Comparison of Image Logs to Nuclear Magnetic Resonance Logs*

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Abstract

Image logs have proven their effectiveness in delivering insight about the complexity of deposition and alteration within many reservoirs. These enhanced logs enable the observation of bedding events and the determination of depositional environments. Secondary porosity events can also be observed in many circumstances with vugs, natural fractures, and drilling-induced fractures, all of which are apparent from the image and available for accurate interpretation by specialized geologists. The contribution of this data to reservoir quality is not easily determined. Observed secondary porosity cannot be quantified from these images and cannot be attributed to changes in permeability. In addition, in many cases, textural changes within the reservoir cannot be observed or determined.

Conversely, nuclear magnetic resonance (NMR) logs provide additional insight into the textural alterations, both depositional and evolutionary, that affect the deliverability of a well. Porosity alteration contribution to permeability can be accurately measured and characterized using the Bray-Smith permeability equation. Drilling-induced events are ignored because of the depth of the measurement involved. Contributing reservoir alterations or secondary porosity can be quantitatively evaluated as a portion of effective porosity.

This paper compares observed textural changes within various reservoirs and the characterization of permeability using this Bray-Smith algorithm. Examples of pore size distribution changes are presented along with natural and drilling-induced fractures. Vugs in carbonate reservoirs are also considered. These results are compared to image logs whenever possible.

In all cases, permeability characterization provides additional clarity regarding the quality of the reservoir. Permeability is accurately compared to production data and core data when available. An assessment of the value of each of these enhanced logging techniques in evaluating and understanding difficult reservoirs is presented.

Introduction

Alteration of the rock matrix is prevalent in many reservoirs throughout the world. This alteration is sometimes the only characteristic that provides productive pathways for hydrocarbons from the formation to a wellbore. Therefore, it is critical to establish and understand the presences of these secondary alteration features. The evaluation of these alterations is a desirable objective.

Connectivity of these features is also important. Image logs have been used to characterize the presence of these types of alterations. They can clearly show the presence of fractures in sandstone and conglomerate reservoirs. They also indicate the presence of fractures and dissolution features in carbonate reservoirs. The presence of these alterations does not always directly indicate the ability of the reservoir to produce. These secondary porosity features may not have connectivity with one another.

Permeability calculations from nuclear magnetic resonance (NMR) devices have been proposed as a solution. The most commonly used model is the Coates equation, which has been in use for many years. This equation requires previous knowledge of the formation or lab-derived measurements to calibrate model parameters. It provides an excellent evaluation if these models are well developed and the formation is consistent. When secondary alteration occurs, however, the models are unable to accommodate these rapid changes in the rock. Consequently, another technique is necessary.

The Bray-Smith equation for the direct calculation of permeability values from only the NMR T_2 response has been recently proposed and applied in several North American reservoirs. The results have been promising in sand, shaley sand, and conglomerate reservoirs. These results have also proven to be quite robust in establishing permeability in secondary porosity portions of the reservoir. A significant number of comparisons of calculated production rates and actual rates have created great confidence that the calculated permeability values are valid in many reservoirs.

Some types of secondary porosity are unique to carbonate reservoirs. These alterations include vugs and solution enhancement of existing irregularities. This alteration may be an artifact of both deposition and composition of the reservoir. In addition, fracture events may have aperture reduction events caused by mineral deposition in the fractures. Any of these situations alter the ability of standard density/neutron porosity to describe reserves and productivity of a formation. An adequate description of these characteristics is desirable to help determine the productive potential of these reservoirs.

Drilling-induced fractures may be present in the wells. These will be apparent from image logs. Analysis techniques enable the identification and segregation of these artifacts of the drilling process.

Large sensitive volume NMR tools can be used to evaluate the reservoir, and are not influenced by the presence of these non-production improving events. This paper shows image logs with drilling-induced fractures and confirms the lack of response for those events in the large sensitive volume NMR response.

This paper demonstrates the application of the Bray-Smith permeability equation to determine assessments of permeability in these formations with secondary porosity events. It includes examples of NMR T_2 derived permeability in pure, unaltered formations, sections with secondary porosity from fractures, secondary porosity from solution enhancement, and examples of vugular porosity development.

The image logs characterization of secondary events in these reservoirs is compared to the permeability response for the large sensitive volume NMR device. In addition, the Bray-Smith characterization of permeability is compared to the image results. Characterization of the secondary porosity events is described and compared between these powerful reservoir evaluation devices.

Technical Challenge

The technical challenge described in this paper begins with an observation; if NMR relaxation, or T_2, can be measured for the entire length of time required to achieve relaxation of all investigated molecules, these measurements can be roughly related to the size of pore where the investigated molecule resides. Figure 1 summarizes the general idea.

Figure 1 indicates that relaxation has a relationship to pore size. In these charts, each of the relaxation lines demonstrates the relaxation of the molecules in a particular pore size. Each pore size is color-matched to the relaxation response that develops from that void size.

In the graph on the left, after 16 ms of observation, each molecule in the very small grey pore size has relaxed. Most of the molecules in the brown pore size have relaxed. The very large pores, represented by blue and dark blue pores, have contributed very little to this response. Even smaller pores, shaded green, yellow, and red, have not provided much signal this early in the measurement. The problem arises in that they have contributed some signal. This signal contribution from each available pore size indicates that a simple sum of response at any point in time cannot characterize the formation. The quantity of porosity, alteration of the porosity, and basic structure of the porosity must be described in a different way.

At the end of 512 ms of observation, virtually all of the molecules in the brown, small blue, red, yellow, and green pores have achieved relaxation. The very large dark blue and light blue pores still have significant relaxation signal to contribute. The complete relaxation of these very large pores does not occur until 8000 ms, or 8 seconds, of time have elapsed. To characterize the amount of these very large pores that are present, the relaxation measurement must continue until that time.

This scenario resembles an academic exercise until the observation is made that these very large pores are exactly the void spaces that contribute to enhanced production in any reservoir system that has secondary porosity in the form of fractures or vugs. Early response is a combination of the relaxation from small and large pores, so discrimination of the relative pore sizes is impossible without more and better information. The late response can be directly attributable to large and very large pore sizes; consequently, an observation in this time window always corresponds to large pores (Borell et al., 2011).

When appropriate NMR tools are run with well-designed logging speed programs, complete measurement of 8000 ms is possible. Large sensitive volume NMR tools are capable of accomplishing this objective because of the large signal-to-noise measurement that is possible. These tools also have a larger measurement window that enables the entire sequence of data to be captured at a reasonable logging speed. After this data is captured, a better description of the reservoir may be established.

The Bray-Smith permeability formation was derived from the ability to capture this full relaxation response. The Bray-Smith permeability equation is used as shown (Smith et al., 2008):

$$Bray-Smith-Perm = \left[(MPHI)^{p} * \left(\sum_{T2Bphi0ms}^{T2Bphi8000ms} wf * T_2Bphi/BVI \right) \right]^{s}$$

Where: Bray-Smith-Perm = calculated relaxation - (T_2) derived permeability
MPHI = total relaxation-derived effective porosity
wf = weight factors for each relaxation-time bin description
T_2Bphi = effective porosity for individual relaxation bins
BVI = bulk volume water irreducible
p and *s* = constants

A major observation from NMR responses is that the T_2 or relaxation time is related to the size of the pore that contains the proton-rich fluids. This equation proceeds from that observation by applying weight factors (*wf)* to each measurement of T_2 time. This process enables a proportionate consideration of each individual event that can be measured by the NMR; a single large time event (such as a vug or fracture) can be identified and discriminated from the matrix response in a reservoir.

Analysis

In each of the reservoirs examined in this paper, a spectrum of NMR response is related to the T_2 relaxation in time. The measurement can be categorized into discrete time. This is the presentation of relaxation on the log. It is useful to have an understanding of this color palette to understand the exhibits that will follow. Figure 2 provides the T_2 spectrum of relaxation that is used in the remainder of this document.

The characterization of many different types of reservoirs with this time discrimination of relaxation have established that secondary porosity events will be evident when measured time is very late. If the only relaxation time measured is less than 64 ms, there will be no secondary porosity. These fractures and vugs behave as very large pore spaces and provide very late time T_2 measurements. Relaxation times of 256 ms and later is the expected response in these secondary porosity conditions.

Figure 2 represents 256 ms with bands of light and dark blue. In addition, in secondary porosity conditions, the light blue of 512 ms, the magenta of 1024 ms, and the gray of 2048 ms and later can also be observed, depending on the extent and size of alterations in the reservoir. A larger presence of these later times should also calculate higher permeability values (Smith et al., 2009).

A good understanding of this basic relationship between relaxation time, the color palette related to those times, and permeability may enable secondary porosity conditions to be recognized in a reservoir. When variations in relaxation measurement are apparent in some sections of a uniformly deposit reservoir, these variations can directly indicate the location of alteration events.

A valid concern in NMR identification of secondary porosity is the influence of drilling-induced fractures on the measurement. Large sensitive volume NMR measurements measure several inches into the formation, based on the bit size. Figure 3 shows an image and NMR log over a section with a very large drilling-induced fracture.

The image log shows a very large drilling-induced fracture centered at around 8,650 ft. The aperture of this feature covers almost an entire pad at that depth. The large sensitive volume NMR response at that depth shows no response. All of the bin time characterization of T_2 is less than 4 ms. Permeability, if any, would be shown as a yellow trace in the last track on the right. There is no calculated permeability with this distribution of T_2 relaxation.

The absence of any NMR response suggests that the extent of the drilling-induced fracture is a surface event and does not extend to the depth of the large sensitive volume NMR measurement. Pad-based NMR tools may encounter this borehole defect and would characterize this as a large secondary porosity event. The large sensitive volume NMR is not affected by this large surface defect. This powerful ability of large sensitive volume NMR provides enhanced confidence that continuous features of alteration actually exist.

Figure 4 shows a NMR presentation of a section with both drilling-induced fractures and secondary porosity from other sources. Drilling-induced fractures can be identified all the way through this section. Secondary porosity is also identifiable from the image log, especially in track 4. Vugs are present in a 3-ft section from 8,685 to 8,688 ft, and again at a 2-ft section from 8,690 to 8,692 ft.

The relaxation spectrum in track 5 shows the response of later relaxation time at those exact depths. The rest of the relaxation track indicates no measurement related to the drilling-induced fractures, which confirms that drilling-induced events will not be measured or characterized by the large sensitive volume NMR measurement made here. The color shading evident in track 5 indicates the increased potential of this reservoir based on these secondary porosity events (Smith and Hamilton 2013).

Track 6 shows the permeability related to these events as calculated by the Bray-Smith permeability equation. The only portion of this display in which this permeability is evident is exactly where the secondary porosity is indicated by the image log. Even these very thin sections of large permeability may be recognized by the NMR because of the ability of the measurement to capture relatively late time relaxation. This bodes quite well for the use of large sensitive volume NMR as a reservoir quality indicator. Pad-based NMR could incorrectly characterize the entire section as productive.

Figure 5 is a karst. The image of the karst in track 4 shows a clear fracture plane at 5,787 ft. The interval for the next 8 ft is highly altered below this collapse point. The rubble zone extends through that entire section, but the image is not clear regarding which porosity sections may have connectivity and which may be filled with small brecciated material.

The NMR relaxation in track 5 enables the relative reservoir quality within the section to be understood. The rock at 5,788 ft is characterized by early relaxation measurements. A quick reference to Figure 2 indicates that 128 ms is the latest arrival; although there is very little of that time measurement, it is definitely present. Most of that section has a much earlier measurement, which indicates small pore spaces and poorer permeability.

Beginning at 5,790 ft, very late time measurements become part of the measurement; below that depth, for the next 5 ft, late time relaxation is evident. The earliest response occurs at 64 ms, and the latest response occurs after 1012 ms. These late time measurements indicate a large, open pore structure, and enhanced permeability as a result.

Inspection of calculated permeability in track 6 confirms this to be the case. Although the porosity is greatest at 5,788 ft, the presence of the small pores results in the lowest permeability calculation in this section. Alternatively, the lowest porosity in the section is at 5,794 ft. Porosity here is 3 pu lower than at 5,788 ft, but the calculated value of permeability is at least one order of magnitude greater than that at the highest porosity.

This demonstrates the power of a NMR tool that is capable of measuring all of the relaxation time. The times, when correctly characterized by volume of each relaxation time, create an excellent correlation to the ability of that portion of the reservoir to produce. A NMR measurement that cannot complete this T_2 measurement cannot establish correct porosity or accurately assess permeability.

Figure 6 shows an interval with secondary porosity in several forms. It also includes a section with a very hot gamma ray (GR). An inspection of the image logs and NMR logs over this section provide valuable insight into the capabilities of these separate technologies.

The image log shows an extensive set of vugs in the section above the hot GR. Below the hot GR, there is a great conglomeration of vugs and pervasive fracture sets. These secondary alterations taken together significantly change the response from the NMR measurement.

The NMR relaxation in track 5 shows very late relaxation times through the entire section. The contribution to porosity by the fracture sets below the hot GR is unmistakable. Porosity in this section is 6 pu greater than in the vug-only enhancement segment. Although both sections have large portions of late relaxation, the effect of this large volume of late time results in an order of magnitude improvement in permeability in the section.

Each comparison of image logs to NMR logs displayed clearly establishes the power and ability of the large sensitive volume NMR to characterize secondary reservoir alteration events. The correspondence of the T_2 relaxation response to reservoir events is absolute. The characterization of that response to permeability is driven by the quality of the reservoir alteration events.

Conclusions

Large sensitive volume NMR measurements can make complete measurements of T^2 relaxation to include all data to 8000 ms. This complete measurement enables the characterization of the relative quantity of pore sizes in any given reservoir segment, which can be analyzed for permeability with the Bray-Smith permeability equation. This equation establishes permeability, accurate to within a fairly narrow range, using only the input from the NMR device.

Drilling-induced fractures can have very deleterious effect on any surface reading measurement. They are obvious when image logs are run. Contact NMR tools will respond to the same events and provide disproportionate estimates of secondary porosity volumes. Large sensitive volume NMR measurements are made deeper in the formation than the propagation of the drilling-induced fractures. These tools provide a clear evaluation of the reservoir without the influence of these artificially induced artifacts.

NMR measurements are very sensitive to even small intervals of very large variation in the quality of porosity and permeability. Secondary porosity alteration in any reservoir can be measured and reported as increases in reservoir quality and quantity.

The comparisons used in this paper include unaltered reservoir to NMR, drilling-induced fractures to large sensitive volume NMR result, drilling-induced fractures with secondary porosity in the form of vugs, a karst interval with varying quality of porosity and permeability, and a greatly enhanced reservoir section with some alteration with vugs and additional areas with fracture enhancement.

In all reservoir conditions evaluated, the NMR obtained the same characterization of reservoir secondary porosity features as the image log. A large sensitive volume NMR device recognizes the presence and quality of these features; the effects of artificially introduced, confusing reservoir events are ignored.

In all cases, the NMR can establish the contribution of these actual secondary porosity features to the value of the reservoir as described by porosity and permeability. Because these are the basic evaluation parameters of any reservoir, the NMR evaluation must be considered as one of the most powerful measurements we can make and consider for reservoirs with secondary porosity features.

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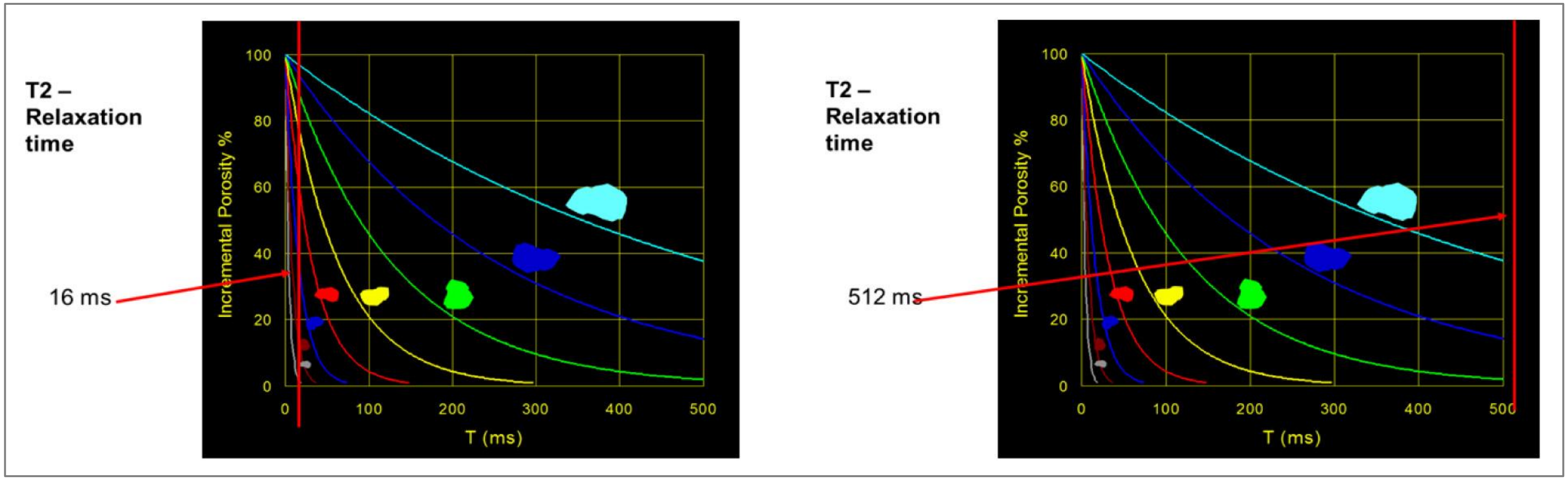

Figure 1. NMR relaxation response at 16 ms and at 512 ms.

Figure 2. Color application for relaxation time.

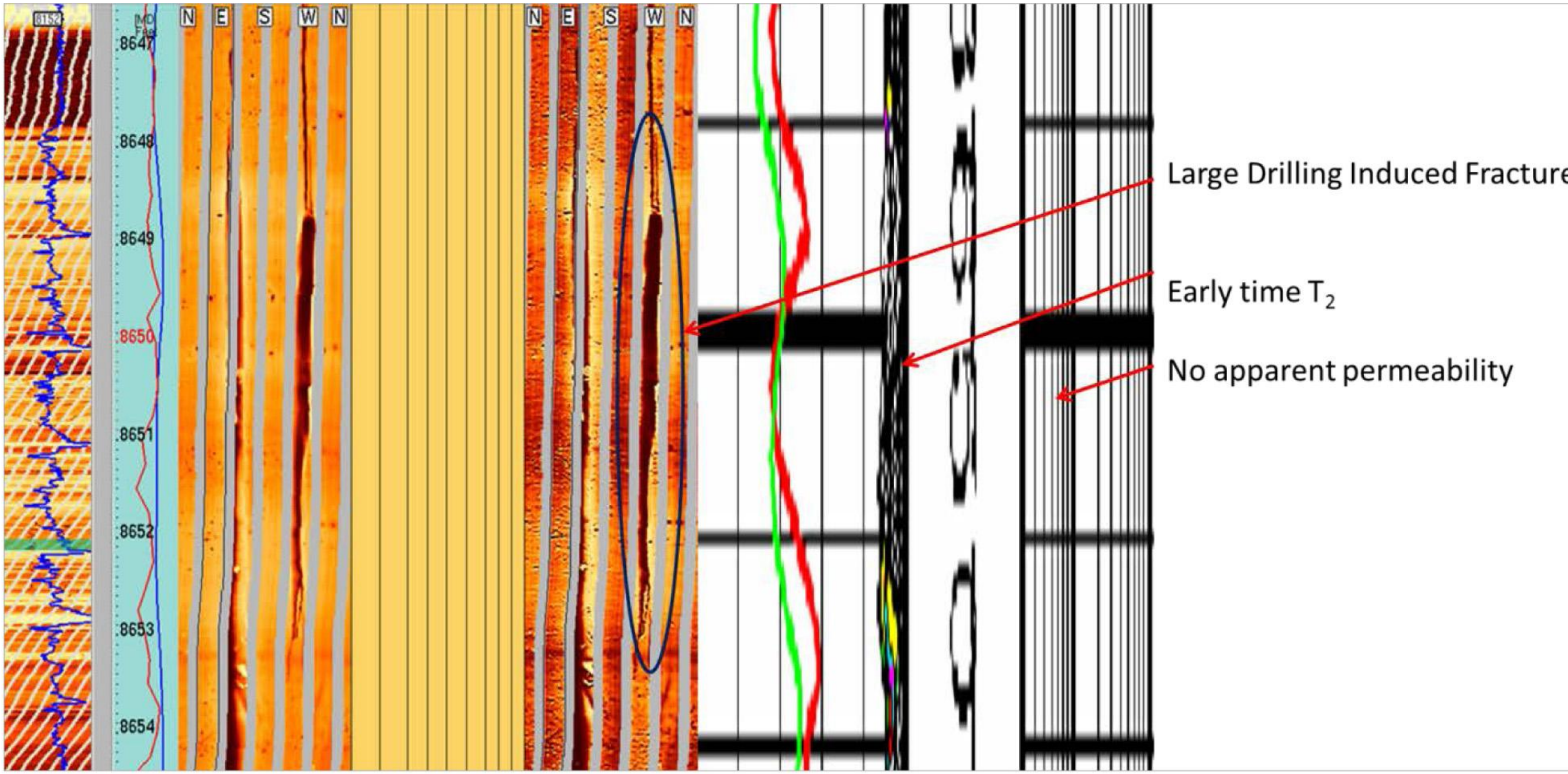

Figure 3. Image and NMR characterization of large drilling induced fracture.

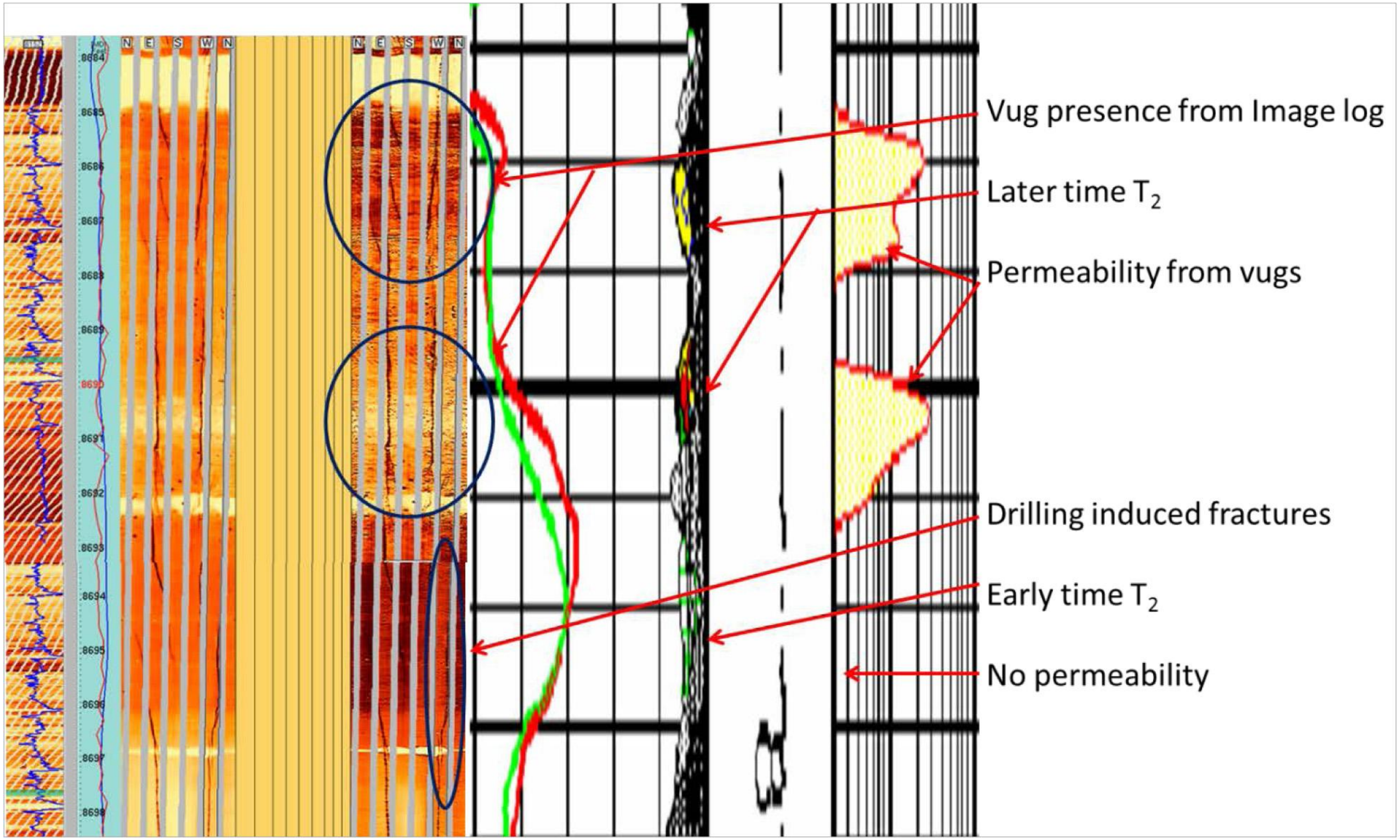

Figure 4. Reservoir section with drilling induced fractures and secondary porosity.

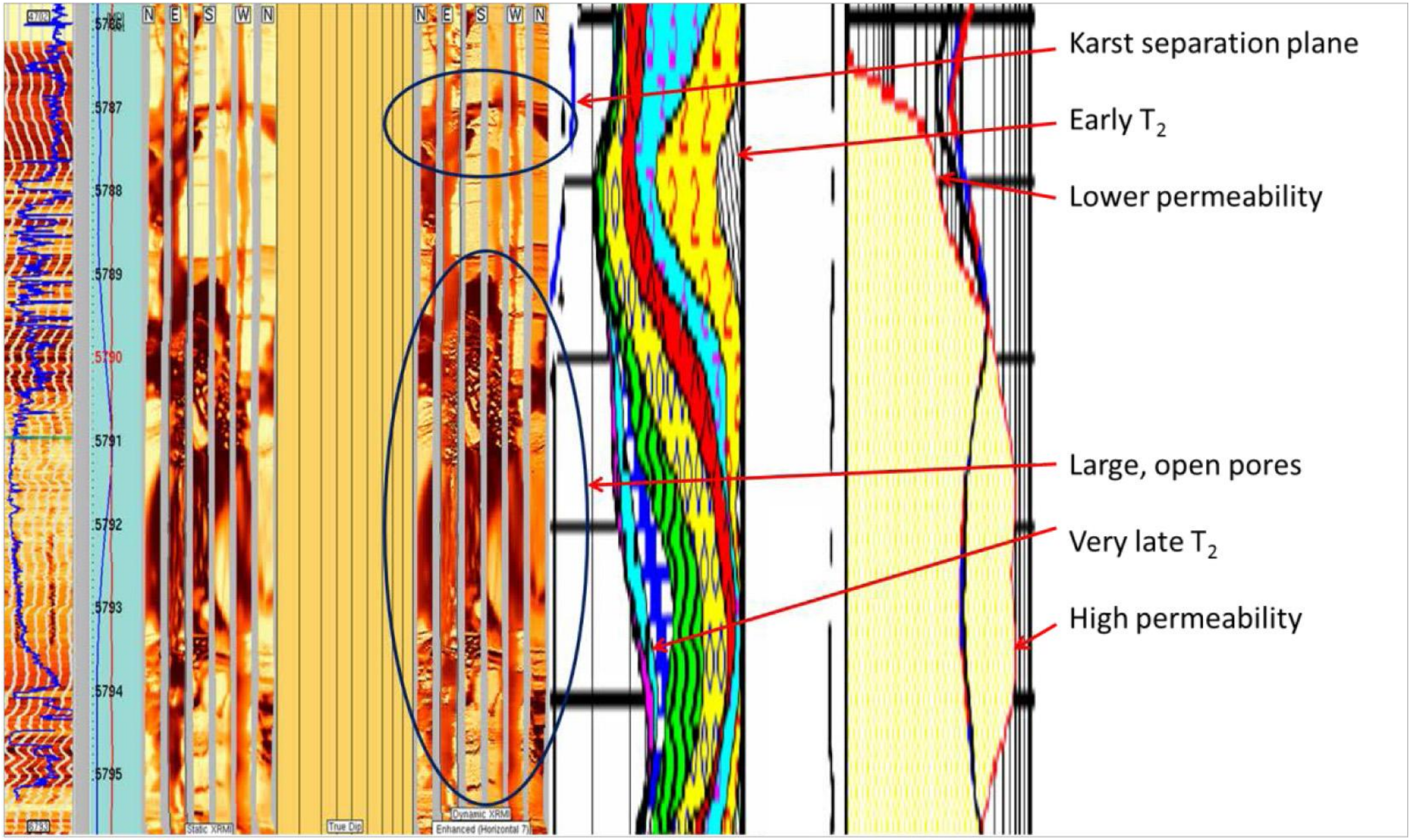

Figure 5. Karst characterization by image and NMR logs.

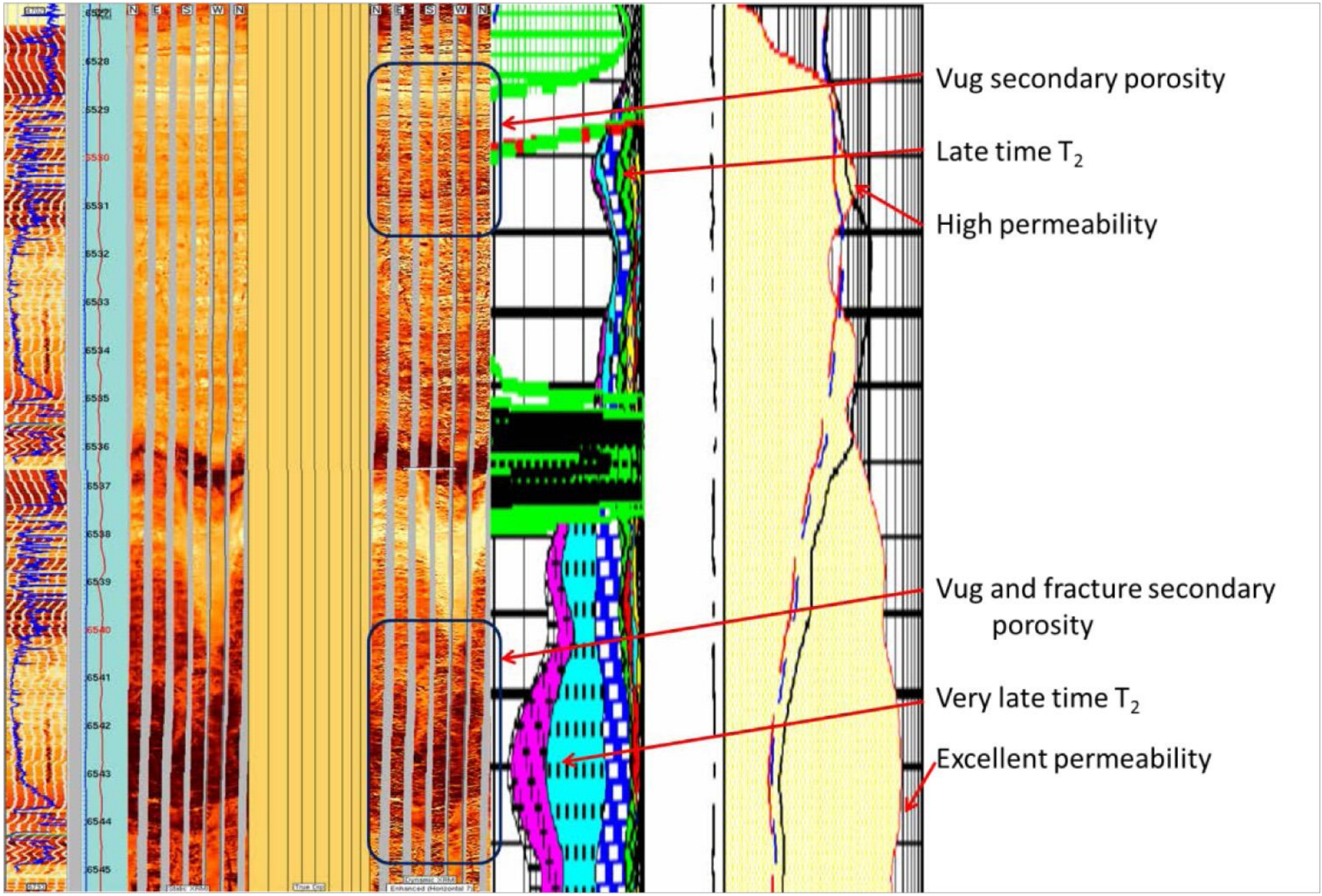

Figure 6. Reservoir segment with vug development along with fracture enhancement.