# Estimating the Effect of Rock Mineral Composition on Reservoir Quality: Application in the Spraberry and Wolfcamp Formations, Permian Basin, Texas and New Mexico

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## ABSTRACT

**Estimation of the mineral and fluid composition of rock formations is important for petrophysical and rock physics analysis. One method of estimating rock composition is by solving a system of linear equations that relate a class of geophysical log measurements to the petrophysical properties of known minerals and fluids as an inverse problem. This method has proven useful for carbonate rocks having complex mineralogies. In this study, we develop a new workflow for estimating the rock mineralogy as an inverse problem and examine the relationship between the rock composition and porosity. We apply the workflow to well log data spanning the Spraberry Formation in the Permian Basin and estimate the volumes of quartz, calcite, and clays. Within the study area, an increase in calcite can be observed to correspond to a decrease in porosity indicating the effect of calcite cementation. An increase in quartz content can be observed to correspond to an increase in porosity. In general, an increase in clay content corresponds to a decrease in porosity indicating the clay may be pore filling. The results indicate that areas having less calcite and less clay minerals also have better reservoir quality. Petrophysical composition maps generated from the results will help reduce the risk in unconventional petroleum exploration.**

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# *Estimating the Effect of Rock Mineral Composition on Reservoir Quality: Application in the Spraberry and Wolfcamp Formations, Permian Basin, Texas and New Mexico*

### *GCAGS Annual Convention, Sep 30 - Oct 2, 2018, Shreveport, Louisiana*

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## Introduction

- Knowledge of the mineral and fluid composition of the rocks is an important step in understanding the heterogeneity of carbonate rocks (Amosu and Sun, 2018a,b; Amosu et al., 2018 a, b, c).
- One method of estimating rock composition is by solving a system of linear equations that relate a class of geophysical log measurements to the petrophysical properties of known minerals and fluids as an inverse problem. This method is useful for carbonate rocks having complex mineralogies; for example, Savre (1963) demonstrated the effectiveness of the method as a means of improving porosity estimates on Permian carbonate rocks in West Texas.
- In this study, we make use of recently acquired wireline well log data from 5 wells in Upton County, Midland basin (within the Permian basin), to carry out petrophysical composition analysis of the Spraberry Formation.
- We examine the relationship between mineral components and porosity from the inversion results by calculating the joint probability distribution between porosity and each component. We then map the distribution of the mineral components within the field. The maps are useful guides for reducing the risk involved in locating new wells and making drilling decisions.

## Study Area and Geological Setting

- The Permian basin is a foredeep basin that developed during the Late Mississippian and Early Pennsylvanian (Hills, 1984).
- Present day structural and tectonic features in the basin include the Central Basin platform, the Midland basin, the Delaware basin, and the Ozona arch (Fig. 1).
- During the Early Permian (Wolfcampian and Leonardian), carbonate deposition occurred on shelves around the Midland and Delaware basins and carbonate and siliciclastic debris were deposited in the basins (Dutton et al., 2005);
- By the Leonardian, the area was a stable shallow-water carbonate platform (Frenzel et al., 1988)

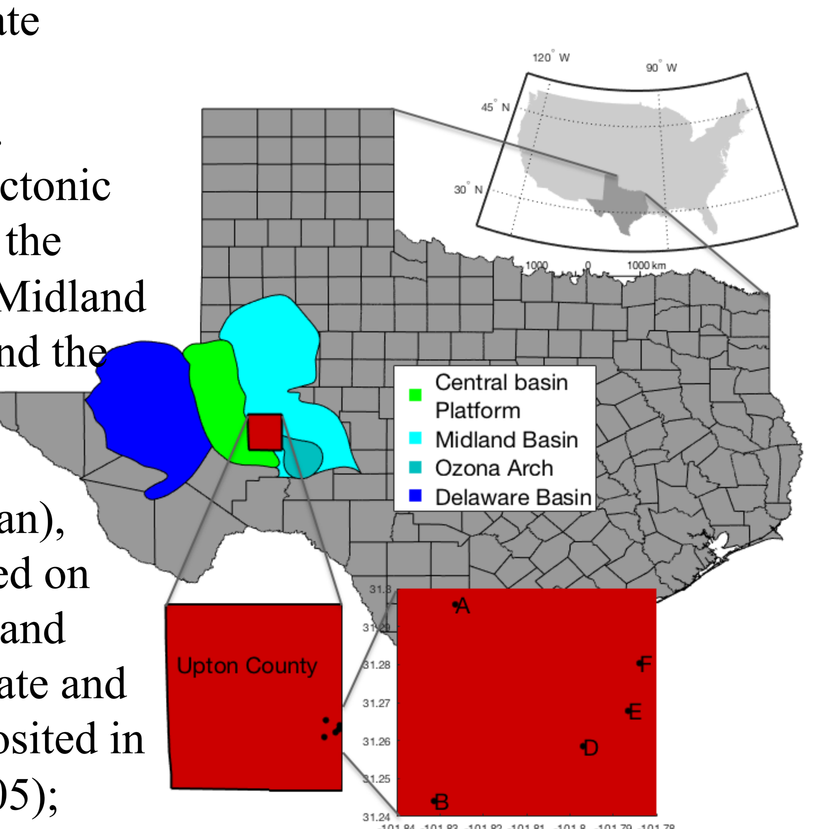


Figure 1: Map showing the location of the wells used in the study in the Midland basin within the Permian basin.

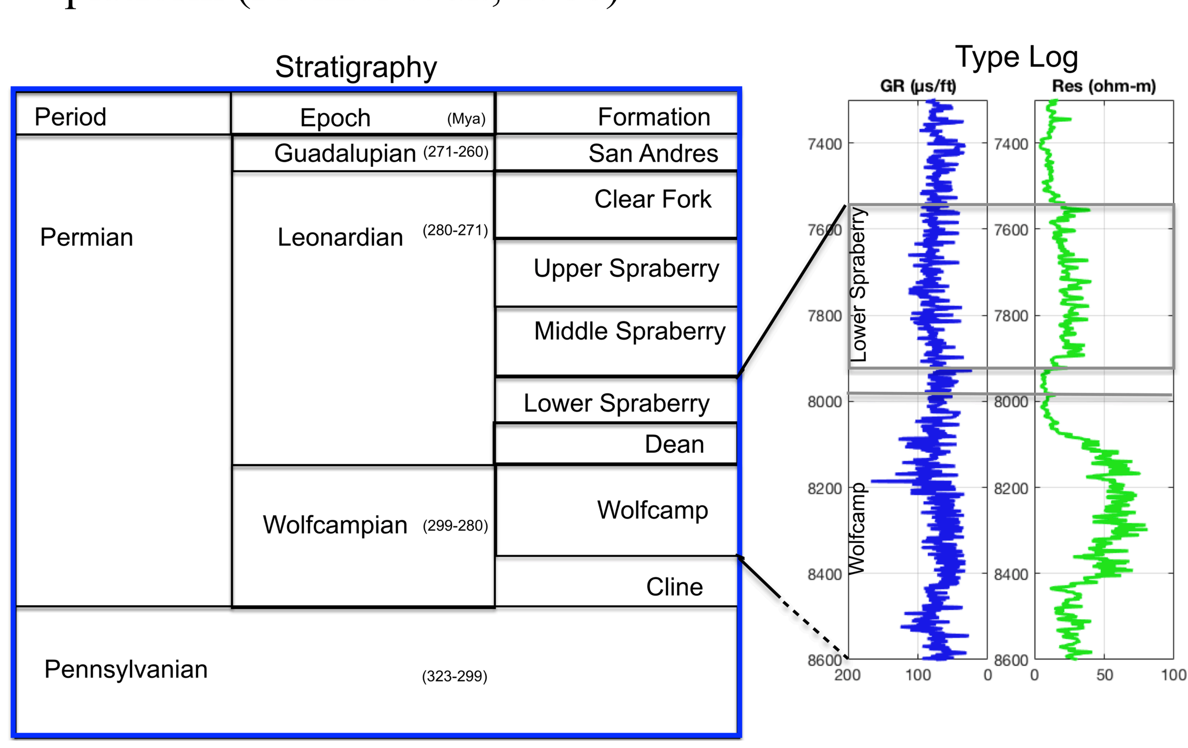


Figure 2: Stratigraphy of the Permian basin, section studied and type log showing the Lower Spraberry and the upper part of the Wolfcamp Formations.

## Data and Methodology

- The data used in this study comes from 5 wells located in Upton County, Midland basin (Fig. 1), which penetrate the Lower Spraberry and Wolfcamp Formations.
- Fig. 2 shows the stratigraphy of the Permian basin, the section studied and and a type log depicting the characteristics of the Lower Spraberry and the upper part of the Wolfcamp. Sequence stratigraphy is useful in identifying the formations and correlation (Amosu and Sun 2017 a , b)
- Inversion of geophysical well logs is usually carried out using a special class of logs that record porosity estimation and are particularly useful in composition analysis of rock formations (Amosu and Sun, 2018, Amosu and Mahmood, 2018).
- Some commonly used measurements include bulk density, photoelectric factor, acoustic velocity, and neutron porosity. Equation (1) is an example of the inversion equation:

$$\begin{bmatrix} \rho_q & \rho_{ca} & \rho_{cl} & \rho_f \\ Pe_q & Pe_{ca} & Pe_{cl} & Pe_f \\ \Delta t_q & \Delta t_{ca} & \Delta t_{cl} & \Delta t_f \\ 1 & 1 & 1 & 1 \end{bmatrix} \begin{bmatrix} V_q \\ V_{ca} \\ V_{cl} \\ \phi \end{bmatrix} = \begin{bmatrix} \rho_l \\ Pe_l \\ \Delta t_l \\ 1 \end{bmatrix}$$

where ρ, *Pe*, Δt, *and* V stand for bulk density, photoelectric factor, sonic travel time and volume fraction respectively. The subscripts *q*, *ca*, *cl*, *f* and *l* stand for quartz, calcite, clay, fluid and log measurement respectively.

- The five wells all have sonic travel time logs, bulk density logs, neutron porosity logs, and photoelectric factor logs.
- For each depth point within the selected zone, we construct and solve the linear system of equations as in equation (1) following (Amosu and Sun, 2018a).

## Results and Discussions

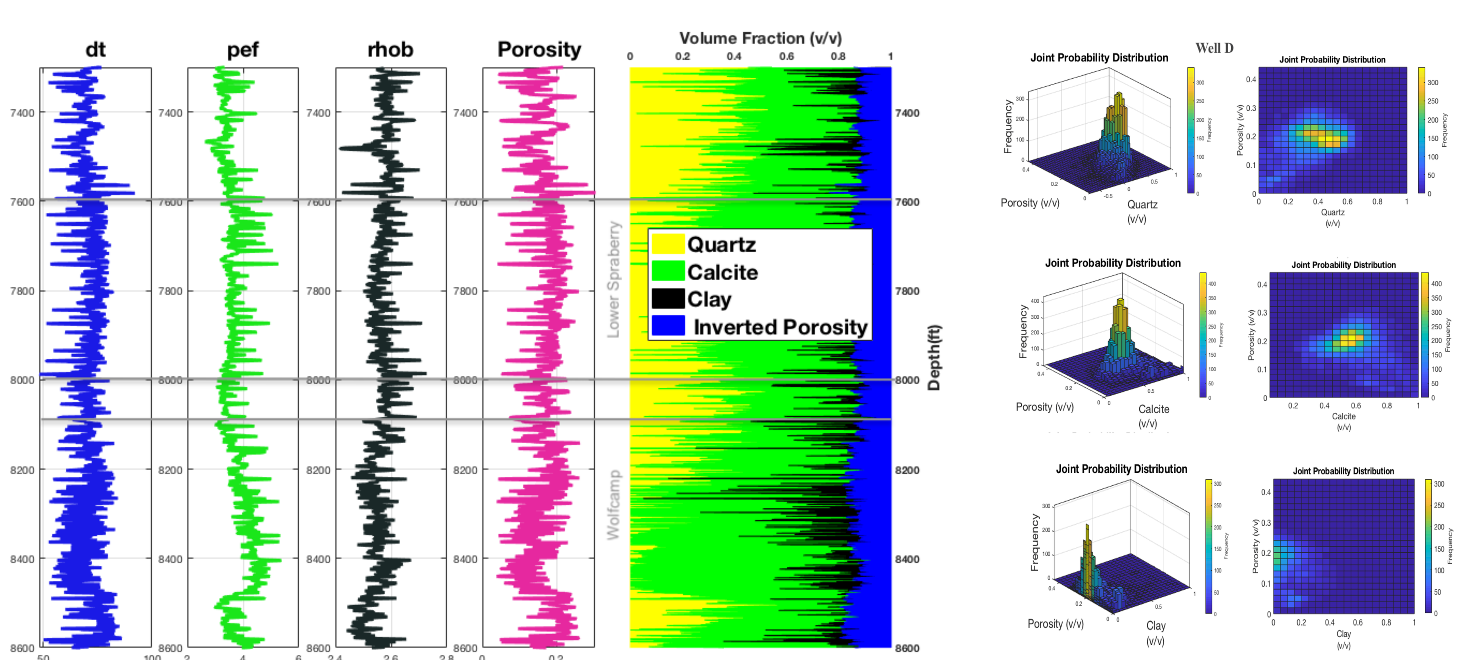


Figure 3 a and b: Petrophysical composition analysis of Well D in Upton county, Midland Basin and Joint probability distribution of porosity and mineral composition elements

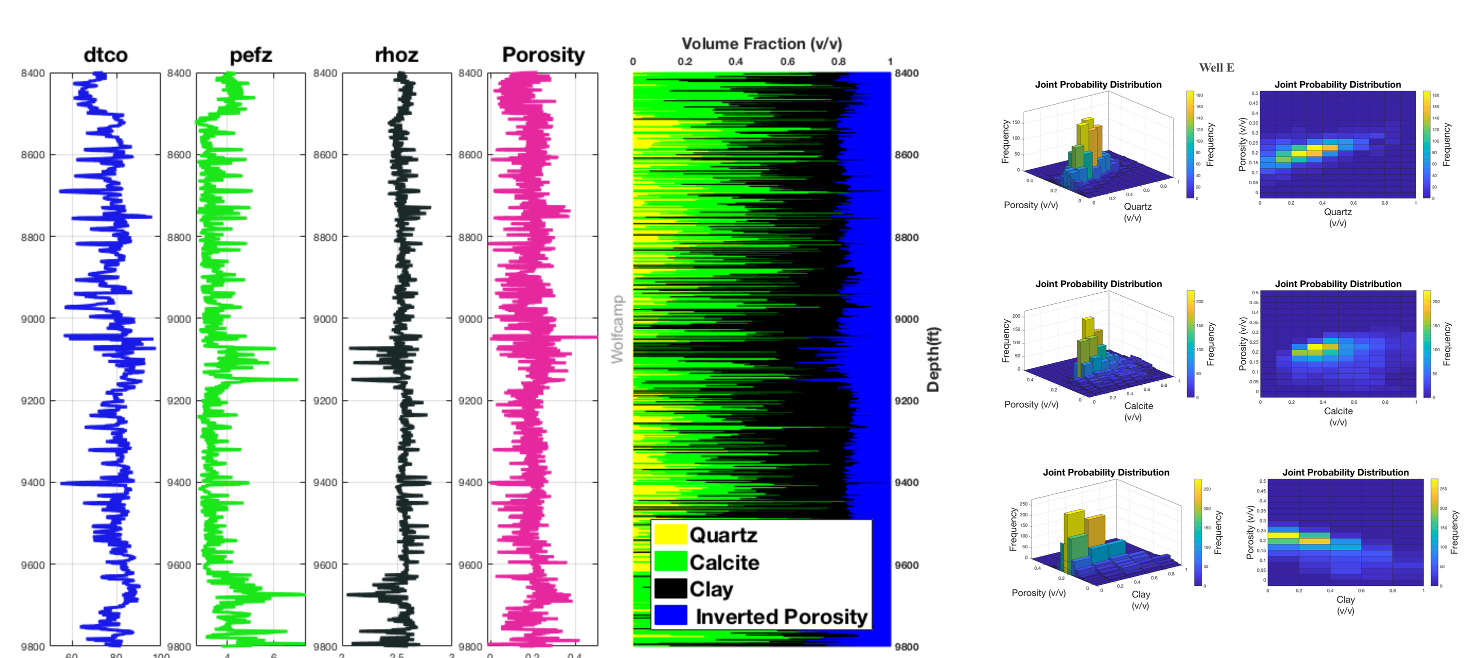


Figure 4 a and b: Petrophysical composition analysis of Well E in Upton county, Midland Basin and Joint probability distribution of porosity and mineral composition elements

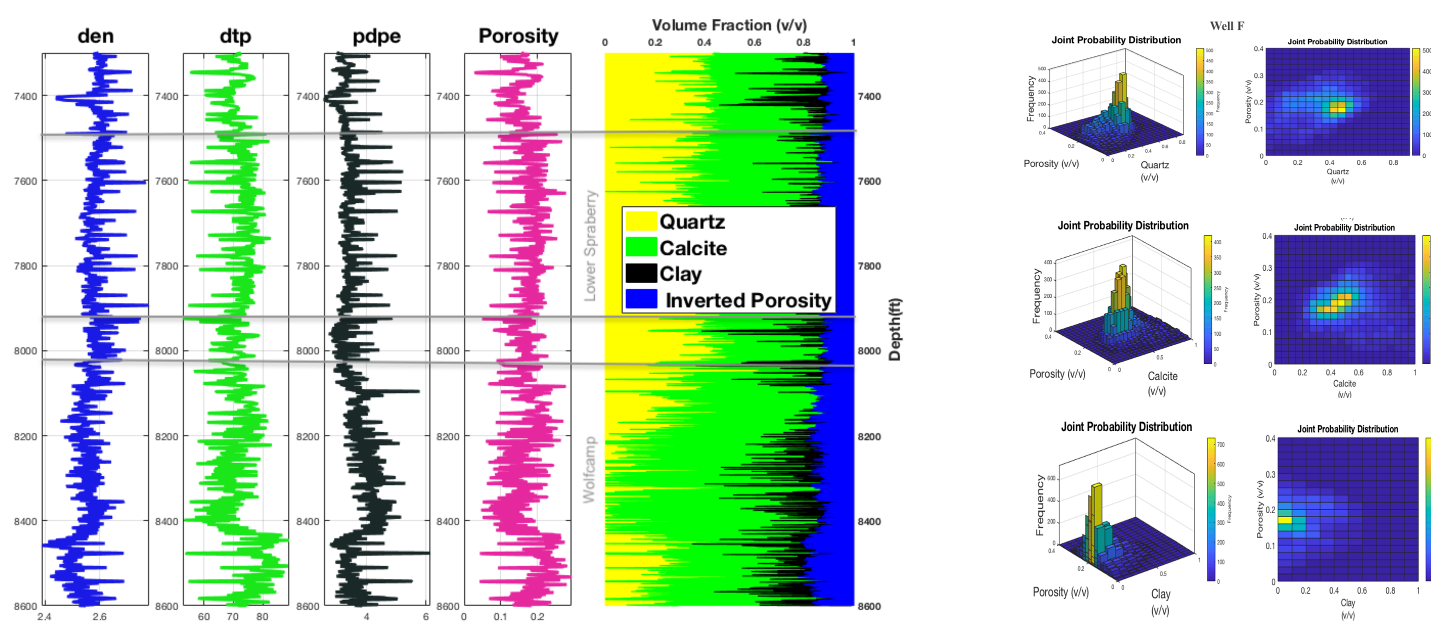


Figure 5 a and b: Petrophysical composition analysis of Well F in Upton county, Midland Basin Joint probability distribution of porosity and mineral composition elements

- We obtain estimates of the variation in the volume of each mineral with depth (Figs 3-5 (a)). We then examine the relationship between the mineral components and porosity by calculating the joint probability distribution between porosity and each mineral constituent.
- Figs3-5 (b) show the joint probability distribution between porosity and each mineral constituent for wells D, E and F. These show general statistical trends in behavior between the mineral components and porosity and can be repeated for other measurements apart from porosity if available.
- In general, porosity increases with the volume of quartz. This could be as a result of interparticle porosity between the quartz grains. Porosity reduces with increase in the volumes of calcite and clay in all wells. This may imply that calcite is acting as a cement and clay may be filling the pore spaces available.
- This is in agreement with photomicrograph thin section analysis from previous studies (Amosu and Sun, 2018a). At well E, porosity slightly increases with calcite, suggesting diagenetic dissolution

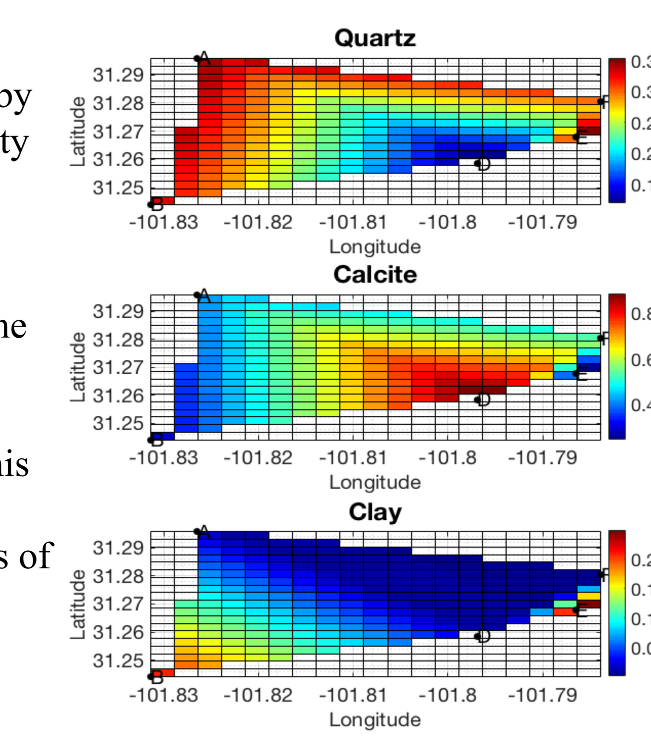


Figure 6: Mineral composition map of quartz, calcite and clay at the depth of 9100 ft.

- We use the data from wells A, B, D, E, and F in constructing a volume map for each mineral constituent (Fig. 6). The region with more quartz correlates with the region with less calcite. If used with a large well log dataset this technique will be useful in reducing the risk associated with making drilling decisions in unconventional plays since the general statistical relationship of each mineral constituent with porosity is known.

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