Oil & Natural Gas Technology

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Quarterly Technical Progress Report

Analysis Of Critical Permeablity, Capillary Pressure And Electrical Properties For Mesaverde Tight Gas Sandstones From Western U.S. Basins

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QUARTERLY TECHNICAL PROGRESS REPORT
FOR THE PERIOD ENDING DECEMBER 31, 2007

TITLE: ANALYSIS OF CRITICAL PERMEABLITY, CAPILLARY PRESSURE AND ELECTRICAL PROPERTIES FOR MESAVERDE TIGHT GAS SANDSTONES FROM WESTERN U.S. BASINS

DOE Contract No. DE-FC26-05NT42660

Contractor: University of Kansas Center for Research, Inc.
2385 Irving Hill Road
Lawrence, KS 66044

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ABSTRACT:

Multisalinity measurements of Archie cementation exponent, *m*, have been completed at 20,000 ppm NaCl (n = 145), 40,000 ppm NaCl (n = 322), 80,000 ppm NaCl (n = 205), and 200,000 ppm NaCl (n = 278). This number of analyses represents nearly twice the number proposed. Archie cementation exponent decreases with decreasing porosity. Nearly all core exhibit some dependence of cementation exponent on salinity. The salinity dependence of *m* is weakly negatively correlated with porosity. Using equations developed the Archie cementation exponent can be predicted for any given porosity and formation brine salinity.

Thin section descriptions and core descriptions are being prepared for posting on the website.

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<u>Acronyms</u>

ϕ = bulk porosity (fraction)
ϕ_2 = fracture or touching vug porosity
m_1 = matrix cementation exponent
m_2 = fracture or touching vug cementation exponent
m_{40K} = archie cementation exponent at 40,000 ppm NaCl,
$Slope_{m\text{-}Rw}$ = slope of m_{Rw} versus logRw for an individual sample
m_x = m at salinity X
log Rw_X = log10 of resistivity of brine at salinity X
$logRw_{40K}$ = log10 of resistivity of 40K ppm NaCl = 0.758.

INTRODUCTION

Objectives - Industry assessment of the regional gas resource, projection of future gas supply, and exploration programs require an understanding of the reservoir properties and accurate tools for formation evaluation of drilled wells. The goal of this project is to provide petrophysical formation evaluation tools related to relative permeability, capillary pressure, electrical properties and algorithm tools for wireline log analysis. Major aspects of the proposed study involve a series of tasks to measure drainage critical gas saturation, capillary pressure, electrical properties and how these change with basic properties such as porosity, permeability, and lithofacies for tight gas sandstones of the Mesaverde Group from six major Tight Gas Sandstone basins (Washakie, Uinta, Piceance, Upper Greater Green River, Sand Wash and Wind River). Critical gas saturation (Sgc) and ambient and *in situ* capillary pressure (Pc) will be performed on 150 rocks selected to represent the range of lithofacies, porosity and permeability in the Mesaverde.

Project Task Overview -

Task 1. Research Management Plan
Task 2. Technology Status Assessment
Task 3. Acquire Data and Materials
- Subtask 3.1. Compile published advanced properties data
- Subtask 3.2. Compile representative lithofacies core and logs from major basins
- Subtask 3.3. Acquire logs from sample wells and digitize

Task 4. Measure Rock Properties
- Subtask 4.1. Measure basic properties (k, ϕ, grain density) and select advanced population
- Subtask 4.2. Measure critical gas saturation
- Subtask 4.3. Measure in situ and routine capillary pressure
- Subtask 4.4. Measure electrical properties
- Subtask 4.5. Measure geologic and petrologic properties
- Subtask 4.6. Perform standard logs analysis

Task 5. Build Database and Web-based Rock Catalog
- Subtask 5.1. Compile published and measured data into Oracle database
- Subtask 5.2. Modify existing web-based software to provide GUI data access

Task 6. Analyze Wireline-log Signature and Analysis Algorithms
- Subtask 6.1. Compare log and core properties
- Subtask 6.2. Evaluate results and determine log-analysis algorithm inputs

Task 7. Simulate Scale-dependence of Relative Permeability
- Subtask 7.1. Construct basic bedform architecture simulation models
- Subtask 7.2. Perform numerical simulation of flow for basic bedform architectures

Task 8. Technology Transfer, Reporting, and Project Management
- Subtask 8.1 Technology Transfer
- Subtask 8.2. Reporting Requirements
- Subtask 8.3. Project Management

EXECUTIVE SUMMARY:

Multisalinity measurements of Archie cementation exponent, *m*, have been completed at 20,000 ppm NaCl (n = 145), 40,000 ppm NaCl (n = 322), 80,000 ppm NaCl (n = 205), and 200,000 ppm NaCl (n = 278). This number of analyses represents nearly twice the number proposed. Archie cementation exponent decreases with decreasing porosity. Nearly all core exhibit some dependence of cementation exponent on salinity. The salinity dependence of *m* is weakly negatively correlated with porosity. Using equations developed the Archie cementation exponent can be predicted for any given porosity and formation brine salinity.

Thin section descriptions and core descriptions are being prepared for posting on the website.

RESULTS AND DISCUSSION:

TASK 4. MEASURE ROCK PROPERTIES

Subtask 4.4. Measure electrical properties

Electrical resistivity measurements were performed on core plugs selected to range widely in geographic location, lithology, porosity, and permeability. To evaluate possible Waxman-Smits cation exchange effects, analyses were performed at 20,000 ppm NaCl (n = 145), 40,000 ppm NaCl (n = 322), 80,000 ppm NaCl (n = 205), and 200,000 ppm NaCl (n = 278). Assuming the Archie intercept value, a = 1, the Archie cementation exponent values for all salinities exhibit a trend of decreasing cementation exponent with decreasing porosity (Figure 1).

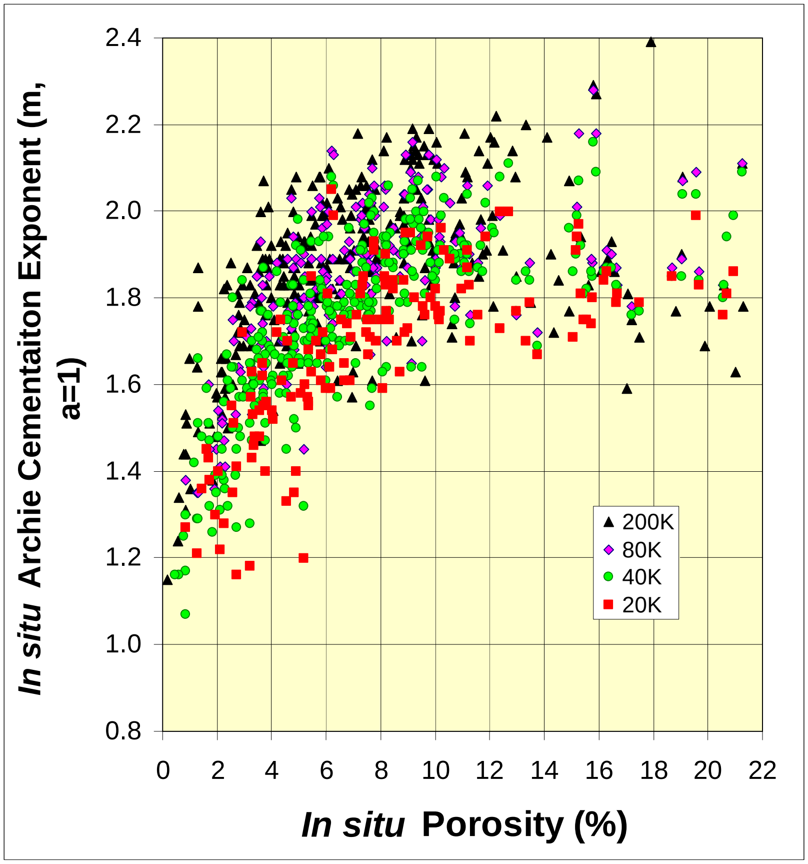

Figure 1. Archie cementation exponent, *m*, versus *in situ* Porosity for Mesaverde sandstone samples at various salinity. Trends for all salinities indicate m decreases with decreasing porosity.

Utilizing the largest set of data at 40,000 ppm NaCl, which also represents a salinity similar to those commonly found in the Mesaverde, the Archie cementation exponent can be modeled either empirically or with a dual porosity model (Serra, 1989).

The dual porosity model for a fractured reservoir or a reservoir with touching vugs represents the conductivity as two circuits in parallel and can be represented by:

$$m = \log[(\phi-\phi_2)^{m1} + \phi_2^{m2}]/\log\phi \qquad (1)$$

Where
ϕ = bulk porosity (fraction)
ϕ_2 = fracture or touching vug porosity
m_1 = matrix cementation exponent
m_2 = fracture or touching vug cementation exponent

In Figure 2 the cementation data are approximately bracketed by for the following conditions:

High: $m_1 = 2.15$, $\phi_2 = 0.0015$, $m_2 = 1$
Intermediate: $m_1 = 2.0$, $\phi_2 = 0.0035$, $m_2 = 1$
Low: $m_1 = 1.8$, $\phi_2 = 0.007$, $m_2 = 1$

The intermediate solution parameters were estimated by trail-and-error solution for the parameters that provided the minimum average error between dual-porosity model and the measured data.

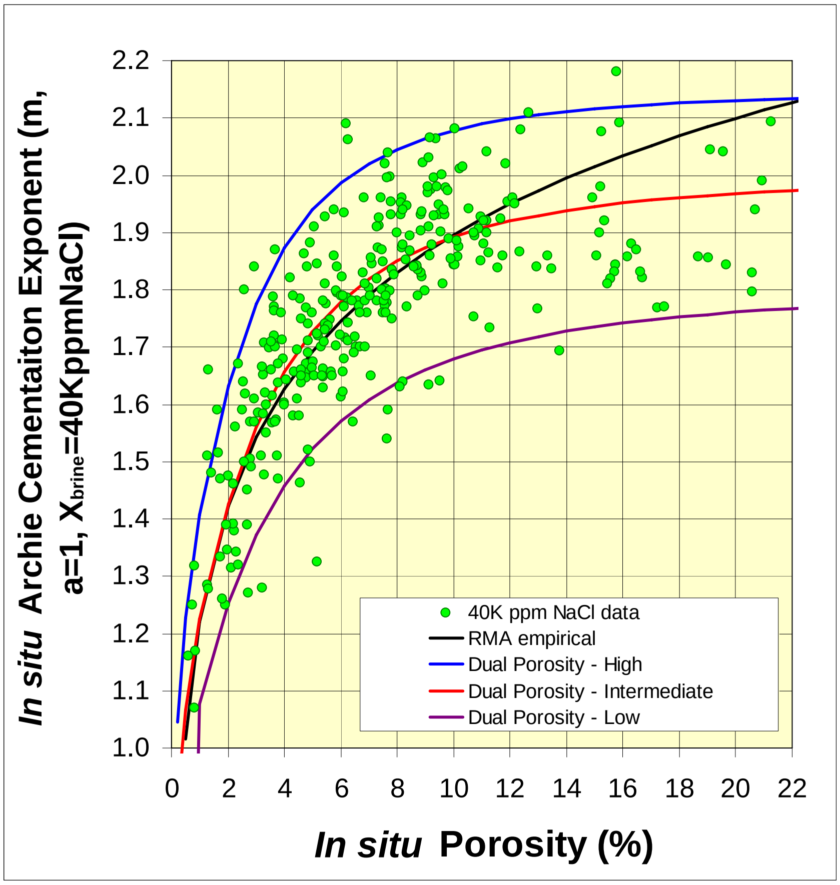

Figure 2. Crossplot of *in situ* Archie cementation exponent, m (assuming A=1) versus *in situ* Porosity showing decreasing m with decreasing porosity and both RMA empirical model (black curve) and high (blue), low (purple), and intermediate (red) dual-porosity models.

Also shown in Figure 2 is the empirical reduced major axis (RMA) analysis solution of the relationship between $\log_{10}$m and porosity. This relationship can be expressed:

$$m_{40k} = 0.676 \log\phi + 1.22 \quad (2)$$

where m_{40k} = archie cementation exponent at 40,000 ppm NaCl, ϕ = porosity in percent.

The RMA analysis provides a more accurate solution for minimum error at the low and high end porosities and appropriately handles the uncertainty in the porosity variable. A linear regression analysis provides an estimation of m using:

$$m_{40k} = 0.538 \log\phi + 1.33 \quad (3)$$

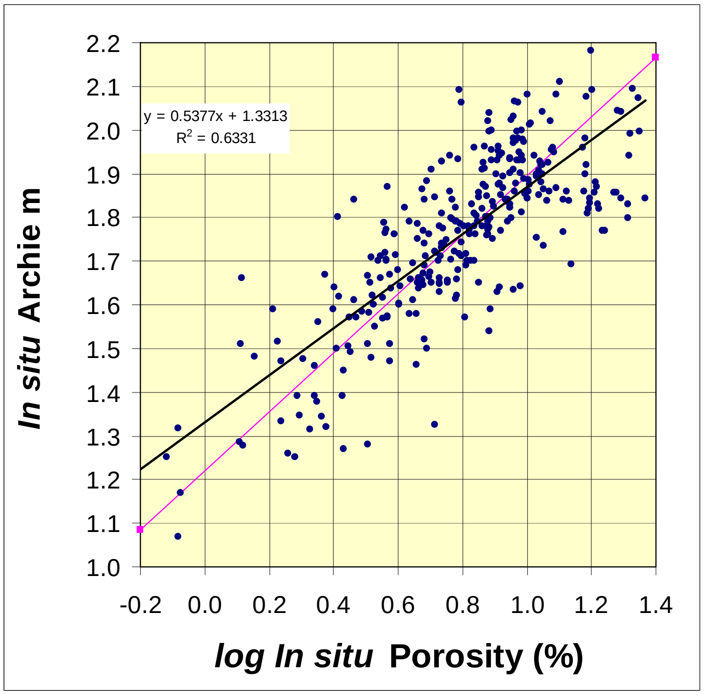

Figure 3. Crossplot of *in situ* Archie cementation exponent, m (assuming A=1), versus $\log_{10}$ *in situ* porosity.

It is important to note that although the dual porosity model is capable of matching the pattern of Archie m data in Figure 2, this alone does not validate the implicit pore architecture of the model for the tight gas sandstones studied. This model assumes that there is present in these sandstones a microfracture(s) that carry current parallel to the matrix. This has not been directly observed. An alternate interpretation of the results is that as porosity decreases:

1) the remaining pores may become progressively more sheet-like or fracture-like with diminishing tortuosity
2) the conductivity of a few larger pores increases disproportionately to their relative volume
3) the remaining pores may actually exhibit decreased m

The empirical RMA log-linear equation predicts very similar m values to the dual porosity model up to approximately 14% porosity. At greater porosity each dual-porosity model approaches a constant that remains constant for all greater porosity, however, the RMA model predicts increasing m values with increasing porosity, which is incorrect. Therefore this equation is limited to $\phi < 14\%$. For $\phi > 14\%$ a constant m = 1.95 is the average of all values.

These results and models cannot be robustly extrapolated to porosity values greater than 24%. Both modeling approaches predict constant cementation exponent values with increasing porosity which cannot hold true for all higher porosity values.

Salinity Dependence

Comparing measured core conductivities versus the saturating brine conductivity (Figure 4), nearly all cores exhibit some salinity dependence and the dependence is highly linear with mean correlation coefficient r2 = 0.97$\underline{+}$0.05 for 308 samples (Figure 4).

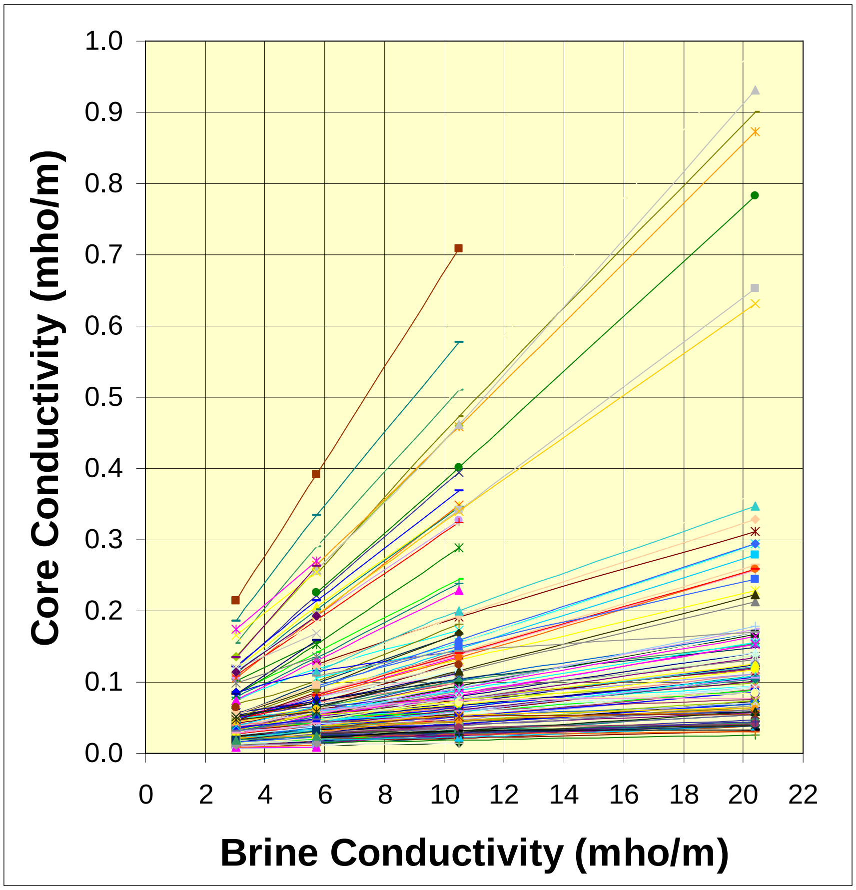

Figure 4. Core conductivity versus saturating brine conductivity for 308 samples.

This dependence can be modeled using the Waxman-Smits equations or using empirical relationships.

Simple empirical models provide an easy method to predict cementation exponents within log analysis software. The salinity dependence shown in Figure 4 can be translated to a relationship between cementation exponent and salinity as shown in Figure 5. The log-linear relationship between m and logarithm of brine resistivity (Rw) allows the correction of predicted m values obtained using Equation 2 to any salinity.

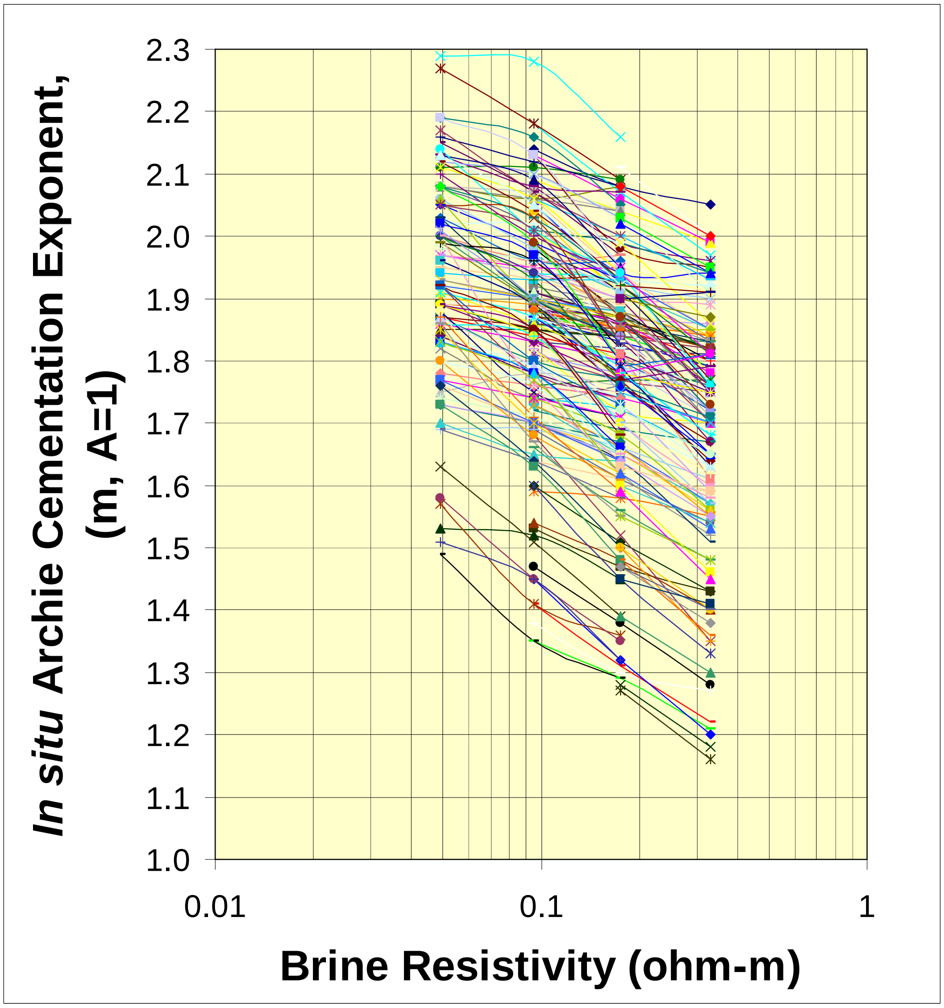

Figure 5. Crossplot of Archie cementation exponent versus saturating brine resistivity for 308 samples. All samples exhibit a highly liner relationship.

Although each core exhibits a highly linear relationship between m and logRw, the exact slope of each core varies with a mean value for all cores of ;

$$\text{Average Slope}_{m\text{-}Rw} = -0.27 \underline{+} 0.32 \text{ (2 standard deviations)} \quad (4)$$

Where $\text{Slope}_{m\text{-}Rw}$ = slope of m_{Rw} versus logRw

The slopes exhibit a weak correlation with salinity (Figure 6). This correlation can be used to improve the prediction of *m* at any salinity:

$$\text{Slope}_{m\text{-}Rw} = 0.00118\ \phi - 0.355 \quad (5)$$

where ϕ is porosity in percent.

Combining the above equations the Archie cementation exponent at any given porosity and reservoir brine salinity can be predicted using:

$$m_X = m_{40} + \text{Slope}_{m\text{-}Rw} (\log Rw_X + \log Rw_{40K}) \quad (6)$$

replacing all terms:

$$m_X = (0.676 \log\phi + 1.22) + (0.0118\ \phi - 0.355) \times (\log Rw_X + 0.758);\ \phi < 14\% \quad (7)$$

$$m_X = 1.95 + (0.0118\ \phi - 0.355) \times (\log Rw_X + 0.758);\ \phi \geq 14\% \quad (8)$$

where m_x = m at salinity X, m_{40} = m at 40K ppm NaCl, log Rw_X = log10 of resistivity of brine at salinity X, $\log Rw_{40K}$ = log10 of resistivity of 40K ppm NaCl = 0.758.

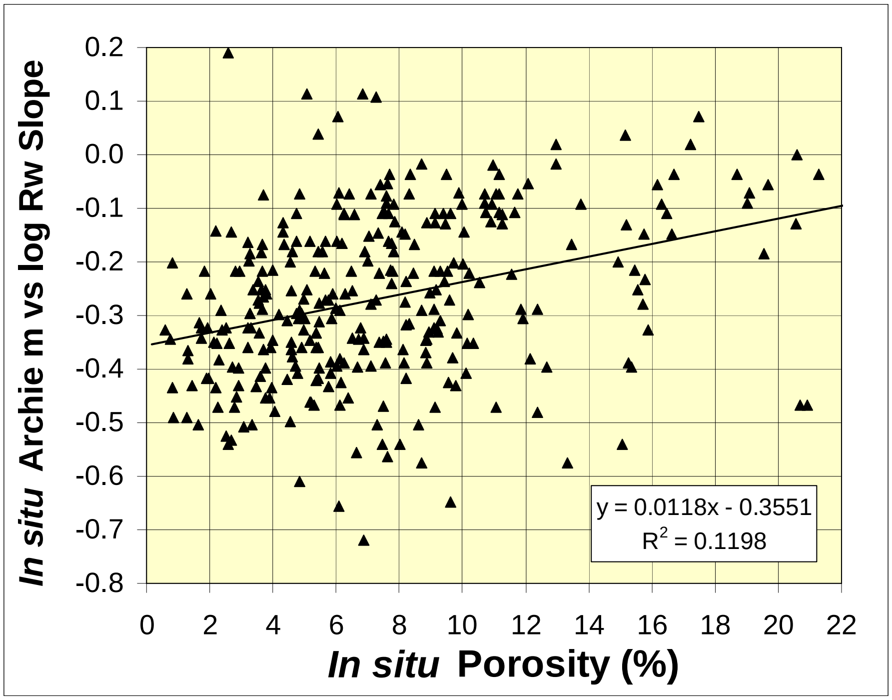

Figure 6. Crossplot of slope of Archie m versus logRw versus porosity.

TASK 8. TECHNOLOGY TRANSFER, REPORTING, PROJECT MANAGEMENT

Subtask 8.1 Technology Transfer

A combined oral and poster presentation was presented at the Rocky Mountain Section meeting of the American Association of Petroleum Geologists at Snowbird, UT in October 6-9, 2007. The talk and poster are posted on the website.

CONCLUSIONS

Multisalinity measurements of Archie cementation exponent, *m*, have been completed at 20,000 ppm NaCl (n = 145), 40,000 ppm NaCl (n = 322), 80,000 ppm NaCl (n = 205), and 200,000 ppm NaCl (n = 278). This number of analyses represents nearly twice the number proposed. Archie cementation exponent decreases with decreasing porosity. Nearly all core exhibit some dependence of cementation exponent on salinity. The salinity dependence of *m* is weakly negatively correlated with porosity. Using equations developed the Archie cementation exponent can be predicted for any given porosity and formation brine salinity.

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