Nuclear Magnetic Resonance Relaxation Permeability Response in Oil Production Conditions*

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Abstract

The empirical application of nuclear magnetic resonance (NMR) relaxation, or T_2, response has been documented in many different formations. The comparison of permeability calculated using only textural information provided by these T_2 measurements has been remarkably successful at emulating the data from cores and from production rates after completion. The Bray-Smith permeability equation used in these studies removes the necessity of external input from cores or other lab studies to arrive at these useful answers. Most of these studies were concluded in dry gas reservoirs.

With the increased emphasis on oil production because of commodity prices, the focus of much of the industry exploration has shifted to this heavier, and more viscous, fluid. The NMR relaxation responses are more complex with the introduction of additional fluids. In many of these reservoirs, three fluids are present: gas, water, and oil of varying thickness and viscosity. Any device that could provide a reasonably accurate permeability response in these conditions would be valuable in determining the economic value of any well or reservoir.

This paper makes a comparison of these relaxation (T_2) events in oil conditions from fields in Argentina using this Bray-Smith solution for permeability. The derived permeability calculated from the Bray-Smith equation is compared to the actual production. Results obtained from the Coates equation are also presented. The more complex fluid conditions and the fluid flow rates are poorly forecast by the Coates method and are reasonably well approximated by the Bray-Smith calculation.

Introduction

Studies have indicated that there is a relationship between pore and pore throat sizes and relative permeability. Intuitively, this seems to be obvious, as molecules that are competing for the same pore spaces will inevitably interfere with each other as they attempt to move through spaces that restrict their movement. Low-porosity systems exhibit a large degree of pore-size-dependent permeability.

Oil molecules, with their higher resistance to movement or higher viscosity, exacerbate this problem. The molecules are less able to rotate to align themselves for movement through a restrictive area. The net result of effective permeability can be quite dramatic.

Several studies that evaluate the ability of permeability algorithms derived from nuclear magnetic resonance (NMR) logs to accurately compare to core-derived permeability for these same reservoirs, have been completed, and the results of these studies published. These results have been remarkably consistent and positive. In each previous study, the permeability estimate is within a small error band of actual laboratory results.

An investigation into the ability of NMR logs to accurately characterize permeability in oil-production environments has not been extensively investigated and published. This paper attempts to evaluate the relationship of the ability of the NMR tool to accurately characterize production predictions in these difficult conditions.

Field Location

The Cerro Dragon oilfield is located 85 km west of Comodoro Rivadavia on the west side of the San Jorge Gulf basin in the Chubut and Santa Cruz Province, Argentina (Figure 1). Pan American Energy, LLC operates 50 fields in this area.

The Cerro Dragon oilfield comprises an area of 3,480 km^2. It was formed in a vast basin in the Mesozoic period. Filling occurred in the rifting stages of the late Jurassic/early Cretaceous period of primarily lacustrine and fluvial systems. The primary production comes from the Comodoro Rivadavia, which is composed of shaly sand, and the Mina el Carmen formation, which is composed of tuffaceous sands, tuffs, and altered tuffs. The average reservoir thickness is between one and eight meters (Acuna et al. 2003, Espina et al. 2009).

Reservoir conditions consist of flow paths that are difficult and tortuous. The permeability from conventional log analysis fails because of great variability within the formation. Extensive coring for permeability description is cost prohibitive.

Some technology that can resolve this difficult issue is required. Recent developments in NMR analysis provide a technique that can effectively evaluate the alterations within the reservoir and accurately establish permeability exclusive of any other log measurement.

Permeability Model

The solution to this permeability issue was very difficult. Textural changes in the rock owing to impurities, both imbricated and deposited, that caused great variation in permeability, sometimes on a foot-by-foot basis. Some parts of the reservoir have no permeability. We made many attempts to correlate these textural events to measurements from standard logs with very poor results, but accurate permeability is critical to define portions of the reservoir that would be productive.

We added NMR logs to the logging suite to provide an additional investigative assessment of the reservoir character and porosity. Permeability was determined to be the most important reservoir characteristic. Low porosity in many cases did not correlate to low permeability. The pore sizes in the formation dictated the productivity of the formation, which is described by the graph of T_2, or relaxation time versus pore size (Figure 2).

General Relationship between NMR T2 Time and Pore Size

This reservoir did not have consistent development of secondary porosity or changes in texture. Alterations of the fabric of the rock could be observed as bin characterizations of the NMR T_2. Textural alterations through deposition or alteration events can be measured and characterized by these minor changes in T_2 relaxation responses.

Any secondary alteration also contributes to permeability. Close observation of these alterations in texture could be significant in determining the potential of this reservoir. Characterization of this texture and fabric are the desired result of the NMR logs.

The Bray-Smith permeability equation from nuclear magnetic resonance (NMR) logs was introduced to the industry several years ago as a technique that could forecast permeability in an accurate manner in any reservoir without the need for external data from cores or other sources. This equation takes the following form:

$$Bray-Smith-PERM = \left[(MPHI)^{p} * (\sum wf * T_2 Bphi / BVI) \right]^{s}$$

Where $MPHI$ = NMR porosity, wf = weight factor, T_2Bphi = segmented bin porosity, BVI = bulk volume irreducible, and p and s are constants derived from core and empirical studies.

Permeability can be determined from this application in the absence of any core or reservoir studies. The permeability characterized is generally within +/- 20% of laboratory permeability. This permeability can be used to target portions of the reservoir that have a greater ability to produce.

Analysis

This complex reservoir has secondary alteration features that are easily observed in NMR responses. These alterations are not consistent from zone to zone, but appear locally enhanced by deposition, solution, or dissolution processes. They contribute to a great diversity in texture of the reservoir. These textural changes are reflected in a great diversity of permeability, as captured by the T_2 measurement and as calculated from the Bray-Smith permeability.

The traditional calculation of permeability has been from the Coates equation and takes the following form:

$$CoatesPerm = \left(\frac{\phi}{C}\right)^4 * \left(\frac{FFI}{BVI}\right)^2$$

Where: C is the Coates Constant, BVI is the irreducible porosity fraction, and FFI is the free-fluid porosity fraction.

This model can characterize permeability in formations that are consistent with very little textural change. In the Comodoro Rivadavia formation, these textural changes are intense, so the Coates and Bray-Smith models do not agree.

Comparison of Bray-Smith and Coates Permeability

The NMR log above demonstrates the great differences that can be observed between the Bray-Smith and the Coates calculations of permeability (Figure 3). Track 1 displays the porosity measurement from the NMR tool. Each slice of time has a component that directly contributes to porosity. The sum of all of these measurements results in effective porosity, which is a direct output of the measurement. This conclusion is only valid when the T_2 measurement is accomplished for a full eight seconds. That length of time is required for every molecule in every pore size to achieve relaxation. Any shorter measurement may reflect an incomplete effective porosity and poor description of texture.

Variation in the quantity in each time measurement is a reflection of fabric alteration in the reservoir. Visually, the interval from 6,114 to 6,128 ft can be described as a coarsening-up sequence. This conclusion is formed by the observation that later-time T_2 measurements increase at shallower depth.

In Track 2, just to the right of the depth track, both permeabilities are plotted. The Coates permeability is a blue-dotted curve and calculates an average permeability of 2–3 md, with a peak permeability of 10 md. The Bray-Smith permeability is shaded in yellow and is showing an average permeability of about 0.5 md, with peak permeability of one md. This is approximately a one-decade difference throughout the interval. The Bray-Smith permeability also has more character, demonstrating the ability to respond to minor variations in the texture of the rock.

The Bbin curve, second from the right, is designed to be a visual tool to estimate the variability of the rock within a specific area. We have learned through comparisons with production that there is a general relationship of good production to pore sizes that was reflected in T_2 measurements greater than 64 ms in time. This curve is the percentage of all pores measured at a specific depth that measure greater than 64 ms divided by total porosity measured for that depth. The result is presented as a percentage from zero to 100% in the track. The intuitive conclusion is that the greater percentage of large pores that are measured at any one point, the higher permeability will be observed for that interval.

The Bray-Smith permeability verifies this relationship and refines it by focusing on the actual textural changes that are occurring within the formation. Careful comparison foot by foot through this log section confirms that this is true. The implication is that visual estimation of permeability from the Bbin curve may be valuable as a quick assessment of deliverability from a reservoir. Qualification of the economic value of the zone can only be determined by the detailed calculation of the permeability reflected by formation texture.

Much geologic information can now be derived and applied from the NMR measurement. The changes in the texture of any reservoir can be vertically described from a single wellbore. Additionally, offset reservoir textures can be accurately measured and related back to the original dataset. This data can be applied in useful three-dimensional descriptions of reservoir quality.

Results

This study was designed to reflect the character of the Comodoro Rivadavia formation as described by the textural measurement of the NMR tool. The complete measurement of the T_2 relaxation spectrum by investigating 8,000 ms has allowed an excellent description of texture variations within the formation. This complete measurement is the deterministic conclusion of permeability that separates the Bray-Smith, or textural perm, from less descriptive permeability characterizations.

For this study, there was a series of results from two separate wells that were completed in oil and water conditions. One well had completion attempts in 12 intervals; the other well had completion attempts in 11 intervals, for a total of 23. These were evaluated by comparing the calculated permeability from the Bray-Smith permeability to actual production from the intervals in the wells. They were also evaluated using the Coates permeability and comparing to actual production.

Well 1 Results

The statistical results for Well 1 are presented in Figure 4. The permeability is cross-plotted with the actual production rates from each of the intervals tested. The statistical line is a “best-fit” regression from origin through maximum production.

The Coates-permeability plot has good coherence to actual rates at the very low end of production. As rates become higher, the dispersion becomes greater. Conformability to actual rates is not evident.

The Bray-Smith characterization is consistent through most of the production with two statistical outliers. Note that the permeability scales for each of these plots it different. This reflects the difference in calculated permeability, as pointed out in the previous panel.

Well 2 Results

Statistical results for Well 2 are presented in Figure 5. In this case, the permeability scale was fixed with production cross-plotted. The coherence for Coates is non-existent. The Bray-Smith calculation has more statistical outliers, but a trend line is clearly established with fair coherence to actual data.

Conclusions

- Texture variations from depositional events or secondary alteration events can be captured and characterized by T_2 relaxation responses from NMR devices as long as an extremely late-time measurement of the T_2 is accomplished. If the late-time data is not acquired, an incomplete understanding of both small and large pore presence within the reservoir will be the result.
- Magnetic resonance logs (NMR) can be used to accurately define permeability through application of the Bray-Smith permeability equation. Statistically, this provides a result that is generally consistent with observed production rates in these oil-productive reservoirs.
- The measured values for effective porosity and the calculated values for permeability are a valid qualitative characterization of reservoir parameters and are accurate enough to be used for economic evaluation of this, and virtually every other, reservoir.

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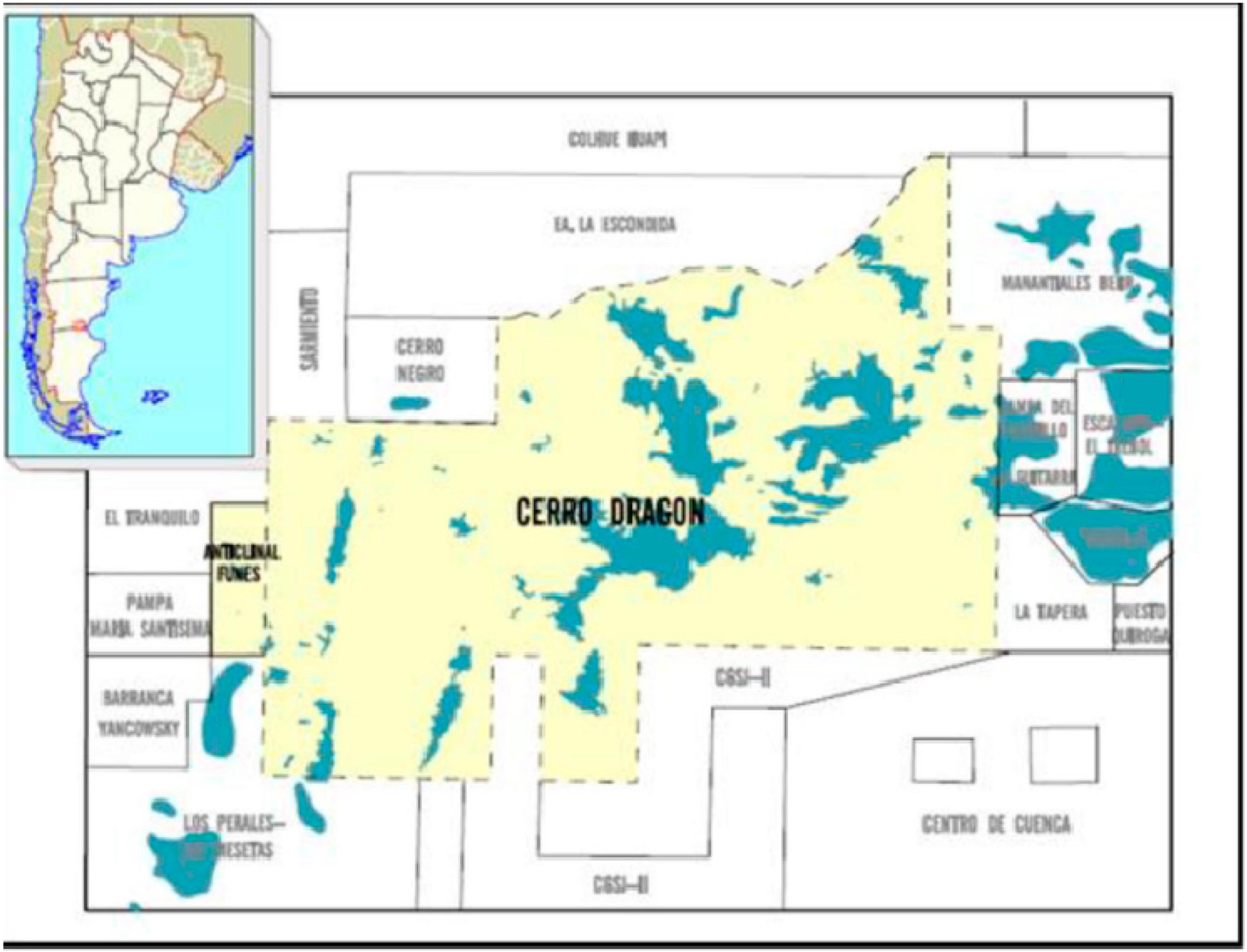

Figure 1. Location Map (Espina, et al., 2009).

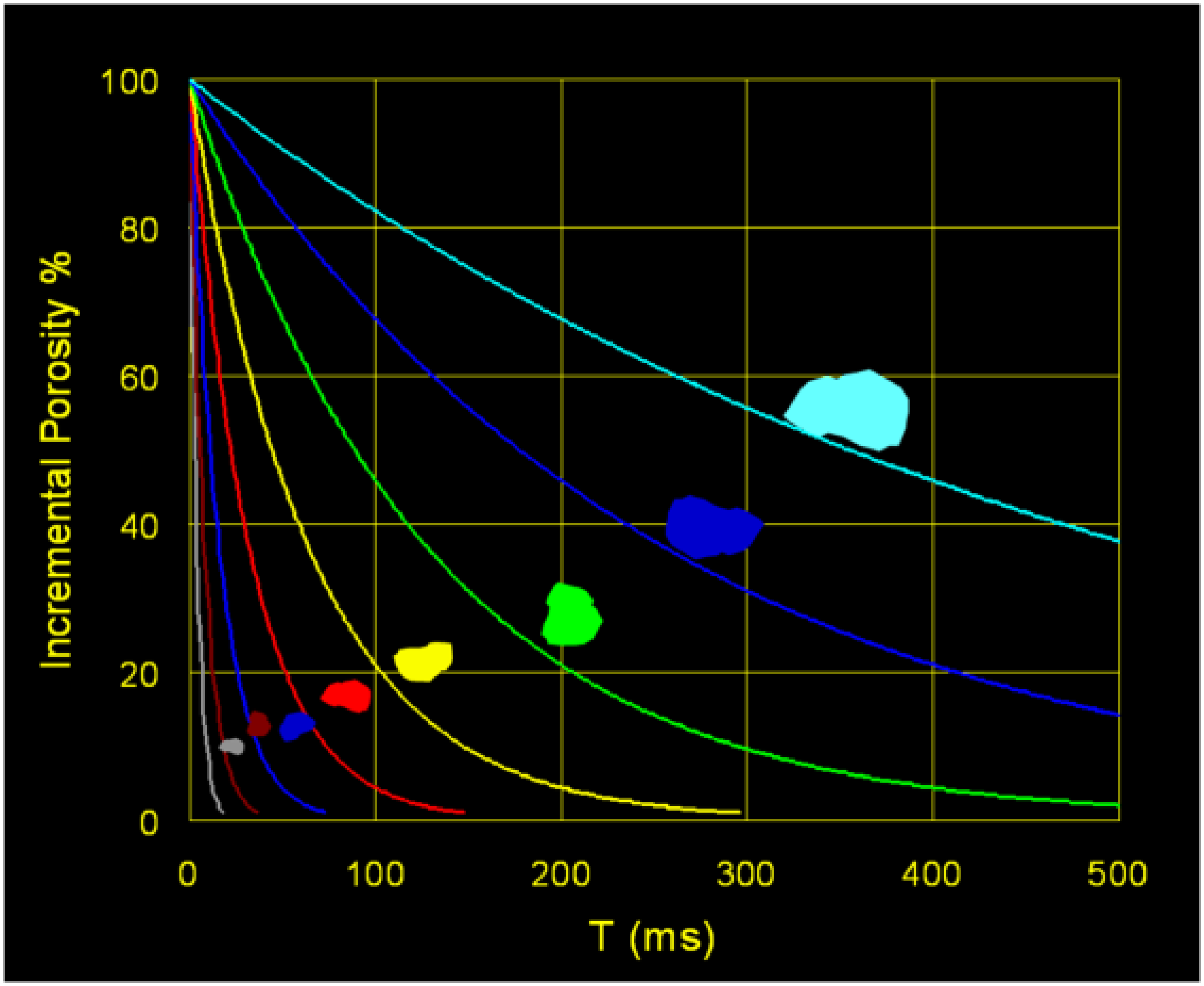

Figure 2. Relaxation time versus pore size.

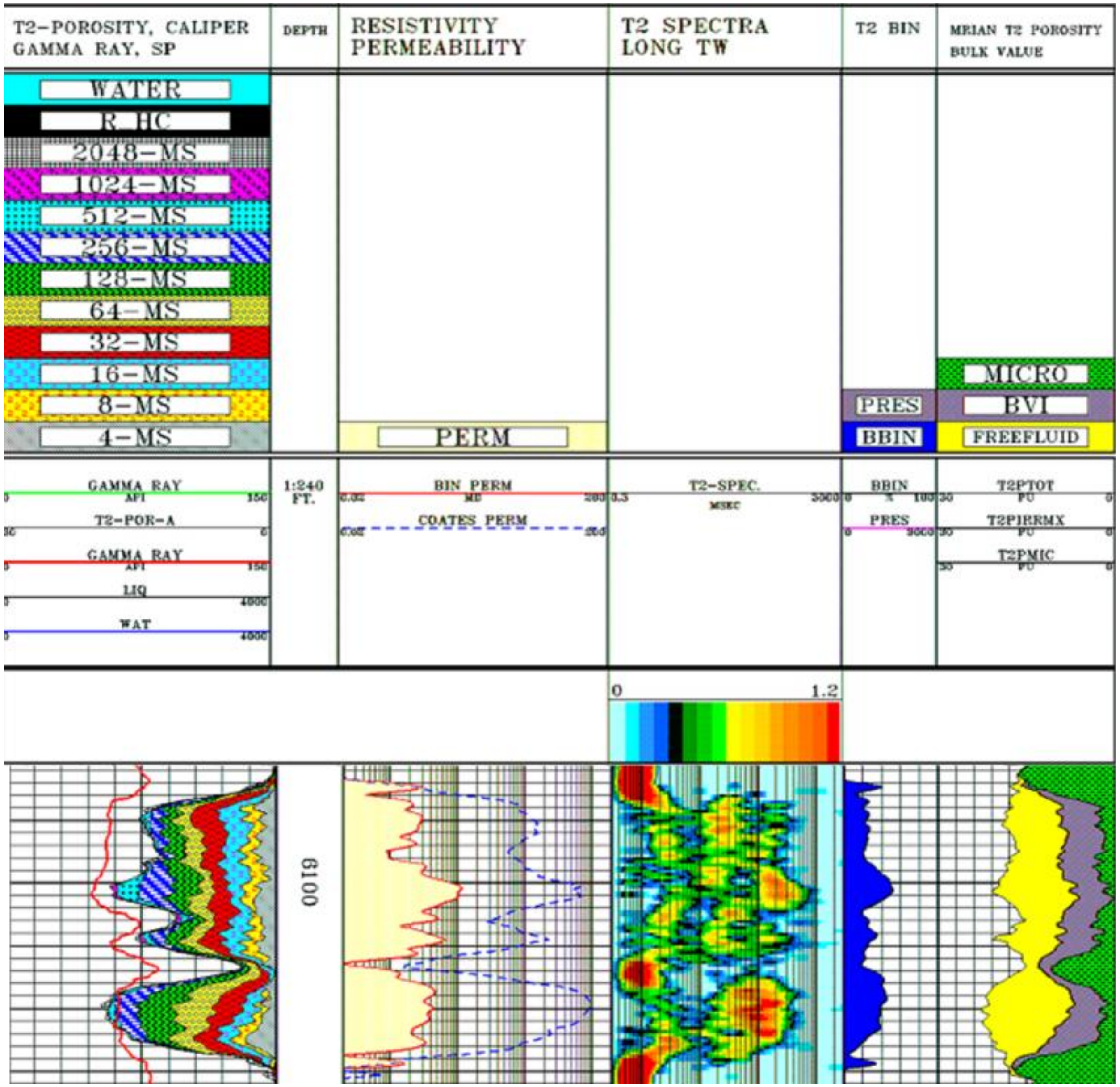

Figure 3. NMR log illustrates the differences that can be observed between the Bray-Smith and the Coates calculations of permeability.

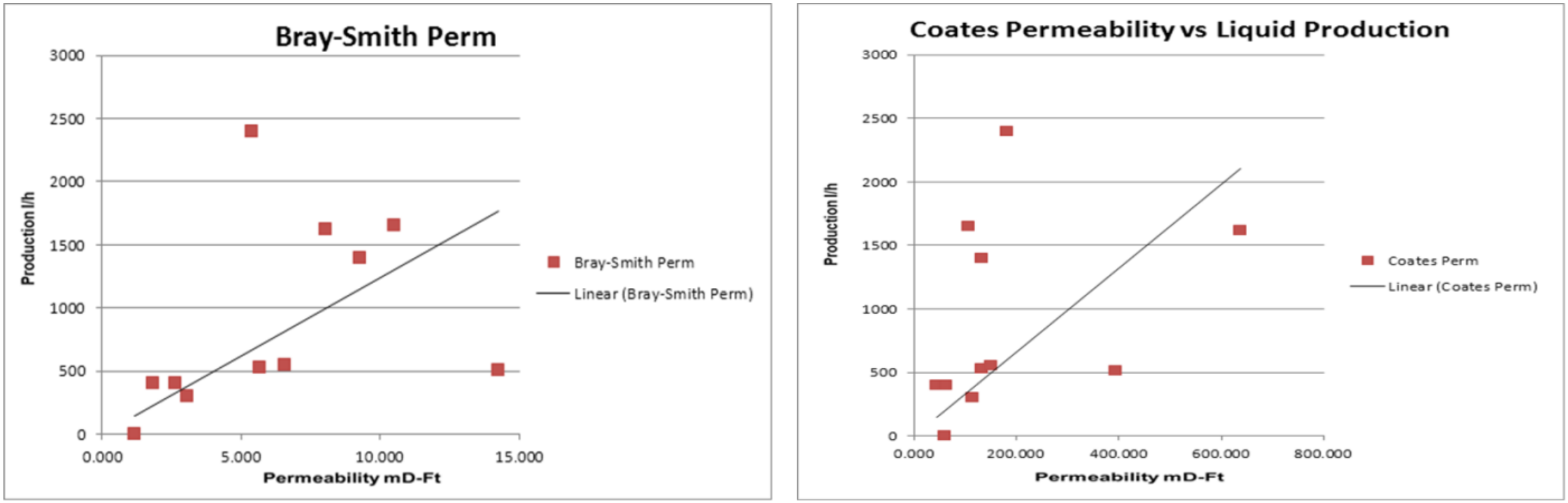

Figure 4. Statistical results for Well 1.

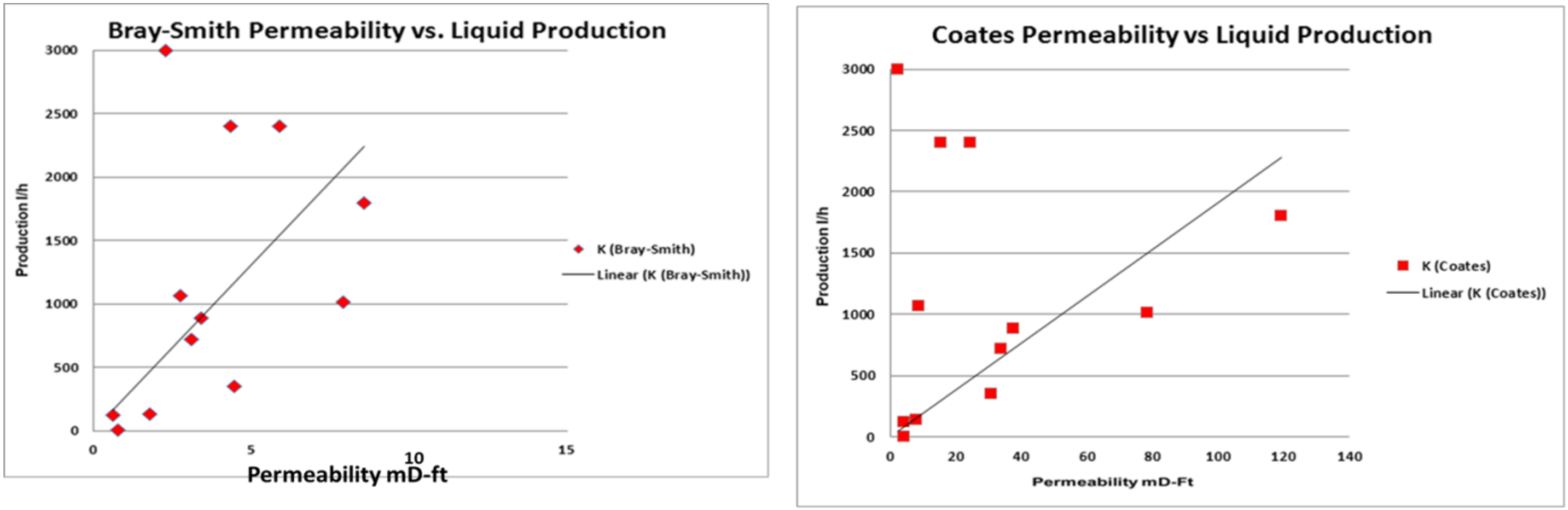

Figure 5. Statistical results for Well 2.