

PERMEABILITY MODELING FROM PETROPHYSICAL MEASUREMENTS IN TIGHT GAS SANDS: EMPIRICAL RELATIONS INCLUDING ANALYSES OF SATURATION PROFILES FROM INDIVIDUAL POROSITY LOG RESPONSES

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ABSTRACT

Standard petrophysical approaches to estimate permeability involve comparisons of porosity with irreducible water saturation. A typical equation, based on work by Timur is:

$$\text{Permeability} = \frac{\text{Constant} \times \text{Porosity}^{\text{Exponent 1}}}{\text{Irreducible Water Saturation}^{\text{Exponent 2}}}$$

Usually, single values of *Exponent1* and *Exponent2* are applied to any one reservoir. Frequently, *Exponent2* is assumed to be 2. For tight gas sands, correlations with core-measured permeability improve if *Exponent1* is assumed to be porosity-dependent, and is calibrated to the specific reservoir.

A second approach to estimating permeability involves consideration of invasion profiles. We have recently developed fluid substitution techniques whereby gas saturation from individual porosity logs (particularly density and neutron) can be calculated and compared with standard resistivity-based calculations of gas saturation. The comparison shows that in tight gas sands, differences between the calculated gas saturations are a function of permeability. The conclusion is reached that for these very low matrix permeability rocks, there is often an increasing degree of mud filtrate invasion as permeability increases. At very low levels of permeability – less than 10 microdarcies – there is essentially no invasion.

Examples from the Rocky Mountains are presented, comparing core permeability with petrophysical estimates of permeability using the 3 approaches, namely:

1. Standard Timur-based equations
2. Modified Timur-based equations using a variable *Exponent1*
3. Invasion profile analysis

INTRODUCTION

Standard petrophysical methods to estimate permeability usually include considerations of relations between porosity and irreducible water saturation. In many medium to high porosity and permeability rocks, often quite satisfactory correlations between core-measured and by estimated permeabilities are attained. However, in tight gas sands, the correlations are much less obvious, and satisfactory petrophysical algorithms to estimate permeability are elusive.

This paper presents two methods of improving correlations between core-measured and log estimated permeability. The first involves adaptation of standard Timur-type equations. The second involves considerations of invasion profiles, by comparing the magnitude of gas saturation, as measured from porosity logs with gas saturation from standard resistivity analysis.

PRIOR WORK INVOLVING PETROPHYSICAL PERMEABILITY ESTIMATES

An excellent summary is given in Vernik, (Petrophysics March-April 2000, pages 138-147). A number of models have been proposed, based on the Kozeny-Carmen equation (Carmen 1956). This equation relates permeability to porosity and surface area of the pore network. Since surface area is hard to measure, empirical correlation with grain size (Berg, 1970, Van Baaren, 1979) or irreducible water saturation (Timur, 1968, Ahmed et al. 1989), or capillary pressure components (Nelson, 1994, Holmes et al., 2005). Vernik (2000) incorporates clay volume for poorly-constituted rocks.

From NMR measurements, an estimate of irreducible water saturation is available, and when combined with porosity, yields permeability (Coates and Dumanoir, 1974).

PERMEABILITY MODELING IN THIS STUDY

Based on the Kozeny-Carmen Equation

A form of the Timur equation, proposed by Schlumberger (Hilchie, 1982) is:

$$k = \frac{\text{Constant} \times \phi^{\text{Exponent 1}}}{S_{wi}^{\text{Exponent 2}}}$$

Where:

k = Permeability, md

$\text{Constant} = 62,500$

$\text{Exponent 1} = 6$

$\text{Exponent 2} = 2$

ϕ = Porosity, fractions

S_{wi} = Irreducible water saturation fractions

To account for levels that are not at irreducible water saturation, we incorporate a constraint involving bulk volume water at irreducible saturation ($BVWi$). Using the approach of Morris and Biggs (1967) we assign a value of $BVWi$ calibrated to rock type:

$$BVWi = \phi \times S_{wi \text{ theoretical}}$$

And use the lower of petrophysically calculated S_w or S_{wi} theoretical to determine k .

For many reservoirs with “normal” porosity/permeability characteristics – average to high values both clastic and carbonate reservoirs – using the equation as presented above gives quite satisfactory results. If there is a mismatch with core measured permeability, it can usually be adjusted by changing – often by only small amounts – the value of Exponent 1 . In most cases, the range of Exponent 1 is from 5 to 7.

However for tight gas sands, the correlations remain poor regardless of the value of Exponent 1 that is used. For these reservoirs, we have developed an algorithm whereby we assign a variable porosity-dependent value to Exponent 1 , with end points to be assigned by the interpreter. For example:

High porosity	18%
Exponent 1 at high porosity	9
Low porosity	3%
Exponent 1 at low porosity	5

Once these have been assigned, the program calculates Exponent 1 for any intermediate porosity values, using

linear interpolation. By trial and error, changes are made to input values until a best fit with core data is attained.

Based on invasion profiles

Traditional approaches to determine depth of invasion involve the interpretation of resistivity profiles (Tixier et al., 1963). Often such approaches are of limited application due to incomplete resistivity suites and/or uncertainties in the magnitude of mud filtrate resistivity, R_{mf} .

Another method documented by Holmes et al. (SPWLA 2005) involves rock physics modeling. As a starting point the following reservoir components are recognized:

Shale volume

Total porosity from a density/neutron or acoustic/neutron combination. Values of porosity so derived are (as far as is possible) independent of matrix properties or fluid content.

Matrix volume

If fluid content (gas vs. water) varies, then both the density and neutron logs are affected:

Density log because fluid density changes

Neutron log because hydrogen index changes

Knowing (or assuming) appropriate matrix properties, density and neutron apparent responses in the presence of any gas/water combination can be derived.

A schematic invasion profile for tight gas sands is shown in Figure 1.

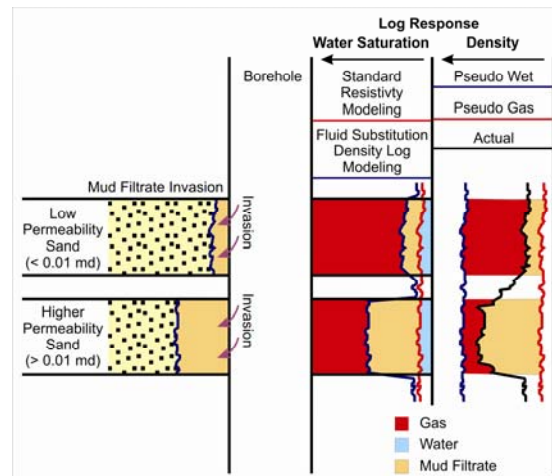


Figure 1: A schematic invasion profile for tight gas sands

Observations on a number of reservoirs indicate that, in tight gas sands, low permeability sands (less than about 10 microdarcies, or 0.01 md) show no invasion. For levels with permeability higher than this, invasion often increases with increasing permeability. Max Peeters of the Colorado School of Mines (personal communication) has come to this same conclusion by independent observation. This observation is not always true. In some reservoirs, especially those with permeabilities greater than 1 md, degree of invasion decreases with increasing permeability.

The approach we use here involves comparison of gas saturation as calculated from density and neutron logs using the fluid substitution modeling described above, with gas saturation measured further away from the well bore, using standard deep resistivity modeling (Figure 2).

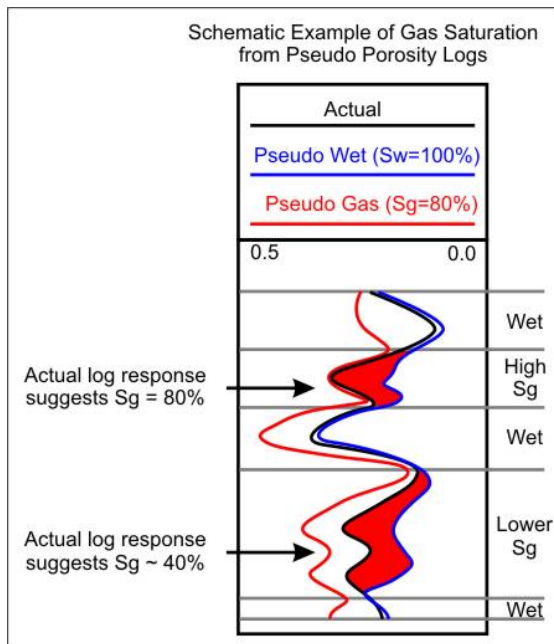


Figure 2: Schematic of gas saturation from pseudo porosity logs.

Continuous profiles of gas saturation as “seen” by each porosity log are calculated – $S_{g \text{ density}}$, $S_{g \text{ neutron}}$, $S_{g \text{ acoustic}}$. It is shown that these values of gas saturation combined with gas saturation from standard resistivity analysis can be related quantitatively to core-measured permeability by an equation of the form:

$$k = \text{Constant} \times e^{b \times S_{g \text{ difference}}}$$

Where:

k = Permeability, md

Constant = Porosity log and reservoir specific (see Table 1)

b = Porosity log and reservoir specific (see Table 1)

$S_{g \text{ difference}}$ = Difference between the S_g as calculated from the resistivity log and the S_g as calculated from each porosity log

Sometimes b is negative (reservoirs where invasion decreases with increasing permeability).

EXAMPLES

Examples of three tight gas sands and one high permeability gas sand:

1. Mesa Verde Formation Cretaceous – from the MWX-1 well in the Piceance Basin, NW Colorado (Figures 3-5)
2. Cretaceous tight gas sand – from Table Rock Field, Washakie Basin, Wyoming (Figures 6-8)
3. Cretaceous tight gas sand – from Green River Basin, Wyoming (Figures 9-11)
4. Cretaceous high permeability sand – from Green River Basin, Wyoming (Figures 12-14)

Porosity color coding on all Porosity/Permeability cross plots is:

- Dark blue – less than 2%
- Light blue – 2% to 4%
- Dark green – 4% to 6%
- Light green – 6% to 8%
- Orange – 8% to 10%
- Pink – 10% to 12%
- Red – 12% to 14%
- Black – more than 14%

For each example, the following data are presented:

1. Core Permeability vs. Log Permeability using a constant exponent 1 in the standard Timur transform.
2. Core Permeability vs. Log Permeability using a variable exponent 1 in the modified Timur transform – listing for all three wells appears in table 1.
3. Depth plots of a cored interval showing the four estimates of permeability
 - a. Standard Timur
 - b. Modified Timur
 - c. From Density Log
 - d. From Neutron Log

Listing of the exponents used for the density and neutron logs are in table 1.

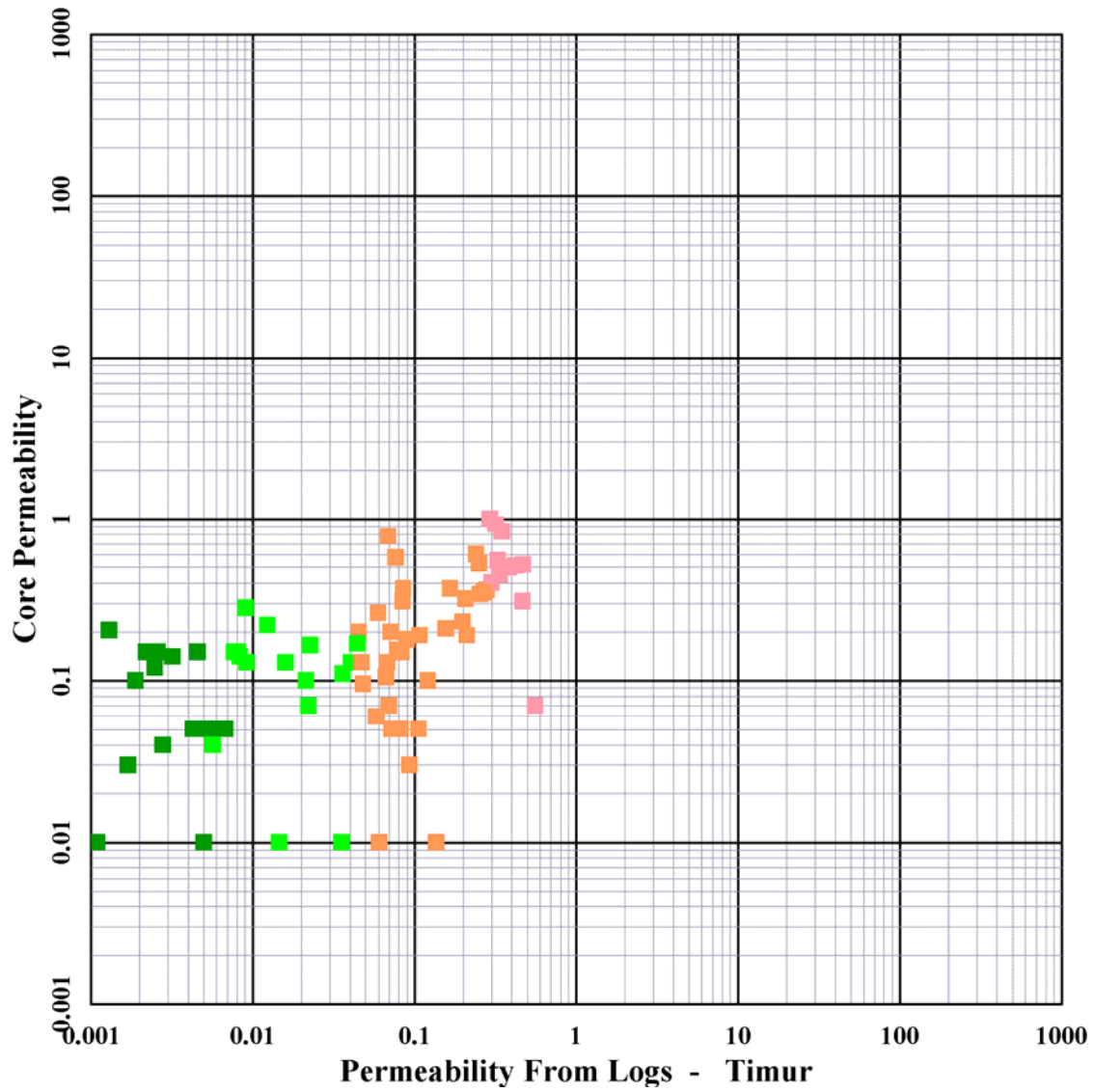


Figure 3: MWX-1, Core Permeability vs. Log Permeability using a Timur transform with a constant exponent of 1.

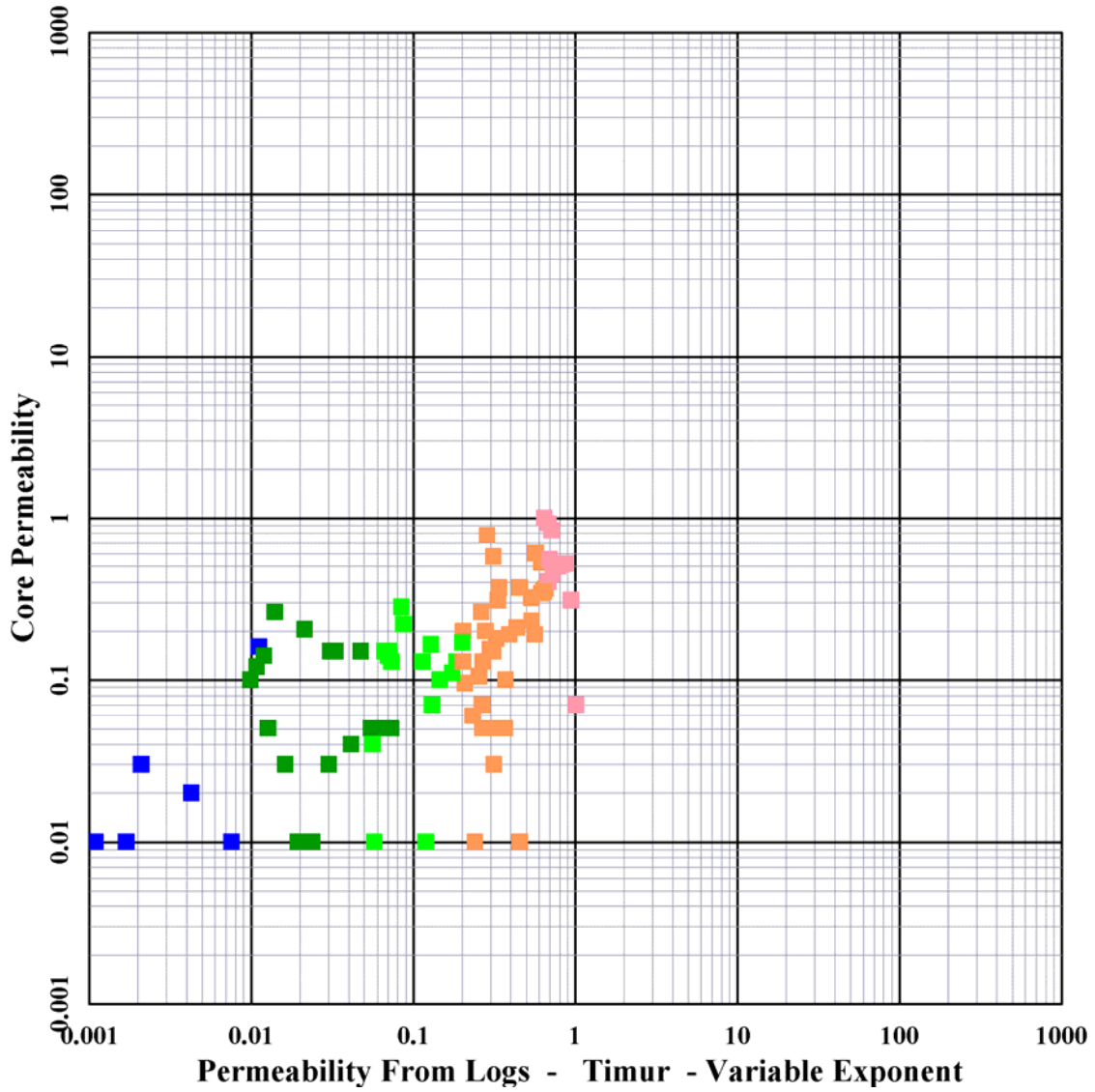


Figure 4: MWX-1, Core Permeability vs. Log Permeability using a Timur transform with a variable Exponent 1.

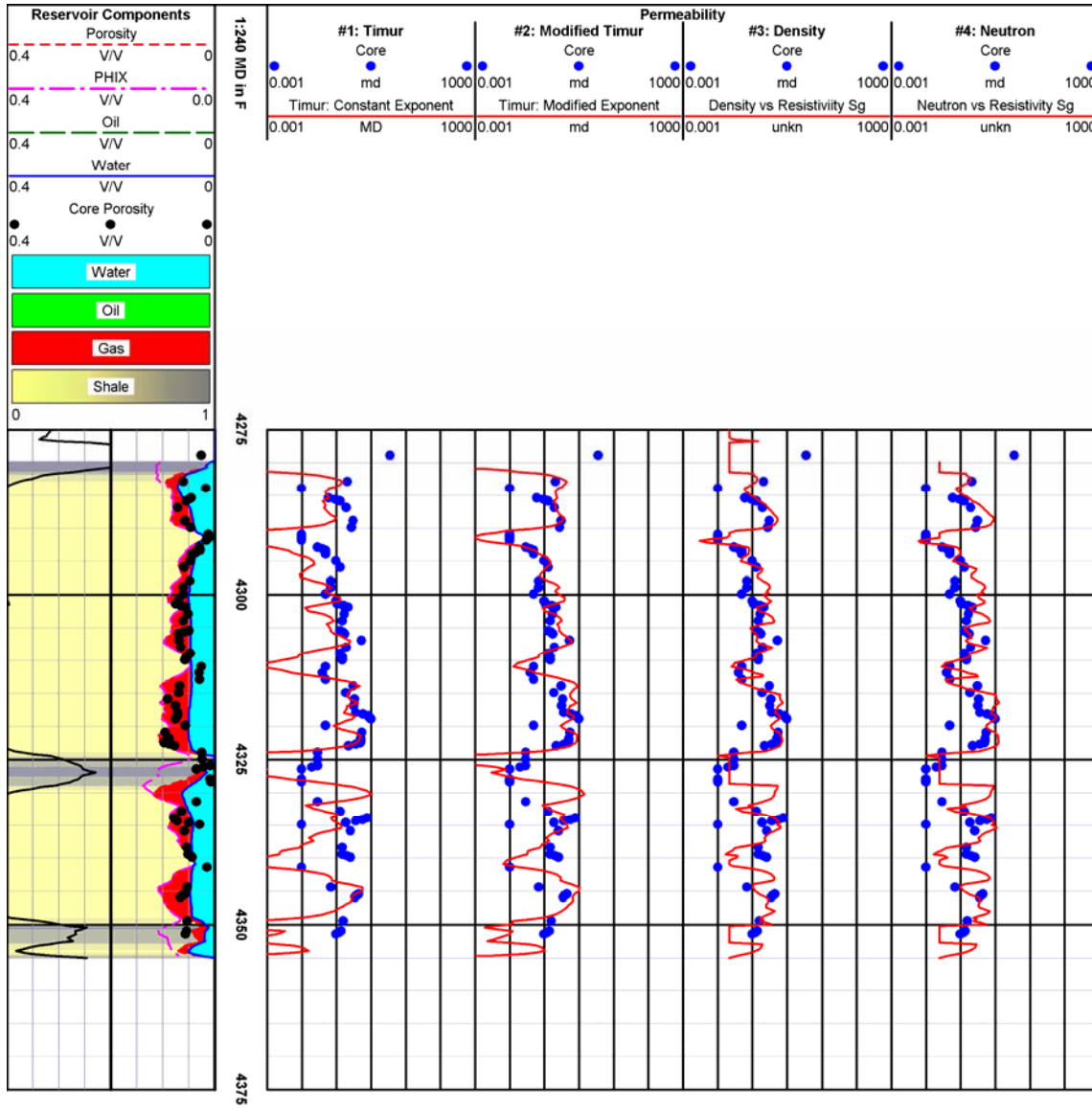


Figure 5: MWX-1, Estimates of permeability from the standard Timur transform, a Timur transform with variable Exponent1, and from the Density and Neutron logs.

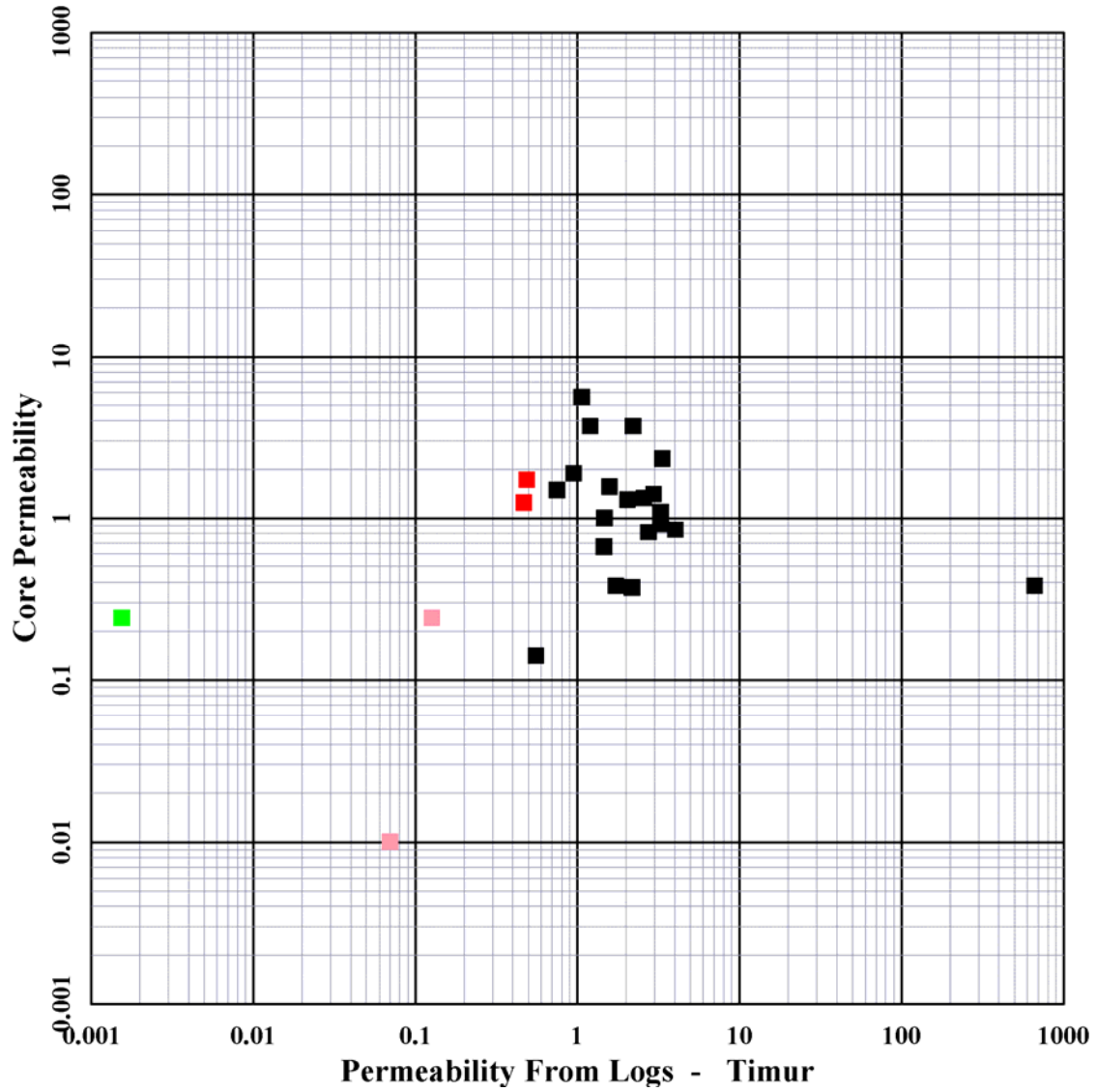


Figure 6: Table Rock Field, Core Permeability vs. Log Permeability using a Timur transform with a constant Exponent of 1.

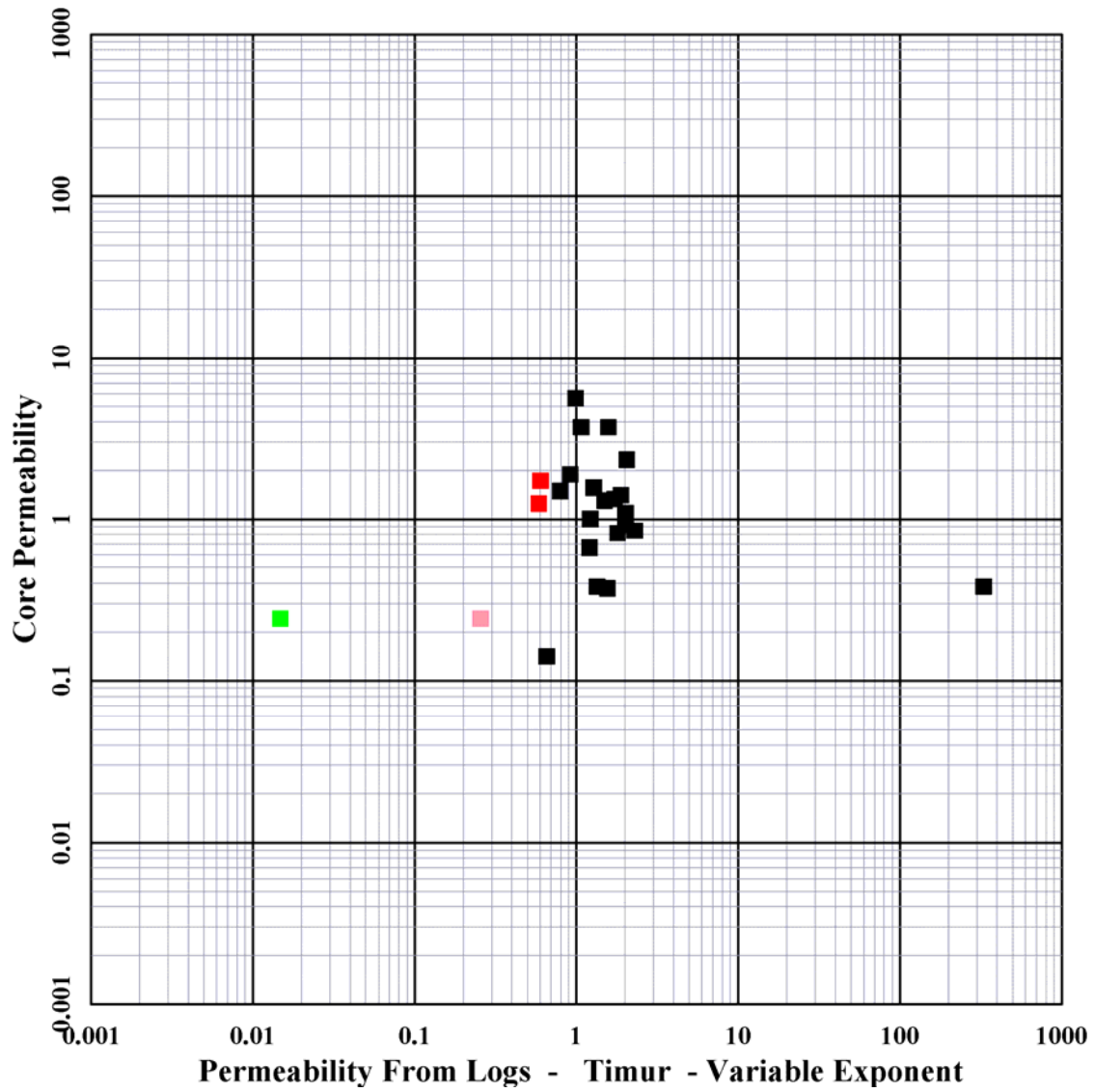


Figure 7: Table Rock Field, Core Permeability vs. Log Permeability using a Timur transform with a variable Exponent l .

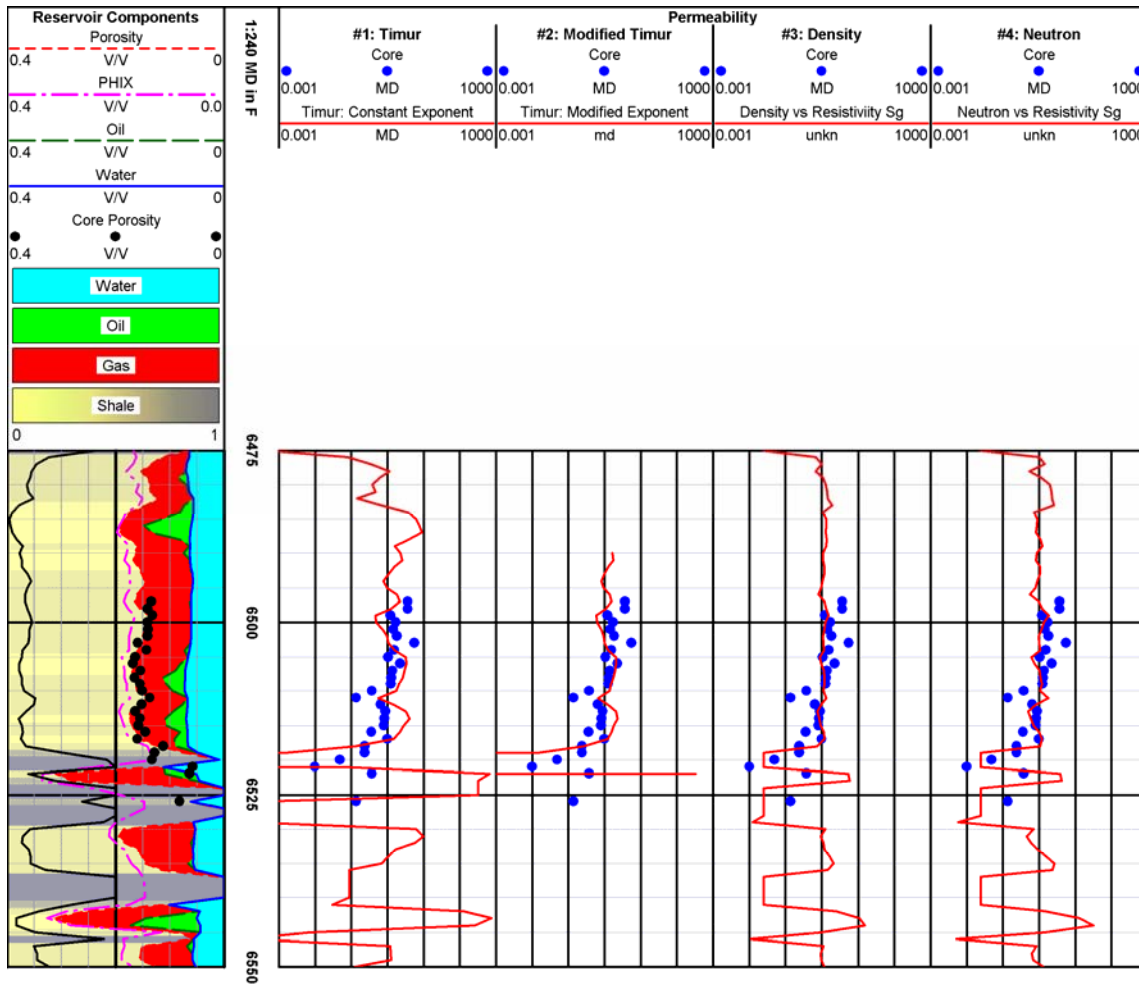


Figure 8: Table Rock Field, Estimates of permeability from the standard Timur transform, a Timur transform with variable Exponent1, and from the Density and Neutron logs.

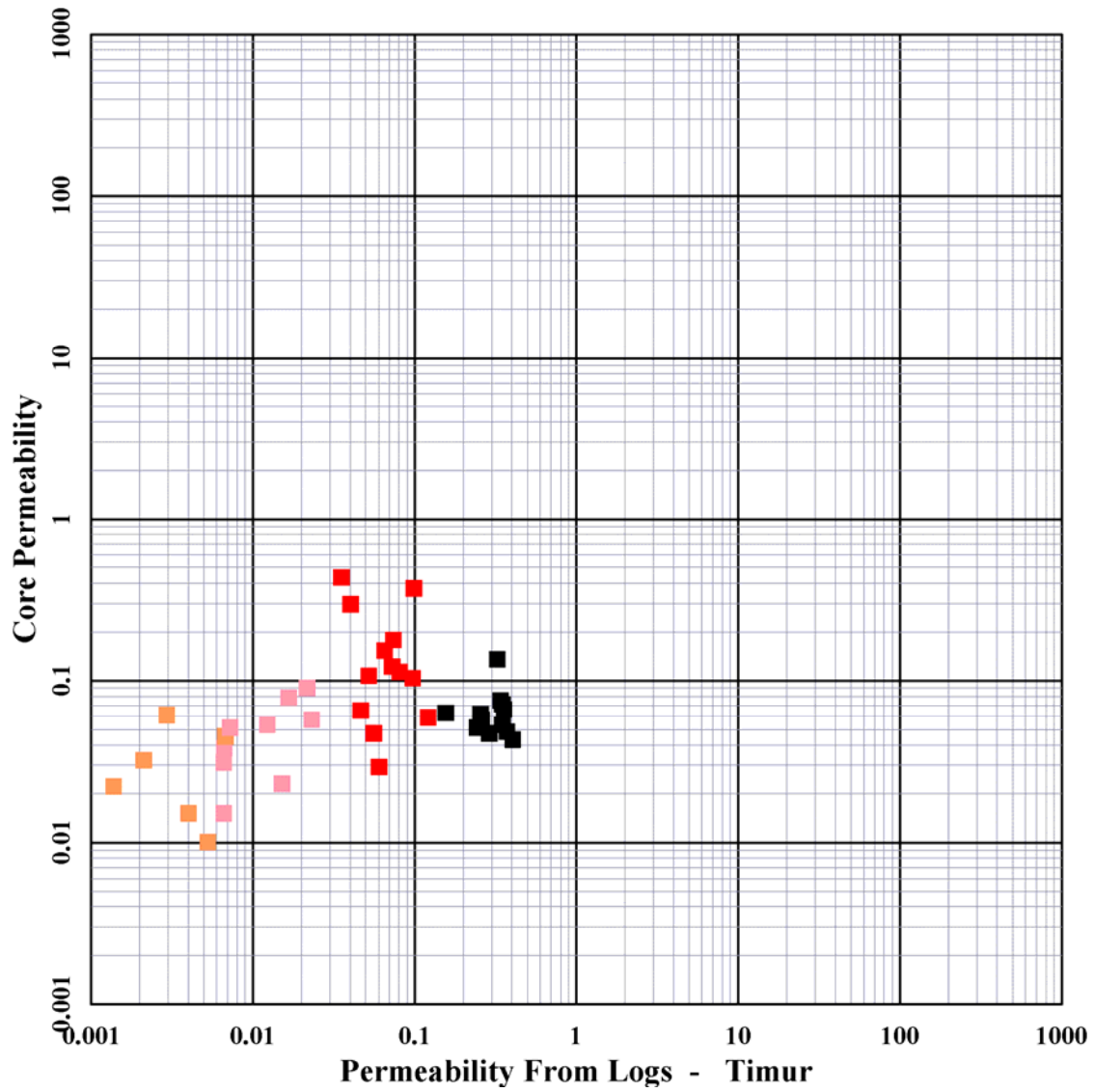


Figure 9: Green River Basin tight gas sand, Core Permeability vs. Log Permeability using a Timur transform with a constant Exponent1 of 1.

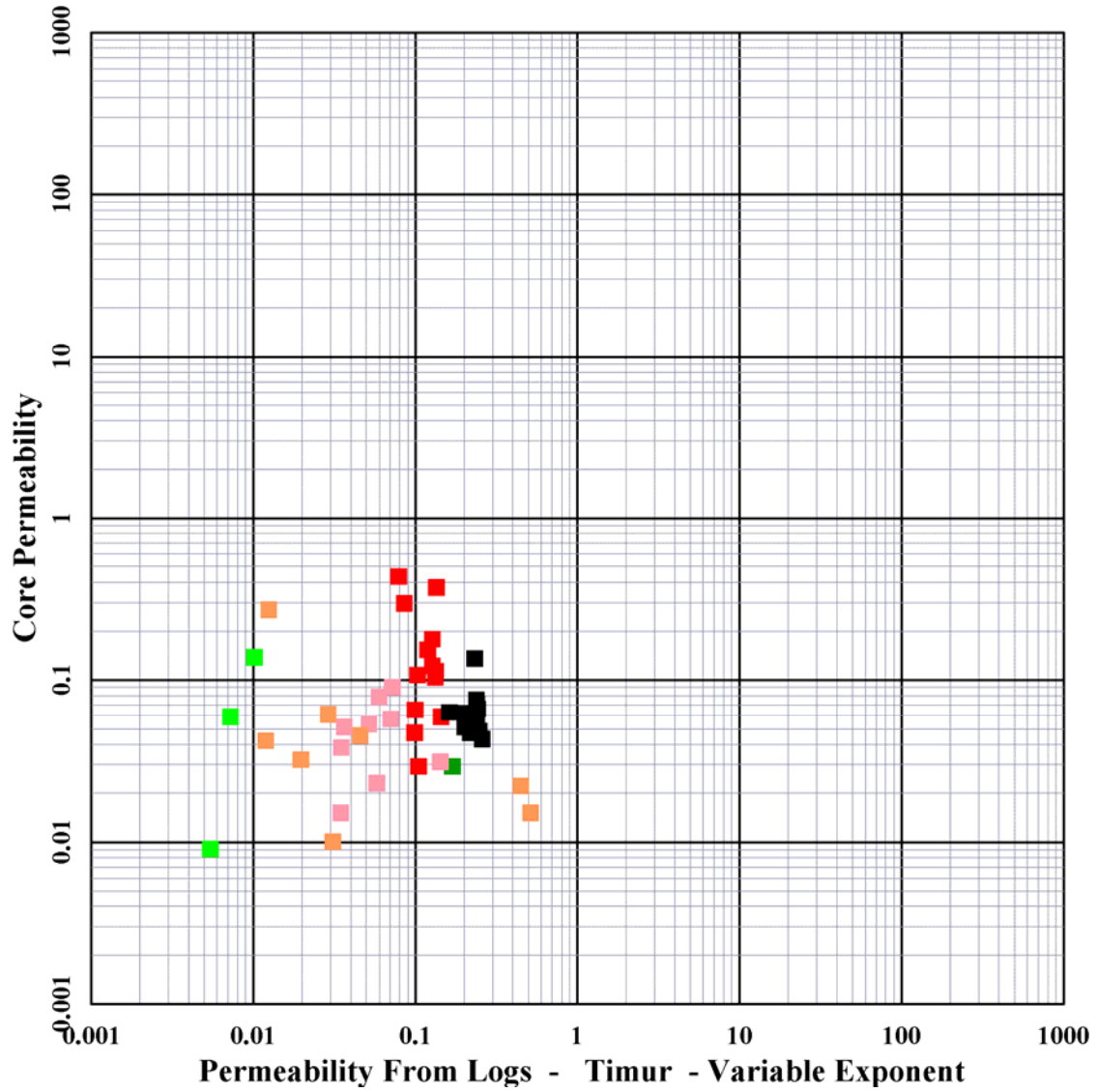


Figure 10: Green River Basin tight gas sand, Core Permeability vs. Log Permeability using a Timur transform with a variable Exponent1.

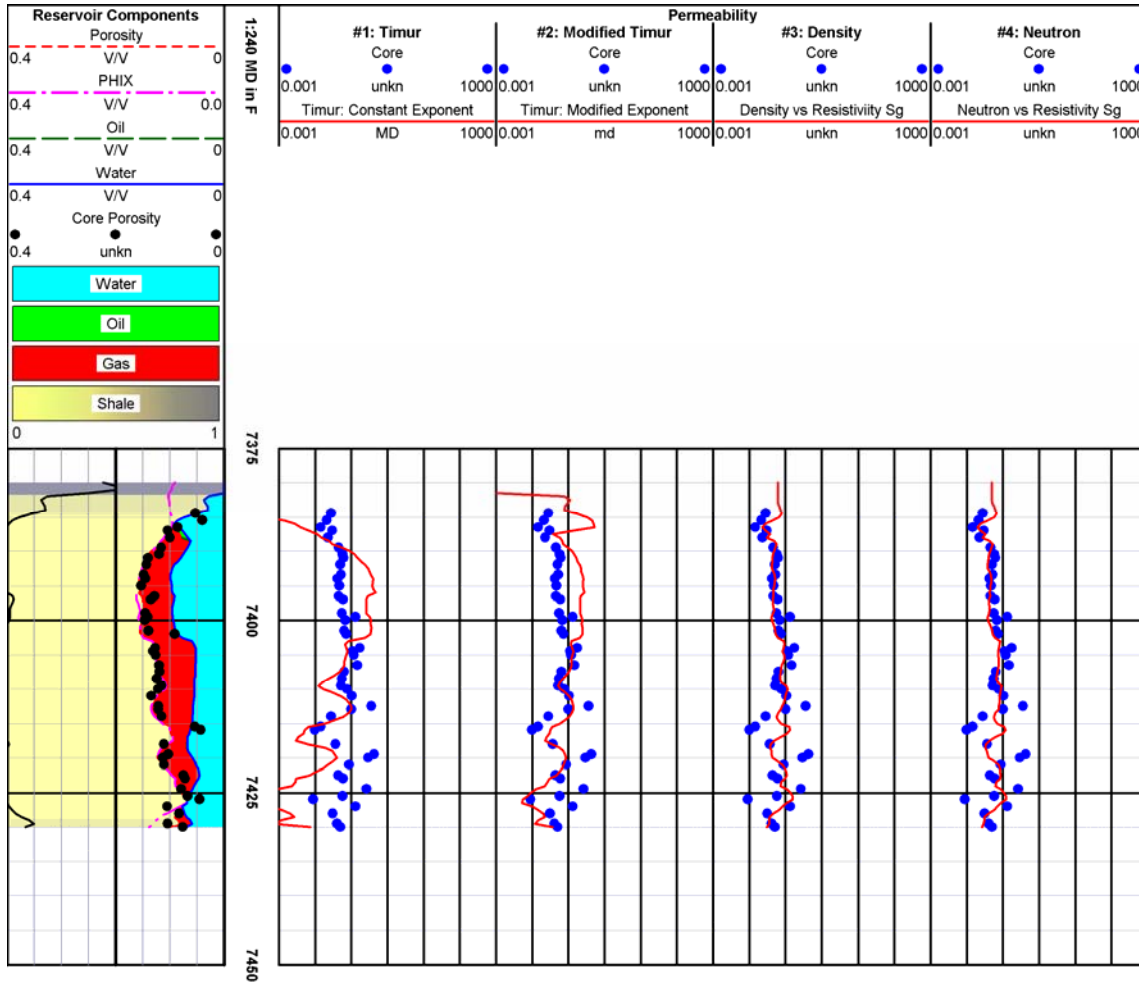


Figure 11: Green River Basin tight gas sand, Estimates of permeability from the standard Timur transform, a Timur transform with variable Exponent1, and from the Density and Neutron logs.

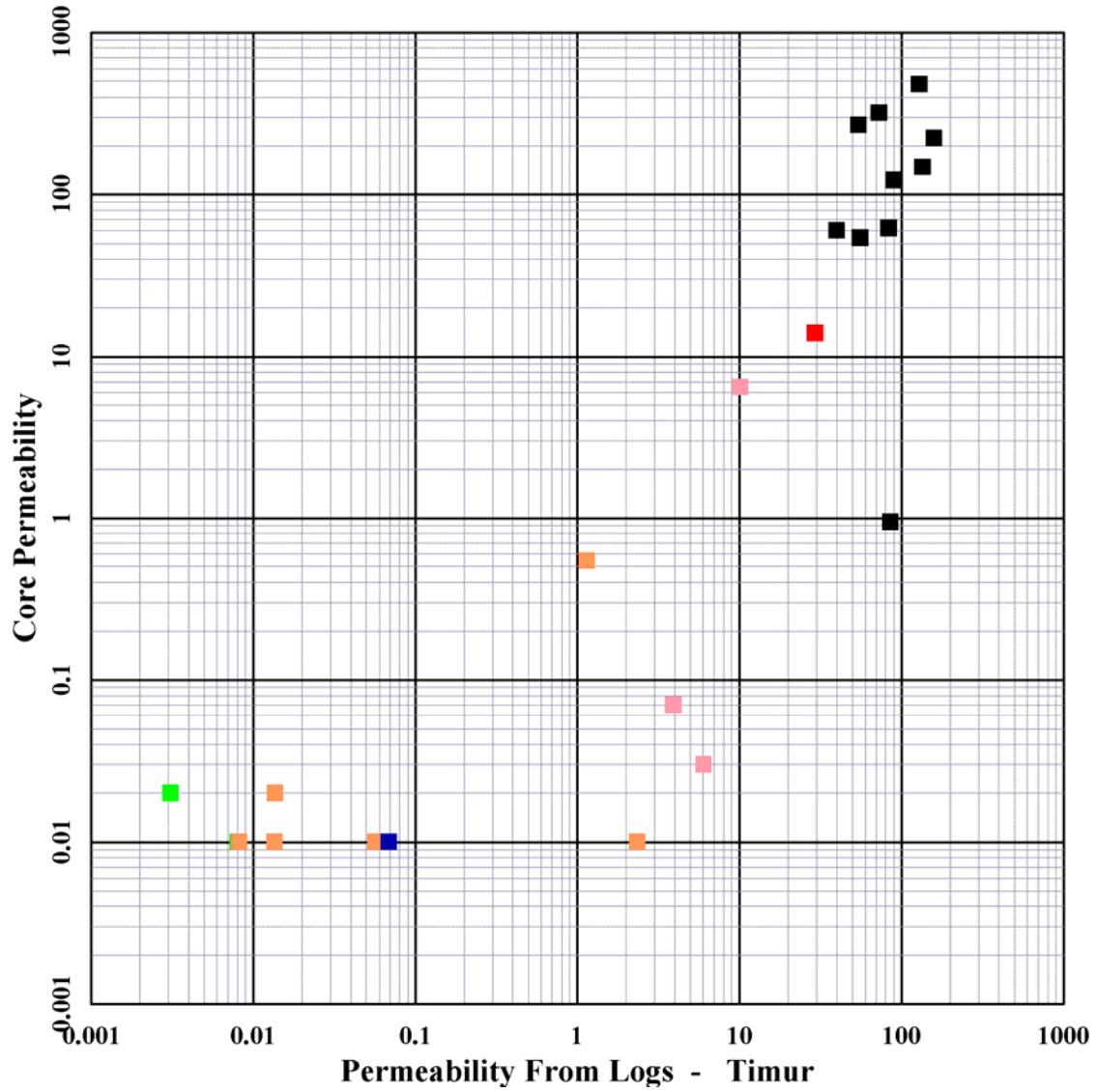


Figure 12: Green River Basin high permeability sand, Core Permeability vs. Log Permeability using a Timur transform with a constant Exponent1 of 1.

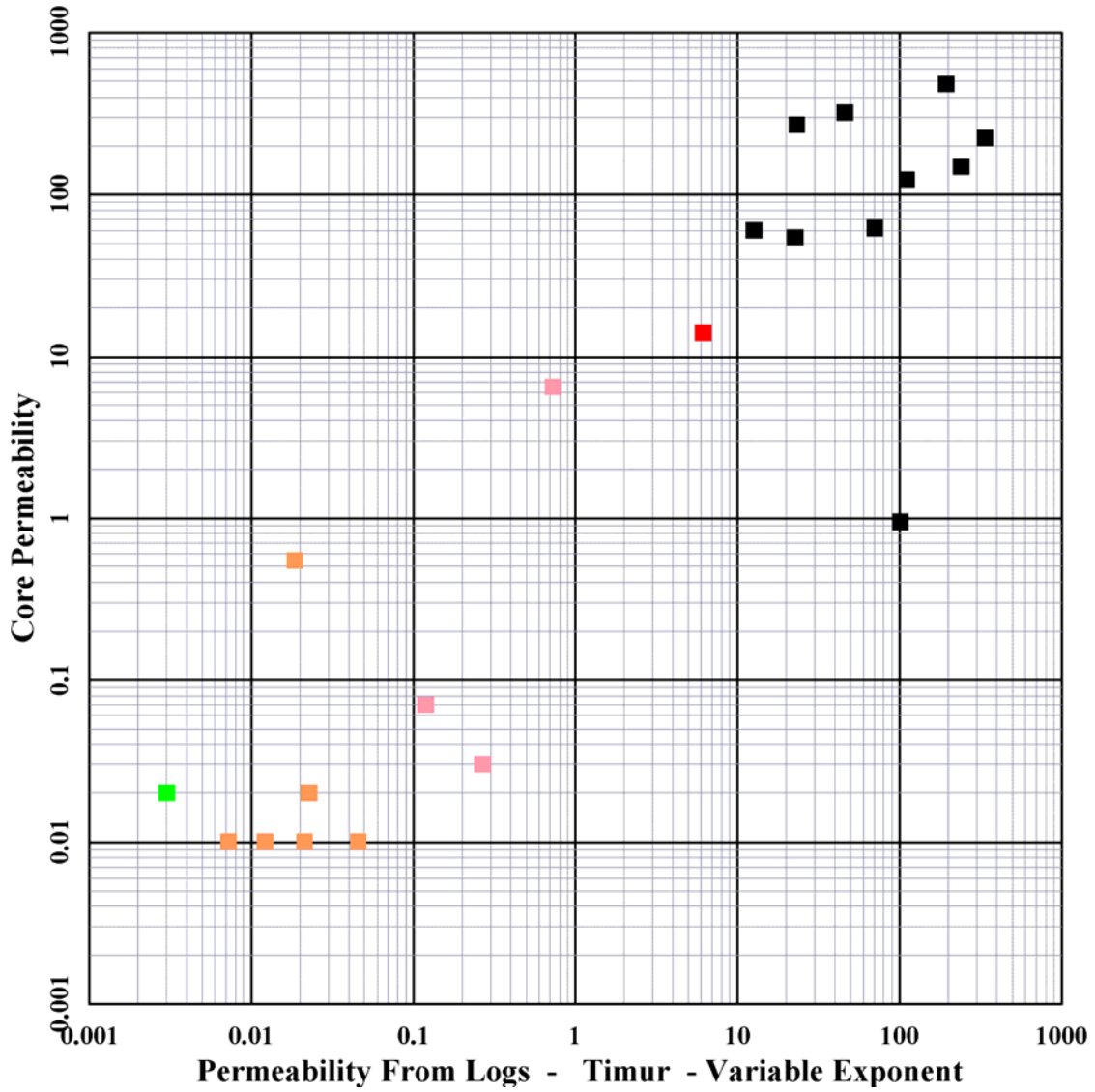


Figure 13: Green River Basin high permeability sand, Core Permeability vs. Log Permeability using a Timur transform with a variable Exponent1.

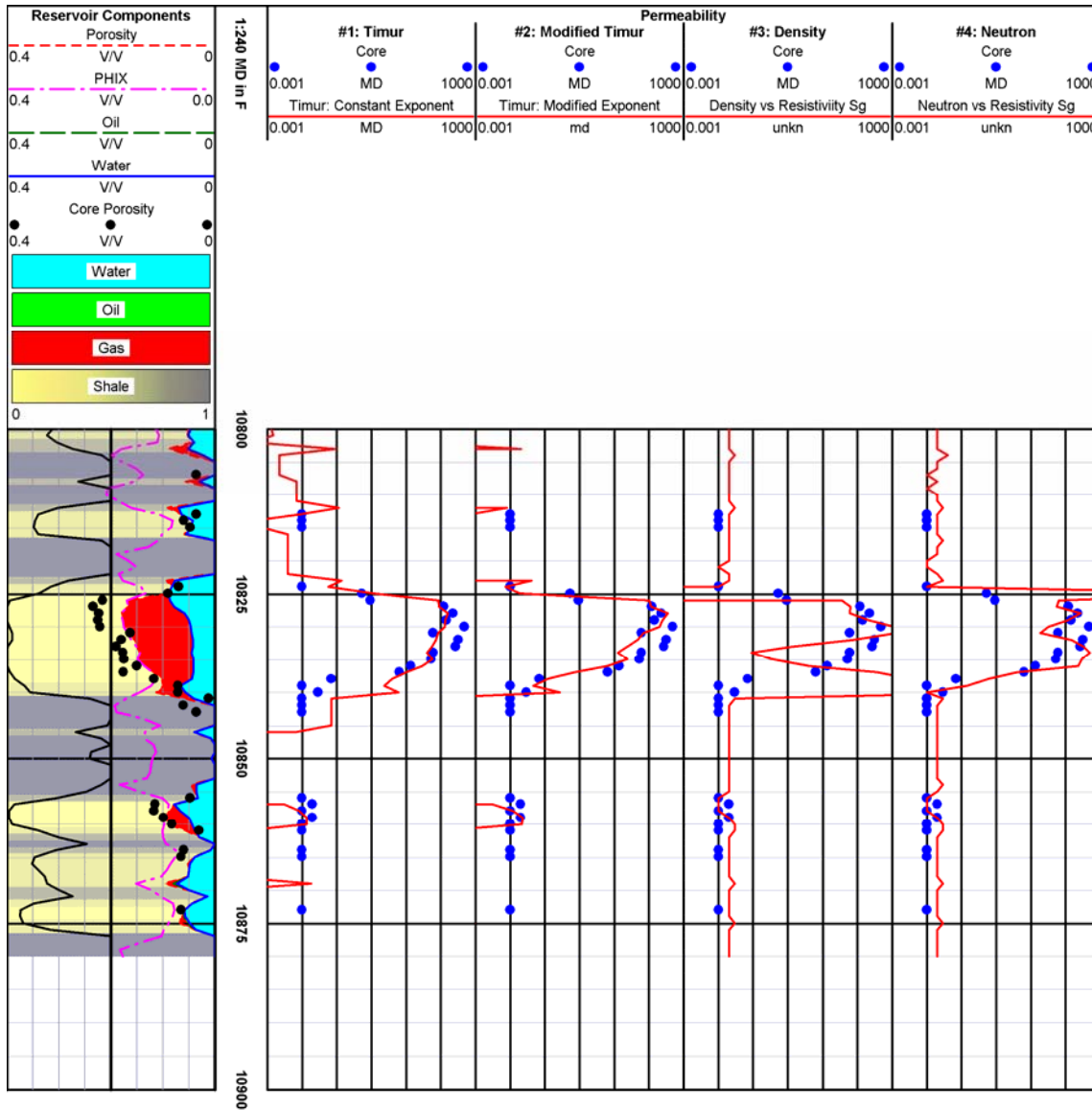


Figure 14: Green River Basin high permeability sand, Estimates of permeability from the standard Timur transform, a Timur transform with variable Exponent1, and from the Density and Neutron logs.

Well	Timur Analysis					Invasion Profile Analysis			
	Original Phi Exp	Sliding Scale Analysis				Density		Neutron	
		High Phi %	Exp	Low Phi %	Exp	Constant	b	Constant	b
MWX-1	6.0	22	7.0	1	4.5	0.022	7.196	0.025	7.196
Table Rock	7.0	20	7.6	2	5.5	0.025	7.87	0.025	8.53
Green River (tight)	7.5	40	12	0.1	5.0	0.06	-2.09	0.05	-1.98
Green River (high perm)	6.0	30	2.0	2	10.0	(a) 0.025	2.19	0.022	1.35
						(b) 20.0	-28.8	40	-23.03

Table 1: Input for permeability modeling:

- a) for permeability less than 0.1 md
b) for permeability more than 0.1 md

CONCLUSIONS

- When applying “Timur” transforms, correlations between log-estimated permeability and core measure permeability improve when a variable porosity-dependent *Exponent1* is applied.
- Invasion effects on porosity logs can be correlated to permeability – lack of invasion implies very low permeability and increasing degree of invasion can be shown in many instances to relate to increasing permeability.
- By comparing permeability estimates with core measures permeabilities, it may be possible to identify intervals where the “normal” invasion profile has changed. Mismatches may be a guide to such changes.
- Invasion profiles will depend on the mud system used to drill the well, and also on length of time the formation has been exposed to the drilling fluid before logging.

LIST OF SYMBOLS

Symbol	Definition	Units
BW_i	Bulk volume water at irreducible saturation	fractions
ϕ	Porosity	fractions
k	Permeability	md
R_{mf}	Mud filtrate resistivity	ohmm
$S_{g\ density}$	Gas saturation from density log	fractions
$S_{g\ neutron}$	Gas saturation from neutron log	fractions
$S_{g\ acoustic}$	Gas saturation from acoustic log	fractions
$S_{g\ resistivity}$	Gas saturation from resistivity log	fractions
$S_{g\ difference}$	Sg resistivity - Sg from the porosity logs	fractions
S_w	Water saturation	fractions
S_{wi}	Irreducible water saturation	fractions

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