

Eyes Wide Shut

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In today's busy office environment, it is all too easy to become focused on the end product (and the associated delivery deadline), at the expense of basic data quality and interpretation algorithm issues: we are, ***in a sense, working with our Eyes Wide Shut.***

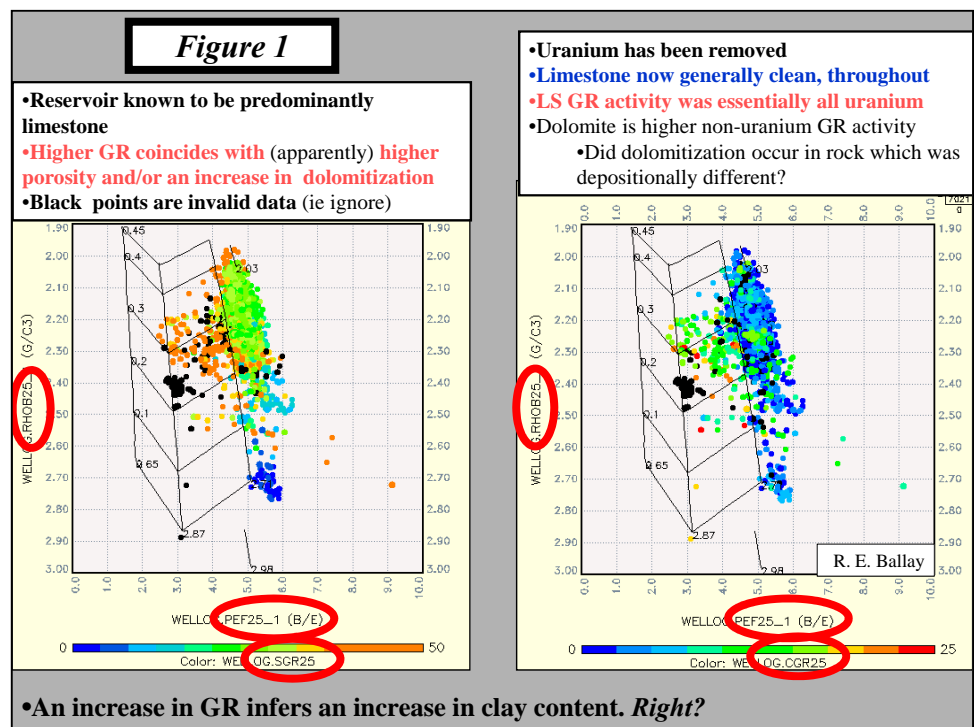
As one of many possible examples, it is common to associate an increase in GR with an increase in clay content, indicative of the need to perform a clay correction to both porosity and S_w .

Figure 1 is the Rhob – Pef crossplot across a well-understood Middle East limestone, with GR in the “z” direction. ***The first observation to be made is that most of the “well understood limestone data” is not trending along the limestone line*** (Pef is offset)?

We have observed this shifted behavior in multiple (other) carbonate reservoirs in which there were core- and geologically-established normalization horizons: tight limestone and anhydrite (Ballay 1994). The issue is furthermore reported in the literature (Kennedy 2002). And so we realize that while the Pef is a valuable mineralogy indicator, its contribution can be enhanced if normalization horizons are available.

The next observation is that GR (clay?) increases as the Rhob-Pef data pair's move in an increased porosity direction. However, ***when the “z” axis is CGR (rather than SGR), the perspective changes.*** We now realize that the limestone portion of the reservoir is responding to uranium, not clay, and so routine porosity and water saturation algorithms are a reasonable starting point.

One explanation for this behavior is that the higher porosity / permeability intervals have (historically) accommodated more fluid flow (relative to the lower quality intervals) which then resulted in an increase in uranium precipitation. A similar response can sometimes be observed opposite perforated intervals, when the original open-hole GR is compared to the GR from time-lapse surveillance measurements.



The same phenomenon has been observed in clastic reservoirs (Malay basin is one of several possible examples), in a field for which there was no spectral gamma ray. In that instance it was SP deflection that separated the reservoir rock from the bounding shale, both having high GR.

As petrophysicists ***we are often faced with tight deadlines, and answer to management who have not benefited from hands-on petrophysical interpretations across non-simple reservoirs. And while no one wants to be the Messenger who brings uncertainty to the table, Due Diligence requires that we avoid the Eyes Wide Shut mentality.***

Focus

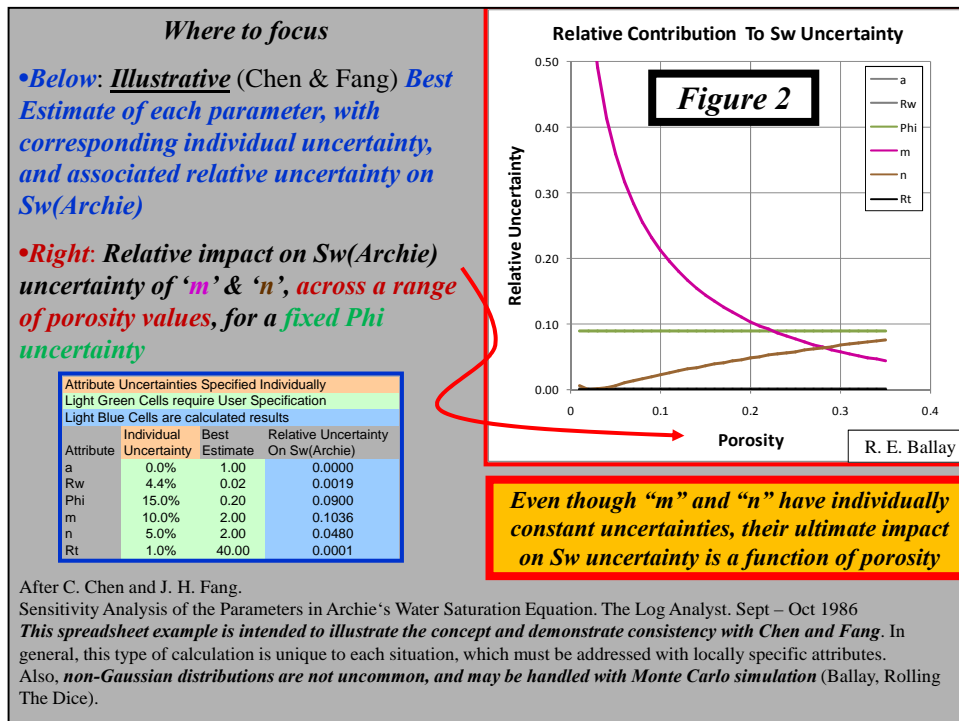
We all realize that our evaluations can be no better than the data, and model, allow. At the simplest level we might select Optimistic, Expected and Pessimistic parameter estimates, and thereby both bound the uncertainty (high and low) in the calculated estimate, and further identify which of the input attributes are dominating that uncertainty.

It is, however, ***relatively simple to address the uncertainty issue in a more comprehensive and analytical fashion, and thereby more efficiently focus our time and budget, in search of an improved evaluation.***

In carbonates, ***our Sw estimates are typically compromised by uncertainty in the (simple) Archie equation attributes.***

$$S_w^n = a R_w / (\Phi^m R_t)$$

In shaly sands the same approach can be applied to an appropriate S_w (Shaly Sand) relation, and indeed the methodology is applicable to any of the deterministic calculations that we use on a daily basis, far beyond petrophysics.



By taking the various partial derivatives of Archie's equation (or any equation of interest) one is able to quantify the individual impact of each attribute upon the ultimate result, and thus ***recognize where the biggest bang for the buck, in terms of a core analyses program or suite of potential logs, is to be found: Figure 2.***

A ***spreadsheet formulation*** (Chen & Fang's results have been coded in Excel) ***allows one to not only easily***

perform the calculations, but to also consider what the effect of a change in reservoir quality (porosity, as one of several possible examples) would mean (because the importance of 'm' and 'n' is linked to porosity), with locally specific values.

At 20 pu, formation evaluation (with Chen & Fang's illustrative parameters) should focus on improved porosity and 'm' estimates, with 'n' of relatively less importance: **Figure 3**.

If porosity rises to 30 pu, however, improved porosity estimates become more important with 'm' and 'n' having similar, and less, impact.

As porosity drops below 20 pu, it is the pore connectivity ('m') that begins to dominate the accuracy.

Think back for just a moment, on how discussions of uncertainty which you may have participated in, became fixated on a single issue without any kind of quantitative consideration

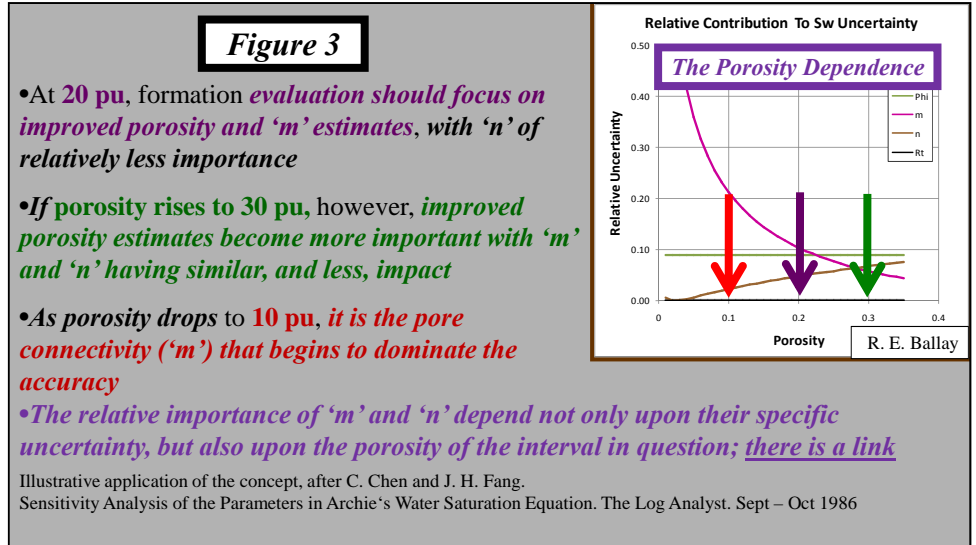
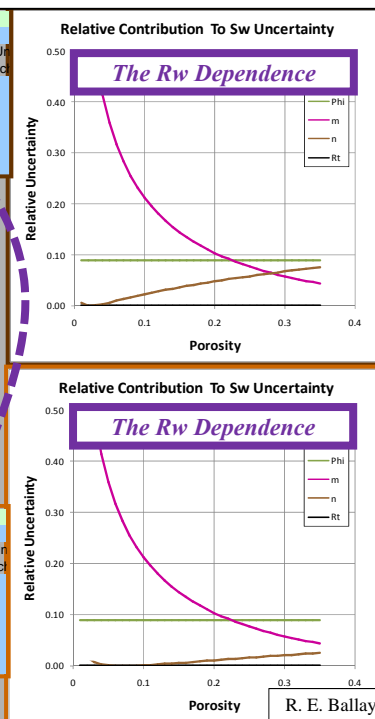


Figure 4

| Attribute | Individual Uncertainty | Best Estimate | Relative Uncertainty On Sw(Arch) |
|-----------|------------------------|---------------|----------------------------------|
| a | 0.0% | 1.00 | 0.0000 |
| Rw | 4.4% | 0.02 | 0.0019 |
| Phi | 15.0% | 0.20 | 0.0900 |
| m | 10.0% | 2.00 | 0.1036 |
| n | 5.0% | 2.00 | 0.0108 |
| Rt | 1.0% | 40.00 | 0.0001 |

- If the water were fresher, say $R_w = 0.2$ instead of 0.02, 'n' diminishes in importance as compared to both the amount of porosity & its connectivity ('m')
- There is a 'link' between the individual input parameters

After C. Chen and J. H. Fang. Sensitivity Analysis of the Parameters in Archie's Water Saturation Equation. The Log Analyst. Sept – Oct 1986



or realization that the dominate attribute can change from one interval to the next.

If the water were fresher, say $R_w = 0.2$ instead of 0.02, 'n' diminishes in importance as compared to both the amount of porosity, and its connectivity ('m'): **Figure 4**.

Key observations are:

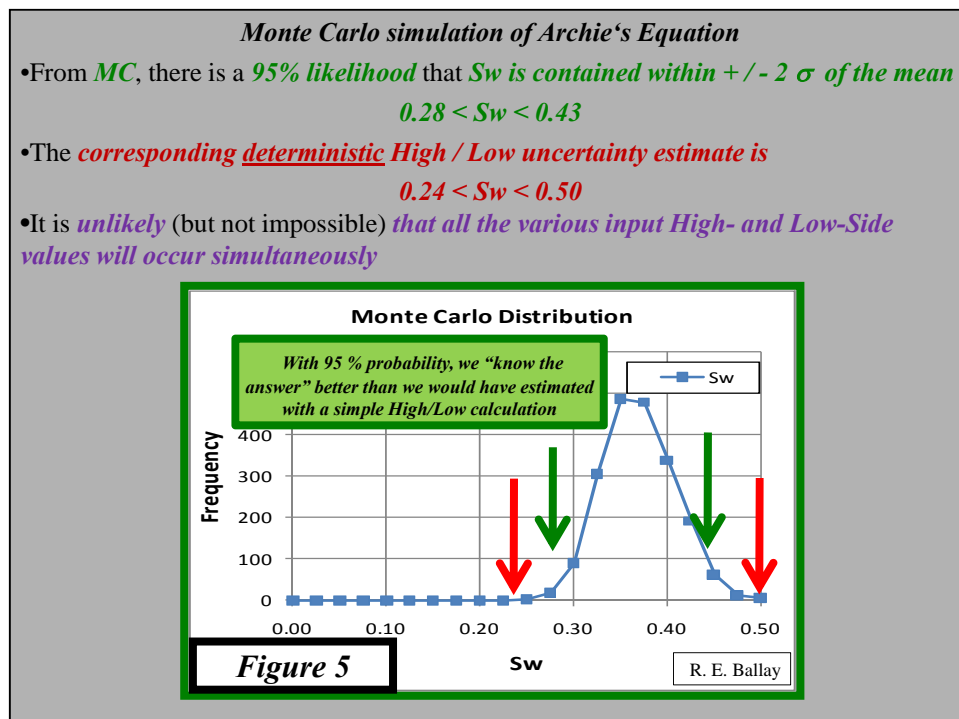
1) **the impact of uncertainty** (or variability) in “*m*” and/or “*n*” (as an example) **upon the ultimate *S_w* estimate is linked to the other, independent input parameters,**

2) an unfortunate bad experience with a previous evaluation may prompt one to focus time and budget on an inappropriate attribute in the next interpretation.

The issue can also be addressed with (an Excel-based) **Monte Carlo simulation**. **An attraction of Monte Carlo is that once the spreadsheet is understood and set up for a specific model, it is straight-forward to modify it for a completely different question** (core analyses, as one of many possible examples). Indeed, our *S_w*(Archie) spreadsheet originated as a reservoir volumetric exercise, kindly posted to the WWW by an unidentified LSU faculty.

Additionally, **non-Gaussian distributions**, which do indeed occur in the oilfield, **can be addressed** with Monte Carlo, and the visual uncertainty distribution output facilitates another dimension of understanding. Finally one **gains insight into the Up- and Down-side possibilities:** **Figure 5.**

With 95 % probability, the estimated value is better known than one would have thought from the simple max- and min-value calculations. This situation arises because it is unlikely (but not impossible) that the various minimum values will occur simultaneously, nor do we expect that all the maximum values will be found in a single instance.

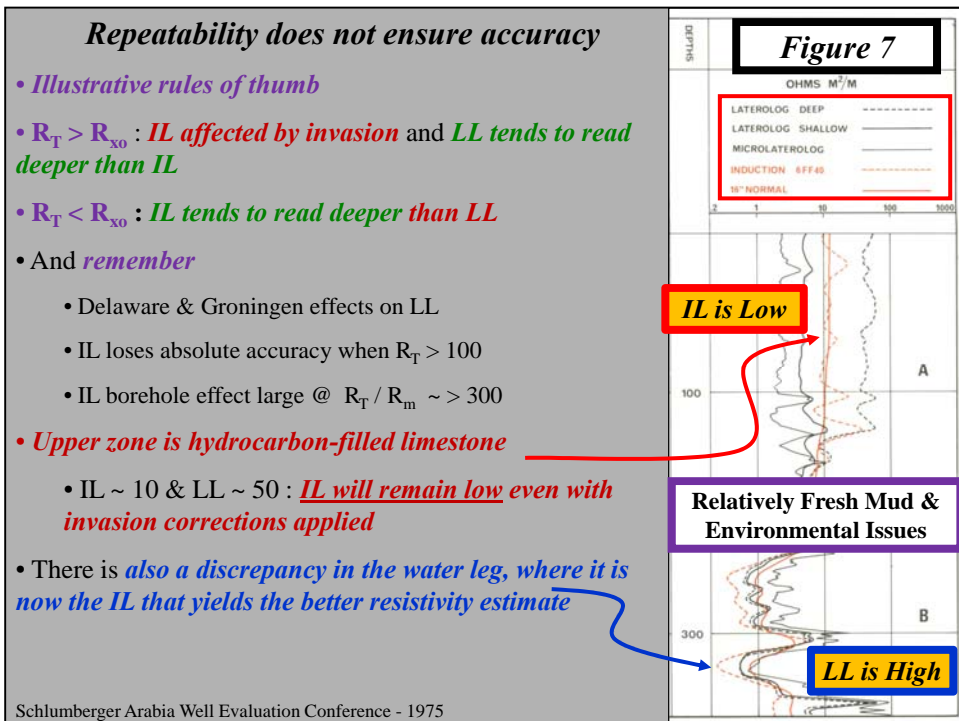
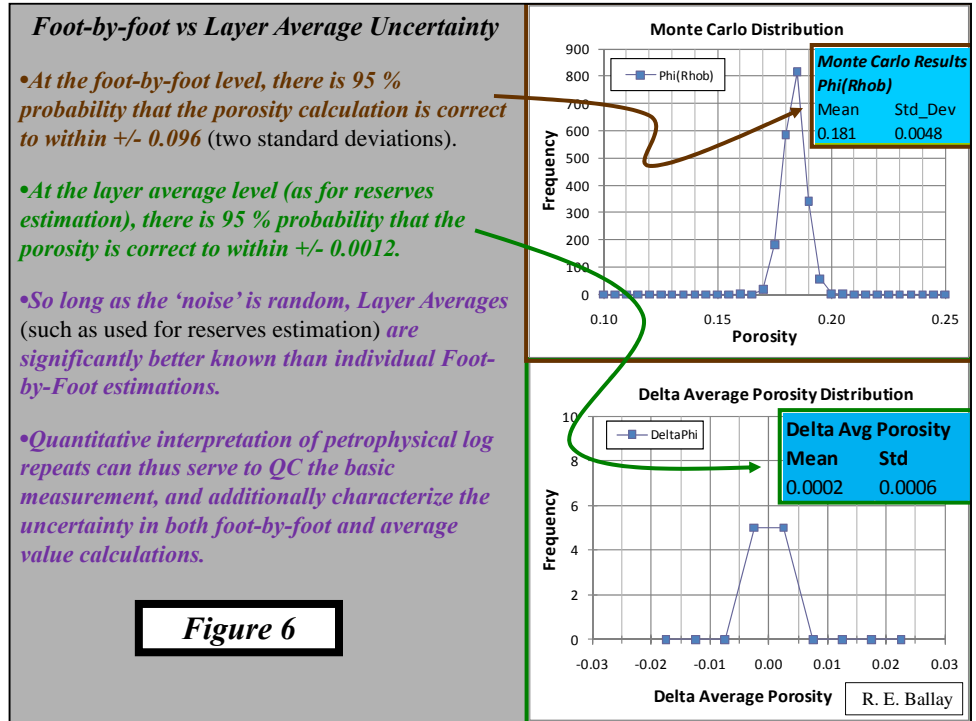


And there is yet **one more bit of good news**. While our attention is typically focused on the foot-by-foot estimates, reserve volumes (and the value of the Company) are usually based upon layer averages. **So long as the uncertainty is random, Layer Averages are more precise than are the individual foot-by-foot estimates: Figure 6.**

In this particular illustration, the statistics result from a physically realistic Monte Carlo simulation of Phi(Rhob).

In practice, one may perform the comparison based upon the actual log repeat data (Main vs Repeat Passes).

In summary, the **attraction of the differential approach** is that **a set of analytical equations result, which may be easily coded into a foot-by-foot evaluation, and then displayed alongside our best-estimate results.**



The attractions of Monte Carlo is insight into the up- and down-side, the easy transition from one simulation to another (once the spreadsheet is set up) and the visual display of the final estimate.

Regardless of which approach is being used to "focus" our efforts, we must remember that "repeatability does not necessarily ensure accuracy": Figure 7. As we look at this resistivity

comparison, let us ask ourselves how many times we have seen S_w calculated (and reported) to one saturation unit precision with no discussion (or test) of the basic measurement accuracy.

Finally, Carlos Torres-Verdin cautions “my experience shows that the **biasing of apparent resistivity curves due to post-processing** techniques (e.g. deconvolution) could be more detrimental to uncertainty than Archie's parameters. The most conspicuous case is the one of a thin, hydrocarbon-saturated bed, where bed thickness and invasion can give you much more uncertainty grief than Archie's parameters”.

Pre-conceived Notions

Experience and pre-conceived expectations go together, and while both are valuable we must also remember that Mother Nature may well have a surprise for us, at the next fork in the road.

As we all know, **molecular volumes are such that the transition from calcite to dolomite is expected to create about 12 pu of porosity but that does not mean that the dolostone will always have more porosity than the limestone:** **Figure 8.**

Based upon 50 years of data, Jerry Lucia found that **the porosity in dolostone can be less**

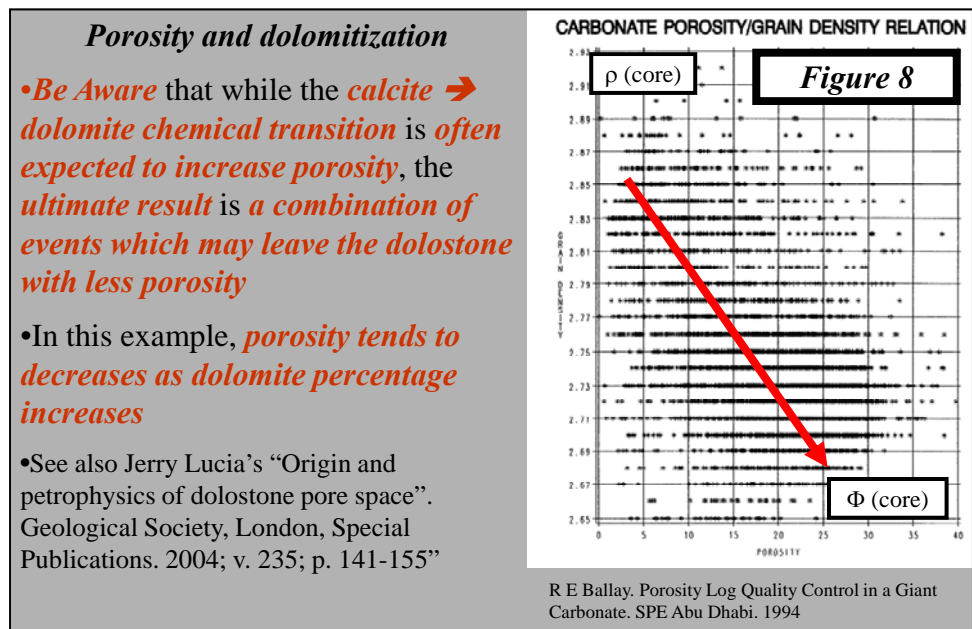
than that of limestone, even though the dolostone may be the better quality reservoir, with the lower pore volume being countered by

- dolomite crystallization resulted in a more efficient pore system,
- dolostone is less susceptible to compaction.

There are, then, counter-effects at play and one does not initially know if the limestone or dolostone will be the better quality.

There is a **second pre-conceived notion** which can lead to misinterpretations in the carbonate world: **the effect of vuggy porosity on the sonic log.**

Formation evaluation complications in the clastic world often center upon clay conductivity issues, whereas in the carbonate world the issue is many times the pore system / geometry.



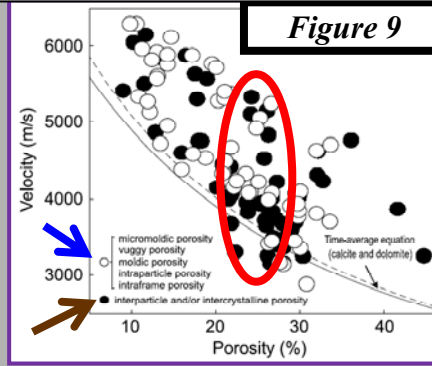
Identification of vuggy porosity

•The **vuggy group** consists of samples whose **primary pore types are vuggy, moldic, intraframe, and intraparticle porosity.**

•The **interparticle group** consists of samples with **interparticle and intercrystalline porosity as the primary pore type.**

•**Plotting the two groups in the velocity-porosity space reveals a considerable overlap. A nearly equal amount of samples from each group display an exceptionally high velocity at a given porosity.**

Quantification of pore structure and its effect on sonic velocity and permeability in carbonates. Ralf J. Weger, Gregor P. Eberli, Gregor T. Baechle, Jose L. Massafiero, and Yue-Feng Sun. AAPG Bulletin, v. 93, no. 10 (October 2009).



There is a long history of contrasting Phi(Density and/or Neutron) versus Phi(Acoustic) as a way to partition porosity into Interparticle and vuggy, but a recent detailed investigation by Weger et al (2009), which took into account the **digitally determined pore geometry, revealed that this “accepted” methodology is in fact**

highly dependent upon specific pore geometry: Figure 9.

Yes, there are indeed geometries for which the Phi(Dt) vs Phi(D-N) approach will suffice, but the situation is one of Caveat Emptor (Let The Buyer Beware), and needs to be verified on a case-by-case basis.

As another example of an issue for which the answer is “obvious”, let us consider Archie’s “m” exponent as a function of porosity. **Intuitively, it would seem that when the porosity becomes low, “m” would typically increase,** and indeed this kind of trend can be found in some of the older Service Company chart books.

Yet with an inquiring mind and the magic of Google Search, we quickly realize:

- 1) **there are a number of situations in which “m” actually decreases as porosity drops,**
- 2) the Chart Book trend can be traced (Focke and Munn) to what was intended to be a specific (not general) reservoir: **Figure 10.**

Archie’s “m” in low porosity

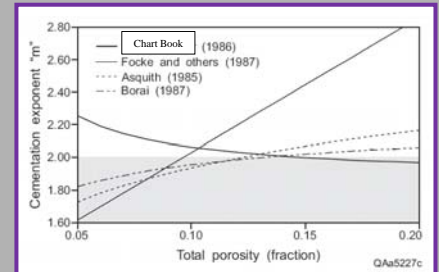
•**Pore geometries control** the interrelationship of **petrophysical properties.**

•The three most important pore-geometry characteristics are

- amount and **types of pores or shape**
- interconnectedness** of pores (tortuosity)
- size of interconnecting **pore throats**

Figure 10

Three of four data sets have ‘m’ decreasing as Phi (Total) decreases



Petrophysical Characterization of Permian Shallow-Water Dolostone. M H Holtz, R. P. Major. SPE 75214, 2002 http://www.beg.utexas.edu/mainweb/presentations/2002_presentations/holtz_spe0402ab.pdf

See also

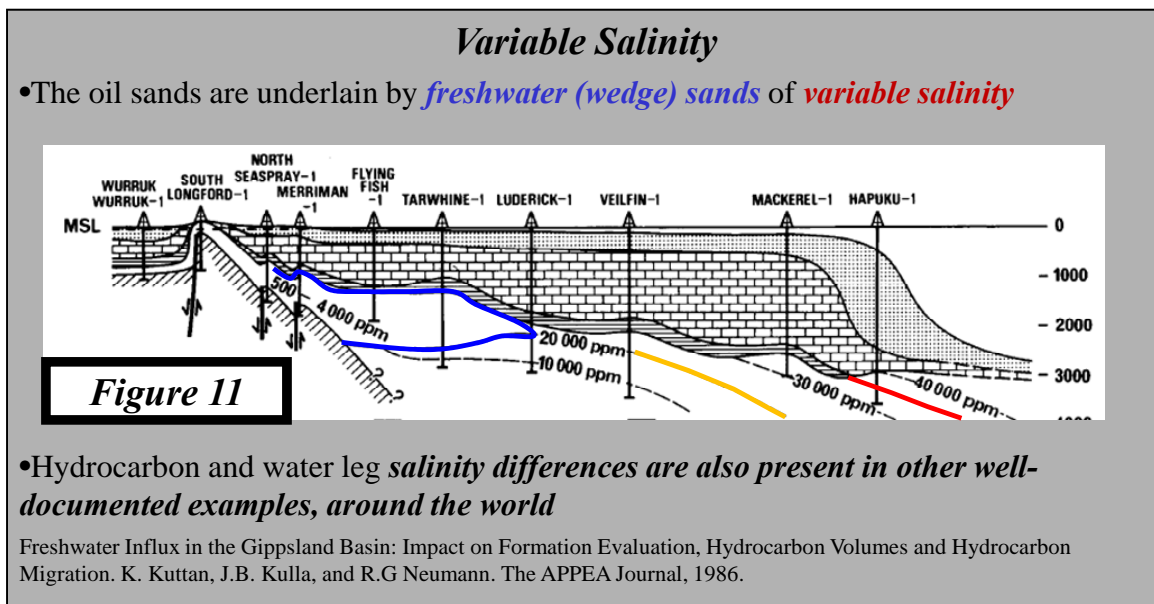
- Focke, J. W. and D. Munn. Cementation Exponents in Middle Eastern Carbonate Reservoirs. SPE 1987.
- Wang, Fred P. and F. Jerry Lucia Comparison of Empirical Models for Calculating the Vuggy Porosity and Cementation Exponent of Carbonates from Log Responses. Bureau of Economic Geology, University of Texas. 1993.
- Verwer, Klaas and Gregor P. Eberli, Ralf J. Weger. Effect of pore structure on electrical resistivity in carbonates. AAPG Bulletin, v. 95, no. 2. Feb 2011.

A fundamental issue is the geometry of the pore system, and the fact that a small amount of “electrically efficient” pores remaining present even as the total porosity decreases, can come to dominate the “net cementation exponent”.

Wang and Lucia (1993) documented early concern about using $\Phi(Dt)$ vs $\Phi(D-N)$ for identification of vuggy porosity, and also put forward a numerical Dual Porosity Cementation Exponent Model which nicely illustrates how this counter-intuitive “m” vs Φ behavior (“m” decreases as Φ decreases) can occur.

And **one final example, the “assumption” that the salinity of the brine in the water leg is the same as that in the hydrocarbon column: Figure 11.**

While this would at first glance appear to be “obvious”, it is in fact **not unusual to find exceptions**. Kuttan et al (1986) illustrate how to recognize the problem and then identify the following provinces in which it occurs: Mahakam Delta (Indonesia), Niger Delta (Nigeria), Lake Maracaibo (Venezuela) plus several Australian basins (Eromanga, Surat, Canning, Bonaparte). The author encountered this very situation in Central Saudi Arabia.



Clinch et al (2011) caution **“The assumption that water properties in the water leg are the same as those in the hydrocarbon leg needs to be proved, not assumed”**.

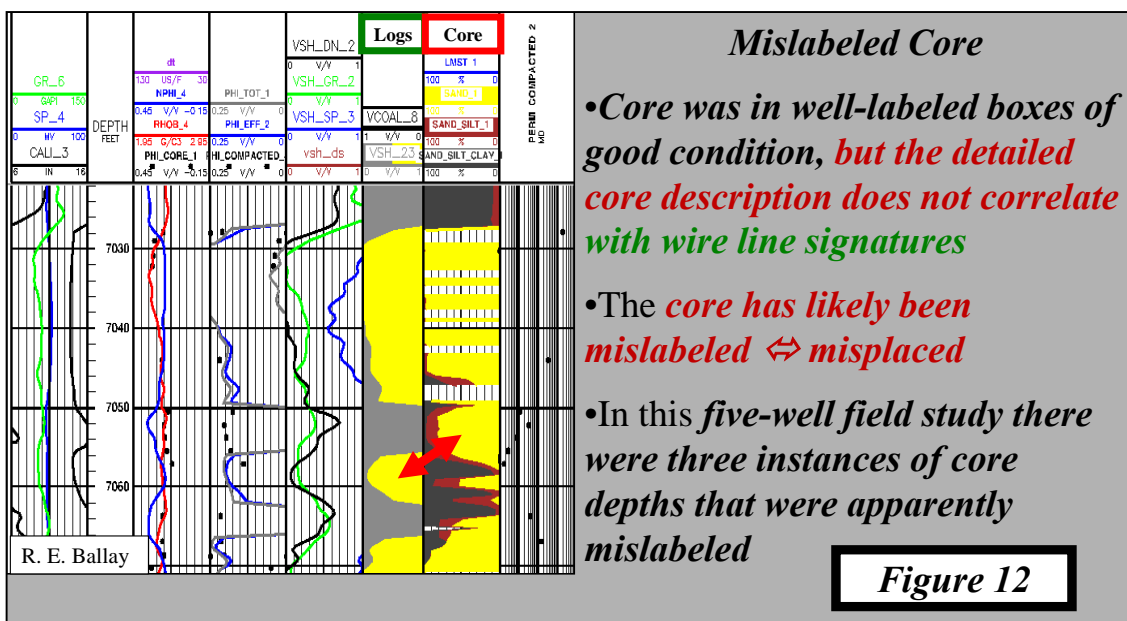
Experience, and expectations based upon that experience, are invaluable but never forget that each new evaluation can be a learning experience.

Core Data

Core data provides a valuable reference against which to compare our log-based calculations. And ***just as the individual log measurements must be placed on depth with one another, so too must the core be adjusted to the logs.***

In shaly sands, with significant GR variations, the Core Gamma Ray can facilitate an improved depth match. In carbonate reservoirs, which may exhibit a relatively suppressed GR signature, CT Scans that yield a pseudo bulk density can contribute.

In many cases, however, we will find ourselves with core information and neither a Core GR or Core CT for comparison. In such an event, ***even with well-labeled core boxes in good condition, we should bear in mind the potential for mislabeled boxes: Figure 12.***



Selection of the core depths to be sampled is an example of an important issue that seldom gets the attention it deserves. Although we will work with whatever results are available, if the opportunity arises ***the question of sample selection deserves careful attention*** and Pat Corbett (1992, 2001 and others) has several relevant articles on the subject (see references). And if conventional core is not an option, Rotary Sidewalls will be sufficient for some basic measurements.

The most common core porosity measurement is based upon Boyle's Law ($P_1V_1 = P_2V_2$), and inherently includes everything needed to calculate the corresponding grain density. Yet, in the busy office environment we have observed, over and over, that ***while the core porosity value is usually compared to log estimates, little attention is given to the core grain density.*** Indeed, in many cases the grain density is not even loaded / displayed with the log calculations.

The core porosity and core grain density measurements are linked. If one is in error, the other is also likely in error, and so **in an environment for which the lowest expected grain density is known** (be it 2.65 gm/cc or 2.71 gm/cc or something else), **the measured core grain density provides QC on the core porosity measurement: Figure 13.**

Most problems with the Boyle's Law porosity measurement are such that the grain density will be low: incomplete cleaning / drying especially with heavy oil and residual salt crystals inside the plug (in saline brine environments) are two examples.

About 50 % of the Field Studies we have done, even with modern data, exhibit this problem and it was not originally

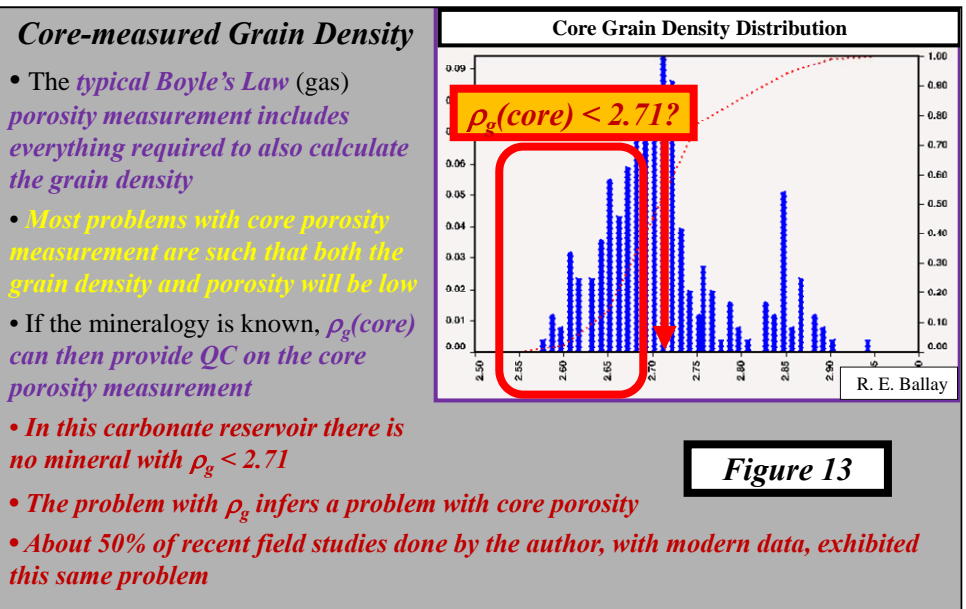
recognized because the core grain density did not receive sufficient consideration (*Eyes Wide Shut*). Nor did the core analyses vendor comment on the problem, when the data was issued (*Did they even notice it? They too, are pressed for time.*).

It is worth mentioning that "unconnected" vug porosity could also lead to unrealistically low core grain density, and so that possibility needs to be eliminated before inquiring with the core vendor (examine the plugs, as a starting point). In nearly every case, our geological partner was able to provide guidance on this question (it was very seldom an issue). It is also possible to simply disaggregate the sample and re-measure the grain density and address the question in that manner.

Not only does the core grain density provide a QC on the core porosity measurement, but it should be further compared to the log-based mineralogy (by weighted volumes). **Comparing Phi(Core) against Phi(Log) is only half the question; we should also compare Rhog(Core) against Rhog(Log).**

If the budget allows, we would like to move beyond the routine grain density, porosity and permeability: Capillary Pressure. Vavra et al (1992) provide a nice over-view of this measurement, which can be done by three different methods (Porous Plate, Centrifuge, Mercury Injection).

Mercury injection is the most common method, and comes to us from Bob Purcell (1949). The NMR enthusiasts amongst us will recognize the name Purcell as the "P" in CPMG sequence: yes the brother of the man who gave us mercury injection, won a Nobel Prize for his NMR work.

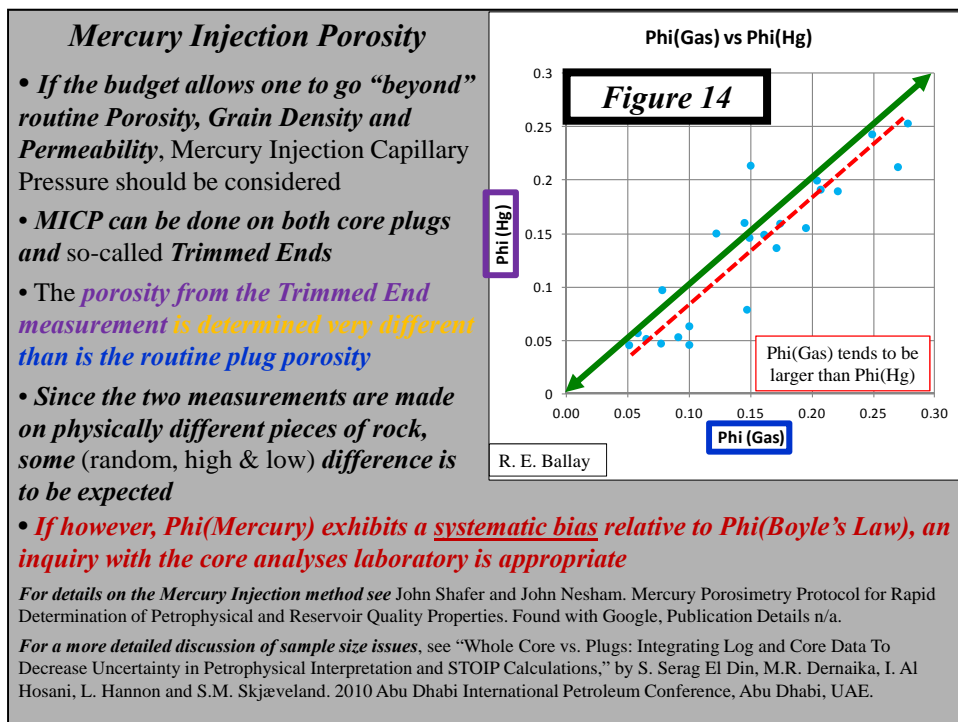


At the simplest level, Mercury Injection provides us with a Saturation – Height reference and a pore throat size distribution, and here again is an example of how the busy office environment can cause us to over-look yet more applications. For Brown and Husseini (1977), and many others since, demonstrate that these measurements can also be used to construct locally specific permeability transforms that can be surprisingly robust (even as compared to modern NMR transforms).

MICP can be done on both core plugs and the so-called Trimmed End from a plug. Both methods yield mercury saturation, **but the porosity upon which the reported saturation is based, is determined very differently.**

In the case of high pressure MICP on Trimmed Ends, the reference porosity may very well be the volume of mercury injected into the pore system at some very high pressure (~55,000 psi), with the inherent assumption that the sample bulk volume was accurately determined prior to pore penetration, and that all the pore volume was filled with mercury at the high pressure limit.

In many cases the available data will also include a gas porosity on the corresponding plug, and due diligence requires that the two be compared. Rock heterogeneity will result in an unavoidable scatter, and so some noise is expected. **A systematic shift (or bias) in the two porosities** though, relative to the 45 degree line, **deserves an inquiry with the core analyses vendor: Figure 14.**



In our experience, different labs have different policies, but one should at least inquire.

While it is the Pressure and Injected Volume (of Hg) that are actually measured, the core analyses lab will often also report a corresponding Pore Throat Radii, and here we again have a QC check, for the mathematical transform [typically $r_c(\text{microns}) = 107.7 \text{ um} / P_c (\text{psi})$] infers a constant relative value of r_c and P_c .

Different people may use slightly different parameters (and hence the constant can be slightly different, one data set to the next), but for a single data set we do expect a “constant” value: Figure 15.

In this illustration, the product of the two numbers, as delivered by the core analyses

vendor, is not constant. **Something has gone wrong, and this must be addressed, before the data can be used.**

If we the geoscientists sometimes find ourselves near over-whelmed with tight deadlines, then it is no surprise that service company personnel are in a similar position. Amabeoku et al (2011) sent samples to four different labs and compared both Conventional and SCAL results, to find the following.

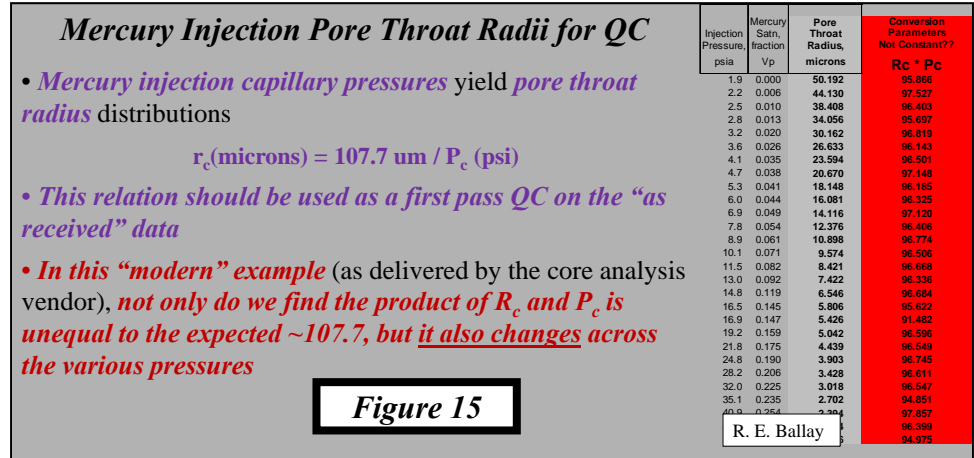
- **Some labs do not have QC protocols in-house** and just report data acquired
 - There seems to be little supervision over technicians who acquire the data
 - Standard lab templates facilitate reporting, but there are no QC checks for the validity of the underlying data

Additional useful core analyses references include (but are not limited to)

- *Recommended Practices for Core Analysis*, Second Edition. February 1998 by American Petroleum Institute,
- *Some practical Lessons Learned During 30 Years in the SCAL Lab*. Ted Braun, SCA International Symposium, September, 2011.

“Simple” Models

Quick-look, or Simple, evaluations serve a number of useful purposes. Firstly, for those in an operations environment, they provide a fast, integrated evaluation of the recently acquired data. That is, while for example the porosity and resistivity logs appear to be valid individually, one must also ensure that the integrated result is reasonable, and we furthermore need first-pass reservoir attributes for delivery to Management.



Later in time, the QL results continue to serve a purpose as a reference against which to compare the more sophisticated, final interpretation. As an example application, probabilistic evaluations of LWD data (with generally larger light hydrocarbon effects) can be vastly superior to deterministic options, in a number of ways, but care (with local experience) must be exercised in setting up the probabilistic Model. In the past ***we have identified faulty (improperly specified) probabilistic results by comparison to QL results.***

Failure to execute QL interpretations, and to compare those results against the final, sophisticated evaluation, can result in one working with their Eyes Wide Shut.

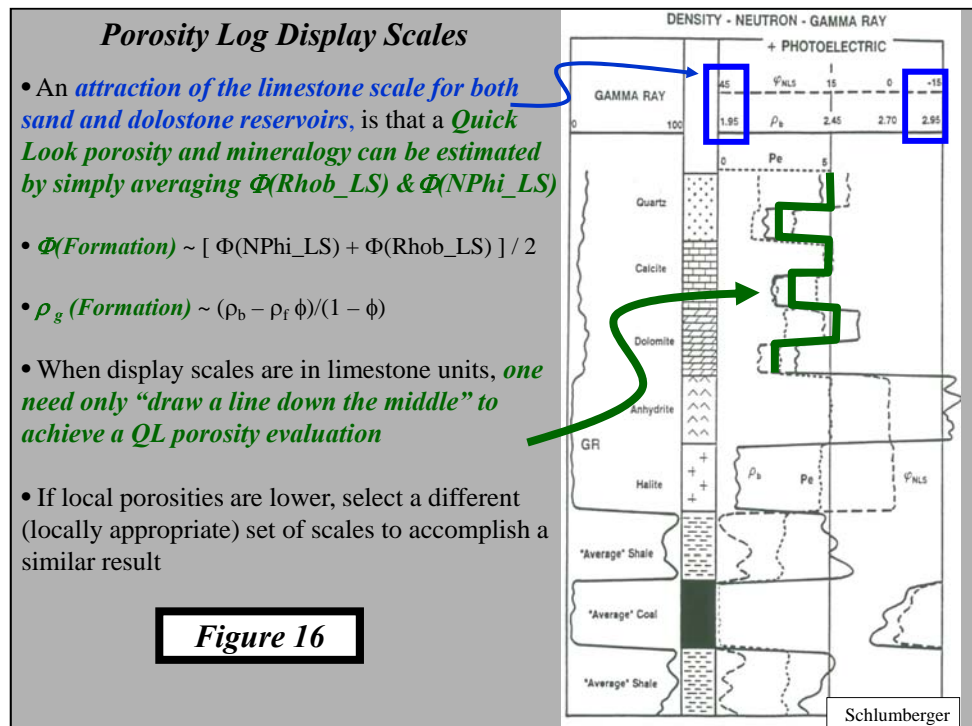
The choice of display scale for the porosity logs is an important issue. Because the environmental corrections for the neutron log typically require limestone units for input, there is merit in having the neutron porosities delivered in LS units even if the reservoir is clastic. And the attraction of working in LS units actually goes well beyond this.

If the bulk density measurement (in gm/cc) is converted to equivalent limestone porosity, the simple arithmetic average of Phi(Neutron/LS) and Phi(Rhob/LS) is often a reasonable porosity estimate in both sandstone and dolostone (and of course limestone): Figure 16.

If one then chooses the display scales appropriately, a reasonable Phi(QL) display can deduced by simply drawing a line down the middle of Phi(Neutron/LS) and Phi(Rhob/LS).

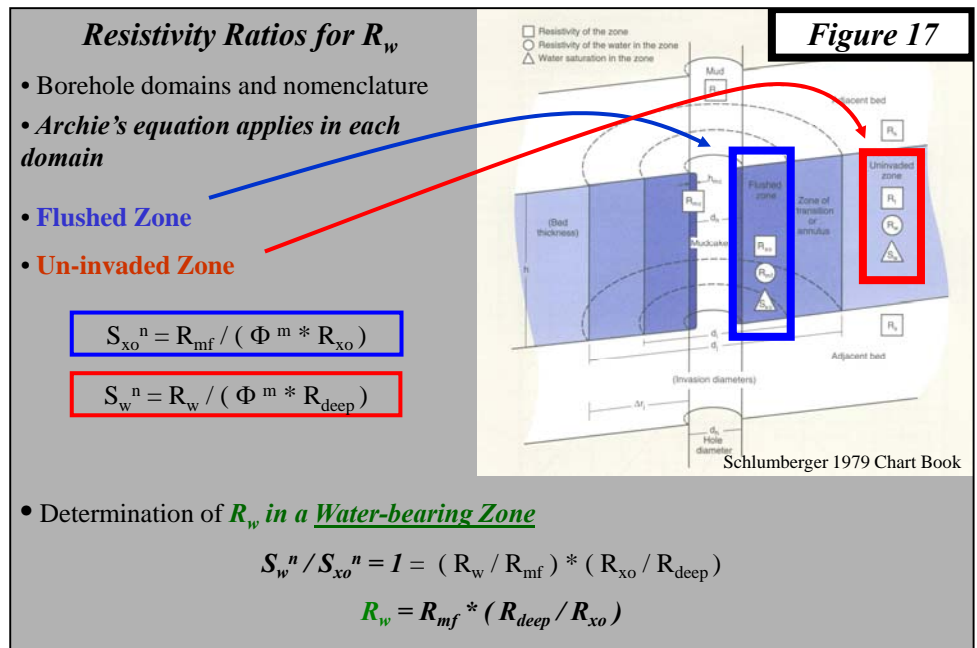
If we further display the final (sophisticated) porosity interpretation along with the properly scaled raw data on the appropriate scale (as in Fig. 16), we then expect that 'final' porosity value to roughly 'go down the middle of the basic raw measurements'. Deviations are expected in shaly and gas intervals, but if observed in clean oil- and/or water-filled rock, should be investigated.

The accuracy of this short-cut varies from one Rhob-NPhi tool combination to the next, and can (should) be tested for a specific situation by cross-plotting Phi(QL) (ie the simple average) against Phi(Final) (the sophisticated estimate) across the non-shaly, non-gas intervals of an



accepted interpretation. Once validated locally, we have a quick and useful reference against which to quickly compare Phi(Best Estimate).

The resistivity measurements are also amenable to quick look interpretations. **Applying Archie to both the Flushed and Unflushed domains, and then taking the ratio of those two equations in the water leg, yields the apparent formation water resistivity as a function of R_{deep} / R_{xo} : Figure 17.**



This simple equation may be coded into the flow chart that we follow in setting up the digital database. That is, **following trace depth-shifting and splicing, execute this algorithm to provide an estimate of R_w well-by-well, thereby jump-starting the interpretation** (we have a reasonable idea of R_w just as soon as the basic data has been assimilated).

If the calculation is performed in the hydrocarbon column, an artificially high R_{wa} will result, and we eliminate this by scaling the display appropriately and disallowing trace display wrap-around.

In general, even in a new area, we will have some idea of the brine salinity: fresh, moderate, salty. When combined with the formation temperature this gives an R_w estimate, and **the display scales are chosen so that only the expected range of R_w values are actually displayed** (the hydrocarbon column wrapping around, without display).

If additional data, such as the SP and/or brine samples, are available then that information should be factored into the analyses.

In working with resistivity ratios, we must bear in mind that one is essentially assuming a step invasion profile. Mother Nature is not always so kind, and if for example R_{xo} is seeing mostly R_{mf} but some R_w , then the assumptions will begin to break down, more or less. See, for example, Good News and Bad News (Ballay 2009) and Invasion Revisited (Allen et al 1991).

Resistivity Ratios for S_w

Figure 18

$$S_w^n = R_w / (\Phi^m * R_{deep})$$

$$S_{x0}^n = R_{mf} / (\Phi^m * R_{x0})$$

Divide (Ratio)

$$S_w^n / S_{x0}^n = (R_w / R_{mf}) * (R_{x0} / R_{deep})$$

Assume

$n = 2$ and $S_{x0} = S_w^{1/5}$

then

$$S_w^2 / S_{x0}^2 = [S_w / S_w^{1/5}]^2 = [S_w^{4/5}]^2 \rightarrow S_w^{8/5} = (R_w / R_{mf}) * (R_{x0} / R_{deep})$$

The resistivity ratio concept also has application in the hydrocarbon column: Figure 18. Now we make two additional (first pass, adjust as appropriate) assumptions: “n” = 2 and $S_{x0} = S_w^{1/5}$. The S_{x0} vs S_w assumption in particular might appear to be shaky, but is in fact fairly robust and in use

worldwide. And with experience in a specific locale, one may fine-tune this exponent.

As was the case with the $R_w(Q_L)$ calculation discussed above, we must bear in mind the assumption of a step profile for invasion.

The utility of the $S_w(Q_L)$ calculation becomes apparent when (as one of several possible examples) one is faced with a variable “m” exponent, such as in a vuggy carbonate: Figure 19.

In this illustration, water saturation is calculated from Archie with “m” taken as 2.0, and also from the resistivity ratio. In those intervals for which similar saturations result, there is confidence. But should the ratio water saturation be greater than $S_w(Archie)$, there is cause for concern (have we used the appropriate “m”?).

And if the Bulk Volume Water is also high, that concern heightens.

In this particular case the author has petrography which reveals that the pore system across the questioned interval is in fact oomoldic. The resistivity increase, which $S_w(“m”=2)$ interprets as hydrocarbon, is in fact the result of a tortuous pore system, and not the presence of hydrocarbons. It is the resistivity ratio saturation that raises the Red Flag.

Evaluation of Vuggy Interval

Figure 19

| Depth (ft) | ϕ | R_t | R_{x0} | S_{wa} | S_w/S_{x0} | S_{wr} | BVW |
|------------|--------|-------|----------|----------|--------------|----------|-------|
| 4,810 (ft) | 0.25 | 3.5 | 12 | 38% | 0.61 | 53% | 0.095 |
| 4,900 (ft) | 0.15 | 9 | 25 | 40% | 0.54 | 47% | 0.060 |
| 4,920 (ft) | 0.11 | 19 | 32 | 37% | 0.42 | 34% | 0.041 |

Illustrative Application: Improved Evaluation of Vuggy Rock

Where:
 $R_w = 0.032$
 $R_{mf} = 0.30$
 S_{wa} = Archie water saturation
 S_{wr} = Ratio water saturation

From Density-Neutron.

- The zone at 4810' has good porosity and low Archie S_w : is it pay??
- But the Resistivity Ratio S_w is high (53% vs 38%): a Red Flag !
- This suggests that the zone may be wet.

From petrography

| Depth (ft) | ϕ | R_t | R_{x0} | S_{wa} | S_w/S_{x0} | S_{wr} | BVW |
|-----------------------|--------|-------|----------|----------|--------------|----------|-------|
| 4,810 (ft) (oomoldic) | 0.25 | 3.5 | 12 | 38% | 0.61 | 53% | 0.095 |

Author, date and publication n/a. Found with Google Search. Chapter V: Combining Water Saturation by Ratio Method, Moveable Hydrocarbon Index, Bulk Volume Water and Archie Water Saturation.

There are a number of **on-line resources to which one may refer for these, and additional, concepts.**

Ross Crain's On-line Tutorial: www.spec2000.net/index.

Kansas Geological Survey Tutorial: www.kgs.ku.edu/Gemini.

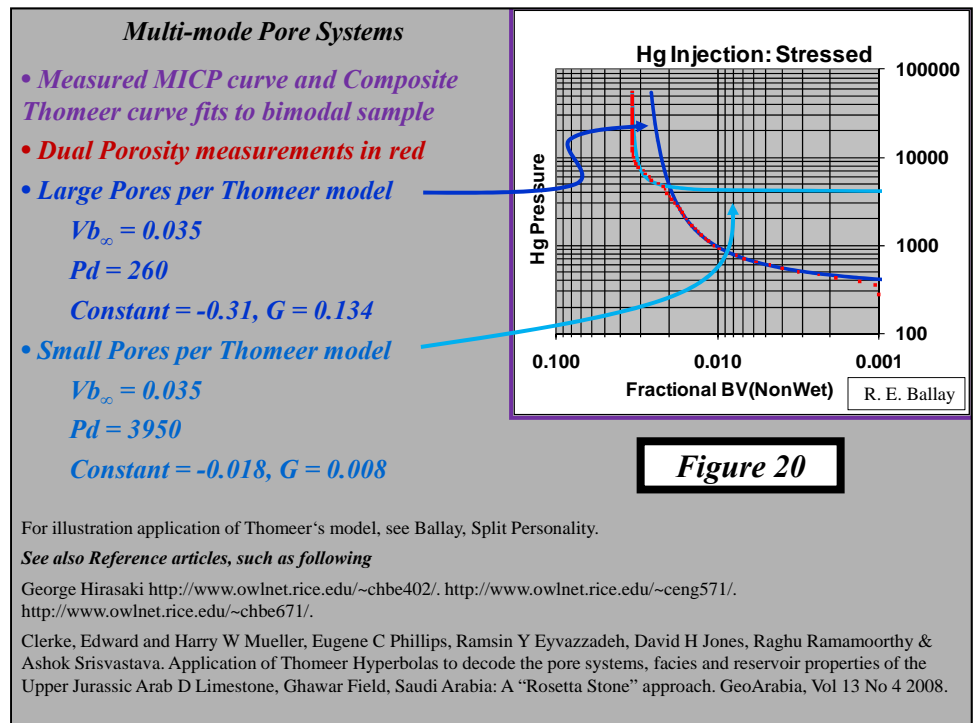
Baker Hughes Tutorial: www.bakerhughesdirect.com/.

For locale specific over-views and suggestions, we have found Schlumberger's Oil Field Review and Middle East & Asia Well Review to be very useful: www.slb.com/.

Multi-mode Pore Systems

In the Real Estate world, it's all about "location, location, and location". **In the Carbonate Petrophysics world, it is often about "the pore system, the pore system, and the pore system".**

Failure to recognize variations in the pore system can cause us to work with our Eyes Wide Shut. And **it may be mercury injection capillary pressure data that raises the Red Flag for the Pore System: Figure 20.**



Although the **Thomeer formulation** is not commonly used outside Shell (where Thomeer worked), it **provides a convenient and physically meaningful representation of multi-mode pore systems** (Ballay, Split Personality and Hirasaki & Clerke articles in the References, for illustrative discussions).

Hyperbolic models (such as Thomeer) **appear in a variety petrophysical discussions, with a common historical application being Bulk Volume Water: BVW = Phi * Sw.** Above the transition zone, BVW takes on a relatively constant value for a specific rock quality, and rock of a specific category (BVW) can be often be safely (with minimal risk of producing water) perforated in the presence of high Sw, so long it falls along the appropriate BVW trend.

Although the BVW graphic is often referred to as a Buckles Plot, Archie utilized this concept at least as far back as 1952 (well before Buckles' paper, but it was Buckles who nicely documented the methodology with illustrative examples) and it is one application of today's modern NMR measurements.

The **Thomeer model of capillary pressure is a hyperbolic relation between Mercury Injection Pressure (Pc) and Bulk Volume (Vb) Occupied** (by the non-wetting mercury), expressed as follows.

$$[\text{Log}(V_b / V_{b\infty})] [\text{Log}(P_c / P_d)] = \text{Constant}$$

- $V_{b\infty}$ is the **fractional bulk volume occupied by mercury extrapolated to infinite mercury pressure**: the vertical asymptote.
- P_d is the **extrapolated mercury displacement pressure** in psi: the pressure required to enter the largest pore throat: the horizontal asymptote.
- **Constant** is the **pore geometry factor**, the distribution of pore throats and their associated volumes: the curvature of the relation.

A multi-mode pore system, which can be recognized with mercury injection data, may affect both Archie's "m" and "n".

If the two porosity components form a parallel circuit, Wang and Lucia (1993) deduce what they refer to as Type 1 and Type 2 Cementation Exponent models that may be used to estimate the implications on S_w . And while the parallel circuit assumption can be questioned (is Mother Nature ever really this simple?), it is a common approach (Waxman-Smiths shaly sand model, for example, and there are others): **Figure 21.**

Dual Porosity Cementation Exponent Model

- **Type 1 dual porosity** (parallel circuit) **"m" model**

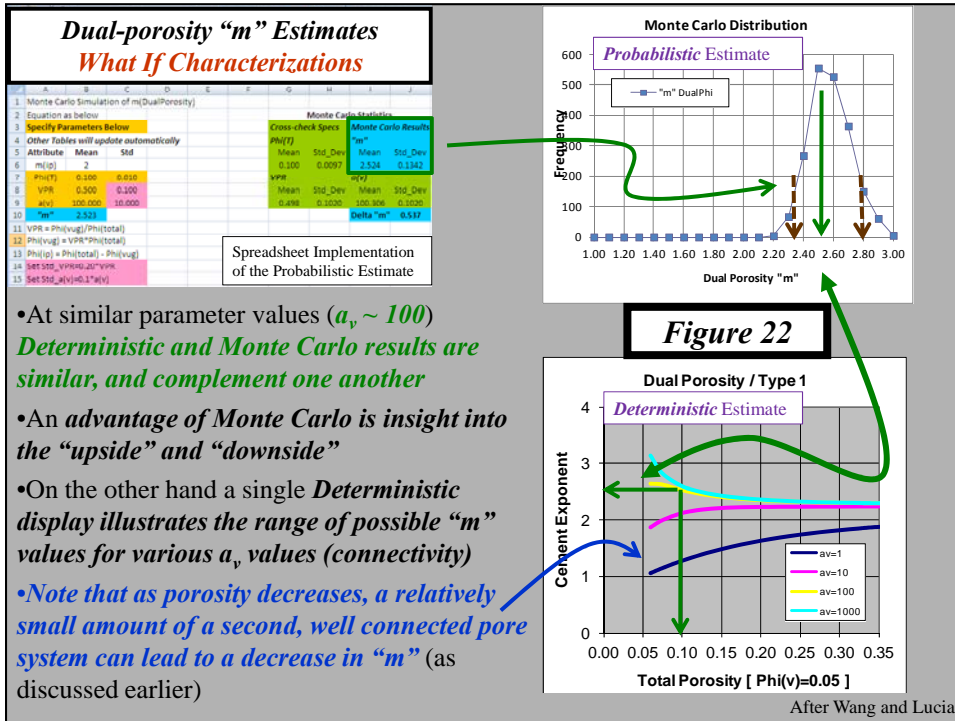
$$m = \frac{\log \left(\phi_{ip}^{m_{ip}} + \frac{\phi_v}{a_v} \right)}{\log \phi_t}$$

- a_v is related to the efficiency of vuggy porosity current paths
 - the connectivity between vugs and interparticle pores
 - the connectivity between various types of touching vugs
- a_v varies from

Figure 21

 - **unity** for reservoirs with **well connected planar fractures**
 - to **infinity** for reservoirs with **isolated vugs**

Wang, Fred P. and Jerry Lucia. Comparison of Empirical Models for Calculating the Vuggy Porosity and Cementation Exponent of Carbonates from Log Responses Bureau of Economic Geology, UT. 1993.



In Wang & Lucia's model, *it is the a_v parameter that represents the connectivity, or lack thereof, of the two pore systems.* In practice, *one will seldom have an exact value for this attribute, and so "What If" (both deterministic and probabilistic: Ballay, Risky Business and Rolling The Dice) calculations are often*

used to bound the range of possibilities: Figure 22.

From the preceding we realize that *the 'composite' "m" will be a function of the porosity partition.* As an example, *consider a system of small and large pores, each of which have an individual "m" of 2.0* (Focke and Munn for detailed investigation of "m").

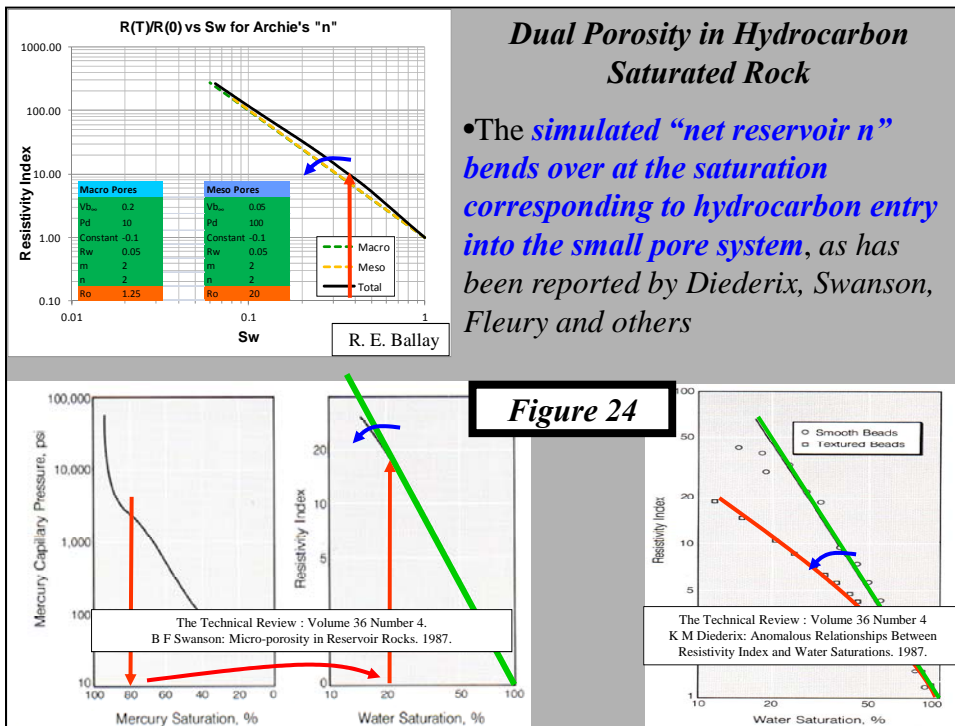
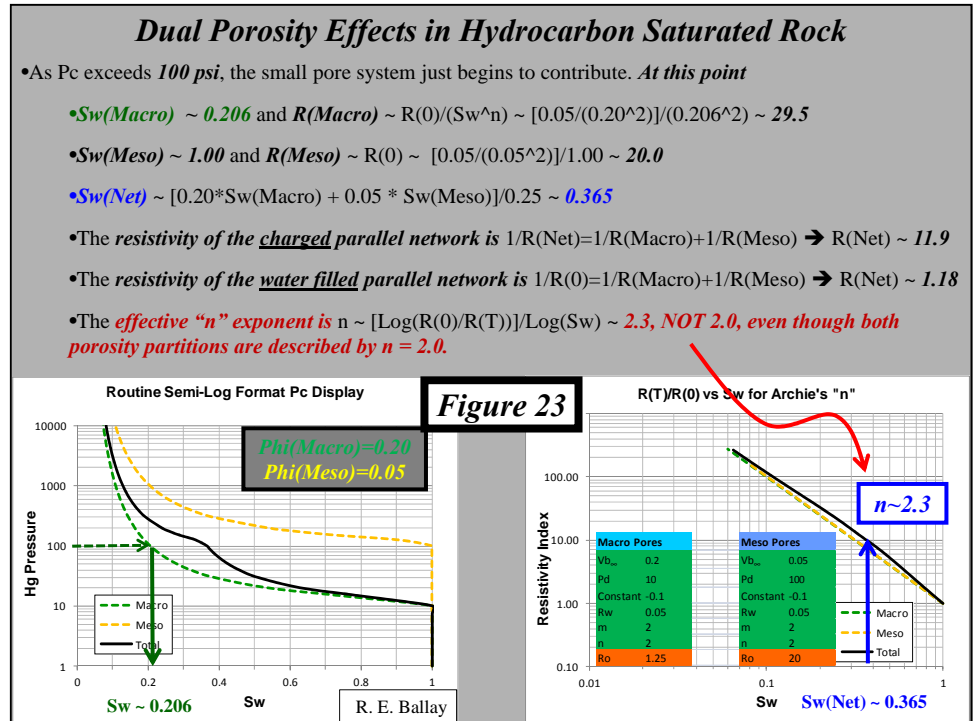
Even though both the Micro & Meso pore systems each have "m" = 2, the composite "m" may differ from 2.0.

| Phi(Micro) | Phi(Meso) | "m" |
|------------|-----------|-------------|
| 0.25 | 0.00 | 2.00 |
| 0.20 | 0.05 | 2.28 |
| 0.15 | 0.10 | 2.47 |
| 0.10 | 0.15 | 2.47 |
| 0.05 | 0.20 | 2.28 |
| 0.00 | 0.25 | 2.00 |

And *because the two different size pore systems de-saturate according to different Pc curves* (as can be nicely envisioned via the Thomeer Pc model), *the porosity partition effects may not be limited to the "m" exponent.*

Maintaining the Dual Porosity concept (as put forward by Wang and Lucia for “m”), it is straight-forward to set up the Thomeer representation of any (locally specific) dual porosity Pc curve, and to then calculate the corresponding net “n” exponent as that (locally) specific porosity partition is de-saturated.

Because the two populations desaturate differently, the net “n” exponent can be non-linear even when each individual partition has an “n” of 2.0: Figure 23.



Once again, we all realize that the reservoir is typically not a simple parallel network (or series for that matter), but this mathematical approach is indeed relatively common in both the clastic and carbonate world, and **the resulting predicted “n” behavior has been reported in independent laboratory studies (Diederix, Swanson): Figure 24.**

Dual Porosity Effects in Hydrocarbon Saturated Rock

•As Pc exceeds 100 psi, the small pore system just begins to contribute. *At this point*

• $Sw(Macro) \sim 0.206$ and $R(Macro) \sim R(0)/(Sw^n) \sim [0.05/(0.125^2)]/(0.206^2) \sim 75.4$

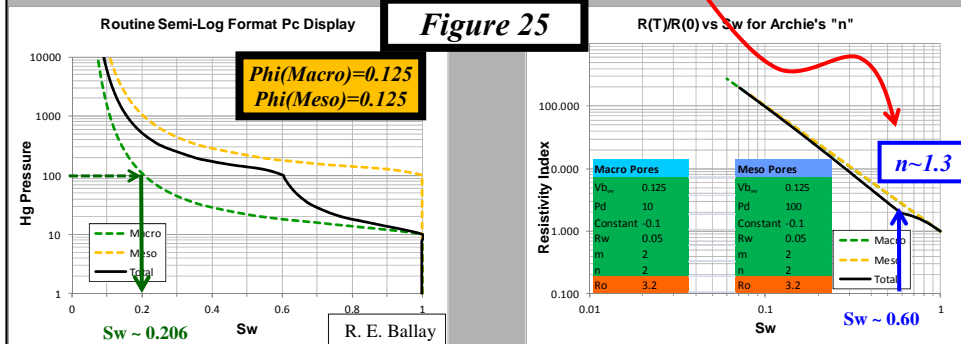
• $Sw(Meso) \sim 1.00$ and $R(Meso) \sim R(0) \sim [0.05/(0.125^2)]/1.00 \sim 3.2$

• $Sw(Net) \sim [0.125*Sw(Macro) + 0.125 * Sw(Meso)]/0.25 \sim 0.60$

•The resistivity of the charged parallel network is $1/R(Net)=1/R(Macro)+1/R(Meso) \rightarrow R(Net) \sim 3.1$

•The resistivity of the water filled parallel network is $1/R(0)=1/R(Macro)+1/R(Meso) \rightarrow R(Net) \sim 1.6$

•The effective "n" exponent is $n \sim [Log(R(0)/R(T))]/Log(Sw) \sim 1.3$, **NOT 2.0**, even though both porosity partitions are described by $n = 2.0$.



As the relative portion of the two (large and small, each with "m" = 2.0 and "n" = 2.0) porosity partitions is varied, we further find that not only can "n" bend downwards, it can also bend upwards: Figures 25 and 26.

Dual Porosity Effects in Hydrocarbon Saturated Rock

•As Pc exceeds 100 psi, the small pore system just begins to contribute. *At this point*

• $Sw(Macro) \sim 0.206$ and $R(Macro) \sim R(0)/(Sw^n) \sim [0.05/(0.05^2)]/(0.206^2) \sim 471$.

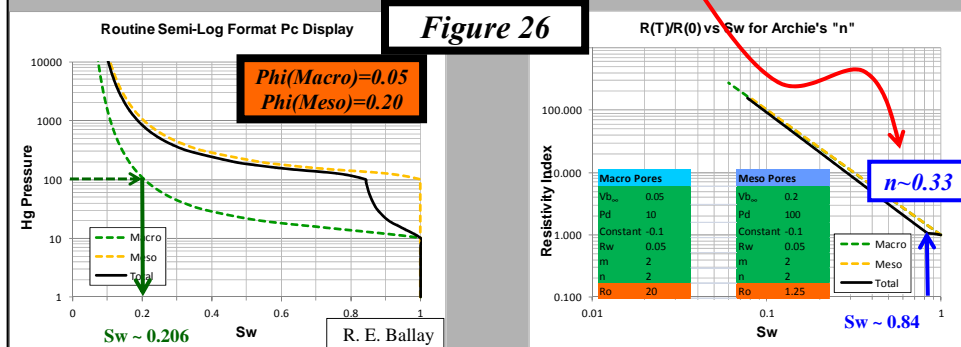
• $Sw(Meso) \sim 1.00$ and $R(Meso) \sim R(0) \sim [0.05/(0.20^2)]/1.00 \sim 1.25$

• $Sw(Net) \sim [0.05*Sw(Macro) + 0.20 * Sw(Meso)]/0.25 \sim 0.84$

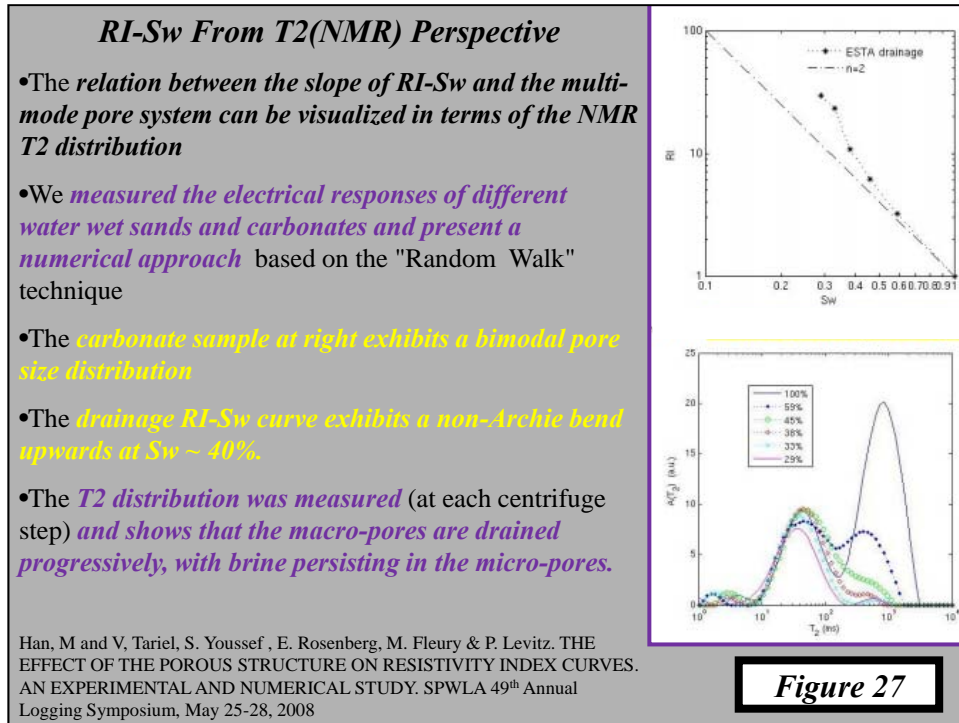
•The resistivity of the charged parallel network is $1/R(Net)=1/R(Macro)+1/R(Meso) \rightarrow R(Net) \sim 1.25$

•The resistivity of the water filled parallel network is $1/R(0)=1/R(Macro)+1/R(Meso) \rightarrow R(Net) \sim 1.18$

•The effective "n" exponent is $n \sim [Log(R(0)/R(T))]/Log(Sw) \sim 0.33$, **NOT 2.0**, even though both porosity partitions are described by $n = 2.0$.



Since there is *often a relation between pore throat radii (P_d) and pore body size (NMR)*, one would *expect that NMR T2 distributions might offer an alternative illustration of the issue, and that is indeed the case: Figure 27.*



The morphology of the pore system thus represents another dimension, beyond simply the magnitude of the porosity.

A dual porosity system (large and small pores) wherein “m” and “n” are both 2.0, for both individual pore systems, can display a surprisingly large range of net “m” and “n” values.

Mercury injection capillary pressure data* can be the measurement which ***Opens Our Eyes to this phenomenon.**

The Transition Zone and Low Resistivity Pay

In addition to general short-comings (as above) with measurements and/or interpretation algorithms, we might also find ourselves faced with “interval issues”.

Consider, as one example, a situation in which ***we have confidence in both the hydrocarbon column S_w calculations*** (by comparison of S_w (Archie) and S_w (Pc) or some other cross-check) ***and the water leg*** (R_{wa} with appropriate “m” is consistent with measured R_w , or some other comparison). ***Although comforting, we do not necessarily know that the transition zone is being properly evaluated.***

Transition zones may present additional challenges. Ehrenberg et al (2005) found that hydrocarbon emplacement more commonly preserves rock quality in carbonates, as compared to clastics, and Efnik et al (2006) finds near dry oil can sometimes be produced in what would have by default been interpreted (and not tested) as a carbonate transition zone.

Pulsed Neutron Logs are typically run long after the original open-hole interpretation has been completed (for surveillance purposes) but ***can in fact contribute*** (at a later date) ***to Quality Control of the OH evaluation in a number of ways*** (Laurent Moinard, personal communication).

As one of several possible examples, let us ***consider a dual porosity system consisting of large and small pores, and the associated transition zone implications: Figure 28.***

Complex Pore Systems and the Transition Interval

- ***Carbonate pore structure can exhibit a wide variety of pore sizes*** ranging from visible to microscopic
- This ***creates a complex fluid distribution in the pore network***
- ***As hydrocarbon charging occurs, macro-pore water tends to be displaced first***
- ***Depending upon the buoyancy pressure and height on the structure, a portion of the meso-pores may become oil charged***

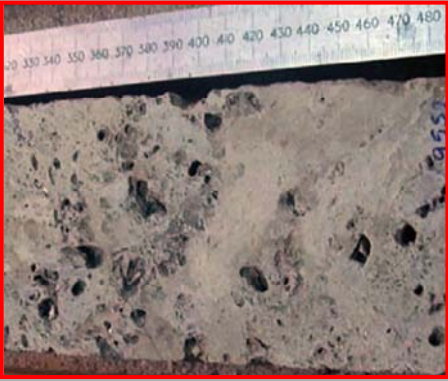


Figure 28

Estimating S_w with a volume measurement
R. Griffiths, A. Carnegie, A. Gyllensten, M. T. Ribeiro, A. Prasodjo, and Y. Sallam. World Oil, October 2006

As one moves upward from the Free Water Level, capillary pressure increases and at some point **the large pores will admit hydrocarbon, while the small pores remain water filled.**

If, for any reason, the water filled small pores form an electrical circuit, S_w as calculated from Archie's equation can be pessimistic across that interval: Figure 29.

Complex Pore Systems and the Transition Interval

• While the **Archie equation** has had tremendous success, there are **limitations in carbonates**

• Archie alluded to limitations in 1942

• One critical **assumption** is that **the measure current moves uniformly through the formation**

• The presence of **water-filled micro-pores in close proximity to the larger hydrocarbon-filled pores may short-circuit the currents**

• This causes the **oil saturation** to be **under-estimated**

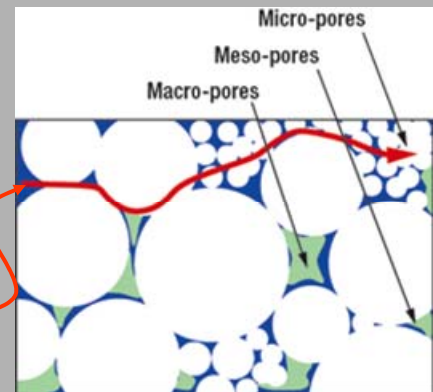


Figure 29

Estimating S_w with a volume measurement

R. Griffiths, A. Carnegie, A. Gyllensten, M. T. Ribeiro, A. Prasodjo, and Y. Sallam. World Oil, October 2006

Interestingly, **the pressure profile across the transition zone can also be compromised** (Griffiths et al, 2006).

- In recent studies, **pressure data across transition zones** have revealed
 - The **upper part** of the zone has an **oil gradient** but the **implied oil density is too light**
- The **lower part** of the zone has a **water gradient** and the **resistivity is usually low**
 - but the **upper section** of this **apparent water gradient will sometime produce oil with a low water-fraction**
- Simple **linear gradients applied to the pressure points can place the interpreted oil-water contact too high**
 - **The result: hydrocarbon in place may be significantly underestimated**

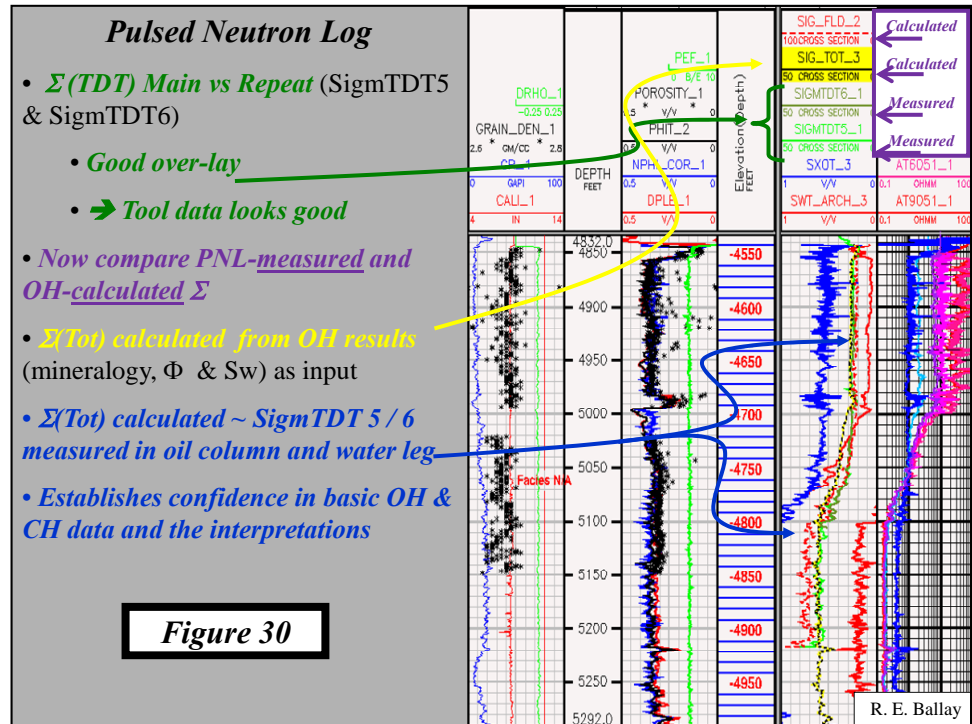
Pressure profiles provide valuable formation evaluation and surveillance information (Ballay 2008), often with a routine (simple linear) interpretation, but we should not “close our eyes” and overlook potential complications: Elshahawi 1999, Carnegie 2006, Larson 2009.

Back to Laurent Moinard and the Pulsed Neutron Log. **The original OH interpretation can be used to create a “synthetic capture cross-section”** according to the PNL bulk-volume weighted response equation, which can then be compared to the measured capture cross-section.

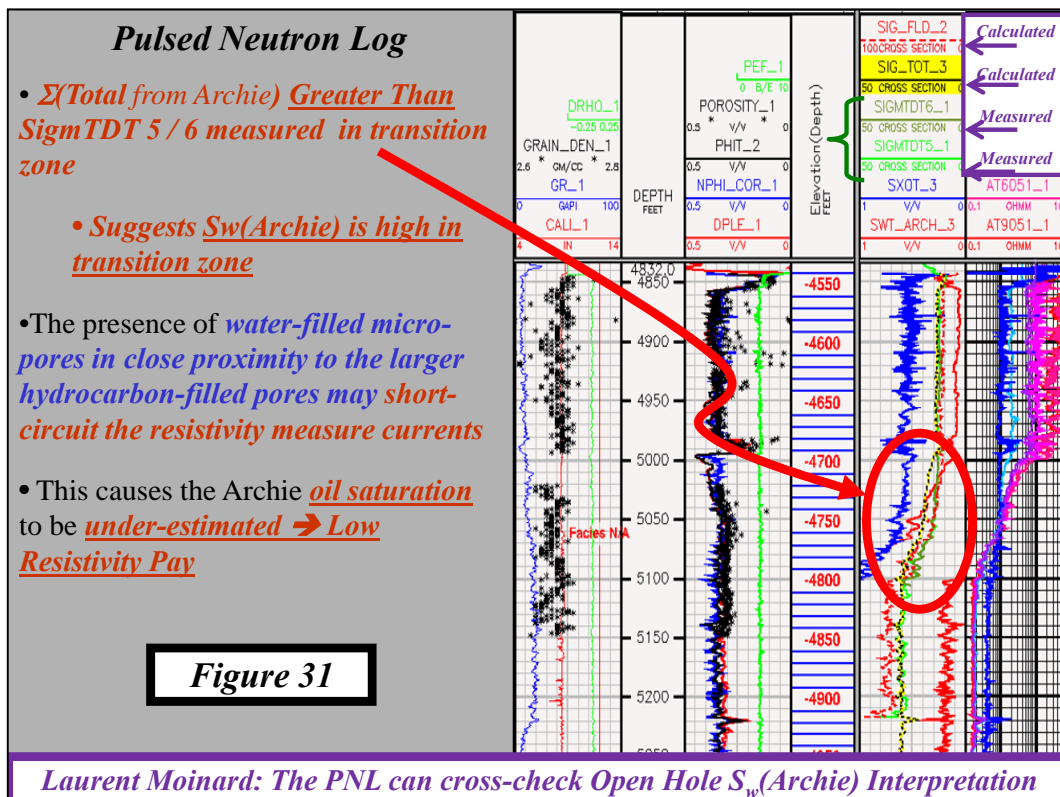
$$\Sigma_{\text{Synthetic}} = (1 - \Phi) \Sigma_{\text{matrix}} + \Phi \Sigma_{\text{fluid}}$$

If the (calculated synthetic) **OH** and (measured) **CH** interpretations are consistent with one another, the synthetic capture cross-section should agree with the measured value: **Figure 30**.

In this example (and indeed, in every such comparison that was done in this field study, with available PNLs), there is a good match between $\Sigma_{Synthetic}$ and $\Sigma_{Measured}$ in the hydrocarbon column and in the water leg.



In the transition zone, however, every such comparison found $\Sigma_{Synthetic} > \Sigma_{Measured}$ indicating that $S_w(PNL) < S_w(Archie)$: **Figure 31**.



SPWLA Abu Dhabi regularly hosts some very interesting and practical conferences (with results posted to their www site: <http://www.spwla-abudhabi.com/>). In one recent Conference (personal communication, Chris Smart) the topic was **Low Resistivity Pay in Carbonates**, where they noted **“Five distinct causes of LRP were identified”**.

The three most likely causes all rely on a dual porosity structure.

- **Fractured formations – Sometimes**
- **Layered formations - Often**
- **Dual Porosity Systems - Most Common**

In the case of fractured and layered formations, the large pores (fractures being regarded as of infinite pore size) are physically separate from the smaller pores. In the case of dual porosity systems, the two pore sizes are juxtaposed.

The three main causes of low resistivity pay can thus result from limited entry of oil into the smaller pores. It is then ***expected that higher in the column*** (above the “Transition Zone”) ***oil would*** (eventually) ***gain access to the smaller pores*** and ***both oil saturation and resistivity would rise***. ***LRP can be a “Transition Zone” phenomenon and not be expected in identical rock higher in the column***.

Cased-hole PNL logs, run for surveillance purposes, can serve as a QC device for the original OH interpretation.

Additional Low Res Pay considerations may be found in the following references: Austin Boyd et al (1995), Roger Griffiths et al (2006), Asbjorn Gyllensten et al (2007).

Finally, there is yet another application of the PNL for OH interpretation purposes: as an independent estimate of R_w . For with mineralogy and porosity from the OH interpretation, and a Σ measurement in the water leg, ***one is able to calculate Σ_{Water} , and from that deduce the formation brine salinity***.

As pointed out by Laurent Moinard, consolidation of the OH and CH data and interpretations can lead to a $1 + 1 = 3$ situation.

Statistical Issues

In a time when pocket calculators have more computing power than did the space capsule that first went to a moon, and when desktop PCs offer pre-programmed statistical packages of unprecedented capabilities, Mark Twain’s words of more than 100 years ago still ring true:

Facts are stubborn, statistics are more pliable.

Petrophysical correlations commonly encounter the following pitfalls.

- Failure to recognize the importance of **“residual” orientation**, in establishing numerical (least squares) correlations.

- Establishing correlations based upon *logarithms* (permeability for example), rather than directly upon the attribute of interest.

Consider first the issue of residual orientation. **The commonly used Linear Least Squares Regression is well-known and often utilized, but what is commonly over-looked is the (implicitly assumed) orientation of the “residual” whose “sum of squares” is minimized.**

Y on X regression (typically the default) yields that set of “m” and “b” (where $Y = m * X + b$) for which the “sum of residual squares” is **minimized in the Y direction**.

X on Y is the set of “m” and “b” ($X = m * Y + b$) for which the “sum of residual squares” is **minimized in the X direction**.

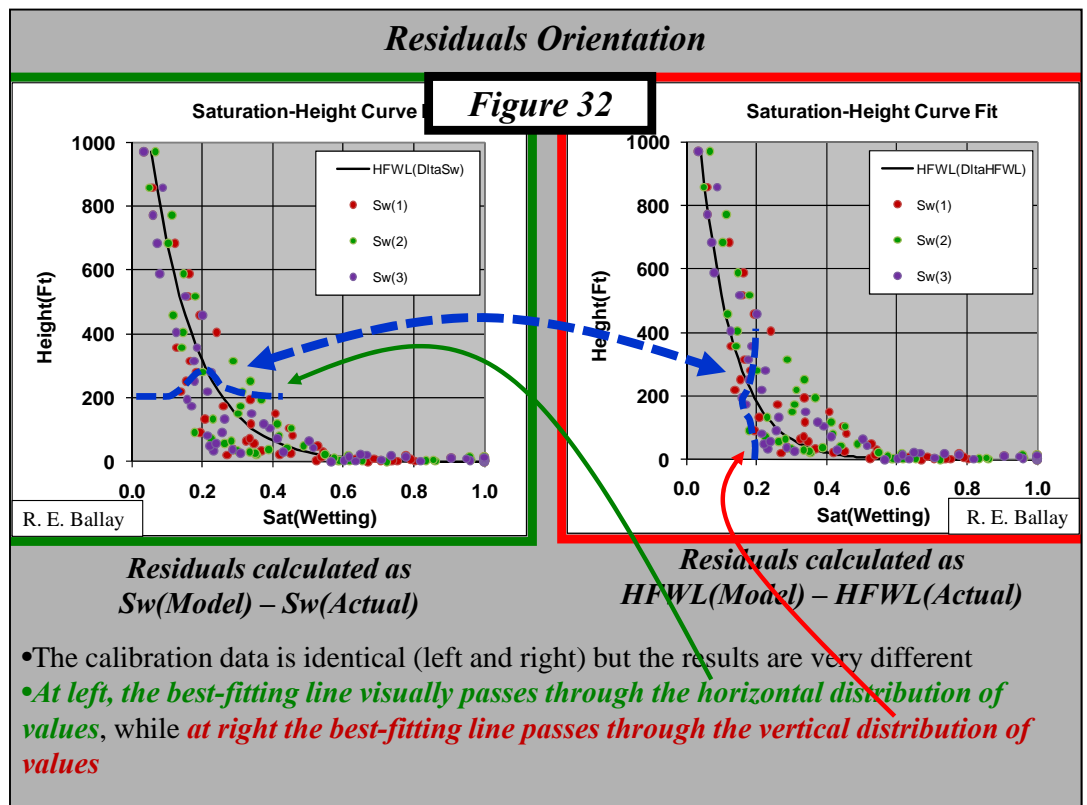
The two sets of Best Fit “m” and “b” coefficients are not the same, and in fact they form the extremal boundary values of an infinite range of possible orientations. The common pre-programmed least squares regression is usually Y on X, and this may, or may not, be appropriate (Ballay, 2010).

The potential for misidentification is compounded when one is working with any property that varies as a function of depth (Pressure Profiles, Saturation-Height, etc) because our natural tendency will be to place depth along the vertical axis, whereas in many applications the residual that should be minimized is in fact along the X axis (Woodhouse, 2005 and Ballay, 2009).

Fortunately, in addition to pre-programmed features (which may, or may not, be appropriate), many software packages offer powerful user-defined curve fitting options (such as Excel’s Solver).

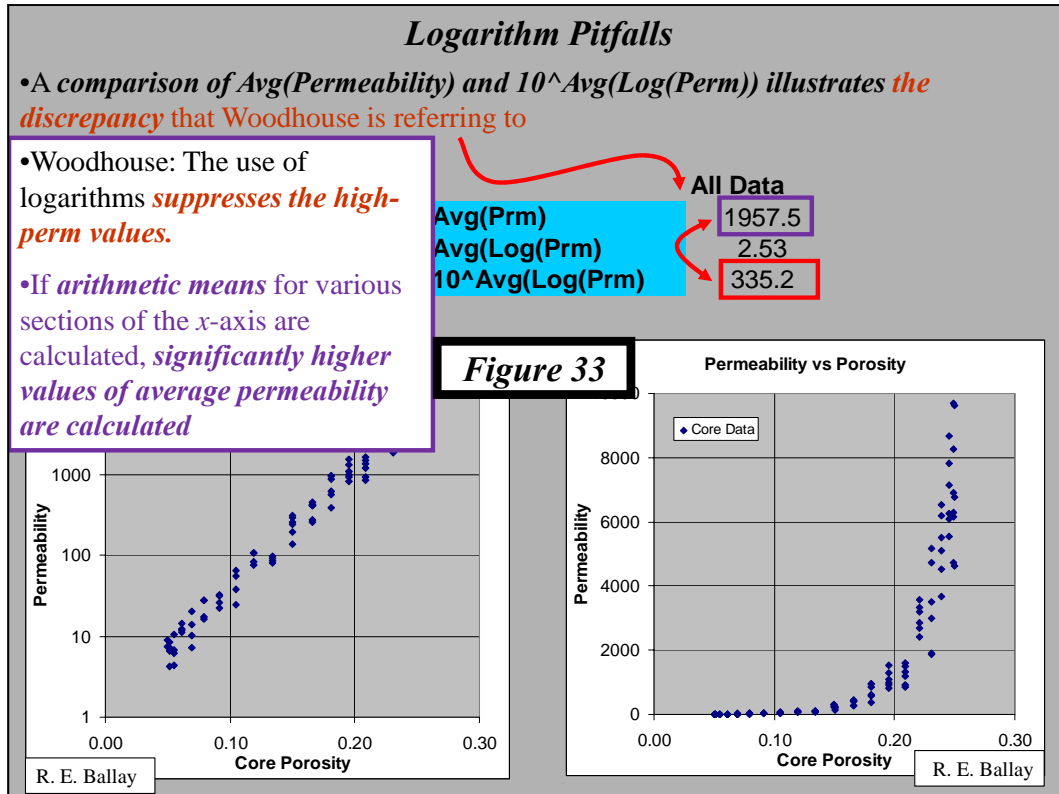
The issue can be illustrated by constructing the Saturation – Height relation based upon actual capillary pressure data: Figure 32.

The Solver feature allows the user to specify the desired residual orientation and to then perform both linear and (a variety of) non-linear curve fits.



In Figure 32 *our eye is drawn to the results on the left because we are mentally expecting the distribution of measured values, about the “best fitting curve” to be centered in the horizontal sense, and not the vertical (depth) sense.*

Solver also allows one to avoid *the logarithm pitfall, which is illustrated in Figure 33.*



In this example we have set up a physically realistic relation between porosity and permeability, based upon an exponential relation. In one case it is the $\text{Log}(\text{Perm})$ that is displayed (via the semi-log graph) while in the other case it is the direct Porosity \leftrightarrow Permeability relation; **both graphics are based upon exactly the same set of input values.**

Before non-linear algorithms (such as Solver) were commonly available, one often established the Porosity \rightarrow Permeability transform by linear least squares regression applied to $\text{Log}(\text{Perm})$.

As Woodhouse (2005) points out, the average of a set of Permeability measurements is not the same as ten raised to the power of the average of the corresponding logarithms.

Transforming to the logarithm domain, determining the average and then transforming that average back into permeability tends to suppress the higher permeability measurements. By working direct with the attribute of interest (in this case permeability, rather than $\text{Log}(\text{perm})$), one avoids this pitfall.

Summary

That old saying “Never criticize a man till you have walked in his shoes” has relevance in the petrophysical world. All too often (particularly in field studies) petrophysical result delivery deadlines are highly influenced by someone who does not have hands-on experience in either basic Petrophysical Data Quality Control, or construction of a multi-well database (including well-to-well cross-checks).

It is then difficult for them to accept the amount of time that can elapse before any (first pass) interpretation is actually executed, and why (tentative) conclusions can change, as the project proceeds. A seemingly simple task such as depth shifting can become very time consuming, particularly if the various measurements are from different tool runs; if tool dragging / sticking is present the individual measurements (at their specific depths) from a single tool run require careful consideration.

In the Real World one seldom has the time to work issues in complete detail, but we should at the very least record concerns, and avoid the Eyes Wide Shut mentality as we strive to meet our deadline.

Acknowledgement

In the ten years since my retirement from Aramco, during which I developed and presented a Carbonate Petrophysics course, it was my good fortune to have many bright and inquiring minds in the audience. To you all I say Thank You, for right up to the very last presentation I found myself considering new possibilities as a result of your questions and comments.

Although I am now retiring, the Carbonate Petrophysics course is not: my friend and colleague Martin Storey has kindly agreed to carry on with not only Carbonate Petrophysics, but his additional personal offerings as well.

Martin may be contacted at mstorey@meranti-petrophysics.com.

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Biography

R. E. (**Gene**) **Ballay**'s 36 years (18 homes, 15 countries) in petrophysics includes both research and operations assignments with carbonate experience ranging from individual Niagaran reefs in Michigan to the Lisburne in Alaska through Ghawar, Saudi Arabia (the largest oilfield in the world).

He holds a PhD in Theoretical Physics with double minors in Electrical Engineering & Mathematics, has taught physics in two universities, mentored Nationals in Indonesia and Saudi Arabia, published numerous technical articles and been designated co-inventor on both American and European patents.

At retirement from the Saudi Arabian Oil Company he was the senior technical petrophysicist in the Reservoir Description Division and had represented petrophysics in three multi-discipline teams, each bringing on-line multi-billion barrel increments.

Subsequent to retirement from Saudi Aramco he established Robert E Ballay LLC, which provided physics - petrophysics consulting services.

He served in the US Army as a Microwave Repairman and in the US Navy as an Electronics Technician: he is a USPA Parachutist, a PADI nitrox certified Dive Master and a Life Member of Disabled American Veterans.



Martin Storey started his oil and gas industry career more than 25 years ago as a logging engineer in Venezuela. He then joined a super-major and was a wellsite petroleum engineer then a Petrophysicist in Gabon and Brunei Darussalam.

In 1998, he became an independent consultant and a trainer, and has consulted internationally since, including in Syria, Malaysia, Oman, Iran, Brunei Darussalam, Suriname, the Ivory Coast and Australia. In most of these countries, he was the Petrophysicist in multi-disciplinary teams working on carbonate as well as clastic oil and gas reservoirs, at all stages of their life cycle. From 2001 to 2004, he was the managing director of TRACS International Australasia, a training and consulting company. He has authored several technical articles and numerous proprietary reports. His areas of main interest include practical Petrophysics, operations, data management and quality.

Starting in 2013, he will be delivering Gene Ballay's "Carbonate Petrophysics" course (and additional courses) in selected locations. He may be reached at the following address.

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