A Petrophysical Model for Shale Reservoirs to Distinguish Macro-Porosity, Micro-Porosity, and TOC*

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Abstract

A petrophysical model is presented whereby a number of shale reservoir components, both solids and porosity, can be identified. Input data are standard open-hole logs to include density, neutron, gamma ray, and resistivity.

The starting point is a standard shaley formation analysis to identify total and effective porosity, shale volume, and fluid saturations in the effective porosity fraction of the rock. A second task is to determine TOC content. The procedures used in this model are those of Passey et al, 1990, and include calibration to core measurements, if available.

Using the data from the initial analyses, detailed examination of the shale fraction of the rock can then be undertaken. First, density and neutron log responses are reduced to the shale only fraction, by subtracting contribution from matrix, effective porosity, and TOC. Then, by using a density/neutron cross plot of the shale only fraction, points are chosen by the interpreter recognizing silt, clay species #1, and clay species #2. Once they have been chosen, it is possible to recognize the volumetric contribution of silt and the two shale components. The properties of the two clay points, bulk density and neutron porosity, are used to define porosity of the clays, which is water filled. The cross plot porosity of the shale contains both clay porosity and free shale porosity, and is greater than or equal to clay porosity. If this relationship is not honored (i.e. clay porosity greater than shale porosity), adjustments need to be made with respect to the log choices of silt, clay 1, and clay 2. Finally, free porosity in the shale is available by subtracting clay porosity from cross plot shale porosity.

A volumetric balance of the porosity components - free shale porosity, TOC, clay porosity, and effective porosity - is compared with total cross plot porosity, to ensure the model accounts for all porosity elements correctly. Mismatches can be rectified by adjusting input parameters of silt, clay species #1 and clay species #1.

Comparisons are now possible among macro porosity (effective porosity), micro porosity (free shale porosity), and TOC. Examples are presented from a number of shale reservoirs, both oil and gas bearing.

Introduction

Conventional reservoirs are routinely analyzed to define porosity accessible to hydrocarbons (often termed effective porosity), and its contained fluids – water, oil, and gas (Figure 1). By contrast, petrophysical evaluation of shale reservoirs is in its infancy. Procedures applicable to conventional reservoirs cannot be applied, and new approaches need to be developed.

This expanded abstract outlines the methodologies proposed to quantify free shale porosity, effective porosity, clay porosity, and TOC in shale reservoirs (Figure 2).

Methodology

1. Solve for Density and Neutron responses in the shale fraction of the formation.

2. From the Rho_{SH} vs. $NPhi_{SH}$ cross plot, choose Silt, Clay #1, and Clay #2 points to create and envelope encompassing the majority of the data (Figure 3).

Choose Clay Porosity values appropriate to Clay 1 and Clay #2. Using the three data points, calculate Clay Porosity:

a. % Silt, % Clay #1, and % Clay #2
b. Clay #1 Porosity Contribution = % Clay #1 x Clay #1 Porosity
c. Clay #2 Porosity Contribution = % Clay #2 x Clay #2 Porosity
d. Clay Porosity = Clay #1 Porosity Contribution + Clay #2 Porosity Contribution

3. Once the Clay Porosity has been calculated, there are two different methods to calculate free porosity in shale. Both methods are used, and shown in the examples for comparison.

a. To determine Free Available Porosity, first calculate Shale Porosity from a RhoSH vs. NPhiSH cross plot. Then, subtract Clay Porosity from the Shale Porosity to define Free Shale Porosity. The Clay Porosity and Free Shale Porosity are then compared on a Cross Plot. Free Shale Porosity should be mostly equal to or greater than Clay Porosity (shown in Figure 4). If Free Shale Porosity is not mostly greater than or equal to Clay Porosity, adjust the choice of Clay #1 porosity or Clay #2 porosity in step 2. Finally, Add Shale Porosity to Effective Porosity to define Free Available Porosity (Passey et. al., 1990).

b. To determine Free Available Porosity, first, on the RhoSH vs. NPhiSH cross plot, identify an envelope occupied by wet clays (Figure 5). Quantify Free Cross Plot Porosity for data falling to the NW of the wet clay envelope. Add Free Cross Plot Porosity to Effective Porosity to define Free Available Porosity (Denver Well Logging Society, 2008).

4. The next step is to estimate Water Saturation (S_w). After attempts to define water saturation using shaley sand approaches failed, an empirical calculation was determined to give the closest comparison when compared with core measured S_w.

$$S_w = \left(\frac{R_w}{R_{wa}}\right) 0.5$$

$$R_{wa} = Phi_T{}^m \times R_t$$

5. Using the S_w estimated in step 4, and Free Available Porosity 1 and 2, Bulk Volume Free Hydrocarbons can now be estimated for both methods outlined in step two.

- Bulk Volume Free Hydrocarbons1 = Free Available Porosity1 x (1-S_w)
- Bulk Volume Free Hydrocarbons2 = Free Available Porosity2x (1-S_w)

6. The final output includes recognition of four porosity components are illustrated in Figure 6.

7. The porosity calculations can be verified and validated by calculating the sum of the porosity elements (Phi_E + Phi_{SH} + Clay + TOC) to create a Reconstructed Total Porosity curve. The Reconstructed Total Porosity curve can then be compared with the original curve, Total Porosity (Figure 7).

Example 1 illustrates the Barnett Clean Formation Model (Figure 8) and Barnett Shale Model (Figure 9); Example 2 illustrates the Niobrara Clean Formation Model (Figure 10) and Niobrara Shale Model (Figure 11); Example 3 illustrates the Western Canada Clean Formation Model (Figure 12) and Western Canada Shale Model (Figure 13).

Reference

Passey, Q.R., S. Creaney, J.B. Kulla, F.J. Moretti, and J.D. Stroud, 1990, A practical model for organic richness from porosity and resistivity logs, AAPG Bulletin v. 74/12, p. 1777-1794.

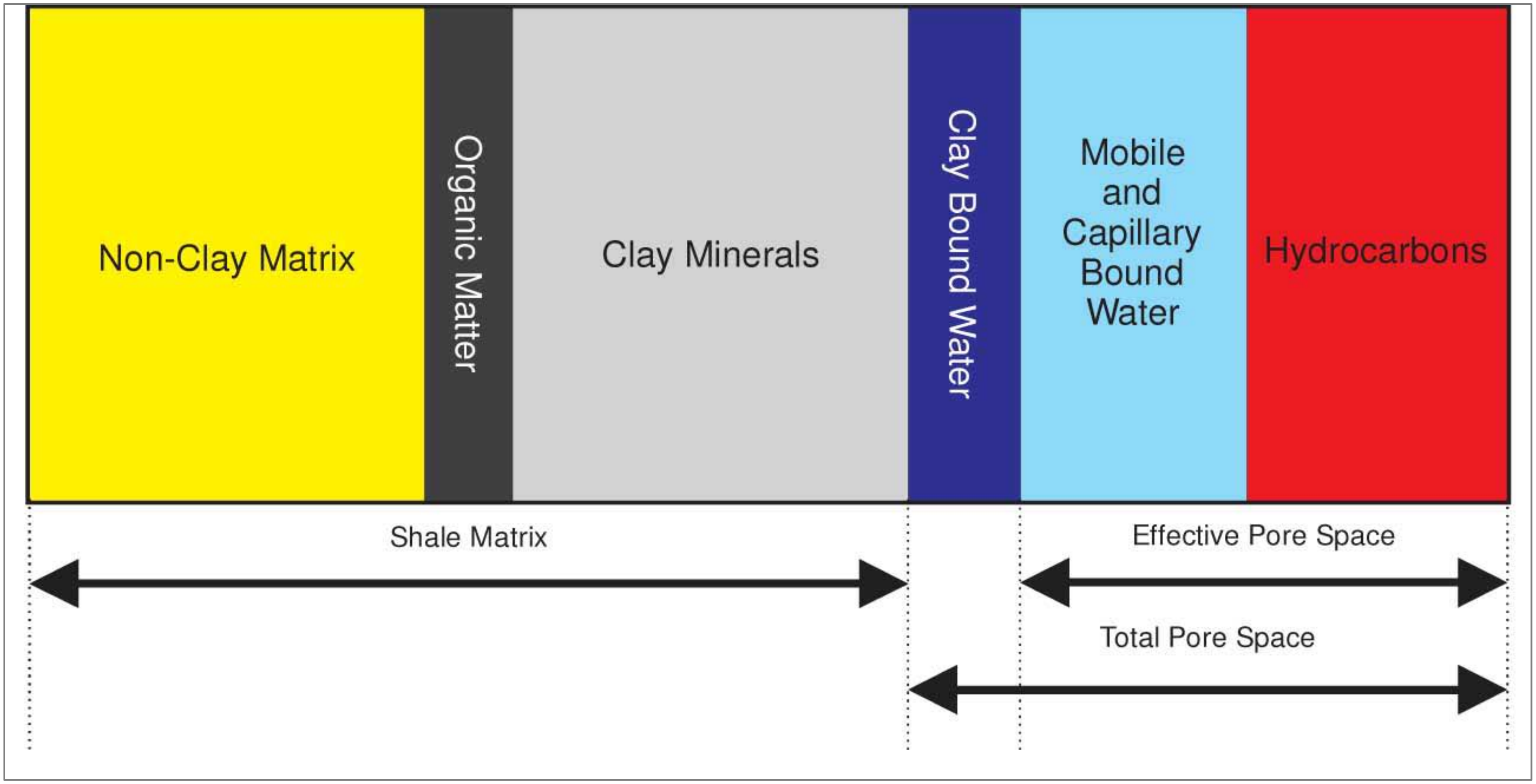

Figure 1. Traditional petrophysical model for shale reservoirs.

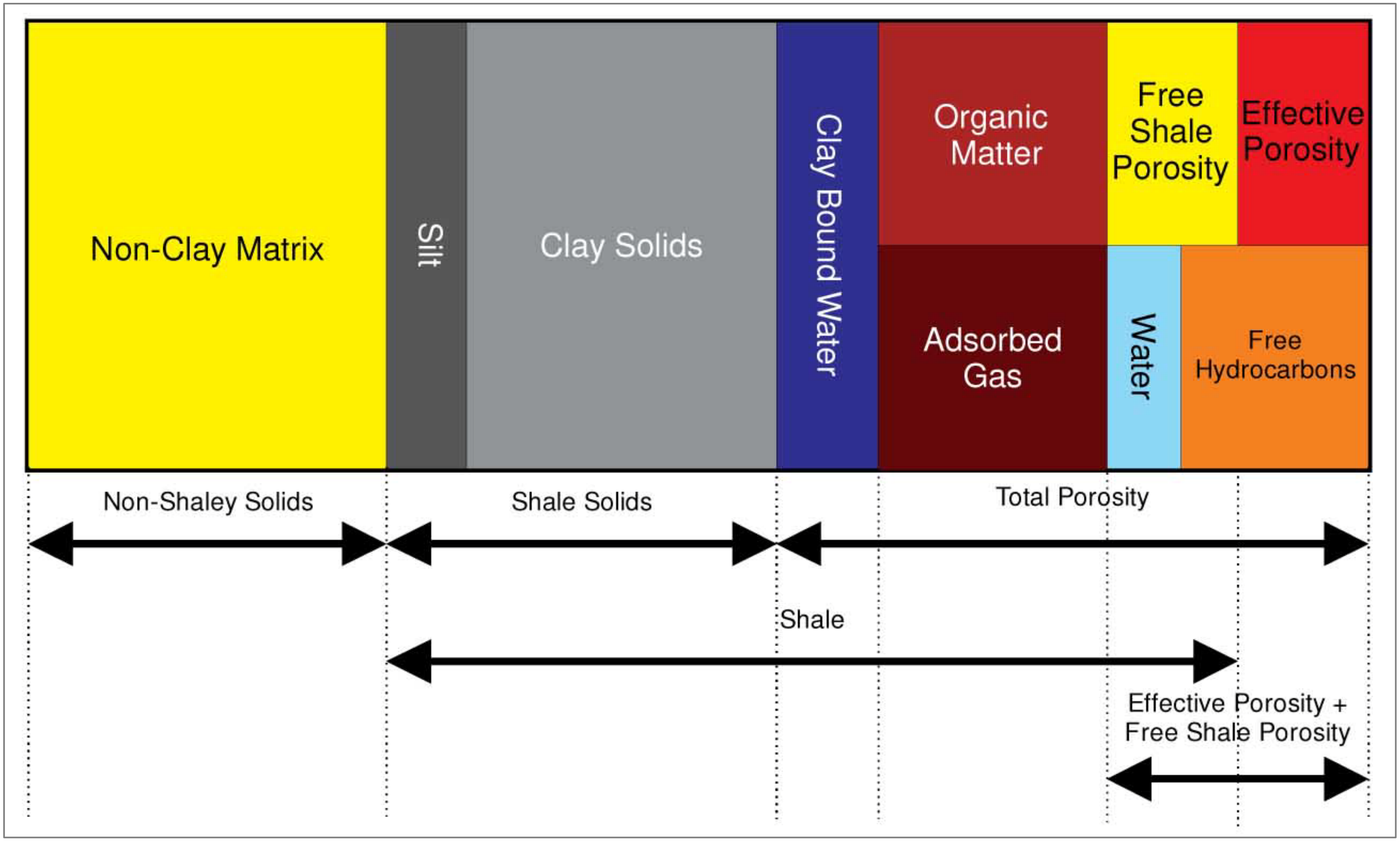

Figure 2. Proposed modified petrophysical model for shale reservoirs.

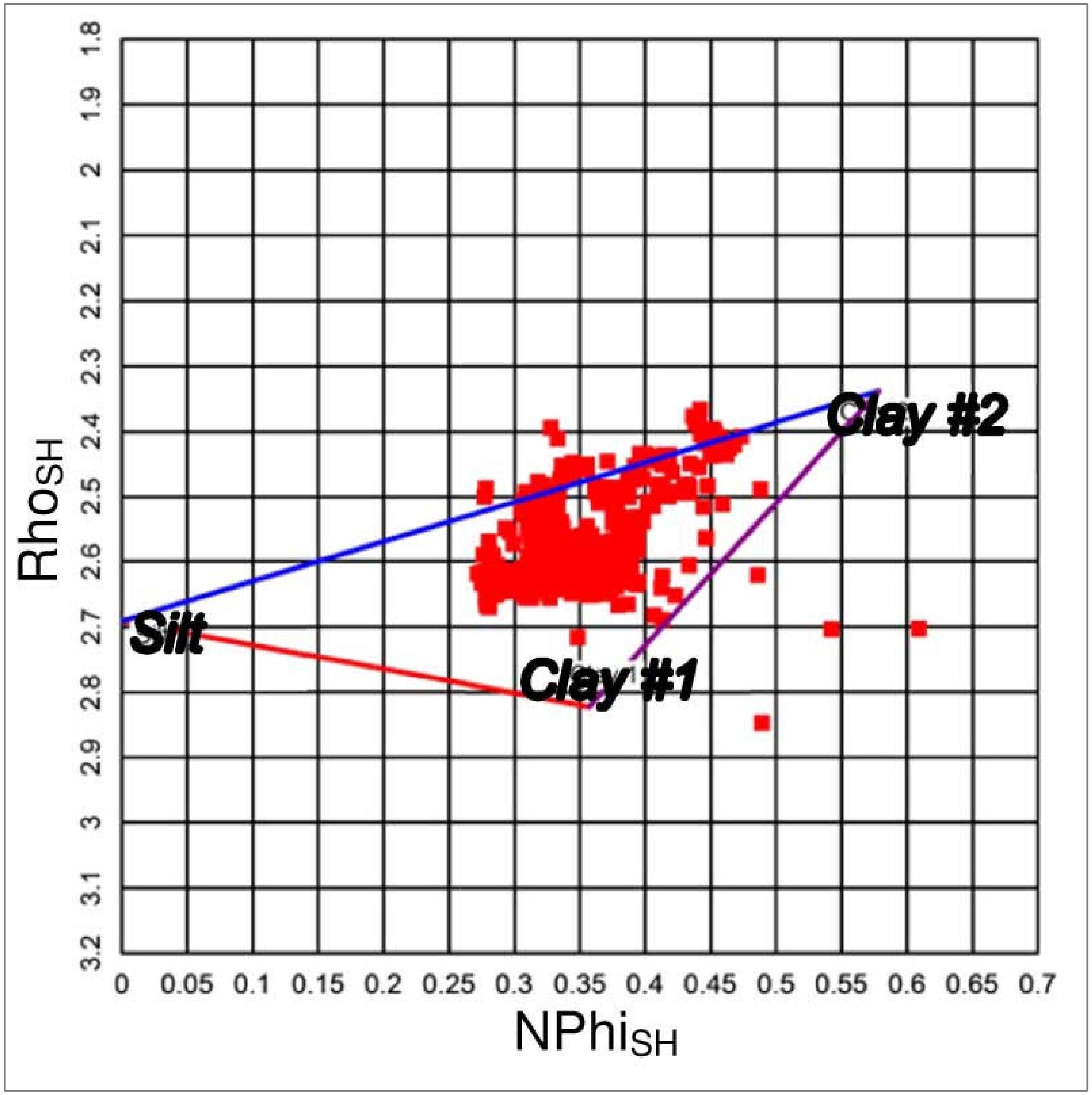

Figure 3. Rho$_{SH}$ vs. NPhi$_{SH}$ cross plot used to choose initial Silt, Clay #1, and Clay #2 points.

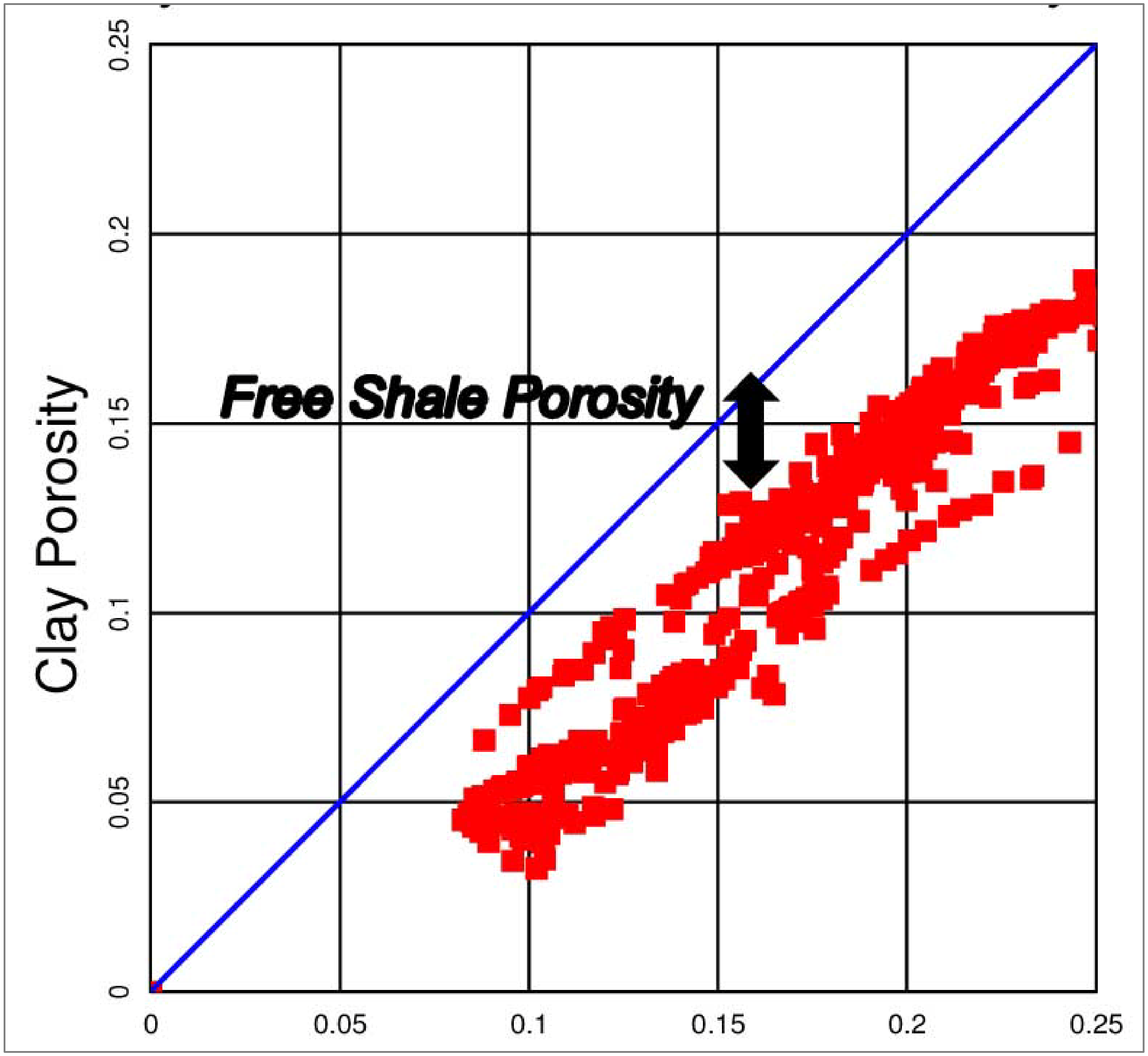

Figure 4. Clay Porosity vs. Free Shale Porosity cross plot. Free Shale Porosity should be mostly equal to or greater than Clay Porosity.

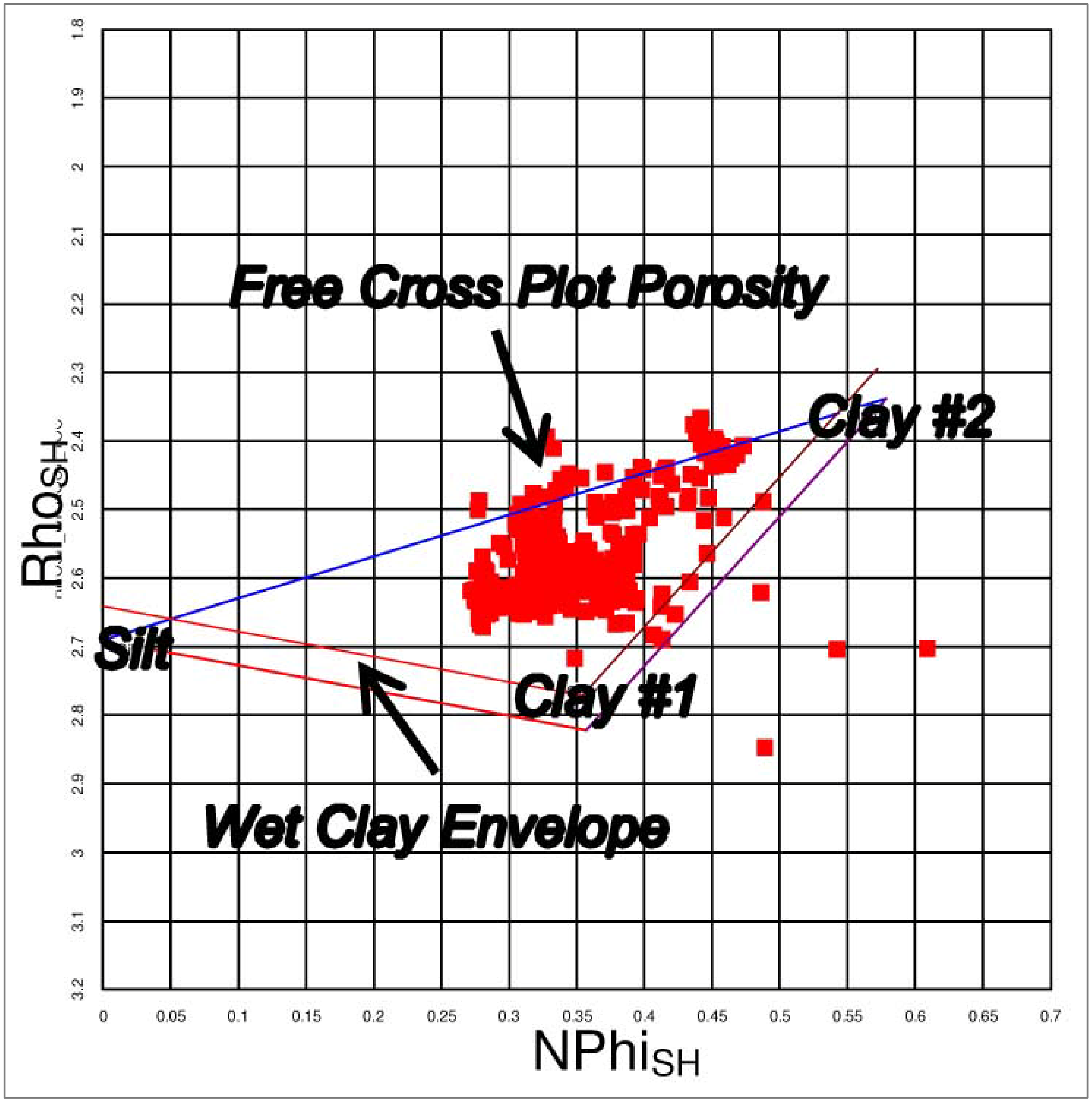

Figure 5. Rho$_{SH}$ vs. NPhi$_{SH}$ cross plot with wet clay envelope.

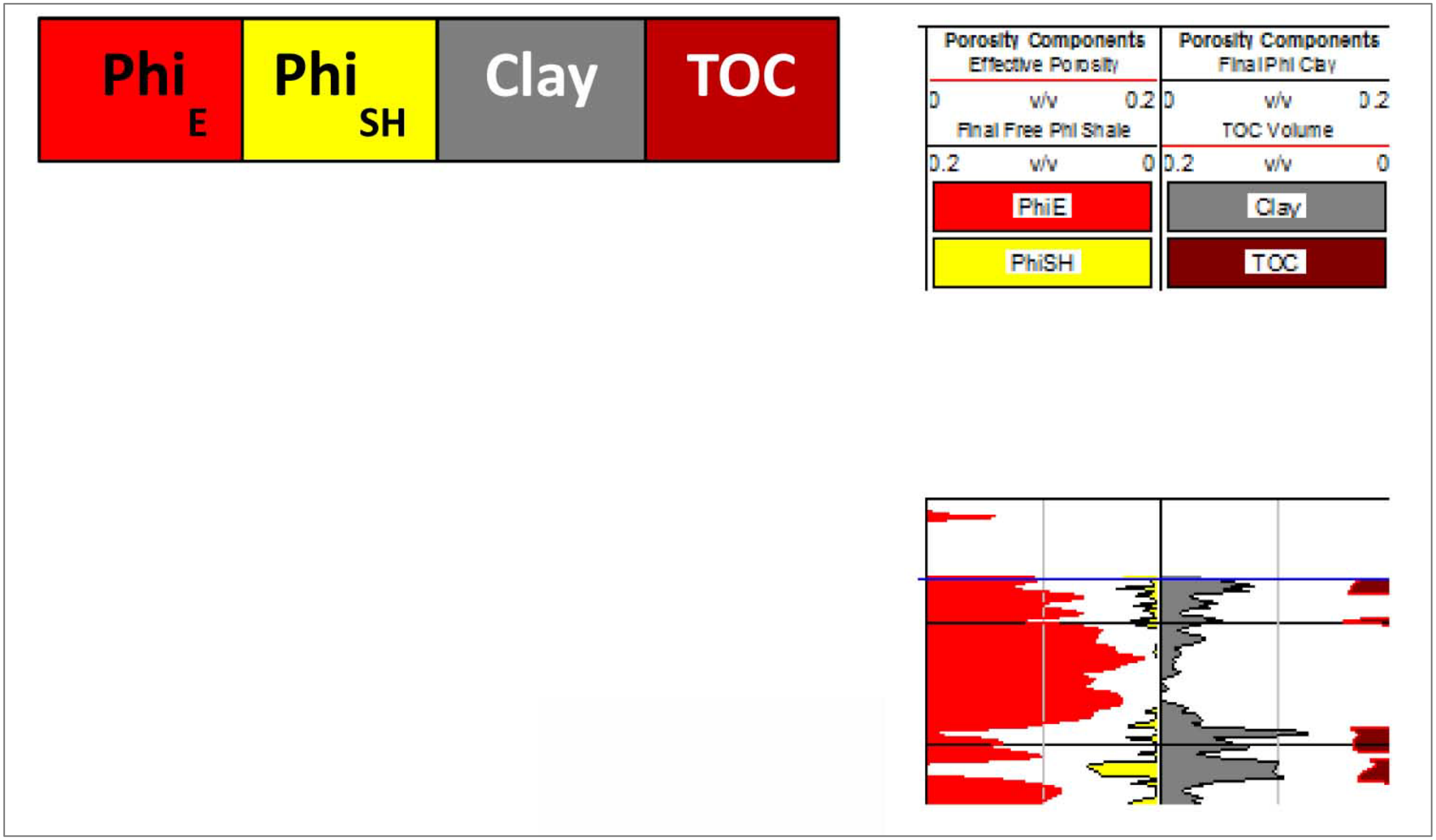

Figure 6. Porosity component output.

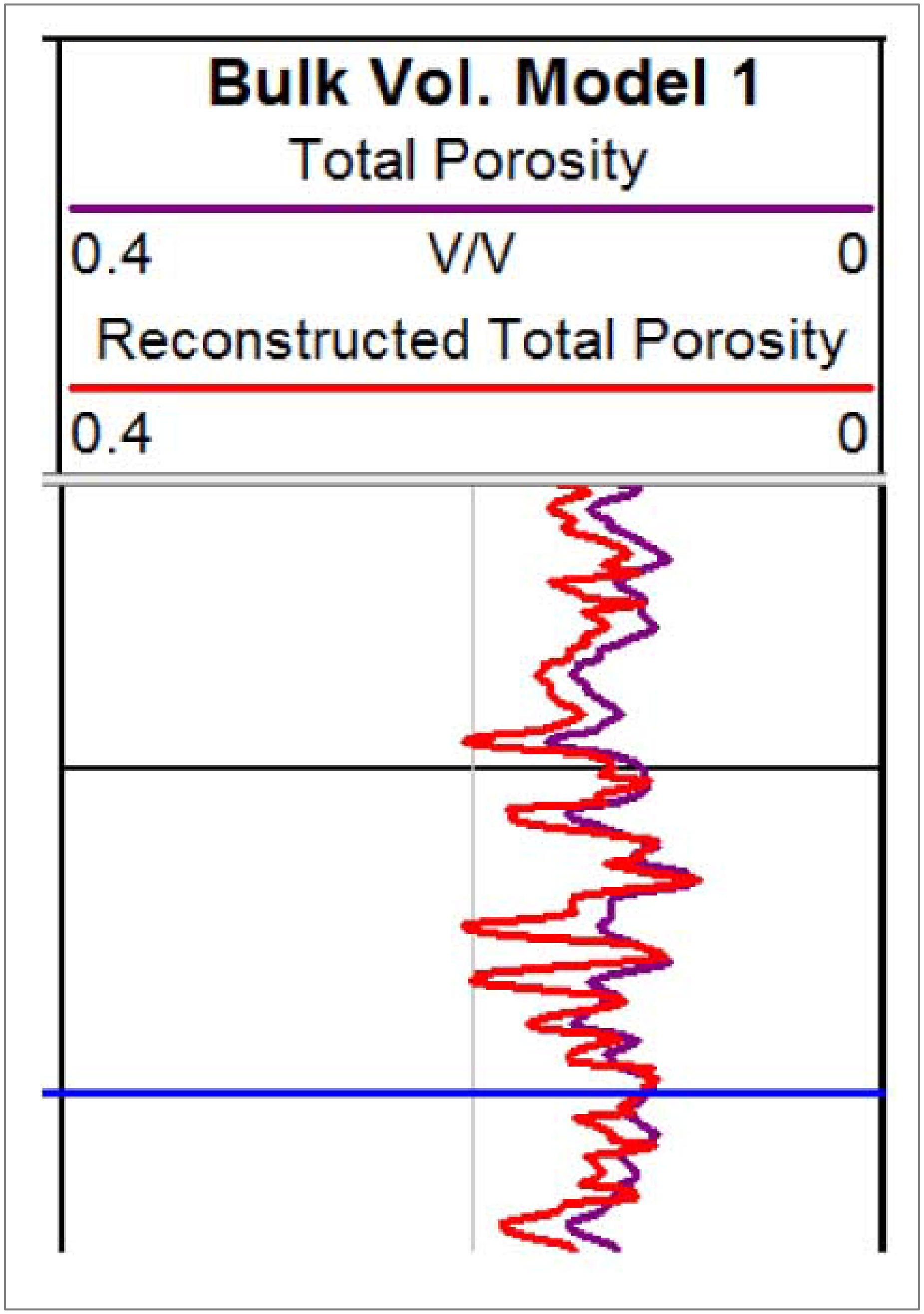

Figure 7. Comparison of Reconstructed Total Porosity (red curve) and Total Porosity (purple curve).

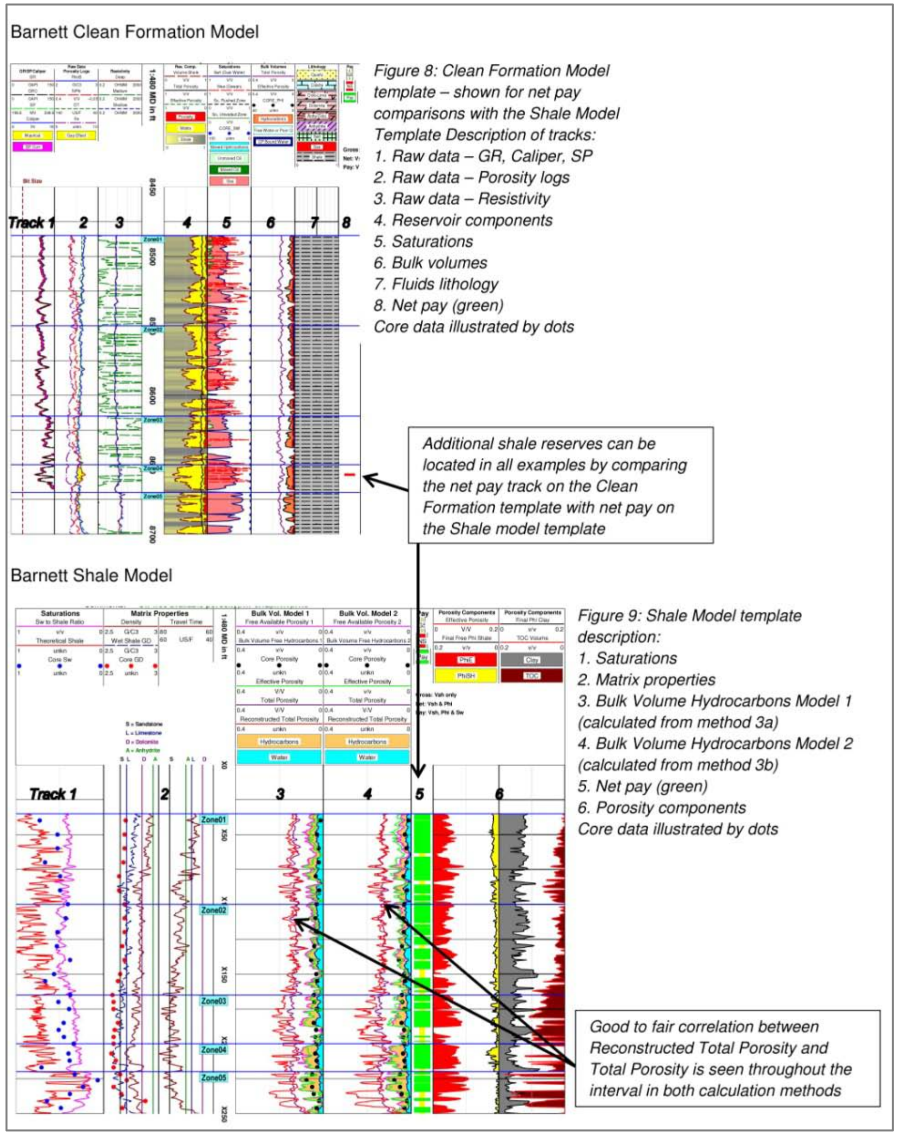

Figure 8. Barnett Clean Formation Model: Clean Formation Model template – shown for net pay comparisons with the Shale Model Template Description of tracks: 1. Raw data – GR, Caliper, SP; 2. Raw data – Porosity logs; 3. Raw data – Resistivity; 4. Reservoir components; 5. Saturations; 6. Bulk volumes; 7. Fluids lithology; 8. Net pay (green); Core data illustrated by dots.

Figure 9. Barnett Shale Model: Shale Model template description: 1. Saturations; 2. Matrix properties; 3. Bulk Volume Hydrocarbons Model 1 (calculated from method 3a); 4. Bulk Volume Hydrocarbons Model 2 (calculated from method 3b); 5. Net pay (green); 6. Porosity components Core data illustrated by dots.

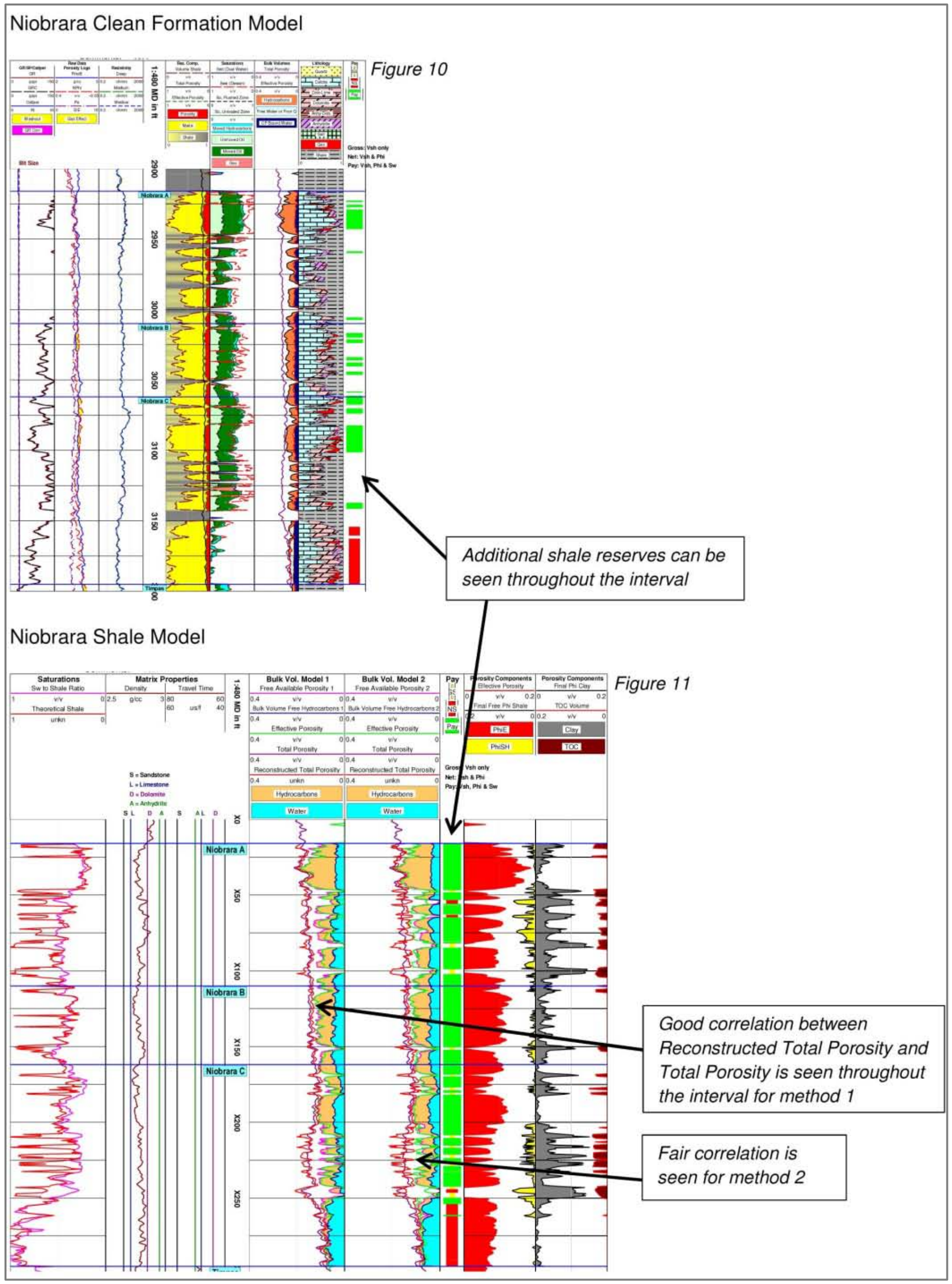

Figure 10. Niobrara Clean Formation Model.

Figure 11. Niobrara Shale Model.

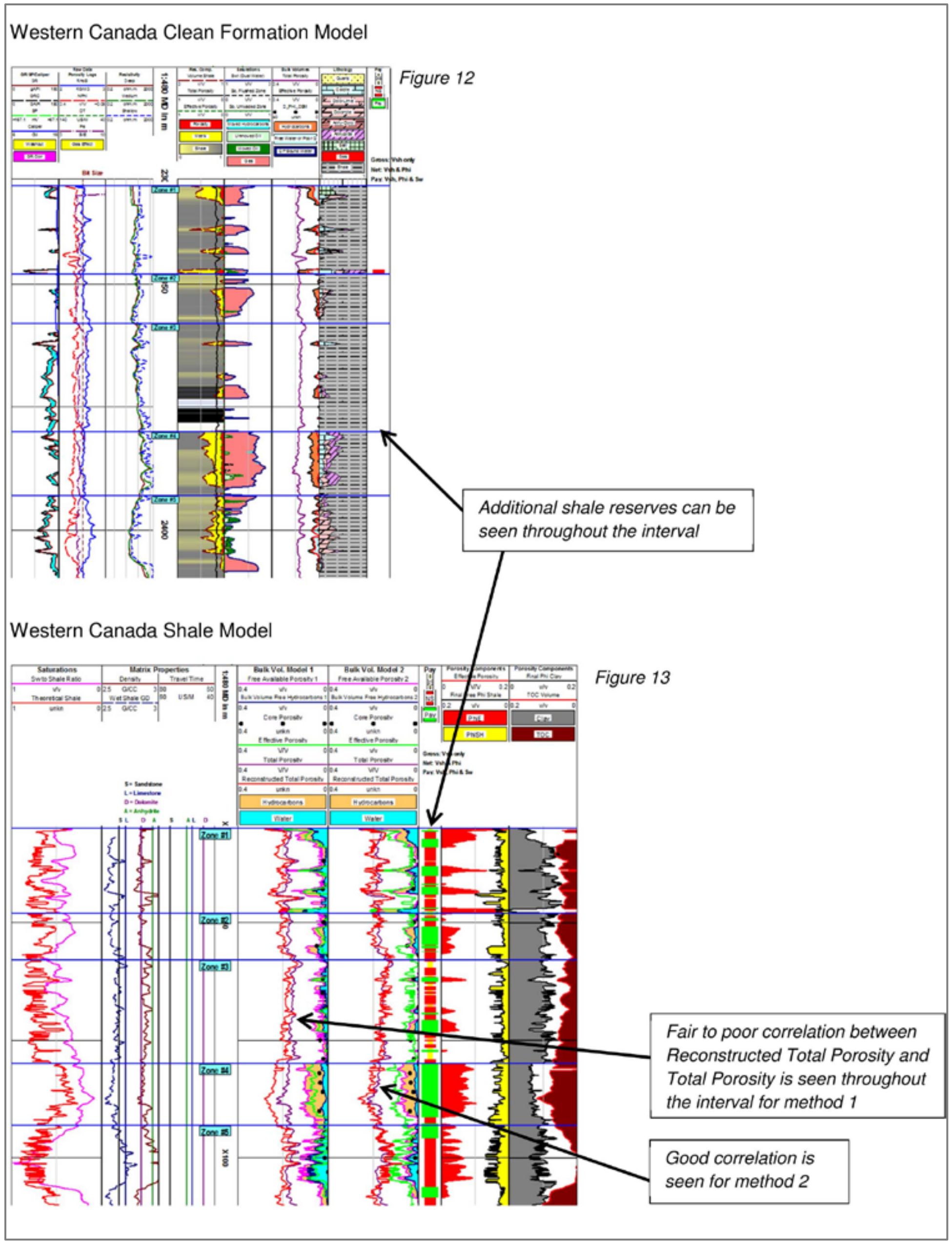

Figure 12. Western Canada Clean Formation Model.

Figure 13. Western Canada Shale Model.