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Flow Zone Index and Saturation Height Function Modelling in Low Permeability Sandstones

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SCAL PROGRAMME DESIGN AND MANAGEMENT
QUALITY CHECKING AND ANALYSIS OF SCAL DATA
CORE TO LOG INTEGRATION
INTEGRATION OF CORE DATA WITHIN RESERVOIR MODELS
SATURATION HEIGHT FUNCTION MODELLING
TRAINING AND MENTORING

Spot the Poro-Perm Competition

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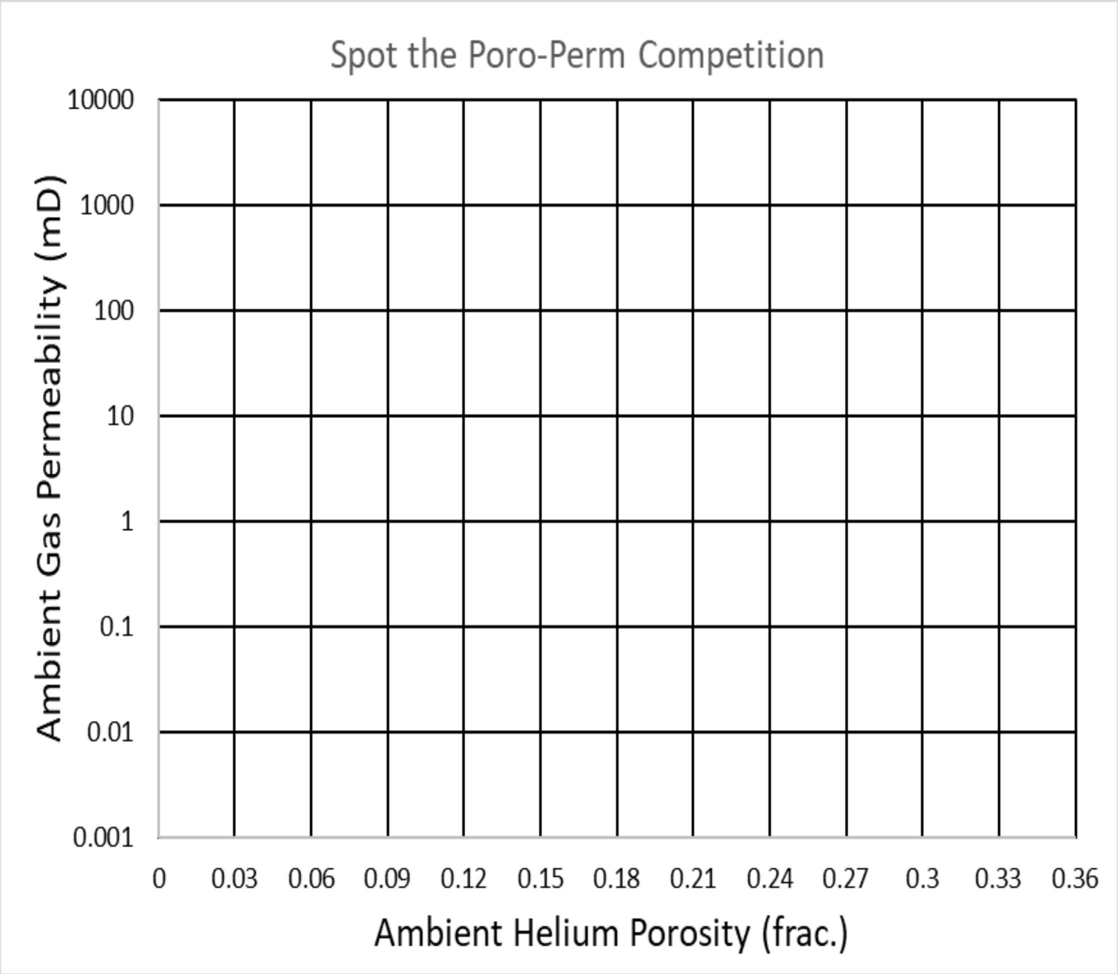

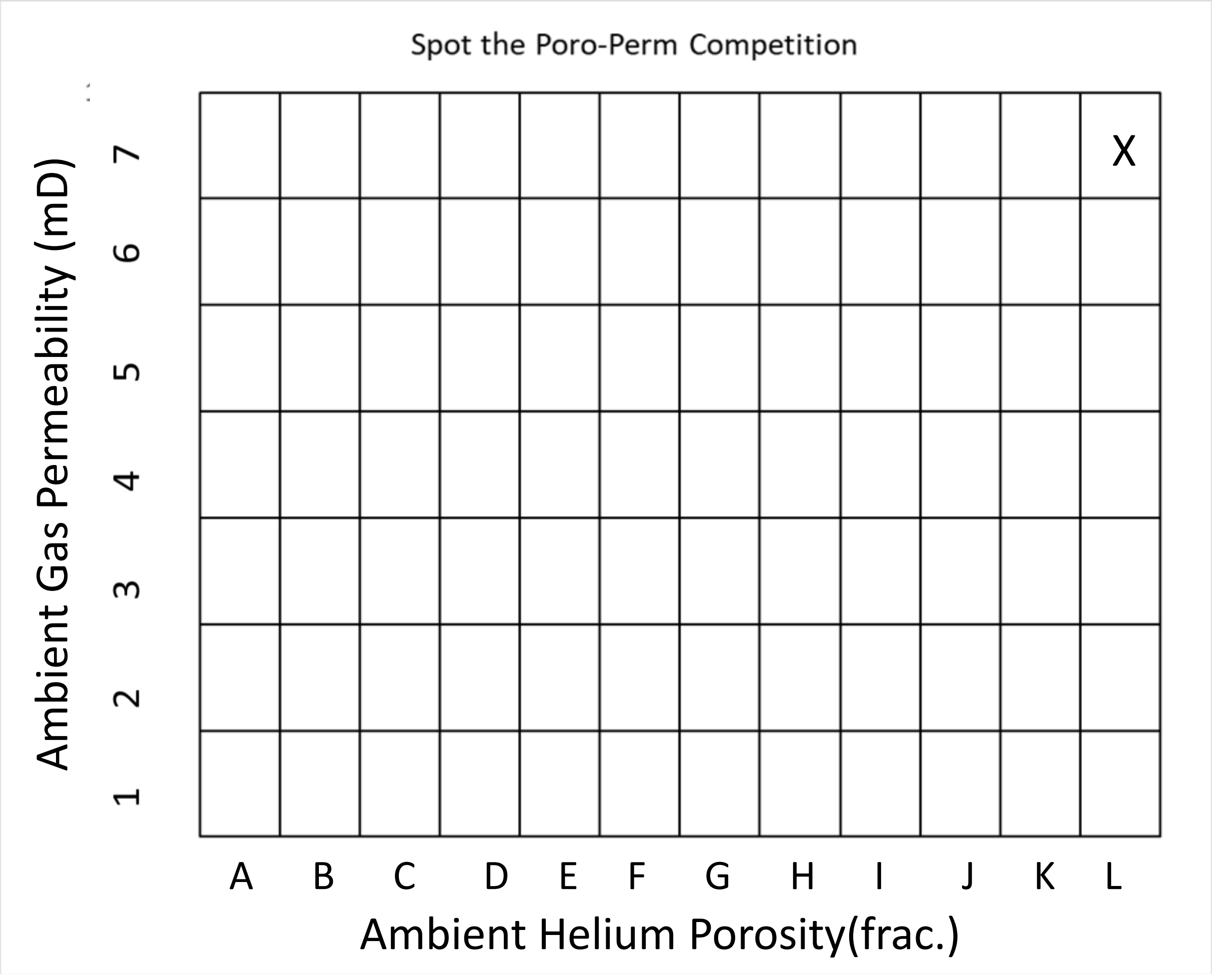

Inspect the plug and guess the location of the porosity and permeability point on the chart on the right.
Give your answer on the sheet I will pass around i.e Adam's guess = square L7
When you pick a square put a cross in it, so others can't pick it.

Introduction

- Low permeability sandstone reservoirs – the core analysis issues
- Making sense of the poro-perm cloud
- Capillary pressure theory and saturation height functions
- A case study

Low Permeability Sandstones – The Issues

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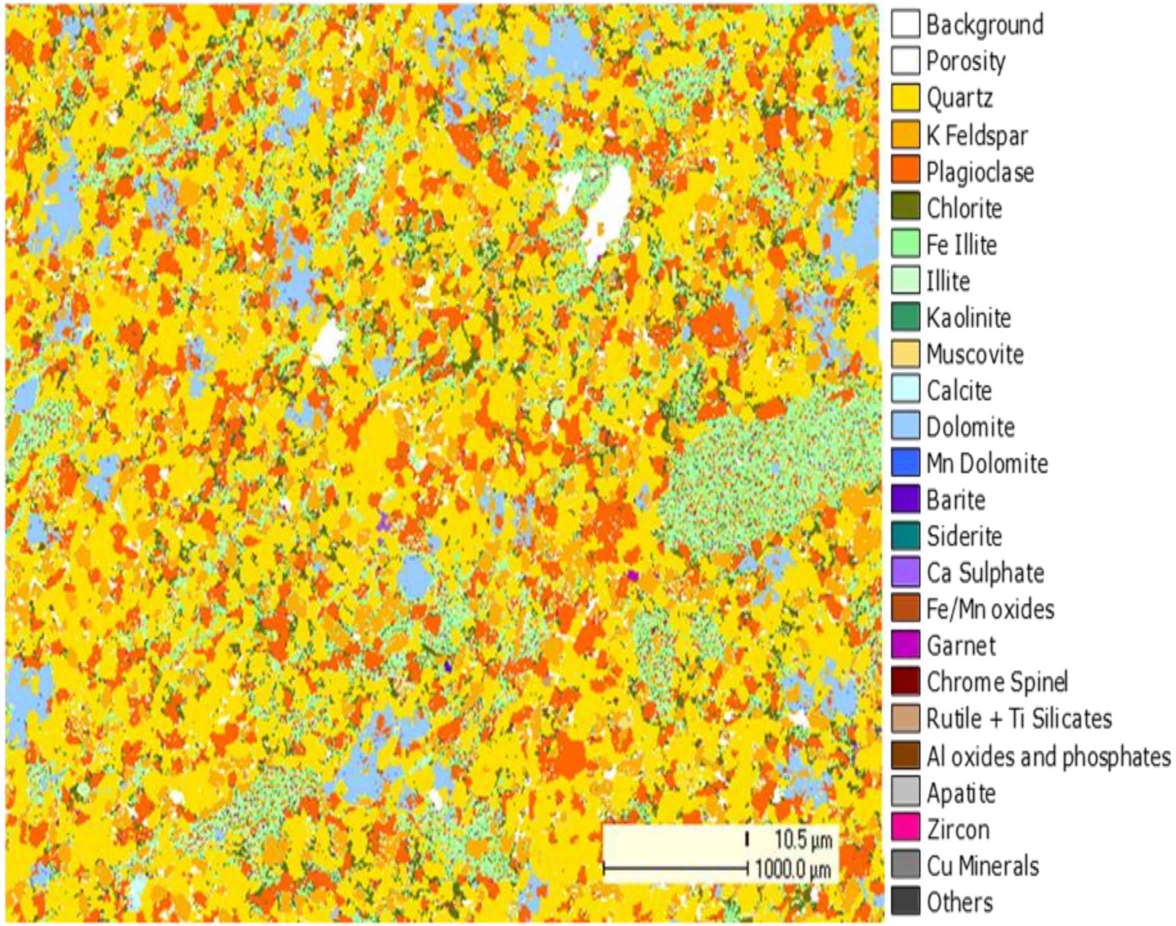
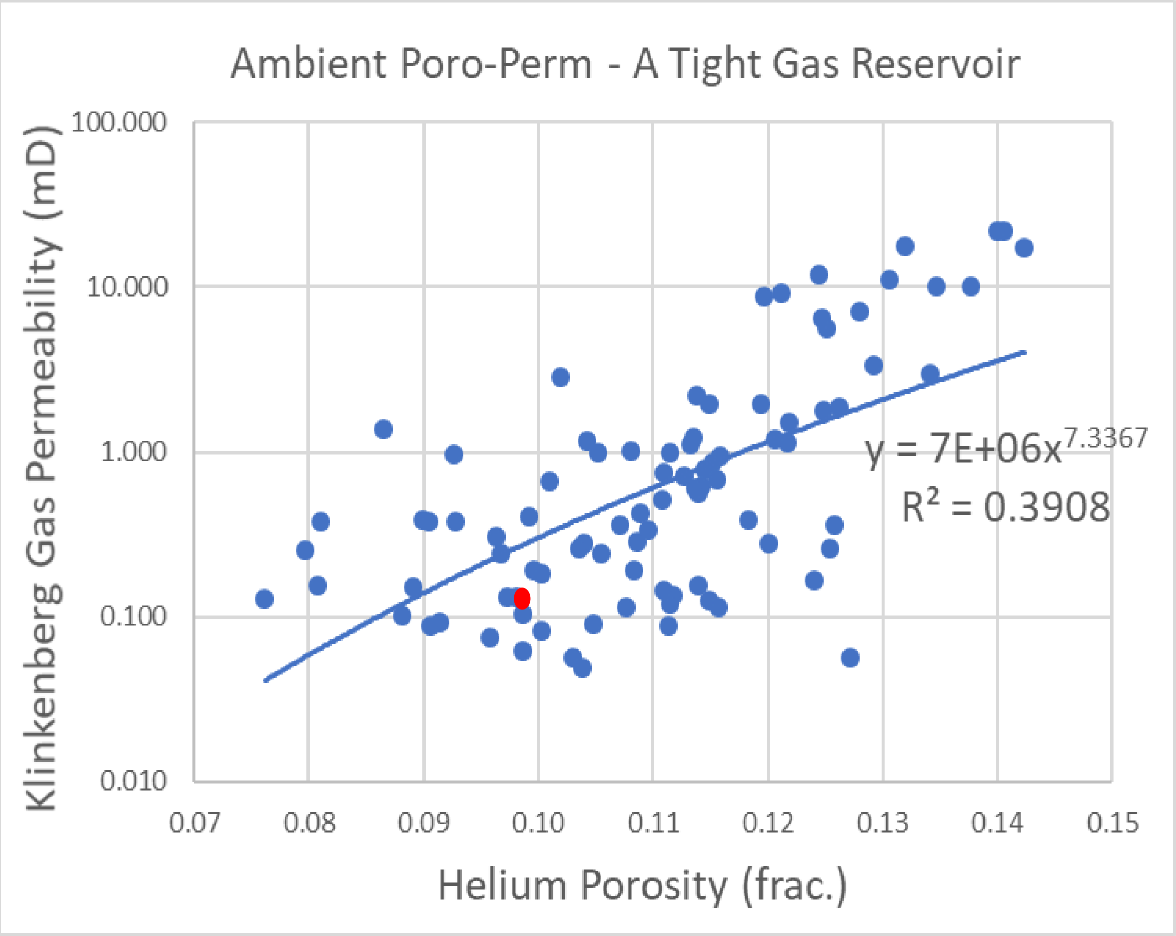
Complex diagenetic overprints depositional structures



QEMSCAN mineral map from a tight gas reservoir core plug (Kg = 0.13mD, Φ = 9.6%, G.D = 2.66g/cc).

Wide porosity and permeability ranges



Simple poro-perm relationships not usable

Low Permeability Sandstones – The Issues

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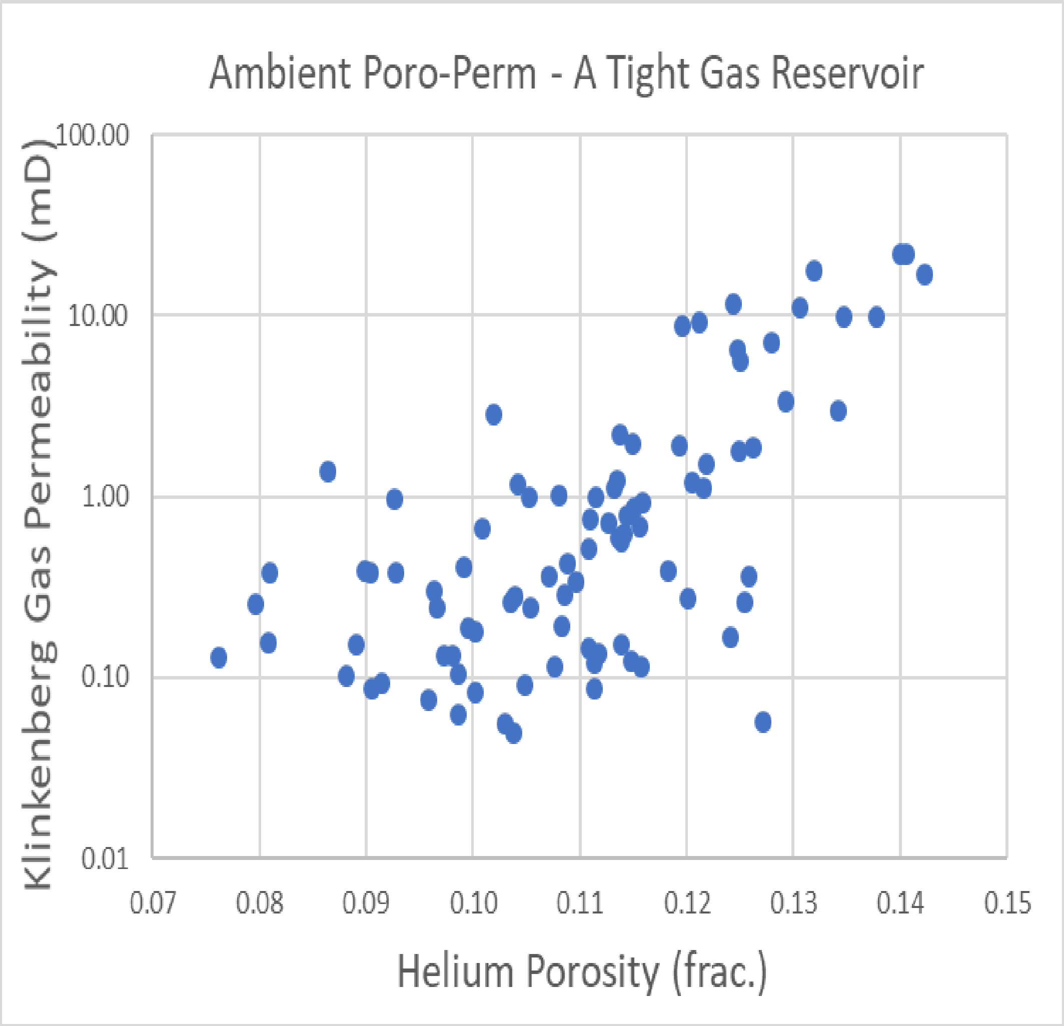

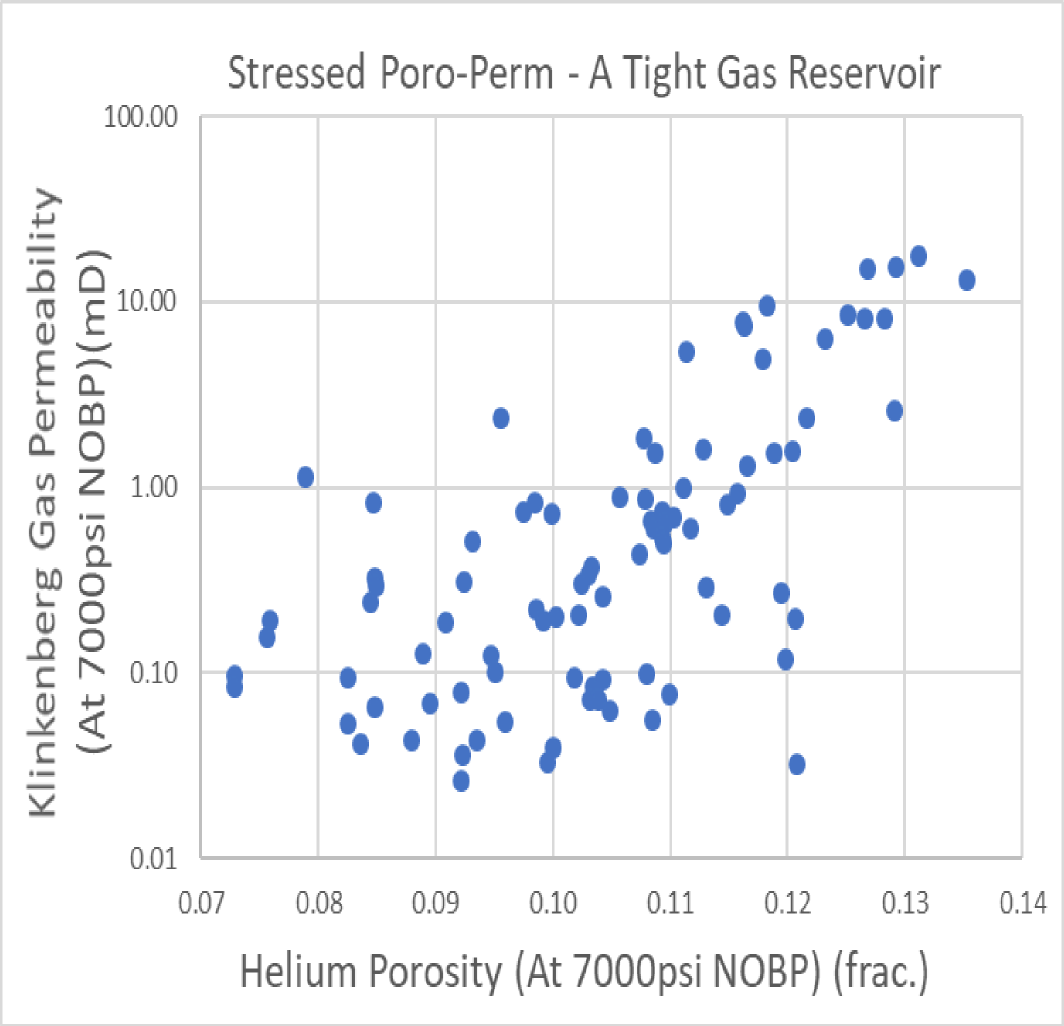

Up to an order of magnitude reduction in permeability when reservoir equivalent net overburden stress applied (7000psi)

Fundamentals of Flow Zone Index (FZI)

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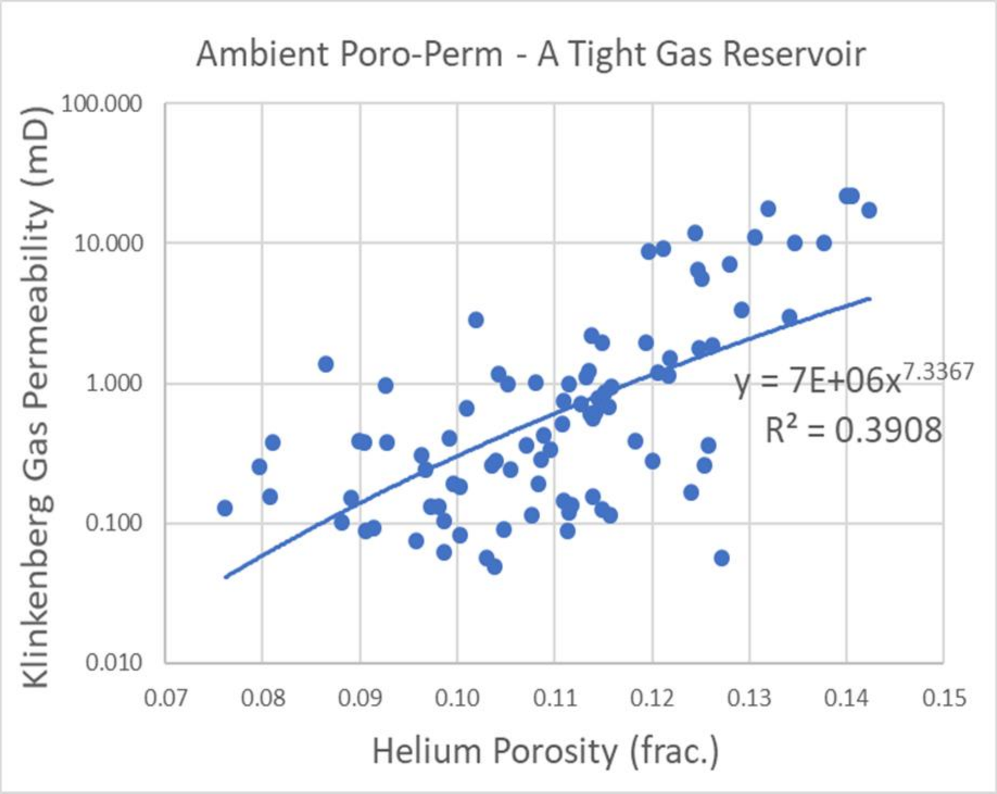
- Rocks in a tight reservoirs can have complex variation in pore geometries within different lithofacies.
- The hydraulic quality of a rock is controlled by pore geometry which in turn is controlled by mineralogy and mineral distribution.
- The traditional approach of characterising the reservoir using depositional facies does not effectively differentiate sandstones of equivalent quality due to diagenetic overprinting.



How can we make sense of this wide poro-perm range?

Fundamentals of Flow Zone Index (FZI)

$$FZI = \frac{RQI}{\Phi_R}$$

Where:

$$RQI\ (microns) = 0.0314 \left(\frac{K}{\phi}\right)^{1/2}$$

$$\phi_R = \frac{\phi}{(1 - \phi)}$$

Note: FZI is related to the Kozany Carman Equation:

$$K = \frac{1}{\tau^2 S_V^2 F_S} \cdot \frac{\phi^3}{(1 - \phi)^2}$$

$$FZI\ (microns) = \frac{1}{\tau\ S_V F_S^{1/2}}$$

Amaefule et al, Enhanced Reservoir Description: Using Core And Log Data To Identify Hydraulic (Flow) Units And Predict Permeability In Uncored Wells, 1993, SPE 26436

Fundamentals of Flow Zone Index (FZI)

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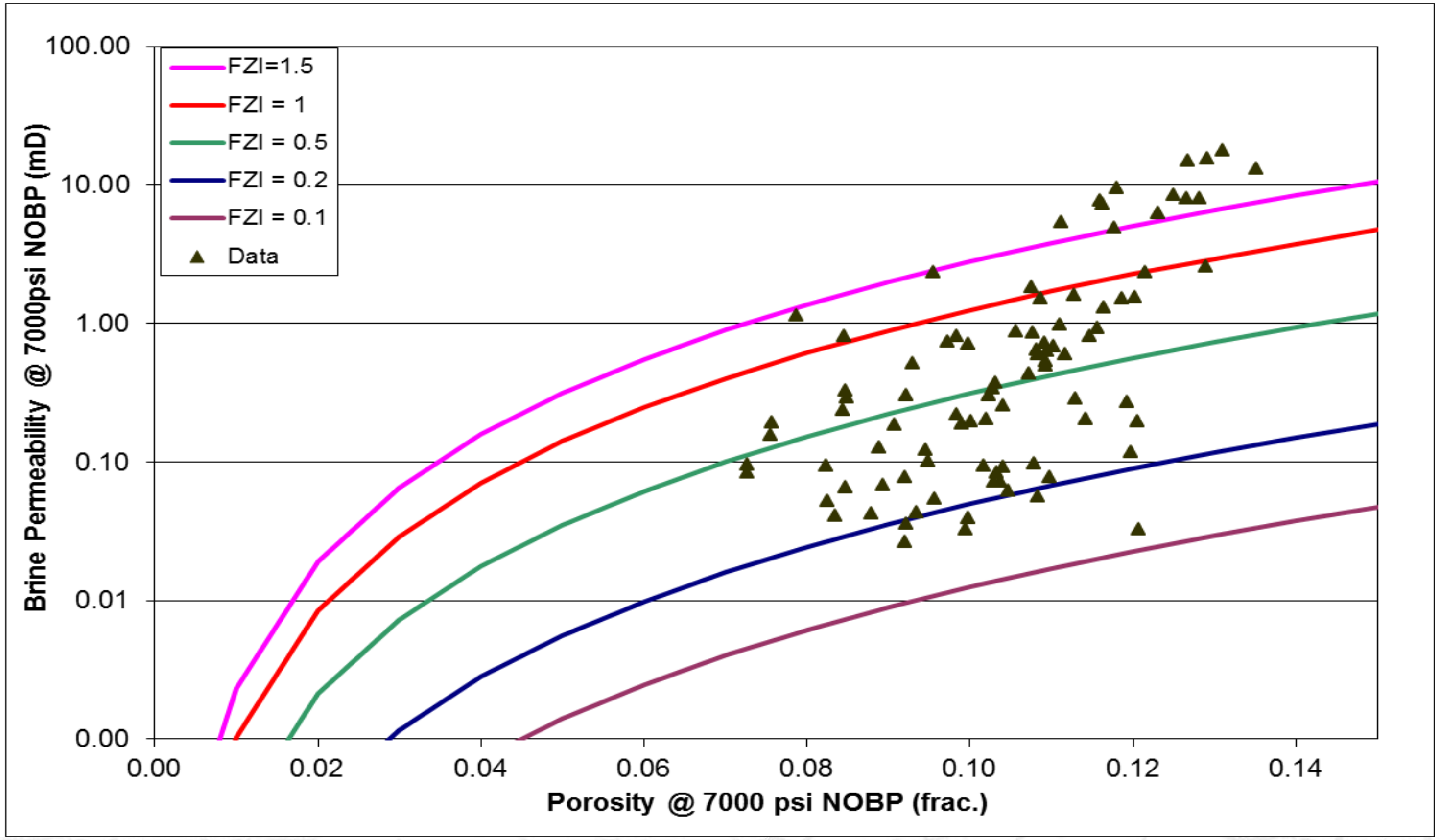
$$FZI = \frac{RQI}{\Phi_R} = \frac{1}{\tau \; S_V \; F_S^{1/2}}$$

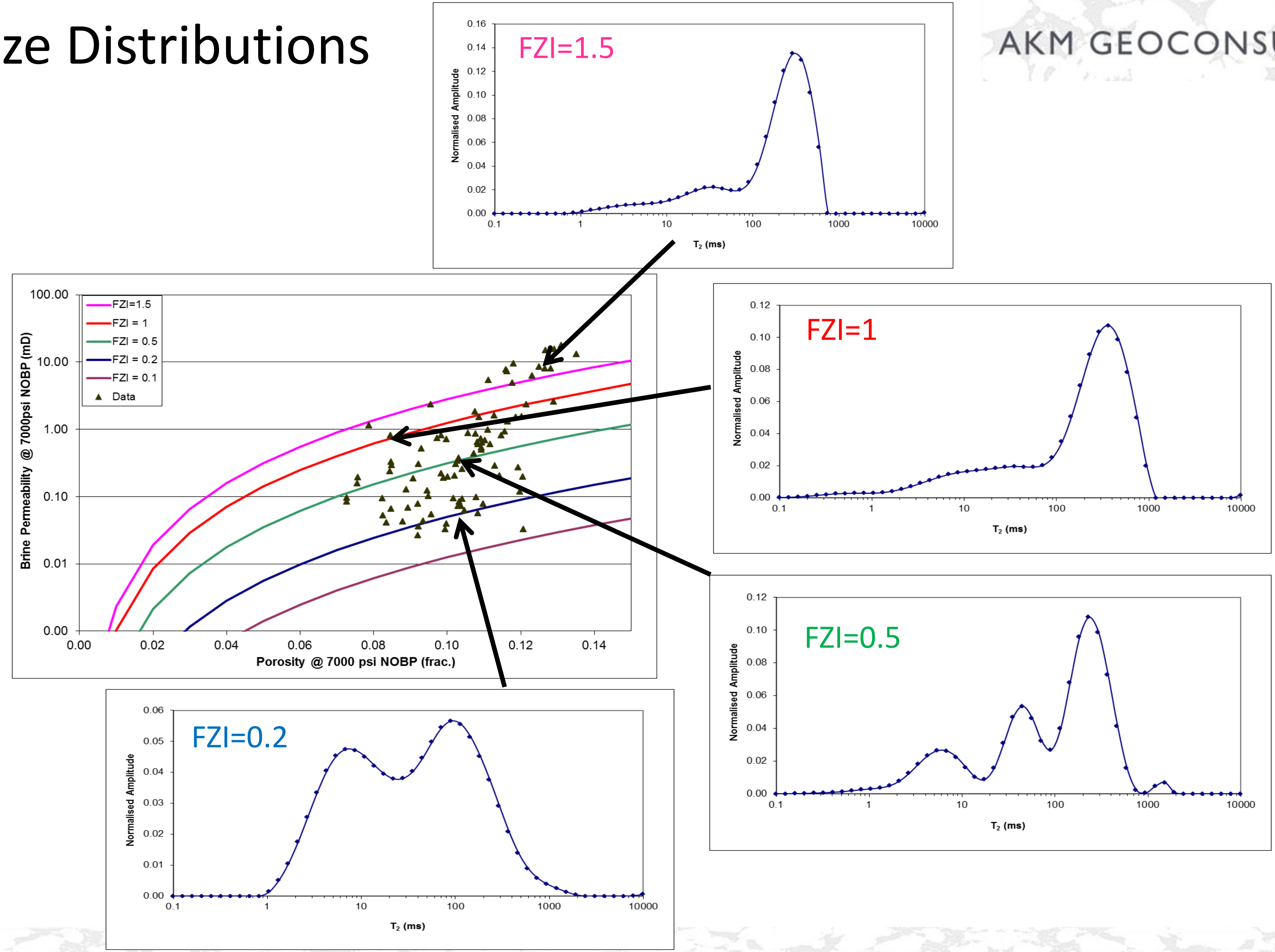
Grain Shape Factor

Tortuosity/
coordination no.

Surface to
volume ratio



FZI & Pore Size Distributions



Flow Zone Index Group Definition

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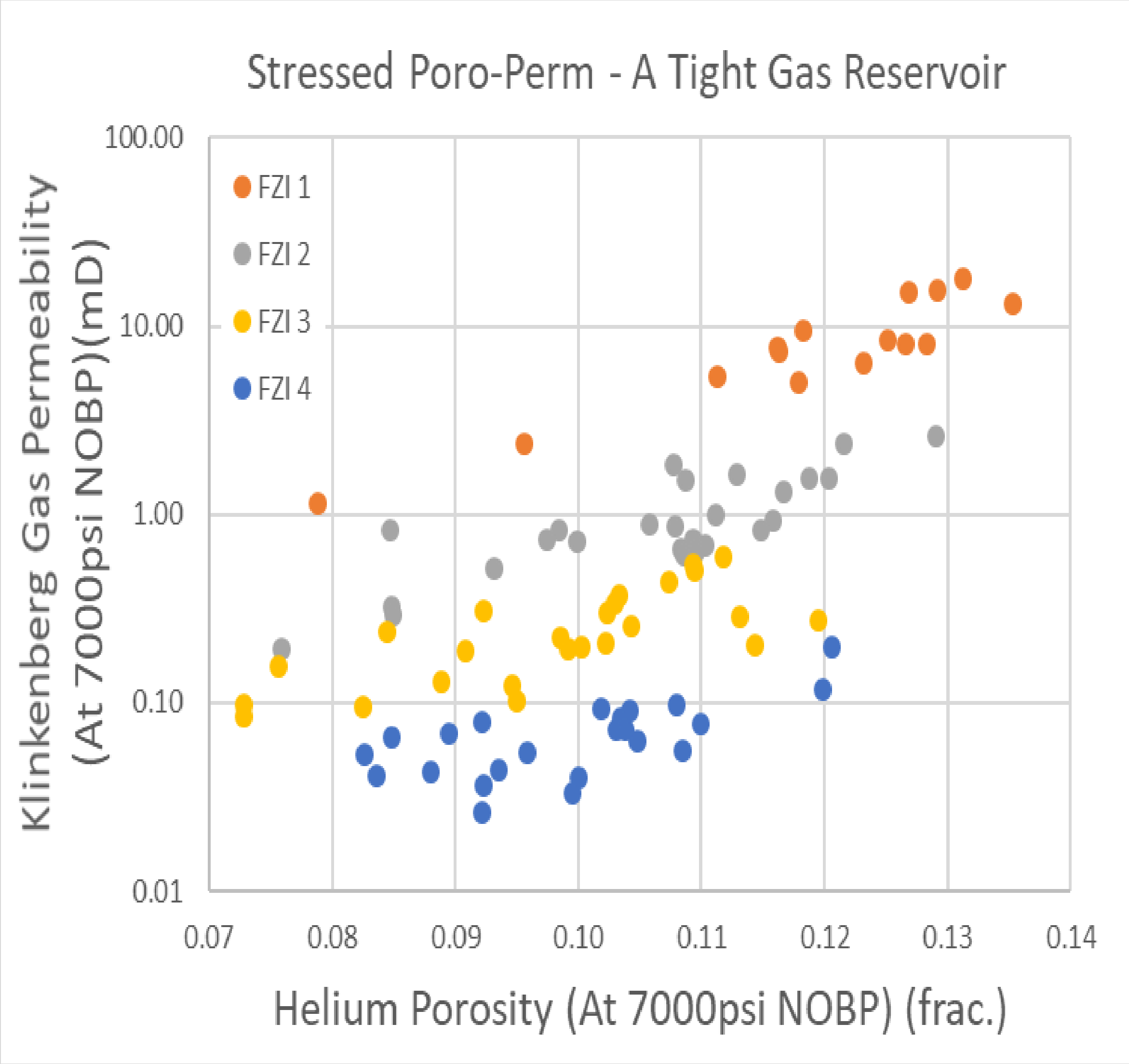

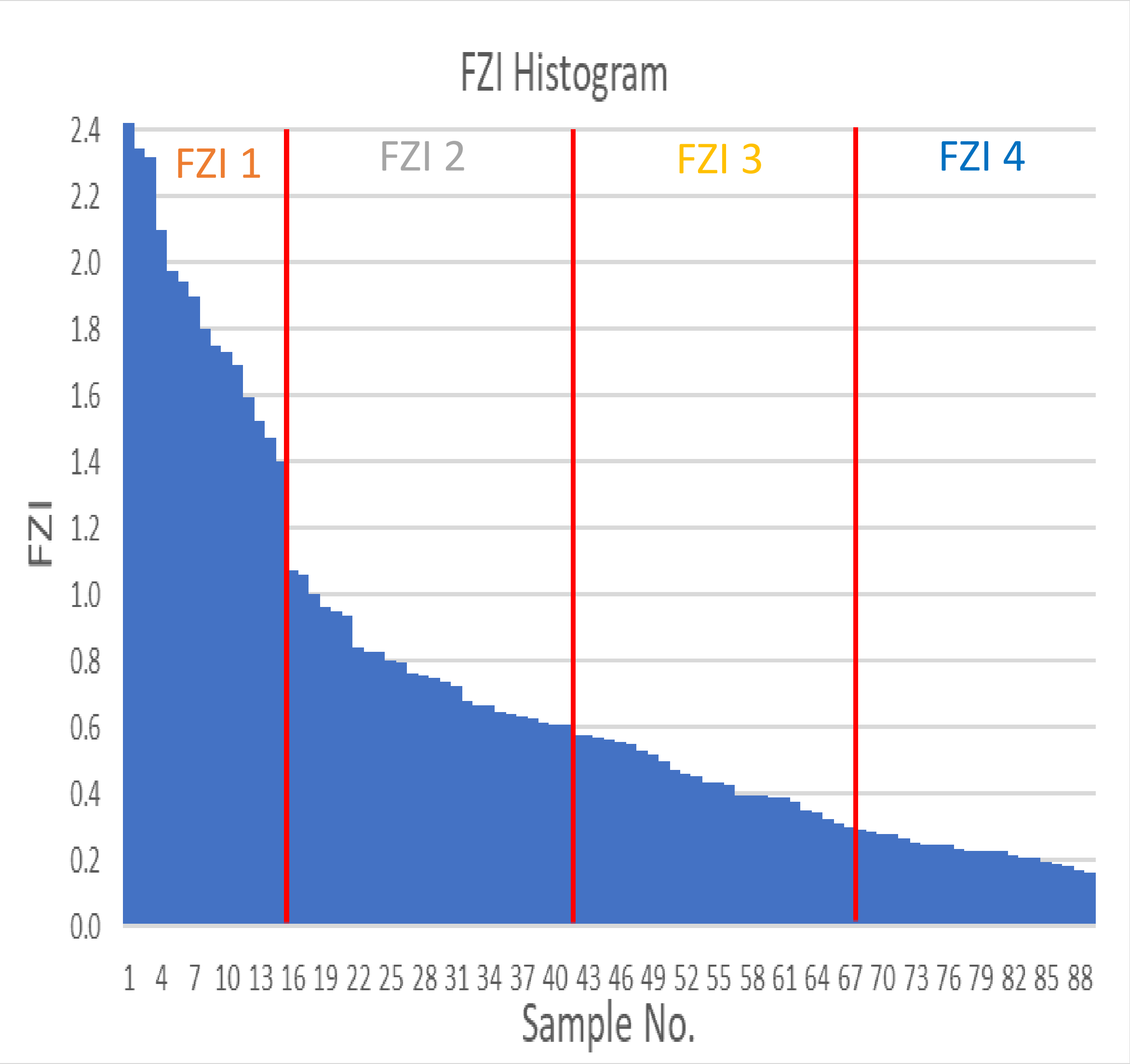

Flow Zone Index Group Definition

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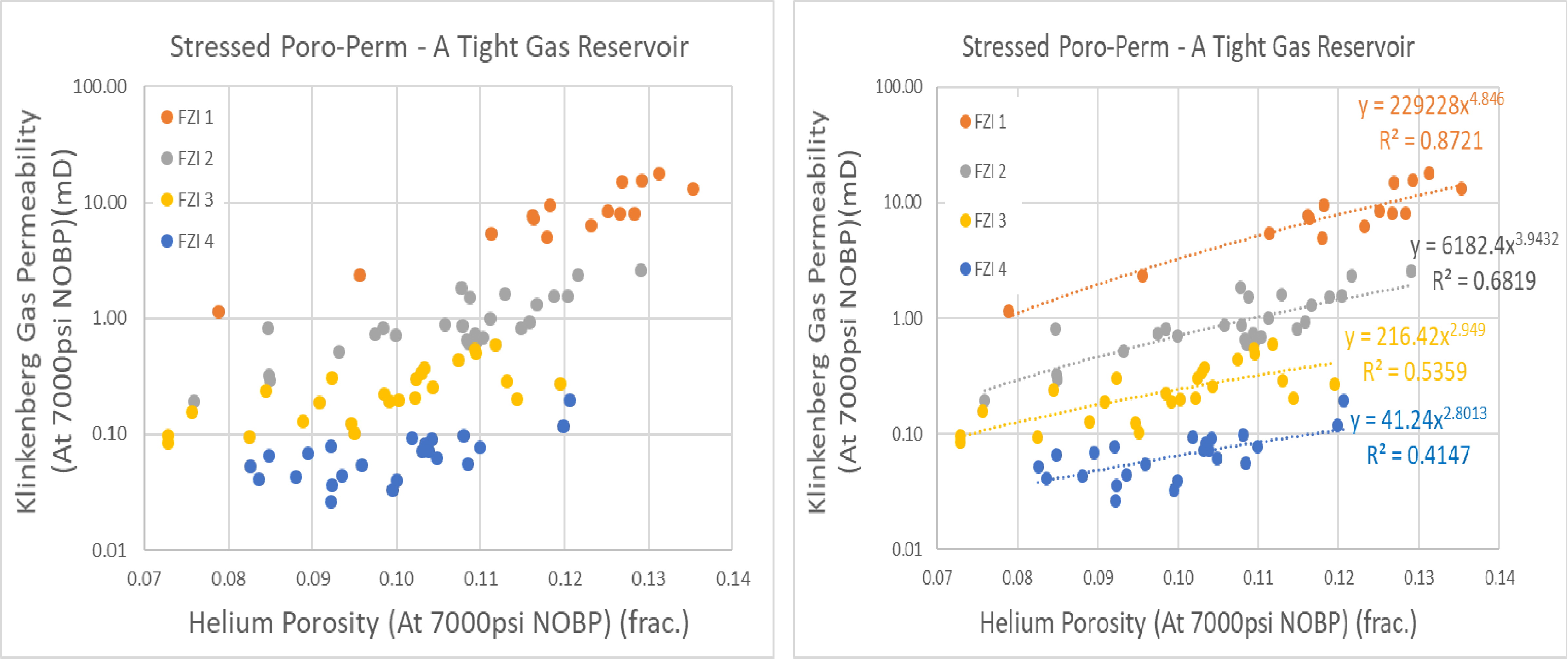
- Each flow zone group has a poro-perm relationship



Flow Zone Index and Mineralogy

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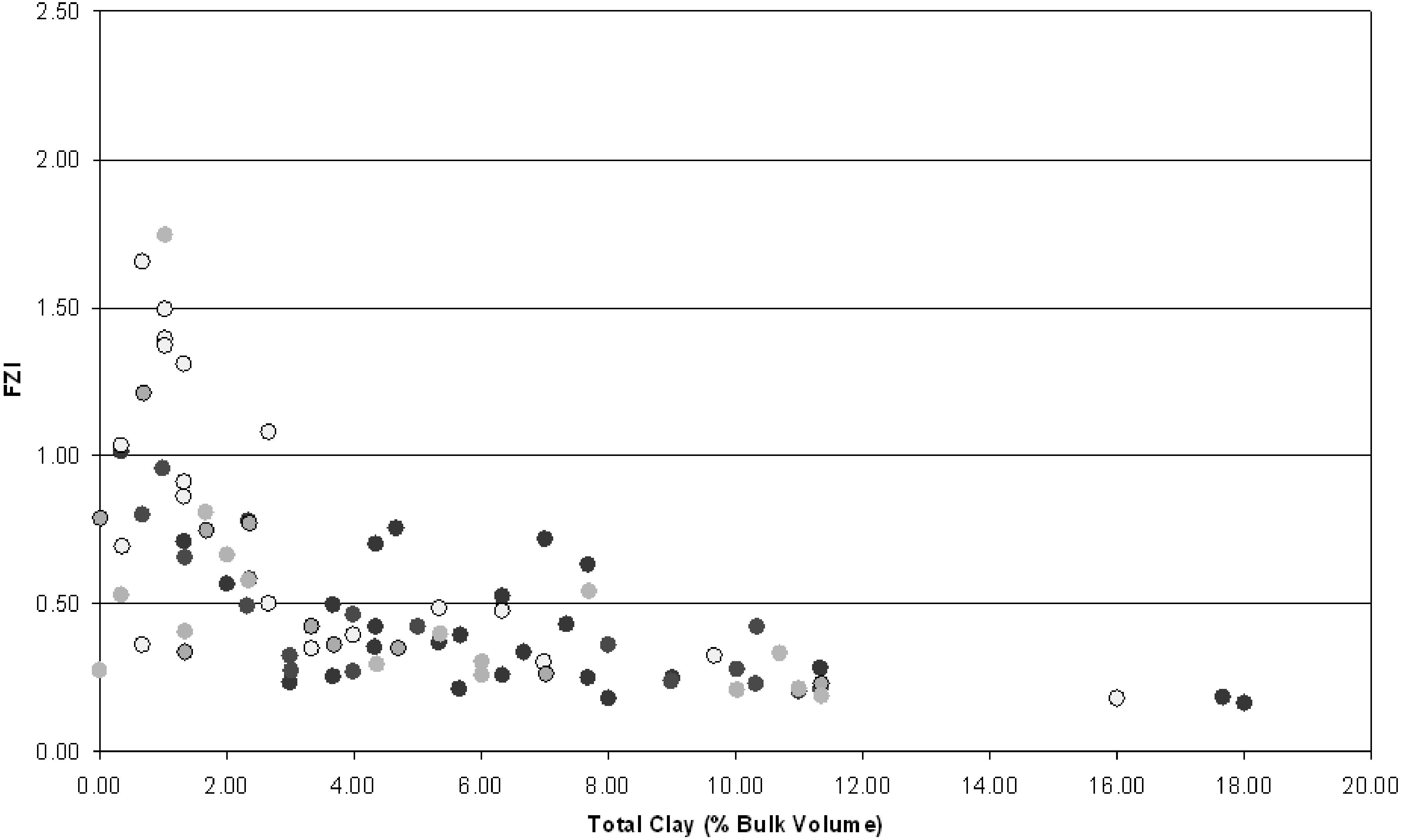


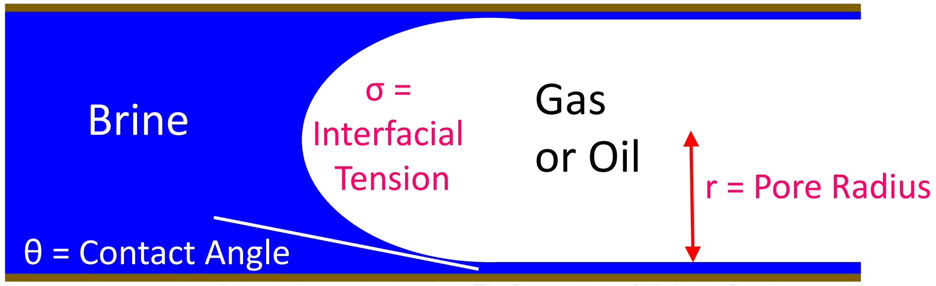
Capillary Pressure – Why is it Important?

- We can calculate saturations from logs – but what happens away from the well control? How do we populate our reservoir model with water saturation between wells?

- If we can not answer this question then we can not calculate hydrocarbon in place.

- Key measurement is capillary pressure:

Definition: *"Capillary pressure is the pressure difference across the curved interface between two immiscible fluid phases. The phases are either wetting or non-wetting with respect to the pore wall."*



$$Pc = \frac{2\,\sigma\,\mathrm{Cos}\theta}{r}$$

Capillary Pressure - Theory

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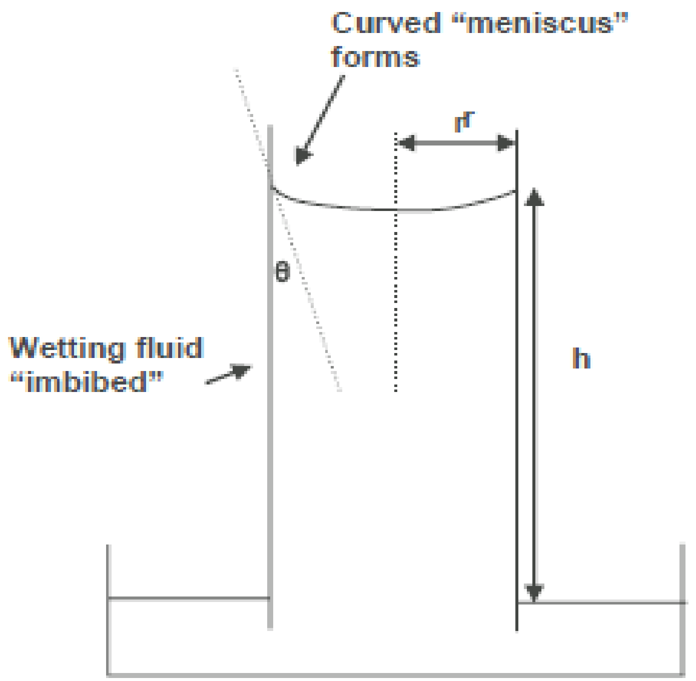
- Water rises in a glass tube due to preferential wetting (wettability), counterbalanced by gravitational forces until equilibrium occurs - Imbibition

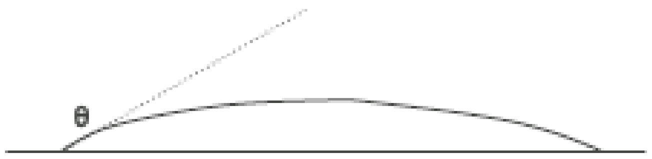


From balance of forces (equilibrium)

$$h = \frac{P_c}{(\rho_w - \rho_g)g} = \frac{2\sigma\cos\theta}{r(\rho_w - \rho_g)g}$$

σ-Interfacial Tension (dynes/cm or mN/m)

θ–Interfacial Contact Angle



Remember, h is vertical height!!!!!!!

& the smaller the r, the higher the h.

- In the reservoir capillary pressure controls, along with buoyancy forces (gravity), the rocks ability to retain brine in the presence of hydrocarbon.
- The balance of these two forces dictate the distribution of fluids in the reservoir.

Capillary Pressure in the Reservoir

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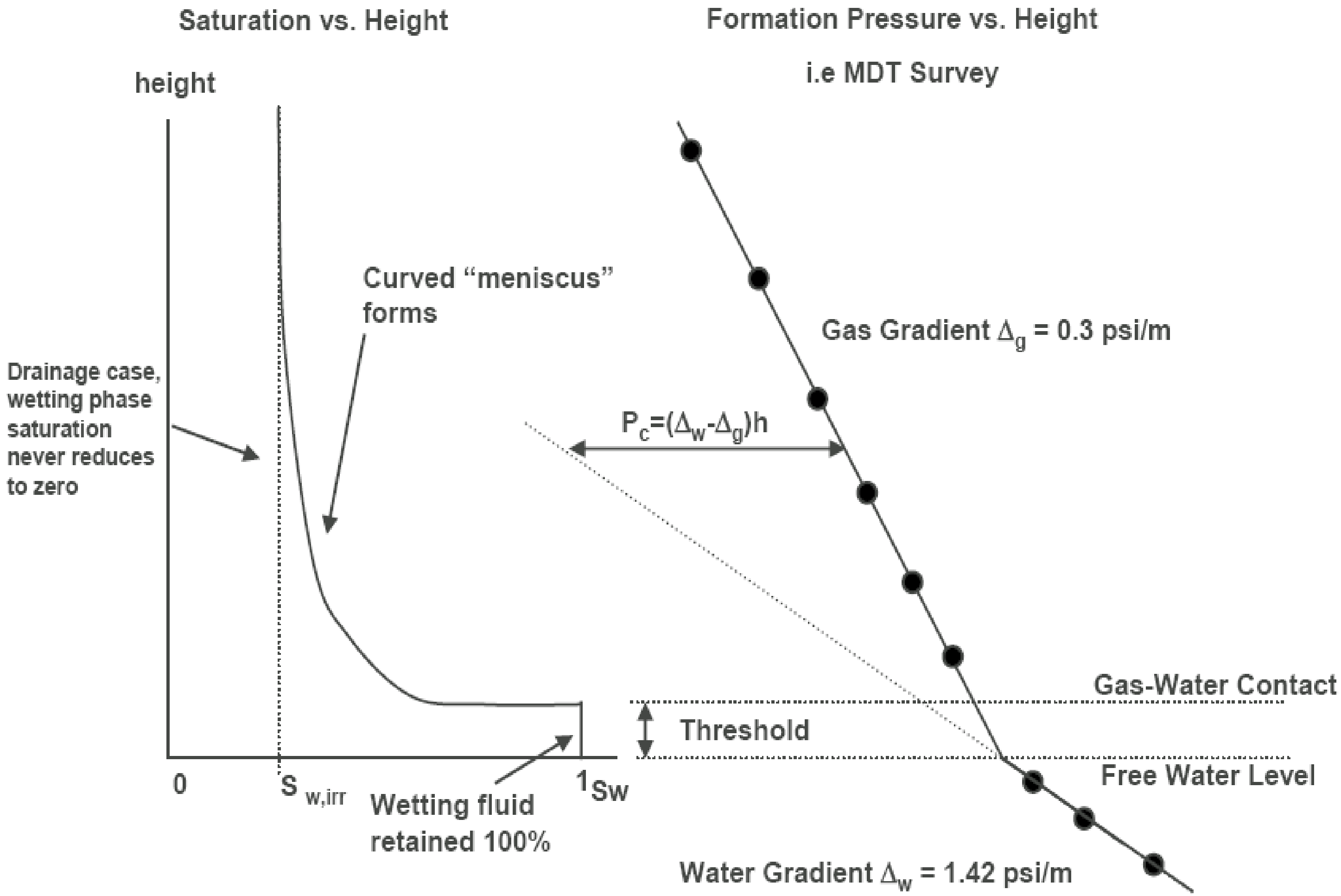
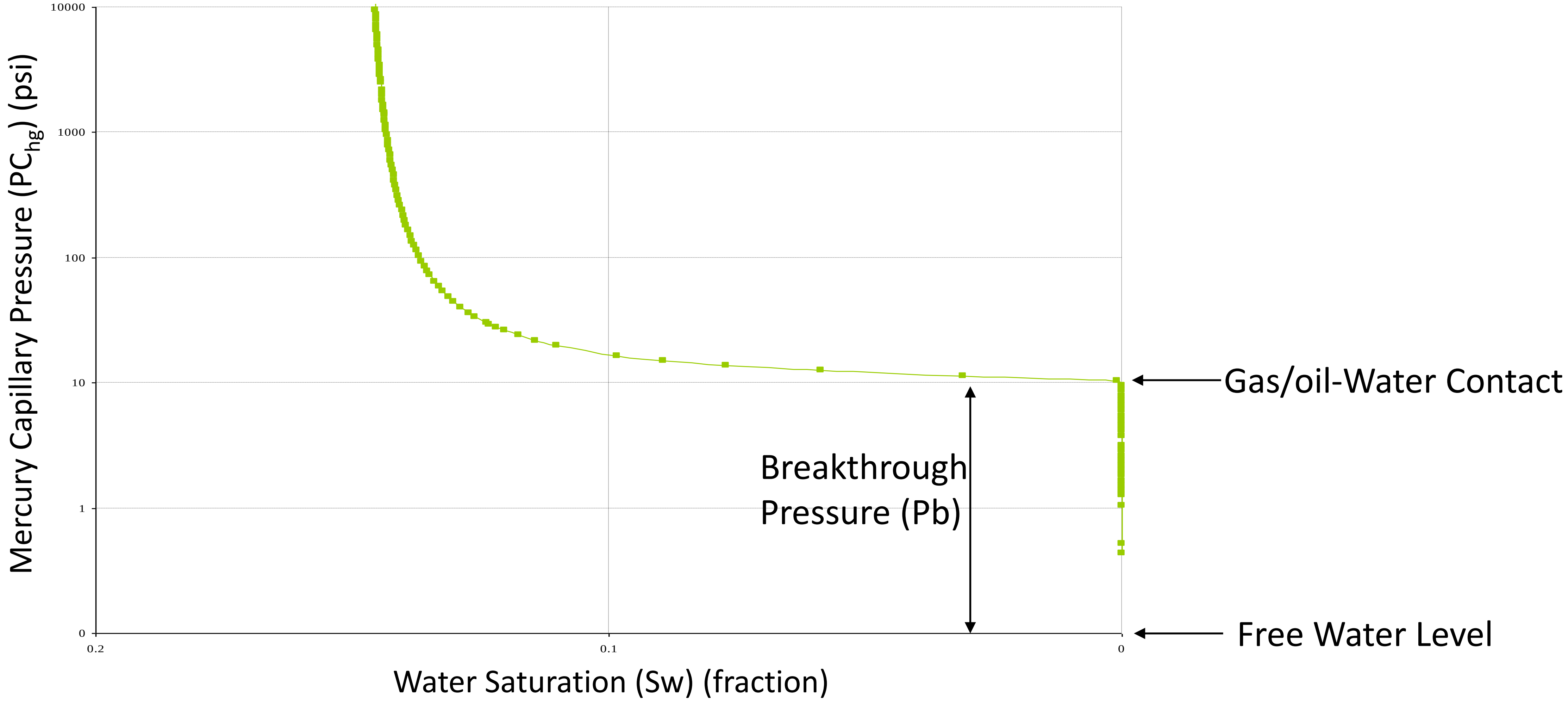
Capillarity and gravity give rise to a saturation-height profile in porous permeable rocks. Drainage occurs when hydrocarbon displaces water downwards on migration into a structure due to buoyancy forces.

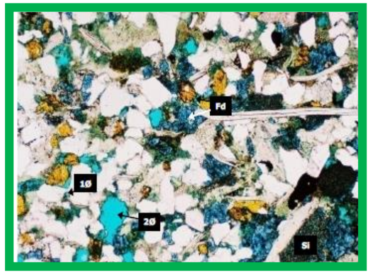


Capillary Pressure - Theory

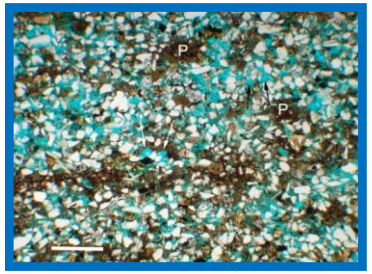


Note: In a mercury injection experiment mercury is the non-wetting phase and air is the wetting phase. Hence air is analogous to water and mercury to gas. This assumes the rocks are water wet.

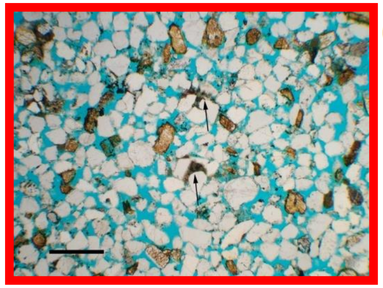
Capillary Pressure in the Reservoir



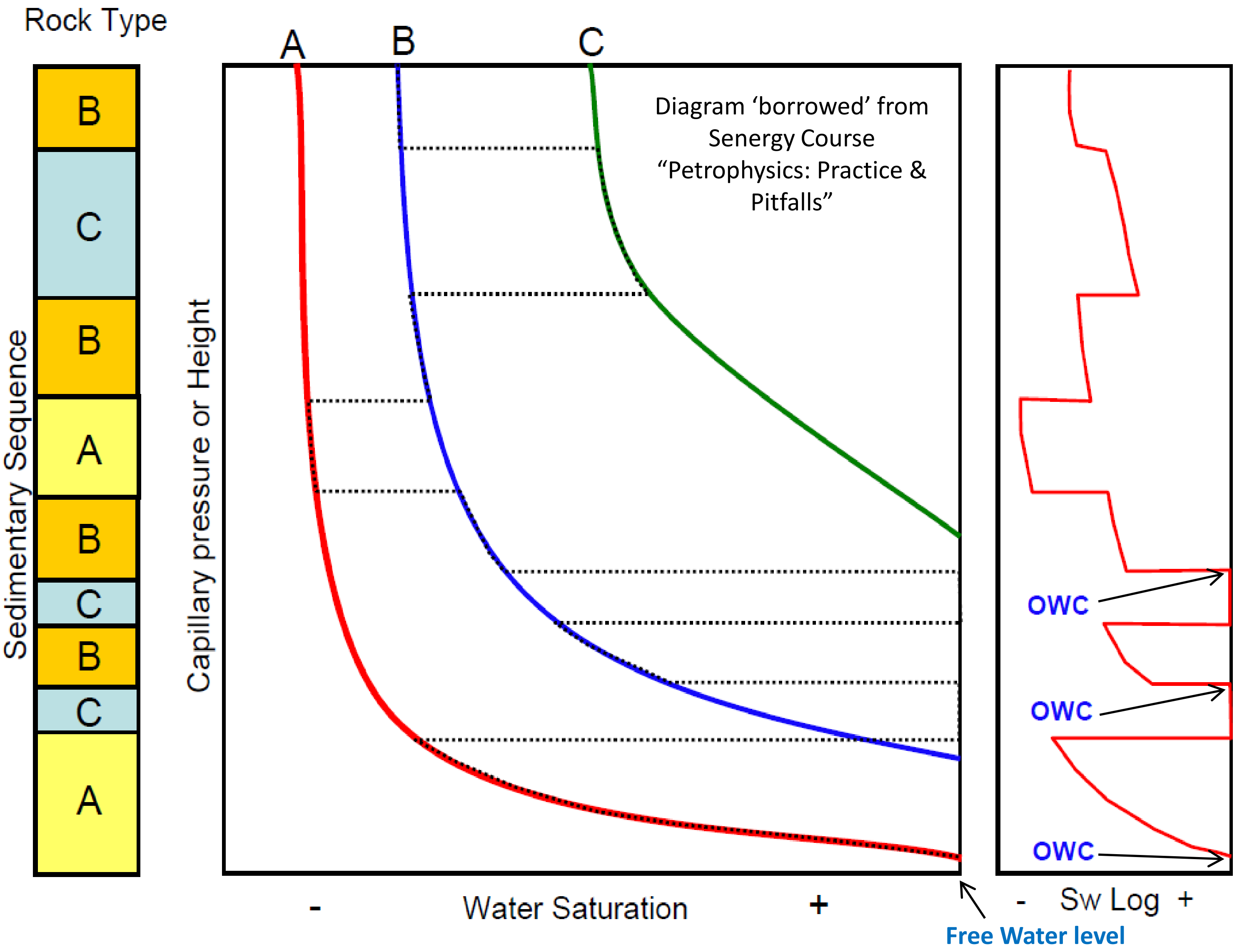
Rock Type C
1.1mD and 14% Porosity



Rock Type B
14mD and 28% Porosity



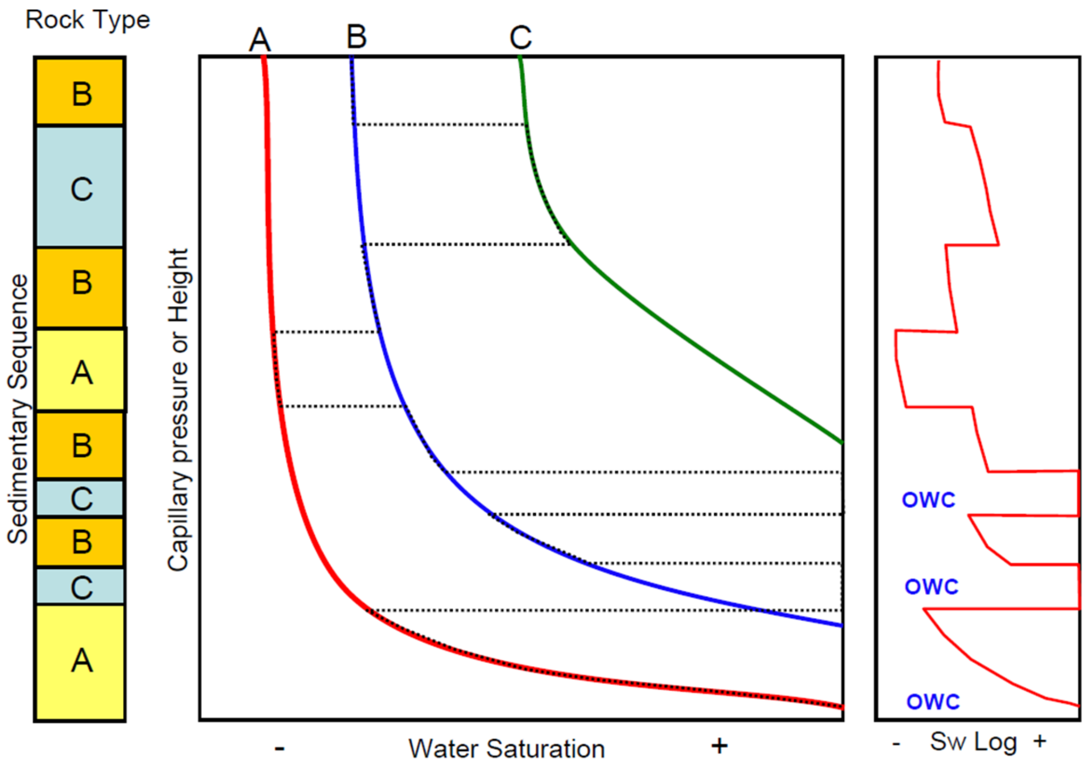
Rock Type A
719mD 25% Porosity



Adam’s Top Tip 1: Don’t confuse free water level with oil or gas water contact.

What is a Saturation Height Function?

- A mathematical function to describe the position and curvature of the capillary pressure curve for each rock type.
- Hopefully the saturation height function water saturations match the log derived saturations.
- The reservoir modeller needs a saturation height function to populate the model saturation away from the wellbore.



What data do we need to build a saturation height function?

- Free water level
    - Need to accurately know FWL to ’anchor’ saturation height function
    - Use formation pressure data or core Dean-Stark saturation data
- Capillary pressure data
    - For all reservoir rock types, both pay and non-pay
    - Special core analysis data
- Permeability model
    - Most saturation height function models require permeability, this can be measured on core or ‘estimated’ from calibrated log models
- Fluids property data for both water and hydrocarbons
    - Density, interfacial tension, contact angle (wettability)

Adam’s Top Tip 2: Keep it simple. Start with the simplest model and only get more complex if you really need to.

Fluid Properties - Capillary Pressure for Different Fluid Combinations

In translating from the lab fluids (at lab conditions) to reservoir fluids (at reservoir conditions), Interfacial tensions and contact angles change, so equivalent Pc changes;

$$\frac{P_{c.lab}}{\sigma_{lab}\cos\theta_{lab}} = \frac{P_{c.res}}{\sigma_{res}\cos\theta_{res}}$$

$$P_{c.res} = \frac{P_{c.lab}\sigma_{res}\cos\theta_{res}}{\sigma_{lab}\cos\theta_{lab}} = (\Delta_w - \Delta_h)h$$

System	θ Contact Angle	cos θ Cos Contact Angle	σ Interfacial Tension	σcosθ
Laboratory				
Air-Water	0	1.000	72	72
Oil-Water	30	0.866	48	42
Air-Mercury	140	0.765	480	367
Air-Oil	0	1.000	24	24
Reservoir				
Water-Oil	30	0.866	30	26
Water-Gas	0	1.000	50	50

Uncertainty in these values will effect hydrocarbon saturations derived from capillary pressure data that is not from the same fluid/gas pair as the reservoir.

Thomeer Model

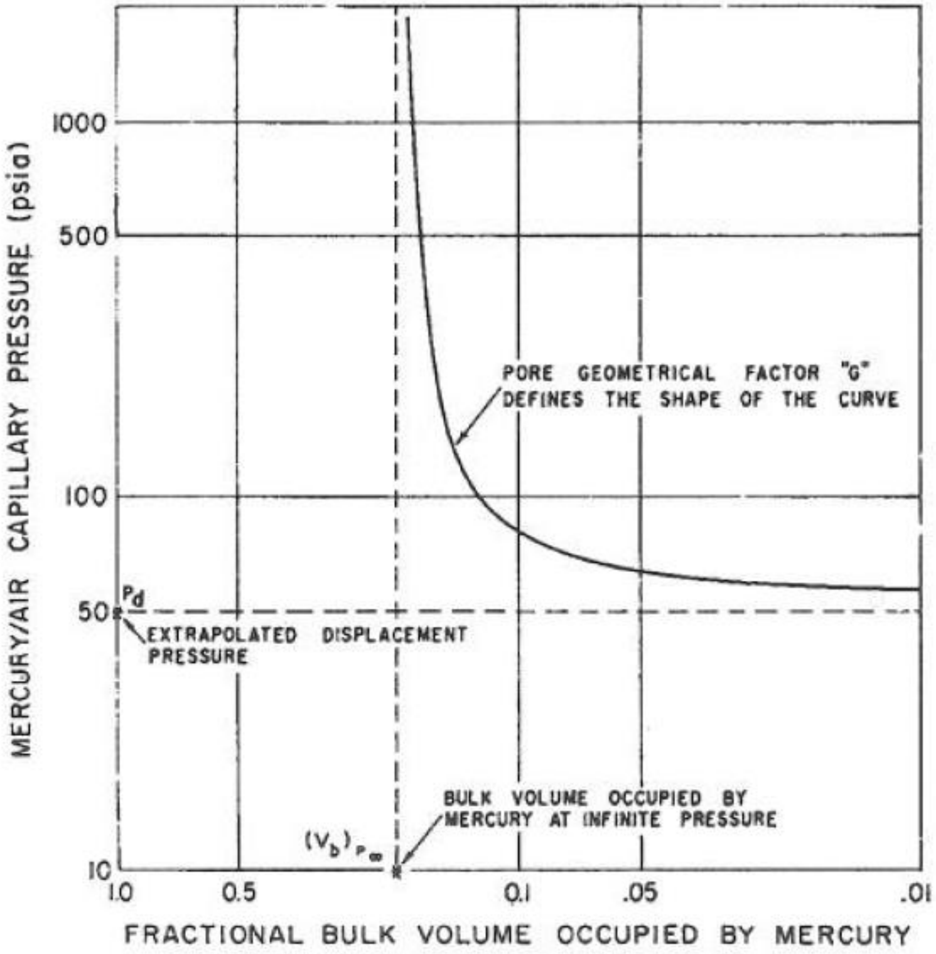


FIG. 1—DEFINITION OF THE PARAMETERS.

$$(\log P_c - \log P_d)\,[(\log (V_b)_{P_c} - \log (V_b)_{P_\infty}] = -C^2 \quad . \; . \; . \; . \quad (1)$$

where the numerical value of C^2 defines the shape of the curve under consideration.

This expression can be written as

$$\frac{(V_b)_{P_c}}{(V_b)_{P_\infty}} = 10^{-C^2/(\log P_c/P_d)} . \quad . \; . \; . \; . \; . \quad (2)$$

Use in saturation height function

where

$(V_b)_{P_c}$ = fractional bulk volume occupied by mercury at pressure P_c,

$(V_b)_{P_\infty}$ = fractional bulk volume occupied at infinite pressure or total interconnected pore volume, **= Effective Porosity**

P_c = mercury/air capillary pressure, psia

P_d = mercury/air extrapolated displacement pressure, psia, and

C pore geometrical factor.

Note: X-axis is fraction of 'bulk volume' occupied by mercury or gas

"Introduction of a Pore Geometrical Factor Defined by Capillary Pressure" – J. Thomeer, JPT March 1960, SPE Paper No.1324

Thomeer Model in a Tight Gas Reservoir

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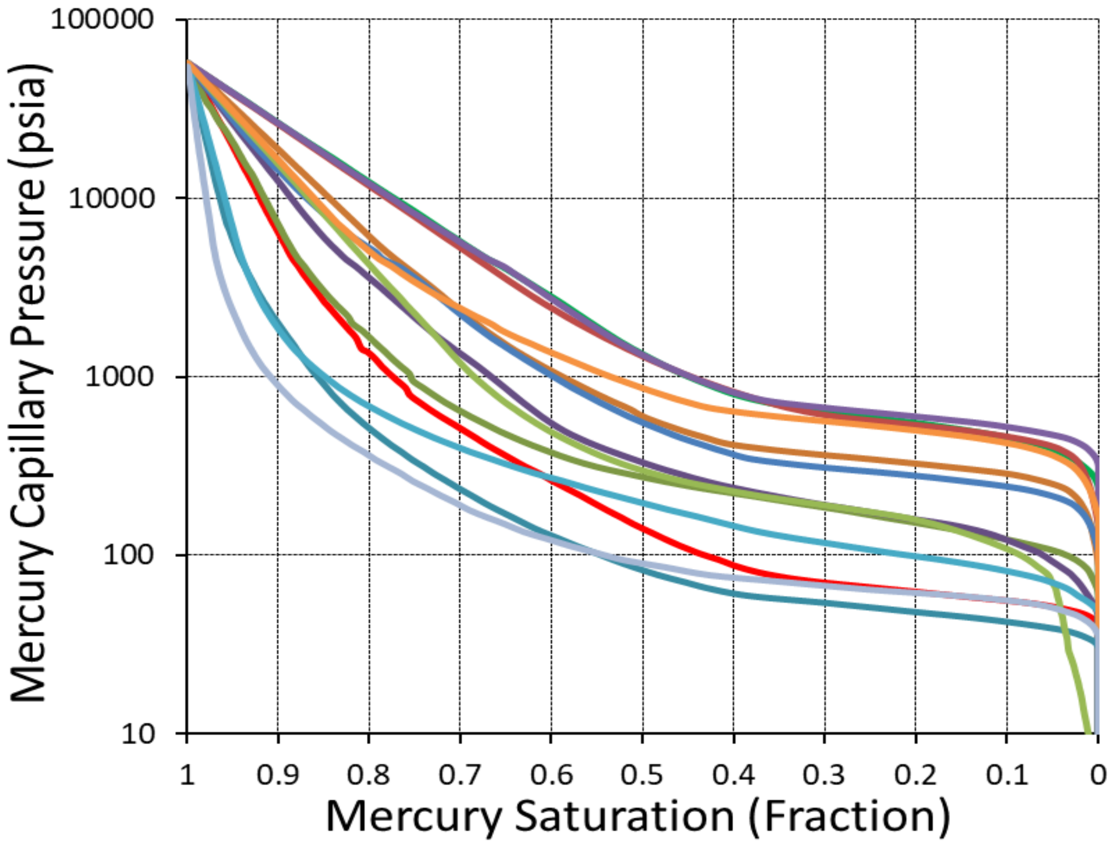

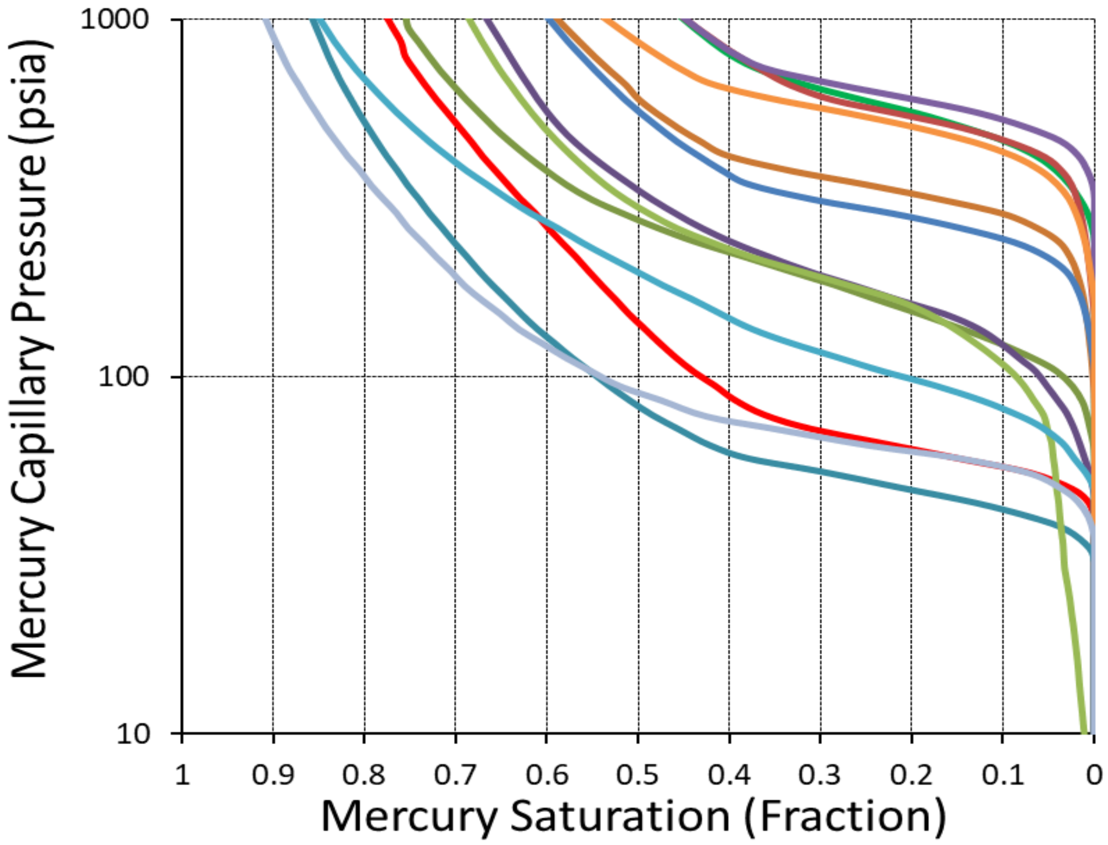

The breakthrough pressures (Pb) and Thomeer shape factors (C) are defined for each capillary pressure curve

We did this using data up to 1000psi mercury capillary pressure because this equates to the maximum reservoir thickness i.e. 200m

Using FZI to computing the Thomeer model Parameters

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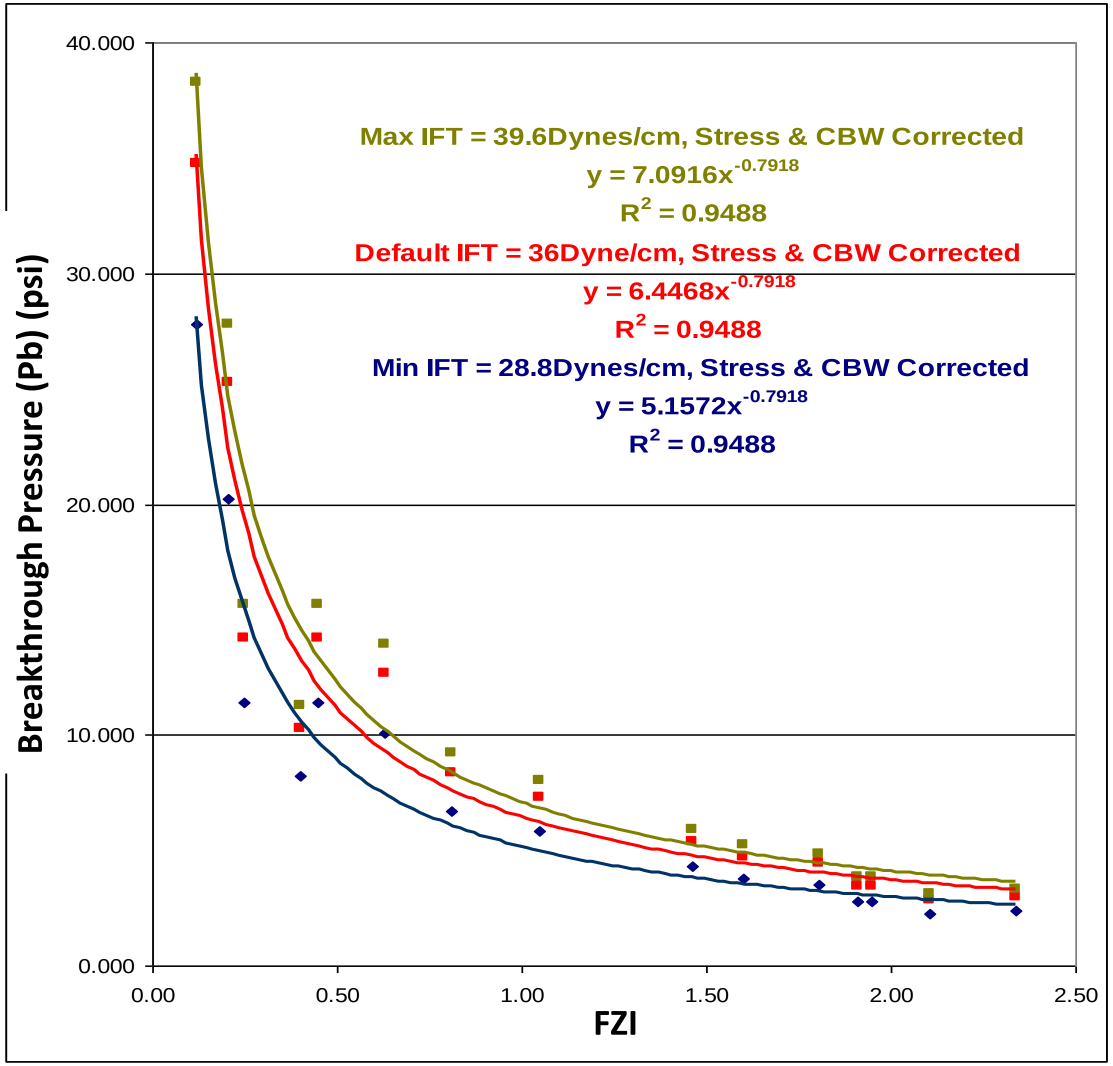
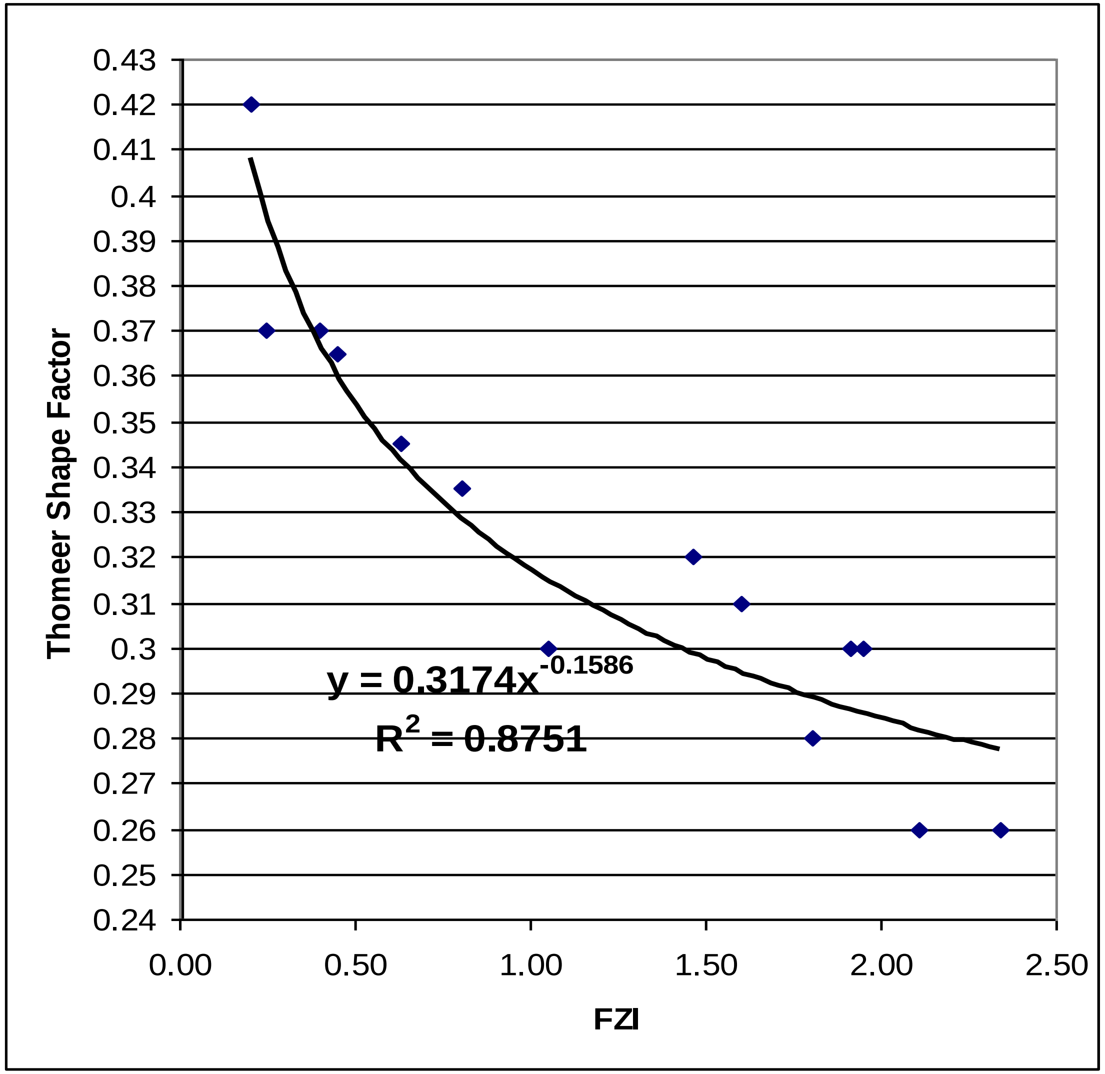
Flow zone index correlates with breakthrough pressure (Pb) and Thomeer shape factor (C)

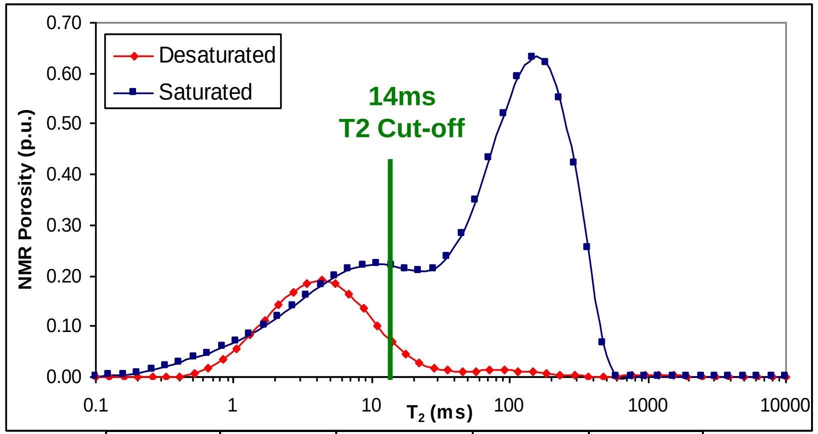




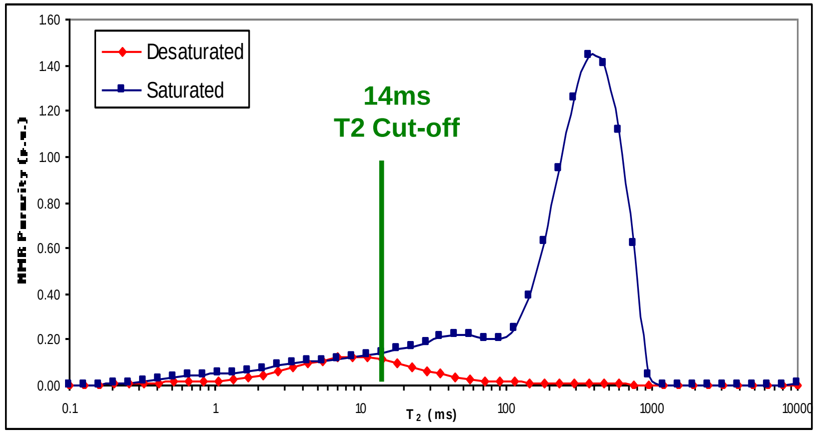
Adam's Top Tip 3: Remember that permeability, porosity & capillary pressure measurements should all be at net overburden stress.

NMR Core Analysis Data

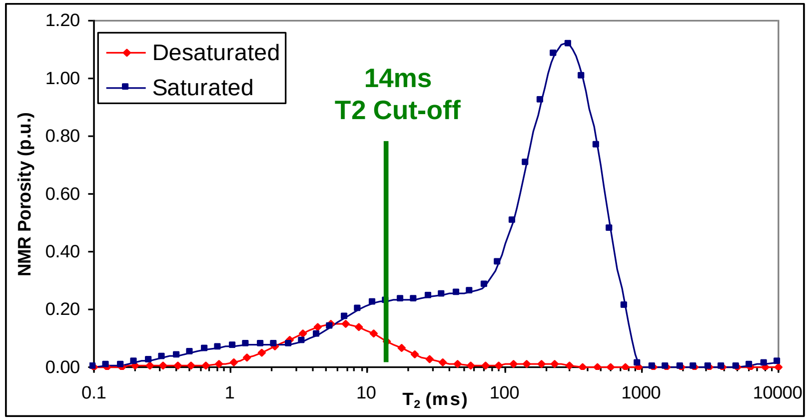
- SCAL Plugs – saturated & desaturated T2 distributions measured.
- T2 cut-off of 14 mS used to differentiate free and bound fluid.



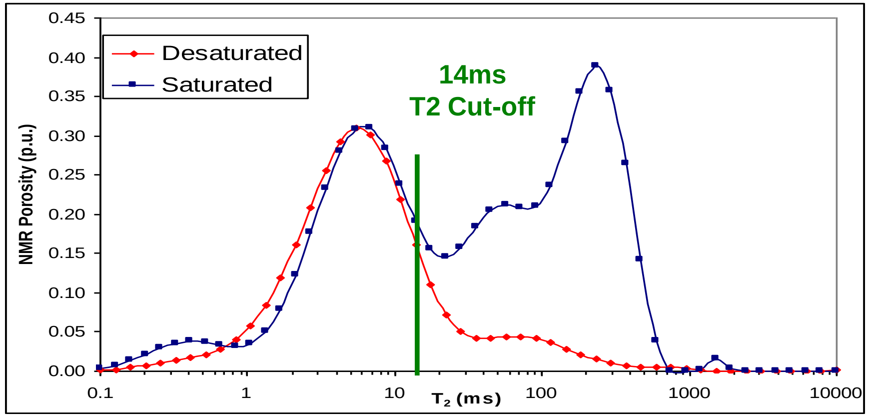
Sample No.	Depth (Metres)	Permeability to Gas, Ka (mD)	Helium Porosity (%)	Sw at Gas-Brine Pc 200psi (frac PV)
2	4382.91	0.22	7.9	0.239



Sample No.	Depth (Metres)	Permeability to Gas, Ka (mD)	Helium Porosity (%)	Sw at Gas-Brine Pc 200psi (frac PV)
3	4389.38	8.6	11.1	0.138



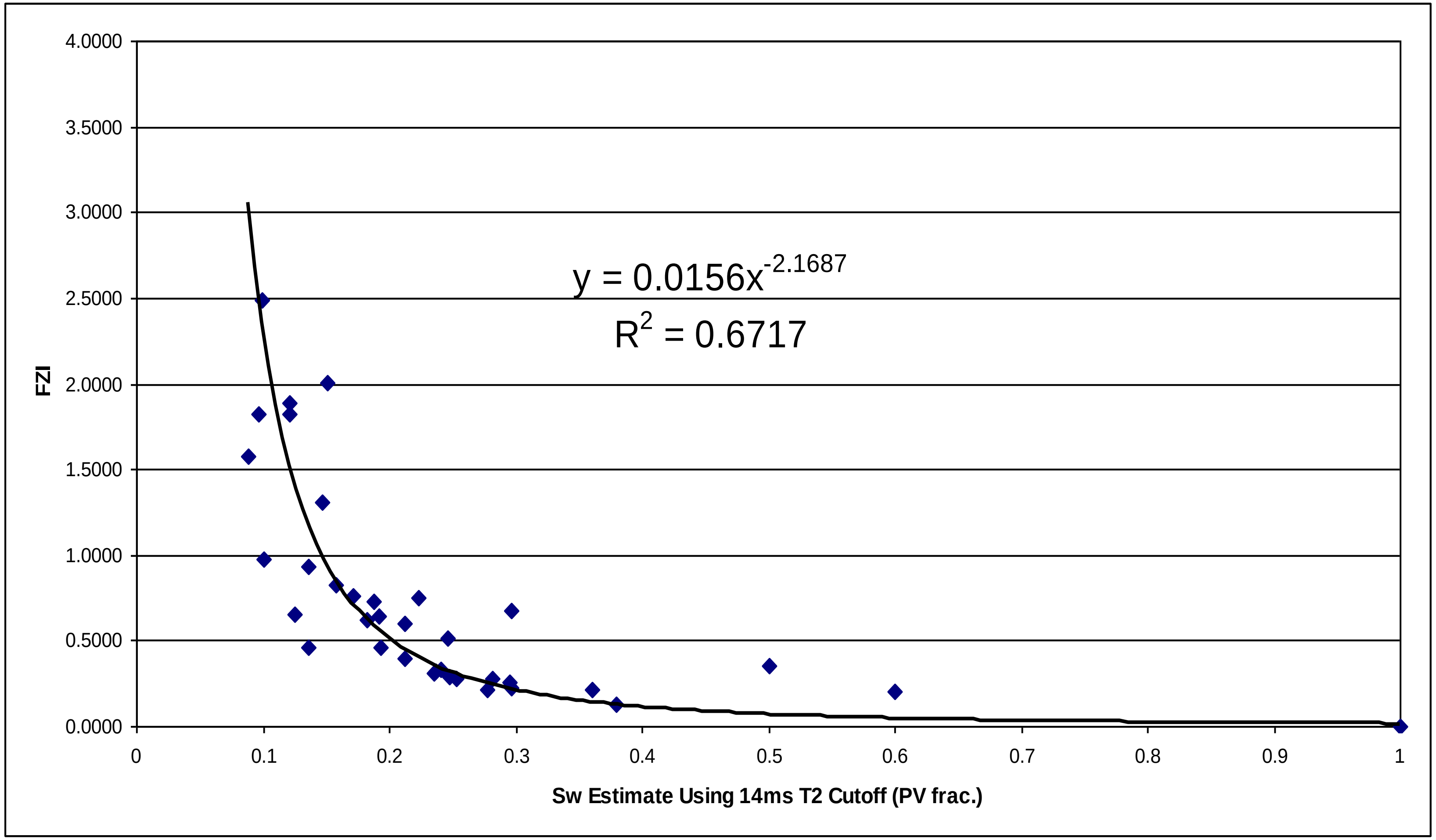
Sample No.	Depth (Metres)	Permeability to Gas, Ka (mD)	Helium Porosity (%)	Sw at Gas-Brine Pc 200psi (frac PV)
4	4403.39	6.0	10.9	0.134



Sample No.	Depth (Metres)	Permeability to Gas, Ka (mD)	Helium Porosity (%)	Sw at Gas-Brine Pc 200psi (frac PV)
5	4424.82	0.44	5.7	0.518

FZI prediction using NMR

Flow zone index can be derived using the NMR log data based on a 14ms T2 cut-off and the following relationship:



This relationship is just a re-worked version of the Timer Coates NMR permeability model

Adam's Top Tip 4: The vast majority of saturation height functions require a permeability model.

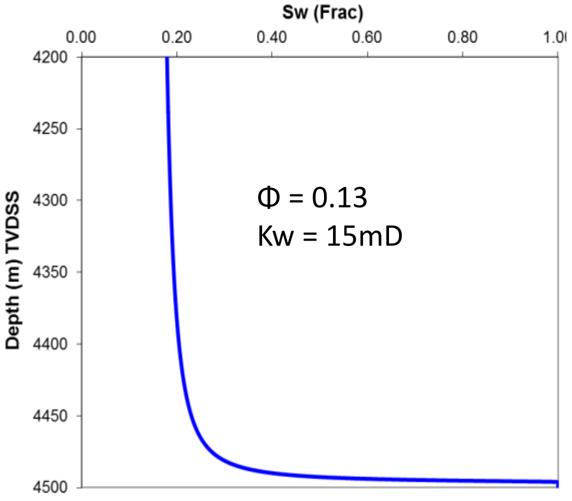
Summary: Saturation height function using the Thomeer model

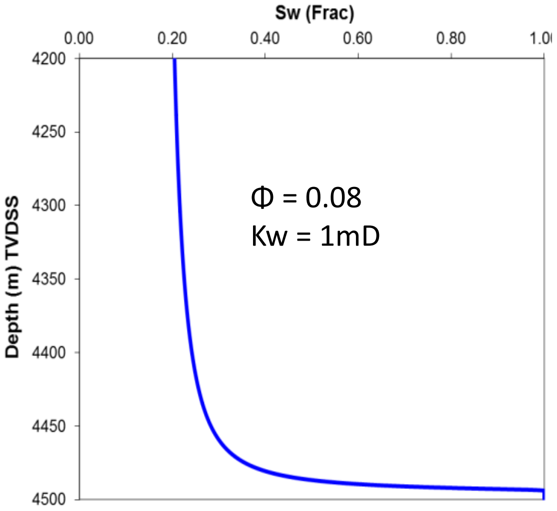
The saturation-height function using Flow Zone Index (FZI):

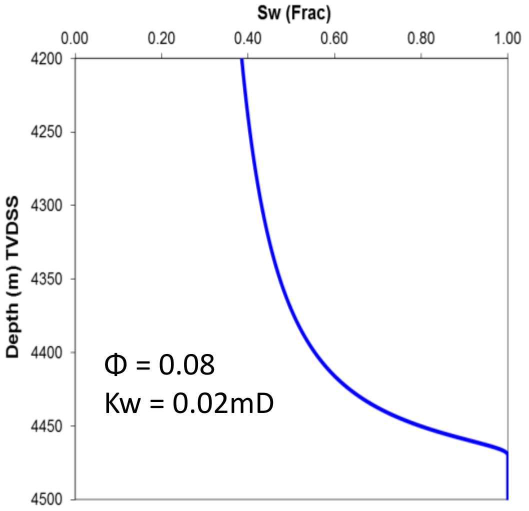
- Breakthrough pressure, $Pb = 6.4468*(FZI^{-0.7918})$
- Thomeer Shape factor, $C = 0.3174*(FZI^{-0.1586})$
- Capillary Pressure from height above FWL (m)

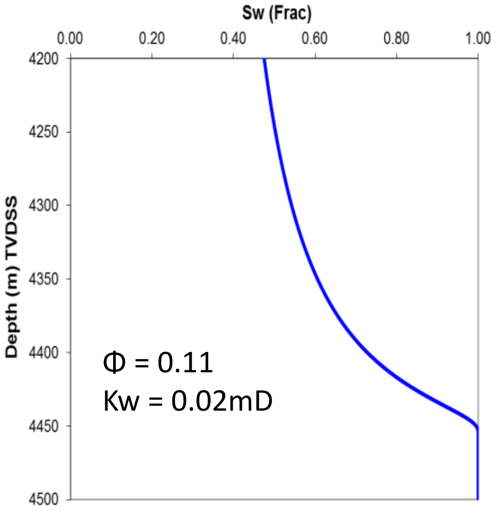
  $$Pc = (Height\ above\ FWL \times 62.42762\ (\rho_w - \rho_g) \times 3.28084)/144$$
- Water Saturation $Sw = 1-(10^{(-C^2/\log_{10}(Pc/Pb))})$

Adam's Top Tip 5: Take care with the units. In our industry we like to mix units. We almost never use SI unit!









Adam's Top Tip 6: Sense check your model in Excel for a wide range of poro-perm values.

The Model vs Experiment

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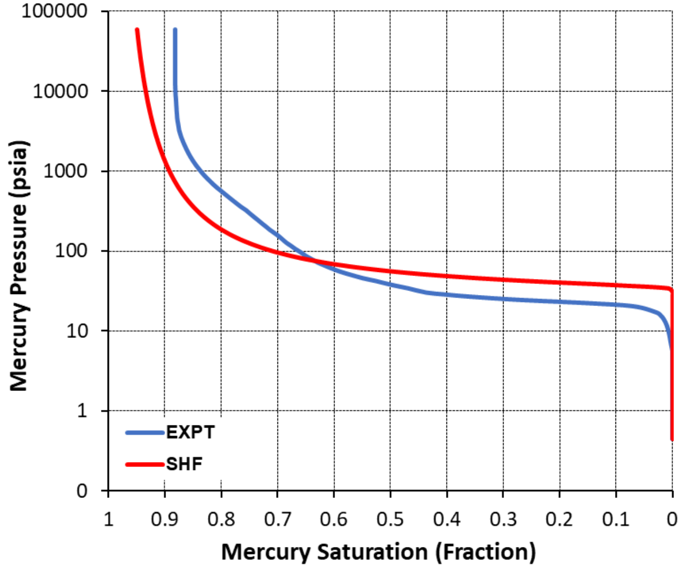
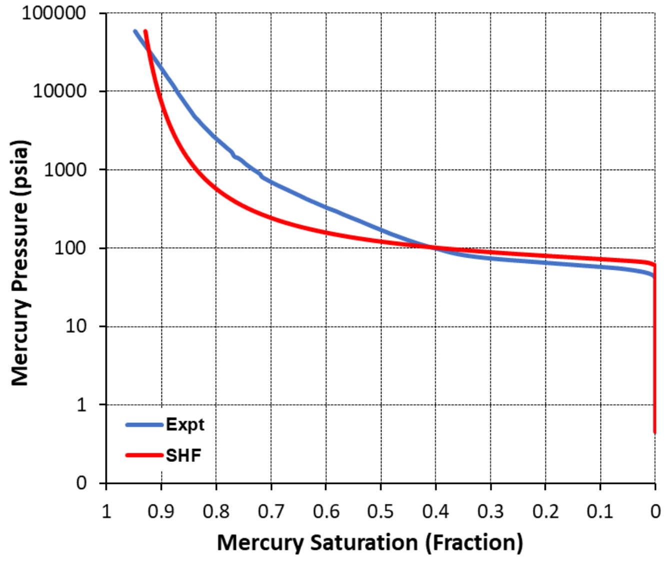
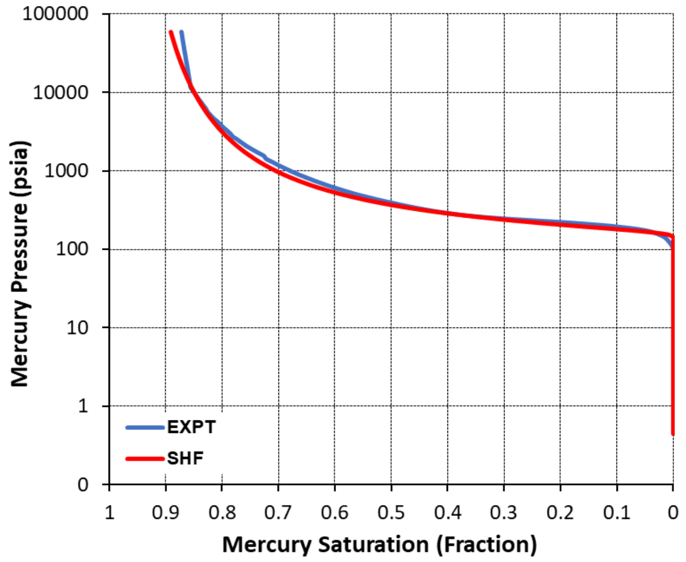
Gas Permeability = 13.9mD, Porosity = 0.118



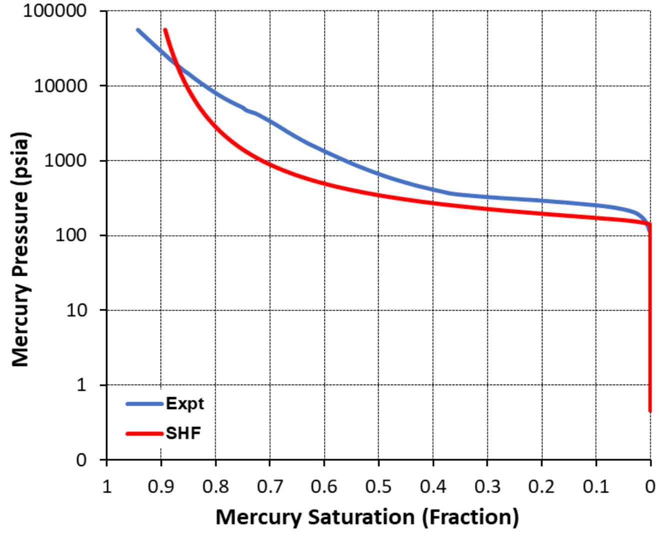
Gas Permeability = 0.70mD, Porosity = 0.076



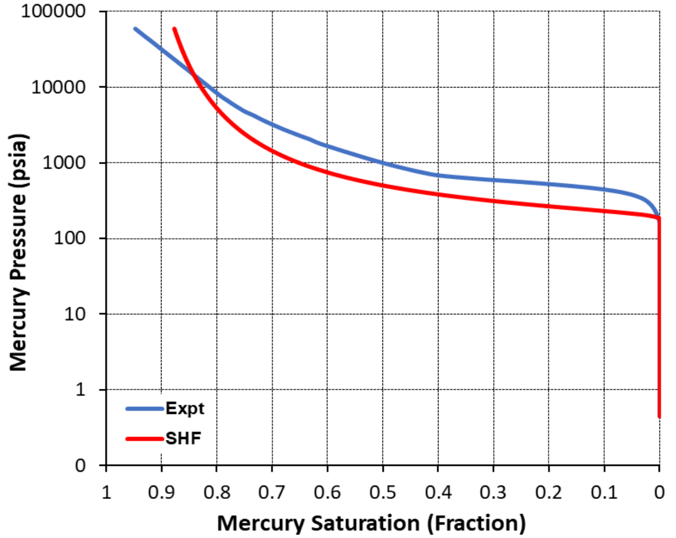
Gas Permeability = 0.24mD, Porosity = 0.104



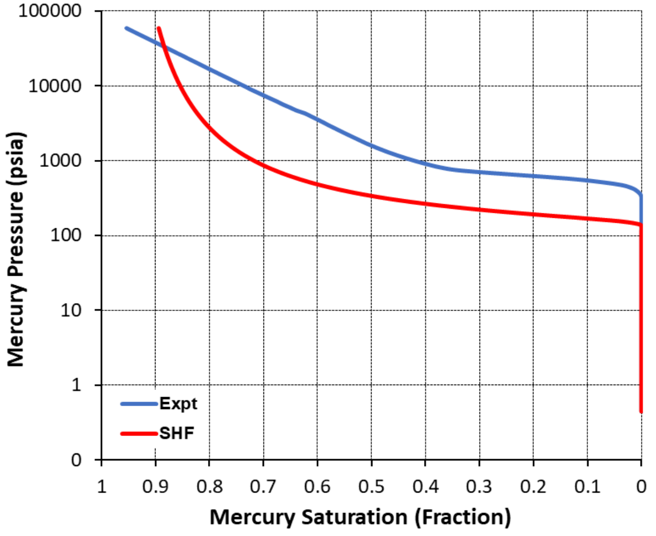
Gas Permeability = 0.08mD, Porosity = 0.072



Gas Permeability = 0.02mD, Porosity = 0.056



Gas Permeability = 0.01mD, Porosity = 0.039



The Model vs Logs

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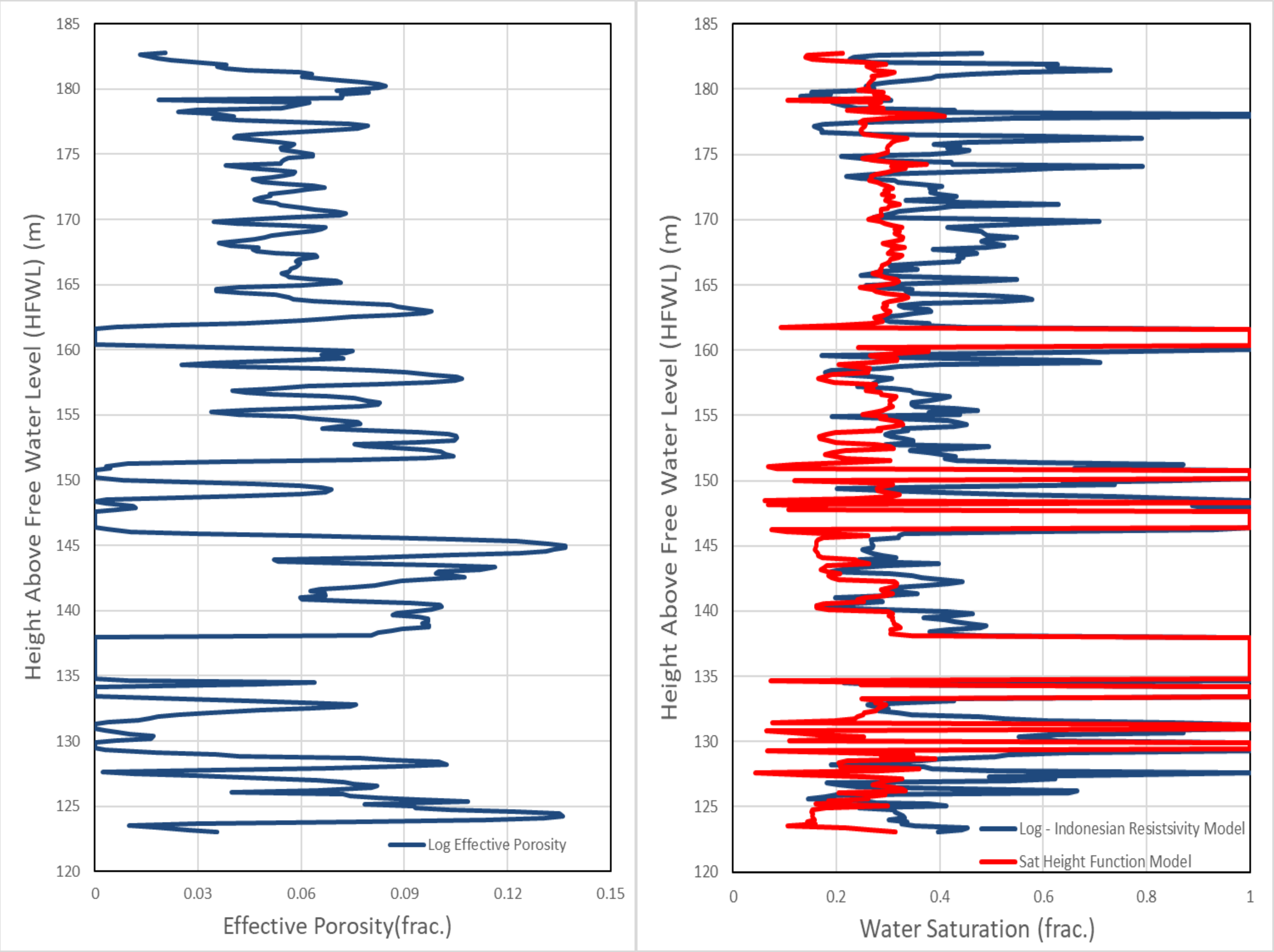

Log Hydrocarbon Pore Volume Thickness (HPVTh) = 2.02m

Model Hydrocarbon Pore Volume Thickness (HPVTh) = 2.35m (+16.4%)

Why the difference between model & logs?

Adam's Top Tip 7: Talk to the reservoir modeller to understand how they have built the model & what they require.

Conclusions

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- Flow zone index is useful for making ‘sense’ of the poro-perm data and linking to capillary pressure properties
- Mercury injection data requires stress correction, SCAL data is required
- The NMR log was useful for modelling permeability and FZI
- Thomeer saturation height function modelled saturations in SCAL plugs and well with reasonable success.
- Thomeer model works in rocks with different pore geometries across a wide poro-perm range.
- Thomeer models threshold pressure, unlike J function models
- Who won the spot the poro-perm competition?

Spot the Poro-Perm Competition - Answer

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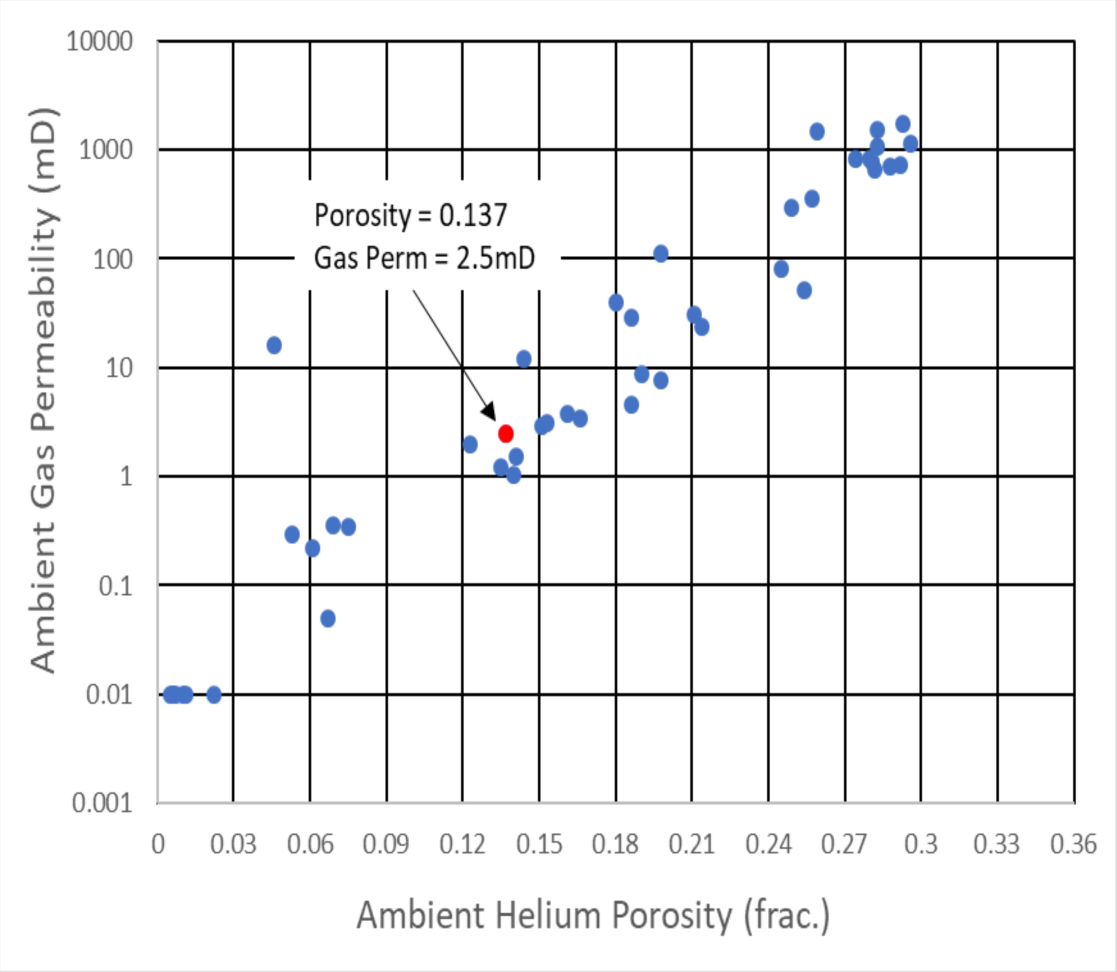

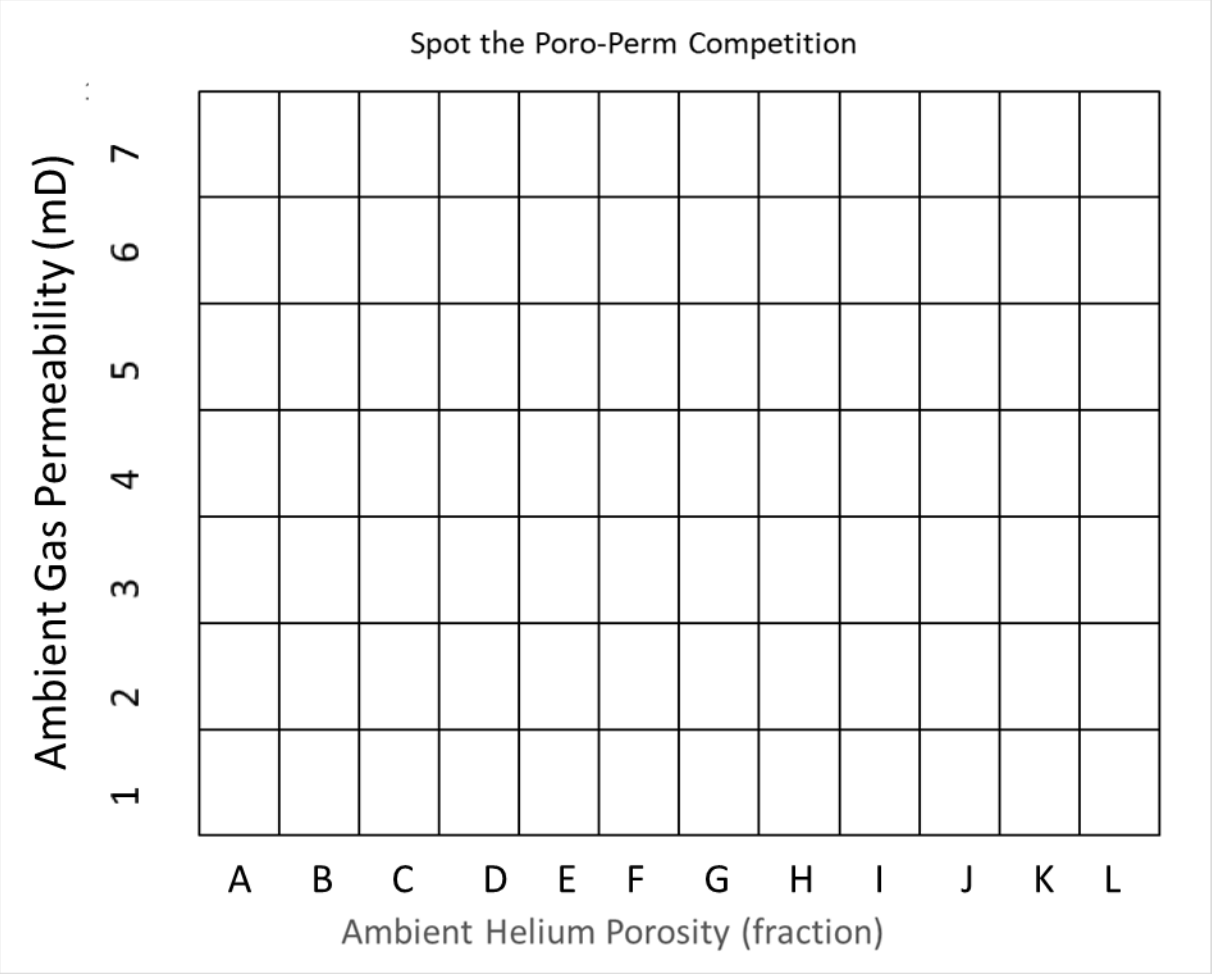

Answer = E4

Helium Porosity = 0.137, Gas Permeability = 2.5 mD, Grain Density = 2.69 g/cc

Any Comments?

Thank You for Listening

Any Questions?

Forthcoming Training Course at Stag Geological Services, Aldermaston:
“Best Practices in Core Handling & Analysis”
15-May-2019 - 3 Days