ROCK TYPING IN TIGHT GAS SANDS: A CASE
STUDY IN LANCE AND MESAPERDE
FORMATIONS FROM JONAH FIELD

by

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ABSTRACT

The Jonah field is one of the biggest tight gas sand fields in the Green River basin. Production profiles from its deeper sections show high liquid hydrocarbons close to the Pinedale anticline, especially in Mesaverde and Lance formations. To assess the potential of condensate production, new approaches for rock classification are needed that will allow us to differentiate between discontinuous sandstone layers and the interbedded siltstones. Currently, the only cutoff used is for gamma ray: rocks below 75 API are designated as sandstones. Although, significant porosity and permeability variations occur within the sandstone zones, the only criterion used to differentiate between reservoir and non-reservoir rocks is porosity: sandstones with porosity > 6% are considered reservoir quality rocks. Porosity is considered the main controlling factor on permeability. A 6% porosity cut off in sandstones was used in net-pay calculations. However, hydraulic rock typing demonstrates permeability is dependent on main pore throat radius, rather than porosity. This study presents rock typing for tight sandstones and siltstones with an understanding of petrophysical properties such as pore structure, porosity, permeability, and cementation.

I studied 14 samples from the Mesaverde and Lance Formations with lithologies varying from clean sandstone to mudstone. X-ray diffraction (XRD) mineralogy and mercury injection capillary pressure (MICP) were measured for all samples. NMR transverse relaxation times ($T_2$) at 2 MHz were also measured for 10 water saturated samples. Nitrogen adsorption tests were performed on 8 samples. Ultrasonic velocities from 10 samples were measured at different confining pressure conditions. Thin section petrography was used to analyze the cementation and pseudomatrix clay effects on pore and pore throat size.

MICP data are used to subdivide rocks into three groups based on pore throat size distribution: reservoir sandstones, non-reservoir sandstone and siltstone/mudstone. Dominant pore throat size for reservoir and non-reservoir sandstones are 400 and 100 nm, respectively.
In order to apply pore throat size rock typing to downhole measurements, NMR pore size classification is used to identify formations. Pore size from NMR demonstrated equivalent behavior to pore throat size from MICP. The logarithmic mean values of $T_2$ transverse relaxation times for reservoir, non-reservoir sandstone and siltstone/mudstone are 22.2 ms, 3.4 ms and 0.29 ms, respectively. Clear separation of reservoir sandstone, non-reservoir sandstone and siltstone is seen based on compressibility behavior from compressional velocity during initial pressure loading. Reservoir sandstone demonstrates the highest compressibility. In addition, siltstone and mudstone were separated based on log differential pore volume distribution from $N_2$ adsorption data.

Based on pore size distribution data, four main rock types are identified in Lance and Mesaverde formations in Jonah field. Rock typing based on gamma ray and porosity logs can be considered as rock classification of end members. To capture transitional behavior in between end members, pore size distribution is needed in logging application. Since NMR $T_2$ distribution show similar spectra to MICP throat size distribution, the rock typing technique can be applied using NMR log data. Separation of mudstone from siltstone can be used for identification of shale end points in log data. Porosity and resistivity of shale end points are inputs in water saturation calculations.
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Tight gas sandstones are poised to play an important role to satisfy future energy consumption. In literature, tight gas sandstones are related to basin-centered gas accumulation (BCGA) systems (Brown et al., 1986; Law and Spencer, 1993; Law, 2002; Masters, 1979; Rose et al., 1986; Spencer, 1985). BCGA systems are typically described as abnormally pressured gas reservoirs lacking a deep free water contact. The main reservoir drive mechanism is overpressure that makes reservoir economically feasible to produce.

Tight gas sandstone reservoirs of the Jonah field are the focus of this study. Jonah Field is located in the Green River Basin, which is one of the larger BCGA systems in North America, Jonah was discovered by McMurry Oil company in 1993 and was one of the onshore natural gas discoveries during the second half of the 20th century. Gas in place within Jonah is estimated to be more than 15 TCF (Warner, 2000). Recent field development in deeper sections demonstrates approximately 0.7 psi/ft. pressure gradient.

1.1 Geological Background

As noted above, Jonah field is located in the Green River Basin, (Figure 1.1). It is bounded by two faults along the west and southeast and by a syncline that separates Jonah from the Pinedale anticline to the northeast (Figure 1.2). Sandstone, siltstone and mudstone were deposited in fluvial channels during the Late Cretaceous (DuBois et al., 2004). The main productive formations are Lance and Mesaverde, which is also referred to as the Lance Pool (Figure 1.3). Towards eastern margin of Jonah, the near top of the productive Lower Lance and Mesaverde Formations are overlain by the so-called Dead Zone which is composed of impermeable claystone and probably represents lake deposits.
Reserve evaluation strongly suggests that porosity includes natural fractures (DuBois et al., 2004). Liquid content of hydrocarbon gets richer along faults. According to Bowker and Robinson (1997), high per-well EUR north of the southeastern fault margin of Jonah (the so-called Line of Death) can be related to the presence of natural fractures. Eocene displacement on the Wind River Mountain thrust fault, which underlies the Pinedale anticline and Jonah field created these natural fractures. Production from the Lance and Mesaverde Formations beyond the western and southeastern fault margins of Jonah is not currently economic.
The Jonah field is a combination structural and stratigraphic trap. Faults along the west and southeast form good seals. Tertiary shale formation above the Lance reservoirs seals the top of Jonah (DuBois et al., 2004). According to Law and Spencer (2004) and Cluff and Cluff (2001), gas migrated into Jonah from deeper Type III kerogen, gas-prone, humic-type coal and carbonaceous shale formations via natural fractures and faults, and generated overpressure during early or middle Tertiary. Gas may have also been generated from coal interbedded within the Mesaverde. The continuous generation and migration of gas from deeper shale sources, efficient traps and late Tertiary uplift and erosion of the Northern Rocky Mountains may all have continued to development of the overpressured reservoirs in
1.2 Challenges in net-pay calculations and hydraulic fracturing

Although, Jonah is considered to be a gas field, production profiles indicate increased liquid hydrocarbon content with depth in the Mesaverde and Lance formations. Geological complexity requires improved completion design, seismic imaging and net-pay calculation for efficient field development in the liquid-rich portions of Jonah.

Reservoir development complexity includes discontinuity and small thickness of individual sandstone bodies, borehole enlargements due to unstable mudstone zones and significant lithology variation internal to the sandstone bodies.

Discontinuity in sandstone layers can decrease reservoir drainage volume by limiting effectiveness of hydraulic fracture stimulation. Lateral variation of sandstone units is not predictable from log data due to shallow investigation depth (<10 inches from borehole). The thickness of individual sandstone layers varies in a range of 10 to 100 ft (Montgomery
Figure 1.4: EUR map of Jonah field. Estimated Ultimate Recovery (EUR) study shows the presence of natural fractures (DuBois et al., 2004). Liquid content of hydrocarbon gets richer along faults. According to Bowker and Robinson (1997), high EUR along the southeastern fault (the so-called "Line of Death") can be related to the presence of natural fractures.

However, according to Shanley (2004), the thickness of gas saturated sandstone units in Jonah field can be as low as 3 ft., which is over an order of magnitude smaller than seismic resolution. This restricted resolution of these sandstones can significantly decrease the accuracy of reservoir volume determined from seismic data and, also lead to underestimation of gas-in-place estimates, and thus EUR.

Montgomery and Robinson (1997) note that alignment of sandstone units is NW-SE across Jonah. Therefore, log interpretation of aligned wells in this direction will increase effectiveness of formation evaluation of individual reservoirs. In addition, well-to-well corre-
lation in NW-SE direction can be used to determine the magnitude of reservoirs.

Lithology variation in sandstone and instability of mudstone formations create challenges in log interpretations. Borehole enlargement due to mudstone collapse can lead to log detection anomalies, especially in sonic and porosity log data. Sonic transit times can be abnormally high if the tool is reading sonic properties of mud as well. Density and neutron porosity logs can read inaccurate porosity values, which will mislead net-pay calculations.

The main productive reservoirs of Jonah are the Lance and Mesaverde sandstones, which have a collective porosity range of 1 to 12% (Cluff and Cluff, 2004). Porosity is locally reduced by cementation by quartz, chlorite, kaolinite, illite and sparse ferroan calcite decreases pore throat size, clog pores and restricts fluid flow (DuBois et al., 2004). Therefore, an entire range of porosity cannot be considered in net-pay calculations.

Significantly, elastic properties calculated from incorrect petrophysical analyses outlined above can lead to improper inputs into the hydraulic fracture simulation models.

Challenges in net-pay calculation and hydraulic fracture stimulation modeling highlight the importance of accurate rock classification. Understanding rock properties of different formations can reduce inaccuracy of formation evaluation and improve future development of Jonah.

1.3 Problem Statement

This study will cover challenges related to field development in the presence of geological complications. For the net pay calculations, sandstone units were considered as productive formations. To differentiate sandstone from siltstone/mudstone, a 75 API unit gamma ray cut off was used as an input. However, gamma ray is not a good mineralogy indicator. In addition, according to Cluff and Cluff (2004), 6% porosity was considered as the cut off to distinguish reservoir rocks and non-reservoir rocks. The summary of the problems that I will address in my work to improve net-pay calculation are:
• Definite gamma ray 75 API to identify sandstone and siltstone/mudstone
• Definite porosity 6% cut off to find reservoir and non-reservoir sandstone
• Lack of adequate rock typing to correlate permeability and porosity in sandstones

1.4 Research Objectives

The objective of this study is to improve traditional rock typing workflows that were used in describing physical properties of different formations and in net-pay calculations. To achieve goals, the following tasks will be fulfilled:

• Identify the most reliable rock typing technique to classify rocks based porosity and permeability.

• Rock classification based on pore size distribution

1.5 Literature review of rock typing

The methodology of log interpretation and core analysis is challenging in tight gas sands. The proper rock classification is needed to decrease the number of uncertainties and to understand the physical properties of formations. Starting from Archie's (1950) pioneering work on petrophysical characterization of rocks based on pore size distribution, rock classification is extended to hydraulic flow units (Pittman, 1992), flow zone indicator (FZI) (Amaefule et al., 1993; Prasad, 2003) and pore-system orthogonality matrix methods (Xu and Torres-Verdún, 2014). Archie (1950) describes pore geometry as the central part of different properties such as porosity, permeability, saturation height, capillary pressure. Velocity-porosity-permeability correlation is found using a flow zone indicator. Rocks can successfully be classified in FZI method, as velocity and permeability are sensitive to cracks. However, sensitivity decreases when an individual porosity-permeability correlation is defined, because
the entire range of porosity is restricted and fails to characterize rocks with single FZI unit (Castillo et al., 2012). Xu and Torres-Verdín (2014) use forward modeling and inversion to extract petrophysical attributes such as pore throat radius, standard deviation and mean of pore throats in order to group rocks in a pore-system orthogonality matrix. The reliability of this method depends on optimization of bimodal Gaussian density function. Derived pore size distribution does not replicate the measured pore throat size distribution from MICP data.

In conventional sandstone reservoirs, compaction is the main driving mechanism for rock property changes. Usually, porosity, permeability and sonic transit times demonstrate decreasing behavior with depth as compaction proceeds due to sediment deposition. This correlation is distorted when diagenesis takes place at the same time, or after compaction. Cementation is the common diagenesis mechanism in sandstone formations. It can preserve porosity in fairly deep burial depths (Prasad, 2003). This happens when early cementation locks grain contacts preventing them from further sliding during compaction. In opposite to porosity preservation, cementation after compaction can be accompanied with decrement in porosity. Quartz and clay overgrowths on grain surfaces and contacts, carbonate cementation in pores and pore throats are common sources for low porosity and permeability in tight sandstones. Effect of diagenesis in these type of formations prevents conventional general porosity-permeability correlation as a response to compaction. However, even in this case, correlation can be found between different rock properties restricted to local mechanisms of deposition and diagenesis. This local behavior can be used to group rocks into different types.

In order to do proper rock classification in tight gas sandstones, first the local mechanisms of deposition and diagenesis should be identified, which control physical properties of rocks. These factors in tight sandstones are mainly cementation and clay effects on pore geometry. Rushing et al. (2008) categorizes rock typing methods in tight sandstones as depositional, petrographic and hydraulic: Depositional group comprises similarities in composition, texture,
sedimentary structure and stratigraphic sequence. *Petrographic* group classifies rocks mainly based on pore structure, clay mineralogy and diagenesis. *Hydraulic* rock typing describes fluid-flow capacity of formations based on pore geometry. For this study, *petrographic* and *hydraulic* methods will be used as guides to develop rock typing based on pore size distribution.
I used log and core data for my study. Using core plugs from selected zones in the Mesaverde formation, Jonah field, I measured nuclear magnetic resonance (NMR), nitrogen adsorption, helium porosity and permeability and ultrasonic velocities under confining pressure. Available log and core data will be discussed in materials section. The mineralogy, petrographic and scanning electron microscopy (SEM) images of core data will be described in the materials section. In the methods section, measurement techniques and data reduction of mercury intrusion capillary pressure (MICP), nitrogen adsorption, ultrasonic experiments, nuclear magnetic resonance (NMR) and finally helium porosity and permeability will be briefly described.

2.1 Materials

In this study, 14 core samples were studied for experiments from well 19-22 SHB in Jonah field (provided by Exaro Energy). The cores belong to Mesaverde formation. For simplicity, samples were labeled with capital letters AA and BB, and numbered with increasing depth. 15 plugs (AA labels) with diameters of 1.5" and lengths of 2" were used for ultrasonic velocity measurements. BB labeled samples are mudstone chips. Mudstone samples have visible fractures induced by coring operation, which make impossible to cut cylindrical plugs. Compressional ($V_p$) and shear($V_s$) velocities are measured under confining stress for 11 (AA) core plugs. Helium porosity and permeability for only four plugs could be measured under pressure conditions. Four additional plugs were too tight to be measured with conventional methods. MICP was measured for all 14 samples. Additionally, NMR and nitrogen adsorption experiments were performed on ten plugs and eight samples chips, respectively. The
summary of measurements are covered in Table 2.1. Note that numbering in parenthesis in sample labels refers to the twin plugs from same depth.

Table 2.1: Measurements. ✓ - measured, * - too small samples for ultrasonic experiment, x - not to be measured. Numbering in parenthesis in sample labels refers to the twin plugs from same depth.

<table>
<thead>
<tr>
<th>Samples</th>
<th>Depth, ft</th>
<th>Dry US</th>
<th>MICP</th>
<th>φ</th>
<th>k</th>
<th>NMR</th>
<th>N2</th>
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<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>x</td>
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<tr>
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<td>✓</td>
<td>✓</td>
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<td>✓</td>
<td>✓</td>
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<td>x</td>
<td>x</td>
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</tr>
<tr>
<td>BB7</td>
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<tr>
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<td>x</td>
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<tr>
<td>AA18</td>
<td>12359</td>
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<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>x</td>
</tr>
</tbody>
</table>

In addition, 80 helium porosity and permeability data from well 113-12 SHB in Jonah field were provided by Exaro Energy for this study. Measurements were done at 4000 psi effective stress condition. The petrographic thin section images for two samples (Figure 2.1(a) and Figure 2.1(b)) and SEM for one sample (Figure 2.2) from Jonah field were also included into discussions to see carbonate cementation, pore shapes and clay overgrowth.

Lastly, environmentally corrected and normalized wireline log data from seven wells in Jonah field were used in this study for log interpretation and core to log correlation purposes. The log types are gamma ray, bulk density, neutron porosity, compressional and shear slowness, caliper, bulk density error and deep resistivity. Sonic logs are not available for well 19-22, from which core samples were used for the experiments.
2.2 Methods

In this section, methodology and data reduction for mercury intrusion capillary pressure, BET nitrogen adsorption, ultrasonic velocity measurements, nuclear magnetic resonance and helium injection porosity and permeability under different pressure conditions will be discussed.

2.2.1 Mercury intrusion capillary pressure (MICP)

Fourteen core samples of upper Mesaverde Formation from Stud Horse Butte were sent to Micromeritics Lab for MICP measurements. First drainage and imbibition cycles were performed on uncrushed samples using mercury as non-wetting phase. Pressure range for drainage cycle was from 0 to 60000 psi.

For data analysis, a gas-water system (reservoir condition) was chosen. Capillary pressure data were converted to reservoir gas-water system from laboratory mercury-air system.
Figure 2.2: CAB 30-30 11294.2. Scanning Electron Image of quartz grain with possible clay coating (A) and infilled cavity (B). Magnified 1,100X. This sample was not carbon coated and was run under partial vacuum. Courtesy of Exaro Energy.

the conversion the following equation and parameters were used:

\[ P_2 = \frac{\sigma_2 \cos \theta_2}{\sigma_1 \cos \theta_1} P_1 \]  \hspace{1cm} (2.1)

\( P_2 \) - reservoir capillary pressure for gas-water system;

\( P_1 \) - lab capillary pressure for air-mercury system;

\( \sigma_2 \) - reservoir interfacial tension (50 mN/m);

\( \sigma_1 \) - lab interfacial tension (485 mN/m);

\( \theta_2 \) - reservoir contact angle;

\( \theta_1 \) - lab contact angle;
Pore size distribution was defined through following equations:

First, pore throat radius was calculated using air-mercury parameters in lab conditions:

$$ r = \frac{2\sigma \cos \alpha}{P_c} \quad (2.2) $$

Then incremental porosity was defined as following:

$$ \text{Incremental Porosity} = 100 \frac{\Delta V}{V_{max}} \phi \quad (2.3) $$

$$ \frac{\Delta V}{V_{max}} \quad - \text{Incremental mercury intrusion} \quad (\%) $$

$$ \phi \quad - \text{Porosity in fraction;} $$

### 2.2.2 Nitrogen Gas Adsorption

Following the MICP measurements, nitrogen adsorption were run on same 8 samples from Mesaverde formation in a Micromeritics ASAP 2020\textsuperscript{TM} instrument to determine total specific surface area, pore volume and pore-size distribution. Measurement consists of three parts: 1) sample preparation; 2) degassing; 3) analysis. Prior to degassing, samples are crushed into smaller chips. In comparison with mudrocks, tight sandstones are quartz rich formations, and microporosity (pore size < 2 nm) associated with clay minerals occupies small portion of total porosity. Mesopores (pore size range 2-50 nm) and macropores (pore size > 50 nm) are the dominant parts of the pore volume. Hence, there is no need to crush samples into grain size. In degassing part, 1-3 grams of sample is degassed for 24 hours at 200 °C temperature in vacuum condition to remove water and moisture from chips. When vacuum reading of 0.005 Torr/min is stable over 15 minutes interval, degassing cycle is complete and sample is ready for analysis (Kuila, 2013). In analysis part, the sample is dosed with nitrogen at certain pressures and constant temperature. The technique is based on physisorption of nitrogen molecules on solid phase (porous material) at subcritical temperature (at 77 K) and subatmospheric pressure (less than 14.5 psi) conditions. The process is reflected
in adsorption/desorption isotherms. An amount of adsorbed/desorbed gas is measured at controlled relative pressure steps \((P/P_0)\), where \(P_0\) is atmospheric pressure and \(P\) is the system pressure. Information about pore structure, shape and size can be determined from the shape of isotherms (Sing et al., 1985).

Theoretically, nitrogen adsorption first is accompanied with the formation of monolayer in the pores. When a sharp bend knee is observed in an isotherm shape, monolayer is followed by formation of multilayer. Information about specific surface area (SSA) is extracted from monolayer part of the isotherm. Specific surface area is calculated from BET (Brunauer, Emmett and Teller) theory (Brunauer et al., 1938):

\[
\frac{1}{V(P/P_0 - 1)} = \frac{1}{V_mC} + \frac{C - 1}{V_mC} (P/P_0)
\]

\(V\) - volume of adsorbed nitrogen (cm\(^3\)/g)

\(V_m\) - volume of nitrogen in monolayer (cm\(^3\)/g)

\(C\) - constant related to the heat of adsorption

\(V_m\) is calculated from the slop and intercept of \(1/[V(P/P_0 - 1)]\) vs. \(P/P_0\) plot, and is used as input in specific surface area calculation:

\[
SSA = 10^{-18} * \frac{V_m a_m N_A}{22414}
\]

\(a_m\) - cross sectional area of the nitrogen molecule (nm\(^2\))

\(N_A\) - Avogadro’s number

BET theory is useful in mesoporous and macroporous rocks. Modified version is used to calculate surface area in microporous part of the rocks (for detailed information refer to Kuila (2013)).

Multilayer adsorption is followed by complete filling of the pores with capillary condensation. This process can be used to extract pore size distribution (PSD). As recommended by
Kuila (2013), PSD is inverted using Barrett, Joyner and Halenda (BJH) technique (Barrett et al., 1951), which assumes pores as a non-connected cylinders. Pore volume is calculated from adsorbed nitrogen amount in a pore size range of 1.7 to 193.5 nm. This is the measurable range of pores by nitrogen adsorption method. Micropore volume (pore size < 1.7 nm) is determined from t-plot technique using Harkins and Jura (1944) method.

2.2.3 Ultrasonic measurements

For this study 11 cores were used for ultrasonic velocity measurements under only confining pressure condition. The compressional \( (P) \) and two orthogonal shear \( (S_1, S_2) \) velocities were measured from the top sides of cylindrical cores at 1 MHz frequency. Ambient ultrasonic velocity measurements were made first and continued by the confining pressure measurements with 500 psi steps (up to 4000 psi for four, up to 5000 psi for seven samples). The velocity data was acquired from highest confining pressure points down to atmospheric pressure with again 500 psi steps in order to see irreversible damage on each core.

The cores were isolated from sides with "heat shrink" and tygon tubes for pressurized measurements. Confining pressure was provided by hydraulic oil. Aluminum transducers that contain piezoelectric crystals (one \( P \) and two orthogonal \( S \) ) were set onto the top and the bottom of the cores to provide ultrasonic waves and to prevent from the leakage. A leak was detected in two samples; the core AA3 at 3500 psi during loading, the core AA11 at the beginning of loading cycle. Hydraulic oil saturated velocity, as well as ambient measurements were disregarded in analysis. Missing compressional and shear velocity data in pressure loading cycles were completed with empirical equation (Greenfield and Graham, 1996):

\[
V = A + BP - Ce^{-\frac{P}{\tau}}
\]  

(2.6)

Where, a linear part of the equation describes pressure dependency of stiff porosity or matrix part of the rock. An exponential part represents soft porosity or fractured part of
the rock. As shown in Figure 2.3, velocity is the exponential function of pressure with the coefficients of \( C = V_{m0} - V_0 \) and crack closure parameter \( \tau \). This behavior is expected till the \( P_c \) crack closure pressure. \( V_0 \) is the velocity at zero pressure, \( A = V_{m0} \) is the intrinsic velocity of matrix, which is found from interception of linear part with \( y \)-axis. \( B = \left( \frac{dV}{dP} \right)_m \) is the slope of the linear part of the Equation (2.6).

Figure 2.3: Schematic representation of pressure dependency of ultrasonic velocities. \( P_c \) is the crack closure pressure. Till this point velocity shows exponential behavior as the function of pressure. At this point, cracks are closed and velocity starts to increase linearly. \( V_{m0} \) is the extrapolated intrinsic velocity of rock matrix, \( V_0 \) is the original velocity of the rock at zero pressure (Greenfield and Graham, 1996).

2.2.4 Nuclear Magnetic Resonance (NMR)

2 MHZ Magritek\textsuperscript{TM} NMR Rock Core Analyzer was utilized for transverse relaxation time \( (T_2) \) measurements. As the scope of measurements were to analyze pore size distribution
and surface relaxivity, only $T_2$ was measured for the 10 fully brine saturated samples using Carr-Purcell-Meiboom-Gill (CPMG) (Carr and Purcell, 1954; Meiboom and Gill, 1958) pulse sequence at ambient pressure and temperature conditions. Oven dried core plugs with diameter of 1.5" and length of 2" were vacuum saturated with brine. In order to avoid clay swelling, distilled water was mixed with crushed clay-rich samples for 24 hours to reach equilibration. Then the mixture was filtered using paper filters to remove the crushed pieces of the rock. After saturation the core plugs were kept submerged in brine for two days.

Before sample measurements were done, background correction was performed to decrease the noise. NMR signal of sample probe with plastic wrap inside was acquired first to prevent overestimation of real sample amplitudes, ultimately overestimation of porosity. Samples were wrapped carefully with plastic wrap to minimize the evaporation of the saturating fluid during the experiment. CPMG pulse sequence was applied to the core plugs. The controlling parameters were summarized in Table 2.2. The experiment was repeated to reach a minimum signal to noise ratio (SNR) for all samples. An inverse Laplace transform (Butler et al., 1981; Dunn et al., 1994) was used to invert the raw data to $T_2$ distribution.

Table 2.2: NMR measurement parameters for sandstones and siltstones

<table>
<thead>
<tr>
<th></th>
<th>Echo Time $\mu$s</th>
<th>Internal Exp. Delay ms</th>
<th>Numbers of Echos</th>
<th>min SNR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sandstone</td>
<td>100</td>
<td>4000</td>
<td>6000</td>
<td>200</td>
</tr>
<tr>
<td>Siltstone</td>
<td>100</td>
<td>1000</td>
<td>1000</td>
<td>100</td>
</tr>
</tbody>
</table>

$T_2$ transverse relaxation time is controlled by three relaxation mechanisms: bulk, surface and diffusion induced relaxation (Coates et al., 1999):

$$\frac{1}{T_2} = \frac{1}{T_{2\text{bulk}}} + \frac{1}{T_{2\text{surface}}} + \frac{1}{T_{2\text{diffusion}}}$$

Assuming fast diffusion regime (Dunn et al., 2002) and long bulk relaxation of saturating fluid (brine) and using short inter-echo spacing in measurements (Coates et al., 1999), surface relaxation mechanism will be the dominant relaxation mechanism. This mechanism
is described in the following equation as (Saidian et al., 2015):

\[
\frac{1}{T_{2\text{surface}}} = \rho_2 \left(\frac{S}{V}\right) = \rho_2 \frac{c}{r}
\]  

(2.8)

Where, \(\rho_2\) (\(\mu\text{m/ms}\)) is the surface relaxivity, \(S\) (\(\mu\text{m}^2\)), \(V\) (\(\mu\text{m}^3\)) and \(r\) (\(\mu\text{m}\)) are pore surface area, volume and pore body radius, accordingly. \(c\) is the constant for pore shape, which is one for planar, two and three for cylindrical and spherical pores (Machado et al., 2012).

Equation (2.8) can be solved for surface relaxivity using \(r\) from mercury intrusion pore size distribution and logarithmic average of \(T_2\) (\(T_{2LM}\)) from NMR measurements. Note that \(r\) in Equation (2.8) represents pore body size, however, mercury measures pore throat size (Equation 2.2). Marschall et al. (1995) provides the term effective surface relaxivity to account for the pore to throat ratio which is embedded in the effective surface relaxivity.

\[
T_2 = \frac{1000r}{c\rho_e}
\]  

(2.9)

In Equation (2.9), \(r\) is pore throat radius from MICP, \(\rho_e\) (\(\mu\text{m/sec}\)) is effective surface relaxivity. \(\rho_e\) is determined from matching of pore size distribution from \(T_2\) and pore throat size distribution from MICP. \(c\) value is considered as one.

The porosity was determined from cumulative pore volume directly measured by the NMR instrument and the bulk volume measured for cylindrical cores. Considering the limit of the instrument, porosity values for \(T_2 < 0.1\) ms were disregarded in calculations.

### 2.2.5 Helium Porosity and Permeability

Helium porosity and permeability were measured with a CMS-300 apparatus. To see effect of depletion on porosity and permeability, experiment were run under different effective pressure conditions. The system uses nitrogen gas to provide confining stress. Injected helium gas acts as pore pressure and provides fluid flow in porous media to measure permeability and pore volume.
Initially, eight core plugs were tested at 1000 psi differential pressure to check measurability of samples. Four out the eight samples were measured at 1000, 2000 and 4000 psi effective pressure conditions.
CHAPTER 3
RESULTS

This chapter summarizes results of performed experiments, and initial observations are made for MICP, nitrogen adsorption, ultrasonic velocity, NMR and helium porosity and permeability measurements. In summary, PSD from MICP, nitrogen adsorption and NMR shows bimodal, trimodal and rarely unimodal shapes. Incomplete incremental porosity and log differential pore volume peaks in small pore size ranges demonstrate the presence of microporosity in MICP and nitrogen adsorption data, respectively. Empirical fitting is applied to ultrasonic data to predict missing experimental data points with around 1% error. Finally, percentage change in porosity is less than in permeability under differential pressure conditions due to presence of cracks.

3.1 Mercury intrusion capillary pressure (MICP)

Figure 3.1(a) and Figure 3.1(b) show MICP curves for mercury and gas-water systems, accordingly. To see capillary effects in reservoir system, mercury-air injection pressure is converted to gas-water pressure using with the Equation 2.1. Water saturation is the wetting phase and calculated from injected mercury volume. In gas-water system, capillary entry pressure starts from approximately 1 psi. High pressure samples demonstrate entry pressure values up to 200 psi. And these samples show higher pressure within entire saturation interval meaning the presence of smaller pore throat sizes.

Mercury intrusion porosimetry technique is useful in describing pore throat size distribution of the rock samples. High injection pressure (maximum value being around 60000 psi) allows mercury to access into all pores with throat diameter values bigger than 3.6 nm. Therefore, in contrast to capillary pressure behavior from centrifuge measurement, mercury injection pressure does not increase asymptotically in small pores and hence irreducible water
saturation is not detectible. Figure 3.2 shows pore throat diameter distribution of 14 samples. Incremental porosity for some of the samples demonstrates "interruption" at 3.6 nm pore throat diameter. This means there are pores in sample with throat diameters smaller than 3.6 nm, and are not accessible by mercury. Microporosity (pore diameter less than 2 nm) will be skipped in calculations causing underestimation of total porosity. Porosity values are reported in Table 3.5.

![Figure 3.1: MICP drainage cycle for 14 samples. a) Drainage cycles for mercury - air system. b) Drainage cycles for gas - water system. Capillary entry pressure range is 1 to 200 psi approximately. Irreducible water saturation is not detectable due to high mercury injection pressure (60000 psi).](image)

### 3.2 Nitrogen Gas Adsorption

The summary of total porosity, micropore volume and specific surface area (SSA) for eight samples are reported in Table 3.1. The difference in micropore volume and SSA among samples are in almost one and two orders of magnitude, correspondingly. These properties have the lowest values for sample AA3. Figure 3.3 demonstrates PSD from log differential pore volume and pore diameter (nm). Area under curves corresponds to the differential volume (dV) occupied by dlog(D) pore size range. The ratio dV/dlog(D) especially emphasizes
Figure 3.2: Mercury pore throat size distribution. "Interruption" of incremental porosity at 3.6 nm means the availability of micropores, which are not accessible by mercury.

the volume occupied by small pores. Majority of the samples show bimodal distribution: first peak is ranging from 1.7 to 5 nm and second peak is in the range of 5 to 100 nm. Due to limitation of instrument, the minimum pore diameter that can be measured is 1.7 nm. However, some of the samples show incomplete first peak at this diameter. This is the indication of microporisty and, there are pores in the formation with body diameter less than 1.7 nm. The samples in Table 3.1 with high micropore volume and SSA belong to these type of formations.

3.3 Ultrasonic measurements

Pressure dependency of ultrasonic $P$ and $S$ velocities are shown from Figure 3.4 to Figure 3.13. Equation (2.6) is used to fit data individually. Velocities for each pressure step are summarized in Table 3.2. Table 3.3 and Table 3.4 show fitting parameters for compressional
Table 3.1: The Summary for Nitrogen Adsorption. MP volume means micropore volume.

<table>
<thead>
<tr>
<th></th>
<th>AA3</th>
<th>BB6</th>
<th>BB7</th>
<th>AA8</th>
<th>AA10</th>
<th>AA11</th>
<th>AA12</th>
<th>BB15</th>
</tr>
</thead>
<tbody>
<tr>
<td>SSA, m²/g</td>
<td>1.8</td>
<td>11</td>
<td>8</td>
<td>5.1</td>
<td>6.2</td>
<td>2.9</td>
<td>2.9</td>
<td>16.3</td>
</tr>
<tr>
<td>MP volume 10⁻⁸ cm³/g</td>
<td>27.3</td>
<td>270.8</td>
<td>134</td>
<td>101.9</td>
<td>167.1</td>
<td>16.6</td>
<td>33.1</td>
<td>473.9</td>
</tr>
<tr>
<td>Porosity, %</td>
<td>1.07</td>
<td>4.65</td>
<td>3.82</td>
<td>2.6</td>
<td>2.38</td>
<td>1.73</td>
<td>1.84</td>
<td>5.71</td>
</tr>
</tbody>
</table>

Figure 3.3: PSD from log differential pore volume and pore size.

and shear velocities, respectively. Missing experimental velocity points for some of the cores were predicted individually (data with red color in Table 3.2). According to Walsh (1965), pressure required for crack closure can be approximated as \( \alpha E_0 \) (\( \alpha \) crack aspect ratio, \( E_0 \) Young’s modulus for solid phase). For example, calculated Young’s modulus for the tight sandstone samples from Jonah field is \( E_0 = 8.5 \) Mpsi. In order to close cracks with the aspect ratio of 0.001, we would need to reach at least to 8500 psi pressure approximately. Velocity prediction beyond this point would be unreliable. In the absence of high pressure
data, empirical fitting will give unrealistic results especially for the linear part of the velocity behavior. In Jonah reservoirs effective pressure is around 5000 psi. Predicted velocities in this pressure range fall into exponential part of the velocity-pressure relationship. In this range error in fitting is around 1%.

### 3.4 Nuclear Magnetic Resonance (NMR)

Figures 3.14 to 3.16 show $T_2$ relaxation time distribution results for 10 samples. Peaks in incremental porosity represent the value of $T_2$ for dominant pore size ranges. Formations demonstrate trimodal, bimodal and rarely unimodal distributions of $T_2$, hence pore size. Porosity calculated from cumulative distribution data (green curves) is summarized in Table 3.5.

### 3.5 Helium Porosity and Permeability

Porosity and permeability data for eight samples measured at 1000 psi differential pressure condition are reported in Table 3.5. Measurements on four selected cores under differential stress conditions demonstrate pressure dependency of porosity and permeability (Figure 3.17(a), Figure 3.17(b); Table 3.6, Table 3.7). Porosity and permeability decrease as the function of pressure. This effect is emphasized in Figure 3.17(c) and Figure 3.17(d). Percentage decrease in permeability is higher than in porosity as cracks are the main pathways for fluid flow. However, main portion of porosity consists of stiff pores. As pressure increases, there is minor decrease in porosity due to crack closure.
Table 3.2: Ultrasonic velocities (km/s) under confining pressure (psi) conditions. Red color coded data are predicted using Equation (2.6).

<table>
<thead>
<tr>
<th>Confining Pressure Steps, psi (loading cycle)</th>
<th>500</th>
<th>1000</th>
<th>1500</th>
<th>2000</th>
<th>2500</th>
<th>3000</th>
<th>3500</th>
<th>4000</th>
<th>4500</th>
<th>5000</th>
</tr>
</thead>
<tbody>
<tr>
<td>AA1 V_s</td>
<td>2.358</td>
<td>2.474</td>
<td>2.573</td>
<td>2.659</td>
<td>2.734</td>
<td>2.799</td>
<td>2.857</td>
<td>2.908</td>
<td>2.954</td>
<td>2.996</td>
</tr>
<tr>
<td>AA3 V_s</td>
<td>2.536</td>
<td>2.643</td>
<td>2.764</td>
<td>2.866</td>
<td>2.956</td>
<td>3.037</td>
<td>3.094</td>
<td>3.163</td>
<td>3.219</td>
<td>3.269</td>
</tr>
<tr>
<td>AA4 V_s</td>
<td>2.560</td>
<td>2.634</td>
<td>2.692</td>
<td>2.740</td>
<td>2.783</td>
<td>2.822</td>
<td>2.860</td>
<td>2.896</td>
<td>2.931</td>
<td>2.966</td>
</tr>
<tr>
<td>AA5 V_s</td>
<td>2.581</td>
<td>2.656</td>
<td>2.726</td>
<td>2.791</td>
<td>2.852</td>
<td>2.908</td>
<td>2.960</td>
<td>3.008</td>
<td>3.054</td>
<td>3.096</td>
</tr>
<tr>
<td>AA10 V_p</td>
<td>4.912</td>
<td>4.932</td>
<td>4.975</td>
<td>4.980</td>
<td>5.015</td>
<td>5.060</td>
<td>5.106</td>
<td>5.127</td>
<td>5.156</td>
<td>5.188</td>
</tr>
<tr>
<td>AA12 V_s</td>
<td>2.865</td>
<td>2.884</td>
<td>2.898</td>
<td>2.911</td>
<td>2.922</td>
<td>2.932</td>
<td>2.942</td>
<td>2.952</td>
<td>2.962</td>
<td>2.972</td>
</tr>
<tr>
<td>AA13 V_p</td>
<td>4.962</td>
<td>4.990</td>
<td>5.044</td>
<td>5.088</td>
<td>5.093</td>
<td>5.103</td>
<td>5.158</td>
<td>5.205</td>
<td>5.221</td>
<td>5.252</td>
</tr>
<tr>
<td>AA13 V_s</td>
<td>3.068</td>
<td>3.07</td>
<td>3.074</td>
<td>3.099</td>
<td>3.107</td>
<td>3.120</td>
<td>3.127</td>
<td>3.127</td>
<td>3.141</td>
<td>3.15</td>
</tr>
<tr>
<td>AA17 V_s</td>
<td>2.739</td>
<td>2.747</td>
<td>2.783</td>
<td>2.825</td>
<td>2.855</td>
<td>2.894</td>
<td>2.913</td>
<td>2.943</td>
<td>2.964</td>
<td>2.990</td>
</tr>
<tr>
<td>AA18 V_s</td>
<td>2.834</td>
<td>2.912</td>
<td>2.954</td>
<td>2.983</td>
<td>3.008</td>
<td>3.031</td>
<td>3.053</td>
<td>3.076</td>
<td>3.098</td>
<td>3.121</td>
</tr>
</tbody>
</table>

Table 3.3: Fitting parameters for P-velocity (Equation (2.6)). A is intrinsic velocity of matrix (m/s); B is the slope of the linear part (m/s-MPa); C is the coefficient for exponential behavior (m/s); D crack closure parameter (1/MPa). $R^2$ is the correlation coefficient between predicted and measured data.

<table>
<thead>
<tr>
<th></th>
<th>AA1</th>
<th>AA3</th>
<th>AA4</th>
<th>AA5</th>
<th>AA8</th>
<th>AA10</th>
<th>AA12</th>
<th>AA13</th>
<th>AA17</th>
<th>AA18</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>4731</td>
<td>5123</td>
<td>4746</td>
<td>5000</td>
<td>4714</td>
<td>4870</td>
<td>4556</td>
<td>4946</td>
<td>5000</td>
<td>5000</td>
</tr>
<tr>
<td>C</td>
<td>1336</td>
<td>1651</td>
<td>1076</td>
<td>1267</td>
<td>1</td>
<td>1</td>
<td>264</td>
<td>46</td>
<td>978</td>
<td>823</td>
</tr>
<tr>
<td>D</td>
<td>0.0522</td>
<td>0.0548</td>
<td>0.0389</td>
<td>0.0295</td>
<td>1</td>
<td>1</td>
<td>0.1699</td>
<td>0.2874</td>
<td>0.0083</td>
<td>0.027</td>
</tr>
<tr>
<td>$R^2$</td>
<td>0.99</td>
<td>0.99</td>
<td>0.99</td>
<td>0.99</td>
<td>0.98</td>
<td>0.98</td>
<td>0.99</td>
<td>0.97</td>
<td>0.99</td>
<td>0.99</td>
</tr>
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</table>
Table 3.4: Fitting parameters for S-velocity (Equation (2.6)). $A$ is intrinsic velocity of matrix (m/s); $B$ is the slope of the linear part (m/s-MPa); $C$ is the coefficient for exponential behavior (m/s); $D$ crack closure parameter (1/MPa). $R^2$ is the correlation coefficient between predicted and measured data.

<table>
<thead>
<tr>
<th>Sample</th>
<th>AA1</th>
<th>AA3</th>
<th>AA4</th>
<th>AA5</th>
<th>AA8</th>
<th>AA10</th>
<th>AA12</th>
<th>AA13</th>
<th>AA17</th>
<th>AA18</th>
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</thead>
<tbody>
<tr>
<td>A</td>
<td>3203</td>
<td>3597</td>
<td>2906</td>
<td>3347</td>
<td>3021</td>
<td>3059</td>
<td>3126</td>
<td>3147</td>
<td>3532</td>
<td>3225</td>
</tr>
<tr>
<td>B</td>
<td>2.477</td>
<td>1</td>
<td>10</td>
<td>1</td>
<td>1.933</td>
<td>1.761</td>
<td>3.223</td>
<td>1.372</td>
<td>1</td>
<td>4.847</td>
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<tr>
<td>C</td>
<td>878</td>
<td>1208</td>
<td>222</td>
<td>625</td>
<td>1</td>
<td>46</td>
<td>1</td>
<td>96</td>
<td>840</td>
<td>331</td>
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<tr>
<td>D</td>
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<td>0.0349</td>
<td>0.0877</td>
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<td>0.0332</td>
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<td>0.0225</td>
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<td>$R^2$</td>
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<td>0.98</td>
<td>0.99</td>
<td>0.98</td>
<td>0.99</td>
<td>0.97</td>
<td>0.94</td>
<td>0.99</td>
<td>0.98</td>
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</table>

Table 3.5: Porosity measured by different techniques. x-measurement has not performed.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Helium</th>
<th>MIP</th>
<th>NMR</th>
<th>N2</th>
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<tbody>
<tr>
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<td>9.8</td>
<td>x</td>
</tr>
<tr>
<td>AA2</td>
<td>11.0</td>
<td>x</td>
<td>x</td>
<td>x</td>
</tr>
<tr>
<td>AA3</td>
<td>10.5</td>
<td>10.1</td>
<td>9.8</td>
<td>1.5</td>
</tr>
<tr>
<td>AA4</td>
<td>8.4</td>
<td>5.1</td>
<td>5.6</td>
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</tr>
<tr>
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Table 3.6: Helium permeability measured at differential pressure conditions

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Table 3.7: Helium porosity measured at differential pressure conditions

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</tr>
<tr>
<td>AA18</td>
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Figure 3.4: Compressional velocity fit for samples AA1 (a) and AA3 (b).
Figure 3.5: Compressional velocity fit for samples AA4 (a) and AA5 (b).

Figure 3.6: Compressional velocity fit for samples AA8 (a) and AA10 (b).
Figure 3.7: Compressional velocity fit for samples AA12 (a) and AA13 (b).

Figure 3.8: Compressional velocity fit for samples AA17 (a) and AA18 (b).
Figure 3.9: Shear velocity fit for samples AA1 (a) and AA3 (b).

Figure 3.10: Shear velocity fit for samples AA4 (a) and AA5 (b).
Figure 3.11: Shear velocity fit for samples AA8 (a) and AA10 (b).

Figure 3.12: Shear velocity fit for samples AA12 (a) and AA13 (b).
Figure 3.13: Shear velocity fit for samples AA17 (a) and AA18 (b).

Figure 3.14: NMR porosity for samples AA1 (a) and AA3 (b).
Figure 3.15: NMR porosity for samples AA4 (a), AA5 (b), AA8 (c), AA10 (d), AA12 (e) and AA13 (f).
Figure 3.16: NMR porosity for samples AA17 (a) and AA18 (b).

Figure 3.17: Helium injection porosity and permeability under differential pressure conditions.
Table 3.8: XRD results by weight percentage

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<th>AA4 12186</th>
<th>AA5 12188</th>
<th>BB6 12200</th>
<th>BB7 12204</th>
<th>AA8 12326</th>
<th>AA10 12328</th>
<th>AA11 12337</th>
<th>AA12 12339</th>
<th>AA13 12343</th>
<th>BB15 12349</th>
<th>AA16 12354</th>
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<td>63</td>
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<td>67</td>
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<td>&lt;3?</td>
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Traditional rock typing in Jonah field uses porosity classification of rocks in sandstones. Porosity is considered main controlling factor on permeability (Cluff and Cluff, 2004). However, this study demonstrates that permeability is dependent upon dominant pore size rather than total porosity. First, hydraulic rock typing is applied to see this effect. Then MICP data are used to subdivide rocks into three groups based on pore throat size distribution: reservoir sandstones, non-reservoir sandstone and siltstone/mudstone. Dominant pore throat size calculated from Thomeer (1960) method for reservoir and non-reservoir sandstones are 400 and 100 nm, respectively. In order to apply pore throat size rock typing to downhole measurements, NMR pore size classification is performed on the same samples. Pore size from NMR demonstrated equivalent behavior to pore throat size from MICP. The logarithmic mean values of $T_2$ transverse relaxation times for reservoir, non-reservoir sandstone and siltstone/mudstone are 22.2 ms, 3.4 ms and 0.29 ms, respectively. In addition, to see compressibility behavior of different rock types, pressure dependency of ultrasonic P-velocity were analyzed. Reservoir sandstone demonstrated highest compressibility and siltstone have the lowest one. In addition, siltstone and mudstone were separated based on log differential pore volume distribution from $N_2$ adsorption data. $N_2$ porosity of mudstone can be used as an input parameter into water saturation calculation.

4.1 Common rock classification

Geologically formations in Jonah field are described as sandstone channels intercalated with siltstones and mudstones. Sandstones exhibit 1-12% porosity ranges and are considered main productive formations (Cluff and Cluff, 2004). Traditionally, 75 API units of gamma ray cut off were used to differentiate sandstone from siltstone and mudstone (DuBois et al.,
Siltstone and mudstone with GR > 75 API were disregarded in net pay calculations. However, cementation by quartz, chlorite, kaolinite, illite and sparse ferroan calcite decreases pore throat size, clog pores and restricts fluid flow (DuBois et al., 2004). Shown in Figure 4.1 is the helium porosity and permeability measured at 4000 psi differential pressure condition from Lance formation, Jonah field. There is a general decreasing behavior in permeability that associated with porosity decrease. A linear regression is used to find general correlation between porosity and permeability close to in-situ reservoir effective stress condition (Cluff and Cluff, 2004):

\[ \log K_{4000\text{psi}} = 0.2135\phi - 3.5861 \]  

Routine core analysis shows that average water saturation decreases with increasing porosity in sandstones (Figure 4.2). The samples with porosity values less than 6% demonstrate 40% or higher water saturation (square symbols). As Jonah formations were in contact with gas-water fluid system, the rocks can be water-wet. In this case, these tight sandstone formations will have more tendency to imbibe water, and prevent gas flow into the wellbore while drilling with water based mud. In addition, fractional flow capacity analysis demonstrates that 90% of fluid flow occurs from the sandstone formations with permeability values higher than 14 \( \mu \text{d} \) (Figure 4.3). According to Equation (4.1), less than 6% porosity samples demonstrate permeability values smaller than 5 \( \mu \text{d} \). Therefore insignificant fluid flow occurs from these type of rocks even after hydraulic fracturing (Cluff and Cluff, 2004).

Low productivity behavior and tendency for high water saturation in low porosity sandstones justify 6% porosity cut off in net pay calculations. In logging application, porosity logs in conjunction with gamma ray can be used as a rock quality indicator. Porosity in sandstone is the key factor in estimation of net-pay. The technique that were used to find a cut-off for porosity is based on helium injection measurements on core samples and is applied to log data. A question arises about reliability of helium injection measurement method for porosity and permeability classification in low porosity formations to be applied to log data field-wide. Next section compares different methods to find which technique is reliable for
low porosity range.

Figure 4.1: In-situ porosity-permeability correlation for Lance formation. A linear regression is used to find general relationship between porosity and permeability at 4000 psi differential pressure condition (Cluff and Cluff, 2004).

4.2 Comparison of Porosity Measurement Techniques

In this section, mercury intrusion porosimetry, NMR, nitrogen ($N_2$) adsorption and helium porosity measurements are compared to check a reliability of the different techniques. A number of data points are not the same in different plots due to availability of measurements (Table 2.1). Figure 4.4 is the comparison of mercury and NMR methods. NMR is higher than mercury within 2% porosity difference. This can be related to NMR reading of clay bound water. $H^+$ and $OH^+$ ions in between clay structure can be estimated by NMR as porosity in conjunction with free water molecules inside pores. However, mercury injection technique detects pores only accessible by mercury. Therefore, with increasing clay content
Figure 4.2: Porosity and water saturation correlation. Routine core analysis shows that average water saturation decreases with increasing porosity in sandstones. The samples (square symbols) with porosity values less than 6% demonstrate 40% or higher water saturation (Cluff and Cluff, 2004).

NMR porosity is getting higher than mercury porosity.

Clay overgrowths can form on pore wall and throat leading to decrement in porosity (Figure 2.2). Also, petrographic analysis shows pseudomatrix clay filling in pores (Figure 2.1(b)). When deposition proceeds, pseudomatrix clay in pores gets compacted and, porosity decreases. Figure 4.5 demonstrates the comparison of $N_2$ and mercury injection techniques. In low porosity interval ($< 6\%$), $N_2$ reads relatively higher porosity than mercury injection with increasing clay content. This discrepancy can be explained as pseudomatrix clay and clay overgrowth effects on pores and pore throat sizes. If the size is smaller than 3.6 nm mercury injection will not count pore volume leading to an underestimation of porosity. A sample
Figure 4.3: Cumulative flow capacity vs. in-situ permeability correlation. 90\% of fluid flow occurs from the sandstone formations with permeability values higher than 14 \( \mu \text{d} \) (Cluff and Cluff, 2004).

with mercury injection porosity value 10\%, has very low \( N_2 \) reading. Lower clay amount (3.5; sample AA1(2)) dictates that main part of pore volume consists of pores with diameter values bigger than 200 nm, which is not detectable by nitrogen adsorption technique.

Quartz and carbonate cementation increase uncertainty level in porosity measurements as well. Carbonate cementation especially in pore throats can limit mercury intrusion and, result in underestimation of porosity. Blue colored substance is epoxy which fills pores (Figure 2.1(a)). Gold color is the carbonate cement on pore walls and throats. The outliers in Figure 4.5 are due to carbonate cement. Data outliers in Figure 4.6 have approximately 16\% carbonate content which can be a cement.

Data inside red circle in Figure 4.7(a) is presented in Figure 4.7(b) and Figure 4.7(c). Although, helium porosity around 10\% is in a good agreement with mercury and NMR, the discrepancy between helium and NMR/mercury increases with decreasing porosity values.
Helium measurement technique is not reliable in low porosities (< 6%).

The main points for this discussion is summarized as:

- Mercury, NMR and helium measurements demonstrate approximately same reading for porosity value > 10%;
- Mercury and NMR are reliable for entire porosity spectra (within 2% porosity difference);
- Helium method is not reliable for low porosity range (< 6%);
- $N_2$ measurements are not reliable for higher porosity range > 10%
- Clay and cementation affect porosity for "shaly" and "sandy" samples, respectively;

The comparison of different porosity measurements bring an importance of pore size and distribution in rock properties. Dominant pore size affects the accuracy of measurements. The limitations in the techniques are related to the size of pores and pore throats.

4.3 Hydraulic Rock Typing (HRT)

Hydraulic rock typing method characterizes rocks based on different flow properties (Pittman, 1992). Differences in rock qualities are classified based on permeability. The important part of the hydraulic rock typing is to find the main pore throat radius which provides dominant fluid flow. To do that, injected mercury saturation $S_{hg}$ is plotted against the ratio of saturation to capillary pressure (Figure 4.8(a)). The value of saturation that corresponds to the apex point has a physical meaning (Thomeer, 1960): at this saturation, continuous fluid flow is reached. In these samples an apex point mercury saturations are close to 35%. Corresponding pore throat is found from cumulative mercury saturation and pore throat radius plot according to Thomeers method (Figure 4.8(b)). This is the main pore aperture that controls a dominant flow. Permeability can be modeled using this pore
喉咙尺寸和孔隙度。Pittman (1992) 开发了一系列的 empirical equations from multi-regression analysis relating dominant pore throat sizes to permeability and to porosity:

$$\log r_i = a + b \log k - c \log \phi$$ (4.2)

Where, $a$, $b$, $c$ are the fitting parameters, $r_i$ (µm) is a radius relevant to $i$th percentile of mercury saturation, $k$ (md) is Klinkenberg-corrected permeability and $\phi$ (%) is porosity. As the apex point mercury saturations were close to 35% percentile (Figure 4.8(a)), the following corresponding equation is used to model permeability:

$$\log k = \frac{1}{0.565} (0.523 \log \phi - \log r_{35} - 0.255)$$ (4.3)

Four pore throat radii ($r_{35}$) and helium porosity measured at 4000 psi differential pressure condition are used as an input into the Equation (4.3) to subdivide rocks into different
Figure 4.5: $N_2$ and mercury injection measurements. In low porosity interval (< 6%), $N_2$ reads relatively higher porosity than mercury with increasing clay content. This discrepancy can be explained as pseudomatrix clay and clay overgrowth effects on pores and pore throat sizes. If the size is smaller than 3.6 nm mercury will not count pore volume leading to an underestimation of porosity. A sample with mercury porosity value 10%, has very low $N_2$ reading. Lower clay amount (3.5; sample AA1(2)) dictates that main part of pore volume consists of pores with diameter values bigger than 200 nm, which is not detectable by nitrogen adsorption technique.

rock types. Four rock types based on permeability behavior from two wells can be seen in Figure 4.9. The quality of rocks decreases from first to fourth type. Note that data points outside of blue circles are outliers. Because helium data is not reliable below 6% porosity. The main rock types are $HRT1$, $HRT2$ and partially $HRT3$ (section with the porosity values > 6%). Fourth group mainly exhibits permeability < 1 $\mu$d, porosity < 6%, and bounded with permeability model corresponding to $R = 0.1$ $\mu$m pore throat radius. These type of sandstones are considered non-reservoir rocks due to low permeability and tendency for high water saturation contents. First and second type of rocks are reservoir sandstones. Permeability is varying from 1 to 100 $\mu$d for the second type, from 100 to 500 $\mu$d for the first type, respectively. Porosity variation is in the range of 6-12%. At porosity value around
10%, the difference in permeabilities between first and second rock type is nearly 10 times. Considering 0-12% as a reliable porosity range for sandstone formation, possible difference in porosities for two groups will be smaller than permeability difference. Permeability is dependent upon main pore throat size, rather than total porosity as dictated by HRT technique. Therefore, despite of slight variation in porosity, formation can be classified due to permeability behavior.

4.4 Flow Zone Indicator (FZI)

Flow zone indicator correlates permeability with porosity considering pore geometry factors. As porosity is the volumetric property of rock, it is not dependent on pore structure. However, permeability depends on the shape, distribution and connectivity of the pores and surface area of the grains which is in contact with flowing fluid. In literature, one of the relationships between permeability and porosity considering pore geometry factors was
Figure 4.7: Mercury injection, NMR and helium porosity comparison. Data inside red circle in (a) is presented in (b) and (c). Although, helium porosity around 10% is in a good agreement with mercury injection and NMR, the discrepancy between helium and NMR/mercury increases with decreasing porosity values. Helium measurement technique is not reliable in low porosities (< 6%).

expressed by Kozeni-Carman for parallel capillary tubes (Carman, 1997; Kozeny, 1927):

\[
    k = \frac{1}{\tau^2 S_{Vgr}^2} \frac{\phi^3}{(1 - \phi)^2}
\]

where \( k \) is permeability (\( \mu m^2 \)), \( \phi \) is porosity in fraction, \( \tau \) is tortuosity and \( S_{Vgr}^2 \) is the specific surface are per unit grain volume. A 2 is the factor related to the assumption of cylindrical pores. In generalized Kozeny-Carman relationship, this factor is replaced by pore shape
Figure 4.8: Thomeer’s method to define main pore throat size. a) Determination of mercury saturation from apex point, which indicates percentile of dominant pore aperture size. At this saturation, continuous fluid flow is reached (Thomeer, 1960). Samples from Jonah field exhibit 35% saturation values. b) Determination of dominant pore aperture size corresponding to 35% saturation.

constant (Amaefule et al., 1993):

\[
k = \frac{1}{F_s \tau^2 S_{Y_{gr}}} \frac{\phi^3}{(1 - \phi)^2} \tag{4.5}
\]

Dividing both sides of Equation (4.5) by porosity and taking square root of both sides will give following expression:

\[
\sqrt{k \phi} = \left( \frac{\phi}{1 - \phi} \right) \frac{1}{\sqrt{F_s \tau S_{Y_{gr}}}} \tag{4.6}
\]

Amaefule et al. (1993) defined the terms of Equation (4.6) as

- Reservoir Quality Index \((RQI)\) - \(0.0314 \sqrt{\frac{k}{\phi}}\). The factor 0.0314 accounts permeability unit conversion from \(\mu m^2\) to md.

- Void ratio \((\epsilon)\), which is the ratio of pore volume to solid volume - \(\left( \frac{\phi}{1 - \phi} \right)\).

- Flow Zone Indicator \((FZI)\) - \(\frac{1}{\sqrt{F_s \tau S_{Y_{gr}}}}\).
Figure 4.9: Permeability classification of rocks using Pittman (1992) 35th percentile method for Lower Lance and Mesaverde formations. Four rock types are identified based on permeability behavior. The quality of rocks decreases from first to fourth type. Fourth group mainly exhibits permeability $< 1 \mu d$, porosity $< 6\%$, and bounded with permeability model corresponding to $R = 0.1 \mu m$ pore throat radius. The main rock types are $HRT_1$, $HRT_2$ and partially $HRT_3$ (section with the porosity values $> 6\%$). First and second type of rocks are reservoir sandstones. Permeability is varying from 1 to 100 $\mu d$ for the second type, from 100 to 500 $\mu d$ for the first type, respectively. Helium porosity and permeability from two wells were provided by Exaro Energy.

FZI term accounts for pore geometry and it does not dependent upon permeability and porosity. It is difficult to measure parameters inside FZI term in laboratory. However, for reservoir engineering purposes, FZI can be expressed as a function of porosity and permeability, which are measurable in experiments:

$$FZI = \frac{0.0314}{\epsilon} \sqrt{\frac{k}{\phi}} \quad (4.7)$$

Equation (4.7) is a measure of rock quality. Closer values of this term define rock type with similar flow properties. Figure 4.10 is a demonstration of rock classification based on
porosity and permeability. Data is the same as in Figure 4.9. Four rock types are identified with different FZI units. Rock quality is improving with increasing FZI values.

Figure 4.10: Permeability and porosity classification of rocks based on $\log(FZI) = -1; -1.5; -1.1; -0.5; 0$. Data is from Lower Lance and Mesaverde formations, Jonah field and, color-coded with FZI values. Four rock types are identified and, rock quality is improving with increasing FZI values.

4.5 Rock Typing using Effective Specific Surface

Porous media in tight sandstones is undergone to severe cementation (Vernik and Kachanov, 2010). Clay filling, quartz/clay overgrowth and carbonate cementation can disconnect pores and severely increase tortuosity. Due to complex pore structure, fluid flow can occur in and orthogonal direction to pressure drop (Alam et al., 2011). Mortensen et al. (1998) considered pore space as orthogonal connected tubes. Fluid flow occurring in this type of pore space will be dependent alignment of tubes respect to the pressure drop. Mortensen et al. (1998)
derived equation to quantify active part of the porosity, which contributes fluid flow:

\[ c(\phi) = \left[ 4 \cos \left\{ \frac{1}{3} \arccos(2\phi - 1) + \frac{4}{3} \pi \right\} + 4 \right]^{-1} \]  

(4.8)

This term replaces tortuosity and pore shape factors in generalized Kozeny-Carman Equation (4.5):

\[ k = c(\phi) \frac{1}{S^2_{g-eff}} \phi^3 \frac{1}{(1 - \phi)^2} \]  

(4.9)

Having calculated the parameter \( c(\phi) \) from porosity, effective specific surface \( S_{g-eff} \) in Equation (4.9) can be used as an independent parameter in porosity-permeability correlation. \( S_{g-eff} \) can be measured with BET nitrogen adsorption technique. In the absence of laboratory data, \( S_{g-eff} \) is calculated from Equation (4.9):

\[ S_{g-eff} = \sqrt{c(\phi)} \phi \frac{1}{1 - \phi} \sqrt{\frac{1}{k}} \]  

(4.10)

Figure 4.11 demonstrates porosity-permeability correlation from two wells. Based on calculated \( S_{g-eff} \) values from Equation (4.10) four rock types are identified. Rock quality increases with decreasing \( \log(S_{g-eff}) \) values. The magnitude of \( S_{g-eff} \) is proportional to the amount of clays in rocks. Higher clay content is associated with poor connectivity between pores, hence with lower permeability. In addition, clay fills pore space and decreases effective porosity. Therefore, there is inverse relationship between \( S_{g-eff} \) and rock quality.

### 4.6 Comparison of Different Rock Typing Techniques

HRT correlates permeability with porosity based on dominant pore throat size, which is independently measured from capillary pressure data. In opposite to permeability, porosity is less sensitive to the pore throat size change. Therefore, HRT method can be considered as permeability classification of rocks (Figure 4.9). Slight variation of porosity can be associated with orders of magnitude difference in permeability due to pore throat size change. In FZI and effective specific surface method, calculated parameters \( \log(FZI) \) and \( \log(S_{g-eff}) \) have
Figure 4.11: Permeability and porosity classification of rocks based on $\log(S_{g-eff}) = -3.5; -2.5; -2; -1.5; -1$. Data is from Lower Lance and Mesaverde formations, Jonah field and, color-coded with $S_{g-eff}$ values. Four rock types are identified and, rock quality is improving with decreasing $S_{g-eff}$ values.

equal weights of porosity and permeability input in Equations (4.7) and (4.10). Low porosity and permeability rocks can give same values of hydraulic units ($\log(FZI)$ and $\log(S_{g-eff})$) as high porosity, permeability rocks. Therefore, certain rock type can comprise entire range of porosity and permeability, which is not physically reliable. However, HRT classification demonstrates that low porosity and permeability rocks are in poor quality type of rocks (Figure 4.9) In Jonah field, the productivity of sandstones with porosity values less than 6% is insignificant to be considered as a good reservoir rock. In addition, reliability of helium injection measurements for low porosity rocks is questionable to be used for rock typing purposes.

FZI and effective specific surface methods were successfully applied to predict compressional velocity from permeability and known hydraulic unit data (Alam et al., 2011; Castillo
et al., 2012; Prasad, 2003). Figure 4.12(a) and Figure 4.12(b) show relationship between permeability and velocity. Higher FZI and effective specific surface show poor correlation with permeability and velocity. Accuracy of prediction of permeability from velocity will not be a successful due erroneous helium injection data.

Figure 4.12: Velocity-permeability correlation with $\log(FZI)$ and $\log(S_{g-eff})$ units. Higher FZI (a) and effective specific surface (b) show poor correlation with permeability and velocity. Accuracy of prediction of permeability from velocity will not be a successful due erroneous helium injection data.

4.7 Rock Typing from pore size distribution

Different permeability behavior for the first and second type of rocks in HRT classification demonstrated an importance of pore geometry in fluid flow properties. According to Rose and Bruce (1949), the shape of the capillary pressure curves is the primary indication of pore geometry. High capillary pressure primarily shows the existence of small pores. Mercury is the non-wetting phase, hence high injection pressure is required for mercury to enter into the small pores. Figure 3.1(b) shows capillary pressure response of gas-water derived from air-mercury system. Three types of pressure behavior can be detected from the shapes of the curves for 14 samples from Mesaverde formation, Jonah field. The same data is color-coded with mercury injection porosity in Figure 4.13. Blue colored curves are siltstone
and mudstone according to gamma ray classification (GR > 75 API), and exhibit highest capillary pressure. Red and light blue colored curves are sandstones (GR < 75 API). Inside sandstone group there are two distinct rock types. Sandstones with light blue color have mercury porosity values less than 6%, hence is less important as reservoir rock (intermediate capillary pressure system). Good quality sandstone (red curves) possesses porosity value around 10%, which is the target formation for production (low capillary pressure system). In this classification, all type of rocks show good correlation of capillary pressure with porosity. Increase in capillary pressure is associated with decrement in porosity.

To emphasize an influence of pore geometry on rock classification, PSD for each type of rock is derived from capillary pressure data (Figure 4.14). Color-coding is remained same with capillary pressure data. Note that PSD in this context means pore throat size distribution. PSD for siltstone and mudstone falls in a range of 3.6 to 10 nm. In this range, productivity of the formations will be very low. Peak in PSD for good quality sandstone (colored with red) occurs at 300 to 600 nm. Sandstones with porosity values less than 6% demonstrate wide range of PSD. With this data set it is not reliable to set boundaries in PSD between different type of rocks. In order to do that, it would be required to measure samples representing entire range of porosity (0-12%). Dominant pore size derived from HRT method is a good permeability indicator, rather than pore size range. The concave shape of $S_{hg}/P_{hg}$ vs $S_{hg}$ plot indicates the presence of dominant pore aperture size which controls permeability (Figure 4.15). Corresponding dominant pore throat diameters are determined using Thomeer’s method as described in HRT (Thomeer, 1960). Average values for reservoir and non-reservoir sandstones are 400 nm and 100 nm, respectively. Siltstone and mudstone group do not exhibit concave shape (Figure 4.15; blue curves).

Rock classification from MICP pore throat size distribution is an interpretation of end members: reservoir sandstone, non-reservoir sandstone and siltstone/mudstone. MICP data for sandstone from Lance formation with porosity values ranging from 5 to 10% approximately falls into the area between low and intermediate capillary pressure systems (Fig-
Figure 4.13: Capillary pressure response of gas-water derived from air-mercury system. Three types of pressure behavior can be detected from the shapes of the curves for 14 samples from Mesaverde formation, Jonah field. Data is color-coded with mercury injection porosity. Blue colored curves are siltstone and mudstone according to gamma ray classification (GR > 75 API), and exhibit highest capillary pressure. Red and light blue colored curves are sandstones (GR < 75 API). Inside sandstone group there are two distinct rock types. Sandstones with light blue color have mercury porosity values less than 6%, hence is less important as reservoir rock (intermediate capillary pressure system). Good quality sandstone (red curves) possesses porosity value around 10%, which is the target formation for production (low capillary pressure system).

However, there is not a correlation in porosity and capillary pressure in Lance samples. Therefore, when describing rocks in between end members, dominant pore size should be used as a quality indicator, rather than total porosity.

PSD derived from MICP experiments is the measure of throat size. Rock classification is made based on pore throat distribution. However, flow property of rocks is sensitive to pore body size as well. In order to capture the effect of pore size, NMR measurements were performed on ten core plugs (Table 2.1). Figures 3.14 to 3.16 show $T_2$ relaxation time.
Figure 4.14: Pore throat size distribution for three type of rocks. PSD for siltstone and mudstone falls in a range of 3.6 to 10 nm. In this range of PSD, productivity of the formations will be very low. Peak in PSD for good quality sandstone (colored with red) occurs at 300 to 600 nm. Sandstones with porosity values less than 6% demonstrate wide range of PSD.

distribution for ten samples. The shape of the cumulative porosity from NMR should exhibit equivalent behavior as capillary pressure curves from MICP. In order to do that, $T_2$ relaxation time is plotted against normalized cumulative porosity (Figure 4.17). Here, normalized cumulative porosity is equivalent to saturation, a reverse of $T_2$ mimics the behavior of capillary pressure. Relaxation time of small pores is shorter than bigger pores. Therefore, the same alignment of rock types is seen when reverse of $T_2$ is used. Siltstone demonstrates the shortest value of relaxation time, while non-reservoir and reservoir sandstones have the intermediate and the longest values, respectively. $T_2$ distribution of incremental porosity is plotted in Figure 4.18. Siltstone (blue curves) and reservoir sandstone (red curves) show
Figure 4.15: Dominant pore aperture size determination using Thomeer’s method (Thomeer, 1960). The concave shape of $S_{hg}/P_{hg}$ vs $S_{hg}$ plot indicates the presence of dominant pore aperture size which controls permeability. Average values for reservoir (red) and non-reservoir (light blue) sandstones are 400 nm and 100 nm, respectively. Siltstone and mudstone group do not exhibit concave shape (blue curves).

clear separation of groups. Higher clay content, hence smaller pores of siltstones shifted the peak to the lower $T_2$ values. The presence of relatively bigger pores in reservoir sandstone group is associated with the longer relaxation time. Effect of cementation on pore and throat sizes in non-reservoir sandstone led to the wide range of $T_2$ without separation of dominant pore size response. The logarithmic mean of $T_2$ for each group can be averaged for NMR log interpretation purposes, which are 22.2 ms, 3.4 ms and 0.29 ms for reservoir, non-reservoir sandstones and siltstone, respectively. Note that NMR measurements were not performed on mudstone samples. Mudstone samples were highly fractured, and it was impossible to cut
Figure 4.16: MICP data from Lance and Mesaverde formations. Mesaverde data (circles) were used to define three rock types: low, intermediate and high capillary pressure systems. Lance sandstone data (solid lines) approximately falls into the area between low and intermediate capillary pressure systems with the porosity values varying from 5 to 10%. However, there is not a correlation in porosity and capillary pressure in Lance samples. Therefore, when describing rocks in between end members, dominant pore size should be used as a quality indicator, rather than total porosity.

cylindrical plugs with diameters of 1.5" and lengths of 2" for $T_2$ measurements. However, for mudstone an expected value of $T_2$ relaxation time should be in the range of siltstone due to abundance of clay minerals.

In order to qualitatively compare PSD from NMR to pore throat size distribution from MICP, Equation (2.8) were used to convert $T_2$ into pore radius values. Figures from 4.23 to 4.25 show comparison of PSDs for ten samples. There is a good match between throat size and pore size for reservoir sandstone and siltstone. Similar behavior of throat size and pore
Figure 4.17: NMR cumulative porosity for different rock types. The shape of the cumulative porosity from NMR exhibits equivalent behavior to capillary pressure curves from MICP. Color-coding is the same as in MICP. $T_2$ relaxation time is plotted against normalized cumulative porosity. Here, normalized cumulative porosity is equivalent to saturation, a reverse of $T_2$ mimics the behavior of capillary pressure. Relaxation time of small pores is shorter than bigger pores. Therefore, the same alignment of rock types is seen when reverse of $T_2$ is used. Siltstone demonstrates the shortest value of relaxation time, while non-reservoir and reservoir sandstones have the intermediate and the longest values, respectively.

Size validates rock typing using NMR and MICP. Information about NMR PSD classification can be applied to downhole measurements. Different rock types can be identified from NMR logs.

In MICP rock typing, siltstone and mudstone are treated as one rock group. However, nitrogen adsorption data in Figure 4.19(a) demonstrates distinction in between two groups. Area under curve graphically represents pore volume. Mudstone samples (green curves) show the highest pore volume. Siltstone (blue curves) and reservoir sandstone (red curves) have subsequently lower readings. Different pore volumes are related to the amount of pores associated with clay. For example, mudstone has higher clay content than siltstone, hence
Figure 4.18: $T_2$ distribution of incremental porosity. Siltstone (blue curves) and reservoir sandstone (red curves) show clear separation of groups. Higher clay content, hence smaller pores of siltstones shifted the peak to the lower $T_2$ values. The presence of relatively bigger pores in reservoir sandstone group is associated with the longer relaxation time. Effect of cementation on pore and throat sizes in non-reservoir sandstone led to the wide range of $T_2$ without separation of dominant pore size response. The logarithmic mean of $T_2$ for each group can be averaged for NMR log interpretation purposes, which are 22.2 ms, 3.4 ms and 0.29 ms for reservoir, non-reservoir sandstones and siltstone, respectively.

Amount of pores will be higher in mudstone samples (Figure 4.19(b)). $N_2$ porosity reading will be reliable in mudstone. Lowest clay content belongs to sandstone sample. Dominant pore size for this sample is 400 nm, which is bigger than nitrogen adsorption limit (200 nm).

Mudstone porosity represents "shale end points" in log data, which is determined from neutron - density porosity cross plot. In Jonah field, water saturation was calculated using dual water model (Cluff and Cluff, 2004). In this model, one of the input parameters is "shale end point" porosity. Figure 4.20(a) and Figure 4.20(b) show comparison of nitrogen porosity with log density porosity ($DPHI$) and neutron porosity ($NPHI$). Both $DPHI$ and $NPHI$ exhibit erroneous porosity values due borehole enlargement effect. Therefore,
use of mudstone porosity measured from $N_2$ adsorption will help to correct water saturation calculations.

Figure 4.19: Mudstone and siltstone classification. a) Area under curve graphically represents pore volume. Mudstone samples (green curves) show the highest pore volume. Siltstone (blue curves) and reservoir sandstone (red curves) have subsequently lower readings. Different pore volumes are related to the amount of pores associated with clay. b) Clay volume fraction of mudstone (green), siltstone (blue) and reservoir sandstone (red).

4.8 Pressure Dependency of Ultrasonic Velocities of Different Rock Types

Comparison of percentage change in helium porosity (Figure 3.17(c)) and permeability (Figure 3.17(d)) of cores measured under different confining pressures indicates the presence of cracks. Percentage decrease in permeability is higher than in porosity as cracks are the main pathways for fluid flow. However, main portion of porosity consists of stiff pores. As pressure increases, there is minor decrease in porosity due to crack closure. Effect of cracks can be seen in core ultrasonic measurements as well (Figure 4.21). In this case, the cracks can be either natural fractures or the cause of coring operation. Crack closure is responsible for exponential growth of velocity during initial pressure loading. To emphasize this effect, velocity data is normalized to the value at 500 psi (Figure 4.22). Clear separation of reservoir
Figure 4.20: Well log derived density porosity ($DPhi$) (a) and neutron porosity ($NPhi$) (b) are compared with $N_2$ porosity. Both $DPhi$ and $NPhi$ exhibit erroneous porosity values due borehole enlargement effect. Therefore, use of mudstone porosity measured from $N_2$ adsorption will help to correct water saturation calculations in Clavier et al. (1977) dual water model.

sandstone, non-reservoir sandstone and siltstone is seen based on compressibility behavior during initial pressure loading. Reservoir sandstone demonstrates highest compressibility.

Figure 4.21: Pressure dependency of ultrasonic compressional and shear velocity. Crack closure is responsible for exponential growth of velocity during initial pressure loading for the reservoir sandstones. However, non-reservoir sandstone and siltstone demonstrate very low compressibility behavior for both P (a) and S(b) waves.
Figure 4.22: Normalized velocity. To emphasize pressure dependency, velocity data is normalized to the value at 500 psi. Clear separation of reservoir sandstone, non-reservoir sandstone and siltstone is seen based on compressibility behavior during initial pressure loading. Reservoir sandstone demonstrates highest compressibility.

Figure 4.23: PSD for samples AA1 (\(\rho_e = 6.5 \mu s\)) and AA3 (\(\rho_e = 3 \mu s\)).
Figure 4.24: PSD for samples AA4 ($\rho_e = 3.5 \mu s$), AA5 ($\rho_e = 5.5 \mu s$), AA8 ($\rho_e = 30 \mu s$) and AA10 ($\rho_e = 15 \mu s$).
Figure 4.25: PSD for samples AA12 ($\rho_e = 50 \, \mu s$), AA13 ($\rho_e = 30 \, \mu s$), AA17 ($\rho_e = 95 \, \mu s$) and AA18 ($\rho_e = 95 \, \mu s$).
5.1 Conclusions

I improved rock typing in Lance and Mesaverde formations in Jonah field by adding pore size distribution effects to the conventional classification of rocks based on gamma ray and porosity. Reservoir sandstones, non-reservoir sandstone, siltstone and mudstone are the main formation types that can be found using gamma ray, porosity and NMR logs. The main conclusions of this study are summarized as:

- Permeability is mainly dependent on dominant pore size, rather than total porosity. Slight variation of porosity in sandstones is associated with noticeable change in permeability. Cementation and pseudomatrix clay filling have detrimental effect on porosity. However, decreasing pore throat size due to cementation causes orders of magnitude change in permeability. The source of cementation is quartz, chlorite, kaolinite, illite and sparse ferroan calcite.

- Conventional classification of rocks based on gamma ray and porosity characterizes end members of formations. A 75 API gamma ray cut off separates sandstone from siltstone/mudstone. A 6% porosity cut off is characteristic for reservoir (>6%) and non-reservoir quality sandstones (<6%). Pore size distribution captures the transitional change in flow properties of rocks in between end members.

- Comparison of hydraulic rock typing (HRT), flow zone indicator (FZI) and effective specific surface area demonstrates that HRT method is more reliable in classification of sandstones by flow properties. In FZI and effective specific surface method, calculated parameters log(FZI) and log(S_{g-eff}) have equal weights of porosity and permeability inputs in Equations (4.7) and (4.10). Low porosity and permeability rocks can give
same values of hydraulic units ($log(FZI)$ and $log(S_{g-eff})$) as high porosity, permeability rocks. Therefore, certain rock type can comprise entire range of porosity and permeability, which is not physically reliable. However, HRT classification demonstrates that low porosity and permeability rocks are characteristic for poor quality type of rocks.

- MICP pore throat distribution shows that dominant pore throat size for reservoir and non-reservoir sandstones are 400 and 100 nm, respectively. Pore size from NMR demonstrated equivalent behavior to pore throat size from MICP. The logarithmic mean values of $T_2$ transverse relaxation times for reservoir, non-reservoir sandstone and siltstone/mudstone are 22.2 ms, 3.4 ms and 0.29 ms, respectively.

- Siltstone and mudstone were separated based on log differential pore volume distribution from $N_2$ adsorption data. Mudstone porosity represents "shale end points" in log data, which is determined from neutron - density porosity cross plot. In Jonah field, water saturation was calculated using dual water model. In this model, one of the input parameters is "shale end point" porosity. Comparison of nitrogen porosity with log density porosity ($DPHI$) and neutron porosity ($NPHI$) shows that both $DPHI$ and $NPHI$ exhibit erroneous porosity values due to borehole enlargement effect. Mudstone porosity measured from $N_2$ adsorption will help to correct water saturation calculations.

- Comparison of porosity measurement techniques gives reliable range for porosity to be applied to log data. MIP, NMR and helium measurements demonstrate approximately the same reading for porosity values $> 10\%$. MIP and NMR are reliable for entire porosity spectra (within 2% porosity difference). Helium method is not reliable for low porosity range ($< 6\%$). $N_2$ measurements are not reliable for higher porosity range $> 10\%$. 

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5.2 Future Recommendations

Based on this rock typing study, the following main points would be helpful to improve net-pay calculations and completion design in Jonah field

- Thomeer’s method of finding a relationship between permeability and dominant pore size can be applied to NMR data to predict permeability from $T_2$ transverse relaxation time (Marschall et al., 1995). To do that, more NMR and MICP measurements are needed in sandstones.

- Clay volume and pore size distribution from $N_2$ adsorption data shows clear separation between siltstone and mudstone. Mudstone formations are impermeable enough to be boundary for reservoir drainage area. Acquisition of more $N_2$ and XRD could be helpful to identify this formation from gamma ray log data. Also, the study of mechanical properties of mudstones would be a future recommendation for fracture barrier analysis.

- Cementation and clay effects severely increase tortuosity. Main pore size and permeability relationship is related to cementation effect. Measured specific surface area would consider clay effect on porosity permeability correlation.
REFERENCES CITED


