NMR Facies Definition for Carbonate Rocks Using Core/log and Pore-Scale Measurements

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Summary

Evaluation of reservoir quality is challenging in carbonates, where simple correlation between hydraulic units is much weaker than in siliciclastic reservoirs. Complexity of the pore network in carbonates is the result of sedimentary environments and diagenetic processes. NMR facies is a new concept, defining volumes of rock with similar NMR properties related to the pore volume/surface ratio and the strength of the mineral surface relaxivity. The combination of NMR core/log data from two wells allows definition of NMR facies for a complex carbonate mineralogic and pore type succession comprised of limestone, dolostone, and anhydrite lithologies. Lithology-independent NMRFs exhibit properties that are tied directly to pore geometry, a key factor in production rate. The evaluation of the pore spaces rather than grain properties delineates trends that are not apparent when using conventional sedimentological facies definition.

Introduction

Carbonate depositional systems and diagenetic processes create wide variations in rock texture. Pore network complexity of carbonates is caused by the presence of a wide variety of pore space types (Choquette and Pray, 1970) with diverse pore sizes, pore shapes and pore connectivity.

The main purpose of this study is to combine the pore system data from multiple sources like NMR, mercury injection capillary pressure (MICP) and petrographic image analysis (PIA), and then characterize pore geometries to define a lithology-independent pore system classes. Conventional NMR well logging gathers pore body information in terms of pore sizes as irreducible bulk volume (BVI), clay-bound water volume (CBW), and movable bulk volume (BVM) leading to effective porosity (Φ_e) and total porosity (Φ_t) definition. NMR facies are then tied to predictive geologic facies, nuclear magnetic resonance relaxation properties (Ohen et al., 1995), and seismic velocities (Prasad, 2002) to provide information about pore structures in the carbonate reservoir. Comparing core porosity with NMR and density logs showed noticeable better result from NMR for Montney and Doig Phosphate (Smith et al., 2012). Minh et al., (2012), established revised 2D NMR mapping to differentiate overlapped T2 signals between water and gas/oil in the complex pore systems in unconventionals.

Methodology

Two cored wells (W#1 and W#2) in the South Pars gas field Permo-Triassic Kangan Dalan carbonate formation reservoir were selected for the study. In addition to porosity, permeability and lithology, we considered dominant porosity types when selecting samples. From thin section studies, we recognized interparticle, intercrystalline and moldic-vuggy as dominant porosity types for gas bearing subzones.

In the subject wells the logging suite included porosity and resistivity logs. In well W#1 182 plugs were selected for routine core analysis and thin section studies. Based on these results, we selected 32 samples for the following special core analysis:

1- NMR relaxometry analyses (28 samples) by GeoSpec equipment operating in 2MHZ frequency with brine saturated samples,

2- Back Scattered Electron (BSE) and petrographic images analysis (PIA) for pore size distributions (32 samples),

3- Mercury injection capillary pressure (26 samples) from whole plug.

In well W#2 742 plugs were subjected to routine core analysis and thin section studies. We selected 25 plugs for further PIA and MCIP analysis.

NMR Facies Definition

Ohen et al. (1995) defined the relaxivity group concept by relating the relaxation time to the porosity, in a form similar to the hydraulic flow unit concept (Amaefule et al. 1993):

$$\log T_2 = \log(\phi_z) + \log[1/(\rho_2 S_{gv})] \tag{1}$$

Using Ohen's equation (1), a relaxivity group would be that set of data which when plotted on a log-log plot of T2 versus ϕ_z, would exhibit a unit slope trend group with each group giving separate $1/\rho_2 S_{gv}$ intercepts.

We defined the effective relaxivity factor (ρ_e) using the following equation as a peak matching:

$$MICP_{peak}value = \rho_e (T_{2\,peak}value) \rightarrow \rho_e = \frac{MICP_{peak}value}{T_{2\,peak}value} \tag{2}$$

To provide another source of information directly related to pore parameters, we used high-resolution petrophysical image analysis (PIA) to generate two dimensional pore size distributions. Similar to that from matching NMR data, to MICP data, we introduce a scale factor, the surface realxivity (ρ_e) for this peak matching process defined as:

$$PIA_{peak}value = \rho_2 * (T_{2\,peak}value) \rightarrow \rho_2 = \frac{PIA_{peak}value}{T_{2\,peak}value} \tag{3}$$

To estimate quantity of possible facies, we plot a cumulative probability of the T_2/ϕ_z ratio in an ascending order that shows seven probable dominant NMR facies associated with a change in specific slope (Figure 1). In this plot, the intervals belonging to a straight line represent a probable NMRF group. When this data is displayed in the cross plot of T2 versus normalized NMR porosity (ϕ_z) (Figure 2), seven NMR facies clusters can be observed. Each NMR Facies has its own value for $1/\rho_2 S_{gv}$ (Figure 2). As the surface relaxivity is constant (ρ_2 =0.22) for both dolomite and calcite minerals, in each specific group every data point members is related to the magnitude of $1/S_{gv}$.

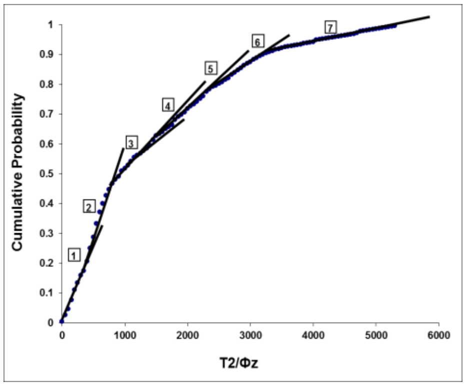

Figure 1. Plot of cumulative probability of T_2/Φ_z ratio reveals seven probable NMR facies

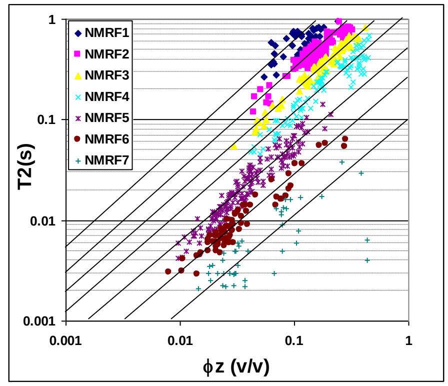

Figure 2. Plot of T_2 relaxation time vs. normalized porosity showing facies distribution

Discussion

T_2, pore throat sizes, RQI, and permeability progressively decreases and specific pore surface area progressively increases indicating reservoir quality declines from NMRF1 to NMRF7. Wireline log data also confirm reservoir quality reduction towards NMRF7. For example, acoustic wave velocities, shallow and deep resistivity, and gamma ray (GR) increase from NMRF1 to NMRF7. Bound fluid volume also increase in this direction and free fluid decreases. This information is interpreted to show that pore body and pore throat sizes decrease toward NMRF7.

Previous authors have noted the important part played in this Formation by the dual porosity component: interparticle porosity and moldic/vuggy. Principally important in our facies trend is the variation in the pore throat sizes. NMRF2 captures large pore bodies associated with large T_2 values while NMRF7 represents thin intervals of small pores and low porosity(Figure 3, left). This trend is also observed using direct pore size measurement from petrographical image analysis, however PIA could not be performed for NMRF 6&7 because of the very small pore sizes (Figure 3, middle). All NMRFs have MICP data representing the pore throat distribution (Figure 3, right) in the predicted order.

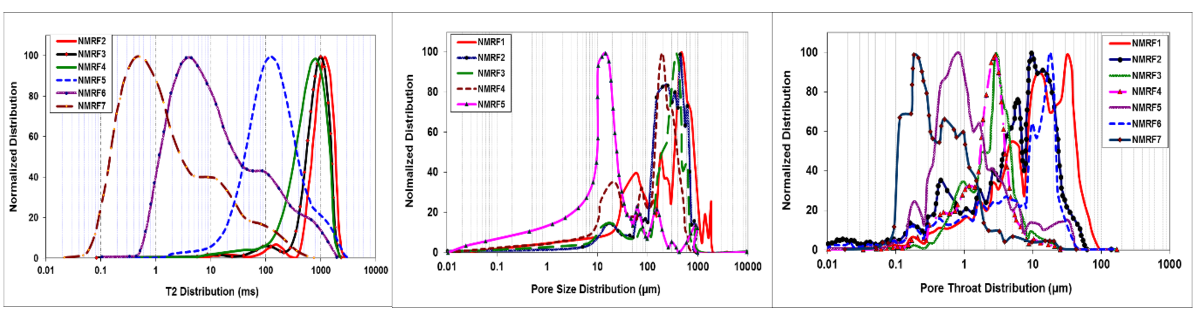

Figure 3. T_2 distribution (left), pore size distribution from PIA (middle) and pore throat distribution from Hg-injection (right) are plotted for seven facies. Trend of quality is detectable easily.

In this section, we may investigate the specific properties of one of NMR facies. The NMRF2 has limestone and dolostone samples with interparticle and moldic-vuggy pores and the oolitic dolo-grainstone. This facies shows a high T_2, low S_{gv} and consequently samples with high reservoir quality. This NMRF possesses large average pore body and pore throat sizes. Figure 4 shows the pore size distribution (mid curve, PIA) indicating bimodality: the first mode is small pores, and the second more populated mode shows the large pores. Well sorted of pore sizes create a NMR (right) and PIA (middle) distribution with a good and tall bell shape. MICP data (dashed) helps to identify the median pore throat and its distribution.

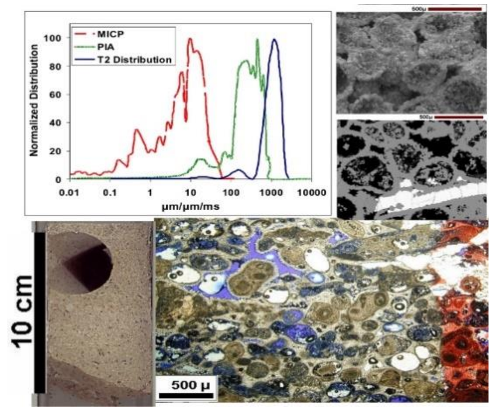

Figure 4. Core, thin section, Scanning Electron Microscopy (SEM), Back Scattered Electrons (BSE) images plus T_2 (right), BSE PIA (middle), and MICP pore throat distribution (left) for NMRF2. (Porosity= 28.53%, Permeability= 76.5md).

The efficiency of this classification can be examined when we investigate gas production rate in various depths of reservoir (figure 5). In section A, porosity is increasing with depth exceeding (17%) dominated by interparticle pore type.

Based on Dunham classification, grainstone is dominant in this zone. NMR facies is improving from 7 to 1 into middle of zone (track4, right).

Section D shows noticeably higher porosity(up to 26%) dominated by moldic/vuggy pore types. Rock texture is grainstone. NMRF facies is dominated in by NMRF3 to NMRF5. Higher porosity does not guarantee higher efficiency. When we compare gas production rate, zone A shows better result by 15% while reservoir pressure is similar for both sections.

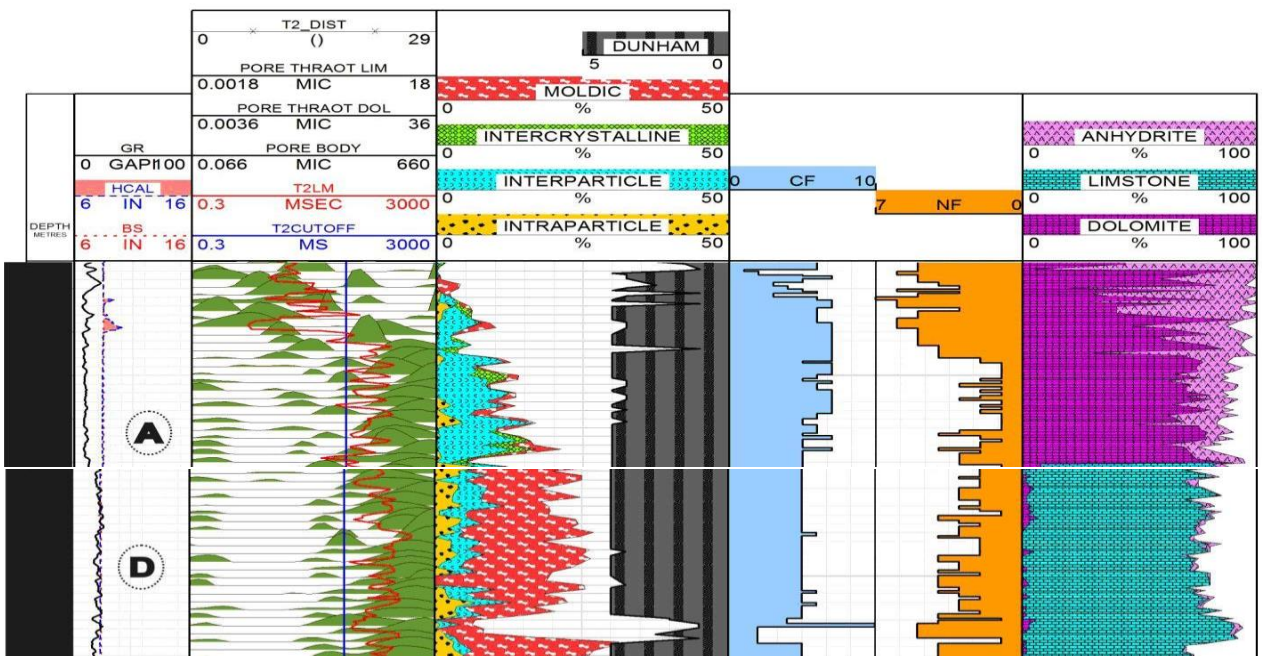

Figure 5. Representation of caliper and GR logs in Track 1, T_2 distribution, T_2LM, T_2 cutoff, Pore Body and Throat Distributions in Track 2, Porosity types and Dunham Classification (1=Mudstone and Boundstone , 2= Wackestone, 3= Packstone, and 4=Grainstone) in Track 3, Core Facies (CF) and NMR Facies (NMRF) in Track 4, and Lithology in Track 5. Thickness of each section is about 40m.

Conclusions

Evaluation of reservoir quality, an attribute of the pore system, is challenging in carbonates, where simple correlation between hydraulic units is much weaker than in siliciclastic reservoirs. NMR facies is a new concept, defining volume of rocks with similar NMR properties related to the pore volume/surface ratio and the strength of the mineral surface relaxivity. The combination of NMR core/log data from two wells allows us define seven NMR facies for a complex carbonate mineralogic and pore type succession comprised of limestone, dolostone, and anhydrite lithologies. Our new NMRFs are independent of lithology, mainly concerning pore geometry properties. The reservoir quality of the NMRF's decreases from NMRF1 to NMRF7. High reservoir quality are supported by large pore throat and pore body sizes (though their ratio is considerably important) while low quality NMRF contain smaller pore sizes and consequently grain surface to volume ratio increases. Primary pore systems dominate in high quality NMRFs with coarse dolomite crystals, whereas in low quality facies secondary porosities and fine intercrystalline pores increase. Porosity connectivity plays important role on production rate which can be shown on NMRFs with higher quality in practice.

Recommendation

This classification can be fundamentally alerted into fast relaxation factors (small pore size, kerogen oil/gas and wettability effect) in unconventional plays (like Duvernay and Montney).

Reference

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