Nuclear Magnetic Resonance Response to Textural Reservoir Changes*

Charlie Smith[1], George Payne[2], and Jon Christensen[2]

Search and Discovery Article #41721 (2015)
Posted November 2, 2015

*Adapted from extended abstract prepared in conjunction with oral presentation at AAPG/SEG International Conference & Exhibition, Melbourne, Australia, September 13-16, 2015, AAPG/SEG © 2015.

[1]Halliburton, Oklahoma City, OK, United States (charlie.smith@halliburton.com)
[2]Herman L. Loeb, LLC, Lawrenceville, IL, United States

Abstract

Carbonate reservoirs may have extensive secondary-porosity features that alter the character of the reservoir. Increased permeability is the result of the presence of these events, but characterizing those using logging devices has proven problematic. Imaging logs can generally identify the presence of these fractures and vugs, but their contribution to permeability cannot be evaluated. Methods, Procedures, Process: Nuclear magnetic resonance (NMR) logs were added to logging programs to assist in the direct identification of the quantity and quality of these alterations. NMR relaxation has been demonstrated to provide an indirect measurement of secondary porosity and a calculation for permeability. Results, Observations, Conclusions: A full core was taken in this carbonate reservoir. Significant secondary-porosity features were identified in the core. Most of these features were small events that were easily identifiable. The NMR logs were also capable of identifying these secondary-porosity events. Their addition to reservoir quality was also evaluated. Novel/Additive Information: This paper presents examples of core identification of secondary features in these reservoirs. At the same depths, NMR identification of the permeability enhancements is also observed. The additional information obtained from NMR secures a log product that provides a quantification of secondary-porosity reservoir properties without the expense of coring.

Introduction

Carbonate reservoirs, without alteration, are generally dense, low-porosity formations that have low porosity on standard porosity measurements from density and neutron logs. These reservoirs may have alteration features that occur after deposition. Extensive secondary porosity features that can alter the character of the reservoir are evident in many productive carbonate reservoirs in the world. These secondary features may take the form of vugs, fractures, or a combination of these.

These features significantly change the ability of the reservoir to produce. In some cases, the porosity log response from density/neutron measurements can be affected by these alterations, but generally, this is not the case. The method of porosity measurements with both of these devices is to measure response from rock data and use the response to estimate the void space from correlations. In formations with significant and non-uniform alteration, correlation to actual formation parameters can be difficult.

Increased porosity and permeability is the result of the presence of these features, but characterizing those using logging devices has been poor. The porosity is not well defined, and permeability cannot be estimated by these measurements. Image logs were added to logging runs to attempt to identify and quantify secondary events in carbonate formations. Image logs can generally identify the presence of these fractures and vugs, but their contribution to permeability cannot be evaluated. The connectivity of these alteration features cannot be determined by the image alone.

Methods, Procedures, Process

Magnetic resonance (MR) logs were added to logging programs to assist in the direct identification of the quantity and quality of these alterations. An MR measurement is the only logging measurement that measures the area of void space available and quantifies it. This is a direct measurement of effective porosity. The rock portion of the reservoir cannot be investigated by MR devices, only the fluid components.

Figure 1 is a representation of the measurements made by an MR device. A very strong magnetic field is introduced in close proximity to the formation. All of the fluids that have polarity, which are in the open spaces in the reservoir, attempt to respond to this field by aligning with the field. This is termed polarization, time 1, or T1.

Each fluid type responds at a different rate, but with sufficient exposure to this field, a statistically accurate sum of the responses from each of the fluid types can be obtained. To make a complete polarization measurement, a significant amount of time is required. Figure 1 shows that the time required is 12 seconds. The sum of all of the T1 measurement is the quantity of effective porosity in the reservoir. This measured effective porosity includes the volume of all of the secondary porosity events. The contribution of secondary porosity in any form can now be accurately measured and included in effective porosity reporting.

The other measurement made by the MR device is made by measuring the response of the molecules in the formation as they respond to alterations in the magnetic field. This is called relaxation, time 2, or simply T2. Figure 2 is a representation of relaxation at 16 milliseconds (ms) and at 128 ms (Smith et al. 2014). Various pore sizes and pore geometries are represented.

The graph indicates the decay of the T2 response in the pore sizes. The pores are also arranged along the bottom of each graph. The pink color in each of the pores represents the molecules that have relaxed; all of the additional color in the pores has yet to contribute to the relaxation signal. At the very early time of 16 ms, all of the molecules in the small pores have contributed to the T2 signal, while only the molecules that are near the pore walls in the larger pores have done so. Later, at 128 ms, all of the molecules in small- and medium-sized pores have completed their contributions to the relaxation signal. The very large pores appear nearly the same in both of the time representations shown.

Reference to Figure 1 provides the understanding that only a significant amount of measurement time will allow for the complete capture of the relaxation event signal. When sufficient measurement can be made, the relative sizes of pores present in the inspected region can be evaluated. Because the sum of all T2 molecule responses is equal to effective porosity, the relaxation time response can be presented to show the porosity contribution, segregated by time in the measurement process.

The MR relaxation porosity, segregated by time, provides the ability to calculate permeability directly from the T2 time description. This relationship is defined by the Bray-Smith permeability equation (Smith et al. 2008), which takes the form:

$$BRAY-SMITH\ PERM = \left[(MPHI)^{p} \times \left(\sum_{T2\ Bphi\ 0\ ms}^{T2\ Bphi\ 8000\ ms} wf \times {}^{T_2 Bphi}/_{BVI}\right)\right]^{s}$$

Where:
Bray-Smith Permeability = Bin-calculated permeability
Bphi = Bin porosity
MPHI = NMR effective porosity
BVI = Irreducible porosity fraction
wf = Bin weighting factor
Factors p and s = Empirically-derived constants

In this equation, the measured relaxation is separated by time, and then multiplied by weight factors that adjust the contribution to permeability. BVI and MPHI are directly measured. The weight factors and the exponents are constants. All terms of this equation are either directly measured by the MR device or they are constants. The permeability from this calculation is extremely robust. This has been applied in many different and varied hydrocarbon reservoirs with a great deal of success.

The presentation of the results of this calculation is accomplished by a partition of the acquisition times and by providing different color representations of each measured time. In each of the exhibits shown later in this document, this color scheme versus time is used. Figure 3 shows how this is presented on a log. Small pore spaces will be early in time, and only secondary porosity features will be represented by late time measurements. In the carbonate reservoir examined in this document, any measurement that is 256 ms or more is an indication of secondary porosity. The precision of the measurements of effective porosity and the calculation of permeability are limited by the physical characteristics of the MR device. MR tools have an antenna aperture where the signal is captured. The smallest aperture in the industry is 6 in., and the largest is 24 in.

When small features, such as fractures and vugs, are a part of the measurements captured, they are statistically insignificant compared to the total signal. There can still be indications of the presence of these features in the signal. This paper compares the MR log response to specific characteristics from the full core that was taken.

Results and Observations

The full core was taken in this carbonate reservoir. Significant secondary porosity features were identified in the core. MR logs were also acquired in this well. These MR logs evaluated both the porosity and permeability in this section. The identification basis for secondary porosity identification in this reservoir is 256 ms or later. Using those criteria, there appears to be secondary porosity present through the entire section. The volume and quality of the alteration is identified by the contribution to total porosity of these late relaxation events. There are portions of the logs where significant measurements of 512 ms and later are identified; however, these measurements are not in all portions of this log. When these very late time measurements are present, the sizes of the secondary porosity features are larger, and the contribution of that pore space to the calculated permeability will be greater.

Figure 4 shows the capture and characterization of porosity at a change condition. At 4,823 ft, there is a shale break. The porosity below the shale break is significantly different from the porosity of the rock above the break. The porosity is shown in track 1 on the log, scaled from 0 to 30% right to left. The portion of the core that is visible does not exhibit evident secondary porosity.

Permeability is illustrated in track 2 and is scaled logarithmically from 0.002 md to 20 md. The core permeability reported averages of roughly 1 md from the top of the interval to 4,835 ft. Below that depth, there is a much greater dispersion in the data. The MR permeability in the same interval is roughly 0.2 md, but the calculated value is not smooth. There are spikes in the data throughout the section, indicating that there is secondary porosity in all areas of the reservoir. The secondary porosity in this portion of the reservoir appears to be constant, with a continuous presence of one-half porosity unit in the 256-md relaxation band.

Figure 5 examines a portion of the interval with consistent core response. The photo on the right is a 1-in. portion of the core at a depth of 4,833 ft. Alterations can be seen in this image as small vugs within the fabric of the rock. The MR log at that same depth indicates a high porosity with a small component of that porosity colored in light blue (512 ms) and a very small portion colored in magenta (1,024 ms). This indicates the presence of the features identified in the core with a total contribution to porosity of just a fraction of a porosity unit.

The effect on the permeability at 4,833 ft is evident with a higher permeability, where the late time measurements in MR porosity are identified. When the porosity begins to drop at 4,837 feet, permeability is lower. Above that depth, higher permeability can be observed in the calculated permeability and is possibly attributable to the presence of the small vug features identified in the core.

Figure 6 highlights another textural alteration in the reservoir at a depth of 4,837 ft. There is a distinct change in the reservoir. The color change in the MR porosity presentation indicates a compositional change, and there begins to be a large variation in the reported permeability from the core. Inspection of the core below 4,837 ft indicates that the core-reported variability events may be a result of the inconsistent texture of the reservoir. There is a significant amount of highly dense material bonded together with cementing material. It looks very similar to a conglomerate on a much smaller scale. This variation appears to have significant impact on both the texture indication in the porosity measurement, as well as the variation in the calculation of permeability.

The arrows in Figure 6 highlight the presence and the effect of this alteration. In addition to the visual change, there are data points that are only 1 ft apart in the core, where the reported permeability is 0.002 md in the lower end and 2 md in the higher end. A little deeper in the section, the reported permeability is as high as 20 md. Close inspection of this interval reveals the following variation: 4,836 ft, 2 md; 4,837 ft, 0.003 md; 4,838 ft, 10 md; 4,839 ft, 0.003 md; 4,840 ft, 0.002 md; and 4,841 ft, 15 md.

These drastic changes within a very short interval highlight the effect of minor alterations on permeability. There can also be a significant impact on effective porosity, but the alterations are so small that they are not recognized by any porosity measuring devices. The effect of the increased presence of secondary porosity on permeability is evident in both the core data and the MR data. An increased presence of 512 ms and 1,024 ms in the relaxation measurement yields a calculated permeability increase from 0.2 md to 0.7 md.

Close examination of the core reveals the effect of textural events in this section on the reported values. Figure 7 is an interesting presentation of a very small segment of the core. In the image, small vugs can be identified at 4,838 ft. These are actually present throughout the image, but the highly dense formation material can also be observed. The core-reported data is from an approximate 1-ft portion of the core, which is tested for porosity and permeability. When the core portion tested has some of the vugs included, a high value for permeability is reported. At 4,838 feet, the core-reported permeability is 10 md. By inference, the core must contain some volume of these secondary porosity features.

When the core tests are performed, where none, or very few of the vugs are captured, a very low value for permeability is recorded. At 4,839 ft, the core-reported permeability is 0.3 md. The visual inspection of the core provides appreciation for the variations within the core and provides an explanation for the great variance in core permeability values reported.

The MR measurement also responds to these secondary porosity vug events. The presence of 256-ms and 512-ms T2 reported times provide confidence that some secondary porosity is present. The variation in the effective porosity measured and the relative sizes of each of the time bands are not readily apparent at this scale. The permeability calculation from the Bray-Smith permeability equation spikes at various points in this interval. The variation is small, from 0.3 md to 0.5 md at best. The indication of secondary porosity permeability enhancement can be identified when secondary porosity features are expected.

Conclusions

Magnetic resonance measurements of polarization (T1) and relaxation (T2) provide a significant amount of useful information in reservoirs with great textural variation. The data shown in this paper relates specifically to a dense carbonate, but the application can be used in any reservoir. Effective porosity measurement is directly accomplished by an MR device. This is the only porosity device available in electric logging that measures pore space. Other porosity tools measure a physical characteristic of the rock and use correlations to arrive at porosity.

Permeability can be calculated when a time-discriminated measurement can be made of relaxation. An accurate time-discriminated T2 can only be accomplished when complete measurement of the time spectrum is accomplished. Based on the antenna for the specific MR device in use, logging speed should be adjusted to accomplish this objective.

The Bray-Smith permeability equation can be used to approximate the permeability, even in highly variable rock. Small events, which occur in only a fraction of the antenna aperture, can still be identified in the textural quality of the rock as measured by the T2 time discrimination. In this reservoir, whenever portions of porosity were represented by 256 ms and later, secondary porosity events were present. The calculation provides for a relatively greater contribution to permeability from those late time events than similar porosity measurements of earlier T2 time.

The additional information obtained from MR secures a log product that provides a general quantification of secondary porosity reservoir properties without the expense of coring.

References Cited

Smith, C., L. Hamilton, and L. Ziane, 2014, Advanced Log Characterization of Complex Carbonate Reservoirs: Paper SPE-170118-MS presented at the SPE Heavy Oil Conference - Canada, Calgary, Alberta, Canada, 10–12 June. Web accessed October 19, 2015, http://dx.doi.org/10.2118/170118-MS.

Smith, C., J. Bray, and S. Ramakrishna, 2008, Utilization of magnetic resonance bin distribution to develop specific permeability: Presented at the Rocky Mountain Geology & Energy Conference, Denver, Colorado, USA, 9–11 July.

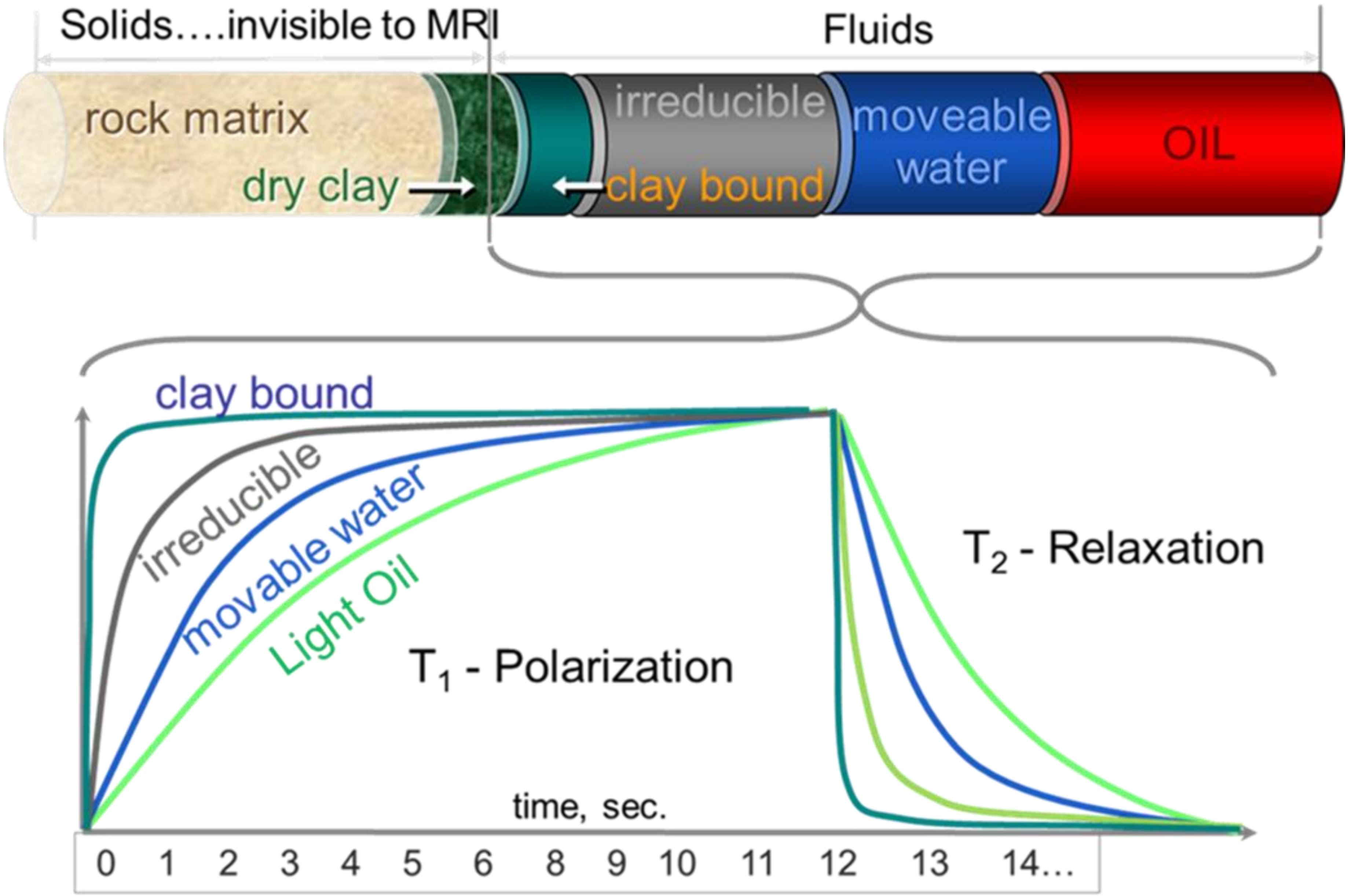

Figure 1. Measurements made by MR devices.

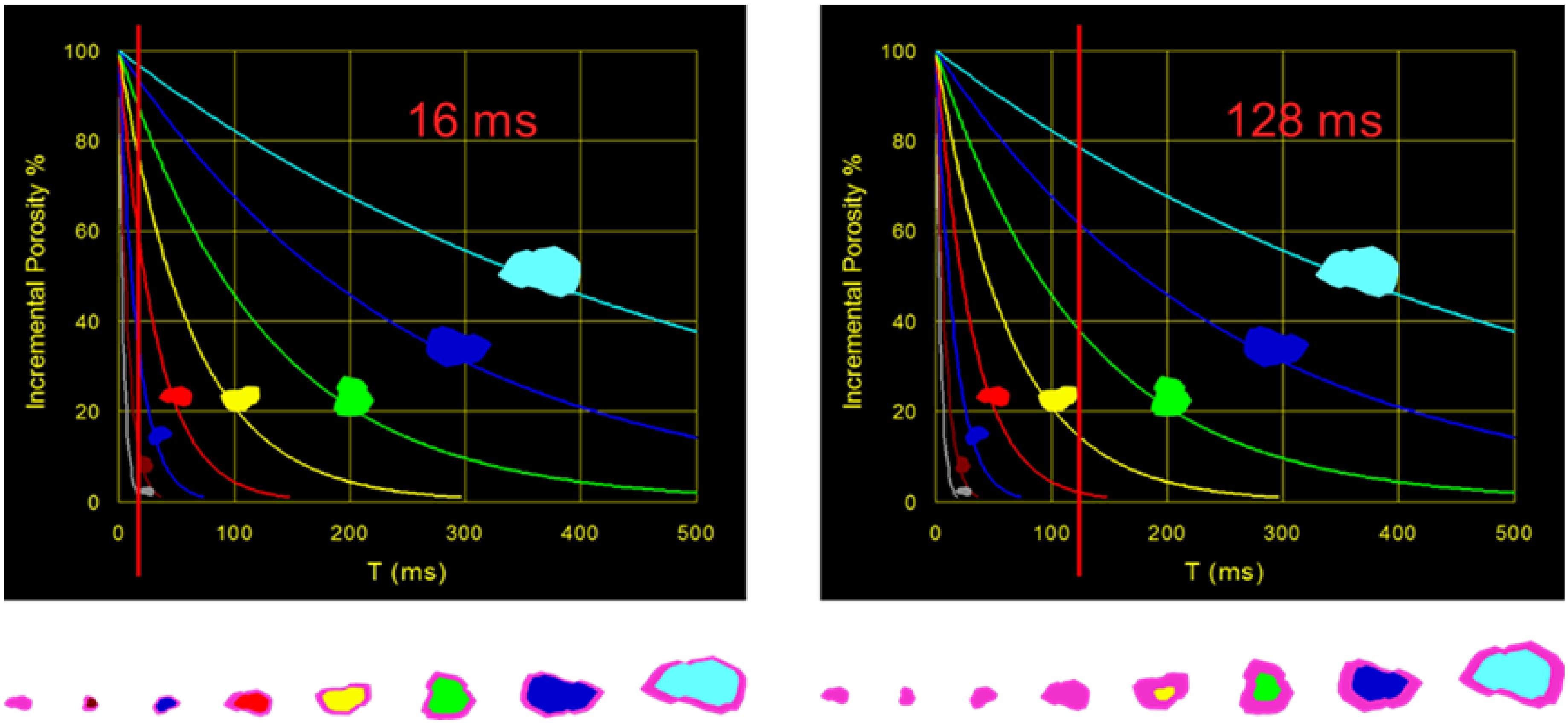

Figure 2. Relaxation response in various pore sizes at 16 ms and at 128 ms.

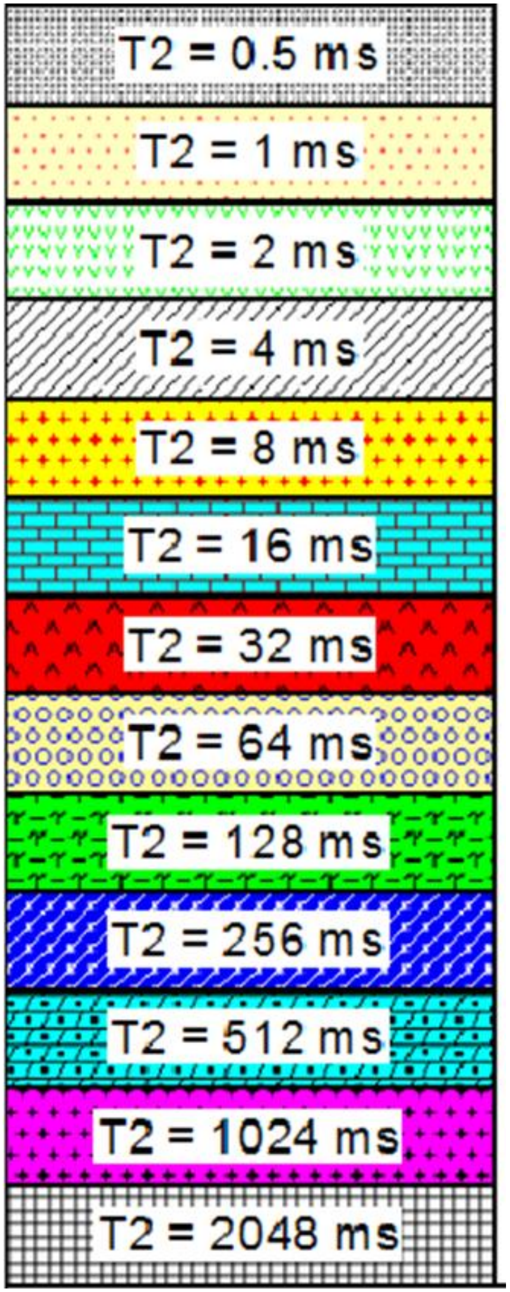

Figure 3. Time segmented representation of MR relaxation time.

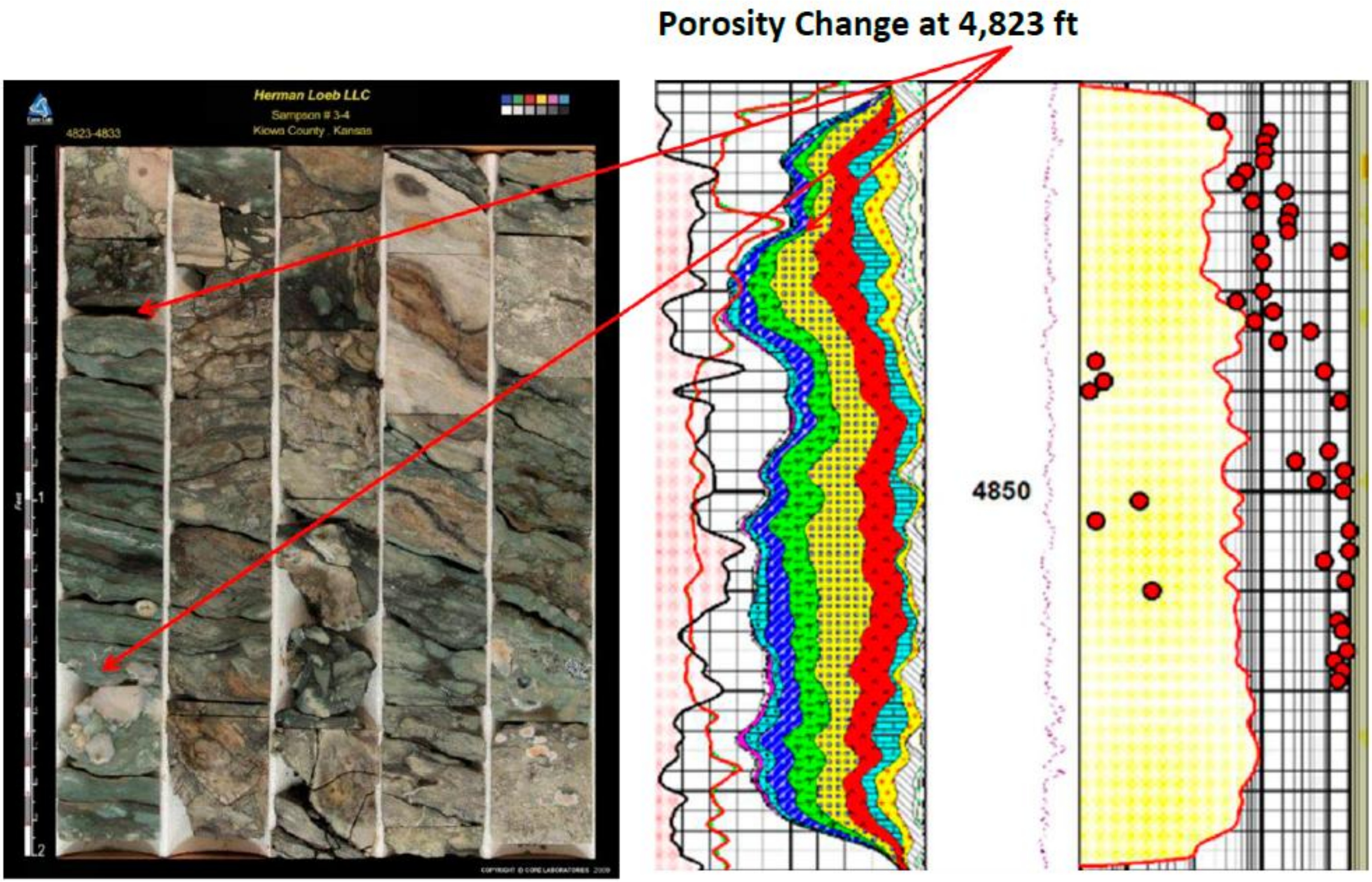

Figure 4. Porosity change below the shale break.

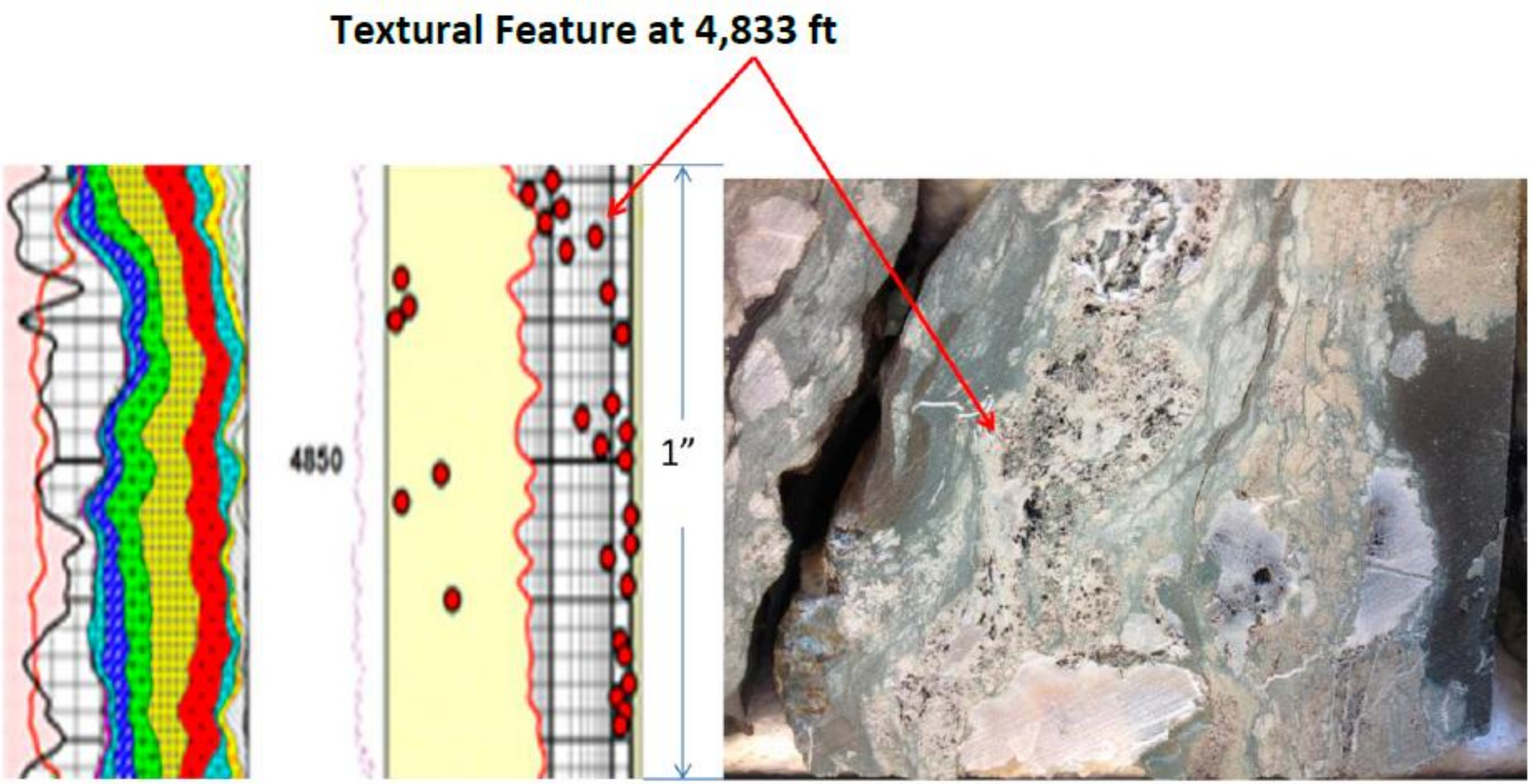

Figure 5. Comparison of relaxation spectrum versus core with small vugs.

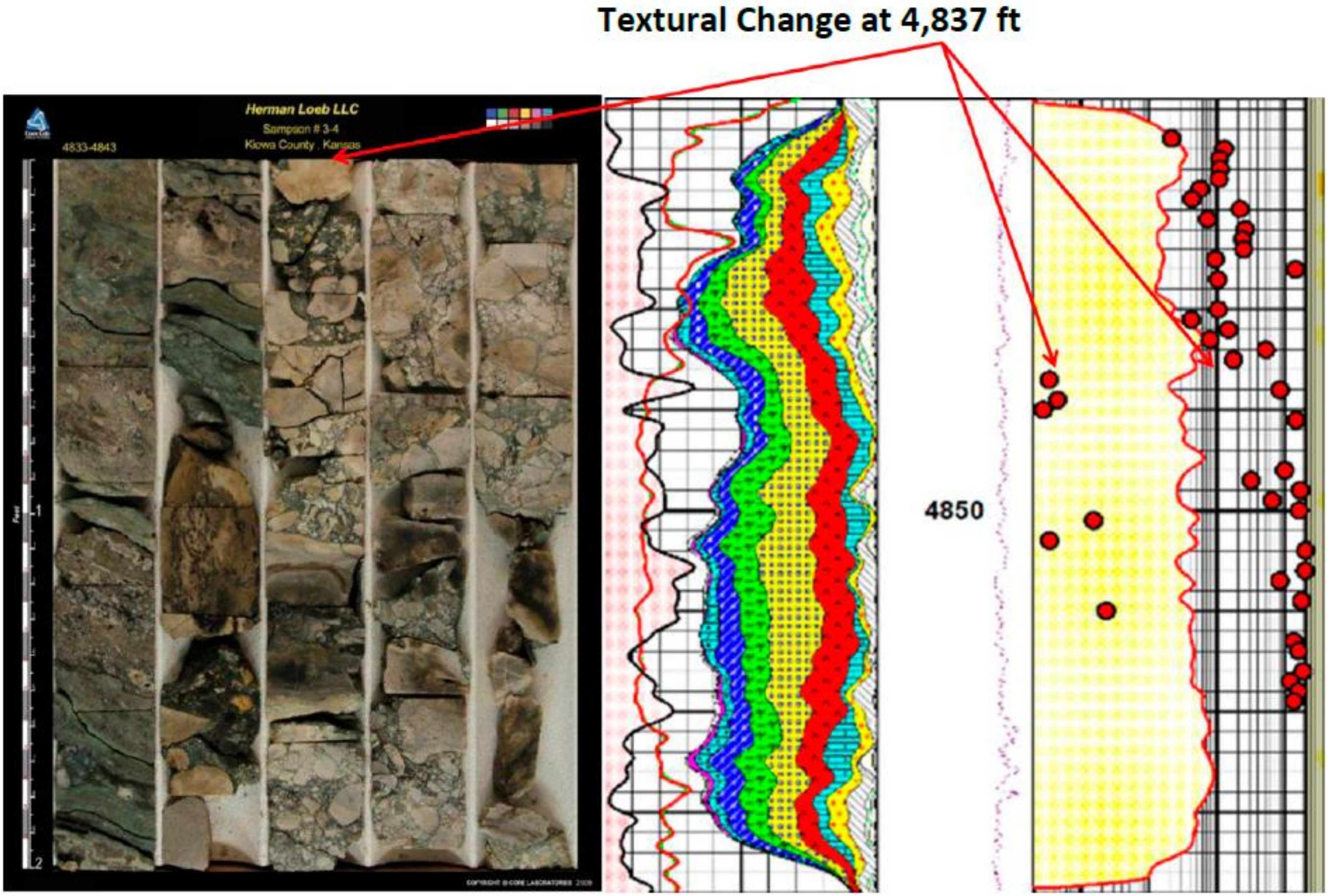

Figure 6. Porosity and permeability change responding to textural change.

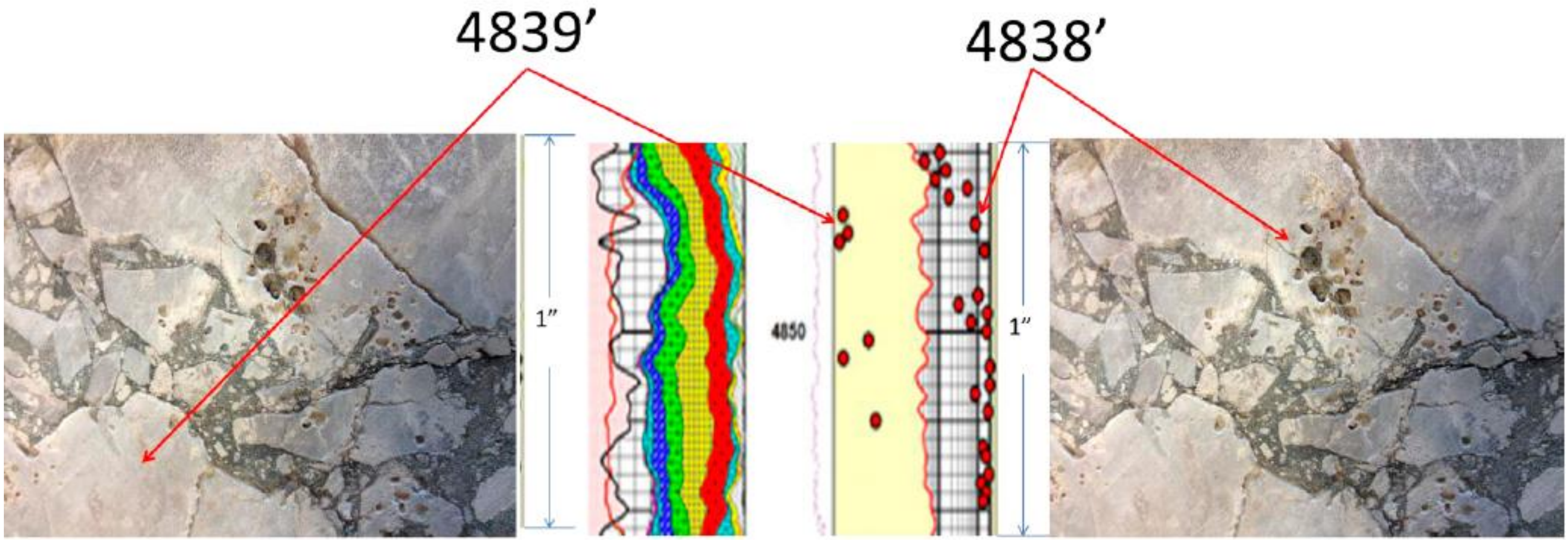

Figure 7. Dense matrix material and vug alteration with permeability from core and MR.