Gang, [3]Jin Long Wu, [3]Shenzhuan Li，[5]Abdullah Aldossary

[1]PetroChina Xinjiang Oilfield Company, Karamay, China.

[2]PetroChina Logging Company Geology Institute, Karamay, China.

[3]SLB, Beijing, China.

[4]PetroChina Xinjiang Research Institute, Karamay, China.

[5]SLB, Dhahran, Saudi. Arabia.

ABSTRACT

Unconventional reservoirs are hot spots worldwide. With the high demand for oil and gas in China, the exploration and development of unconventional reservoirs remain at a high level. Sweet-spot identification is one of the most critical steps in formation evaluation. In unconventional reservoirs, the complex mineralogy and relatively low porosity result in low contrast between the resistivities in oil-producing zones and those in water zones. Reducing the uncertainties regarding the type of fluid in the reservoir and determining its potential producibility is the key to acquiring high production and further defining the optimal landing zones for future horizontal drains.

Nuclear magnetic resonance is a common technology used for evaluating the porosity and pore geometry of hydrocarbon-bearing reservoirs, which is based on the cut-off analysis method and is used in oil and gas exploration. However, it is not sufficient for fluid typing in unconventional reservoirs. A new generation of nuclear magnetic resonance tools provides continuous T1-T2 measurements to help provide a solution for fluid characterization. Continuous T1-T2 measurements enable the separation and quantification of different existing fluids in pore systems, thereby solving the fluid typing issue. This technology can also be integrated with other wireline logs, including spectroscopy, which provides a more confident result for fluid assignment.

In this paper, case studies are presented from a tight oil and shale oil reservoir in the Junggar Basin of Western China. Dedicated 2D data analytics technology was used to extract relevant signals from 2D nuclear magnetic resonance T1-T2 measurements. The fluid was further assigned based on local knowledge of unconventional reservoirs and related core analysis results. The integrated workflow combining the wireline borehole electrical image, nuclear spectroscopy, and nuclear magnetic resonance provided insights on the fluid composition in the pore system. Besides the accurate measurements of lithology-independent porosity and pore size distribution from nuclear magnetic resonance, the T1-T2 specific measurement of clay-bound water volume matches well with the properties estimated from nuclear spectroscopy logs. This lowered the uncertainties regarding fluid types in the tight oil reservoir where resistivities fail to differentiate water and oil zones.

In this paper, we discuss a novel combination of advanced logging methods in unconventional reservoirs, which can help the operators to ascertain the potential of these reservoirs. The oil zones identified by these new methods have promising oil production. The integrated workflow illustrated in our case studies can be applied and extended to the exploration of other unconventional reservoirs in China.

EXTENDED ABSTRACT

Introduction

Unconventional reservoirs are hot spots worldwide. With the high demand for oil and gas in China, the exploration and development of unconventional reservoirs remains at a high level. Fukang Sag is in the southeast Junggar Basin, controlled by its paleogeomorphology. Two sets of thick Middle and Upper Permian reservoirs are located in the east slope and sag areas. Both have a similar distribution pattern, and both of which provide favorable conditions for the formation of lithologic-stratigraphic reservoirs.

Geological studies indicate that the Permian Lucaogou Formation is a typical lacustrine reservoir deposited in a saline water environment mainly composed of dolomite mudstone and siltstone, characterized by high feldspar, volcanic debris, and low quartz content. The formation is relatively dense, with a matrix porosity between 1% and 7%. Pore types are mainly intergranular and dissolved pores； microfractures are undeveloped. Kerogen is well distributed in this formation, and the relationship between oil and water in the reservoir is complex.

With all the characteristics mentioned above, the response of conventional logs is complex, with frequent spikes on resistivity logs. All these responses have driven the evaluation of sweet spots using conventional logs but with more uncertain results. In this study, an integrated workflow was provided to solve lithology, rock structure, porosity, pore size distribution and fluid identification together with the combined advanced new logging technologies, including advanced spectroscopy, electronic imaging, and 2D nuclear magnetic resonance.

Methods

Advanced spectroscopy uses both capture and inelastic gamma-ray spectroscopy measurements, providing precise dry weights for elements and minerals based on a stripping-oxide closure-lithology processing workflow. It also provides a measurement of the total carbon in the formation. The difference between total carbon measured in the formation and inorganic carbon estimated from the carbonates of the mineralogical model is the total organic carbon (Craddock et al. 2013).

Figure 1 shows a case study from this region. In this case, the advanced spectroscopy measurements for minerals (including illite, quartz, feldspar, dolomite, calcite, and pyrite) matched well with the result coming from X-ray diffraction (XRD) core analysis. Total organic carbon also showed a good trend compared with the result from a rock pyrolysis experiment.

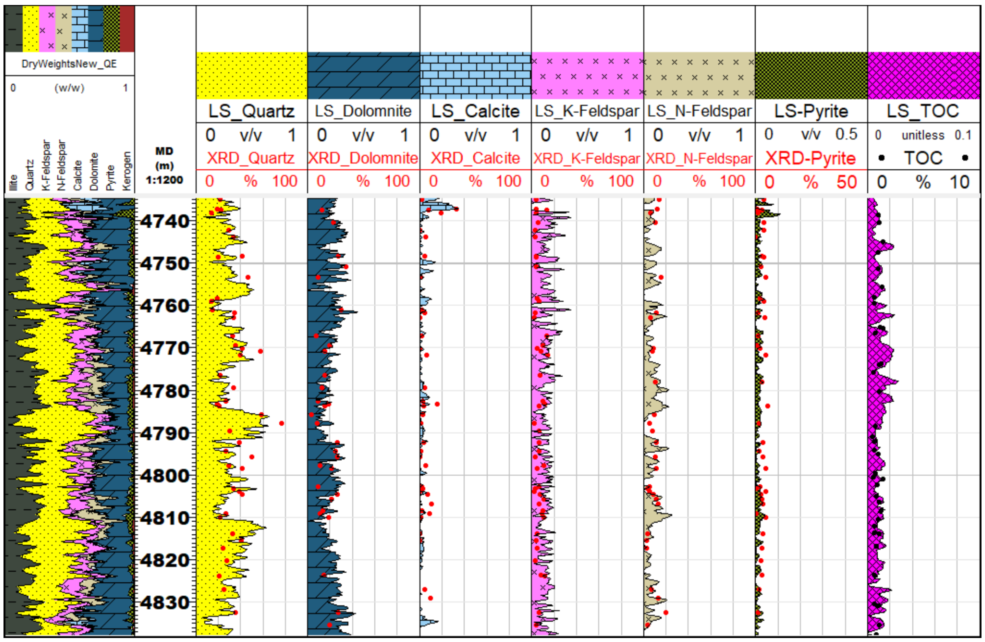

Figure 1: Mineral comparison between spectroscopy measurement and XRD analysis.

Nuclear magnetic resonance fulfills the petrophysical property analysis based on cutoffs to evaluate the porosity and pore geometry of hydrocarbon-bearing reservoirs (Agut et al., 2000; Keating. 2010). However, in the T2 space, the hydrocarbon response is often masked by the water response due to its diffusivity. To separate hydrocarbons from water in the T2 spectrum, traditional analysis methods have been acquired by using multiple T2 measurements taken at different waiting times.

In tight low-permeability reservoirs, the difference in results from the above method does not provide a confident interpretation for the reservoir type. As we know, relaxation due to diffusion only applies to T2 and never to T1. Given the typical magnetic field gradients of the logging tool, the oil and gas signal can easily be distinguished from the T1/T2 ratio (Anand et al. 2017). This behavior enables the method by using distinctive T1-T2 nature for various so-termed porofluid facies, quantifying patterns of pore size and fluid type variations becomes a reliable method in unconventional reservoirs (Venkataramanan et al. 2018).

Organic kerogen, which is a solid component, has very short T2 and is therefore not detected by downhole logging tools. Both bitumen and clay bound water have short transverse relaxation times, however these can be potentially differentiated since the viscous bitumen has a higher T1/T2 ratio in comparison to the clay bound water which also has a short transverse relaxation time but lower T1/T2 ratios. Light oil in organic versus inorganic porosities could also have distinct signatures on the T1-T2 maps, and so does free water in the mixed wet pores in comparison with other components.

In general, water signatures tend to have lower T1/T2 ratios, closest to the T1=T2 line of the map, whereas hydrocarbons tend to have higher T1/T2 ratios (normally T1/T2>=3). Basically, on the T1-T2 map, using downhole nuclear magnetic resonance tools, it is possible to distinguish fluids including bitumen, clay bound water, producible and unmovable oil, and capillary and free water, as shown in **Figure 2**. When interpreting with T1-T2 maps, it is better to calibrate the fluid typing result using the local core experiment result. When there is not enough core data available to lower the uncertainty of the fluid typing result from the T1–-T2 map, an alternative calibration can be performed using other measurement interpretation results, such as water saturation matches with the estimate from dielectric dispersion analysis, or clay bound water matches with the estimation from spectroscopy measurements.

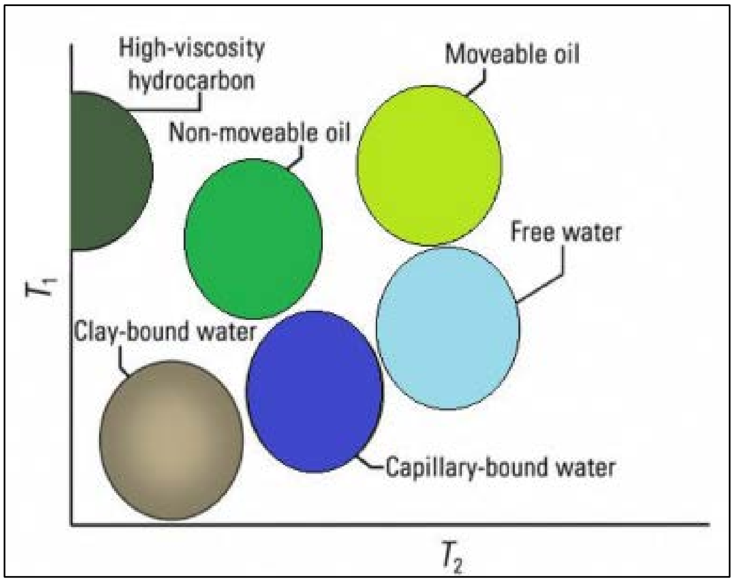

Figure 2: Schematic illustration of 2D nuclear magnetic resonance fluid responses.

Based on current experiences and research on the Lucaogou Formation in Fukang Sag, the fluids classification result of the case study is shown in **Figure 3**, where bitumen, clay-bound water, irreducible oil, capillary bound water, oil, and water are distinguished with stacked T1-T2 analysis.

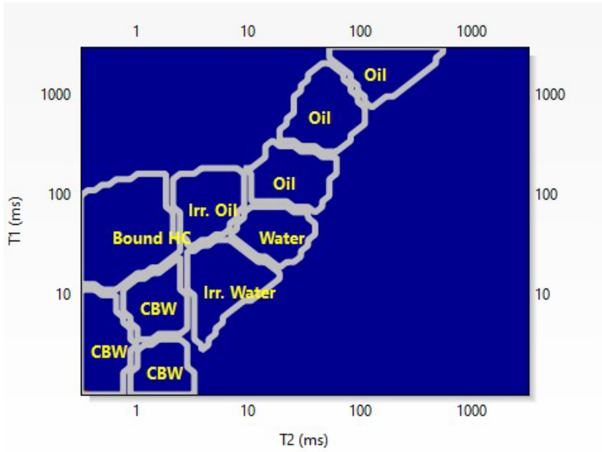

Figure 3: Lucaogou formation fluid assignment, Fukang Sag.

Total organic carbon (TOC) measured by advanced spectroscopy is based on the response from both kerogen and oil. Oil and bitumen volume from nuclear magnetic resonance T1-T2 analysis solves the TOC for oil and bitumen, then TOC for kerogen is calculated. Reservoir producibility index (RPI) is then evaluated which treats the light hydrocarbon as a positive reservoir quality (RQ) indicator and both kerogen and bitumen as negative RQ indicators (Ravinath et al. 2019).

Analysis

To better evaluate the petrophysics of the Lucaogou Formation in the Fukang Sag, a combination of triple-combo logs, advanced spectroscopy, borehole electrical image for oil-based mud and 2D nuclear magnetic resonance logging data were acquired. As shown in **Figure 4**, vertical variety inside the Lucaogou Formation is well defined based on several specs in this case study, including mineralogy and lithology, kerogen distribution, porosity and pore size distribution, and oil-water distribution.

From the triple-combo logs, three different types of formation were recognized, as shown in Track 1, Figure 4.

- Type I shows high gamma ray and wide cross-over for density and neutron measurements; it is acting as good source rock with high shale volume, and the short T2 character indicates the porosity is mainly filled with clay-bound water and the reservoir is not effective. TOC is relatively high, in the range of 2% to 4%.
- Type II exhibits medium to high gamma ray with moderate density and neutron crossover. This interval is a good shale oil reservoir, where the shale volume is moderate (average 25%), carbonate content is relatively large (in the range of 20% to 40%) and feldspar content is slightly increased. The total TOC content is around 2% to 5%, a bimodal structure is observed on the T2 spectrum, and both medium and large pore size pores are developed. Free fluid volume is around 3% to 5%, and open fractures were picked from the electronic image.

- Type III shows a big difference, with low gamma ray and a narrow overlay between density and neutron measurements. Shale volume trends higher to around 20%, and feldspar content is up to 40%. The T2 spectrum indicates a single model structure with medium and large pore size existing in the pore space, with a free fluid porosity varying from 1% to 5%.

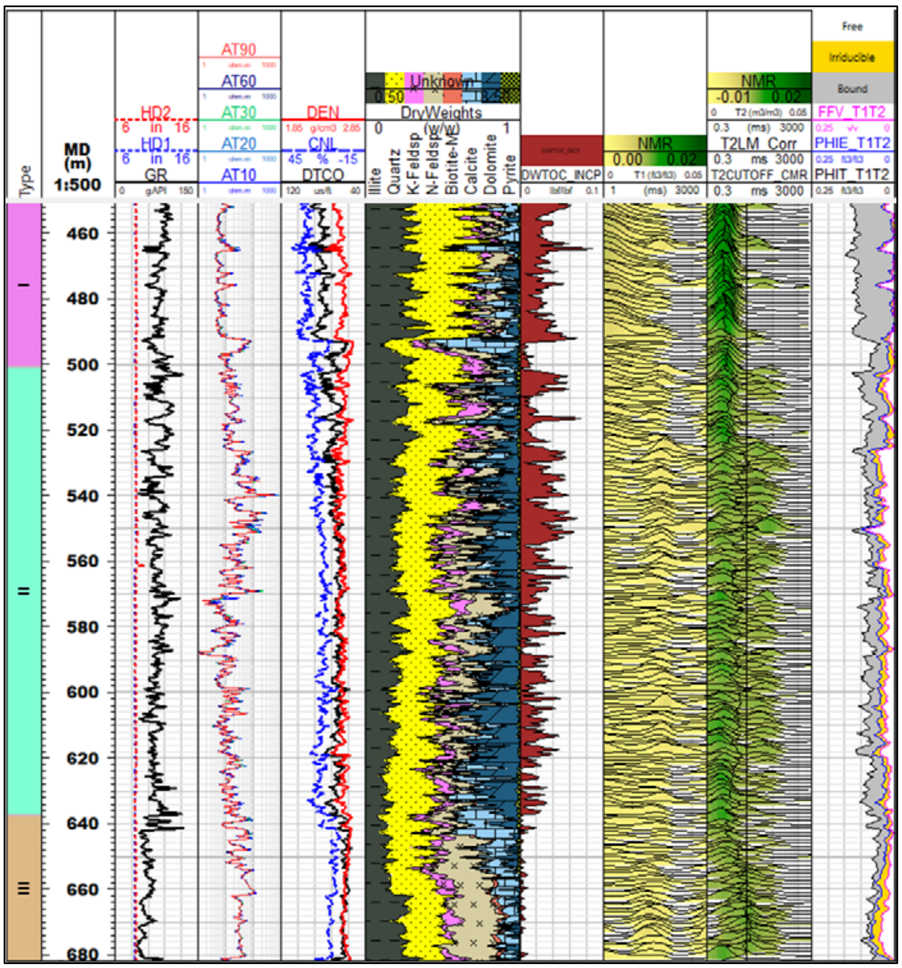

Figure 4: Schematic illustration for vertical properties variation in the Lucaogou Formation.

All the characteristics mentioned above indicate that Type II is the target shale oil sweet spot with excellent reservoir quality and good source rock qualities when compared with Type I facies. Type III logging response indicates this interval is a conventional sandstone reservoir with a small amount of volcanic dust at the bottom. **Figure 5** shows the typical electronic borehole image features for Type I and Type II shale oil facies. Lamination is more obvious for Type II, as shown in both the static and dynamic borehole images, and the static resistivity image also shows more resistance (white color) than Type II. The difference in resistivity is controlled by the minerology and pore structure. Type II has better shale oil potential than Type I.

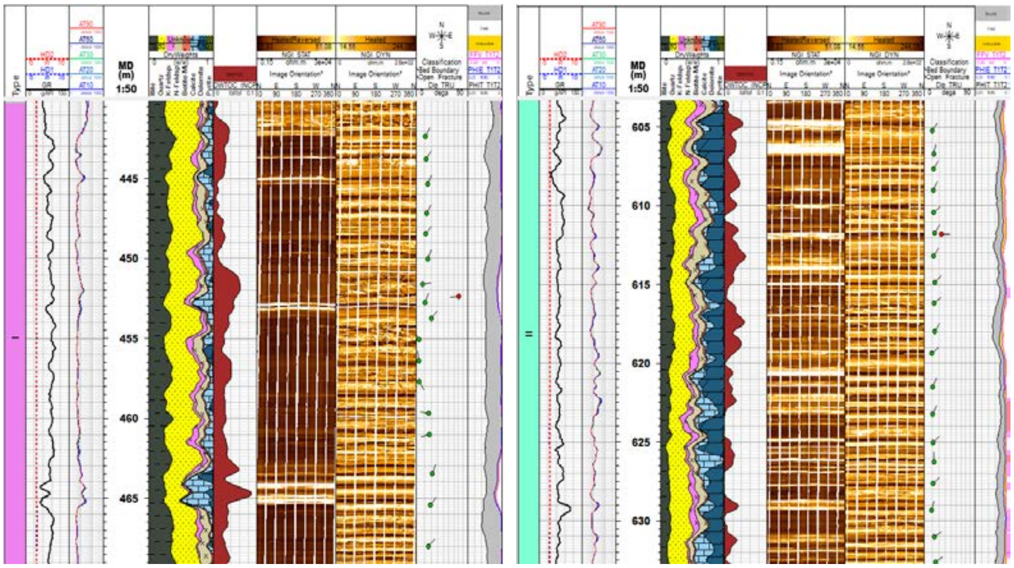

Figure 5: Typical electronic image characteristics for shale oil facies.

Hierarchical clustering is analyzed based on the full interval T1-T2 spectrum stacking result. As shown in **Figure 6**, ten clusters have been classified, and each of them is assigned to a fluid type. The detailed fluid assignments are based on T2 distribution and T1/T2 ratio: Clusters 1, 3, and 4 are clay-bound water, Cluster 2 is bitumen, Cluster 6 is irreducible water, Cluster 5 is irreducible oil, Cluster 7 is water, and Clusters 8,9, and 10 are oil. The volume fraction of each fluid type is calculated based on the assignment.

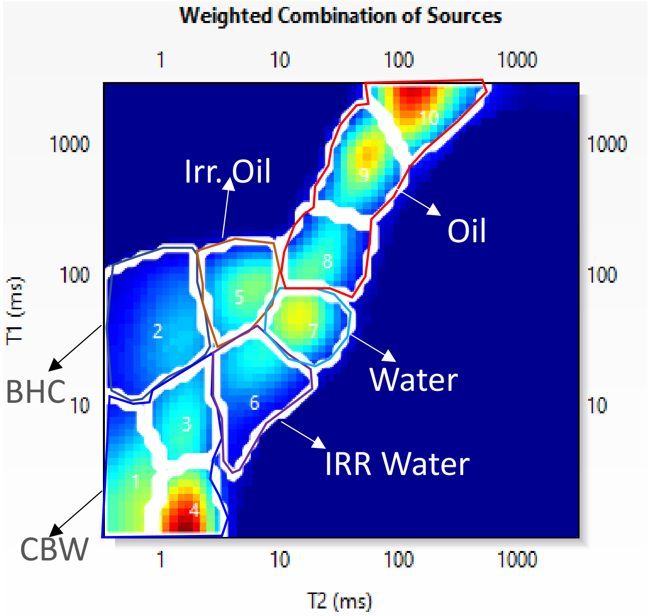

Figure 6: Schematic illustration of 2D nuclear magnetic resonance fluid responses.

Despite the vertical heterogeneity from mineral distribution, lithology, and pore distribution, fluid distribution also showing vertical variations. **Figure 7** shows the T1-T2 map in different depth, with mainly oil in the pores at the top, and a larger water-volume fraction seen from the porosity spaces as the depth increases. RPI was also calculated to enhance the producibility evaluation, although plot 1-2 shows larger oil volume compared to plot 4-6, because of the presence of kerogen, RPI for plot 1-2 is not as good as plot 4-6. However, the water volume in free pore size increased significantly starting from X653m, thus water will be easily produced for the interval.

Further tests were conducted in the interval with a high RPI, oil and water are showing the same amount in the testing period.

An integrated workflow solved the key reservoir characterization issues when we investigated the Lucaogou shale oil formation. Spectroscopy combined with electronic imaging solved for minerals and lithology, nuclear magnetic resonance T-T2 analysis solved for porosity, and fluids quantification, which represents physical properties and oil-bearing properties. Meanwhile, TOC content indicates the source rock quality. With the combination of TOC and oil volume from 2D nuclear magnetic resonance, the RPI is further rated as a guide for fracturing and production operations.

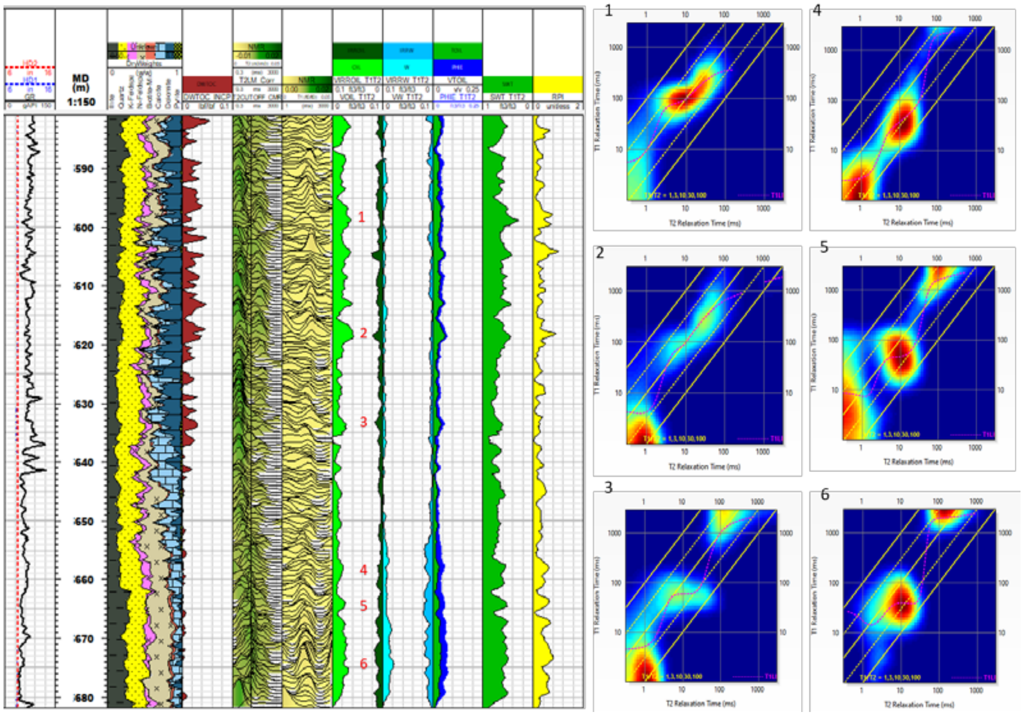

Figure 7 vertical variance of fluid typing

Conclusion

This paper discussed a novel workflow that combined new logging technologies in shale oil evaluation, which can help operators ascertain the reservoir potential in any special area. The sweet spot identified by this methodology indicated areas with promising oil production and provided very confident proof for the regional geological study. There are numerous shale oil pay zones in China, including Mahu Sag in the Junggar Basin, Gulong Sag in the Songliao Basin, as well as the Sichuan Basin, Ordos Basin, Bohaibay Basin and Qadam Basin, and others. The workflow illustrated in this case study can be applied and extended to other unconventional pay zones in China.

Acknowledgment

The authors would like to express their gratitude to PetroChina Xinjiang Oilfield and SLB for their support.

References

1. Agut, R., Levallois, B., and Klopf, W. 2000. Integrating Core Measurements and Nuclear Magnetic Resonance Logs in Complex Lithology. Paper presented at the SPE Annual Technical Conference Exhibition, Dallas, Texas, USA, 1–4 October. SPE-63211-MS. https://doi.org/10.2118/63211-MS.
2. Anand, V., Sun, B. Q., Mosse, L. et al. 2017. Toward Accurate Reservoir Characterization from New-Generation Nuclear Magnetic Resonance Logging. Paper presented at the SPWLA 58th Annual Logging Symposium, Oklahoma City, Oklahoma, USA, 17–21 June. SPWLA-2017-BBB.
3. Craddock, P., Herron, S., Badry, R. et al. 2013. Hydrocarbon Saturation from Total Organic Carbon Logs Derived from Inelastic and Capture Nuclear Spectroscopy. Paper presented at the SPE Annual Technical Conference Sand Exhibition, New Orleans, Louisiana, USA, 30 September–2 October. SPE-166297-MS. https://doi.org/10.2118/166297-MS.
4. Kausik, R., Jiang, T. M., Venkataramanan, L. et al. 2019. Reservoir Producibility Index (RPI) Based on 2D T1-T2 Nuclear Magnetic Resonance Logs. Paper presented at the SPWLA 60th Annual Logging Symposium, The Woodlands, Texas, USA, 15–19 June. SPWLA-2019-Q. https://doi.org/10.30632/T60ALS-2019_Q.
5. Keating, K. 2010. The Effect of Inhomogeneous Surface Relaxivity on Nuclear Magnetic Resonance Relaxation Rates. Paper presented at the 2010 SEG Annual Meeting, Denver, Colorado, USA, 17–22 October. SEG-2010-3946.
6. Venkataramanan, L., Evirgen, N., Allen, D. F. et al. 2018. An Unsupervised Learning Algorithm to Compute Fluid Volumes from Nuclear Magnetic Resonance T1-T2 Logs in Unconventional Reservoirs. Petrophysics 59 (05): 617–632. https://doi.org/10.30632/PJV59N5-2018a4.
7. Zhang, H., Wu, J. F., Wang, Y. et al. 2020. New Generation Nuclear Magnetic Resonance T1-T2 Logging and Integrated Formation Evaluation in Unconventional Reservoirs in China. Paper presented at the Abu Dhabi International Petroleum Exhibition & Conference, Abu Dhabi, UAE, 9–12 November. SPE-203392-MS. https://doi.org/10.2118/203392-MS.

q