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Organic Carbon Content Determined from Well Logs: Examples from Cretaceous Sediments of Western Canada

Dale R. Issler (dissler@NRCan.gc.ca), **Kezhen Hu**,
Geological Survey of Canada,
3303 33rd Street N.W., Calgary, Alberta T2L 2A7
John D. Bloch, Dept. of Earth and Planetary Sciences,
Northrop Hall, University of New Mexico, Albuquerque, NM 87131
and
T. John Katsube, Geological Survey of Canada,
601 Booth Street, Ottawa, ON K1A 0E8

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ABSTRACT

Core petrophysical (porosity, density) and geochemical (mineralogy, organic properties) data for Colorado Group shale were used to calibrate well log methods for determining total organic carbon (TOC) content. Log data include sonic transit-time (t), bulk density ($_b$), formation resistivity (R_{fm}), and neutron porosity ($_N$), and both single (t, $_b$, $_N$) and dual log (t-R_{fm}, $_b$-R_{fm}, $_N$-R_{fm}, t- $_b$, t- $_N$) techniques are presented. Log data are not normalized nor do we require *a priori* knowledge of thermal maturity. Thus our methods are less subjective than some published empirical methods (e.g. Passey *et al.*, 1990). Our equations include physical parameters for the inorganic rock matrix (ma) that are determined using core measurements e.g. t_{ma}, R_{ma}, $_{ma}$ and $_{Nma}$. t, $_b$ and $_N$ are expressed as functions of porosity and TOC content whereas R_{fm} depends on porosity and thermal maturity. We tested our methods using core data from wells in Alberta and Saskatchewan. Calculated and measured TOC show good correspondence in wells with good borehole conditions and quality logs. For the test wells, our approach yields more accurate results than the log R method (Passey *et al.*, 1990). Our formulation is general and can be applied to any sedimentary basin provided that model coefficients are adjusted to reflect changes in the factors that control log responses (e.g. lithology, stress, diagenesis, temperature). In principle, it should be possible to use radioactivity logs to determine organic matter type (not shown) and resistivity logs to determine organic maturity. In addition to source rock characterization, our methods can be used to study compaction, erosion and pore pressures in sedimentary basins because they resolve the physical (porosity) and chemical (TOC) contributions to log response.

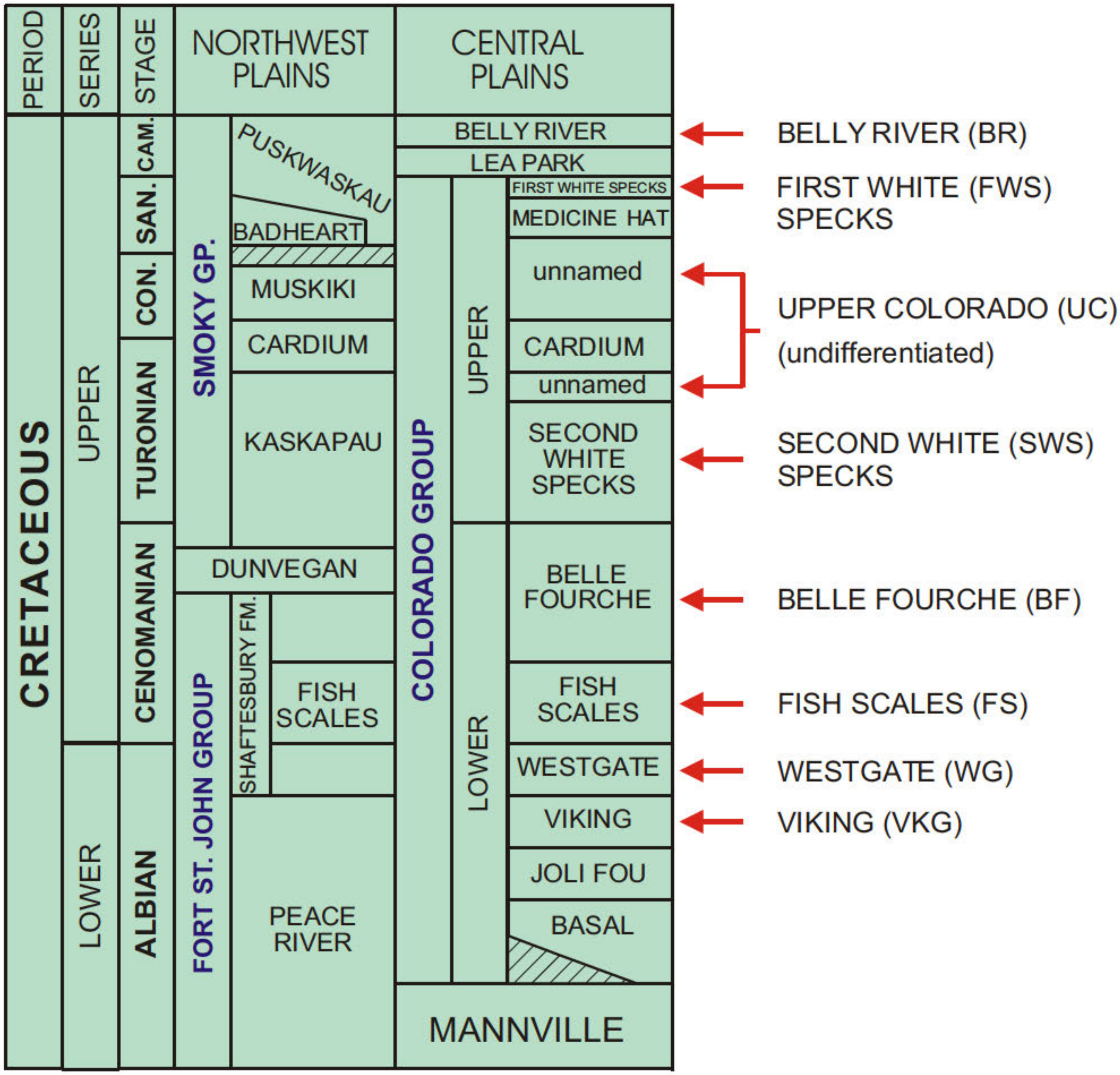
INTRODUCTION

Typical properties of petroleum source rocks include: (1) high t (low velocity), (2) low $_b$, (3) high $_N$, (4) high radioactivity (due to enhanced U concentration) and, for thermally mature source rocks, (5) high resistivity (due to hydrocarbon saturation). A number of methods, based on empirical correlations between log properties and organic properties, have been proposed for TOC determination. Single log methods have used density (Schmoker, 1979), gamma ray (Schmoker, 1981) and spectral gamma ray (Fertl and Rieke III, 1980) logs. Mendelson and Toksöz (1985) used physically-based rock component models for sonic, neutron and density logs. Dual log methods include cross plots (Meyer and Nederlof, 1984), graphical log overlay methods (Passey *et al.*, 1990) and empirical/physical models (Carbolog® method of Carpentier *et al*., 1991). Multi-log techniques include cross plots (I-X method; Dellenbach *et al*., 1983), multi-variate regression analysis (Mendelson and Toksöz, 1985) and neural networks (Huang and Williamson, 1996).

The above methods have yielded mixed results, with correlations and model predictions varying from good to poor. Single log methods and rock component models are most affected by unknown variations in physical properties and composition. Normalized graphical log overlay methods can, in part, compensate for physical and chemical property changes and poor borehole conditions. However, for the Passey *et al*. method, baseline determination is subjective and thermal maturity must be known. Multi-variate regression analysis and neural network models can yield good local results but they are not universally applicable.

In the present study, we have developed rock component (mineral matrix, organic carbon, pore fluid) models with physical parameters that can be determined from core petrophysical and geochemical data. TOC estimates can be obtained directly from log data without the need for subjective user input or log normalization. The method was calibrated using core data from Alberta but it gives good results for test wells in both Alberta and Saskatchewan.

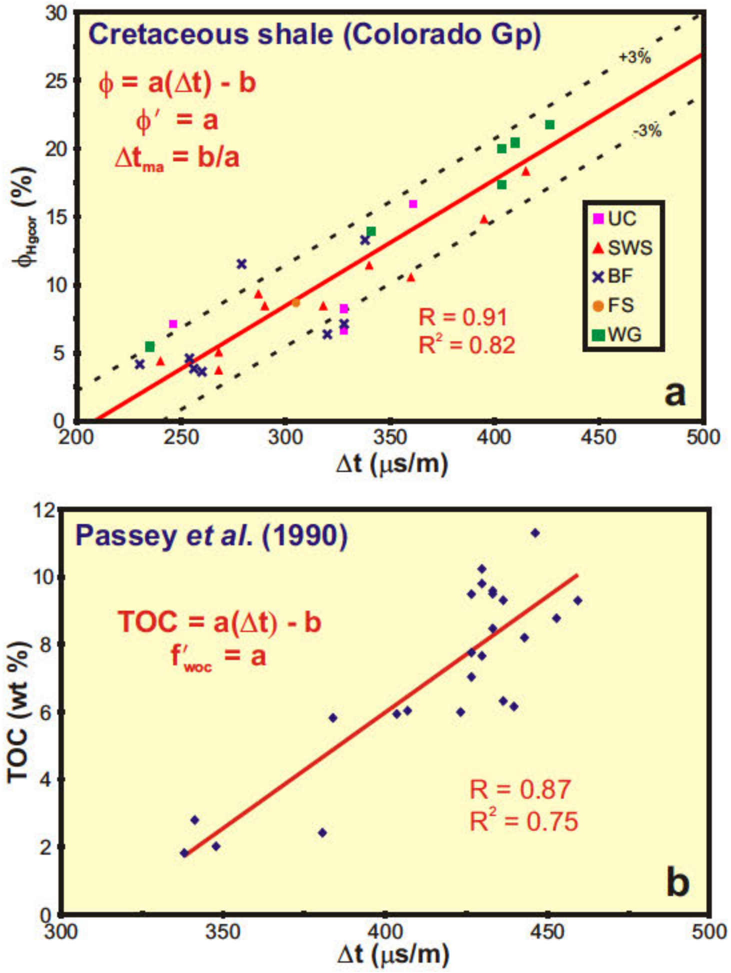
Stratigraphy and Sampled Shale Intervals



Shale core samples were collected from the Belly River Group and formations of the Colorado Group from wells in Alberta (red arrows indicate sampled intervals). Samples were analyzed for organic properties (Rock-Eval analysis), quantitative mineralogy, trace elements and petrophysics (mercury and helium porosity). These data were used to calibrate rock component parameters for log-based TOC models. Rock units can be classified according to paleo-oxygen conditions at the time of deposition (based on sedimentary textures, fossil assemblages, organic/inorganic geochemistry): anaerobic/dysaerobic (FWS, SWS, FS); dysaerobic/aerobic (UC, BF); aerobic (BR, WG, VKG).

Single Log Methods for TOC Determination

Porosity and TOC versus Sonic Transit-Time



Sonic Transit-Time (Δt) Method

$$f_{woc} = f'_{woc}(\Delta t - \phi/\phi' - \Delta t_{maOCF})$$

where: f_{woc} = TOC (wt%)

Known Parameters

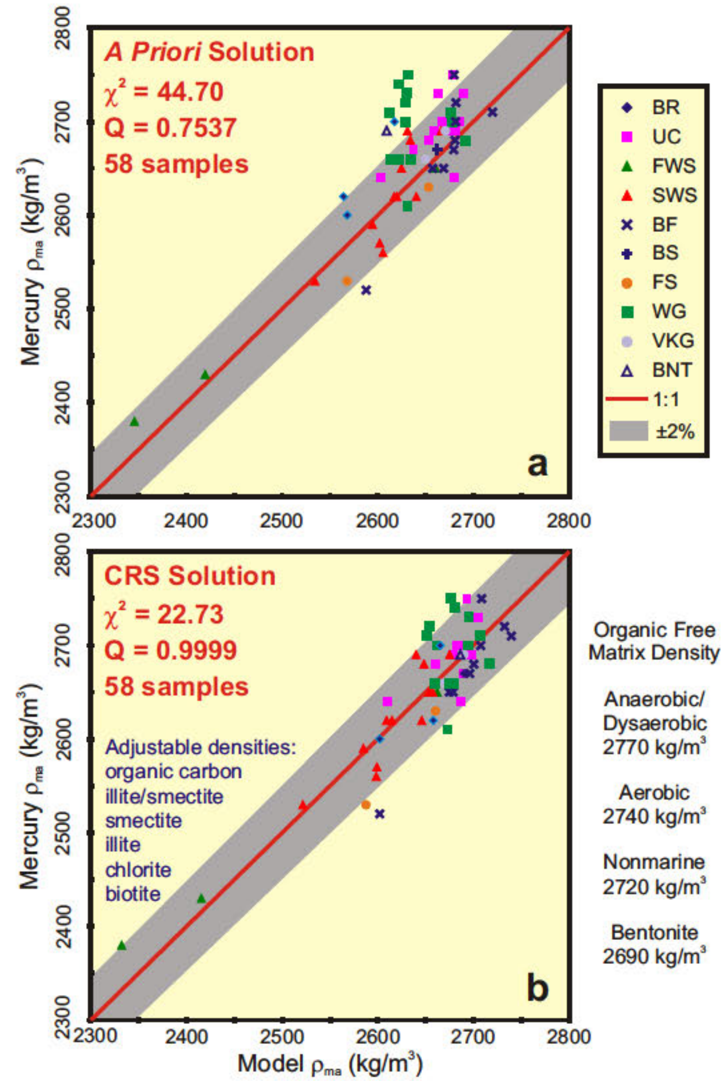
- Δt from sonic log
- ϕ', f'_{woc} from slopes of ϕ vs Δt (panel a) and TOC vs Δt (panel b)
- Δt_{maOCF} - Δt for organic carbon-free mineral matrix (based on Δt_{ma}, f'_{woc})

Unknown Parameter

ϕ - porosity determined using ϕ(Δt) (panel a) in low TOC interval

Model assumes that Δt is a function of ϕ, TOC and lithology. The effects of light hydrocarbons, borehole conditions, etc. on log response are ignored. Model parameters are determined from correlations of core ϕ (for low TOC shale) and TOC (from Passey *et al.*, 1990) with Δt for sedimentary rocks from Western Canada. To apply the single sonic log method, ϕ, derived from Δt data for low TOC intervals (panel a), can be assumed to be constant or can be estimated by interpolation of ϕ-depth data.

Calculated Shale Matrix Density



Density (ρ) Method

$$f_{woc} = \left[\frac{\dfrac{1 - 0.01\phi}{\rho_b - 0.01\phi\rho_w} - \dfrac{1}{\rho_{maOCF}}}{0.01\left(\dfrac{1}{\rho_{OC}} - \dfrac{1}{\rho_{maOCF}}\right)} \right]$$

where: f_{woc} = TOC (wt%)

Known Parameters

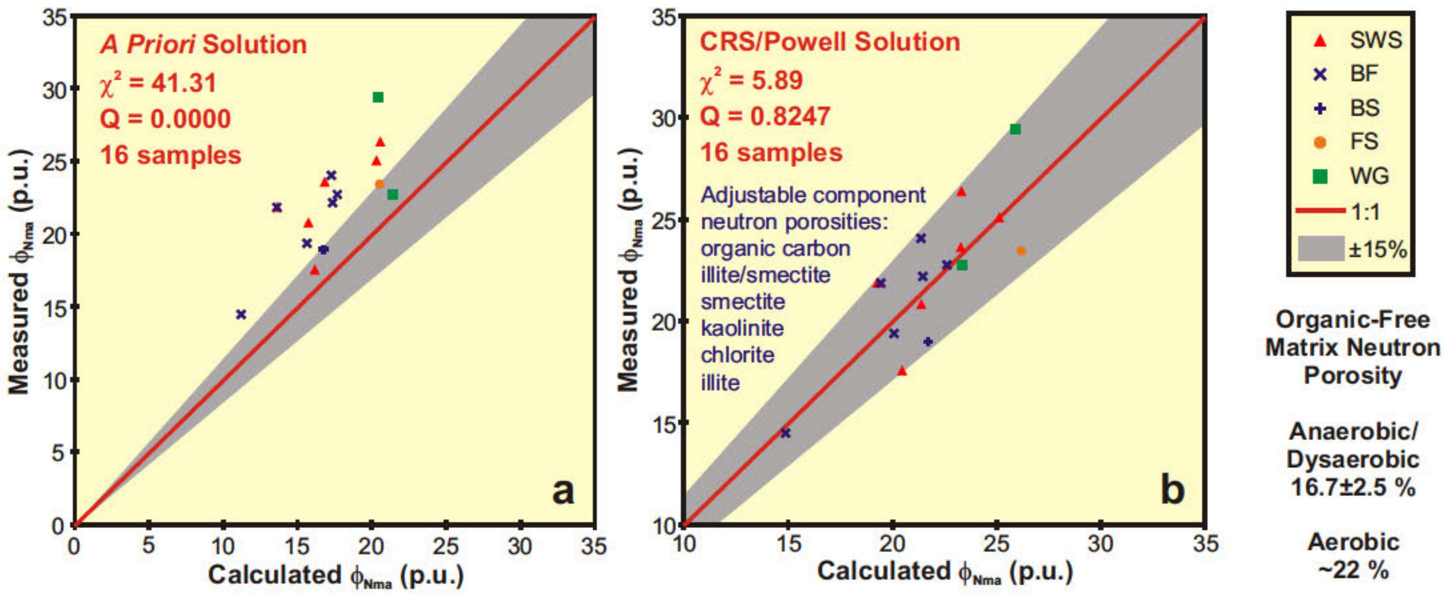
- ρ_b, ρ_w - log bulk density and assumed pore fluid (water) density
- ρ_{maOCF}, ρ_{OC} - density for organic carbon-free matrix & organic carbon

Unknown Parameter

ϕ - porosity determined using $\phi(\rho_b)$ in low TOC interval

Model assumes that saturated bulk density, ρ_b, is a function of ϕ, TOC and lithology. The effects of light hydrocarbons, borehole conditions, etc. on log response are ignored. Model parameters, ρ_{maOCF} and ρ_{OC}, are determined by inverse modelling of component density and bulk grain density data using a controlled random search (CRS) technique. To apply the single density log method, ϕ, derived from ρ_b data for low TOC intervals, can be assumed to be constant or can be estimated by interpolation of ϕ-depth data.

Calculated Shale Matrix Neutron Porosity



Neutron Porosity (ϕ_N) Method

$$f_{woc} = \frac{C_1\phi_N - C_2\phi - C_3}{C_4 - C_5\phi - C_6\phi_N}$$

where: f_{woc} = TOC (wt%)

Known Parameters

- ϕ_N - log neutron porosity
- ϕ_{NmaOCF}, ϕ_{NOC} - neutron porosity for organic carbon-free matrix & organic C
- ρ_{maOCF}, ρ_{OC} - density for organic carbon-free matrix & organic C

Unknown Parameter

ϕ - porosity determined using $\phi(\phi_N)$ in low TOC interval

Model assumes that ϕ_N is a function of ϕ, TOC and lithology. The effects of light hydrocarbons, borehole conditions, etc. on log response are ignored. Model parameters, ϕ_{NmaOCF} and ϕ_{NOC}, are determined by inverse modelling of component ϕ_N and bulk matrix ϕ_N (given by ϕ_N - ϕ) values using a controlled random search (CRS) technique. To apply the single neutron log method, ϕ, derived from ϕ_N data for low TOC intervals, can be assumed to be constant or can be estimated by interpolation of ϕ-depth data.

Porosity from Resistivity

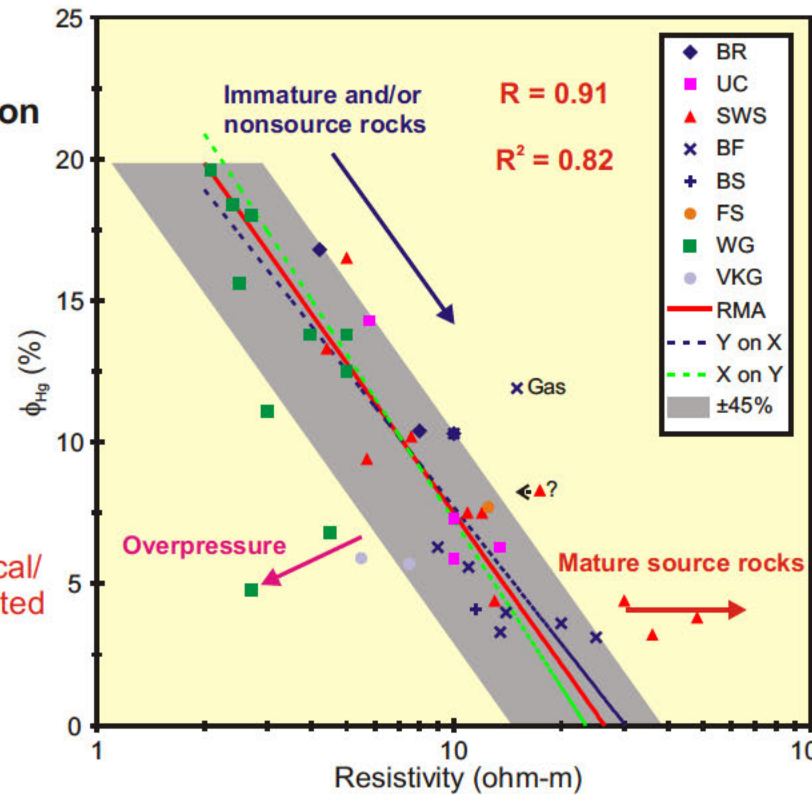
Mercury Porosity vs Formation Resistivity for Cretaceous Shale of the WCSB

$R_{fm} = R_{ma}\exp(\alpha_{ma}\phi)$

R_{fm} - formation resistivity

R_{ma} - apparent matrix resistivity

α_{ma} - constant dependent on physical/ chemical properties of saturated rock



Empirical Resistivity (R) Method for Porosity (ϕ)

$$\phi = a - b\ln(R_{fm})$$

where: $a = \dfrac{-\ln(R_{ma})}{\alpha_{ma}}$; $b = \dfrac{1}{\alpha_{ma}}$

Known Parameters

- R_{fm} from resistivity log
- a, b determined from ϕ vs $\ln(R_{fm})$ regression analysis
- R_{ma}, α_{ma} - empirical matrix parameters determined from a and b

General Features

No explicit T dependence for R_{fm} (incorporated in a, b)

Applies to horizontal beds (resistivity is anisotropic)

Excludes mature source rocks (only for water-saturated pores)

Works remarkably well (limited change in pore fluid composition)

Model assumes that R_{fm} is a function of water-saturated ϕ and lithology. The effects of hydrocarbons, borehole conditions, etc. on log response are ignored. Model parameters, R_{ma} and α_{ma}, are determined by correlation of R_{fm} with core ϕ. Resistivity can be used to obtain detailed ϕ variation with depth for use in combination with sonic, density or neutron logs for TOC prediction.

Porosity from Resistivity

Apparent Formation Resistivity Factor (F_a) for Cretaceous Shale of the WCSB

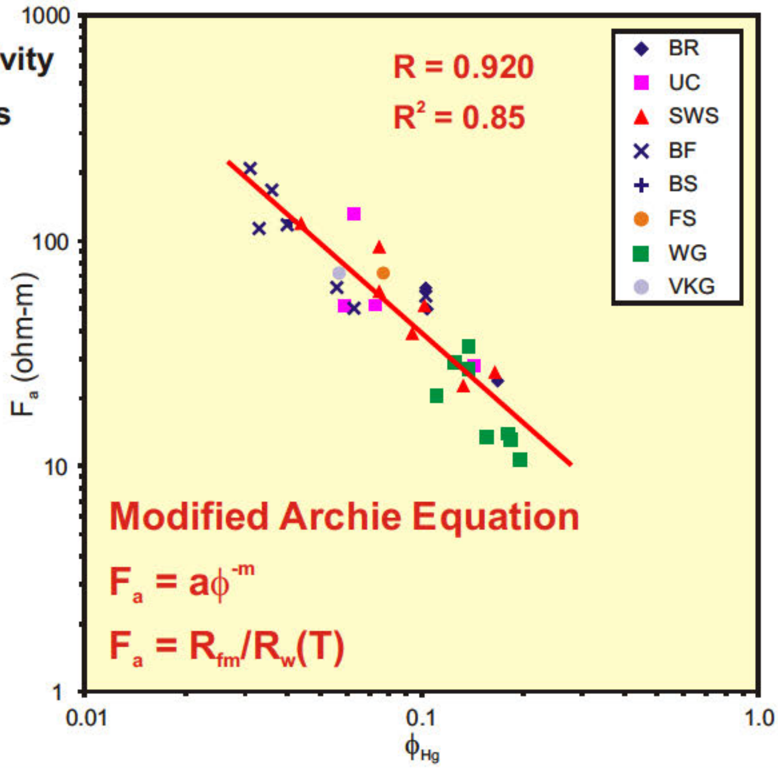
a - lithology-dependent constant
m - cementation factor

assume:

(1) constant R_w = 0.18 ohm-m at 25 ° C (sea water)

(2) Use Arps' formula to correct R_w to *in situ* temperature, T

$$R_w(T) = \frac{8.37}{(T + 21.5)}$$



Modified Archie Method for Porosity (ϕ)

$$\phi = \left(\frac{c_1}{(Gz + T_s + 21.5)R_{fm}} \right)^{1/m}$$

where: c_1 = 8.37a

Known Parameters

- R_{fm} from resistivity log
- a, m determined from lnϕ vs ln(F_a) regression analysis
- z, G, T_s - depth, geothermal gradient and surface temperature

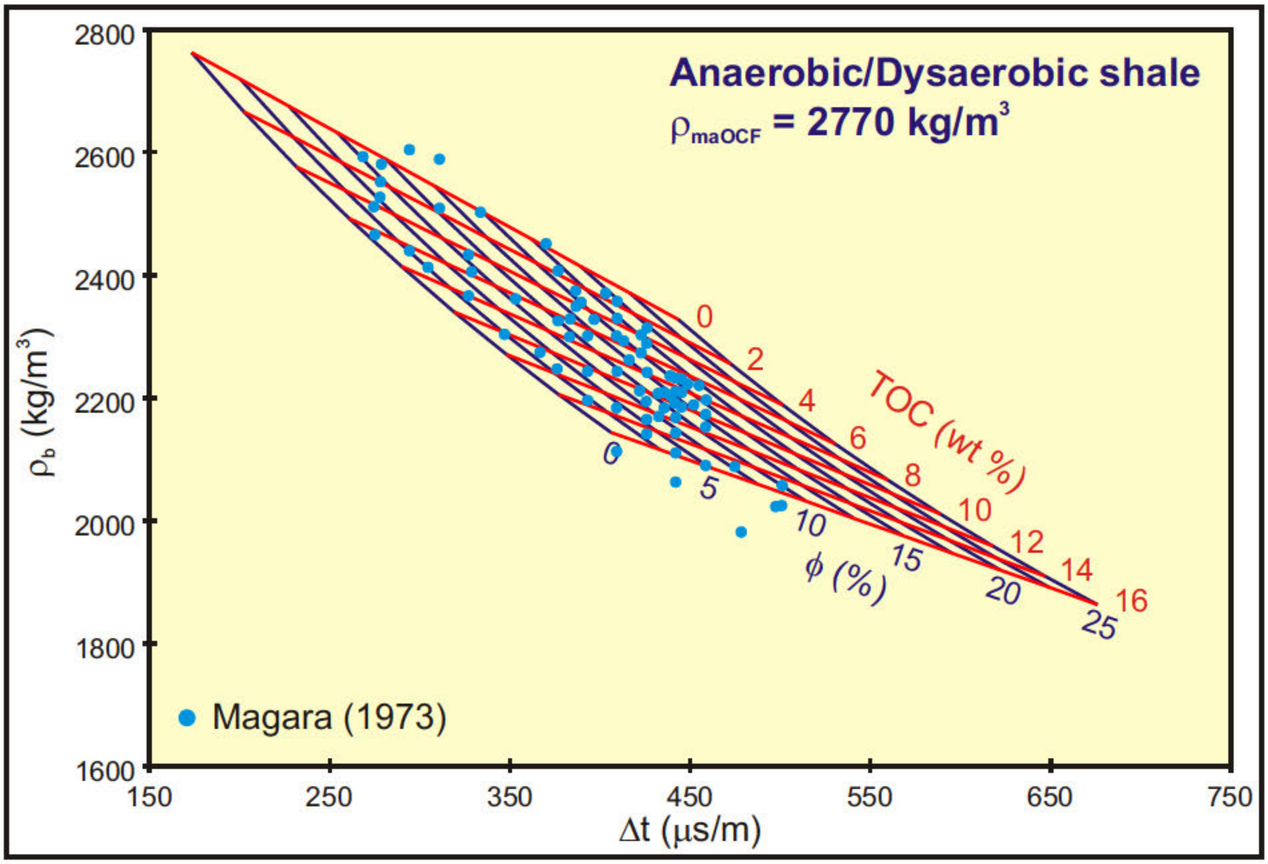
General Features

Includes T dependence for R_{fm} (incorporated in assumed R_w)
Applies to horizontal beds (resistivity is anisotropic)
Excludes mature source rocks (only for water-saturated pores)
Works remarkably well (limited change in pore fluid composition)

Model assumes that R_{fm} is a function of water-saturated ϕ, temperature (through its effect on pore water resistivity, R_w) and lithology. The effects of hydrocarbons, borehole conditions, etc. on log response are ignored. Archie parameters, a and m, are determined by correlation of calculated apparent formation factor (assuming sea water for pore fluid) with core ϕ. Resistivity can be used to obtain detailed ϕ variation with depth for use in combination with sonic, density or neutron logs for TOC prediction.

Dual Log Methods for TOC Determination

Dual log methods include the following log combinations: sonic-density, sonic-neutron, sonic-resistivity, density-resistivity and neutron-resistivity. As with the single log methods, joint log responses are assumed to be a function of , TOC and lithology (hydrocarbons, borehole conditions, etc., are ignored). Both and TOC can be resolved uniquely using dual log methods. This allows for more accurate TOC determination in sediments with heterogeneous distributions. Conversely, sediment compaction trends can be better resolved in sediments with variable organic matter content. For example, the blue dots on the $_b$- t plot (next page) represent log data which were used by Magara (1973) in a study of shale compaction for the Western Canada Sedimentary Basin. In that study, values were estimated from density log data assuming a constant matrix density and then these values were correlated with t values so that sonic logs could be used to calculate trends. This plot shows that much of the variation in shale density is due to variable organic matter content as opposed to and thus a constant matrix density is an invalid assumption for these sediments.



Sonic-Density (Δt-ρ) Method

$$af_{woc}^2 + bf_{woc} + c = 0$$

with solution: $f_{woc} = \dfrac{-b - \sqrt{b^2 - 4ac}}{2a}$ (in wt% TOC)

Known Parameters

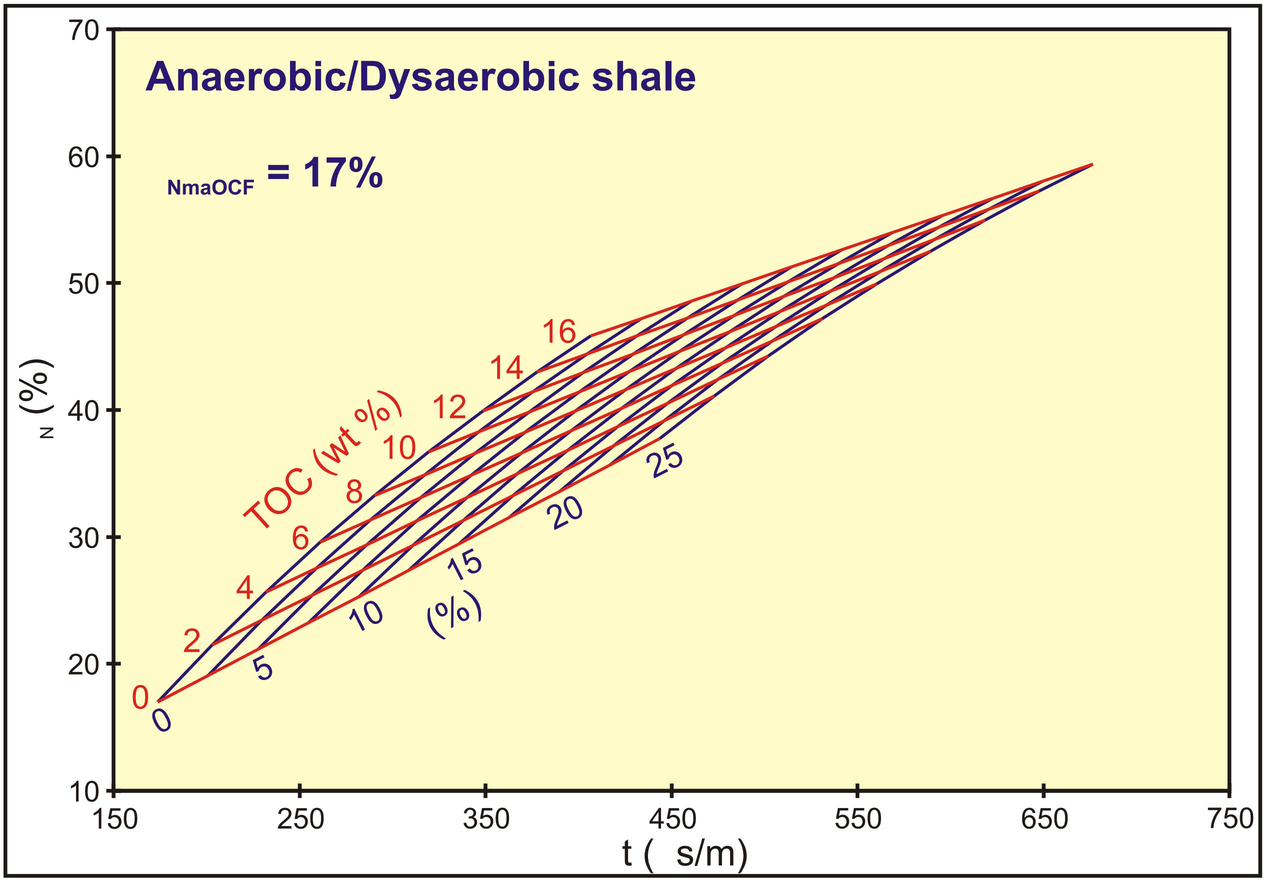
- Δt, ρ_b from sonic and density logs, respectively
- a is a function of ϕ', f'_{woc}, ρ_w, ρ_{maOCF}, ρ_{OC}
- b is a function of Δt_{maOCF}, Δt, f'_{woc}, ϕ', ρ_b, ρ_w, ρ_{maOCF}, ρ_{OC}
- c is a function of Δt_{maOCF}, Δt, ϕ', ρ_b, ρ_w, ρ_{maOCF}

General Features

Can determine both TOC and ϕ uniquely

Bentonites appear as organic-rich units

Sensitive to borehole conditions



Sonic-Neutron (t- $_N$) Method

$$af_{woc}^2 + bf_{woc} + c = 0$$

with solution: $f_{woc} = \dfrac{-b + \sqrt{b^2 - 4ac}}{2a}$ (in wt% TOC)

Known Parameters

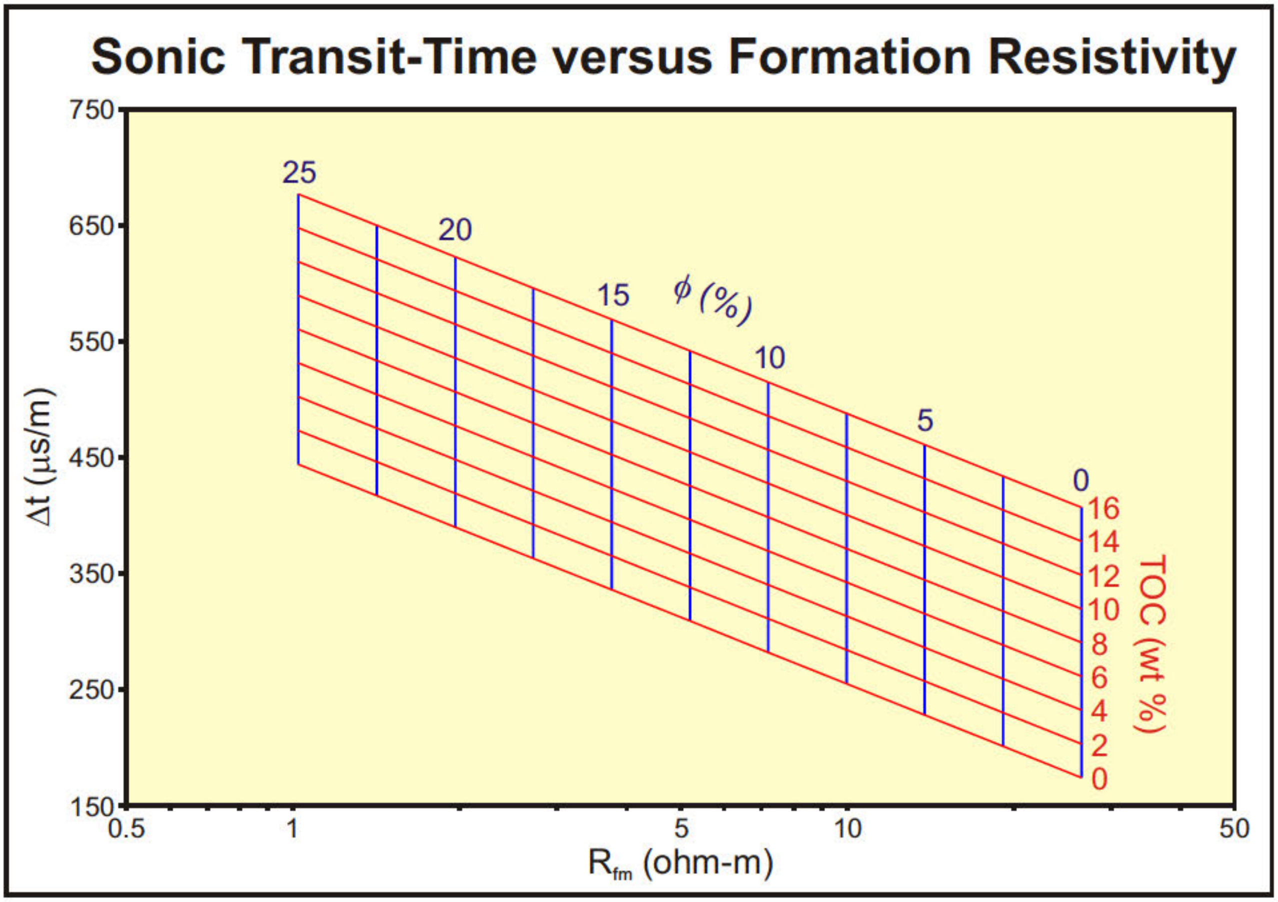
- t, $_N$ from sonic and neutron logs, respectively
- a - function of ′, f'_{woc}, $_{NmaOCF}$, $_{NOC}$, $_{maOCF}$, $_{OC}$
- b - function of t_{maOCF}, t, f'_{woc}, ′, $_N$, $_{NmaOCF}$, $_{NOC}$, $_{maOCF}$, $_{OC}$
- c - function of t_{maOCF}, t, ′, $_N$, $_{NmaOCF}$, $_{OC}$, $_{maOCF}$

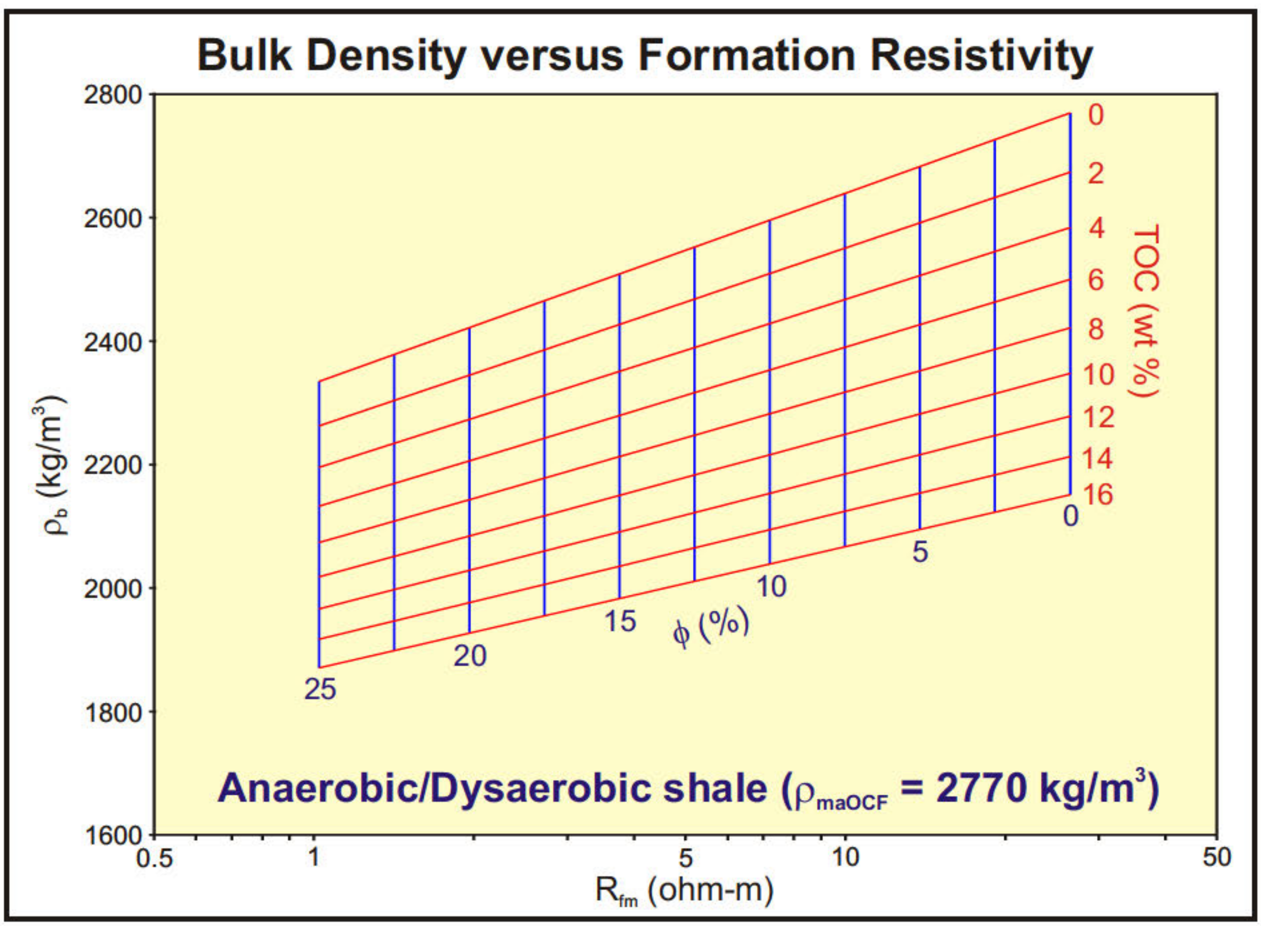
General Features

Can determine both TOC and uniquely

Bentonites appear as organic-rich units

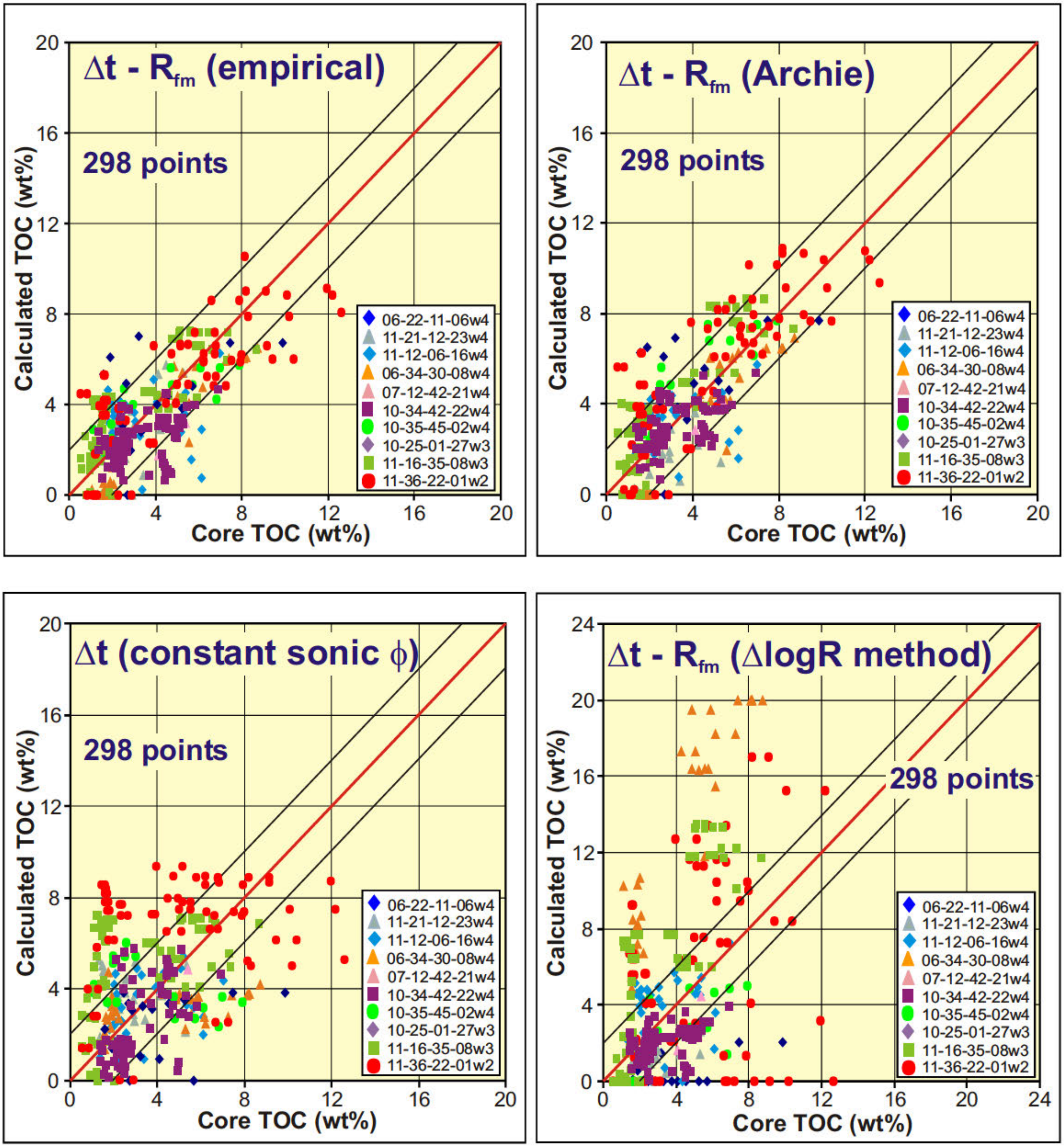
Sensitive to borehole conditions, mineralogy, log calibration


Sonic Transit-Time versus Formation Resistivity
Δt (μs/m)
750
650
550
450
350
250
150
0.5
1
5
10
50
Rfm (ohm-m)
ϕ (%)
25
20
15
10
5
0
TOC (wt %)
16
14
12
10
8
6
4
2
0

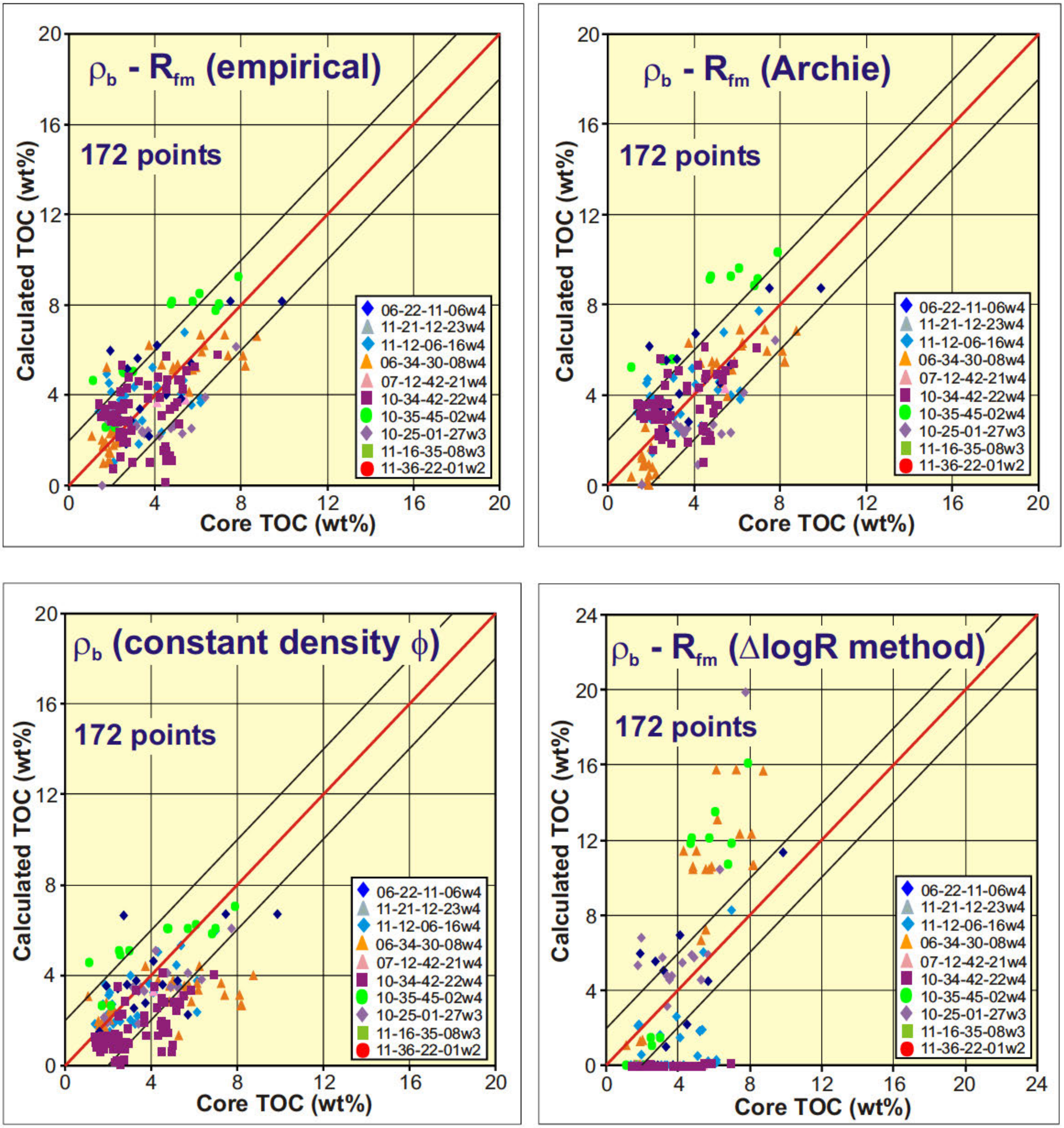

Bulk Density versus Formation Resistivity
ρb (kg/m3)
2800
2600
2400
2200
2000
1800
1600
0.5
1
5
10
50
Rfm (ohm-m)
TOC (wt %)
0
2
4
6
8
10
12
14
16
ϕ (%)
0
5
10
15
20
25
Anaerobic/Dysaerobic shale (ρmaOCF = 2770 kg/m3)

Calculated (Log) versus Measured (Core) TOC

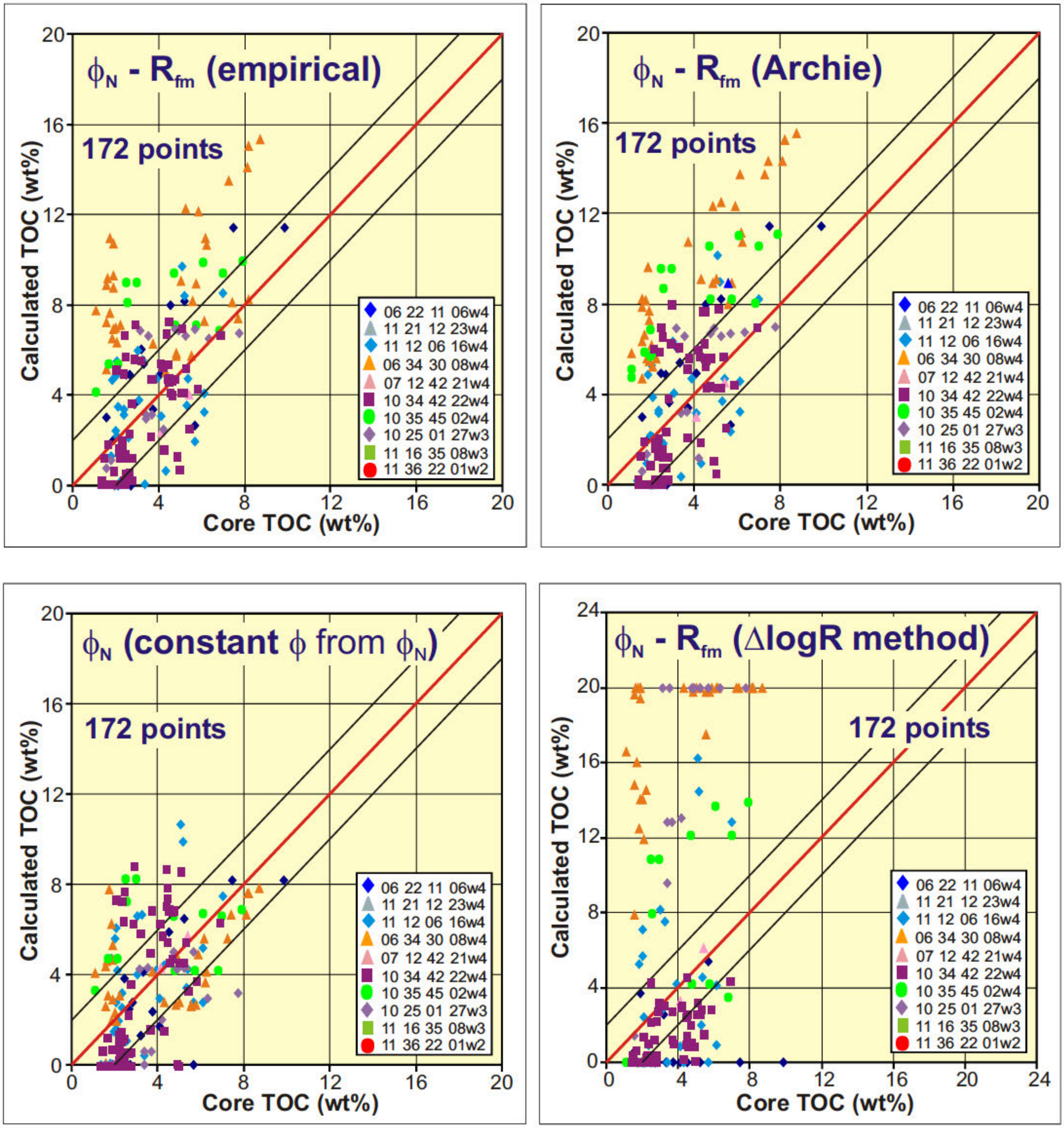
The rock component models were tested using core TOC data (Rock-Eval 2 and 6) from ten Alberta and Saskatchewan wells with digitized logs and good borehole conditions. Rock-Eval 2 TOC data are from Bloch *et al*. (1999) whereas Rock-Eval 6 data are from re-analysed and new core samples. The next series of pages show plots comparing measured TOC with calculated values derived from different logs and combinations of logs. For these plots, the following restrictions were applied to the data: (1) borehole enlargement (as measured by the caliper diameter minus the bit size) had to be 20 mm to minimize borehole effects on log readings; (2) samples in close proximity to concretions and bentonites were excluded in cases where these special lithologies unduly distorted log responses. Results should be assessed in light of the following limitations: (1) differences between log and core sample measurement scales; (2) variable accuracy in log and core depths; (3) variable log quality (calibration, borehole roughness, hydrocarbons, etc.); (4) the accuracy of discrete TOC measurements and whether they are representative. Best results for rock component models are obtained using t-R_{fm} and $_{b}$-R_{fm} data with most model TOC predictions within ±2 wt% of measured values. In contrast, $_{N}$-R_{fm} data yield poor results. Better results for the constant model suggests that log calibration is the problem and that normalization of $_{N}$ data may improve results significantly. logR model results are poor for all three log combinations (better results could be achieved only by adjusting LOM values until model predictions fit observed data).



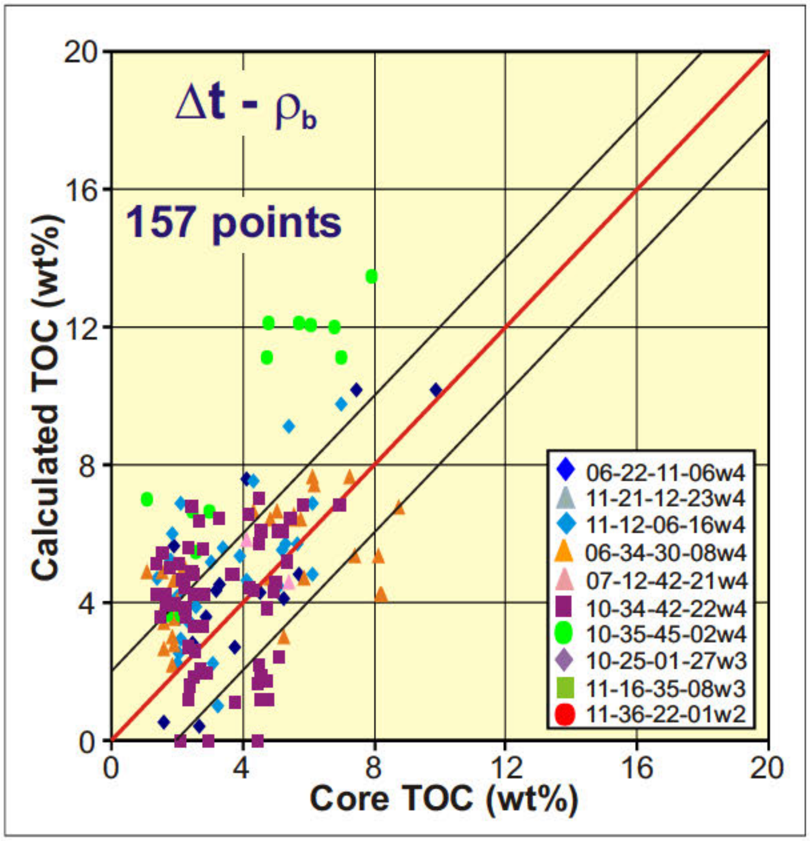
Δt - R_fm (empirical)
298 points
Δt - R_fm (Archie)
298 points
Δt (constant sonic φ)
298 points
Δt - R_fm (ΔlogR method)
298 points
Calculated TOC (wt%)
Core TOC (wt%)
06-22-11-06w4
11-21-12-23w4
11-12-06-16w4
06-34-30-08w4
07-12-42-21w4
10-34-42-22w4
10-35-45-02w4
10-25-01-27w3
11-16-35-08w3
11-36-22-01w2

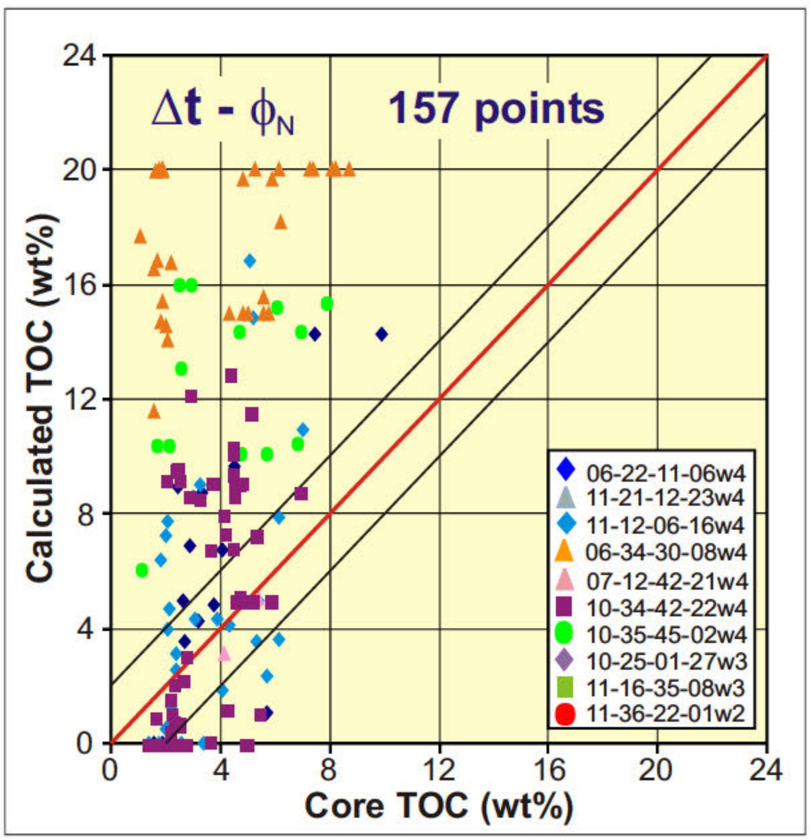


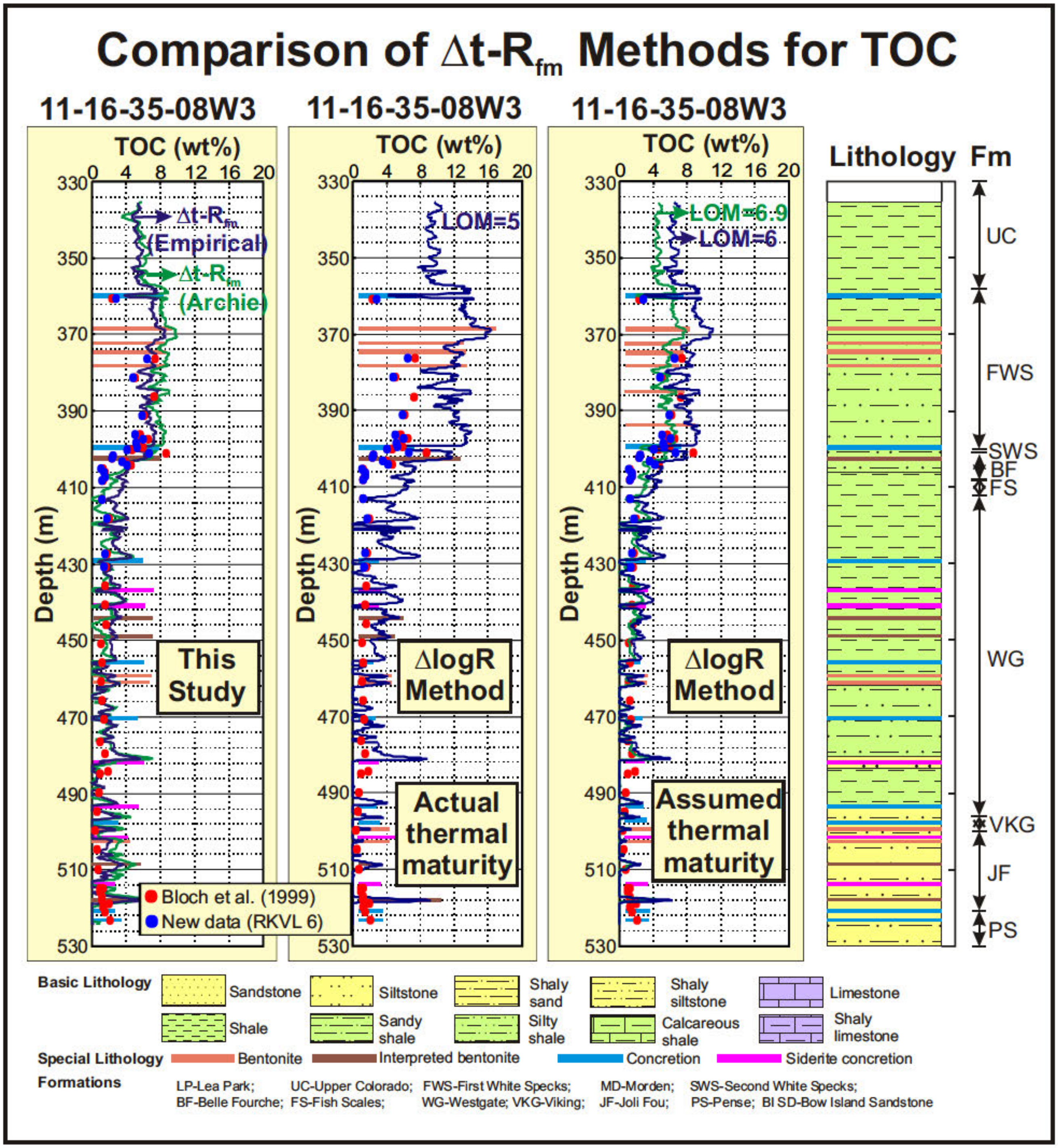
ρb - Rfm (empirical)
172 points
Calculated TOC (wt%)
Core TOC (wt%)
ρb - Rfm (Archie)
172 points
Calculated TOC (wt%)
Core TOC (wt%)
ρb (constant density φ)
172 points
Calculated TOC (wt%)
Core TOC (wt%)
ρb - Rfm (ΔlogR method)
172 points
Calculated TOC (wt%)
Core TOC (wt%)
06-22-11-06w4
11-21-12-23w4
11-12-06-16w4
06-34-30-08w4
07-12-42-21w4
10-34-42-22w4
10-35-45-02w4
10-25-01-27w3
11-16-35-08w3
11-36-22-01w2



ϕN - Rfm (empirical)
172 points
Calculated TOC (wt%)
Core TOC (wt%)
06 22 11 06w4
11 21 12 23w4
11 12 06 16w4
06 34 30 08w4
07 12 42 21w4
10 34 42 22w4
10 35 45 02w4
10 25 01 27w3
11 16 35 08w3
11 36 22 01w2
ϕN - Rfm (Archie)
172 points
Calculated TOC (wt%)
Core TOC (wt%)
06 22 11 06w4
11 21 12 23w4
11 12 06 16w4
06 34 30 08w4
07 12 42 21w4
10 34 42 22w4
10 35 45 02w4
10 25 01 27w3
11 16 35 08w3
11 36 22 01w2
ϕN (constant ϕ from ϕN)
172 points
Calculated TOC (wt%)
Core TOC (wt%)
06 22 11 06w4
11 21 12 23w4
11 12 06 16w4
06 34 30 08w4
07 12 42 21w4
10 34 42 22w4
10 35 45 02w4
10 25 01 27w3
11 16 35 08w3
11 36 22 01w2
ϕN - Rfm (ΔlogR method)
172 points
Calculated TOC (wt%)
Core TOC (wt%)
06 22 11 06w4
11 21 12 23w4
11 12 06 16w4
06 34 30 08w4
07 12 42 21w4
10 34 42 22w4
10 35 45 02w4
10 25 01 27w3
11 16 35 08w3
11 36 22 01w2


Δt - ρb
157 points
Calculated TOC (wt%)
Core TOC (wt%)
0
4
8
12
16
20
06-22-11-06w4
11-21-12-23w4
11-12-06-16w4
06-34-30-08w4
07-12-42-21w4
10-34-42-22w4
10-35-45-02w4
10-25-01-27w3
11-16-35-08w3
11-36-22-01w2


Δt - φN
157 points
Calculated TOC (wt%)
Core TOC (wt%)
0
4
8
12
16
20
24
06-22-11-06w4
11-21-12-23w4
11-12-06-16w4
06-34-30-08w4
07-12-42-21w4
10-34-42-22w4
10-35-45-02w4
10-25-01-27w3
11-16-35-08w3
11-36-22-01w2



The figure above shows a comparison of the ΔlogR method with the rock component-based model of this study. Both methods use sonic transit-time and resistivity logs to calculate the depth variation in TOC for the C.M.S. Vanscoy 11-16-35-8W3 well of central Saskatchewan. Red dots represent measured TOC analyzed on core samples using a Rock-Eval 2 instrument (Bloch *et al.*, 1999); blue dots represent re-analyses of the same samples using a Rock-Eval 6 instrument. For the rock component model, results are presented for both empirical (blue) and Archie (green) resistivity porosity methods. The ΔlogR method gives poor results for the Vanscoy well when observed thermal maturity is used (level of organic metamorphism, LOM 5; Hood *et al.*, 1975). An LOM value of 6.9 provides a good fit to the data but it is not representative of the true maturity. LOM values were estimated for all the test wells using regional maturity maps and well measurements and, with these values, the ΔlogR method yielded poor results. LOM values can be adjusted to give a closer match between observed and calculated TOC but this involves *a priori* knowledge of the TOC content which limits general application of the ΔlogR method.

Conclusions

(1) Core-calibrated rock component models give good estimates of TOC content for Cretaceous shale of Western Canada

(2) No subjective user input is required to use the models (e.g. no baseline selection, organic maturity not needed)

(3) Best results are from dual log methods using sonic-resistivity (t-R_{fm}) and density-resistivity ($_{b}$-R_{fm}) combinations

(4) Rock component models that use resistivity are restricted to water-saturated rocks (i.e. immature source rocks with $R_{fm} < 30$ ohm-m)

(5) logR method (Passey *et al.*, 1990) is very sensitive to the selected value for the level of organic metamorphism (LOM) and therefore it gave generally poor results for the study wells

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