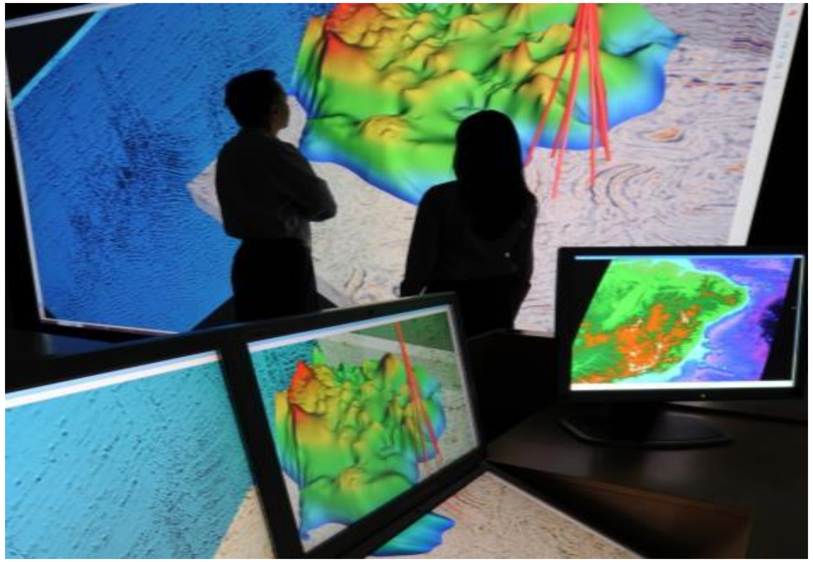
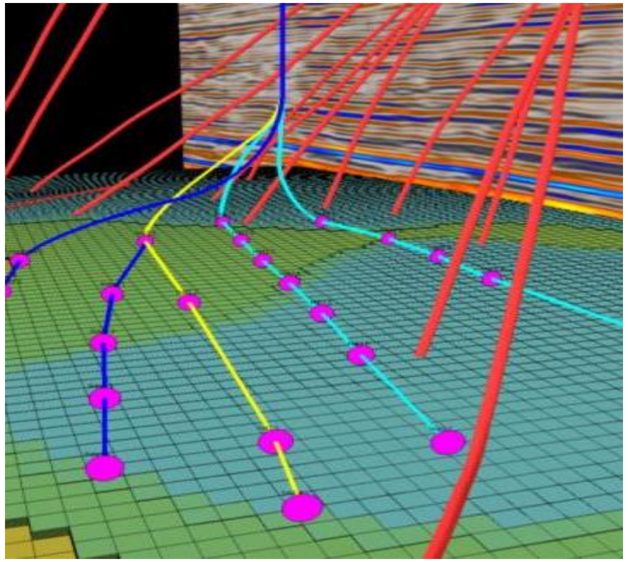
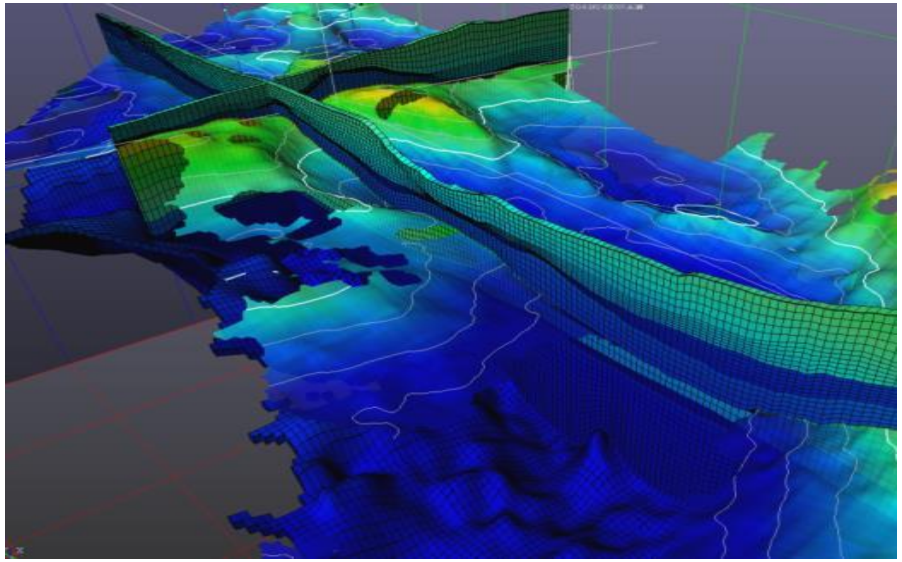
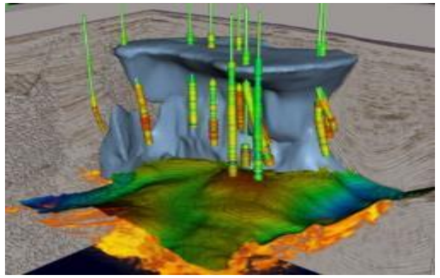

Reservoir Petrophysics

Ranjit Subudhi

Principal Consultant Geoscience

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Agenda

- Reservoir Rock Properties
- Deterministic Petrophysics (Demo)
- Probabilistic Petrophysics (Demo)
- Integrated Reservoir Rock Typing (Demo)
- Saturation-Height Modelling (Demo)

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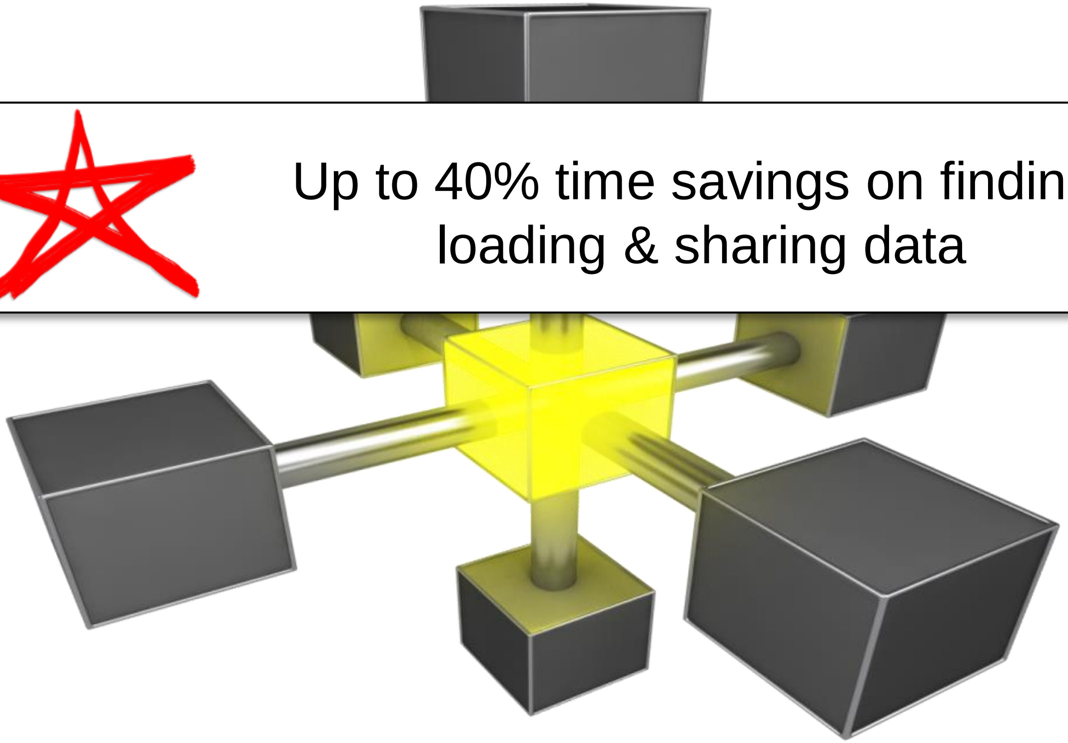
Critical Disciplines – OilField Cycle

Oilfield Lifecycle

- Geophysics
- Geology
- Petrophysics
- Geomechanics
- Reservoir Engineering
- Prod / Drill / Comp / Cement / Facilities Engineering

Up to 40% time savings on finding, loading & sharing data



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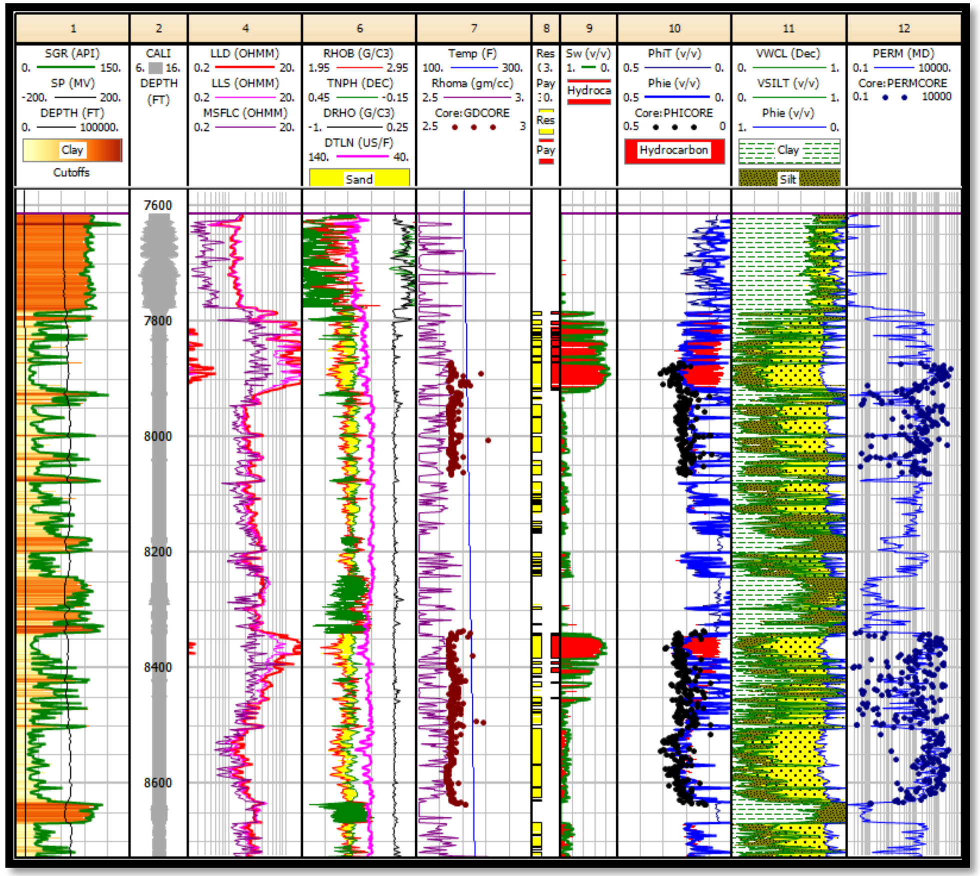
Objectives

- The goal of formation evaluation;
  - Are there any Hydrocarbon and if so Oil or Gas?
  - Where are the Hydrocarbons?
  - How much Hydrocarbon contained in the formation?
  - How producible are the Hydrocarbons?



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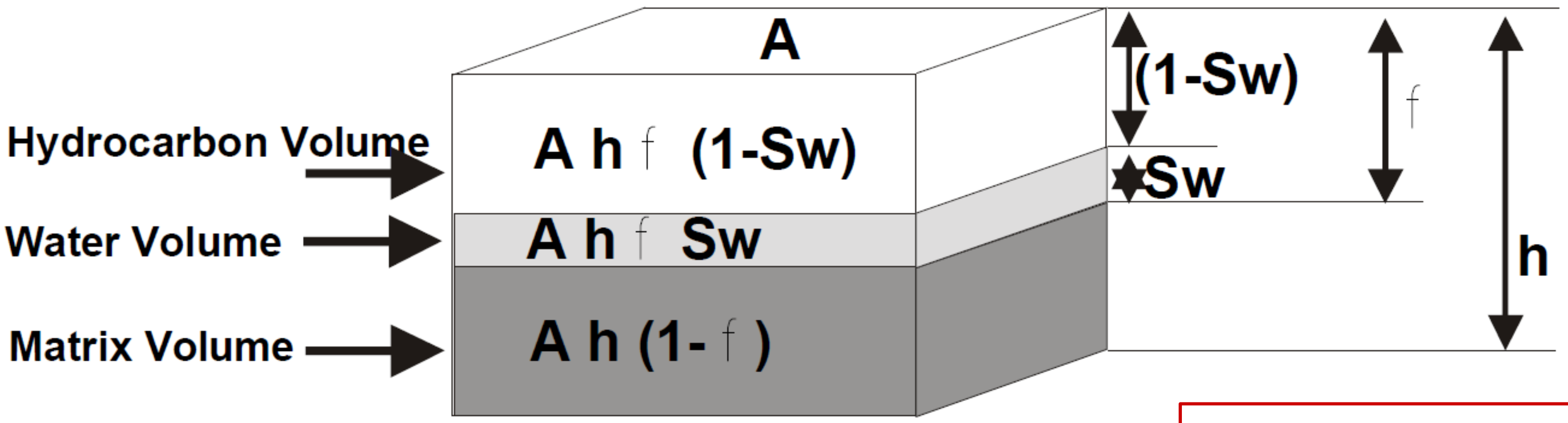
Calculating Hydrocarbon Volumes in a Reservoir



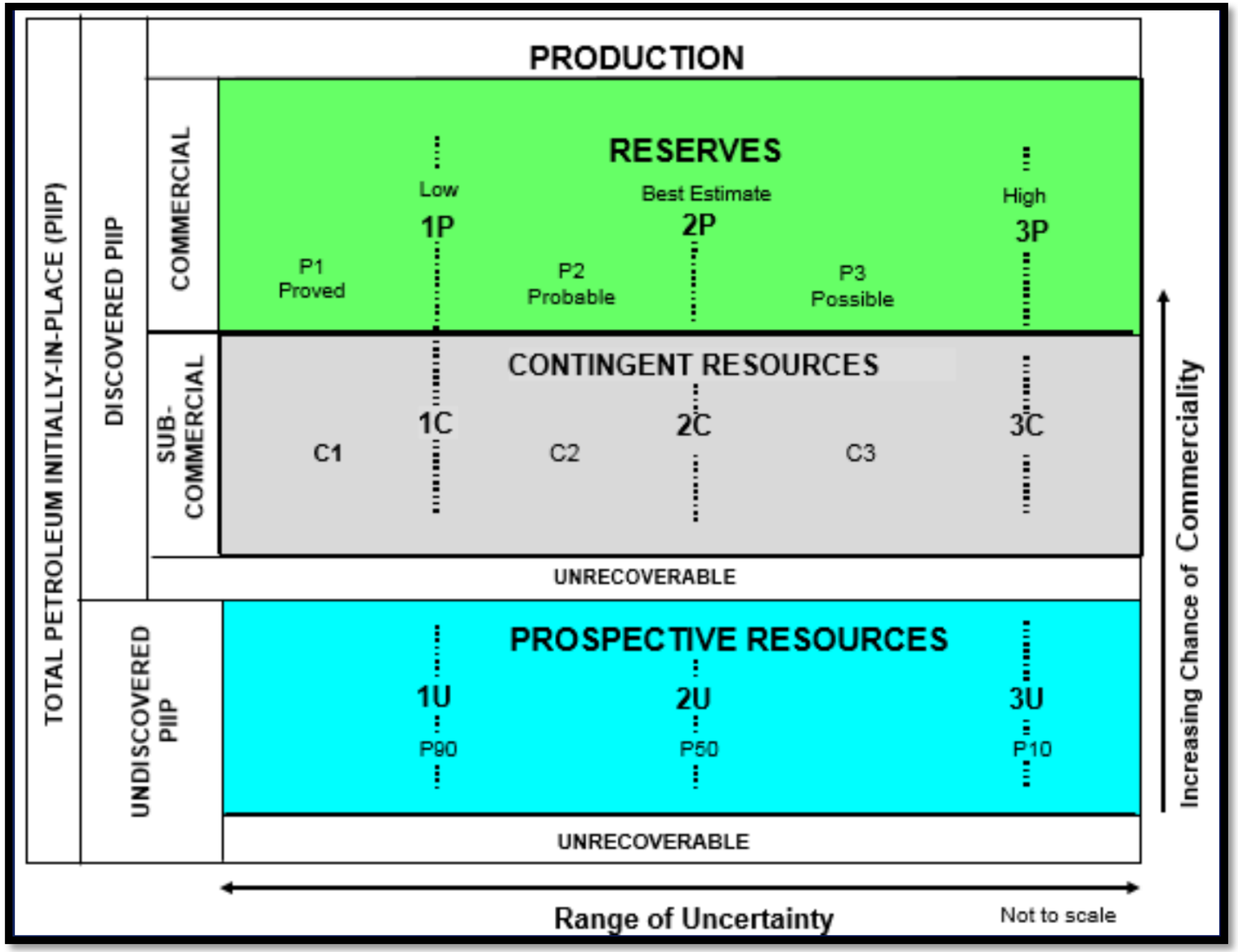
STOOIP = (7758 *AhØ* (1- *Sw*))/Bo *bbl*

STGOIP = (43560 *AhØ* (1- *Sw*))/Bo *cu*. *ft*.

- A = Drainage Area
- h = Net Pay
- Ø = Effective Porosity
- Sw = Water Saturation
- Bo = Formation Volume Factor

Resource Classification Framework

- Prospective resources
  - Prospect
  - Lead
  - Play
- Contingent Resources
  - Development Pending
  - Development On Hold
  - Development Unclarified
  - Development Not viable
- Reserves
  - On Production
  - Approved for Development
  - Justified for Development



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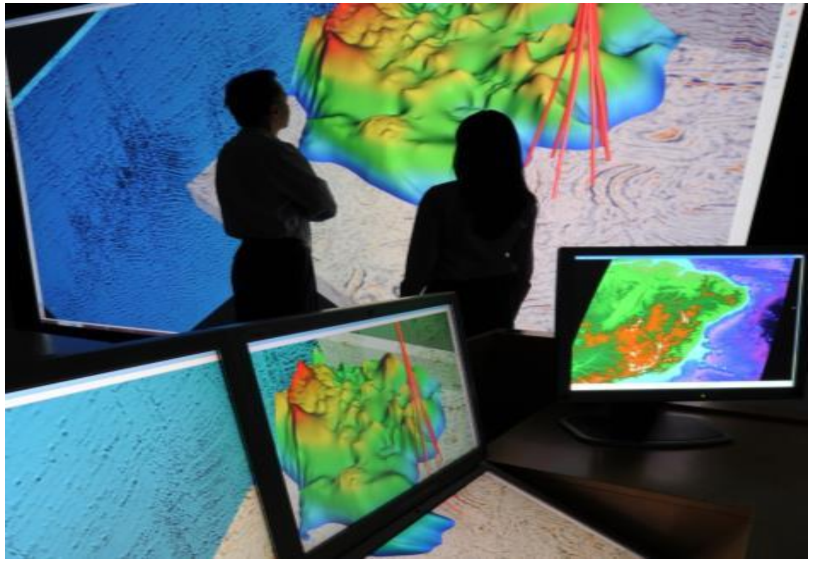
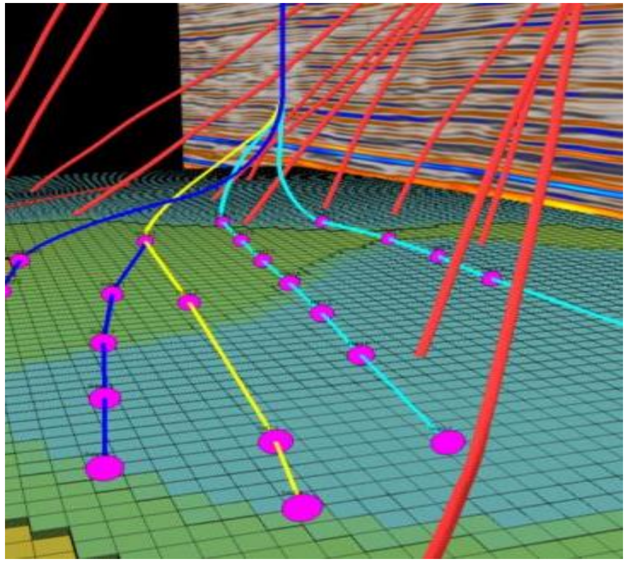
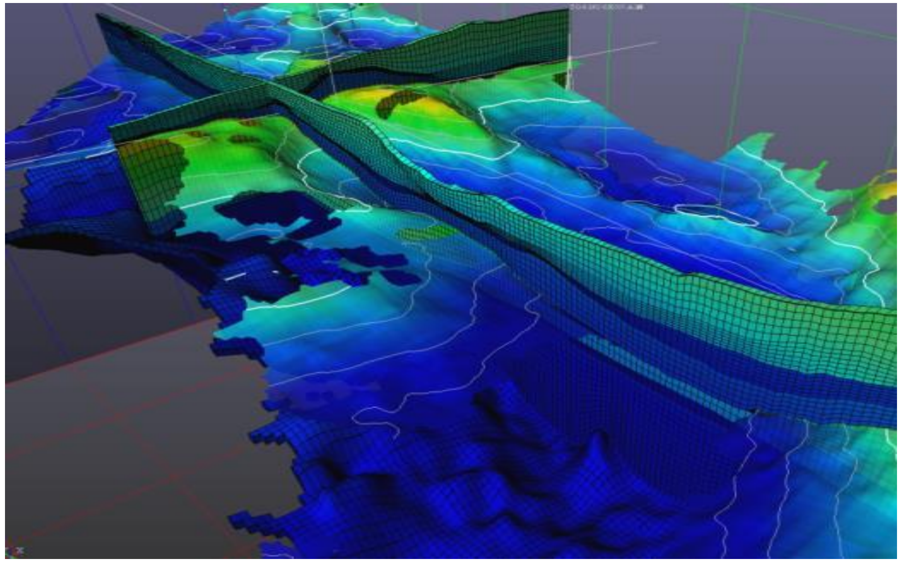
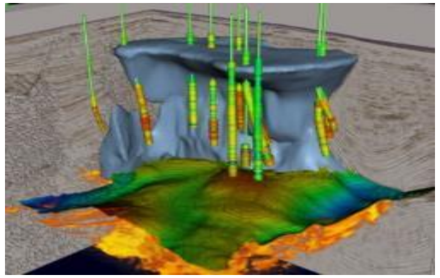

Reservoir Properties: Porosity & Permeability

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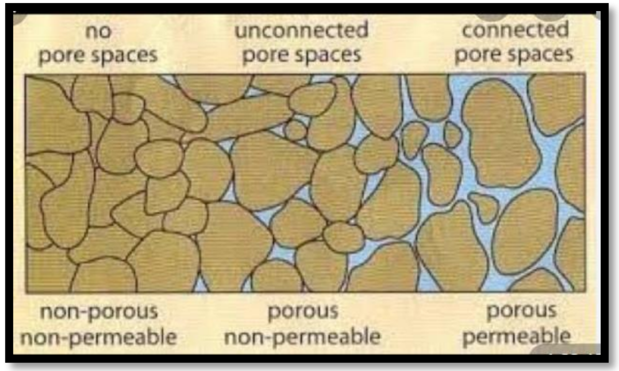
Porosity

- The *porosity* of a rock is the fraction of the volume of space between the solid particles of the rock to the total rock volume.
  - $\varphi = \frac{Pore\ Volum}{Bulk\ Volume}$
- **Origin**
  - Primary Porosity: Developed during the formation of rock.
    - » Inter-granular or inter-particle
    - » Intra-granular
    - » Inter-crystalline
    - » Bedding planes
  - Secondary Porosity: Developed after the formation of rock.
    - » Solution porosity or Dissolution
    - » Dolomitisation
    - » Fractures
    - » Vugs
- **Connectivity**
  - Total Porosity: Accounts both connected as well as isolated pores.
  - Effective Porosity: Accounts only inter-connected Pores.



- Controls on Porosity:
  - Grain Packing
  - Grain Size
  - Grain Shape
  - Grain Size Distribution
  - Secondary Controls on porosity

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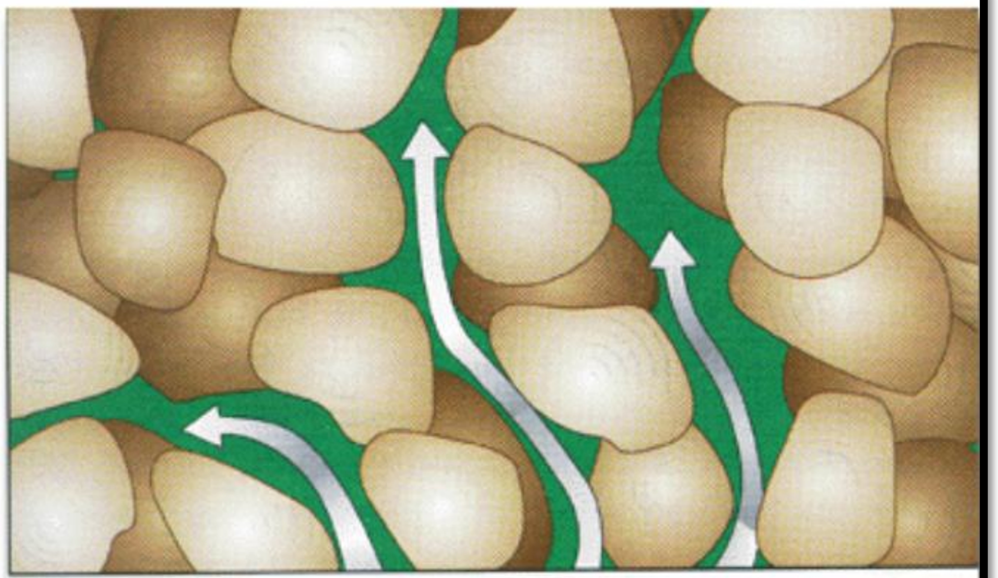
Porosity measurements

- Core porosity
  - Measure two of: pore volume, grain volume and bulk volume of core plug and ratio them.
  - Direct measurement but:
    - Measure $Ø_t$ or $Ø_e$ (or something in between) depending on pore types present, clay content and method of cleaning and drying.
    - Measured under laboratory conditions rather than reservoir stress. Require correction to reservoir conditions for comparison with or calibration of log porosity.
- Log Porosity
  - Sonic, Density, Density/Neutron, NMR.
  - Porosities measured differ.
  - **No** log measures porosity directly.
  - Calibrate to core when possible.

Permeability

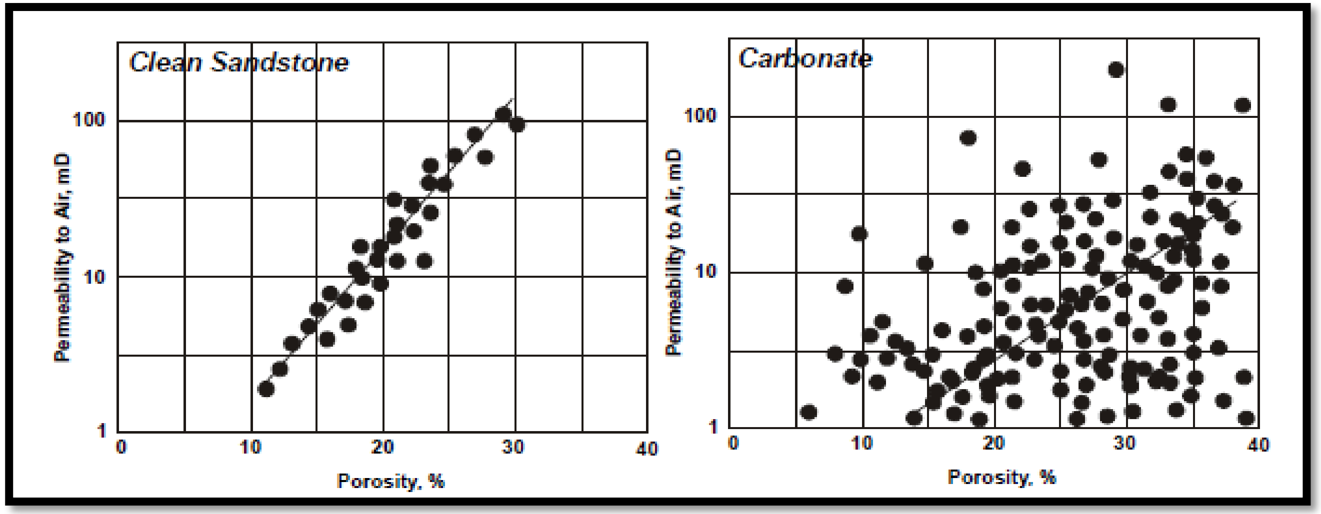
- The permeability of a rock is a measure of the ease with which the rock will permit the passage of fluids.
- It is clear that permeability will depend on porosity; the higher the porosity the higher the permeability. However, permeability also depends upon the connectivity of the pore spaces, in order that a pathway for fluid flow is possible.
- The connectivity of the pores depends upon many factors including the size and shape of grains, the grain size distribution, and other factors such as the operation of capillary forces that depend upon the wetting properties of the rock.
- If the rock contains one fluid, the rock permeability is maximum, and this value is called the absolute permeability.
- If there are two fluids present, the permeabilities of each fluid depend upon the saturation of each fluid, and can be plotted against the saturation of the fluid. These are called effective permeabilities.



Connected pores give a rock permeability.

PoroPerm Relationship

- Permeability depends upon porosity.
- Depends upon the connectivity of the flow paths in the rock.
- Depends, therefore, in a complex way upon the pore geometry of the rock.
- Is a directional quantity that can be affected by heterogeneous or directional properties of the pore geometry.



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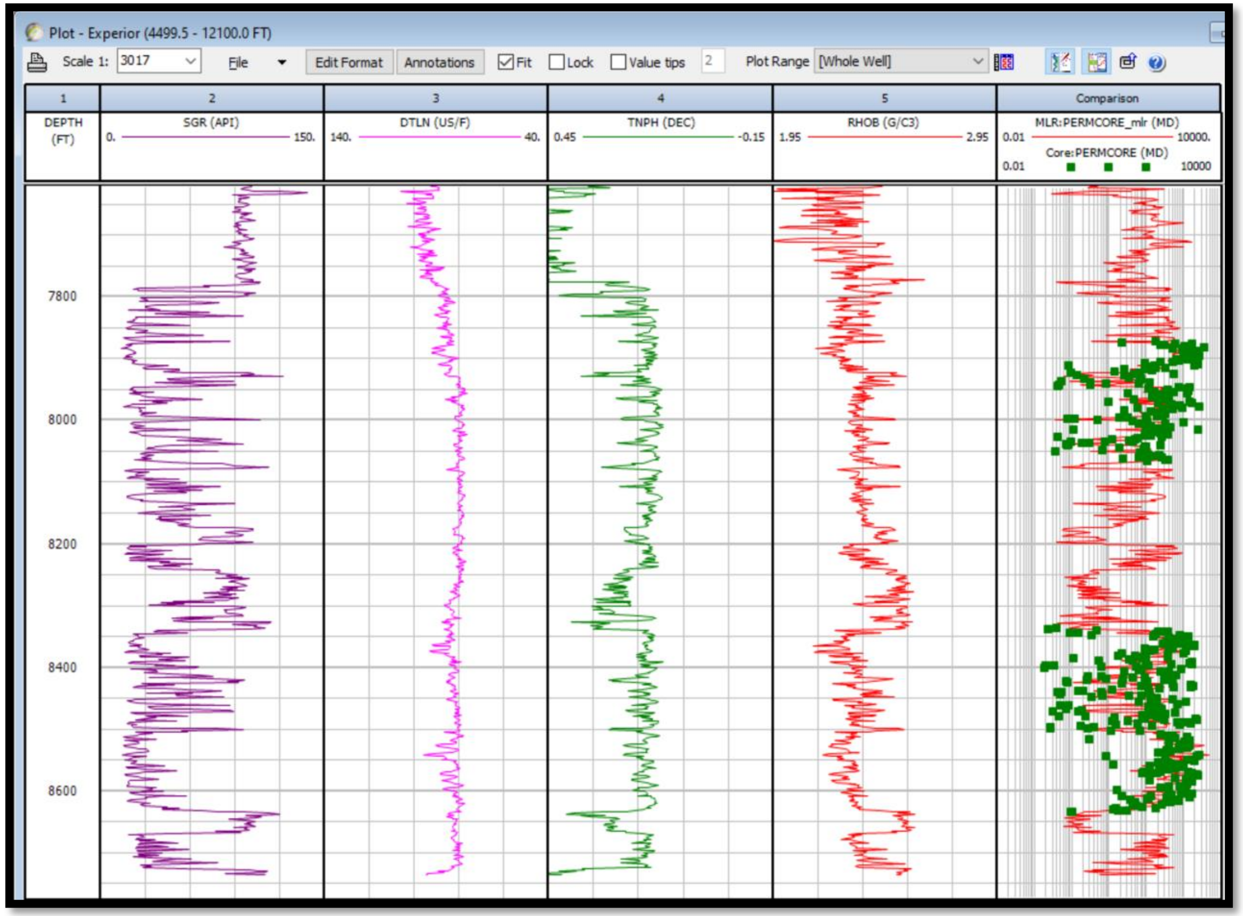
Permeability Estimation from Logs

- The permeability can be predicted from the open hole log data such as GR, RHOB, DT, NPHI etc.
- Core Permeability points can be used to calibrate the log derived permeability.



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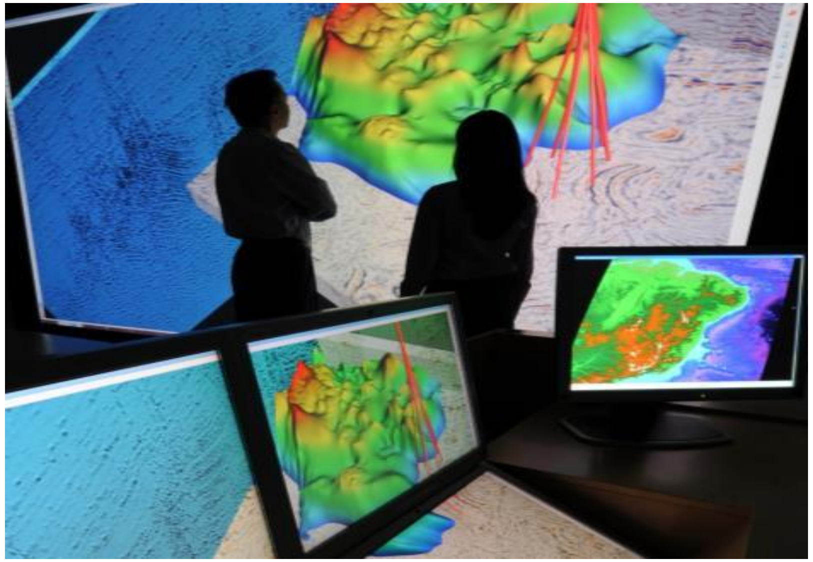
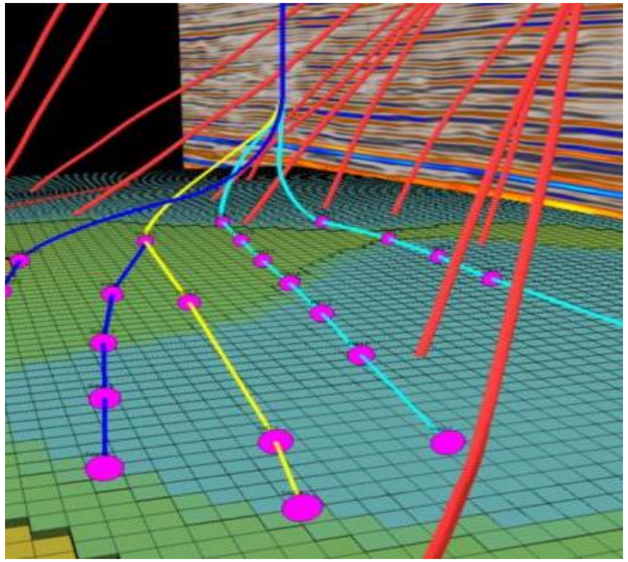
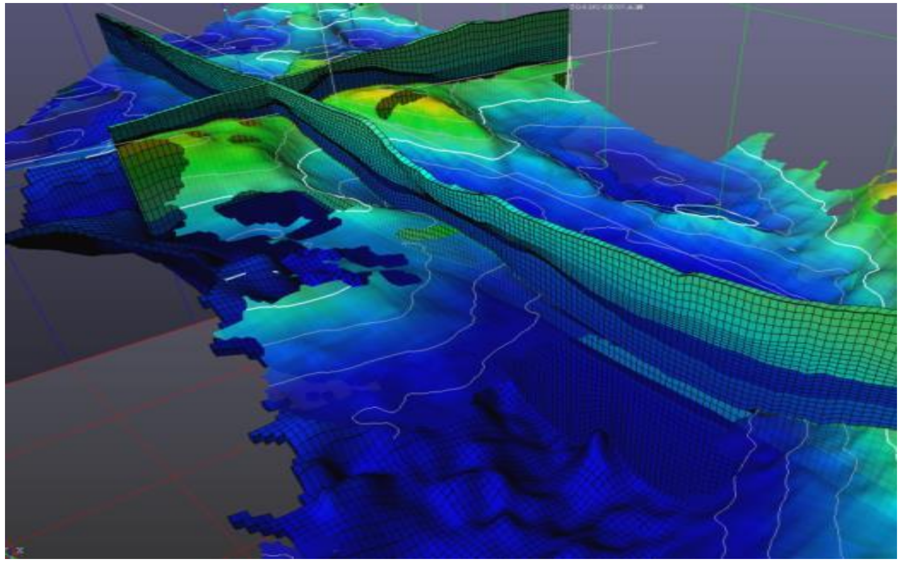
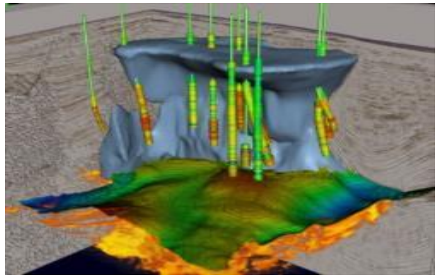

Fluid Saturation and Capillary Pressure

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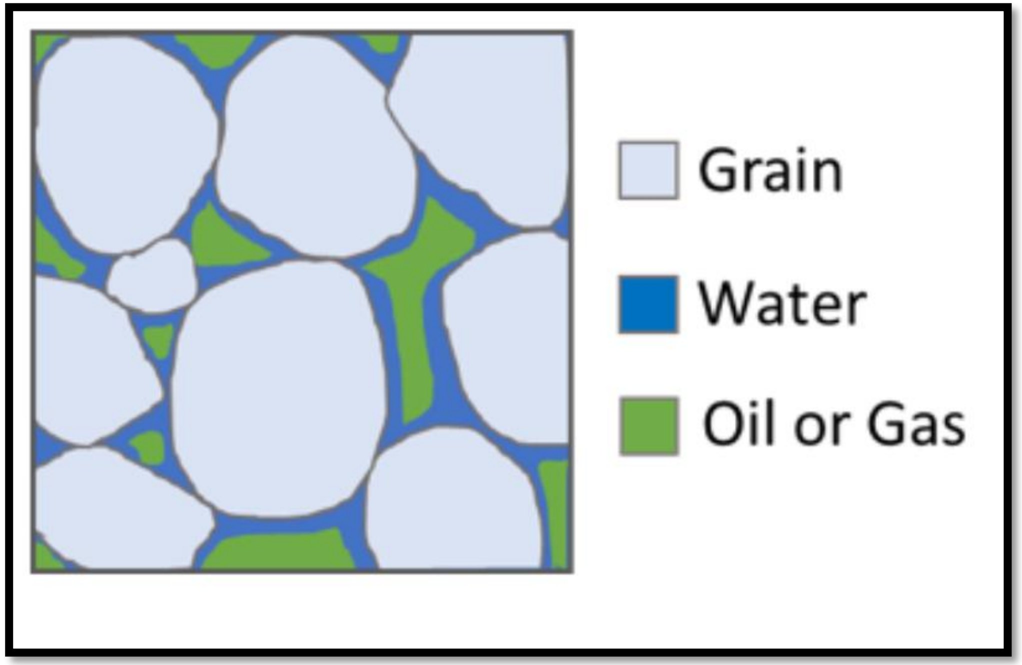
Fluid Saturation

- Saturation is defined the fraction or percent of the pore volume occupied by a particular fluid (oil, gas or water).

- Mathematically, It can be expressed as;
  - $$Fluid\ Saturation = \frac{Total\ Volume\ of\ the\ Fluid}{Pore\ Volume}$$

- We define the pore fraction of each of these as *Sg*, *So* and *Sw*, respectively. Hence, *Sg* + *So* + *Sw* = 1.
- Critical Oil Saturation: For the oil phase to flow, the saturation of the must exceed a certain value which is termed as the critical oil saturation.
- Residual Oil Saturation: When Oil is displaced by water in porous media, there will be some oil left whose saturation is known as the Residual Oil Saturation.
- Moveable Oil Saturation: the fraction of pore volume occupied by movable oil.



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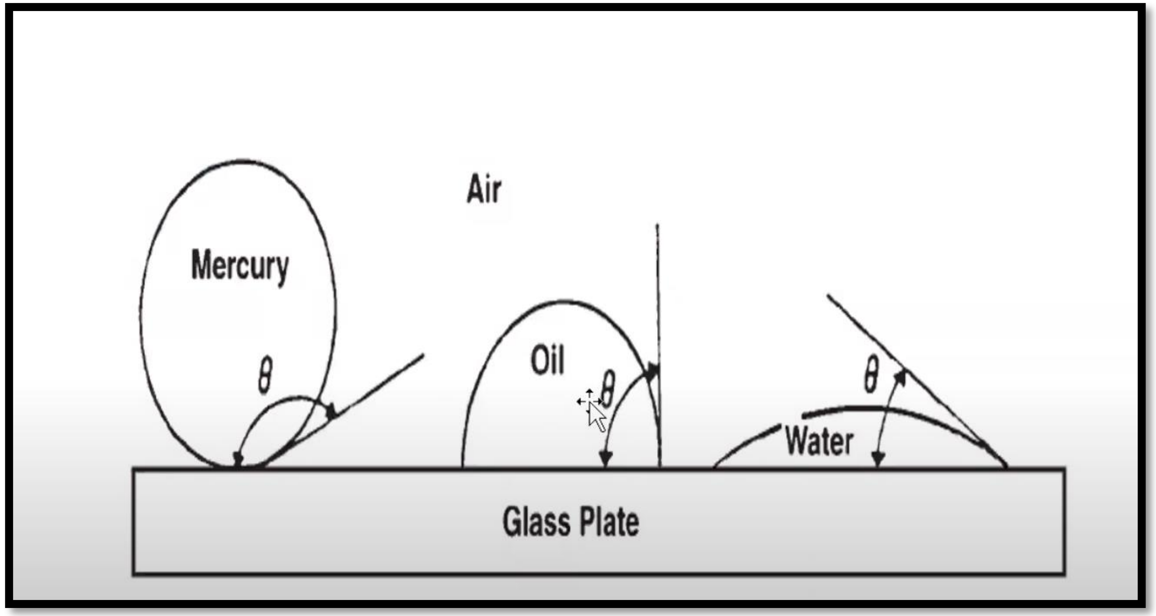
Fluid-Solid Interactions (Wettability)

- The *wettability* of a surface is the type of fluid which is preferentially attracted to that surface.
- The spreading tendency can be expressed by measuring the angle of contact at the liquid solid surface is called the contact angle.
- As the contact angle decreases, the wetting characteristics of the liquid increases.

Contact Angle relative to Fluid A, θ (degrees)	Description
0	Extremely Fluid A wet
0-30	Significantly A wet
30-60	Moderately Fluid A wet
60-90	Weakly Fluid A wet
90	Neutrally wet
90-120	Weakly Fluid B wet
120-150	Moderately Fluid B wet
150-180	Significantly B wet
180	Extremely Fluid B wet



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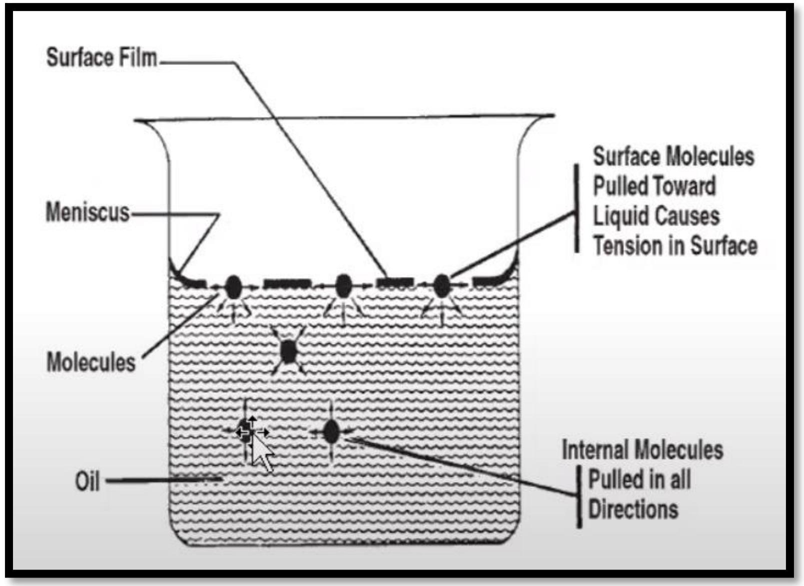
Fluid- Fluid Interaction

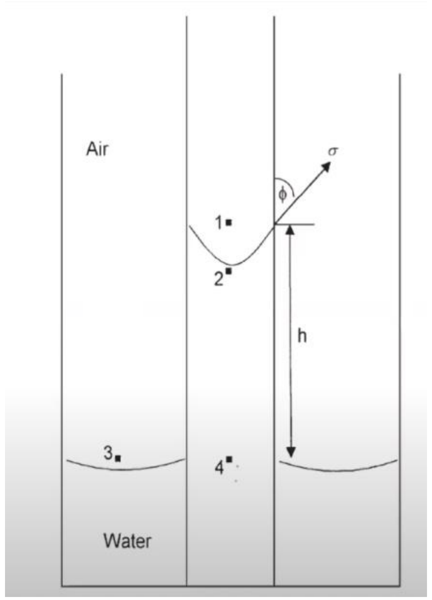
- When two immiscible fluids are in contact, some forces act on their interphase.
- When these two fluids are liquid and gas, the term surface tension is used to describe the forces acting on the interface.
- When the interface is between two liquids, the acting forces are called Interfacial tension.
- Water and Gas System:

$$\sigma_{gw} = \frac{r\,h\,\rho_w\,g}{2\cos\theta}$$

- Oil and Water System:

$$\sigma_{ow} = \frac{r\,h\,g\,(\rho_w - \rho_o)}{2\cos\theta}$$





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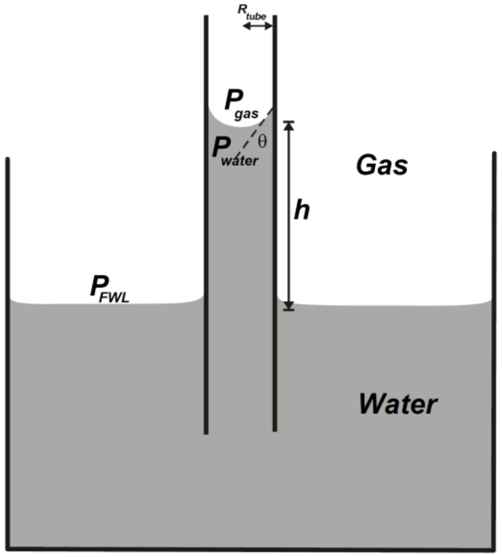
Capillary Pressure

- Capillary pressure is the difference in pressure between two immiscible phases of fluids occupying similar pores due to interfacial tension between the phases.
- Capillary pressure = (pressure of the non wetting Phase) – (Pressure of the wetting Phase)
- Three types of the Capillary Pressure;
  - Water – Oil Capillary Pressure (Pcwo = Po – Pw)
  - Gas – Oil Capillary Pressure (Pcgo = Pg – Po)
  - Gas – Water Capillary Pressure (Pcgw = Pg – Pw)
- Capillary pressure can be expressed by;

$$Pc = gh\Delta\rho$$



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Reservoir Scenario

- **Gas/Water System:**

$$P_c = \frac{2\,\sigma_{gw}\,(\cos\theta)}{r}$$

and

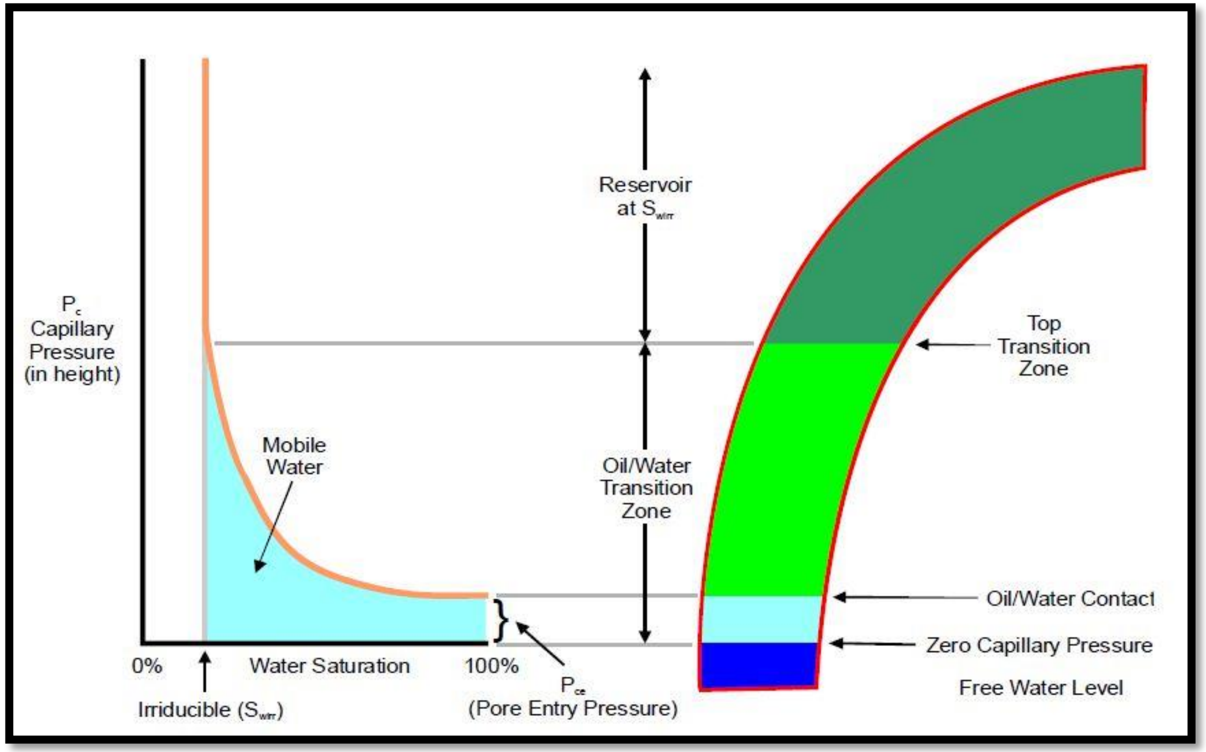
$$h = \frac{2\,\sigma_{gw}\,(\cos\theta)}{r\,g\,(\rho_w - \rho_{gas})}$$

where ρ_w = water density, gm/cm^3

σ_{gw} = gas-water surface tension, dynes/cm

r = capillary radius, cm

θ = contact angle



- **Oil/Water System**

$$P_c = \frac{2\,\sigma_{ow}\,(\cos\theta)}{r}$$

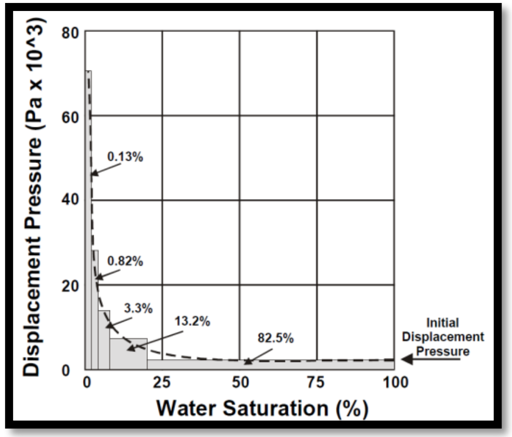
and

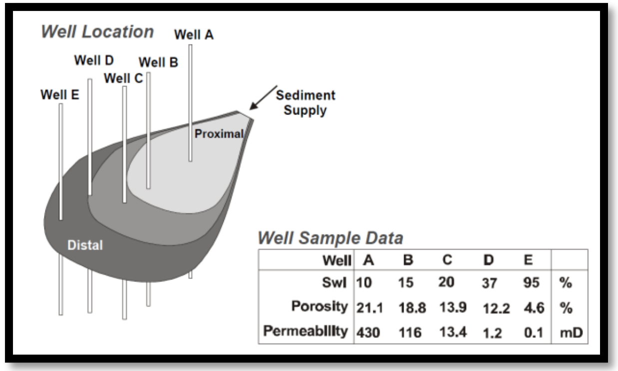
$$h = \frac{2\,\sigma_{wo}\,(\cos\theta)}{r\,g\,(\rho_w - \rho_o)}$$

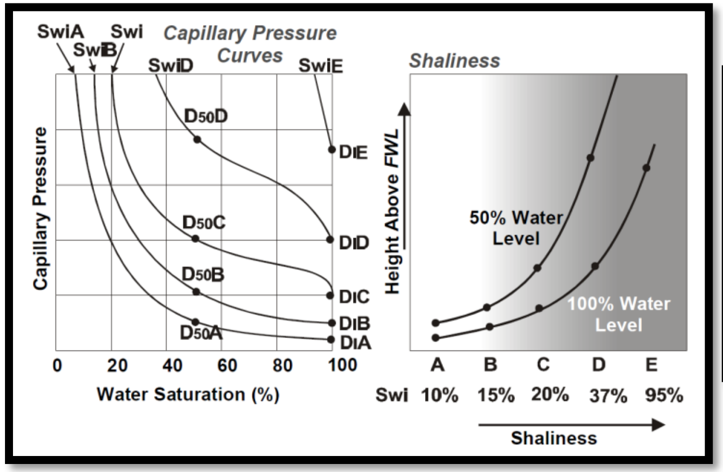
where σ_{wo} is the water-oil interfacial tension.

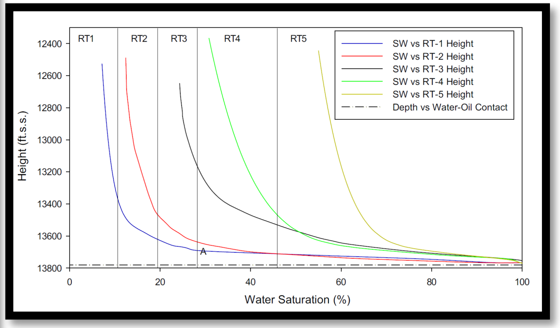
Use of Capillary Pressure Data

- Capillary pressure in a reservoir determines the saturation distribution, and hence the total in-situ volumes of fluids (oil/water/gas).
- Capillary pressure curves can tell us much about the variation of saturations across a reservoir.
- Capillary pressure data can be used in reservoir rock typing study.
- Estimating Fluid Contacts.









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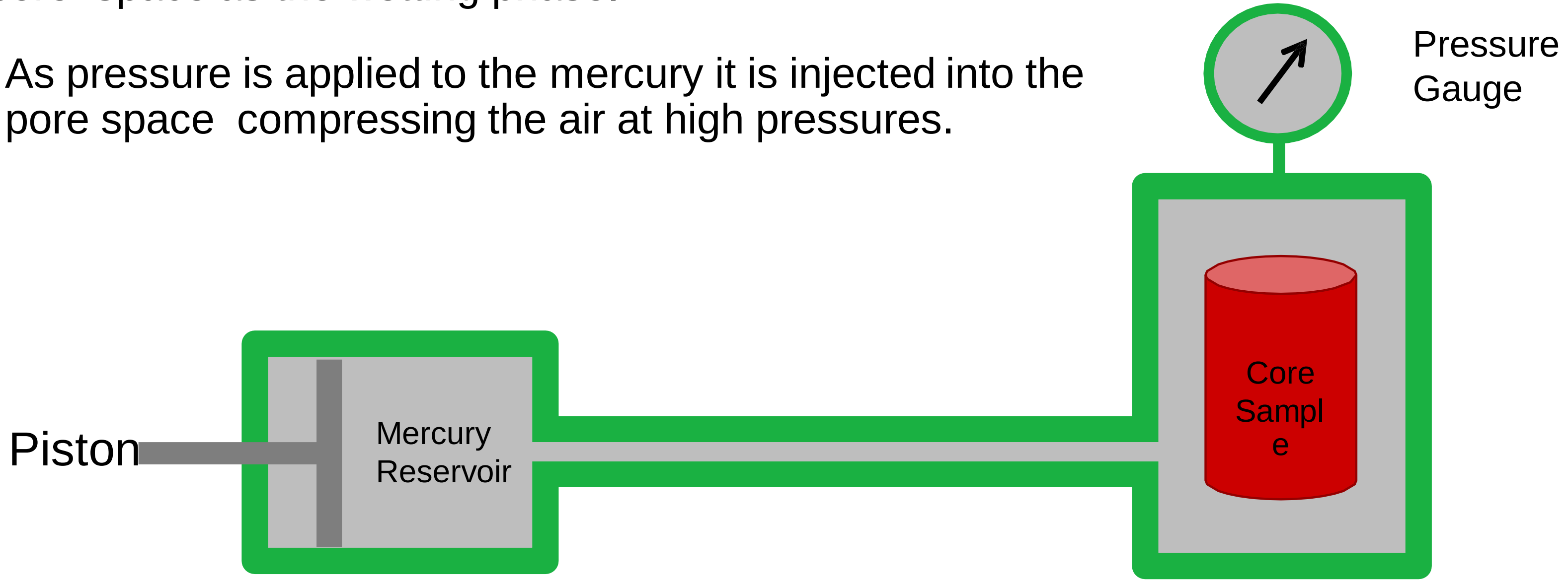
Lab Methods for Measuring Capillary Pressure

- Porous Plate
- Centrifuge
- Mercury Injection
  - A cleaned, dried sample is placed into the apparatus with air occupying the pore space as the wetting phase.
  - As pressure is applied to the mercury it is injected into the pore space compressing the air at high pressures.



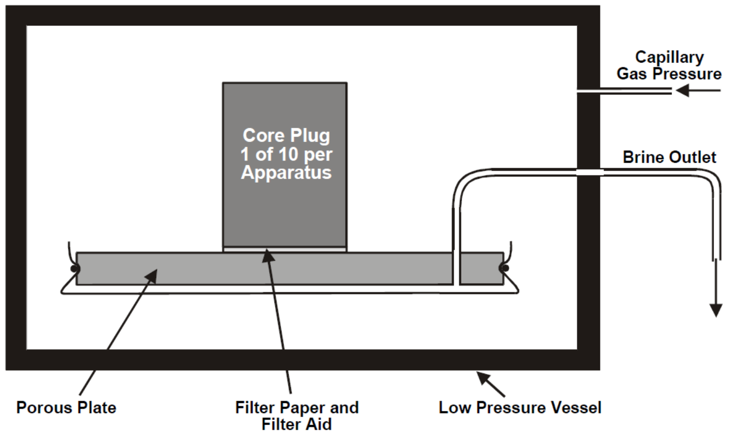


Figure 4.15 Porous plate capillary pressure measurement.

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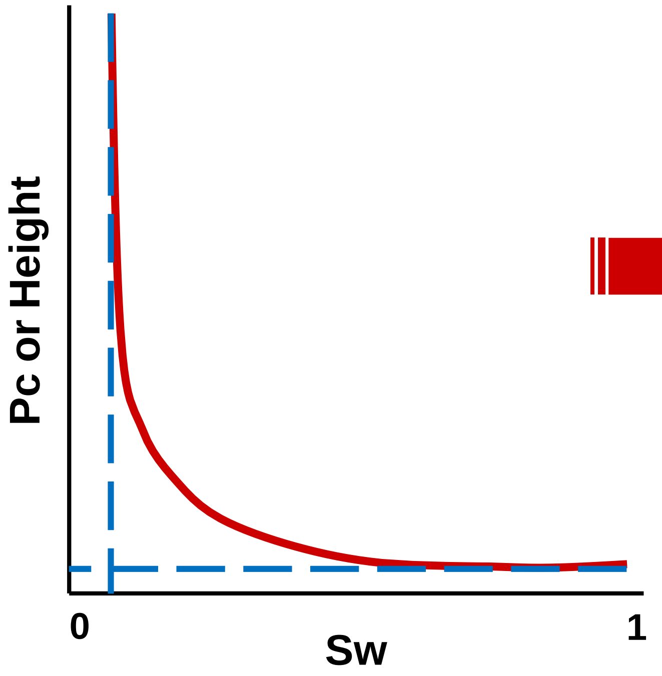
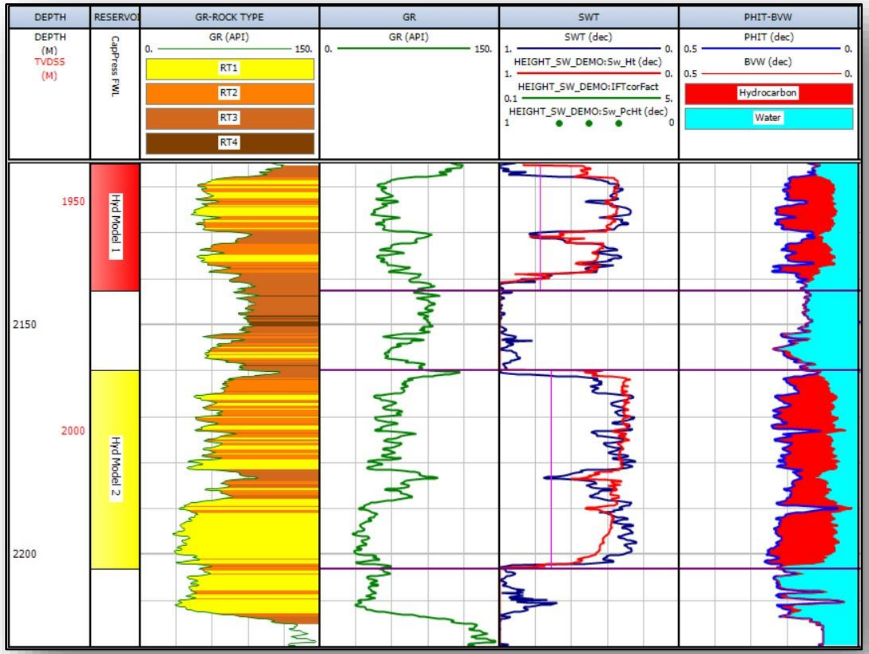
Sw-HT Modelling

Saturation Height Modelling is performed to obtain **saturation height functions.** **Saturation Height Function** is further used to predict the saturation anywhere in the reservoir for a given height above the free water level and for a given reservoir permeability or porosity, or to estimate permeability once water saturation is known. Reservoir water saturation decreases with increasing height above the FWL, where capillary pressure is zero.

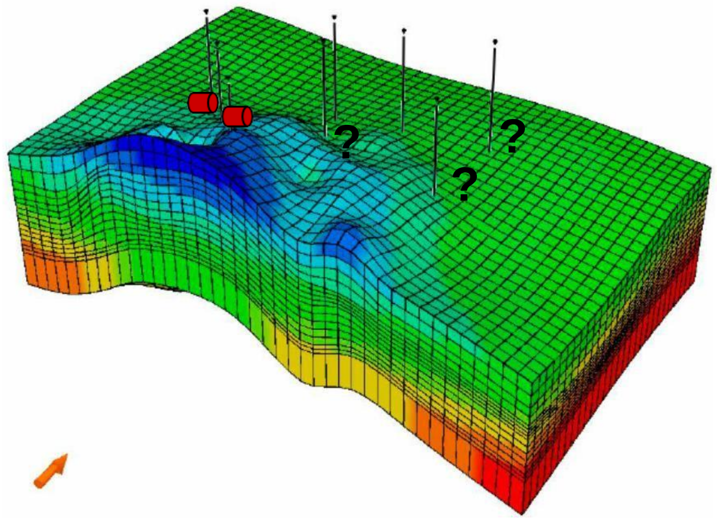
Core Scale → **Log Scale** → **Geological Model**





Saturation Law

Sw = f(Pc or H)



Saturation Height Modelling Workflow

Capillary Pressure Set up

- The Capillary Pressure Set-Up & Corrections interface is used to set up the study well (or wells) and their Capillary Pressure (Pc) and associated Water Saturation (Sw) datasets. The corrected / converted Pc and water saturation curves that are output from this module are subsequently used in the Capillary Pressure Functions module.

Capillary Pressure Functions

- The Capillary Pressure Functions module takes, as inputs, the wells and Pc curves (PcCorr, SwPcCorr, PcUse) that are created in the Capillary Pressure Set-up module. Each core plug that was flagged as Plug Status Good or Part Good and has the Select Plug column selected in the Individual Plugs for Display table on the Data View / Edit tab is loaded into this module.

Saturation versus Height curves

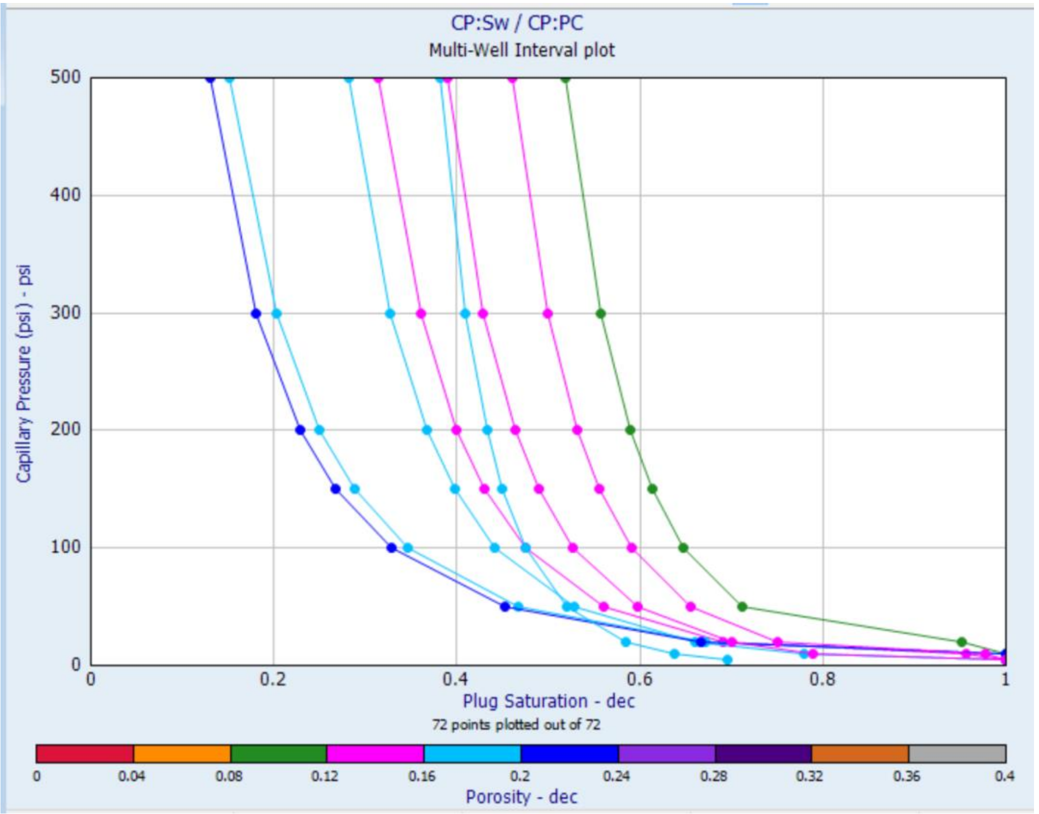
- The Saturation Versus Height Curves module is used to take the functions that have been developed in the Capillary Pressure Functions and Log Sw Vs. Height Functions modules and to apply these functions to multiple wells and multiple reservoir zones. The module can also be used to calculate an unknown Free Water Level (FWL) in a well, using a function to predict the Most Likely value.

Lab to Reservoir conversion

- Reservoir and Lab Fluid/rock Properties

$$P_{c(res)} = P_{c(lab)} \frac{(\sigma \cos\theta)_{res}}{(\sigma \cos\theta)_{lab}}$$

- Stress Correction
- Clay bound water correction
- Salinity correction
- Closure correction



Reservoir and Laboratory fluid / rock properties

Measurement	Method	Contact Angle	Interfacial Ten.	Contact Angle	Interfacial Ten.
Type	ID	Laboratory	Laboratory	Reservoir	Reservoir
Units		deg	dynes / cm	deg	dynes / cm
Mercury Inj	1	140	480	30	30
Centrifuge	2	0	72	30	30
Porous Plate	3	0	72	30	30

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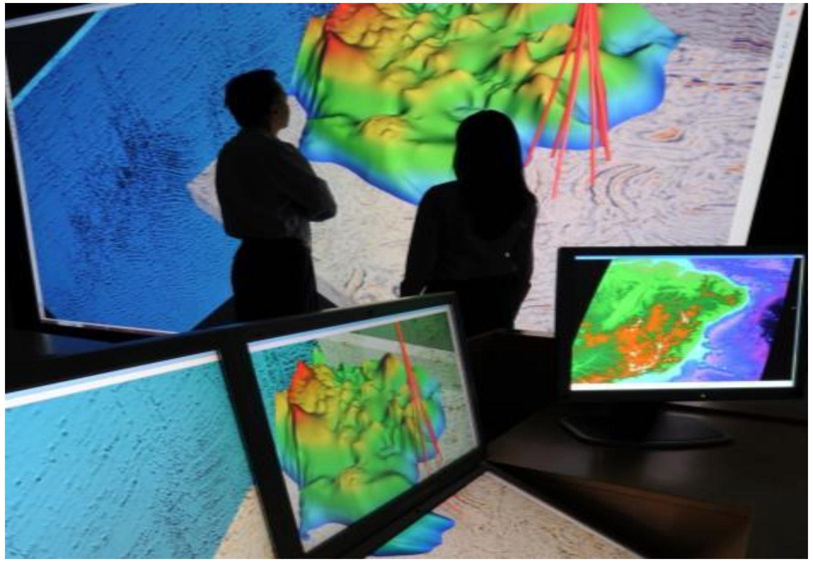
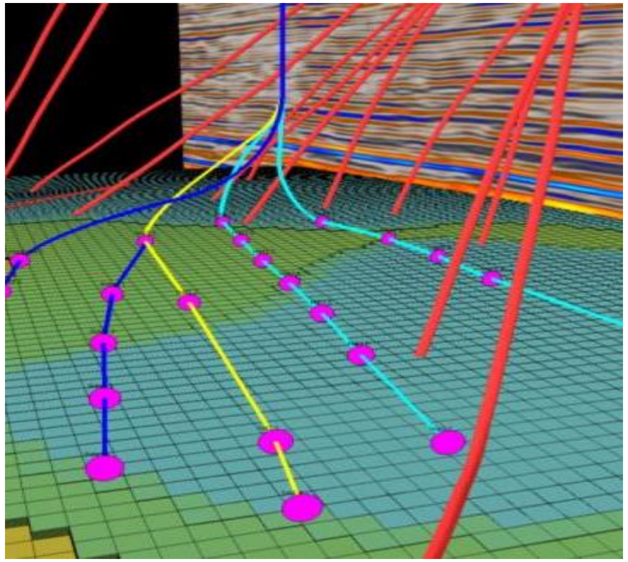
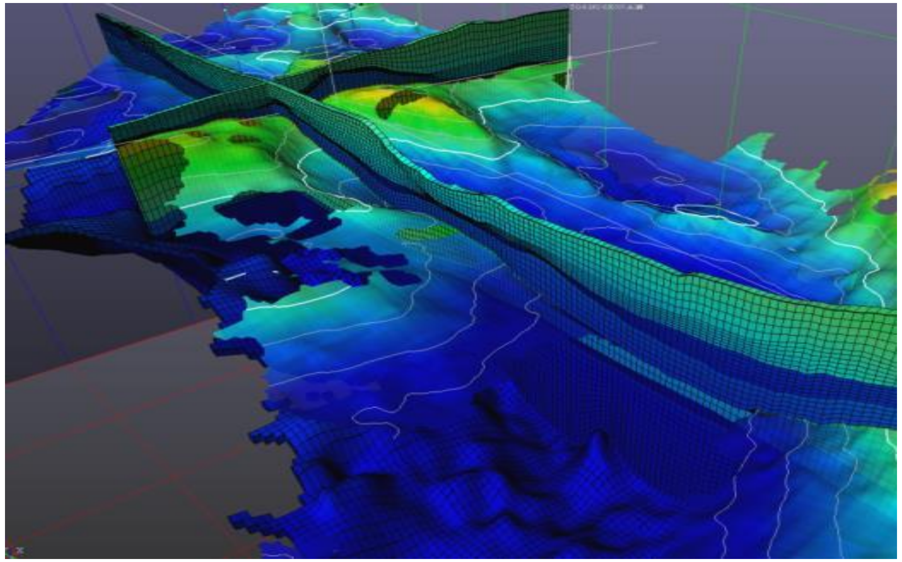
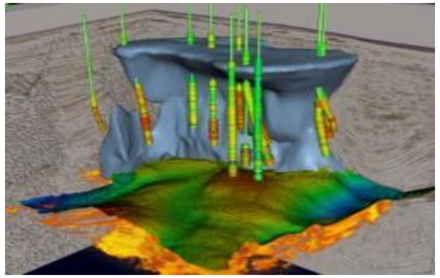

Deterministic Petrophysics:

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Deterministic Petrophysics Workflow

Lithology

Shale/Clay Volume Estimation

Porosity Computation

Water Saturation Calculation

Fluid Zones

Permeability Determination

Net Pay / Net Reservoir Quantification

Reality check

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Log Evaluation Workflow: Reality Checks 1

- Look for consistency:
- Lithology, hydrocarbon shows and core data should be identified prior to log evaluation.
- Lithology and Clay volume:
  - Compare with clays and other minerals seen in core.
  - Use core grain density as guide to main matrix material.
  - Compare with core mineralogy (XRD, thin section).
- Porosity
  - Porosity: Differences or similarity of different log porosities.
  - Log to core comparison or calibration.
  - Sense check magnitude of porosity.

Log Evaluation Workflow: Reality Checks 2

- Log derived water saturation should be compared with:
  - Capillary pressure curves.
  - Core fluid saturation measurements
  - DST and WFT samples.
  - Discrepancies may point to the need for modified interpretation.
- Log derived permeability should be calibrated to core data.
  - Compare cumulative log permeability with production log inflow profiles.
  - Compare permeability-height (KH) from log permeability with KH from well tests.
- Net Pay and Net Reservoir should be compared to permeability indicators and core if available.
- Effective formation evaluation is a process of integration of different data types in order to provide a robust interpretation.

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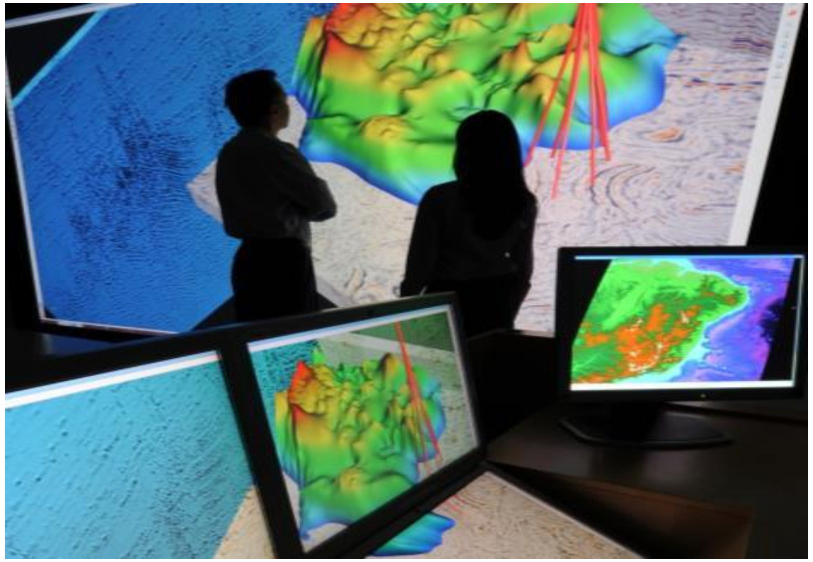
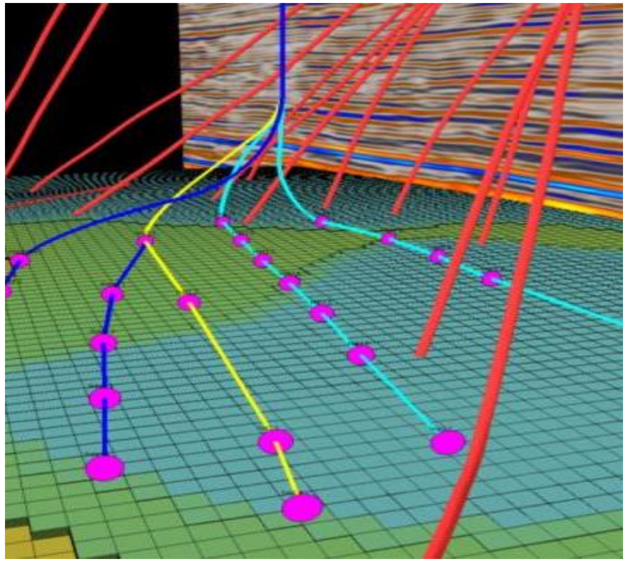
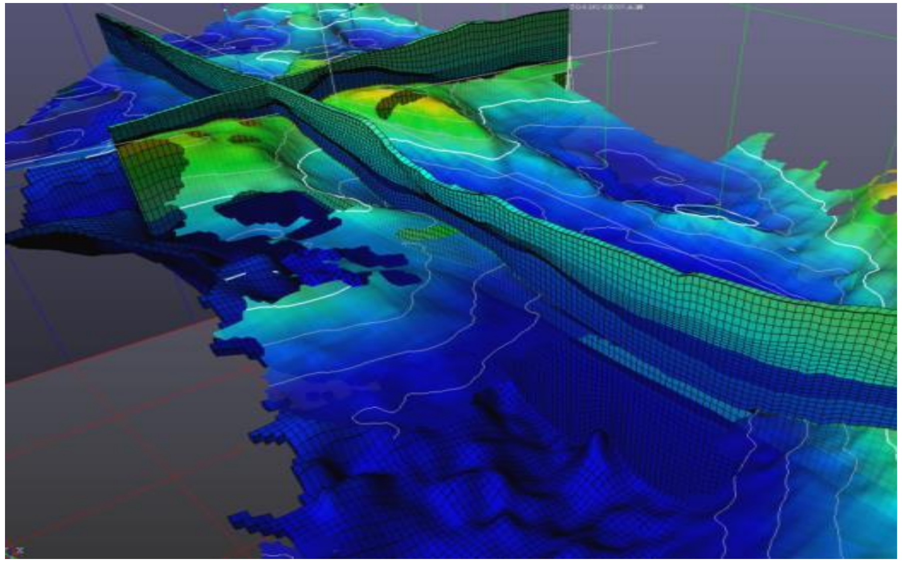
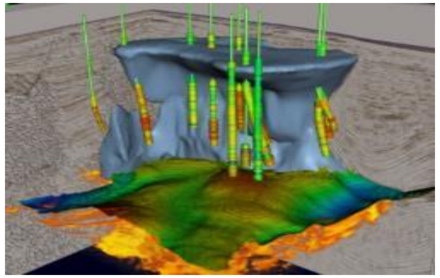

Deterministic Petrophysics: Lithology & Clay Volume

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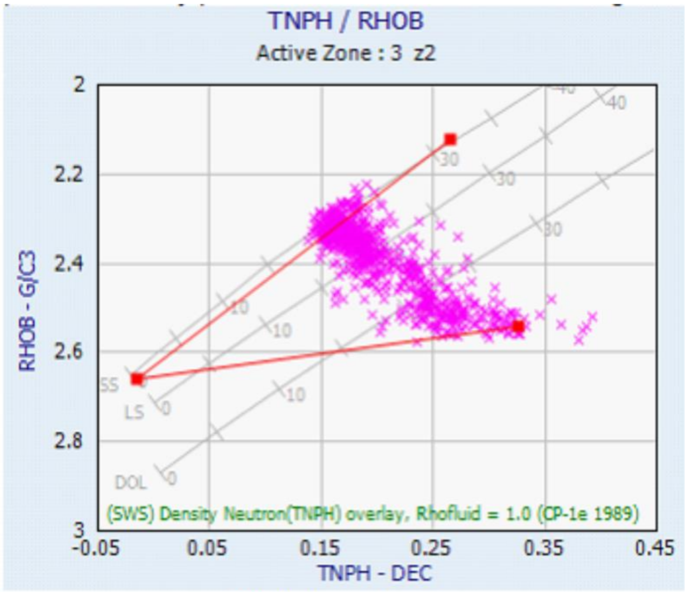
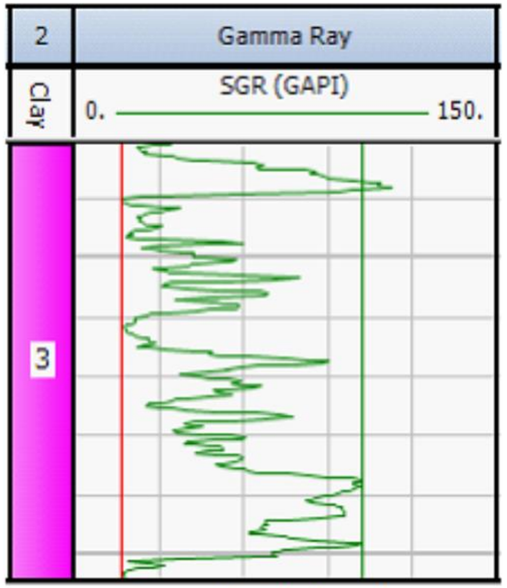
Clay or Shale Analysis

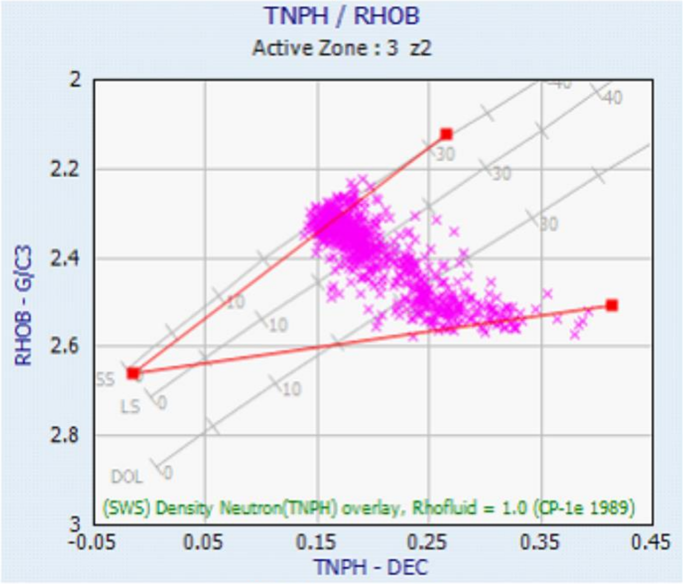
- Shales normally contain 50-80% of clay. The actual clay contain could change at each depth level.
- Shale picks are normally made to the edge of the cloud of points while clay picks are made outside the cloud to give around 60-80% clay content.



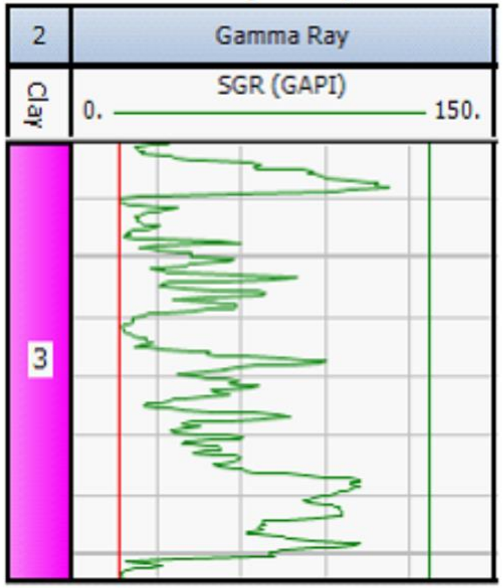
N/D Shale point pick



Gamma Ray Shale pick



N/D Clay point pick



Gamma Ray Clay Pick

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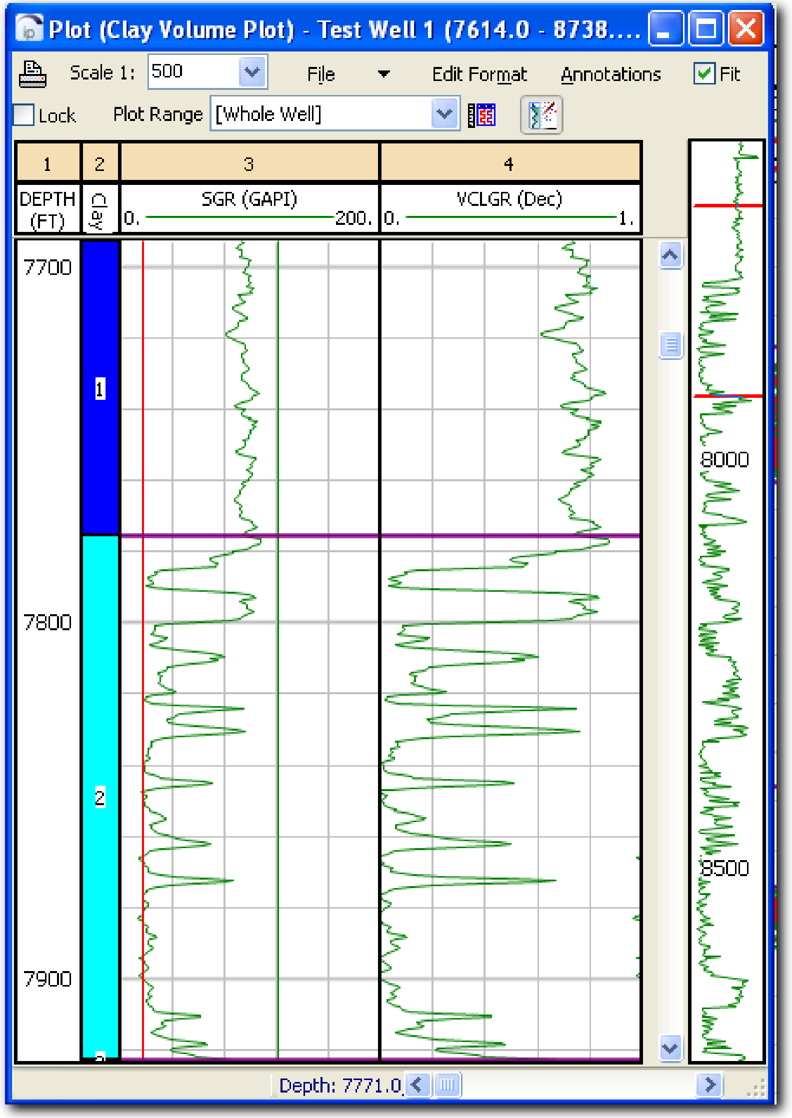
Clay Volume Determination from Wire-line Logs

- Commonly used Clay Indicators are:
  - GR.
  - SP.
  - Resistivity (in hydrocarbon-bearing reservoir).
  - Neutron-Density log Cross Plot.

- Typically determine V_{clay} using several alternative methods and use either the minimum or average value of them
  - Care required:
    - » If radioactive minerals (other than clays) occur in sands V_{clayGR} is an overestimate.
    - » If hydrocarbon type is gas V_{clayDN} is an underestimate.

- The V_{clay} from logs should be calibrated or compared with core data where possible:
  - Shale count observed in core.
  - Thin section point count data.
  - XRD data.



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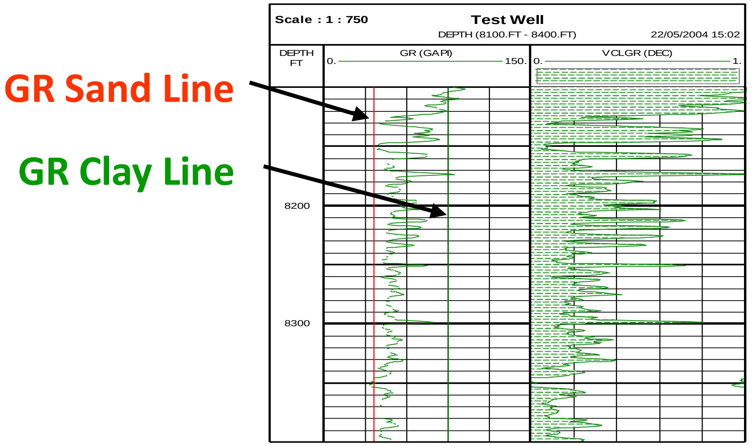
Clay Volume from Gamma Ray V_{clayGR}

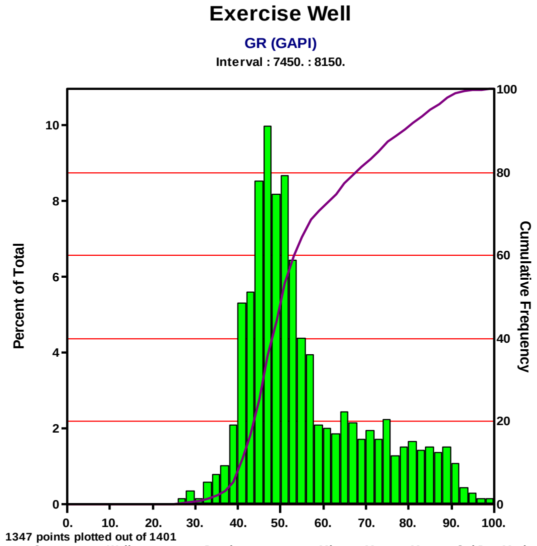
- Normally shales contain radioactive minerals and sands do not.
- Sands may contain radioactive minerals e.g. Biotite, Potassium feldspars or Glauconite. Need corroboration with other clay indicators.
- **Select 'clay'** and **'clean sand'** lines.
- Typically 5 and 95 percentile values of GR are adopted as GR_{sand} and GR_{clay} respectively.
- V_{clay} is obtained from the following equation:

$$V_{clayGR} = \frac{(GR_{\log} - GR_{sand})}{(GR_{clay} - GR_{sand})}$$

Where, V_{clayGR} = Clay volume from GR (v/v)

GR_{log} = Log GR (GAPI)
GR_{sand} = GR in clean sand (GAPI)
GR_{clay} = GR in clay/shale (GAPI)





1347 points plotted out of 1401

Curve	Well	Depths	Min	Max	Mean	Std Dev	Mode	P5	P50	P95
GR	Exercise Well	7450.F - 8150.F	27.54	99.125	55.968	14.36	47.	39.95	51.459	86.126
All Zones			27.54	99.125	55.968	14.36	47.	39.95	51.459	86.126

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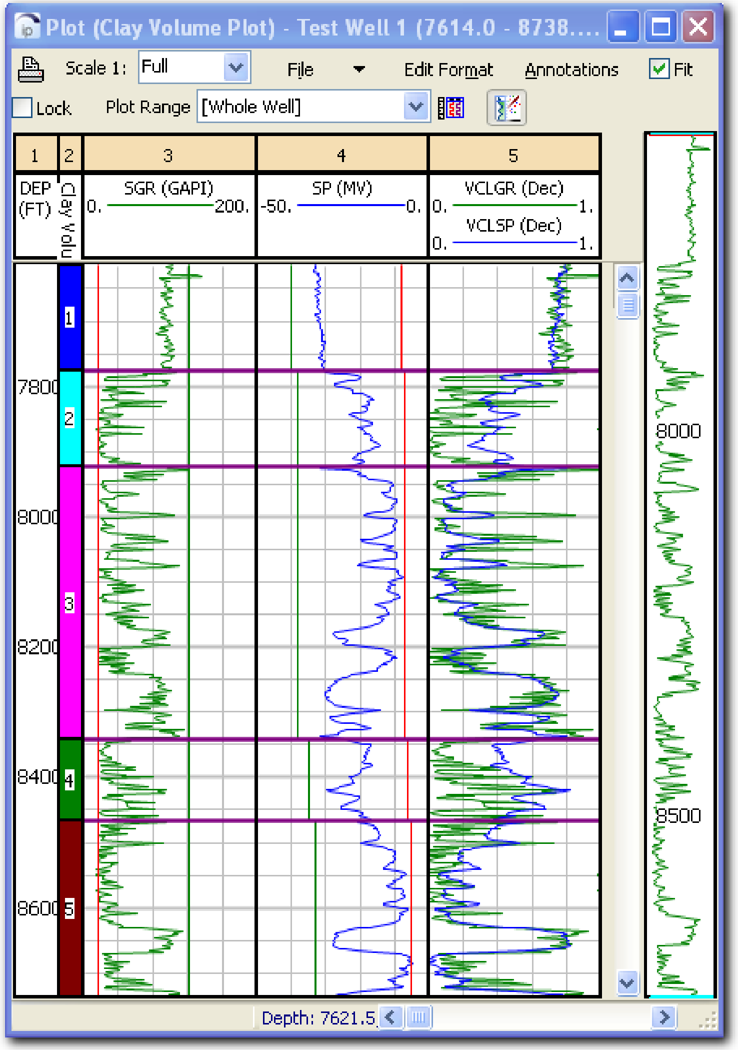
Clay Volume from SP

- Responses in clay and sand – sand line and clay line.
- Select 'clean' and 'clay' lines (methods for choosing parameters are
- essentially the same as for GR).
- V_{clay} calculated using the following equation:

$$V_{claySP} = \frac{(SP_{\log} - SP_{sand})}{(SP_{clay} - SP_{sand})}$$

- Where,
  - V_{claySP} = Clay volume from SP (v/v)
  - SP_{log} = Log SP (mV)
  - SP_{sand} = SP in clean sand (mV)
  - SP_{clay} = SP in clay/shale (mV)



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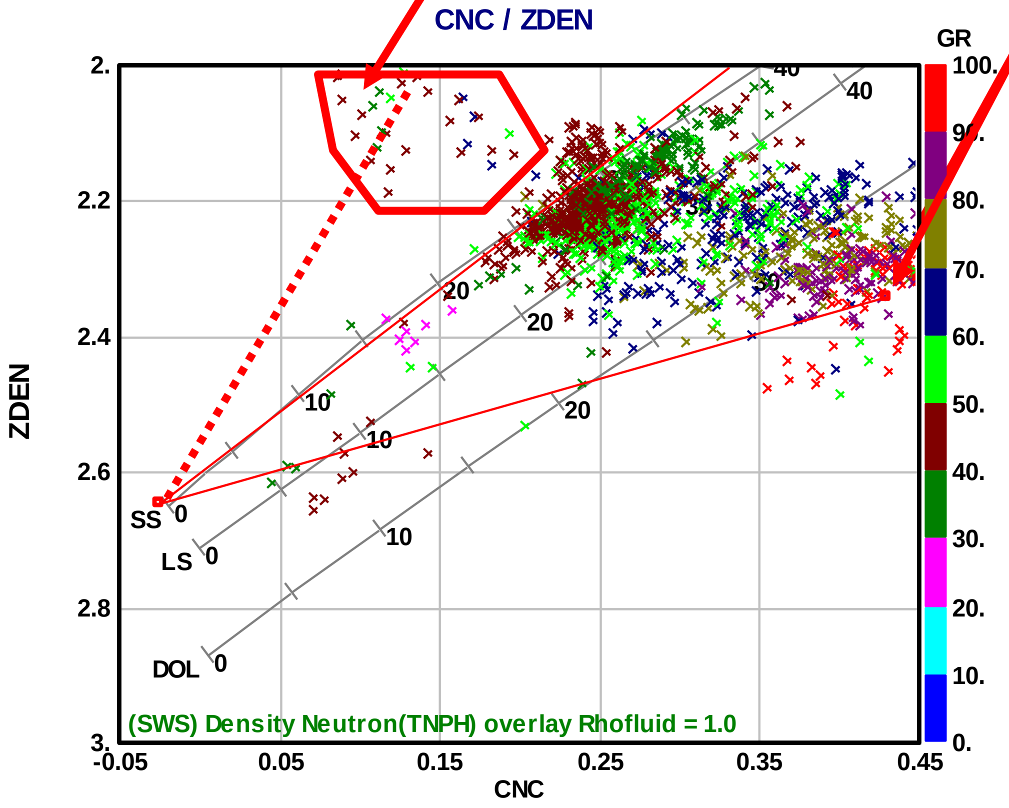
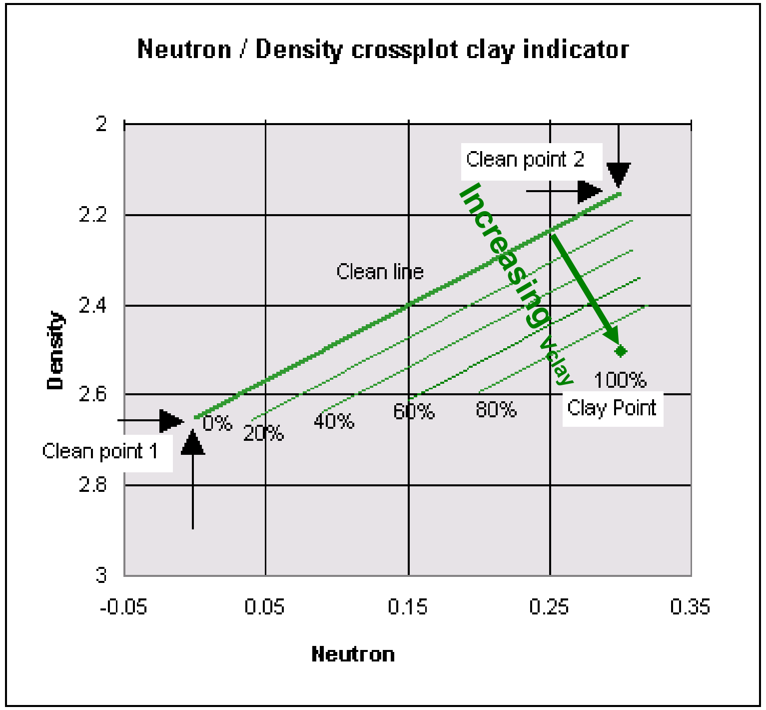
Clay Volume from Neutron/Density Cross-plot

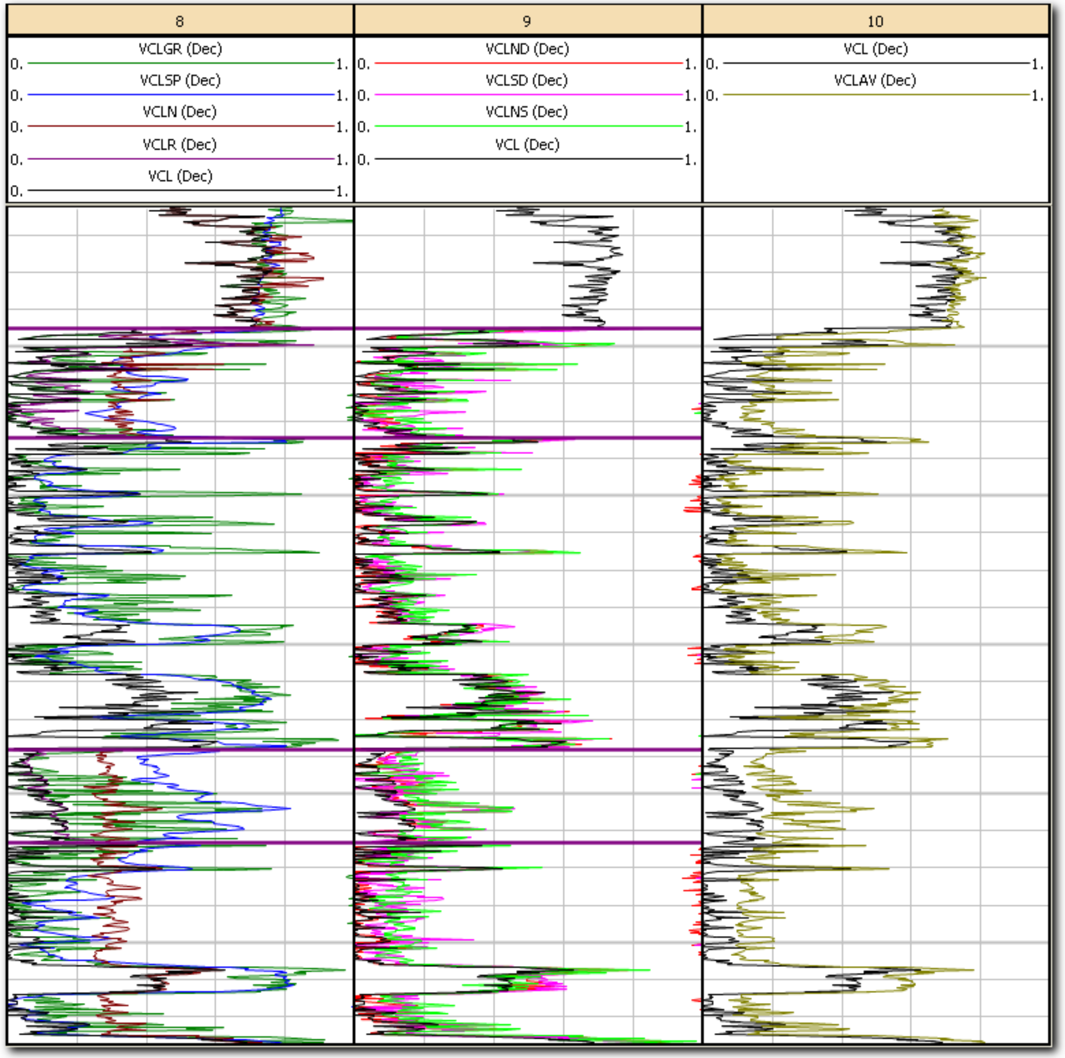
Gas affected data: will lead to underestimate of Vcl from D/N cross-plot unless clean line is adjusted in gas zones.

May wish to place the Clay point at a position of greater data density; it should not be at the extreme edge of plotted data.





Clay Volume



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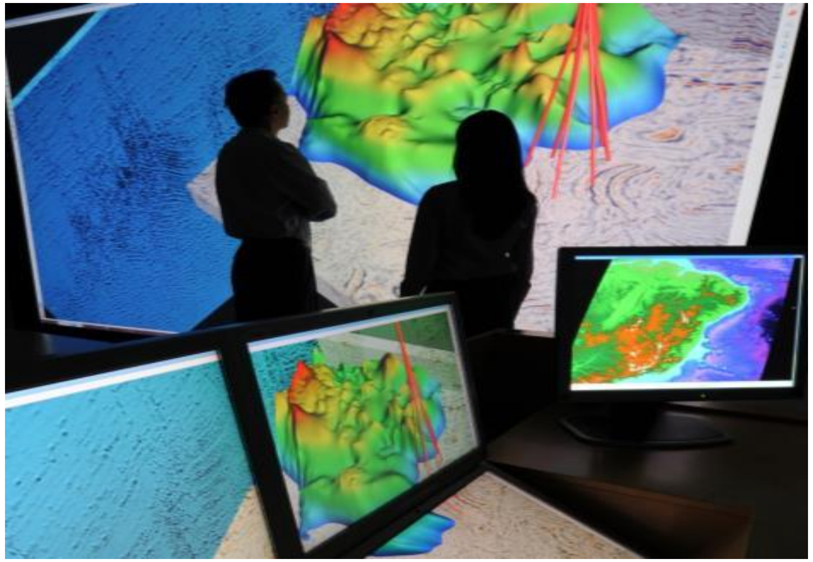
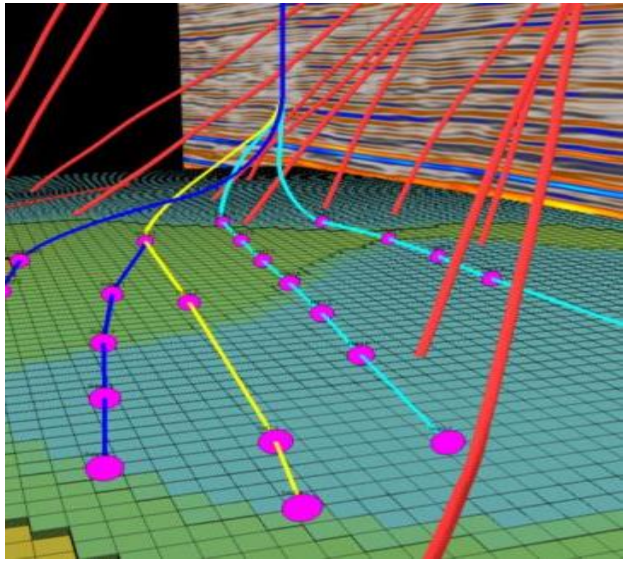
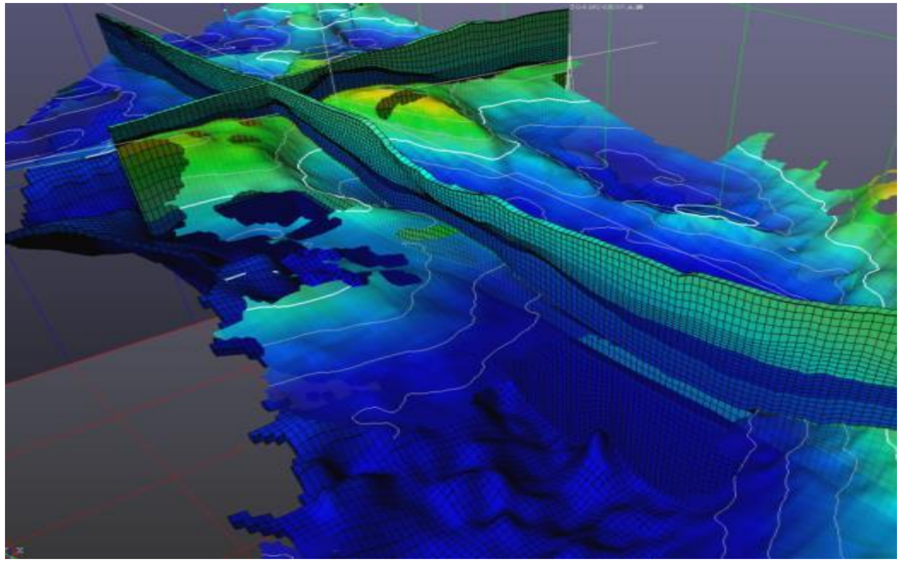
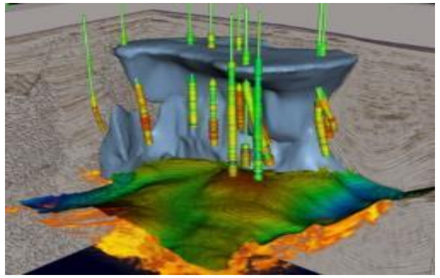

Deterministic Petrophysics: Porosity & Permeability

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Porosity from Density

- The Density measurement is the most reliable means of deriving porosity from logs given:
  - Good hole conditions
  - Fairly constant grain density

- Density porosity is calculated using:

$$\phi_d = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

Where,

$Ø_d$	=	Density porosity (v/v)
ρ_b	=	Log bulk-density (gm/cc)
ρ_{ma}	=	Matrix density (Sandstone 2.65, Limestone 2.71, Dolomite 2.88 gm/cc)
ρ_{fl}	=	Apparent fluid density (Approximate using: Fresh water-based mud 1gm/cc, oil-based mud 0.85 gm/cc)

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Porosity from Sonic -Wyllie Time Average (WTA) Equation

For much of the depth interval drilled in any well, the sonic log is likely to be the only means of deriving porosity.

There are two equations (**Wyllie** time average and **Raymer-Hunt-Gardner**)
In the **Wyllie Equation**, or the **'Time Average'** equation, porosity is assumed to be a linear function of the interval transit time:

$$\phi_s = \frac{(\Delta t_{\log} - \Delta t_{ma})}{(\Delta t_{fl} - \Delta t_{ma})} * \frac{1}{B_{cp}}$$

Where,

$\varnothing_s$	=	Sonic porosity (v/v)
Δt_{log}	=	Interval transit-time measured by the sonic log (μsec/ft)
Δt_{ma}	=	Matrix transit-time (μsec/ft)
Δt_{fl}	=	Transit-time of fluid contained in the formation (μsec/ft)
B_{cp}	=	'**Compaction factor**' determined by comparison with core or regional experience. Often assumed to be 1.

Matrix	Δt_{matrix} (μsec/Ft)	Filtrate	Δt_{fluid} (μsec/Ft)
Silica	55.5	OBM	200-220
Calcite	47.6	WBM	189
Dolomite	43.5		

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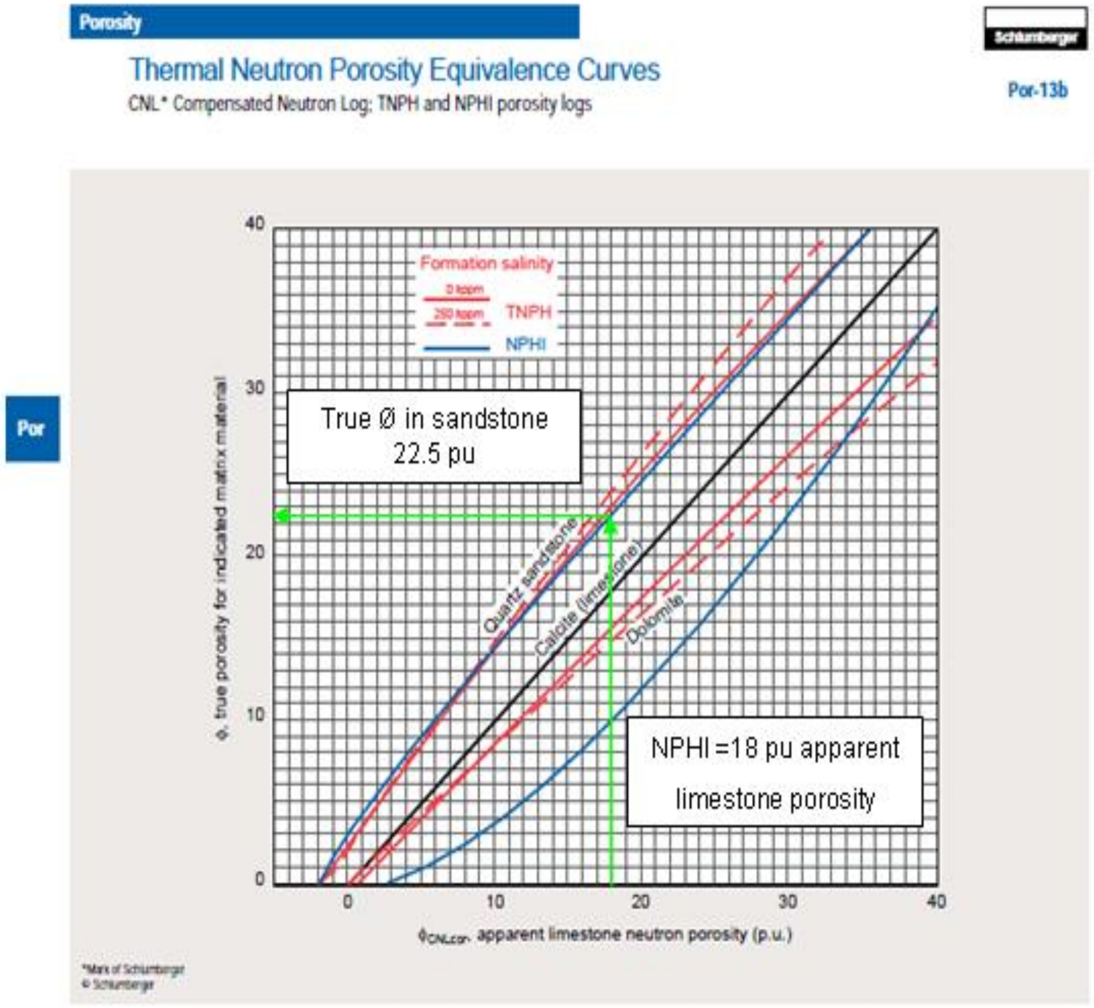
Porosity from Density-Neutron Combination

- Neutron porosity is seldom used independently:
  - However neutron porosity may be the only porosity log in some early wells.
  - Usually used in combination with the density log.
    - » Weighted average porosity:
      - Oil/water $\phi_{nd} = \frac{\phi_d + \phi n}{2}$
      - Gas $\phi_{nd} = \sqrt{\frac{\phi_d^{\,2} + \phi_n^{\,2}}{2}}$
    - » Density-Neutron Cross-plot porosity
- Density-Neutron combined porosity is particularly useful in gas zones where $Ø_d$ and $Ø_s$ tend to be overestimates unless core is available to calibrate them.



If neutron was logged in Limestone units convert to actual matrix before use in weighted average $Ø_{nd}$

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Effective Porosity

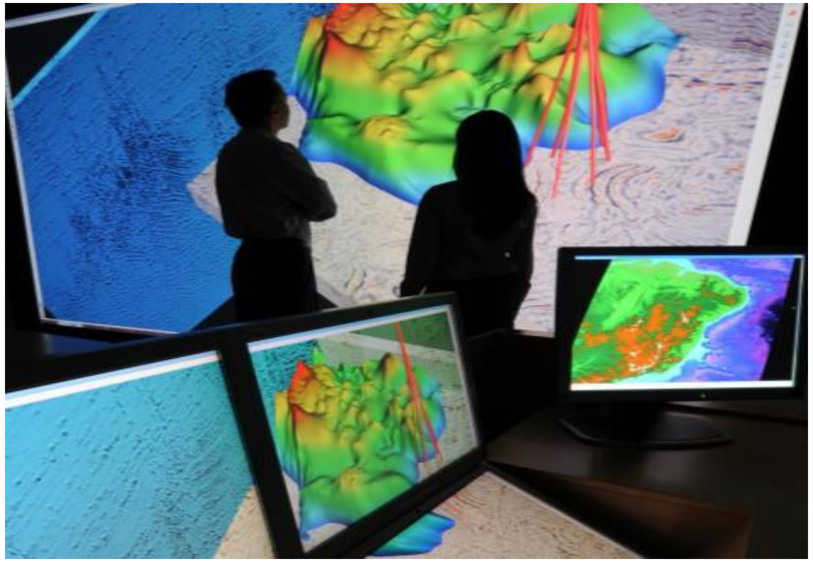
- Effective porosity:

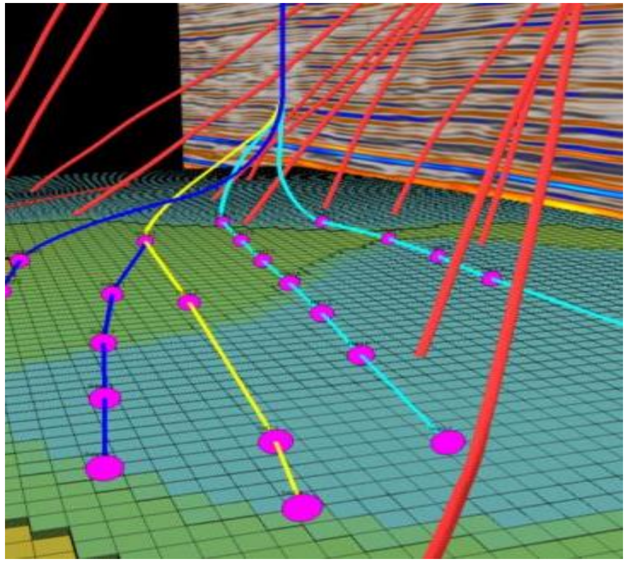
$$\varphi_e = \varphi_t * (1 - Vcl)$$

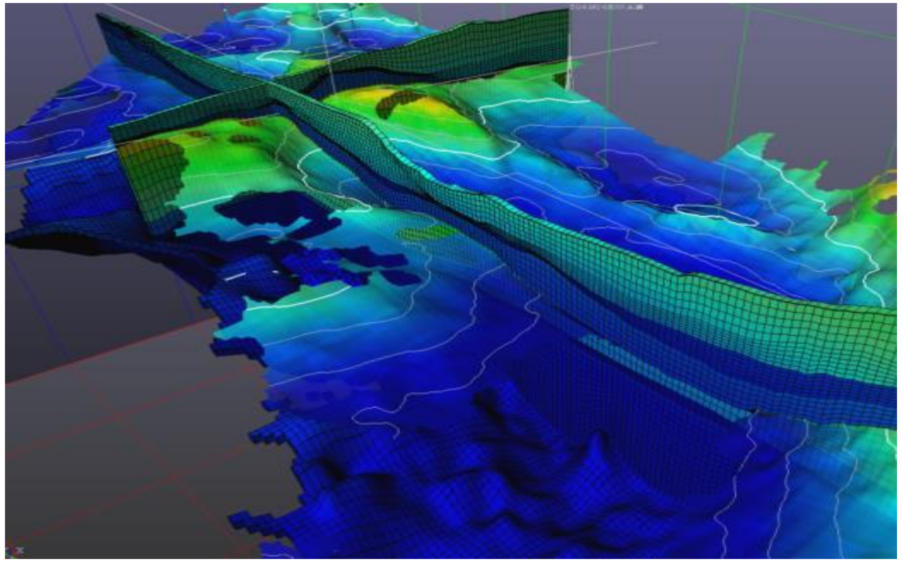
Where, $Ø_e$ = Effective porosity (v/v)

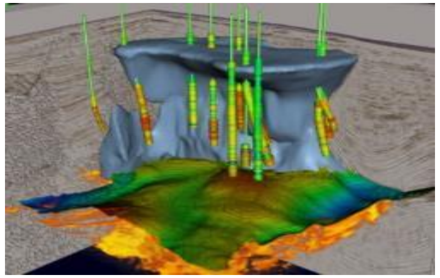
$Ø_t$ = Total porosity (v/v)

V_{cl} = clay volume (v/v)









Deterministic Petrophysics: Water Saturation

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Water Saturation The Archie Equation

- Archie Equation

$$S_w = \left(\frac{a}{\phi^m} * \frac{R_w}{R_t} \right)^{\frac{1}{n}}$$

- Six unknowns:
- True formation resistivity R_t is taken as the most suitable deep reading resistivity, environmentally corrected if necessary.
- Formation water resistivity R_w
  - » SP interpretation
  - » From R_{wa} in a water leg
  - » Pickett plots
  - » Water samples
- Porosity: log total porosity
- Tortuosity constant (a), Cementation exponent (m) and Saturation exponent (n):
  - **Preferably determined from Core measured Formation Factor (F_R) and Resistivity Index (I) respectively.**
  - **Check suitability of a and m using Pickett plot in the absence of core data**

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Alternative Shaly Sands Water Saturation Equations Comparison

- Several equations are shown at right in conductivity form which facilitates comparison.
- The similarities and differences between equations are apparent.

Name	Equation	Year Published
Archie	$C_t = \phi^{+m} x S_w^{+n} x C_w$	1941
Laminated Model	$C_t = \phi^{+m} x S_w^{+n} x C_w x (1 - V_{sh})^{1-m} + V_{sh} x C_{sh}$	
Simandoux	$C_t = \phi^{+m} x S_w^{+n} x C_w + V_{sh} x S_w x C_{sh}$	1963
Indonesia (Poupon-Leveaux)	$C_t = \phi^{+m/2} x S_w^{+n/2} x C_w^{0.5} + V_{sh}^{(1 - V_{sh}/2)} x S_w^{+n/2} x C_{sh}^{0.5}$	1971
Waxman Smits	$C_t = \phi^{+m^*} x S_{wt}^{+n^*} x C_w x (1 + R_w + \frac{B x Q_v}{S_{wt}})$	1968
Dual Water (Clavier Coates & Dumanoir)	$C_t = \phi^{+m0} x S_{wt}^{+n0} x C_w x \left[1 + (\alpha x v_q x \frac{Q_v}{S_{wt}}) x \left(\frac{C_{cw}}{C_w - 1} \right) \right]$	1977
Normalised Qv (Juhasz)	$C_t = \phi^{+m^*} x S_{wt}^{+n^*} x C_w x \left[1 + \frac{Q_{vn}}{S_{wt}} x \left(\frac{C_{cw}}{C_w} - 1 \right) \right]$	1981
	Where $Q_{vn} = Q_v / Q_{vsh}$	
Dual Water (Vsh Method)	$C_t = \phi^{+m0} x S_{wt}^{+n0} x C_w x \left[1 + \frac{S_{cw}}{S_{wt}} x \left(\frac{C_{cw}}{C_w} - 1 \right) \right]$	1982
	Where $S_{cw} = \frac{(V_{sh} x \phi_{sh})}{\phi_t}$	

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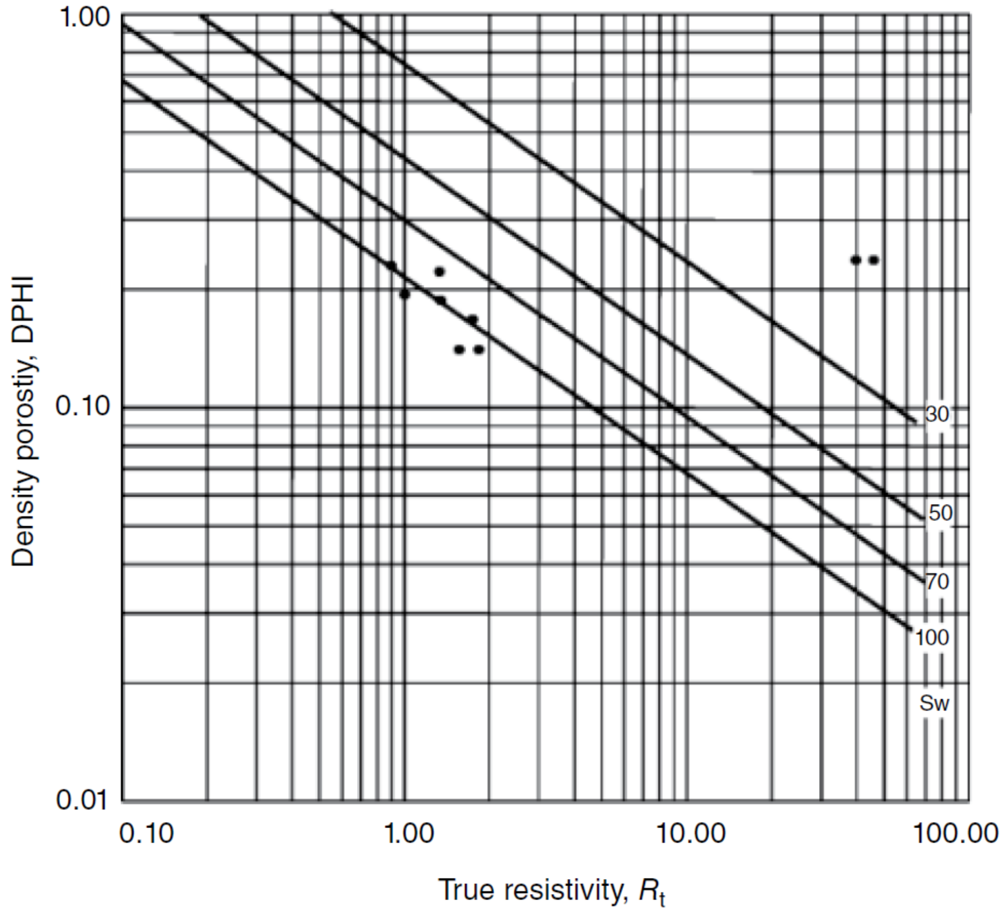
Pickett Plot

- The Pickett plot is the most commonly used method of *R*w determination in the absence of formation water samples.
- The method can be applied regardless of the type of drilling mud, provided that there is a water-bearing, clean sand interval.
- The Pickett method simply uses a logarithmic version of the Archie equation:
- $$\log R_o = \log(aR_w) - m\log\phi$$



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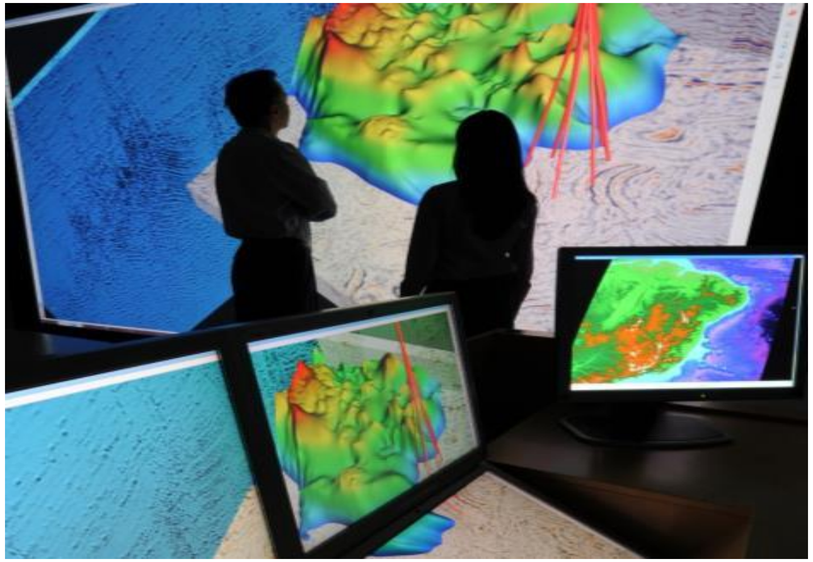

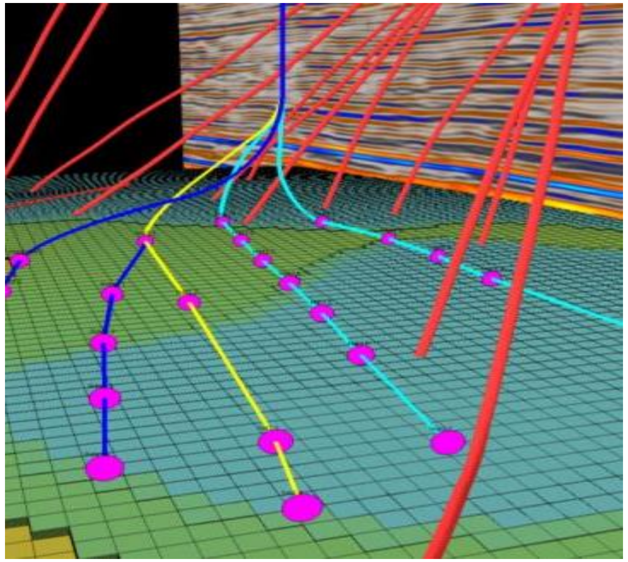

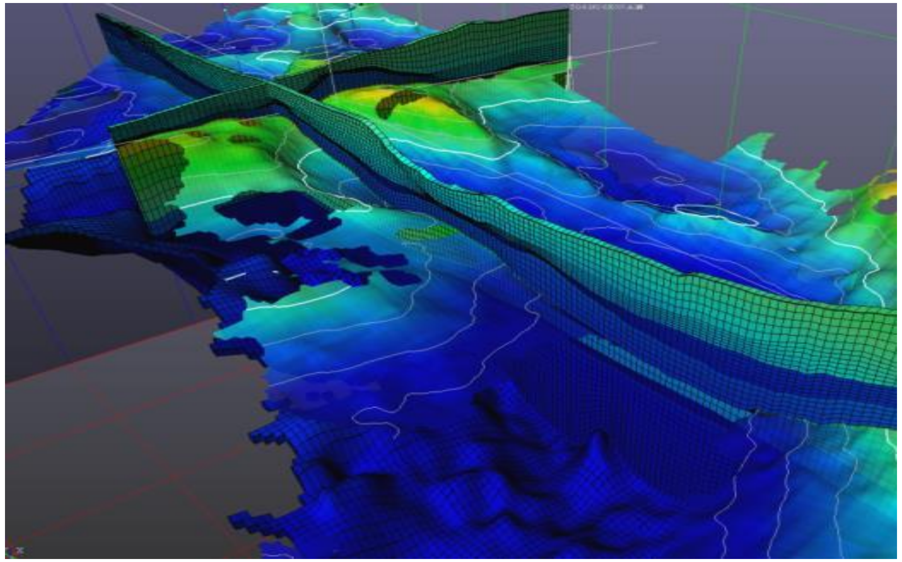

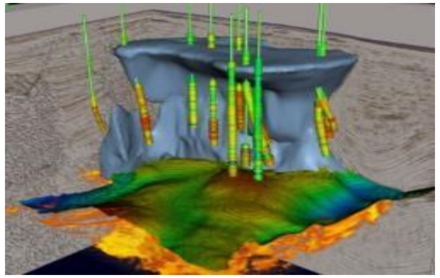

Deterministic Petrophysics: NetPay

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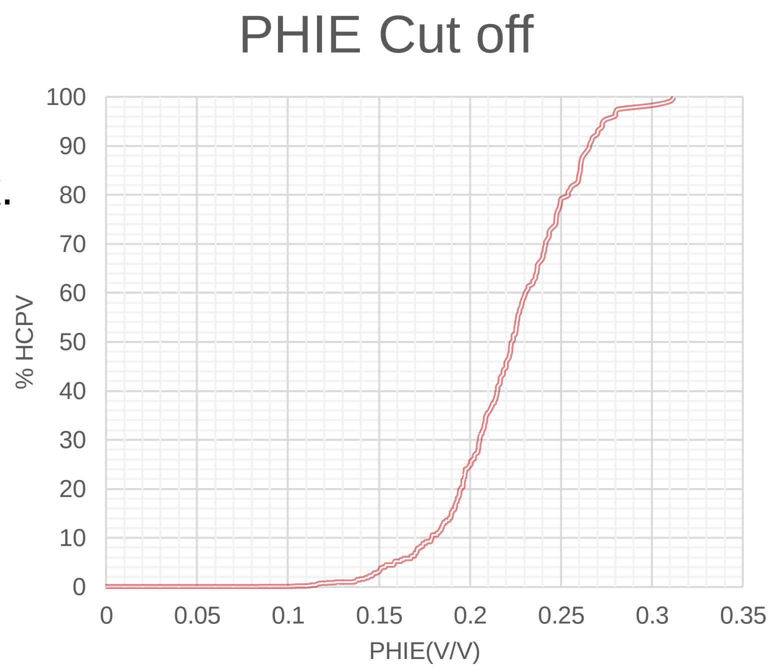
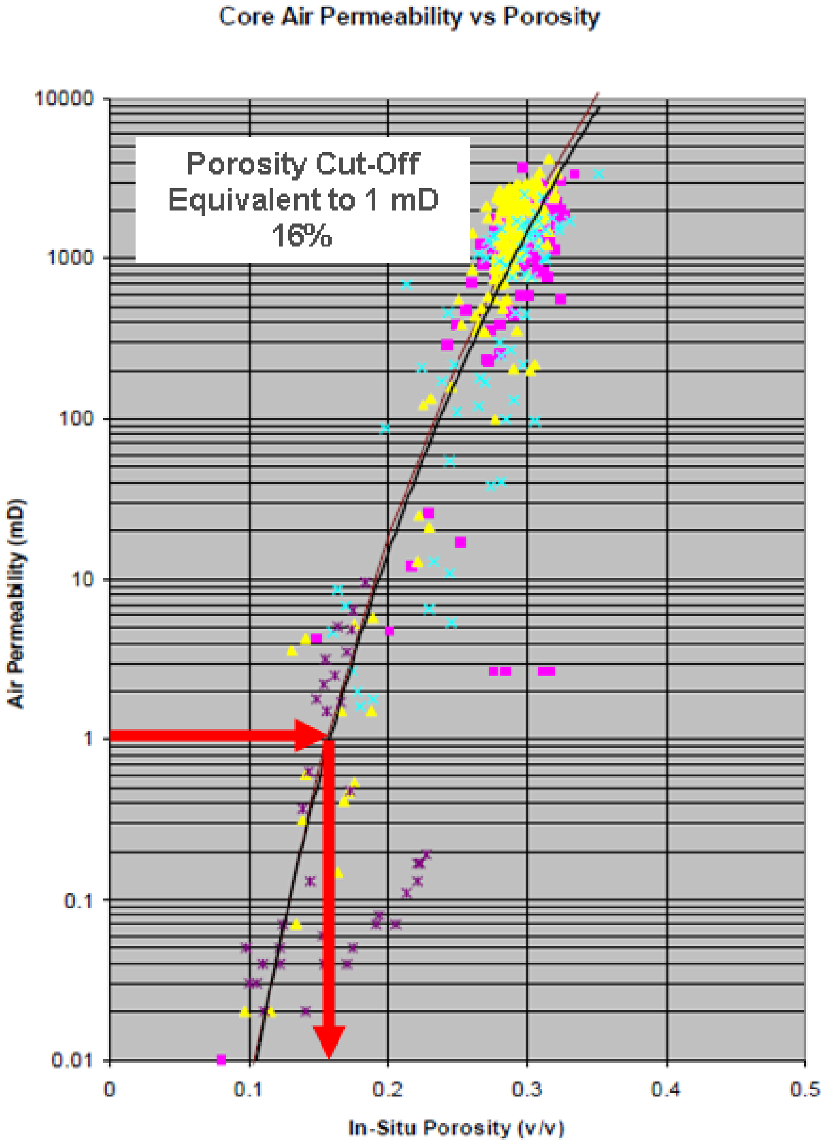
Basic Interpretation Workflow Net Pay

- Gross Rock:
  - Comprises all rock in the evaluation interval.
- Net Sand:
  - Comprises those rocks which may have useful reservoir properties.
  - Sand is a generic oilfield term for lithologically clean sedimentary rock.
  - Determined using a V_{clay} cut-off.
  - **The cut off is generally arbitrary and of the form Vcl <= Cut-off**
- Net Reservoir
  - Comprises those rocks which do have useful reservoir properties.
  - Determined using a porosity cut-off on Net sand.
  - **Vcl <= Cut-off and Ø> = Cut-off**
- Net Pay (*h*):
  - Comprises the net sands that contain hydrocarbon.
  - Determined using a water saturation cut-off on Net Reservoir
  - **Vcl <= Cut-off and Ø >= Cut-off and Sw <= Cut-off**



Determination of Net Cut-off using Porosity/Permeability cross-plot

- Determination of porosity cut-off equivalent to a 1mD permeability cut-off in an oil reservoir and 0.1mD for gas reservoirs,



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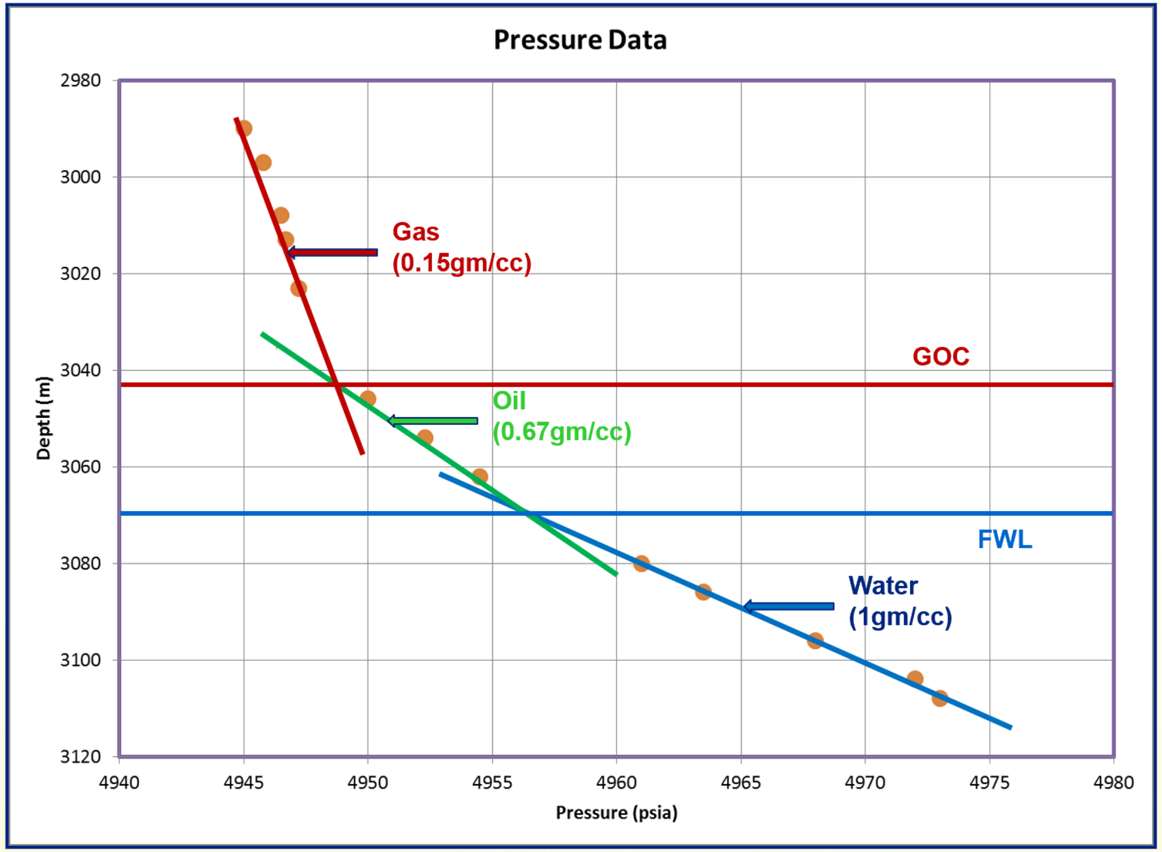
Wireline Formation Test

- Four main applications
  - Formation pressure measurement
  - Permeability and skin
  - Formation fluid characterization
  - Reservoir characterization



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Exercise

- Calculate the Vcl from GR
- Calculate the density porosity as Total Porosity
- Calculate the effective porosity
- Calculate the Rw from Pickett plot
- Calculate the water saturation using Archie equation
- Carry out the cut-off sensitivity analysis for net pay cut off
- RFT Pressure Plot

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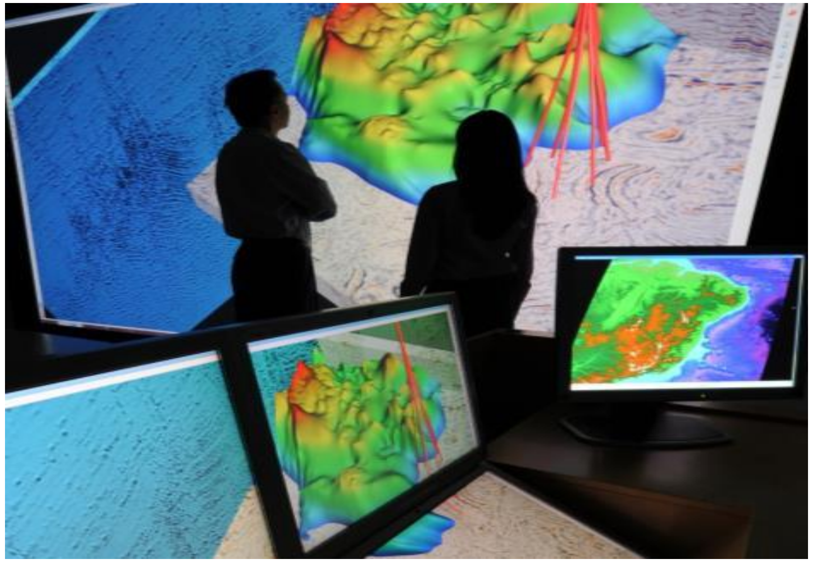
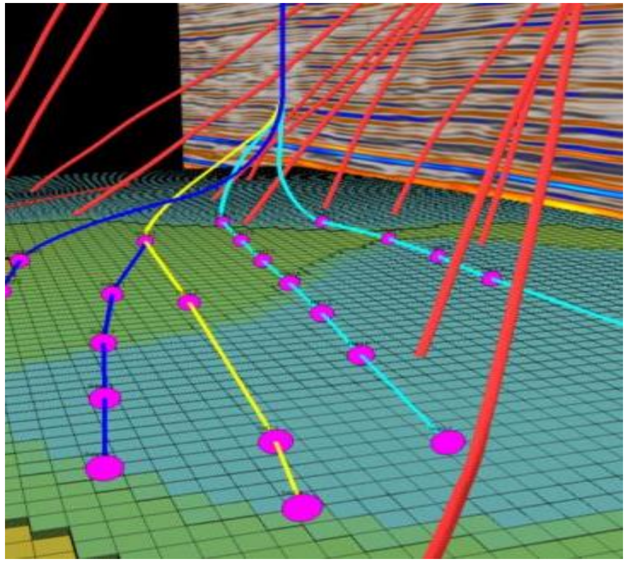
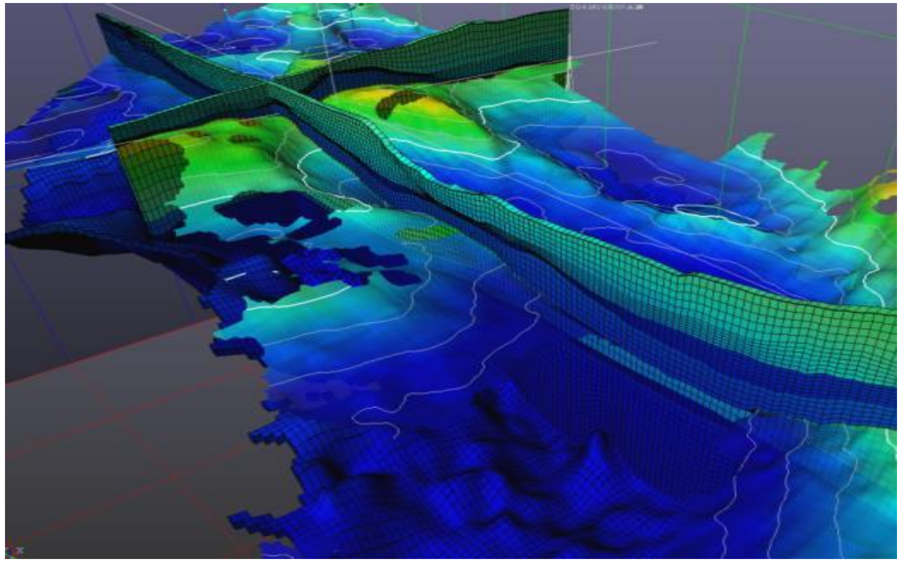
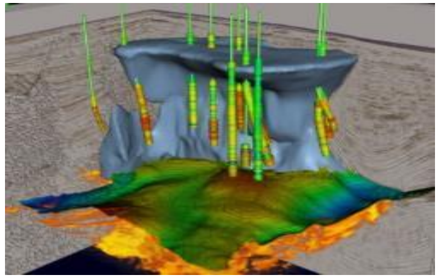

Probabilistic Petrophysics

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Deterministic Petrophysics

- The typical methodology followed by the Petrophysicist is to carry out the petrophysical analysis by following a series of stepwise calculations.
- The results of each step are dependent on the prior steps.
- The methodology includes;
  - Calculate clay volume
  - Calculate porosity
  - Calculate water saturation

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Example

- Let's assume log reading of each porosity log; **Density = 2.4 gr/cc; Neutron = 0.2, Sonic = 75 us/ft**.

$$\rightarrow \; RHOB = (V_{LS} \times \rho_{LS}) + (V_{SS} \times \rho_{SS}) + (V_{DL} \times \rho_{DL}) + (\phi \times \rho_f)$$

$$2.4 = (V_{LS} \times 2.7) + (V_{SS} \times 2.65) + (V_{DL} \times 2.8) + (\phi \times 1.0)$$

$$\rightarrow \; NPHI = (V_{LS} \times NPHI_{LS}) + (V_{SS} \times NPHI_{SS}) + (V_{DL} \times NPHI_{DL}) + (\phi \times NPHI_f)$$

$$0.2 = (V_{LS} \times (0)) + (V_{SS} \times (-0.04)) + (V_{DL} \times (0.05)) + (\phi \times 1.0)$$

$$\rightarrow \; SONIC = (V_{LS} \times DT_{LS}) + (V_{SS} \times DT_{SS}) + (V_{DL} \times DT_{DL}) + (\phi \times DT_f)$$

$$75 = (V_{LS} \times 47.5) + (V_{SS} \times 55.5) + (V_{DL} \times 43.5) + (\phi \times 189)$$

$$\rightarrow \; 1 = V_{LS} + V_{SS} + V_{DL} + \phi$$

Probabilistic Petrophysics

- Probabilistic technique use “inverse” approach to estimate the formation parameters.
- The analysis is done by solving simultaneous equations described by one or more interpretation models
- Log measurements or tools and response parameters are used together in response equations to compute the volumetric results for formation components (minerals and fluids).
- Once the volumes are calculated, the tool responses are reconstructed using the same system of equations.
- The reconstructed logs are compared against the input data to determine the quality of volumetric results.
- The deviation of reconstructed tools from the true log readings, taking into consideration the uncertainty of each tool, is called the incoherence function. It is this function that the solver tries to minimize to achieve the most probable answer.

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Advantages of Probabilistic Petrophysics

- The use of all logs and other data according to the accuracy of the data, resulting in optimized answers.
- The use of data from other sources e.g. geological, core, experimental logging tools.
- The ability to solve for very complex lithologies.
- The output of “quality” indicators indicate how well the model fits the data.
- The flexibility to define unique models without additional software

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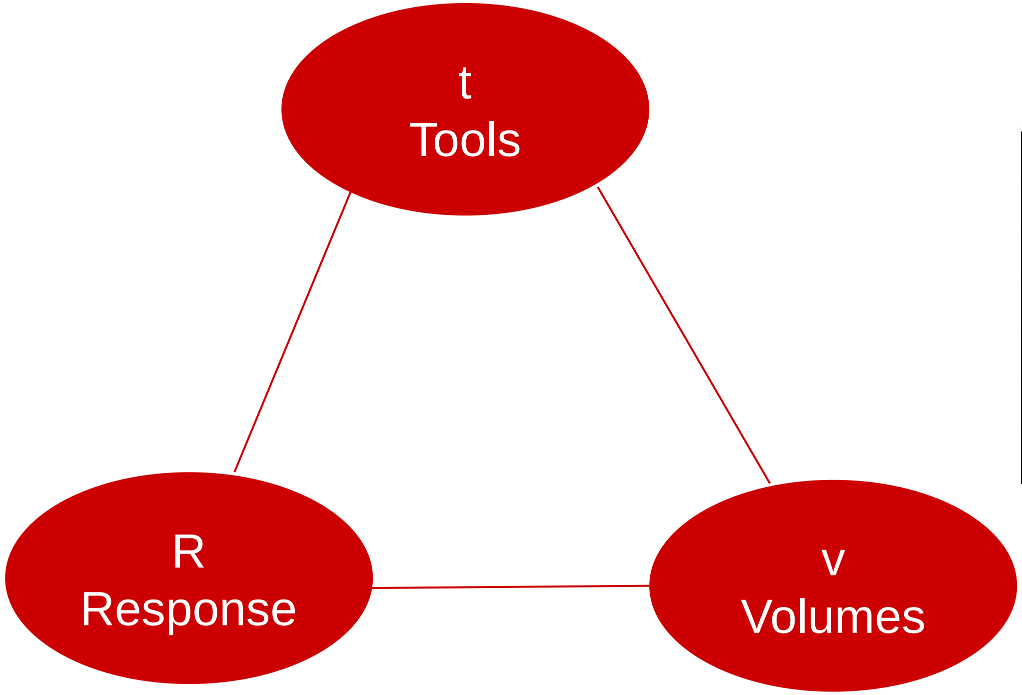
Petrophysics Model



$$t = Rv$$

$$\begin{bmatrix} \alpha_{a,1} & \alpha_{b,1} & \alpha_{c,1} & \alpha_{d,1} & \alpha_{e,1} & \alpha_{f,1} \\ \alpha_{a,2} & \alpha_{b,2} & \alpha_{c,2} & \alpha_{d,2} & \alpha_{e,2} & \alpha_{f,2} \\ \alpha_{a,3} & \alpha_{b,3} & \alpha_{c,3} & \alpha_{d,3} & \alpha_{e,3} & \alpha_{f,3} \\ \alpha_{a,4} & \alpha_{b,4} & \alpha_{c,4} & \alpha_{d,4} & \alpha_{e,4} & \alpha_{f,4} \\ \alpha_{a,5} & \alpha_{b,5} & \alpha_{c,5} & \alpha_{d,5} & \alpha_{e,5} & \alpha_{f,5} \\ \alpha_{a,6} & \alpha_{b,6} & \alpha_{c,6} & \alpha_{d,6} & \alpha_{e,6} & \alpha_{f,6} \\ \alpha_{a,7} & \alpha_{b,7} & \alpha_{c,7} & \alpha_{d,7} & \alpha_{e,7} & \alpha_{f,7} \end{bmatrix} \begin{bmatrix} A \\ B \\ C \\ D \\ E \\ F \end{bmatrix} = \begin{bmatrix} 1 \\ 2 \\ 3 \\ 4 \\ 5 \\ 6 \\ 7 \end{bmatrix}$$

Where:

A, B, C, D, E, and F = minerals and fluid Volumes to be evaluated

1,2,3,4,5,6, and 7 = tool responses

$\alpha_{i,j}$ = response parameters

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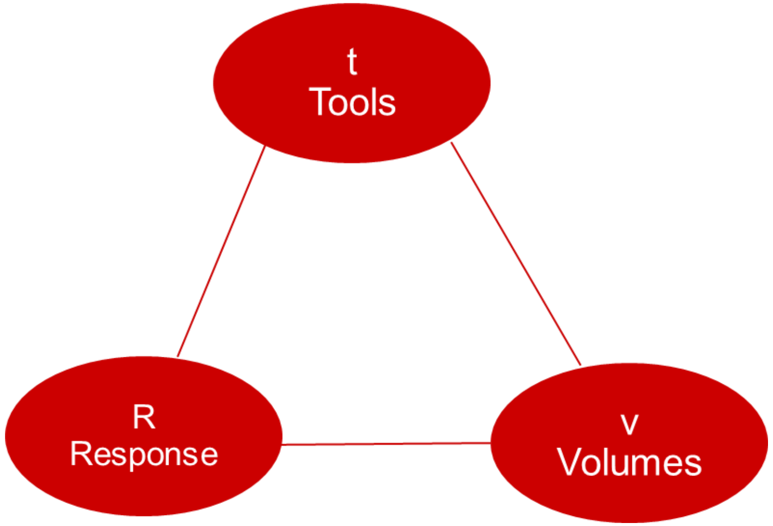
Interpretation Model

- Inverse Problem: ***t*** and ***R*** are used to compute ***v***. The inverse problem solves for formation component volumes
- Forward Problem: also known as log reconstruction, uses ***R*** and *v* to compute ***t***. A log reconstruction problem is computed for each inverse problem, or Solve process.
- Calibration Problem: ***t*** and ***v*** are used to compute ***R***.



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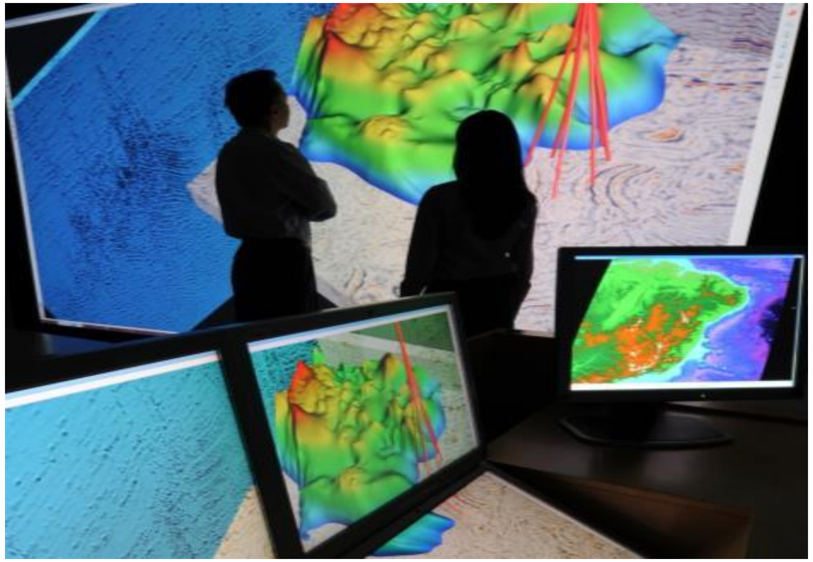
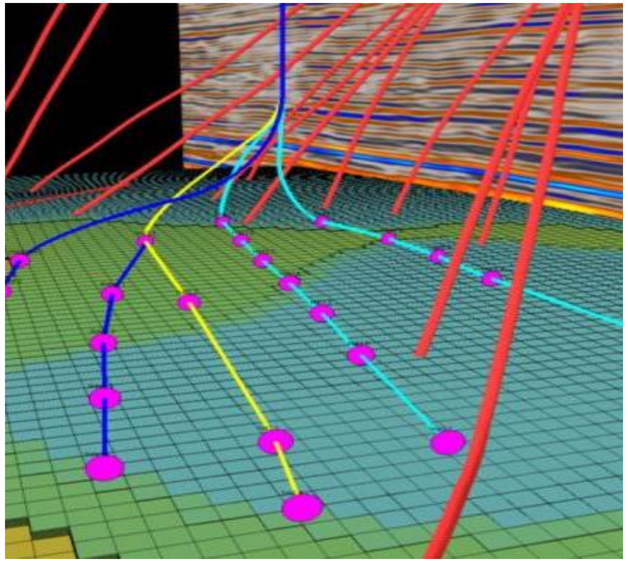
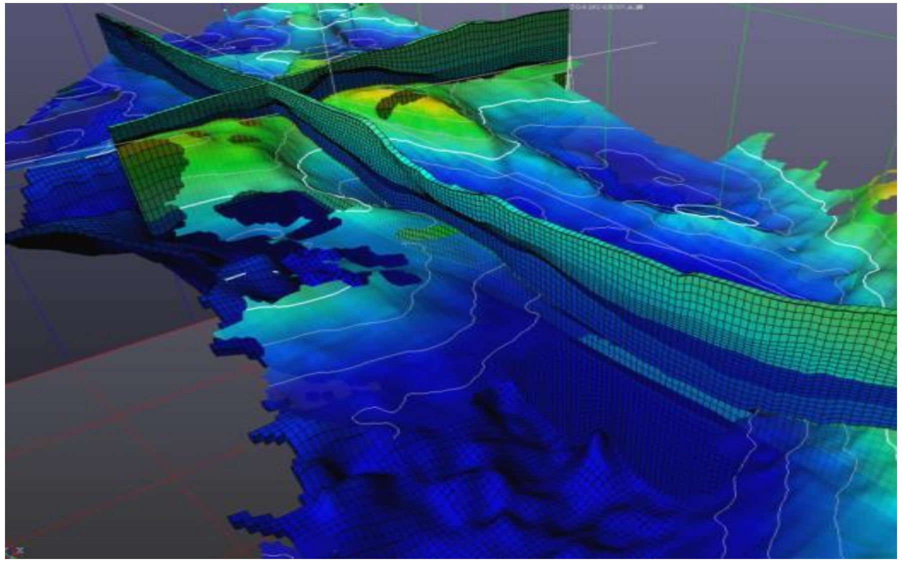
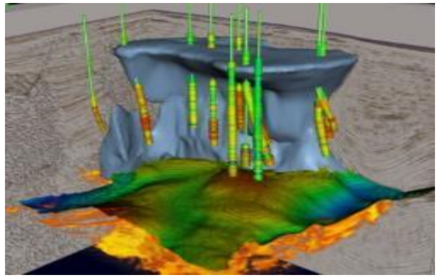
Using Δ as a Quality Indicator

- Δ can be thought of as a measure of the fit of the model to the input data.
  - Bad hole resulting in unreliable data.
  - Incorrect selection of endpoint values.
  - The presence of mineral volumes not accounted for in the model.
  - Data not properly correlated.
  - Bad data (improper calibration, tool malfunction etc.)









Rock Typing

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Rock Typing

- Rock typing is the act of grouping rocks based on a similar and common property

- Rock typing is a very important step in the construction of both static and dynamic reservoir models.

- It controls the 3D distribution of heterogeneities and consequently it influences the volume in place as well as the flow behavior.

- The Reservoir Rock Typing (RRT) can be achieved by integration of the core description, thin section, conventional core analysis, MICP data and open hole log data.

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Different Rock Typing Definitions

- Biofacies: A grouping of sedimentary deposits based on palaeontological attributes suchas fossil assemblages that are restricted to a particular environment allowing differentiation of that unit from adjacent units.
- Electrofacies: Grouping of sedimentary deposits based on electrical well log properties allowing it to be distinguished from adjacent beds.
- Facies: The term facies was introduced to include both sedimentological and palaeontological characteristics.
- Flow Units: Hydraulic flow units/flow zones within a reservoir are defined by the physical properties (both geological and petrophysical) of the rock that have an impact on fluid flow and are used to identify pore geometry variations within different lithofacies.
- Lithofacies: A grouping of sedimentary deposits based on similar lithological and chemicalproperties of the rock .
- Petrofacies: Reservoir petrofacies are defined by the petrographic attributes (textures, mineralogy, diagenetic effects) of the rock bodies and rock units that impact both petrophysical and geophysical properties which in turn impact how they are defined during exploration and production.

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Rock Typing Workflow

- Two steps are included in rock typing;
  1. Rocks are classified into lithofacies based on core observations and thin sections according to their mineralogy, deposition textures and pore types.
  2. Lithofacies are further subdivided into rocks types according to petrophysical properties such as MICP, log data and porosity-permeability relationships.

- The following workflow can be used to establish a continuous RRT:
  - ✓ Geological Facies (Core description, CT Scan, Thin Sections and XRD data)
  - ✓ Core Analysis based RRT
  - ✓ Log curve based RRT
  - ✓ Continuous RRT

Geological Facies

- Geological facies will be classified based on the texture, grain size and sorting. The core data including core description and any relevant literature from all the wells will be thoroughly reviewed to get an addition information regarding the reservoir characteristics.

- All the thin sections along with SEM and XRD data will be examined to understand the different rock types and characterizing pore types based on the following parameters;
  - Mineralogical components of each thin section petrographically based on the visual estimation of the different mineral phases.
  - Grouping and identifying grains systematically.
  - CT scan samples can be used to identify and quantify the reservoir heterogeneity.

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Core RRT

- The Routine core analysis (RCA) and MICP data can be used to classify the Flow units.

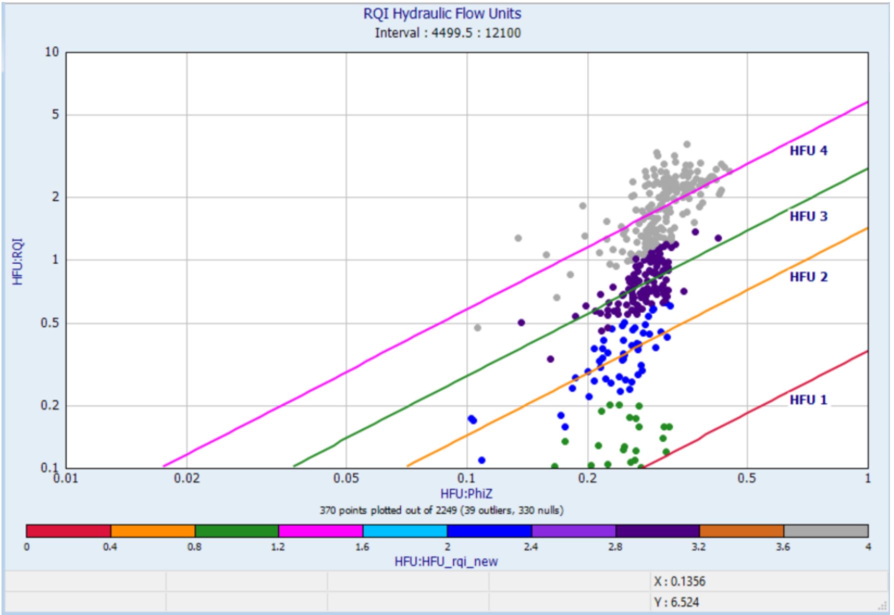
- The core porosity and permeability data from RCA will be used to classify the rock types based on Hydraulic flow units method such as **Rock Quality Index (RQI), Winland and Pitman's method**.

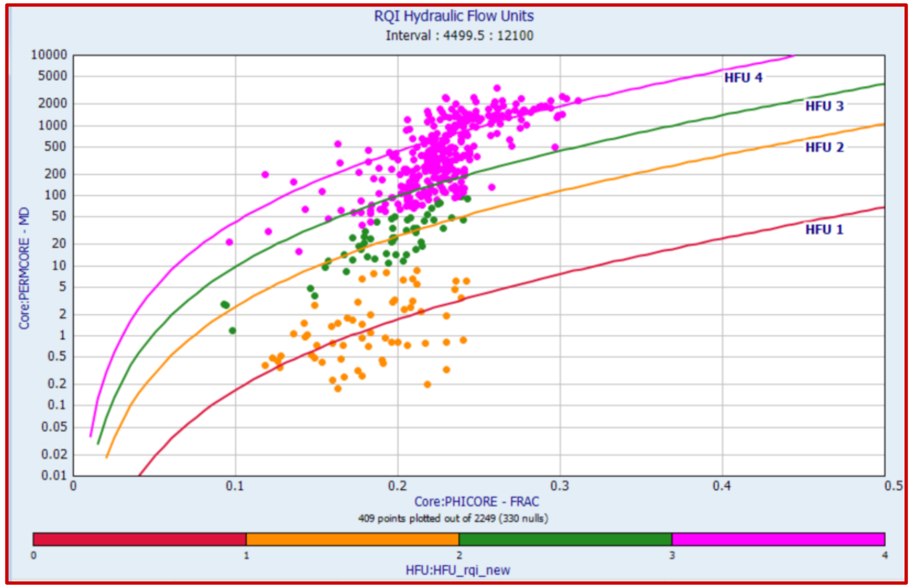
- Correlation between the RRT from RCA and SCAL will be compared in order to reveal the correlation between porosity and fluid behavior or permeability in the reservoir.

Hydraulic Flow Units

- The Routine core analysis (RCA) and MICP data can be used to classify the Flow units.

- The core porosity and permeability data from RCA will be used to classify the rock types based on Hydraulic flow units method such as **Rock Quality Index (RQI), Winland and Pitman's method**.





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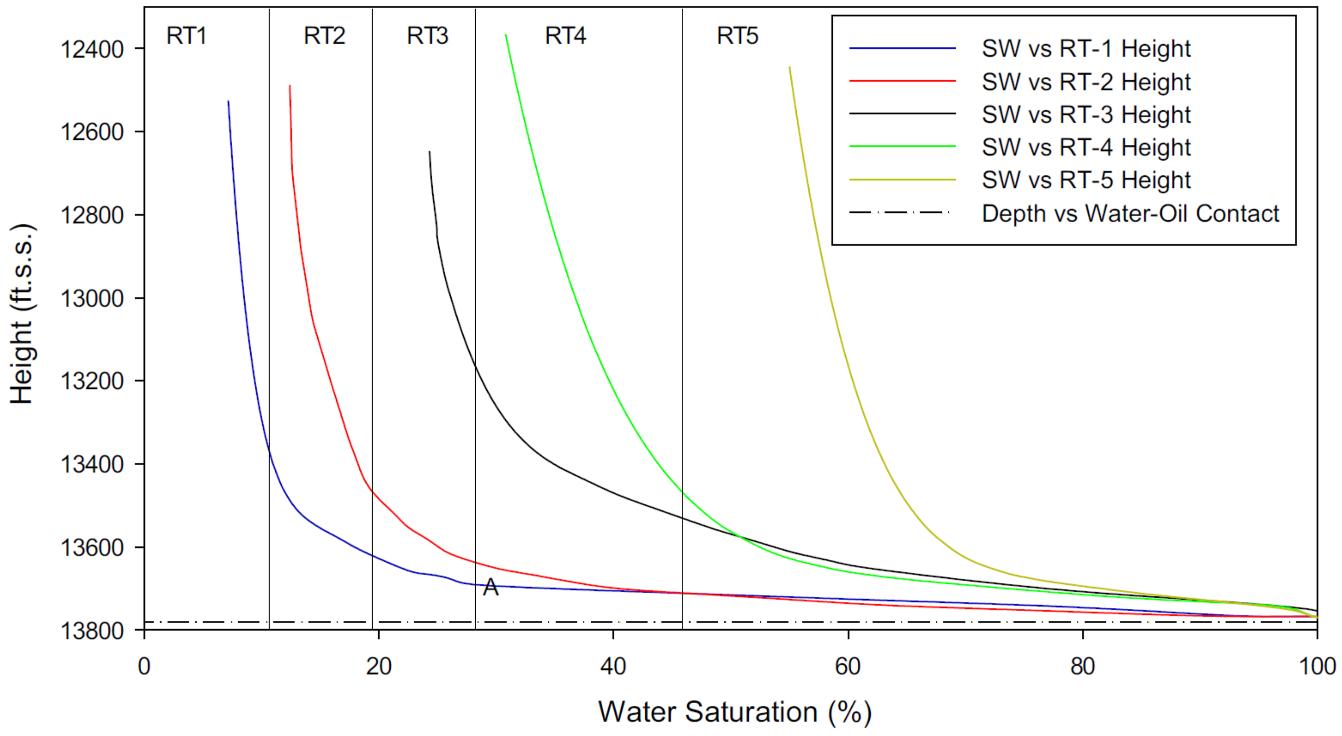
Capillary Based RRT

- The classification of capillary pressure MICP data will be carried out based on the irreducible water saturation and the capillary pressure at different water saturations on capillary pressure curves.

- RRT with lowest Swir and displacement pressure at different water saturation belongs to the best reservoir quality and vice versa.



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Log RRT

- The open hole logs raw and interpreted data will be used to duplicate the cored RRT.

- The objective of this process is to train, test and validate a methodology to calibrate the RRT over cored interval and implement the same process for the uncored interval to predict the same RRT.

- Various machine learning algorithms such as ***Fuzzy logic, Neural Network, Clustering techniques and Self organizing Map*** will be used to predict the rock types from the wireline open hole log data such as GR, RHOB, NPHI and DT. The available core facies can used to calibrate the log derived rock types.

ML based RRT

- The most widely used methods used to define Rock Type, are used to identify which intervals have similar responses in logs, with respect to others, which allows to identify facies or rock types. These modules are :
    - ***Cluster Analysis (K-mean clustering).***
    - ***SOM (Kohenen Self Organising Maps).***
    - ***Neural Network***
- Each uses different mathematical techniques, and in both cases, the result depends on the input data:
    - Triple Combo logs tend to the field of “Lithofacies”
    - NMR logs tend to the "Flow Units" field.
- Clusters or nodes (SOM) are consolidated to remove deviations due to vertical resolution and layer boundaries; for example, more clusters are calculated than expected output facies.
- **Clustering technique and SOM can be run without being calibrated using hierarchical consolidation; or they can be calibrated with an input curve, which typically could be the core facies.**

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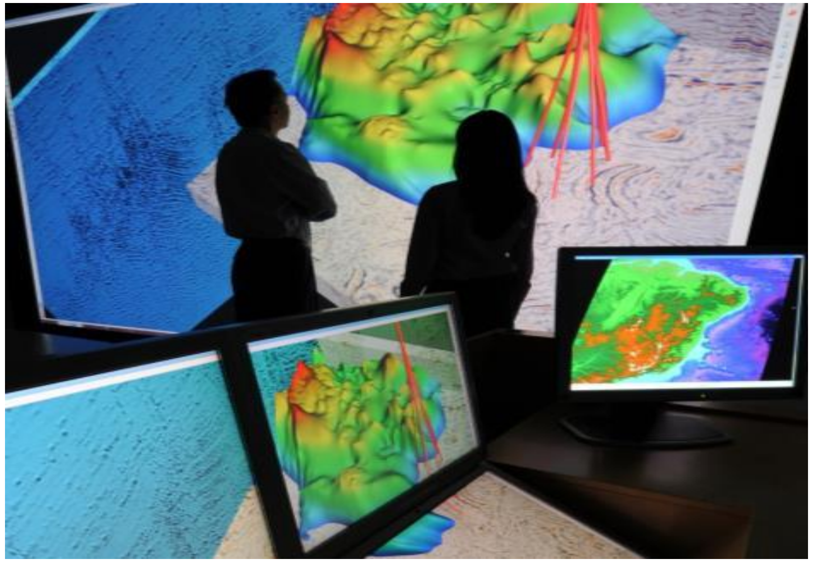

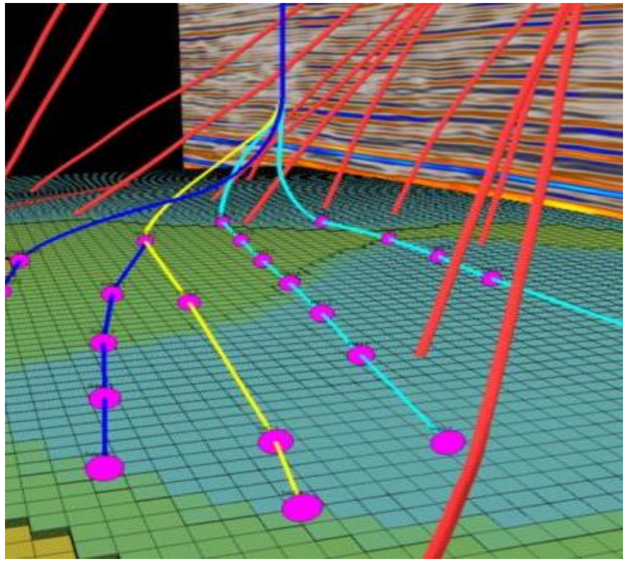

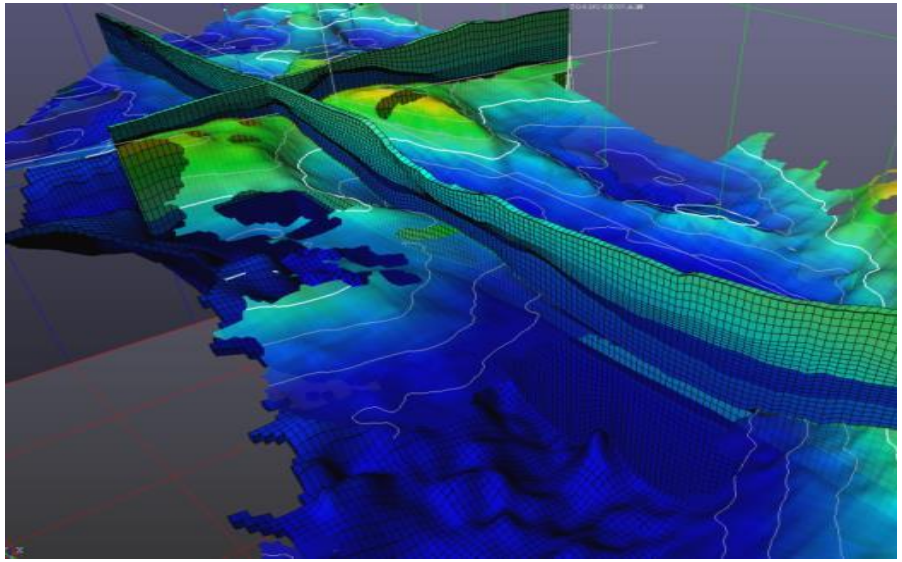

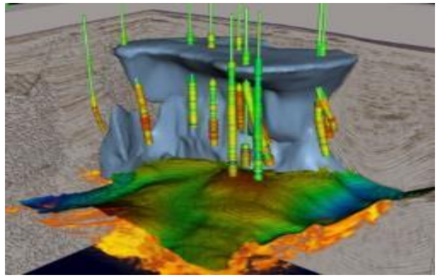

Clustering Analysis

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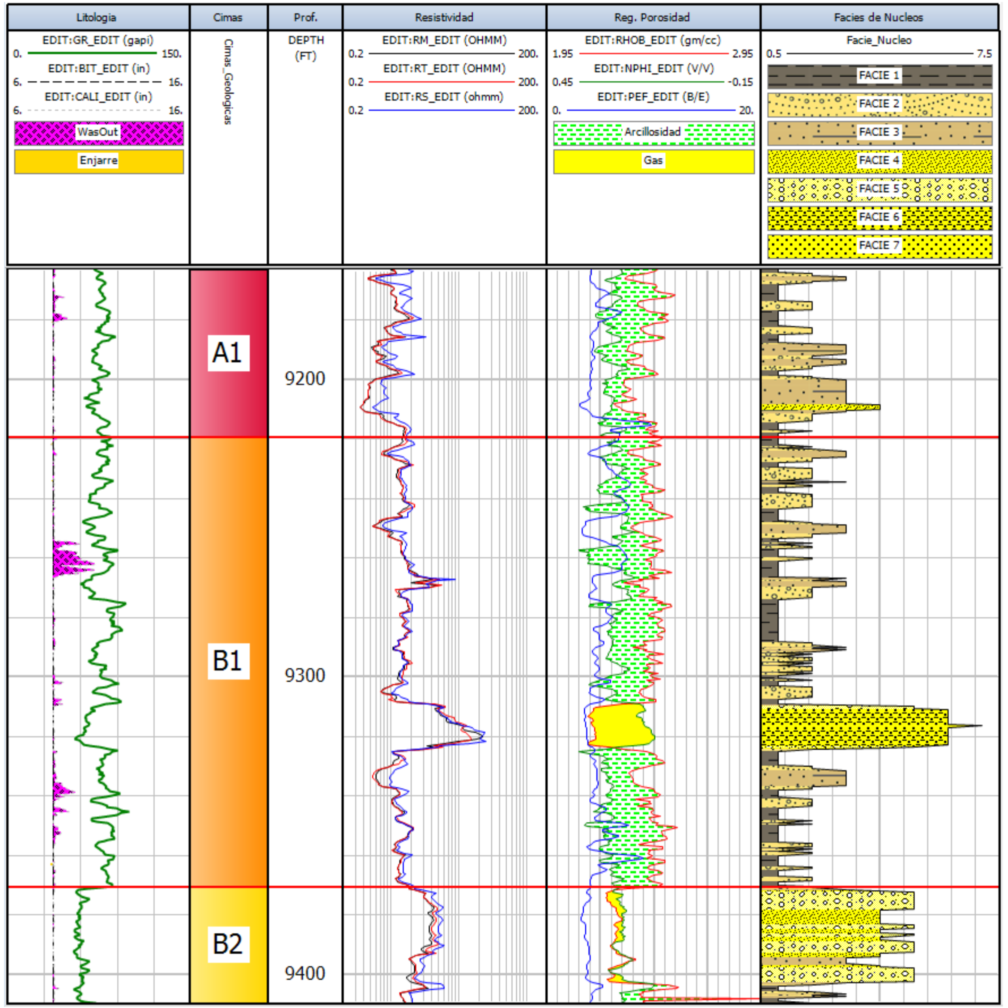
Clustering Analysis

- This technique classifies the samples or properties into groups called "clusters", so that the samples or properties in the same cluster are more similar to each other than the samples or properties in others.
- **<u>This theory is a means of classifying the observed data into significant classes or groups .</u>**
- For example, we may want to develop "facies codes" based on a set of wireline logs (GR, SP, Density - Neutron, Resistivity, among others).
- In this classification scheme, the higher the level of the grouping, the more similar the members of the respective class are.



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Fundamentals concept of Cluster Analysis

- **This technique is usually done in two stages:**

1. First, the data is divided into manageable data clusters:
    - The number of clusters should be sufficient to cover all the different ranges of data seen in the logs.
    - 15 to 20 clusters is a reasonable number for most data sets.
2. The second step, which is more manual, is to take these 15 to 20 groups and group them into a manageable number of geological facies. This may involve reducing the data to 4 to 5 groups.

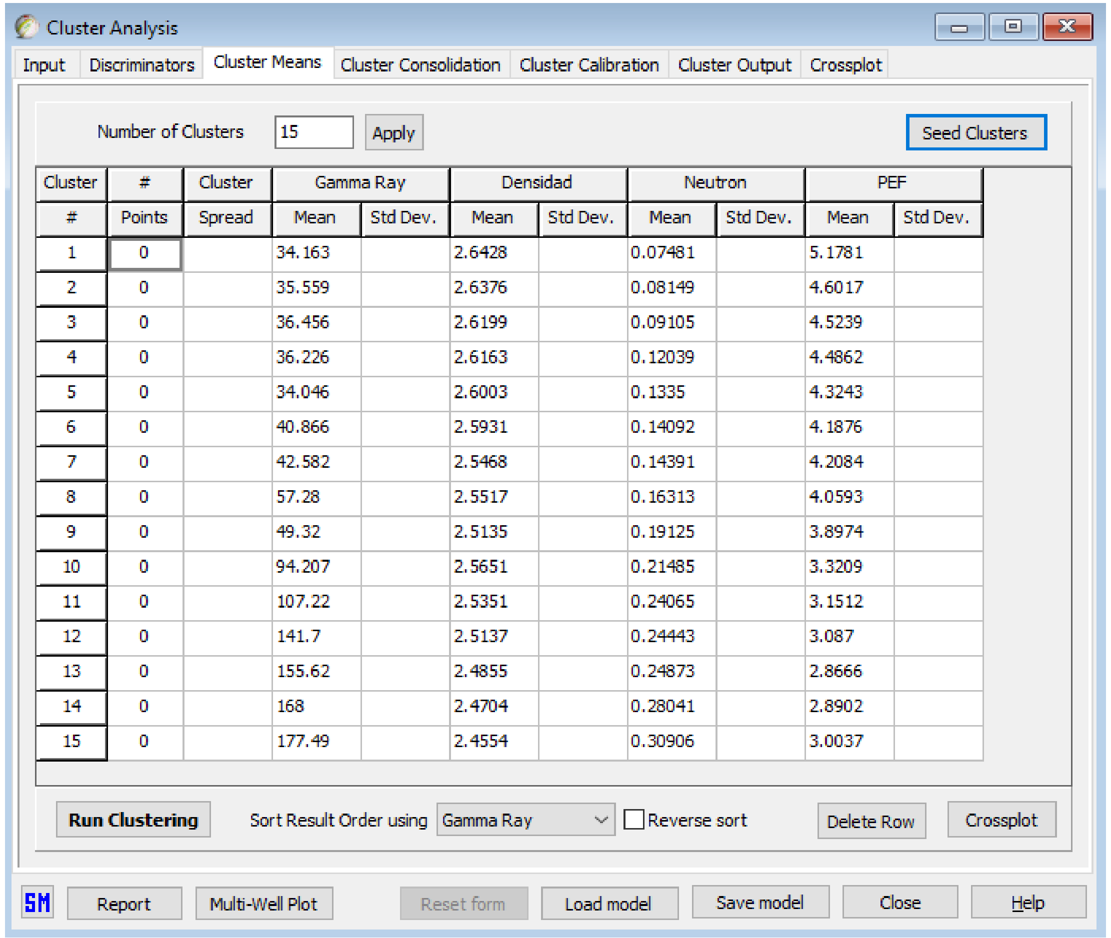
Cluster Means

1. The first stage uses the K-mean statistical technique, to group the data into a known number of clusters, which is entered.

   The number of clusters must be greater than the desired number of facies, generally 2x or 3x more; that is, if you want to predict 5 facies, you must generate 10 or 15 clusters

   For this to work, an initial assumption must be made of the mean value of each group for each input log. The initial assumption can affect the results, and for good results, the initial values should cover the full range of the logs.

2. The initial assumptions can be entered manually in the K-mean table of the Cluster Means tab, or you can use the button "Seed Clusters"; ***which works by calculating the first major component of the well log data.***



Cluster #	# Points	Cluster Spread	Gamma Ray Mean	Gamma Ray Std Dev.	Densidad Mean	Densidad Std Dev.	Neutron Mean	Neutron Std Dev.	PEF Mean	PEF Std Dev.
1	0		34.163		2.6428		0.07481		5.1781	
2	0		35.559		2.6376		0.08149		4.6017	
3	0		36.456		2.6199		0.09105		4.5239	
4	0		36.226		2.6163		0.12039		4.4862	
5	0		34.046		2.6003		0.1335		4.3243	
6	0		40.866		2.5931		0.14092		4.1876	
7	0		42.582		2.5468		0.14391		4.2084	
8	0		57.28		2.5517		0.16313		4.0593	
9	0		49.32		2.5135		0.19125		3.8974	
10	0		94.207		2.5651		0.21485		3.3209	
11	0		107.22		2.5351		0.24065		3.1512	
12	0		141.7		2.5137		0.24443		3.087	
13	0		155.62		2.4855		0.24873		2.8666	
14	0		168		2.4704		0.28041		2.8902	
15	0		177.49		2.4554		0.30906		3.0037	

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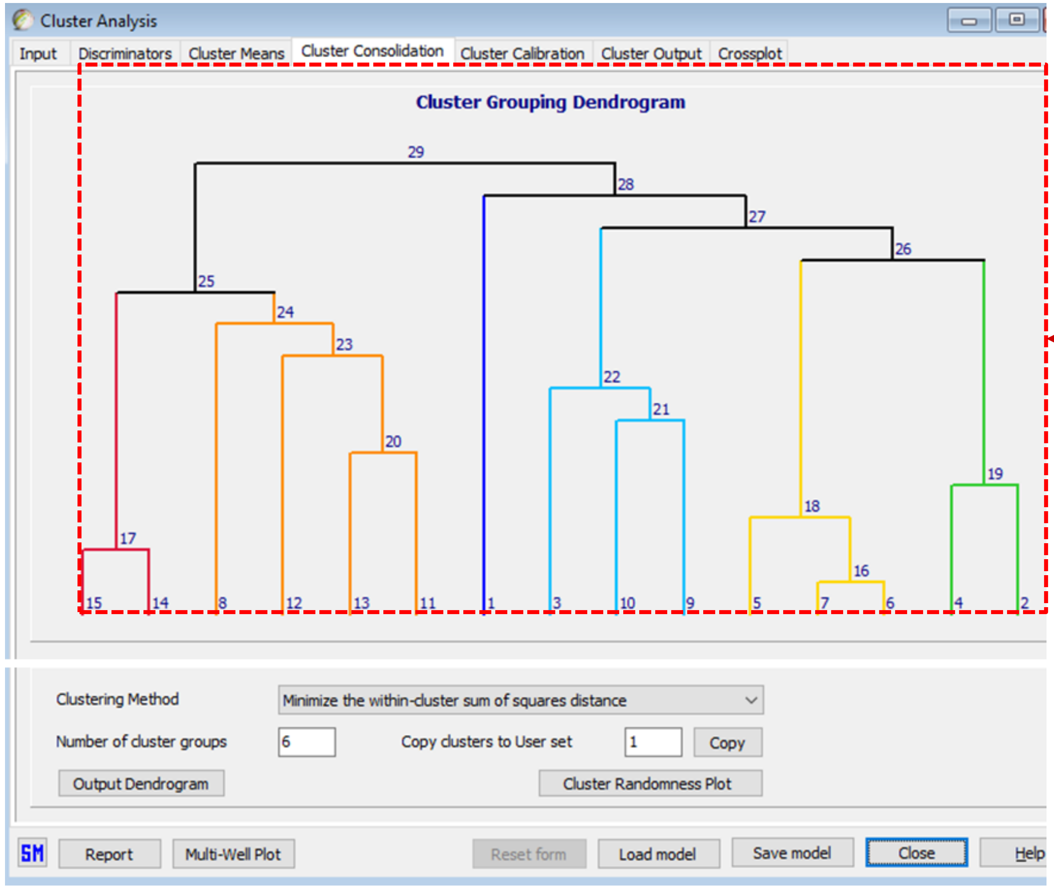
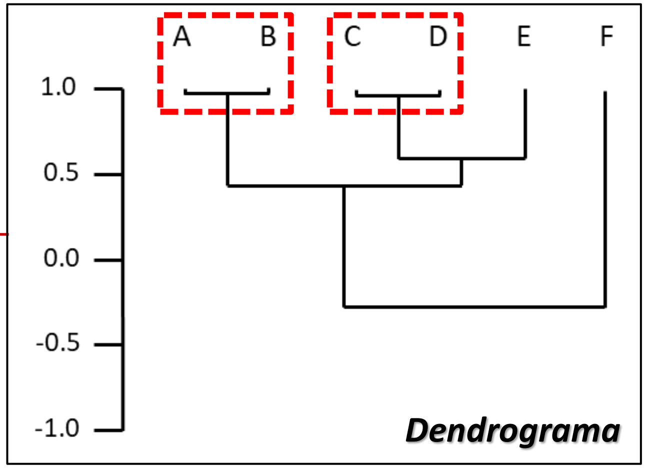
Cluster Consolidation



- In this case, a hierarchical grouping technique is used to group the data (cluster analysis), according to the following criteria:
- Hierarchical grouping works by calculating the distances between all clusters, and then merging them. The pairs of objects or clusters with the highest similarities are grouped or linked first. In the example, clusters A with B and C with D were merged.



- The new cluster distance to all other clusters is recalculated, and the two closest clusters are merged again. Two objects can be connected only if they have the highest similarities to each other. In the example the CD clusters with E.
- This process continues until you have only one cluster. The results can be plotted as a dendogram. Continuing with the example, AB was then merged with CDE, and then the latter ABCDE with F.

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Cluster Consolidation.

Methodology

As explained above, the distance between objects is determined with the following equation:

$$d_{ij} = \sqrt{\frac{\sum_{k=1}^{m}\left(X_{ik} - X_{jk}\right)^2}{m}}$$

Where:

d_{ij}: is the distance between sample i and sample j

X_{ik}: is the property k, measured in sample i.

X_{jk}: is the property k, measured in sample j.

m: total measured properties.

Suppose we have six data or samples defined as A, B, C, D, E, and F; to which 4 different properties have been measured (porosity, quartz content, rock fragments and feldspar), as shown in the following table:

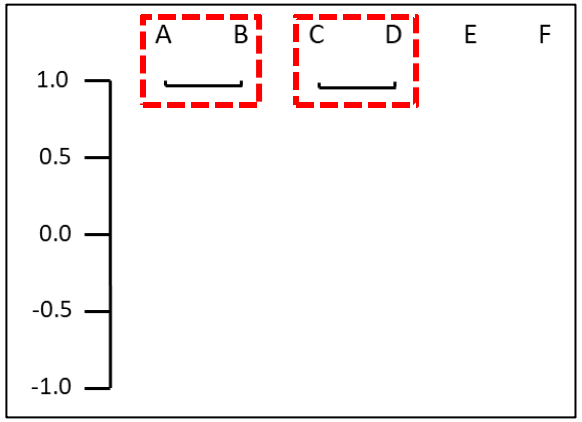
Sample	Pore	Quartz	Rock Fragment	Feldspar
A	0.24	1.78	0.69	3.32
B	0.48	2.07	2.41	4.78
C	0.76	4.05	1.20	3.21
D	0.23	2.98	0.85	2.06
E	0.04	3.33	3.39	2.63
F	1.98	0.98	2.01	2.20

Applying the previous equation, the different combinations of distances between all the samples can be determined, taking into account the 4 properties; This would allow calculating the distance similarity matrix shown:

	A	B	C	D	E	F
A	1	**0.911**	0.767	0.704	0.440	-0.107
B	**0.911**	1	0.539	0.500	0.570	**0.168**
C	0.767	0.539	1	**0.991**	0.587	-0.719
D	0.704	0.500	**0.991**	1	**0.665**	-0.768
E	0.440	0.570	0.587	0.665	1	-0.388
F	-0.107	0.168	-0.719	-0.768	-0.038	1

The first step in grouping by the peer group method is to find the highest correlations between each other, in each column, to form or combine the clusters:

- Samples A & B, combined
- C&D samples, combined
- Sample E, looks more like D, but is not the highest mutual pair.
- Sample F, not paired in this iteration.



Dendrogram with initial clusters, AB and CD

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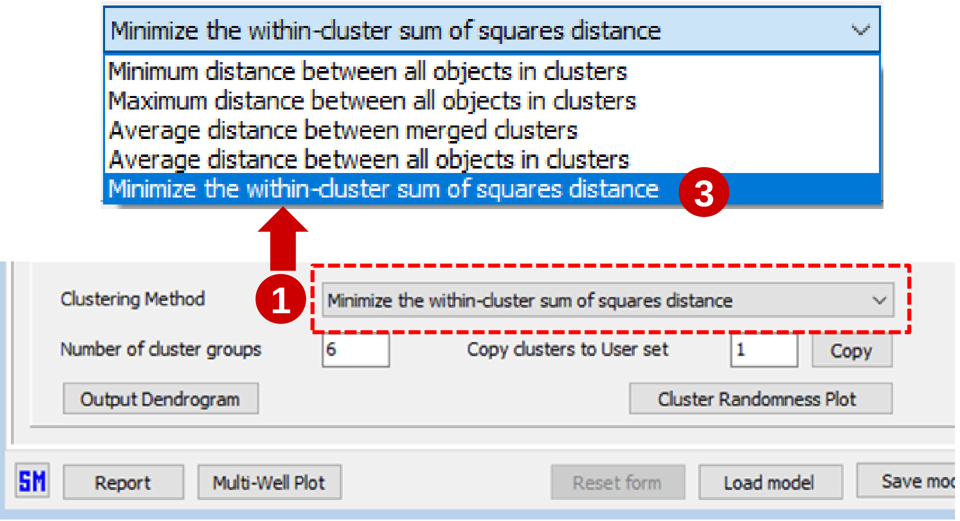
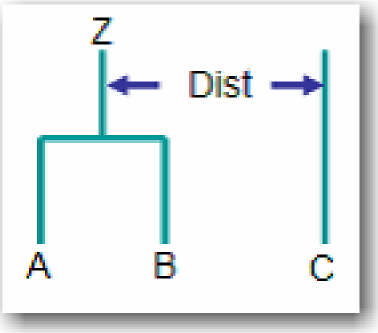
Cluster Consolidation.

Methodology





1. The Software has five different grouping methods, which define how clusters are combined.

2. These methods will show considerably different results.

3. The default method ***"Minimize the within-cluster sum of squares distance"*** gives good results, separating the different lithological records within different clusters.

4. The five methods differ in how the updated distance is calculated after two clusters have been joined.

5. If we assume that clusters A and B have been joined or combined to form cluster Z (as indicated in the diagram on the left), we need to calculate the distance from Z with the other cluster called C.

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Cluster Consolidation.

Methodology

For the different methods, the calculations are done as shown:

1. **<u>Minimum distance between all objects in clusters</u>:** The distance from Z to C is the minimum of the distances (A to C or B to C).

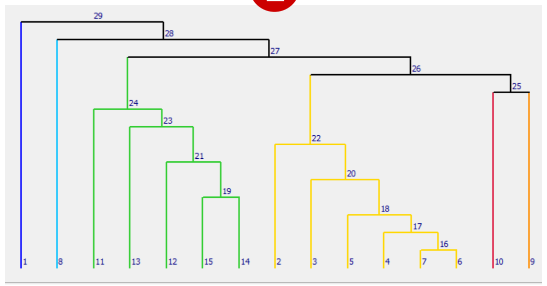
2. **<u>Maximum distance between all objects in clusters</u>:** The distance from Z to C is the maximum of the distances (A to C or B to C).

3. **<u>Average distance between merged clusters</u>:** The distance from Z to C is the average of the distances of all the objects that should be within the cluster formed by the combination of the clusters and C.

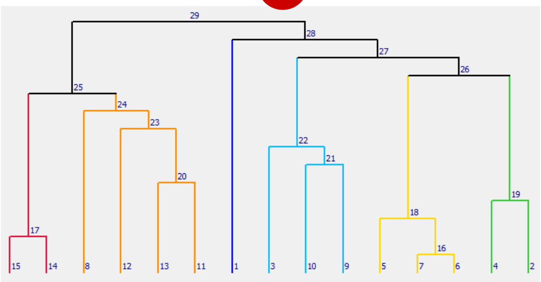
4. **<u>Average distance between all objects in clusters</u>:** The distance from Z to C is the average of the distances from objects within cluster Z to objects within cluster C.

5. **<u>Minimize the within-cluster sum of squares distance (Default):</u>** Clusters are formed to minimize the increase in the sums of squares within the cluster. The distance between two clusters is the increase in these sums of squares, of the two clusters that were combined.

1

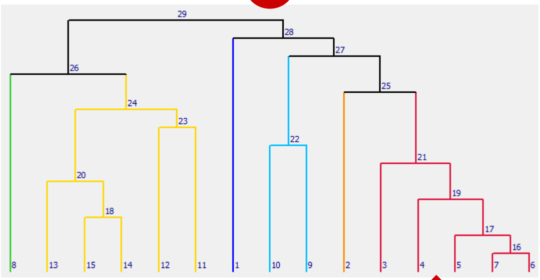


2

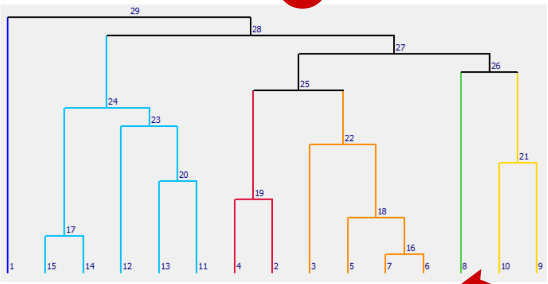


In general, option 1 will lead to long thin clusters, while option 2 will lead to clusters that are more spherical.

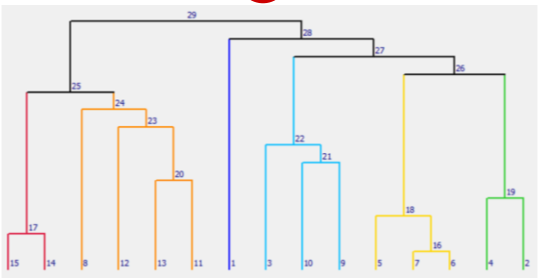
3



4



5



The distance of options 3 and 5 tends to generate clusters similar to those obtained with <u>**option 4**</u>.

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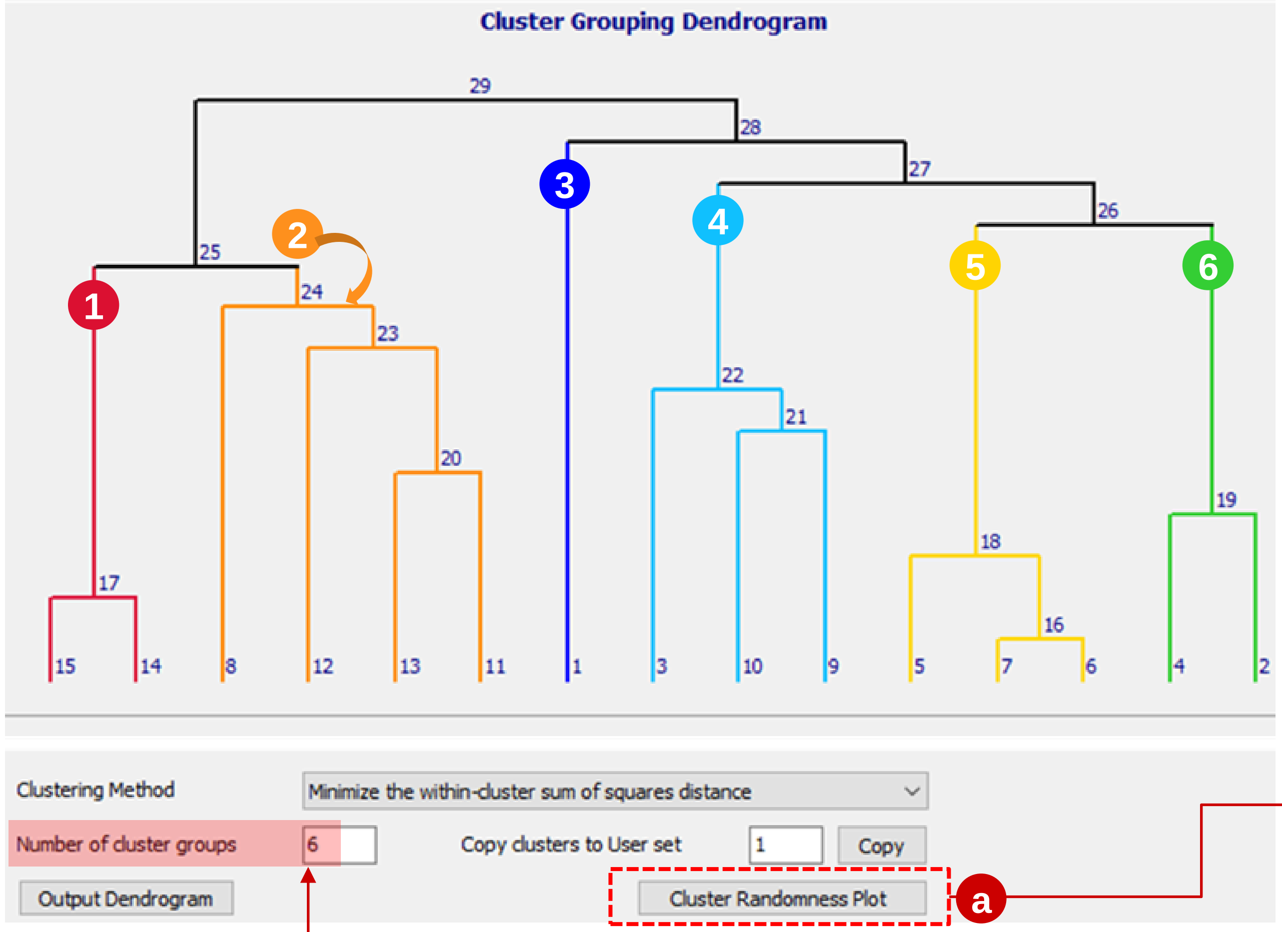
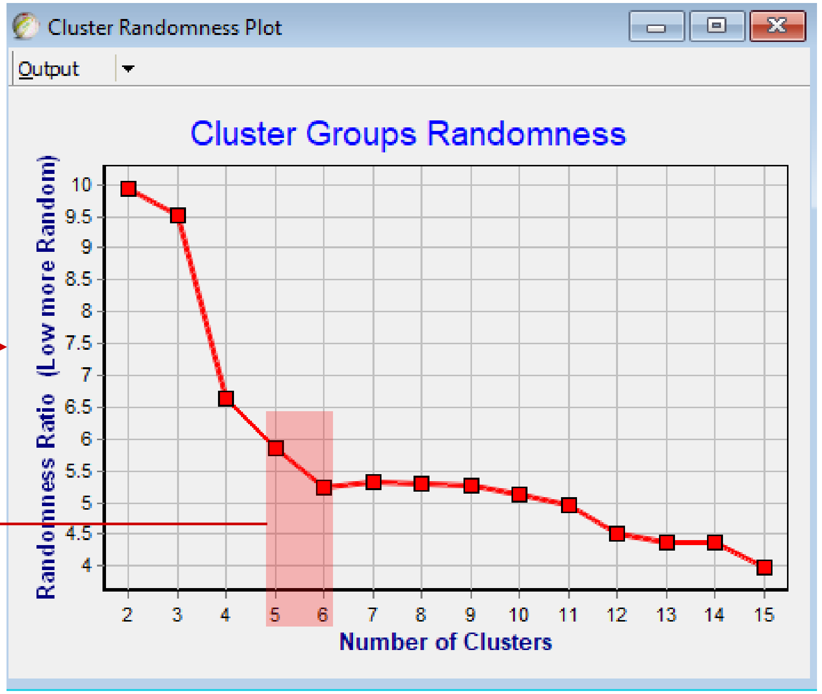
6. Cluster Consolidation.

Methodology



a. A cluster randomization diagram can be used to help select the number of groups.

This graph shows how random the cluster is, compared to a completely random arrangement of clusters.



The graph is interpreted by selecting the number of groups that are least random (highest peaks). In the example above, a group of 5 or 6 might appear to give the most likely information in grouping the record data.

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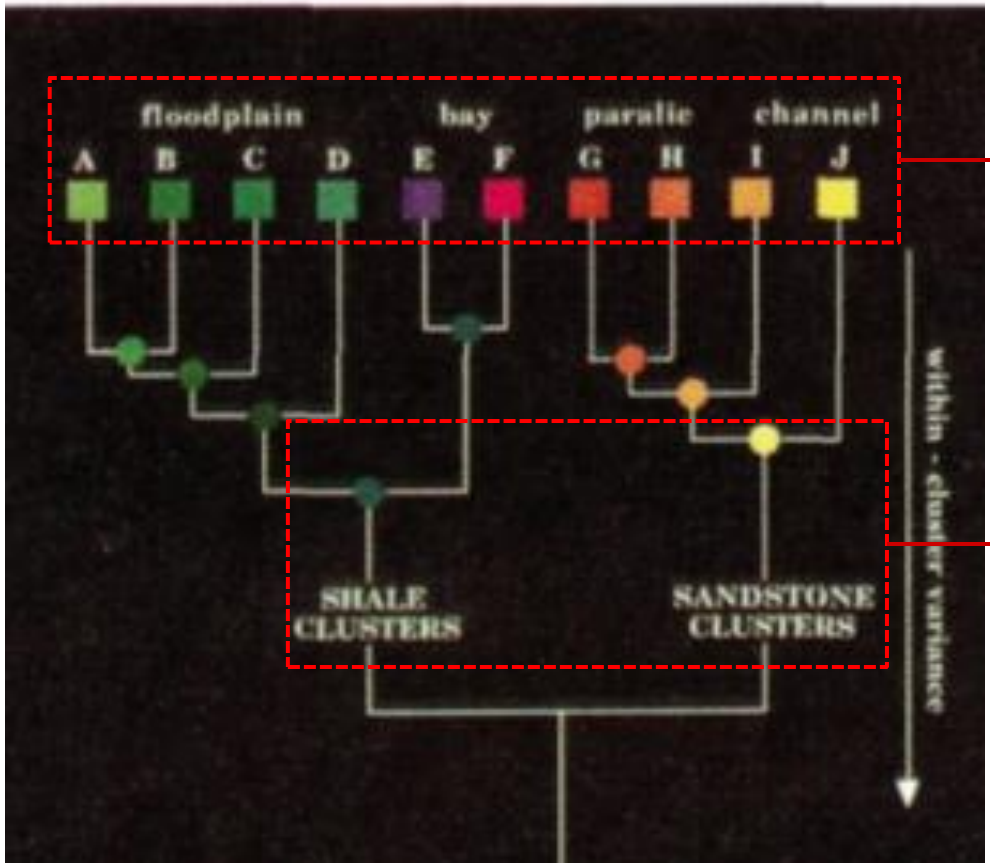
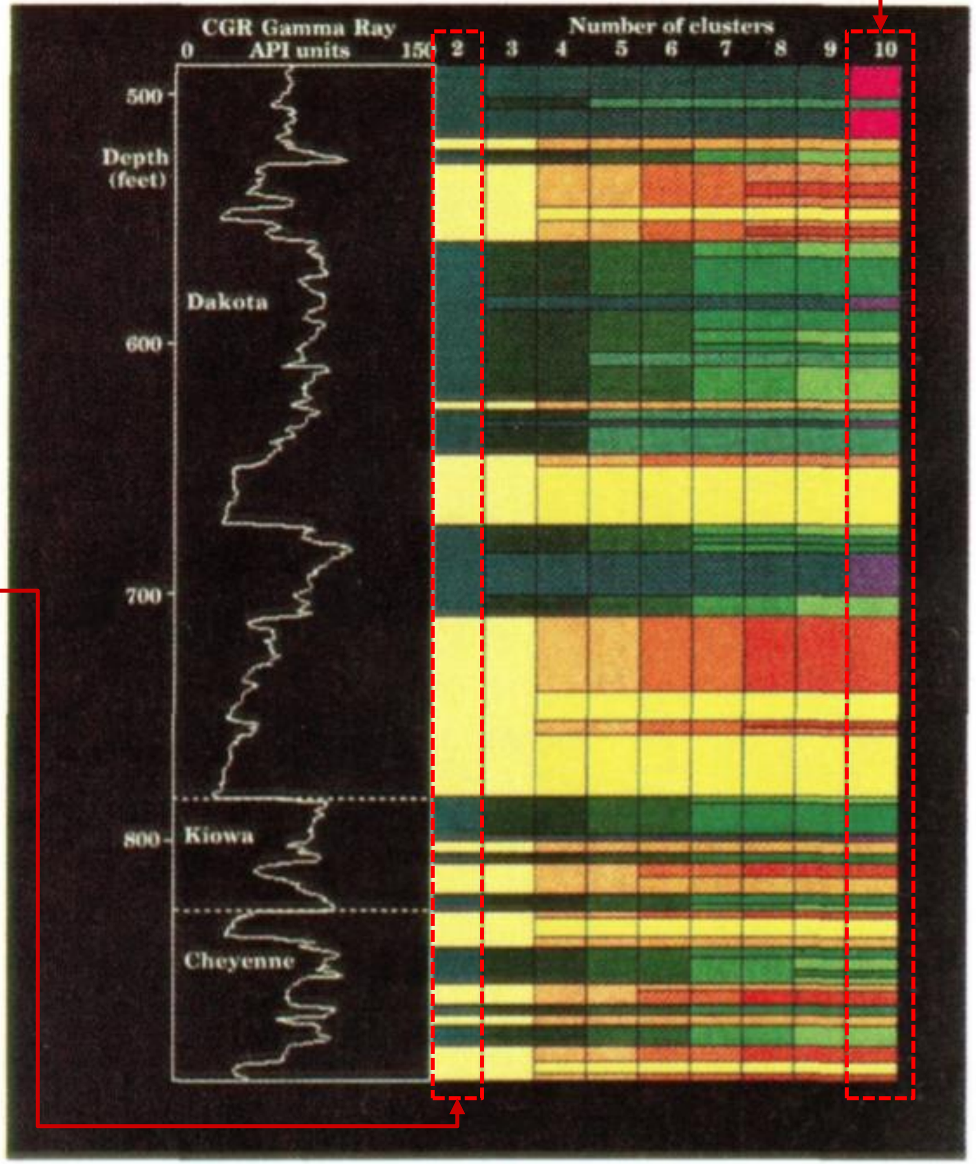
6. Cluster Consolidation.

Examples





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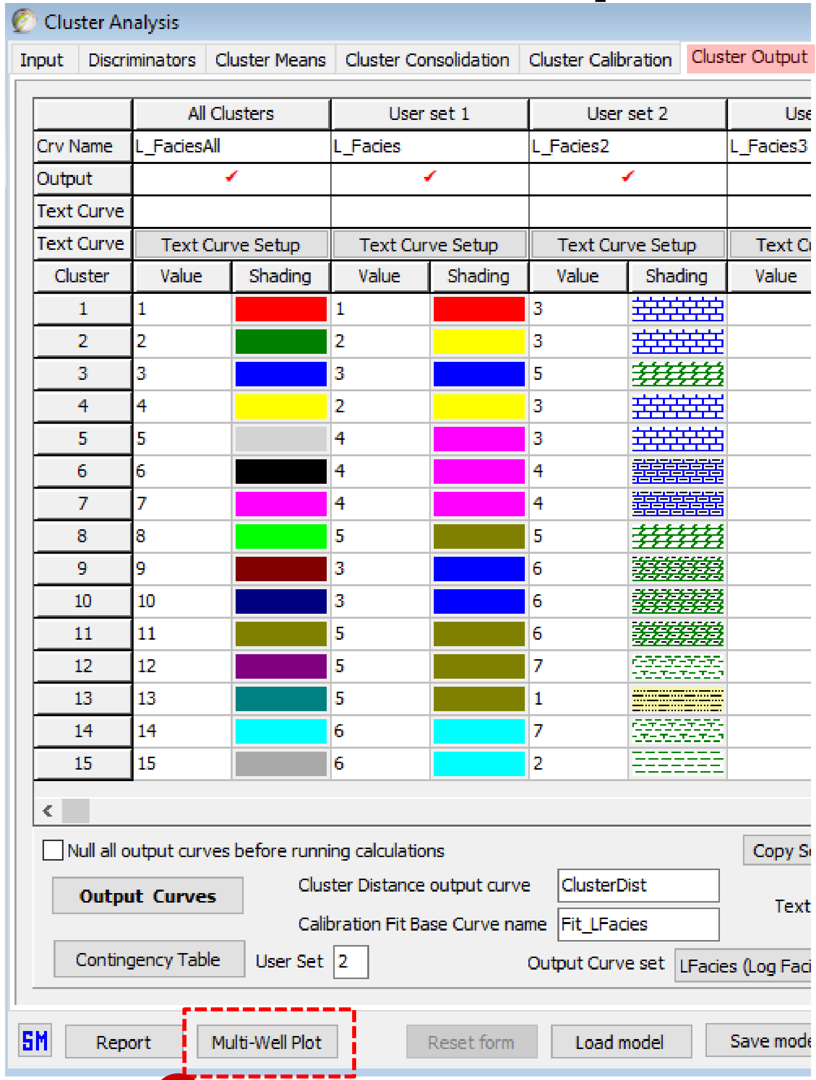
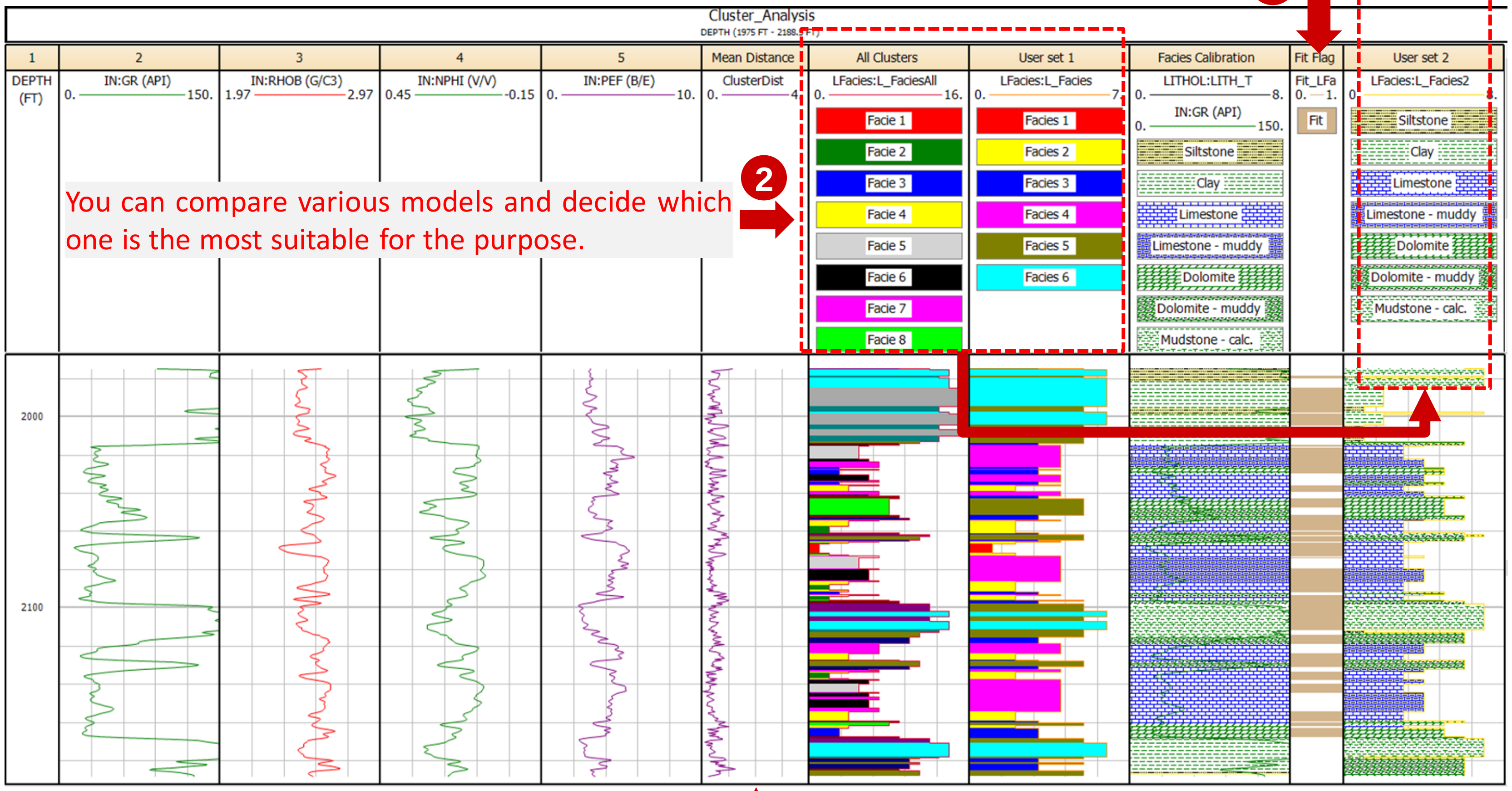
8. Cluster Output.



The Flag or "Fit Flag" curve shows where the calibrated model correctly matches the calibration facies (shaded area); and where was it wrong.

3



2

You can compare various models and decide which one is the most suitable for the purpose.

1

To view the grouping results, click the Multi-Well Plot button. This opens the Multiple Well Correlation Chart, with a default facies diagram for each of the selected wells.

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THANK YOU