

## The “m” Exponent in Carbonate Petrophysics

R E (Gene) Ballay, PhD  
www.GeoNeurale.com

**In 1952 Archie stated** “In discussing the petrophysics of limestones, it is necessary to first classify them in a manner to portray as much as possible the essential pore characteristics of a reservoir. **The application of petrophysical relationships in limestones can be much more difficult than for sandstones because of the heterogeneity.** This is due mainly to the **variation of pore size distribution.**”

•The essence of carbonate petrophysics is (often) pore system heterogeneity, as compared to clay conductivity issues for clastics

•The foundation of the Lucia petrophysical classification is the concept that pore-size distribution controls permeability and saturation

•The focus of this classification is on petrophysical properties and not genesis

•Petrophysical classifications focus on contemporary rock fabrics that include depositional and diagenetic textures

•To determine the relationships between rock fabric and petrophysical parameters, one must define and classify pore space as it exists today in terms of petrophysical properties

•Addition of vuggy pore space alters the manner in which the pore space is connected

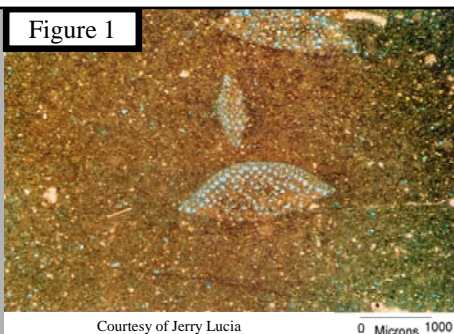


Figure 1

Courtesy of Jerry Lucia

0 Microns 1000

**The attribute within Archie’s equation which represents the pore system tortuosity is the “m” exponent.**

Complications in carbonate formation evaluation can arise due to mixed mineralogy’s (which affects the estimation of total porosity) and wettability (Sweeny & Jennings)/surface roughness (Diederix) which drive the “n” exponent, but **from one perspective the “m” exponent can be said to often represent the essence of carbonate petrophysics.**

As compared to clastic petrophysics,

which is typically compromised by clay conductivity issues, carbonate petrophysics issues will in many cases revolve around proper **characterization of the pore system, which reflects both depositional and diagenetic properties.** Jerry Lucia advises us to focus on petrophysical properties, not genesis, and we thus realize that **petrophysical zones may be genuinely different than geological zones:** Figure 1.

While there are several carbonate classification systems in the public domain (Lucia, Lønøy, etc), **Focke and Munn’s work is particularly complete in that it illustrates each of the following:** Figure 2.

- Pore geometry per thin sections.
- Laboratory “m” measurements correlated with thin section descriptions.
- Wireline methodology for determining “m” in the wellbore, across

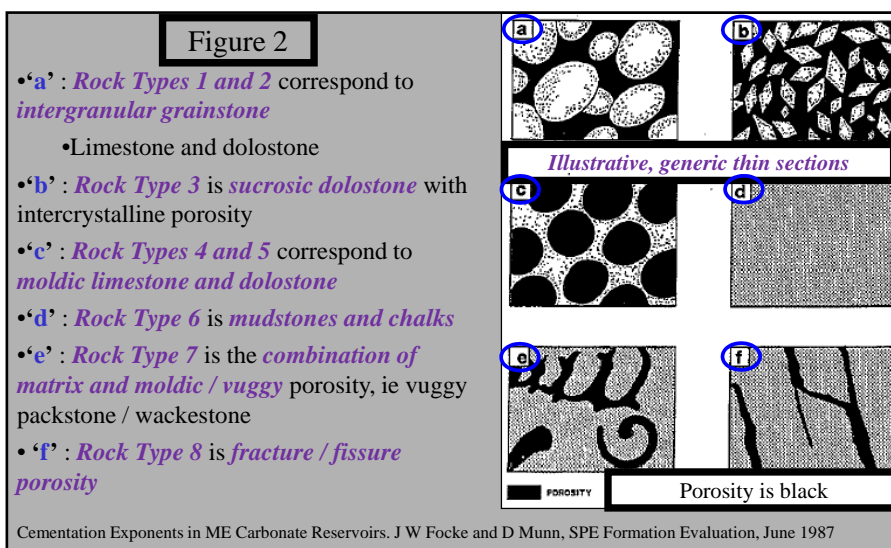


Figure 2

•‘a’ : Rock Types 1 and 2 correspond to **intergranular grainstone**

•Limestone and dolostone

•‘b’ : Rock Type 3 is **sucrosic dolostone** with intercrystalline porosity

•‘c’ : Rock Types 4 and 5 correspond to **moldic limestone and dolostone**

•‘d’ : Rock Type 6 is **mudstones and chalks**

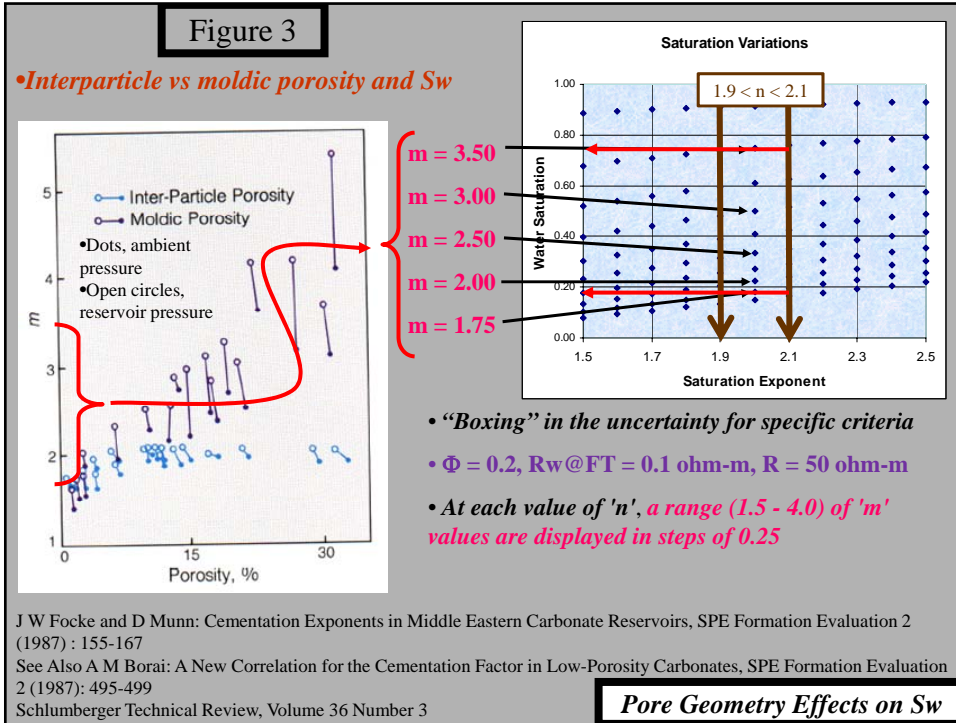
•‘e’ : Rock Type 7 is the **combination of matrix and moldic / vuggy** porosity, ie vuggy packstone / wackestone

•‘f’ : Rock Type 8 is **fracture / fissure porosity**

Cementation Exponents in ME Carbonate Reservoirs. J W Focke and D Munn, SPE Formation Evaluation, June 1987

both the water leg and hydrocarbon column.

- Comparison of wireline-determined “m” and lab-determined “m”.



Focke and Munn find that the difference between an inter-particle and vuggy pore system can be as large as an “m” of ~ 2 versus an “m” of ~ 4, corresponding to **an Sw uncertainty of ~ 20 % versus ~ 75 %**: Figure 3.

**The consequences can be devastating**: an interval of high resistivity (apparently pay) may be nothing more than relatively tortuous, water-filled pore system.

One **approach to this uncertainty is to combine**

**a non-Archie tool** (such as the dielectric) **with a conventional** (shallow reading, since the dielectric is also shallow) **resistivity measurement, and with this multiplicity of measurements deduce what the foot-by-foot “m” is in the wellbore**: Figure 4.

**Another option might be to partition the pore system with modern tools** (Gomaa et al, Ramamoorthy, et al, etc) and to **then independently estimate the corresponding foot-by-foot “m” with some kind of electrical circuit model** (Aguilera, Wang & Lucia, etc).

**An attraction of a mathematical representation of the “m” exponent is that “what if” calculations can be done**, to ascertain the

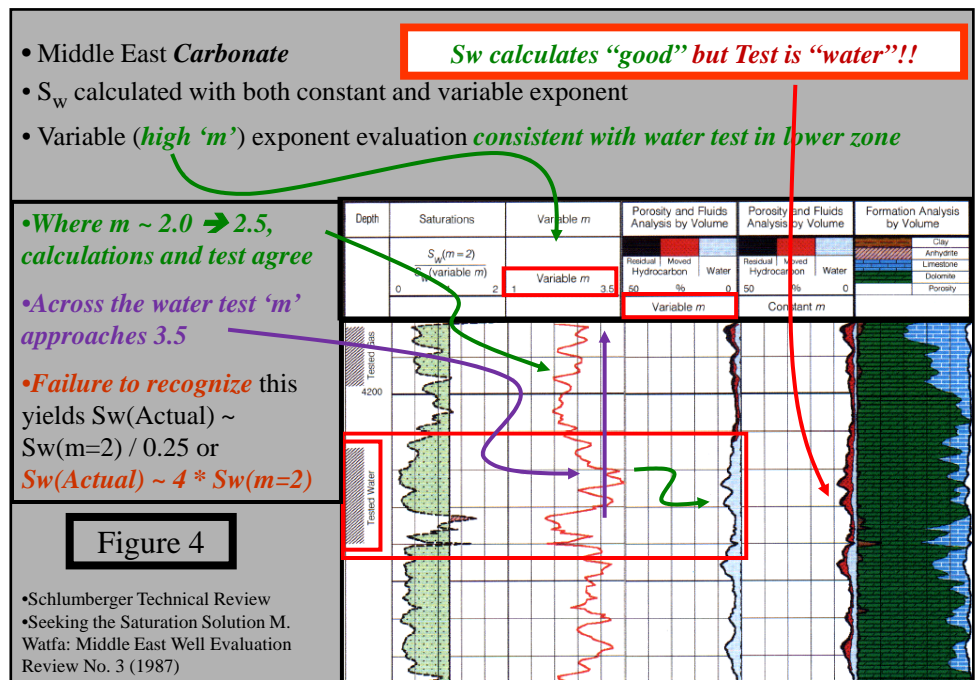


Figure 5

• In the graphic at right, cementation exponents calculated by the *Archie equation* (thick black line -  $m_{res}$ ) are compared with those from *SPI/Nugent*, *Nurmi/Asquith*, *Lucia*, modified *Myers*, and *Dual Porosity*.

$$m \geq \frac{2 \log \phi_s}{\log \phi_t}$$

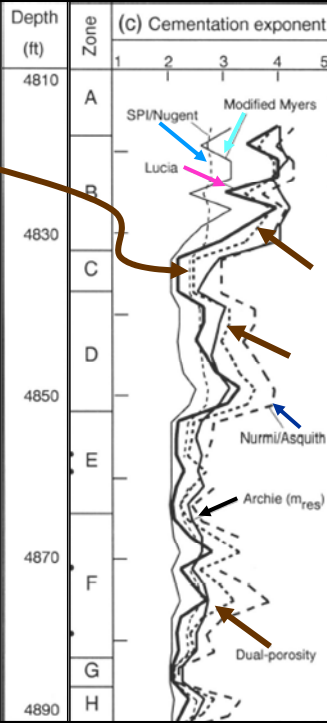
$$m \leq \frac{2 \log (2\phi_s - \phi_t)}{\log \phi_t}$$

$$m = 1.9 + 2.2 \left( \frac{\phi_{sv}}{\phi_t} \right)$$

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

Cementation Exponent Models vs Wireline "m"  
 $m(\text{Dual Porosity}) \sim m(\text{Archie})$

Comparison of Empirical Models for Calculating the Vuggy Porosity and Cementation Exponent of Carbonates from Log Responses. Fred P. Wang and F. Jerry Lucia



range of estimates corresponding to a range of input uncertainties (uncertainty in, for example, the porosity partition).

**Regardless of what approach is used to estimate the wellbore "m", due diligence requires** that at every opportunity the result be compared against the inferred Archie estimate in the water leg [where  $Sw = 1$  and  $m = \log(Rw/Ro)/\log(\Phi)$ ]: Figure 5.

**We should furthermore not lose sight of the fact that** there may be intervals, particularly in the vicinity of the transition zone, across which the Archie calculation is simply not valid (Griffiths et al).

### Where to Focus

**Although the "m" exponent may (logically) be the first issue that comes to mind in carbonate evaluation, it does not always dominate the uncertainty in Sw estimates.** There are **two basic ways of identifying "where the focus should be"**: Figure 6.

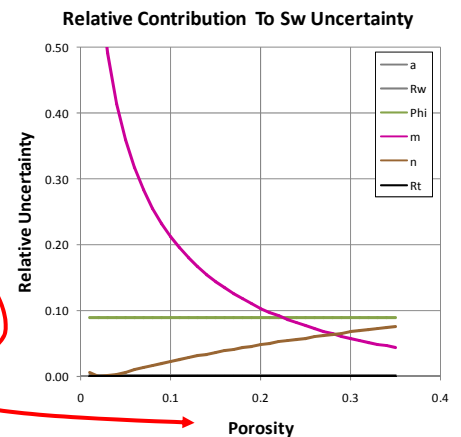
- Take the various partial derivatives of Archie's equation, and compare magnitudes for locally specific values and uncertainties.
- Monte Carlo simulation.

**The two options complement one another** in that the derivatives are easy to code into a spreadsheet or

•**Below**: Illustrative (Chen & Fang) **Best Estimate of each parameter, with corresponding individual uncertainty, and associated relative uncertainty on Sw(Archie).**

•**Right**: **Relative impact on Sw(Archie) uncertainty of 'm' & 'n', across a range of porosity values, for a fixed Phi uncertainty.**

| Attribute Uncertainties Specified Individually |                        |               |                                    |
|--|------------------------|---------------|------------------------------------|
| Light Green Cells require User Specification   |                        |               |                                    |
| Light Blue Cells are calculated results        |                        |               |                                    |
| Attribute                                      | Individual Uncertainty | Best Estimate | Relative Uncertainty On Sw(Archie) |
| 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          | 0.0480                             |
| Rt   | 1.0%                   | 40.00         | 0.0001                             |
| Sw   |                        | 11%           |                                    |
| Sw^n   |                        | 1%            |                                    |
| Sw^n=0.367 is an inflection point              |                        |               |                                    |



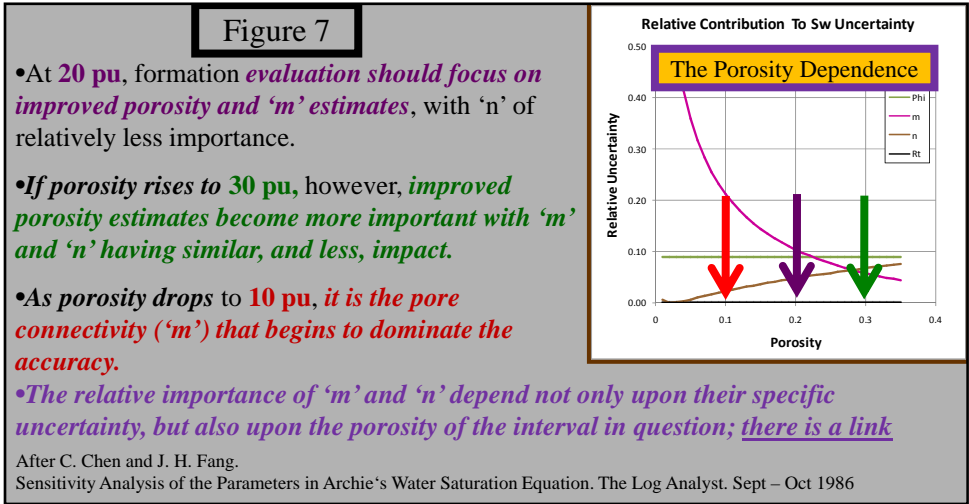
Identifying the **Biggest Bang for the Buck**, in Improved Sw Estimation

Figure 6

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

petrophysical s/w package (for foot-by-foot display), while the Monte Carlo gives insight into the up- and down-sides (with 95% confidence, the uncertainty will be less than high – low calculations).

Using Chen and Fang’s parameters to illustrate the differential approach (Figure 6) we note that as porosity varies, the relative importance of “m” and “n” also varies. That is, **the importance of a single attribute, “m” for example, is linked to the magnitude of other attributes.**



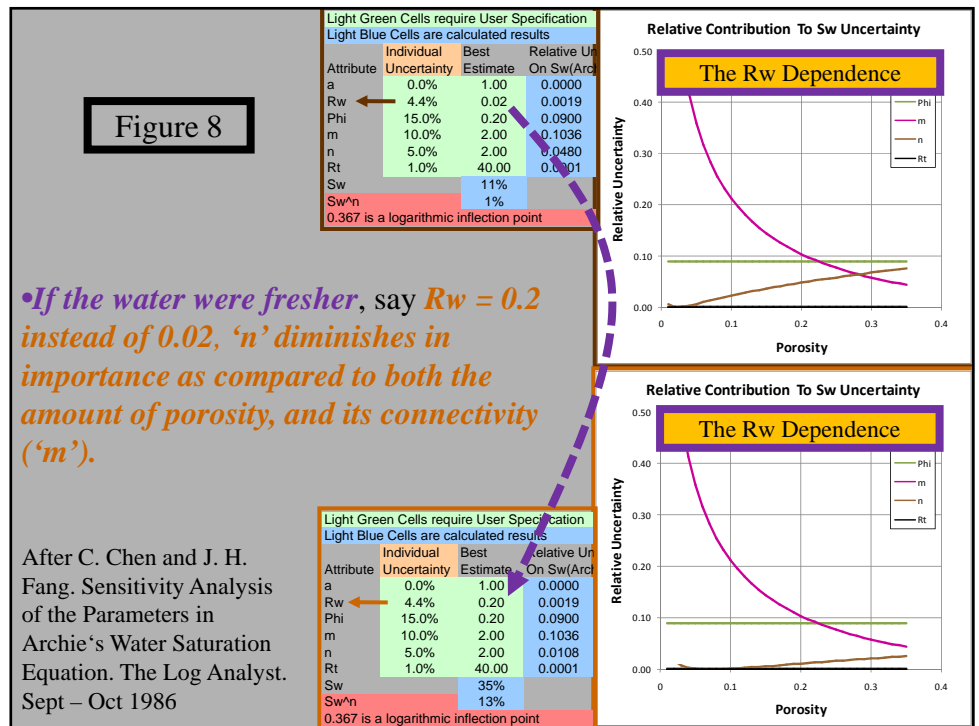
In the case at hand, a 20 pu formation evaluation should focus on improved porosity and ‘m’ estimates, with ‘n’ of relatively less importance. As porosity drops to 10 pu, the pore connectivity (‘m’) begins to dominate the accuracy: Figure 7.

The mental image that

emerges is that as porosity decreases, its connectivity (or efficiency) becomes increasingly important.

Were the formation water resistivity to change, it’s quite possible that the focus should also change: Figure 8.

In summary, **each situation should be evaluated with its locally specific parameters and uncertainties, and our focus (and budget) applied accordingly.**



## “m” and Carbonate Pore Systems

**Archie measured the porosity, permeability and resistivity of brine saturated carbonate and non-shaly sand samples, across a range of brine salinities, to observe a linear relation between  $R_o$  (brine saturated sample resistivity) and  $R_w$  (brine resistivity).**

This resistivity ratio is known as the Formation Factor, where

$$FF = R(\text{sample}) / R(\text{brine}) = 1 / \phi^m$$

**Archie commented that ‘m’ was about 1.3 in unconsolidated rock and increased as the cementation increased.** A typical formation “starting point” value for “m” is 2.0.

It was Hubert Guyod who gave us the term “cementation exponent, and who incidentally, also suggested the original name of the SPWLA Journal (The Log Analyst).

The “m” exponent typically involves a log-log display of the basic data, and as such is less intuitive than a simple linear display. Semi-log and log-log displays are common in many petrophysical endeavors (phi – perm, etc), however, and it’s useful to be able to “draw our own line” through the data and deduce the corresponding exponent. **The Key to working with the**

**Log-Log displays is to “think in terms of decades” and ‘take logarithms’ when working with numerical values.**

**Sketching “our line” through Archie’s 1942 data and drawing upon the slope-intercept formulation of a linear relation, reveals that “m” ~ 2.0 is indeed a reasonable starting point with that data set: Figure 9.**

While it was Mr Guyod who gave us the terminology

“cementation exponent”, it appears that we derive the “m” nomenclature from the mathematician’s slope-intercept representation of a straight line, wherein the slope is denoted by “m”:  $y = m \cdot x + b$ .

Looking ahead just a bit, to the Resistivity Index (in contrast to the Formation Factor), it would further seem that our “n” nomenclature may have arisen alphabetically, since “n” follows “m”.

Interestingly from a historical perspective, this kind of relationship had been postulated earlier by Sundberg, but without the supporting data.

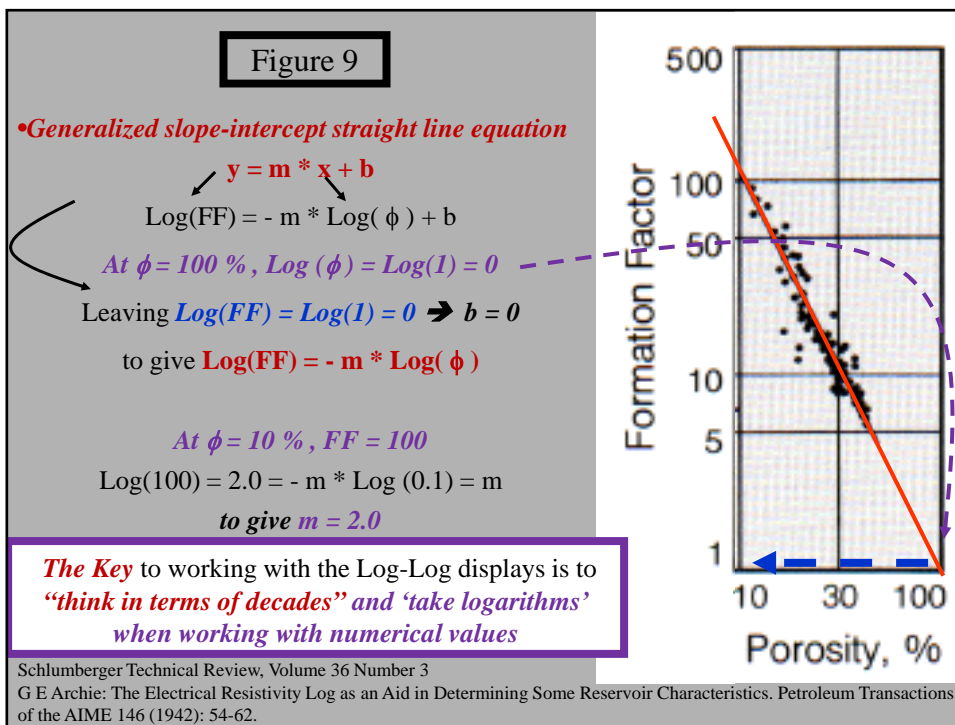
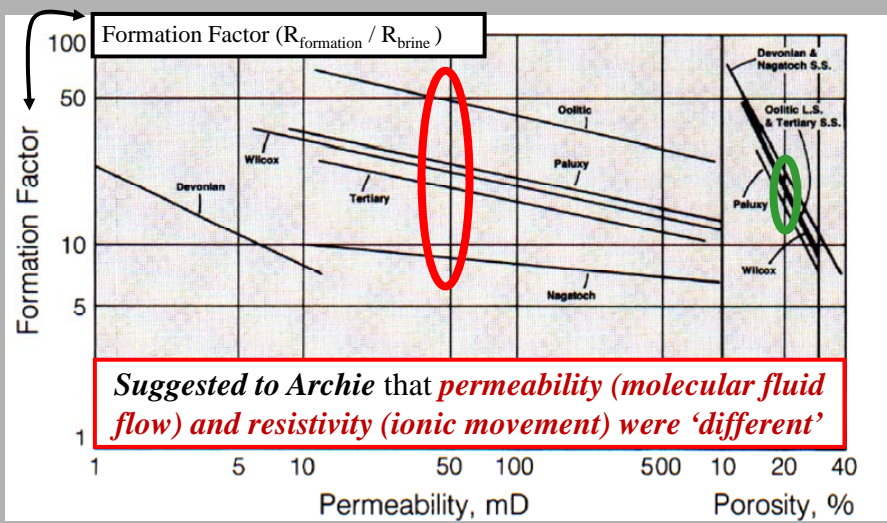


Figure 10

•Archie's 1947 Data - Sandstone and Limestone



G E Archie: Electrical Resistivity as an Aid in Core Analysis Interpretation, AAPG Bulletin 31 (1947): 350-366  
Schlumberger Technical Review, Volume 36 Number 3

Conceptually, given that both represent a “flow”, one might expect a stronger relationship between resistivity and permeability, as compared to resistivity and porosity. Archie addressed this by plotting his measurements both ways: Figure 10.

Perhaps surprisingly, the various Formation Factor measurements converge much better when displayed against porosity, than against

permeability, prompting Archie to suggest that molecular fluid flow (permeability) and ionic motion (current) were “different”. Those who have worked both IG/IX and chalk systems are already aware of this, having noticed that the “m” for the two very different permeabilities can both be about 2.

Verwer et al have performed a digital image analysis of thin sections representing carbonate plugs upon which resistivity measurements were made. Three attributes were recognized as playing an important role.

- Perimeter over area: two-dimensional equivalent to the pore surface / pore volume ratio.
- Dominant pore size: the upper boundary of pore sizes with which 50% of the porosity on the thin section is composed.
- Microporosity: calculated as the difference between the observed macro-porosity in DIA and the measured porosity from the plug sample.

Their measurements, nicely illustrated with accompanying thin sections, demonstrate that in addition to our intuitive expectations,

- samples with high resistivity can have high permeability,
- samples with low permeability can have a (relatively) low “m” exponent.

As Archie pointed out in 1952, carbonate pore systems may be quite variable, causing an “m” = 2 calculation to be non-representative. Wyllie and Gregory bounded the “m” exponent for a range of bead packs consisting of unconsolidated and cemented spheres, via chemical flushes, and found the relation between formation factor and porosity could involve an additional parameter, “C”, which differed from unity.

$$FF = R(\text{sample}) / R(\text{brine}) = C / \phi^m$$

“C” is formation dependent, and **the range of “m” exponents was found to be  $m \sim 1$  for**

**unconsolidated beads**  
**→  $m \sim 4$  for cemented beads:** Figure 11.

**Focke and Munn then conducted a detailed study of “m” measurements on actual carbonate samples, supported with thin section descriptions to find systematic relations between the “porosity type” and “m”.**

While the **intergranular / intercrystalline pore system had  $m \sim 2$**  (so long as  $\phi > 5$  pu), consistent with Archie’s

earlier lab work, **vuggy pore systems could exhibit an “m” that reached 5:** Figure 12.

Their **Rock Type 4**, representing a **diagenetic inversion** in which Original Porosity → Rock and Original Rock →

Porosity is **an example of where an increase in porosity corresponds to an increase in vuggy porosity content.**

Because the vuggy porosity is “less efficient” at electrical conduction, **the “m” exponent (counter-intuitively) rises as porosity increases:** Figure 13.

Figure 11

- Wyllie and Gregory constructed **bead packs with varying degrees of cementation**
  - The baseline represents a formation of unconsolidated spheres
  - This data **prompted them to propose the relation**
- $$FF = C / \phi^m$$
- ‘C’ was a **formation dependent constant**
  - **$m \sim 1$  for unconsolidated spheres**
  - **$m \sim 4$  for cemented bead pack**

M R Wyllie and A R Gregory: Formation Factors of Unconsolidated Porous Media: Influence of Particle Shape and Effect of Cementation, Petroleum Trans of the AIME (1953): 103-110.  
 Schlumberger Technical Review, Volume 36 Number 3

Archie commented that **‘m’ was about 1.3 in unconsolidated sand and became higher as cementation increased**

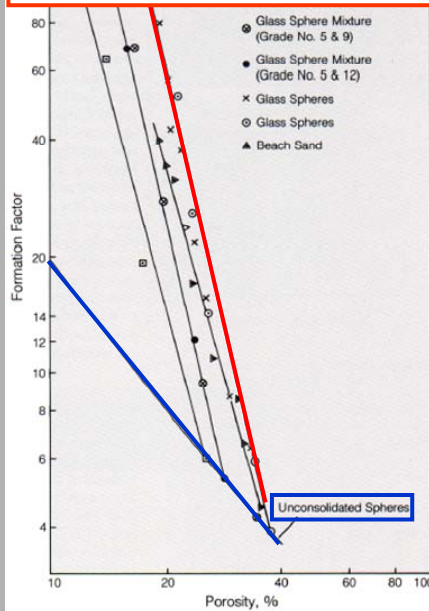
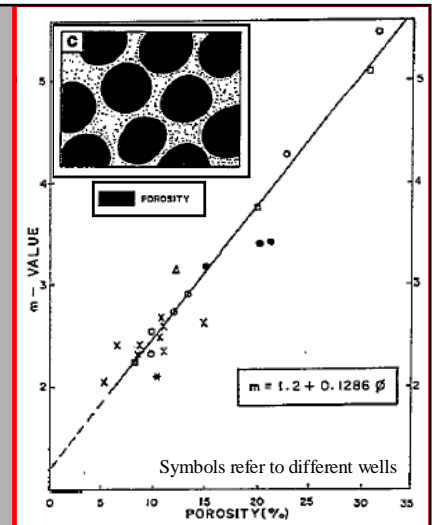


Figure 12

- Geological descriptions of hundreds of samples** reveal a **systematic relation between Rock Type and Archie’s ‘m’ exponent**
- Rock with a more tortuous and/or poorly interconnected porosity** (moldic) display well-defined trends of **increasing ‘m’ with increasing porosity**
- The additional **moldic porosity is less effective at electrical conduction**
- In some rock **‘m’ is found to rise from 2 @ 5 pu, to 5.4 @ 35 pu**
- ‘m’ variations, within a specific Rock Type, can be reduced by segregating the samples of a specific Rock Type into Permeability Classes**

Cementation Exponents in Middle Eastern Carbonate Reservoir.  
 J W Focke and D Munn, SPE Form Evaluation, June 1987



•**Rock Type 4, the moldic limestone grainstone**, represents a diagenetic inversion whereby the original porosity (between the grains) was filled with cement, and the original grains were dissolved to form the current porosity

• **Rock Type 4**, the moldic limestone grainstone, represents a *diagenetic inversion* whereby the *original porosity* (between the grains) was *filled with cement*, and the *original grains* were *dissolved to form the current porosity*

- Perm Class 1:  $Perm < 0.1 md$
- Perm Class 2:  $0.1 md < Perm < 1 md$
- Perm Class 3:  $1.0 md < Perm < 100 md$
- Perm Class 4:  $100 md < Perm$

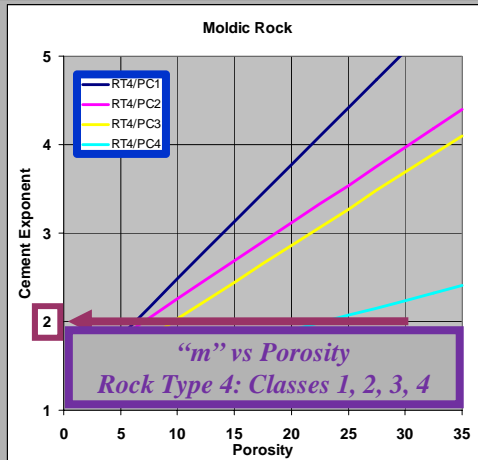
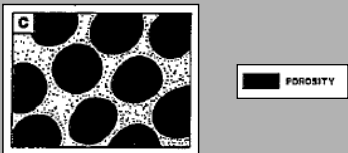


Figure 13

Although extreme, diagenetic inversion is reported in other studies, for example Eberli et al, who illustrate it with thin sections and describe the process as *“the original grains are dissolved to produce pores as the original pore space is filled with cement to form the rock”*

Focke and Munn next noticed that the correlation between “m” and porosity could be

Cementation Exponents in Middle Eastern Carbonate Reservoir. J W Focke and D Munn, SPE Form Evaluation, June 1987

improved by breaking that Rock Type into permeability classes, each of which corresponded to diagenetically inverted rock, but with different permeabilities. We shall return to the different “m” vs  $\phi$  trends associated with the different permeability classes, within the context of a digital “m” exponent model, shortly.

**Fracture porosity has an effect opposite to vuggy porosity**, conceptually forming a kind of “short circuit”, which is represented mathematically by a decrease in value: Figure 14.

• **Fracture porosity** has an *effect opposite to vuggy porosity*

• Provides a conductive conduit => *lowers ‘m’*

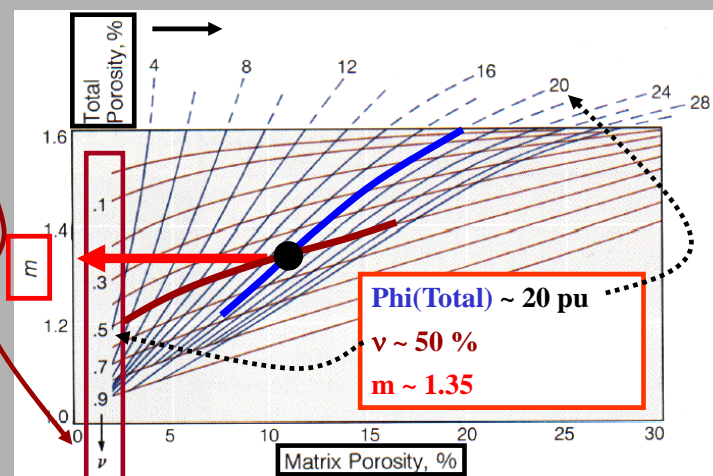
• “m” can be estimated with Charts

Figure 14

Illustrative calculation

$v$  is the fraction of porosity that is fracture

R Aguilera: Analysis of Naturally Fractured Reservoirs from Sonic and Resistivity Logs, SPE 4398, Journal of Petroleum Technology 26 (1974)  
 R Aguilera: Analysis of Naturally Fractured Reservoirs from Conventional Well Logs, SPE 5342, Journal of Petroleum Technology 28 (1976)  
 Schlumberger Technical Review, Volume 36 Number 3





## Digital “m” Exponent Model

•The *Dual Porosity Cementation Exponent model follows from a simple two component* (intergranular and vuggy porosity) *electrical model*

$$1/R(\text{equivalent}) = 1/R_1 + 1/R_2 = C_0 = C_1 + C_2$$

•*Each component satisfies Archie’s relation between resistivity and formation factor*

$$\text{Resistivity} = R_w * FF \Leftrightarrow \text{Conductivity} = C_w / FF$$

•*Formation Factor is related to porosity as  $FF = a / \Phi^m$*

•The *two component parallel circuit equation is then*

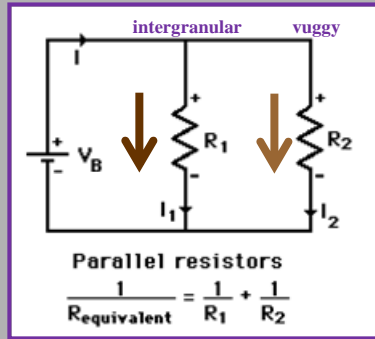
$$C_0 = C_w [1/FF_1 + 1/FF_2]$$

$$C_0 = C_w [\Phi(1)^{m(1)} / a(1) + \Phi(2)^{m(2)} / a(2)]$$

•*Now take  $a(1)$  as 1.0,  $m(2)$  as 1 and allow  $a(2)$  to vary from 1 to infinity* [ $a_v(2)$  represents the tortuosity of the vuggy partition]

Comparison of Empirical Models for Calculating the Vuggy Porosity and Cementation Exponent of Carbonates from Log Responses. Fred P. Wang and F. Jerry Lucia

Figure 15



Within the Lucia system, “vuggy” porosity is everything that is not interparticle, and includes both “touching vugs” (fractures, etc) and separate vugs (moldic, intraparticle, etc). While there are charts available to estimate “m”, as a function of vuggy porosity content, for the various scenarios, it would be advantageous to have a digital model.

*There are several*

*digital models available, and here we use Wang & Lucia for illustrative purposes, because:*

- It is based upon a simple circuit model that is easy to follow for those not particularly comfortable with electrical circuit theory,
- It allows for both “touching” and “separate” vugs, and everything in between,
- Wang and Lucia included independent QC checks on the viability of their model,

Wang and Lucia represent vuggy rock as a two component, parallel circuit: Figure 15.

Each component (independently) satisfies Archie’s equation, and they then simplify the resulting “net conductivity” expression by setting the “m” of the vuggy fraction to be 1 and representing the tortuosity of the vugs (be they touching, separate or something in between) with a parameter  $a_v$ : Figure 16.

•*Type I formula: Assuming that  $m_v$  is 1 and that  $a_v$  varies from 1 to infinity, we can write the parallel circuit equation as below*

$$C_0 = C_w \left( \phi_{ip}^{m_{ip}} + \frac{\phi_v}{a_v} \right) \quad (29)$$

$$m = \frac{\log \left( \phi_{ip}^{m_{ip}} + \frac{\phi_v}{a_v} \right)}{\log \phi_t} \quad (30)$$

•*The deduction of the net effective ‘m’ from the conductivity equation follows from* (relative to the simple Archie relation)

$$R_o = R_w / (\Phi^m) \Rightarrow C_o = C_w * (\Phi^m)$$

*Take logarithm of  $C_o - C_w$  equation*

$$\log(C_o) = \log(C_w) + m \log(\Phi)$$

*Following exhibit* ..... Details following exhibit

Figure 16

Comparison of Empirical Models for Calculating the Vuggy Porosity and Cementation Exponent of Carbonates from Log Responses. Fred P. Wang and F. Jerry Lucia

**Figure 17**

• **Type I formula:** Assuming that  $m_v$  is 1 and that  $a_v$  varies from 1 to infinity, we can write the parallel circuit equation as below (details in exhibits following)

$$C_0 = C_w \left( \phi_{ip}^{m_{ip}} + \frac{\phi_v}{a_v} \right) \quad (29)$$

$$m = \frac{\log \left( \phi_{ip}^{m_{ip}} + \frac{\phi_v}{a_v} \right)}{\log \phi_t} \quad (30)$$

• **The deduction of 'm' from the conductivity equation follows from** (relative to the simple Archie relation)

$$R_o = R_w / (\Phi^m) \Rightarrow C_o = C_w * (\Phi^m)$$

$$\log(C_o) = \log(C_w) + m \log(\Phi)$$

$$m \log(\Phi) = \log(C_o) - \log(C_w) = \log(C_o / C_w) = \log \left[ \phi_{ip}^{m_{ip}} + \frac{\phi_v}{a_v} \right]$$

$$m = \log(C_o / C_w) / \log(\Phi) = \log \left[ \phi_{ip}^{m_{ip}} + \frac{\phi_v}{a_v} \right] / \log(\Phi)$$

This leaves them with an expression for the “net cementation exponent” as a function of the total porosity, the porosity partition, the exponent of the interparticle fraction ( $m_{ip}$ ) and the “connectivity” of the vuggy fraction ( $a_v$ ): Figure 17.

**With this digital model in hand, due diligence requires that it be “tested”, with one such test being a comparison of the calculated “m” to that inferred from**

**Archie’s equation in the water leg**, Figure 5, where they find that **an appropriate choice of  $a_v$  results in a match**.

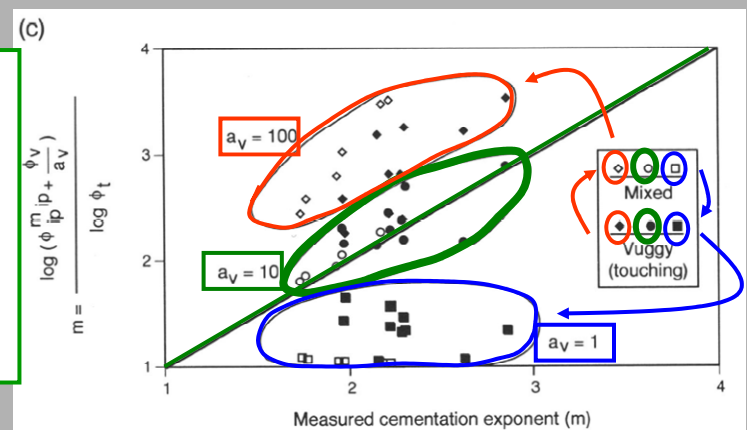
While there is a tendency to think of non-fracture vugs as “separate, without contribution to permeability”, a literature search will reveal instances of the permeability actually increasing, with the presence of vuggy content. This behavior brings forward the importance of parameter  $a_v$ , which is available to represent such a situation.

Wang and Lucia also tested their model in such a situation, drawing upon **Meysers data**, where they **again found that a locally appropriate choice of  $a_v$  brought measurements and estimates into agreement**: Figure 18.

**The attraction of a digital model is that it allows “what if” calculations.** Suppose, for example, a visual examination of core indicates that about 1 pu of vuggy porosity is present, dispersed amongst the matrix porosity. If that vuggy porosity is not well connected (ie  $a_v \gg 1$ ) and the total porosity is ~ 5 pu or

•  $a_v$  represents the connectivity, or lack thereof, of the vuggy portion of the pore system

• This indicates that equation 30 can be used to model reservoirs with separate vugs, touching vugs, and fractures using appropriate values of  $a_v$



**Figure 18**

$$m = \frac{\log \left( \phi_{ip}^{m_{ip}} + \frac{\phi_v}{a_v} \right)}{\log \phi_t} \quad (30)$$

Comparison of Empirical Models for Calculating the Vuggy Porosity and Cementation Exponent of Carbonates from Log Responses. Fred P. Wang and F. Jerry Lucia

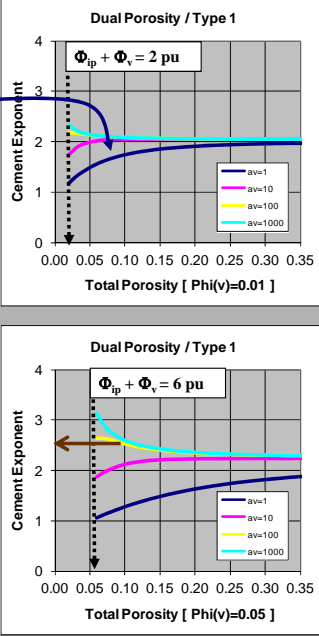
Dual-porosity Model / *What If Characterizations*

•So long as  $\Phi \sim 5$  pu and greater, only at  $a_v \sim 1$  does a small ( $\Phi_v \sim 1$  pu) cause the Cementation Exponent to differ from  $m_{ip} = 2.0$

$$m = \frac{\log \left( \frac{m_{ip} \Phi_p + \frac{\Phi_v}{a_v}}{\log \Phi_t} \right)}{\log \Phi_t}$$

•So long as  $\Phi \sim 10$  pu (or more) and the “vugs” are not present as fractures (or connected vugs), an “m” of  $\sim 2.5$  would be a reasonable starting point.

Figure 19



more, the dual porosity model would indicate that an effective “m” of about 2 is a reasonable starting point: Figure 19.

If, however, that 1 pu is present in the form of well-connected vugs (fractures), then  $a_v \sim 1$  and the effective “m” becomes much more sensitive to the porosity partition and connectivity.

Next consider an interval with about 5 pu of vuggy porosity (Figure 19, again), with a matrix cementation exponent of 2. So long as the total porosity is 10 pu or greater, a reasonable initial

value of the effective “m” would be about 2.5, so long as the vuggy portion is not well connected.

Building upon this concept, we realize that **if it is possible to partition porosity, foot-by-foot in the wellbore, then one may also calculate “m” foot-by-foot and use that exponent value to then estimate Sw**. In such a situation, it would be advisable to seek out a water interval at the first opportunity and compare the resulting Sw (which is hopefully close to 100 %) with that deduced from an inversion of Archie (as Wang & Lucia did, in Figure 5), for validation purposes.

If the calculated dual porosity exponent is a fair representation of the inverted Archie “m”, then the **evaluation of vuggy intervals hinges upon the accuracy of the porosity partition, which may in fact be a hurdle. Limitations that will arise are,**

- the image log will be compromised if the vug size is less than the button resolution, about 3 → 5 mm,
- in carbonates the NMR T2 will lose the pore size relation at pore body sizes of about 50 → 100 um.

Monte Carlo Dual-porosity Model  
*What If Characterizations*

| Specific Parameters Below        |         | Monte Carlo Statistics |         |
|----------------------------------|---------|------------------------|---------|
| Attribute                        | Mean    | Std_Dev                | Std_Dev |
| m(ip)                            | 2       | 0.102                  | 0.097   |
| Phi(v)                           | 0.005   | 0.005                  | 0.005   |
| VPR                              | 0.500   | 0.100                  | 0.100   |
| a_v                              | 100.000 | 10.000                 | 10.000  |
| Phi(vug)                         | 0.003   |                        |         |
| Phi(vug) + VPR*Phi(total)        |         |                        |         |
| Phi(vug) + Phi(total) - Phi(vug) |         |                        |         |
| Std_VPR40.20*VPR                 |         |                        |         |
| Std_Sig_Loc40.27WV               |         |                        |         |

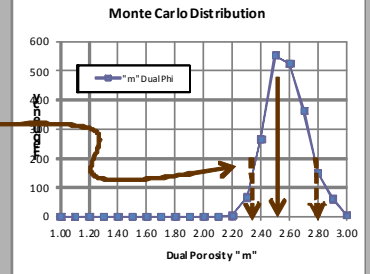


Figure 20

- The Monte Carlo method relies on repeated random sampling to model results
- Advantages of Monte Carlo include
  - any type of distribution can be used to characterize the uncertainty distribution of any parameter
  - normal, log normal, etc
  - insight is gained into the “upside” and “downside”

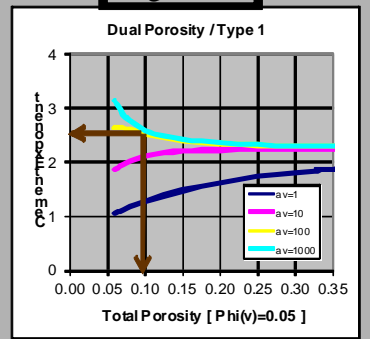
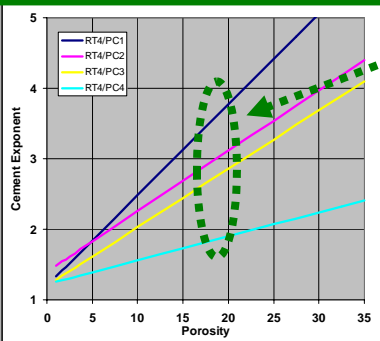
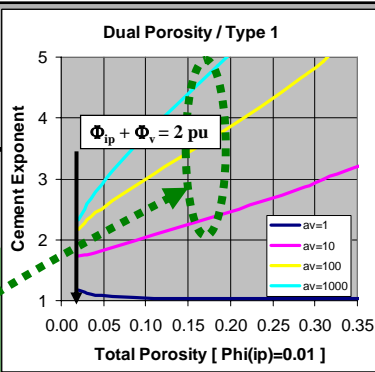


Figure 21

•Matrix has a relatively uniform amount of interparticle porosity (the background), with variable amounts of vuggy porosity, with different degrees of connectivity

$m_{ip} = 2.0$ ,  $\Phi_{ip}$  &  $a_v$  constant across range of  $\Phi_v$

•The Dual Porosity Model has captured the essential trends of the independent Focke & Munn data.



**Focke & Munn's Data**

•Rock Type 4, Perm Classes 1 => 4, a *molitic limestone grainstone*: representing a *diagenetic inversion* whereby the *original porosity* (between the grains) was *filled with cement*, and the *original grains* were *dissolved to form the current porosity*

The Dual Porosity Model vs Lab Data

There is **yet another advantage of expressing the vuggy pore system exponent in mathematical form: it becomes possible to perform a Monte Carlo simulation:** Figure 20.

Now we are able to account for uncertainty in the various inputs (the porosity partition, as an example), and characterize the Best Estimate in terms of probabilities. That is, rather than go with a high / low estimate, one can identify (for

example) 95 % of the MC distribution. In many cases we will find that, if we can accept two standard deviations of uncertainty (95 %), the likely high / low values are not so extreme as the possible high / low. This is because, in general, it is unlikely that all the high (or low) input values will occur simultaneously.

**The preceding illustrations represent a fixed vuggy portion in the presence of more or less matrix porosity. It is also possible that most of the porosity is in the form of vugs, with some small amount of (background) matrix porosity:** Figure 21.

That is, instead of a constant 1 pu (or 5 pu) of vuggy porosity, as the total porosity goes up and down (Figure 19), one might have a small amount of interparticle porosity, with more or less vugs present. **The dual porosity model exponent trends are now very different, because the bulk of the porosity is not "efficient".**

So long as the vugs are not connected, Figure 21 reveals a trend of increasing "m", with increasing "porosity". **As  $a_v$  varies from slightly connected ( $a_v \sim 10$ ) to separate ( $a_v \sim 1000$ ), the different trends separate, and exhibit a pattern very similar to what Focke and Munn found experimentally.**

Focke and Munn's Rock Type 4 (diagenetically inverted), with different permeability classes, can be represented with the dual porosity model. At a simple level, the  $a_v$  values correspond to the choking off of the pore throats, which both reduces permeability and increases "m".

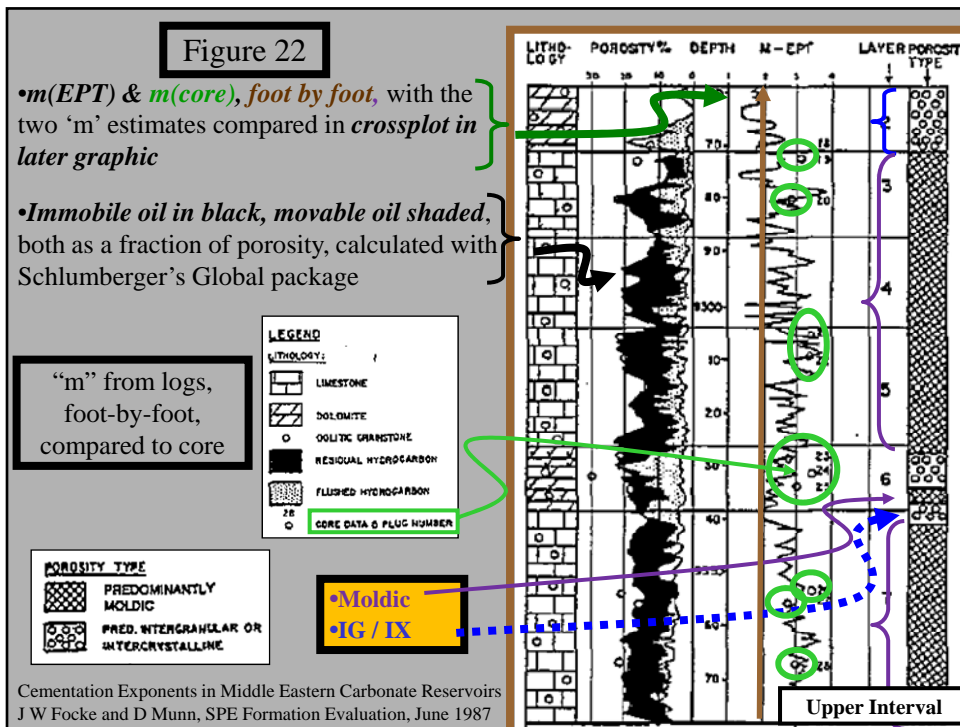
**It is important to realize** that, conceptually, some pore systems may not satisfy the parallel circuit assumption and that additionally in some reservoirs the pore system is a triple porosity system, not dual. In such a situation, this parallel circuit dual porosity model is not going to be sufficient.

## “m” from non-Archie Techniques

If the pore system can be partitioned, a mathematical model of the “m” exponent will allow one to then evaluate the hydrocarbon column with variable “m”. **An alternative approach is to include an additional tool in the suite, which when combined with a resistivity measurement, allows one to deduce the local “m”, and to then use that “m” in the interpretation of the deep resistivity.**

**Focke and Munn combined the dielectric log with an Rxo measurement** in just this way, to

- calculate “m” foot-by-foot in the hydrocarbon column,
- compare the wellbore “m” estimates with lab “m”.



Although the concept is straight-forward, **Focke and Munn were careful to point out key issues that must be kept in mind.**

- The evaluation requires that the dielectric be paired with routine porosity and Rxo tools, which have a greater depth of investigation and less vertical resolution. They are then reflecting a

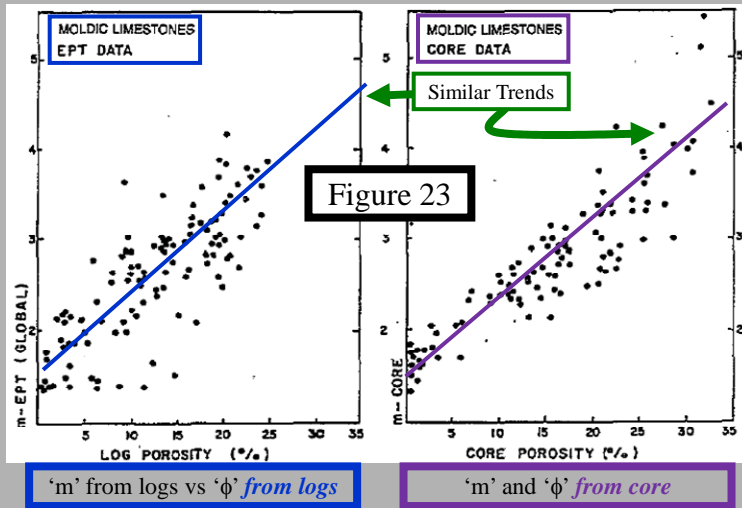
larger volume of reservoir than is the dielectric.

- Rxo may also be reflecting a mix of mud filtrate and formation brine. If so, an ‘effective’ value -  $R_{mfe}$  - should be used.
- Archie’s saturation exponent is assumed to be 2.0 and carbonates can assume non-water wet values with  $n > 2.0$ .

In their illustrative well, two **pore systems are recognized, moldic and IG/IX**: Figure 22.

As expected, **the moldic porosity exhibits an increased “m”, and reaches ~ 3.5** in places, as seen with both lab data and the dielectric-based estimate.

•Wireline  $m(EPT)$  vs Laboratory  $m(core)$  are in general agreement



Cementation Exponents in Middle Eastern Carbonate Reservoirs J W Focke & D Munn, SPE Form Evaluation, June 1987

Lab and wireline can also be compared via crossplot. Recognizing the different volumes of investigation, and attempting to compensate, Focke and Munn crossplot “m” versus “porosity” for core, and for log: Figure 23.

In the moldic intervals, the two results display an almost identical trend of increasing “m” as (moldic) porosity increases.

Rasmus and Kenyon provide yet another

illustration of the contribution that a dielectric log can make in the presence of oomoldic porosity.

***In the time since Focke and Rasmus, significant advances have been made in dielectric measurements, and they now offer more sophisticated options*** (Zapping Rocks. Romulo Carmona, et al. Oilfield Review. Spring 2011.).

### Summary

In 1952 Archie pointed out the complications that arise with carbonate pore systems, which can result in tortuous water-filled pore systems having a resistivity similar to an inter-particle pore system that is hydrocarbon charged. ***In one sense*** then, and recognizing that other complications can be present, ***the cementation exponent (which represents the pore system tortuosity) represents the essence of carbonate petrophysics.***

Wyllie and Gregory “bounded” the “m” with laboratory bead pack studies, finding that in a pack of unconsolidated beads “m”  $\rightarrow$   $\sim 1$ , while “m”  $\rightarrow$   $\sim 4$  in a chemically cemented pack.

***Focke and Munn*** interpreted ***hundreds of carbonate formation factor measurements, within the context of thin section descriptions***, to find a ***systematic relation between Rock Type and “m”.***

***In the case of moldic porosity***, Focke and Munn found that ***“m” systematically increases as total porosity increases***: the additional porosity is simply “not effective” in the electrical conduction sense.

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

• The three most important pore-geometry characteristics are

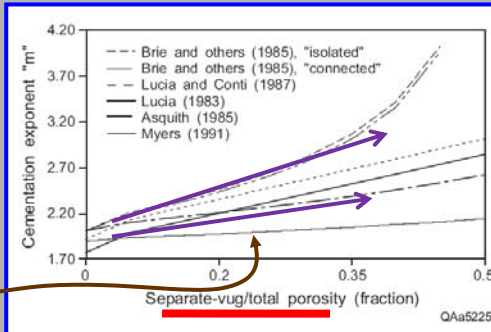
- amount and **types of pores or shape**
- **interconnectedness** of pores (tortuosity)
- size of interconnecting **pore throats**

Figure 23

*As the separate vug fraction increases, so too does the Archie 'm'*

• Various "m" exponents **as a function of vuggy porosity ratio**

• Note the "Myers" trend is relatively flat: the vugs in this data set exhibit "touching" behavior.



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](http://www.beg.utexas.edu/mainweb/presentations/2002_presentations/holtz_spe0402ab.pdf)

In general, the presence of vuggy porosity corresponds to an increase in "m", with the magnitude of that increase differing from one data set to the next: Figure 23.

There are **both charts and mathematical models that allow one to estimate "m"** for various porosity partitions. The **advantage of the mathematical model** is that they easily allow both foot-by-foot

estimates and Monte Carlo simulation.

Charts and models **should always be tested, at the first opportunity, by comparing the "m" estimate to that deduced by inverting Archie's equation in the water leg of a representative well**. In the case of the Dual Porosity model used for illustrations herein, that comparison is reasonable. The Dual Porosity "m" model is also found to match the independent lab measurements of Meyers, and to capture the patterns reported by Focke and Munn.

A **wellbore alternative** to "m" models is to **add a non-Archie tool to the tool suite**, which allows an effective "m" to be deduced. That "m" is then used to interpret the deep resistivity measurement.

**Regardless of the approach used, we should bear in mind** that particularly in the vicinity of the transition zone, the reservoir may fail to satisfy the basic Archie criteria.

### Acknowledgement

Mohamed Watfa's *Archie's Law: Electrical Conduction in Clean, Water-bearing Rock* is an important single-point historical overview source. Focke and Munn's *Cementation Exponents in Middle East Carbonate Reservoirs* literally "set the standard" for a systematic investigation of the issue, back in 1987. To these "must read" articles I have added more recent material, and my personal thoughts / techniques.

This one is for my Mother, who is always there, through thick and thin.

### References

- Aguilera, R. Analysis of Naturally Fractured Reservoirs from Sonic and Resistivity Logs, SPE 4398, Journal of Petroleum Technology 26 (1974): 1233-1238
- Aguilera, R. Analysis of Naturally Fractured Reservoirs from Conventional Well Logs, SPE 5342, Journal of Petroleum Technology 28 (1976): 764-772

Al-Ghamdi, Ali and Bo Chen, Hamid Behmanesh, Farhad Qanbari & Roberto Aguilera. An Improved Triple Porosity Model for Evaluation of Naturally Fractured Reservoirs. Trinidad and Tobago Energy Resources Conference. June 2010.

Archie, G. E. The Electrical Resistivity Log as an Aid in Determining Some Reservoir Characteristics. Petroleum Transactions of the AIME 146 (1942): 54-62.

Archie, G. E. Electrical Resistivity as an Aid in Core Analysis Interpretation, AAPG Bulletin 31 (1947): 350-366

Archie, G. E. Classification of Carbonate Reservoir Rocks and Petrophysical Considerations. AAPG, Vol 36, No 2, 1952.

Ballay, Gene and Roy Cox. Formation Evaluation: Carbonate vs Sandstones. 2005. [www.GeoNeurale.Com](http://www.GeoNeurale.Com).

Ballay, Gene. Risky Business. March 2009. [www.GeoNeurale.com](http://www.GeoNeurale.com)

Ballay, Gene. Rolling the Dice. July 2009. [www.GeoNeurale.com](http://www.GeoNeurale.com)

Ballay, Gene. Coffee Or Tea. October 2009. [www.GeoNeurale.com](http://www.GeoNeurale.com).

Ballay, Gene. Split Personality. December 2009. [www.GeoNeurale.com](http://www.GeoNeurale.com).

Ballay, Gene. Statistics Are Pliable. February 2010. [www.GeoNeurale.com](http://www.GeoNeurale.com).

Ballay, Gene. The Biggest Bang for the Buck. April 2011. [www.GeoNeurale.com](http://www.GeoNeurale.com)

Carmona, Romulo et al. Zapping Rocks. Oilfield Review. Spring 2011

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

Diederix, K. M. Anomalous Relationships Between Resistivity Index and Water Saturations in the Rotliegend Sandstone (The Netherlands), Transactions of the SPWLA 23rd Annual Logging Symposium, Corpus Christi, Texas, July 6-9, 1982, Paper X

Eberli, Gregor P. and Gregor T Baechle, Flavio S Anselmetti & Michal L Incze. Factors controlling elastic properties in carbonate sediments and rocks. THE LEADING EDGE JULY 2003

Focke, J. W. and D Munn. Cementation Exponents in ME Carbonate Reservoirs. SPE Formation Evaluation, June 1987

Gomaa, N. and A. Al-Alyak, D. Ouzzane, O. Saif, M. Okuyiga, D. Allen, D. Rose, R. Ramamoorthy & E. Bize. Case study of Permeability, Vug Quantification and Rock Typing in a Complex Carbonate. 2006 SPE Annual Technical Conference and Exhibition. San Antonio, Texas, U.S.A., 24–27 September 2006.

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

Guyod, H. Fundamental Data for the Interpretation of Electric Logs, The Oil Weekly 115, No 38 (October 30,1944): 21-27



Hartmann, Dan and Edward Beaumont. Predicting Reservoir System Quality and Performance. [www.searchanddiscovery.net/documents/beamont/index.htm](http://www.searchanddiscovery.net/documents/beamont/index.htm)

Herrick, D. C. and W. D. Kennedy. SPWLA 34th Annual Logging Symposium, 1993. ELECTRICAL EFFICIENCY: A PORE GEOMETRIC MODEL FOR THE ELECTRICAL PROPERTIES OF ROCKS.

Lønøy, Arve. Making Sense of Carbonate Pore Systems. AAPG Bulletin, v. 90, no. 9 (September 2006), pp. 1381–1405

Lucia, Jerry. The Oilfield Review. Winter 2000

Lucia, Jerry. Rock Fabric/Petrophysical Classification of Carbonate Pore Space for Reservoir Characterization. AAPG Bulletin 79, no. 9 (September 1995): 1275-1300.

Lucia, Jerry. Petrophysical parameters estimated from visual description of carbonate rocks: a field classification of carbonate pore space. Journal of Petroleum Technology. March, v. 35, p. 626–637. 1983.

Lucia, Jerry. [www.beg.utexas.edu](http://www.beg.utexas.edu)

Mazzullo, S. J. Overview of Porosity Evolution in Carbonate Reservoirs

[www.searchanddiscovery.net/documents/2004/mazzullo/images/mazzullo.pdf](http://www.searchanddiscovery.net/documents/2004/mazzullo/images/mazzullo.pdf)

Myers, M. T., 1991, Pore combination modeling: a technique for modeling the permeability and resistivity properties of complex pore systems: Society of Petroleum Engineers, Annual Technical Conference and Exhibition, SPE paper no. 22662.

Morgan, W. B. and S. J. Pirson. The Effect of Fractional Wettability on the Archie Saturation Exponent

Ramamoorthy, Raghu and Austin Boyd, Thomas J. Neville, Nikita Seleznev, Haitao Sun, Charles Flaum & Juntao Ma. A New Workflow for Petrophysical and Textural Evaluation of Carbonate Reservoirs. Petrophysics, Vol 51, No 1, February 2010.

Rasmus, J. C. and W E Kenyon. An Improved Petrophysical Evaluation of Oomoldic Lansing-Kansas City Formations Utilizing Conductivity and Dielectric Log Measurements, Transactions of the SPWLA 26th Annual Logging Symposium, Dallas, June 17-20, 1985, Paper V

Sundberg, K. Effect of Impregnating Waters on Electrical Conductivity of Soils and Rocks, Petroleum Transactions of the AIME 97 (1932): 367-391.

Sweeney, S. A. and H Y Jennings Jr: The Electrical Resistivity of Preferentially Water-Wet and Preferentially Oil-Wet Carbonate Rock, Producers Monthly 24, No 7 (May 1960): 29-32

Toumelin, E. and C. Torres-Verdín. INFLUENCE OF OIL SATURATION AND WETTABILITY ON ROCK RESISTIVITY MEASUREMENTS: A UNIFORM PORE-SCALE APPROACH. SPWLA 46<sup>th</sup> Annual Logging Sym. New Orleans, LA. June, 2005.

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

Wang, Fred P. and F. Jerry Lucia. Comparison of Empirical Models for Calculating the Vuggy Porosity and Cementation Exponent of Carbonates from Log Responses.

Watfa, M. et al. Archie's Law: Electrical Conduction in Clean, Water-bearing Rock. Technical Review, Volume 36 Number 3

Watfa, M. Seeking the Saturation Solution. Middle East Well Evaluation Review No. 3 (1987)

Wyllie, M. R. and A R Gregory: Formation Factors of Unconsolidated Porous Media: Influence of Particle Shape and Effect of Cementation, Petroleum Trans of the AIME (1953): 103-110.

## Biography

R. E. (Gene) Ballay's *35 years in petrophysics* include *research and operations* assignments in Houston (Shell Research), Texas; Anchorage (ARCO), Alaska; Dallas (Arco Research), Texas; Jakarta (Huffco), Indonesia; Bakersfield (ARCO), California; and Dhahran, Saudi Arabia. His carbonate experience ranges from individual Niagaran reefs in Michigan to the Lisburne in Alaska to 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 bringing on-line three (one clastic, two carbonate) multi-billion barrel increments. Subsequent to retirement from Saudi Aramco he established Robert E Ballay LLC, which provides physics - petrophysics training & consulting.

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