Integration of Static and Dynamic Reservoir Parameters for Thin Bedded Low Resistivity Pay*

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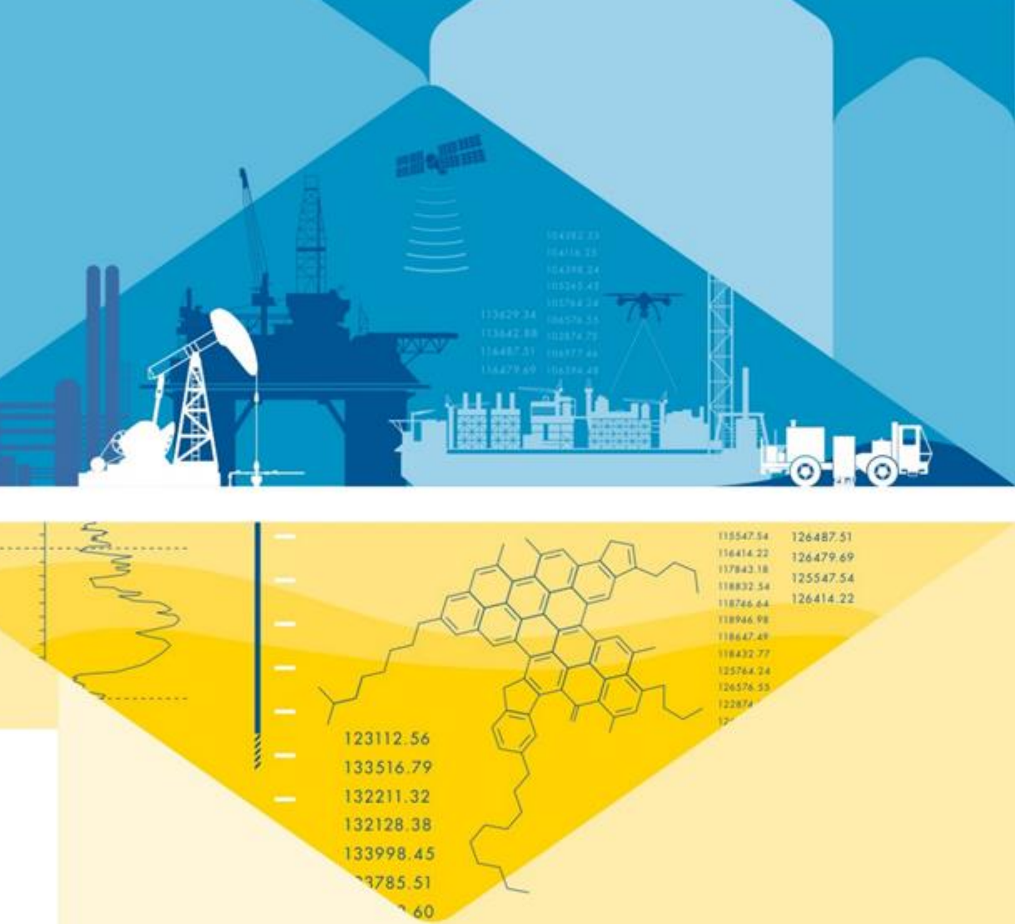
Abstract

In this presentation two reasons of low resistivity pay are presented and discussed. First reason is thin beds development in turbidite flows channels and levies environment. Second reason is development of water saturated microporosity, unavailable for hydrocarbons due to high capillary pressure. Identification of such facies based on standard logging suite data is challenging due to low resistivity of reservoir, even at significant height above free water level. Thin bed evaluation, using LowReP method, helps to boost reservoir properties. Second part of the presentation demonstrates importance of integration between reservoir properties derived by a petrophysicist (porosity, saturation, permeability and saturation height model) and properties used by reservoir engineers (relative permeability and fractional flow). A novel approach, based on permeability calculated from free fluid porosity – permeability relationship is utilized, and new formulation of saturation height model is proposed, which reconciles all of the above properties.



INTERGRATION OF STATIC AND DYNAMIC RESERVOIR PARAMETERS FOR THIN BEDDED LOW RESISTIVITY PAY

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Shell Global Solutions International BV

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ABSTRACT

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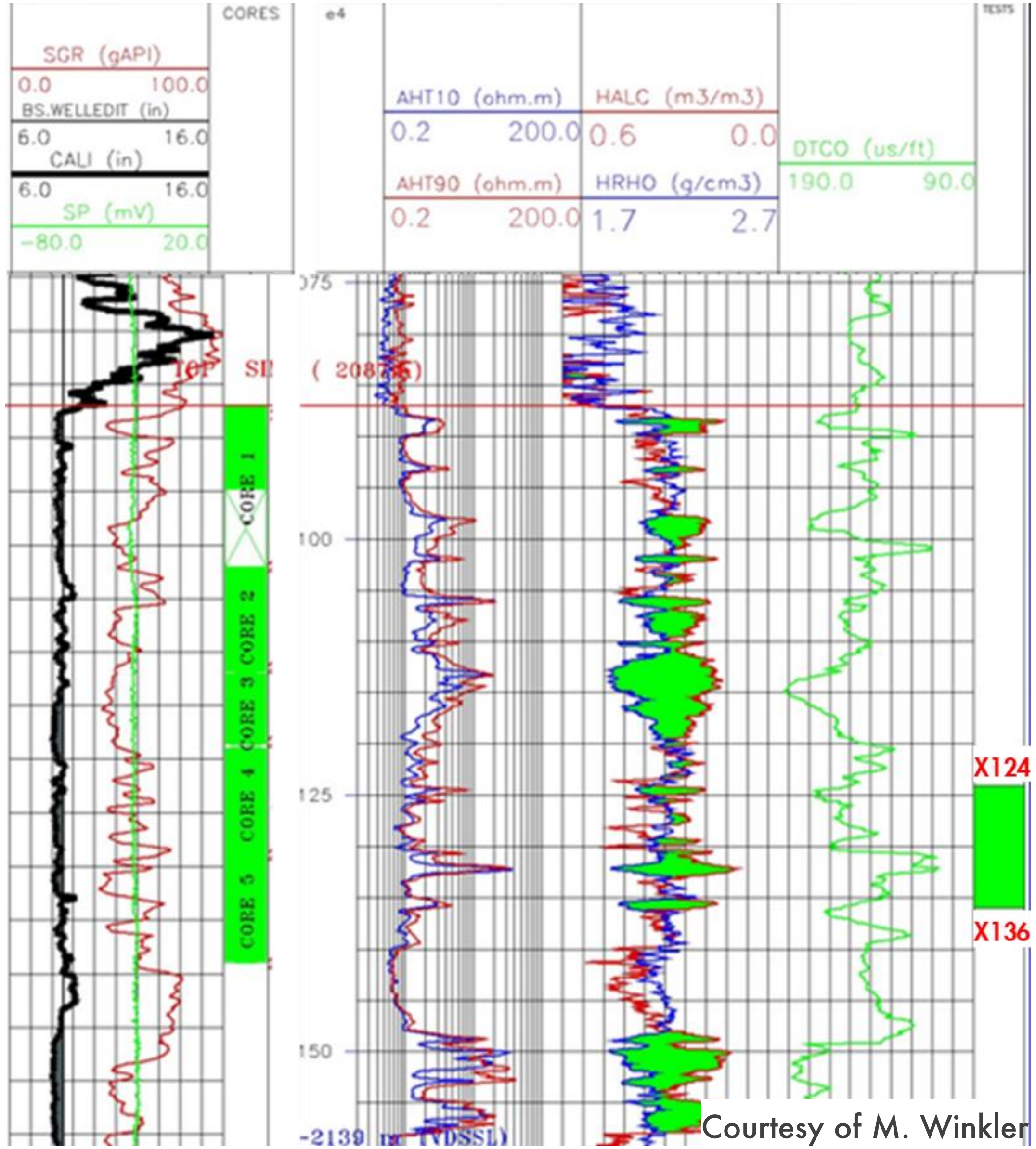
OUTLINE

1. Case studies
2. General workflow of think bed analysis
3. Integration of all static and dynamic reservoir parameters using new formulation of saturation height model.

THIN BEDDED LOW RESISTIVITY PAY

Test results: 44 MMscf/day

Standard log responses and simple evaluation models can give you incorrect estimates of the well's productivity.



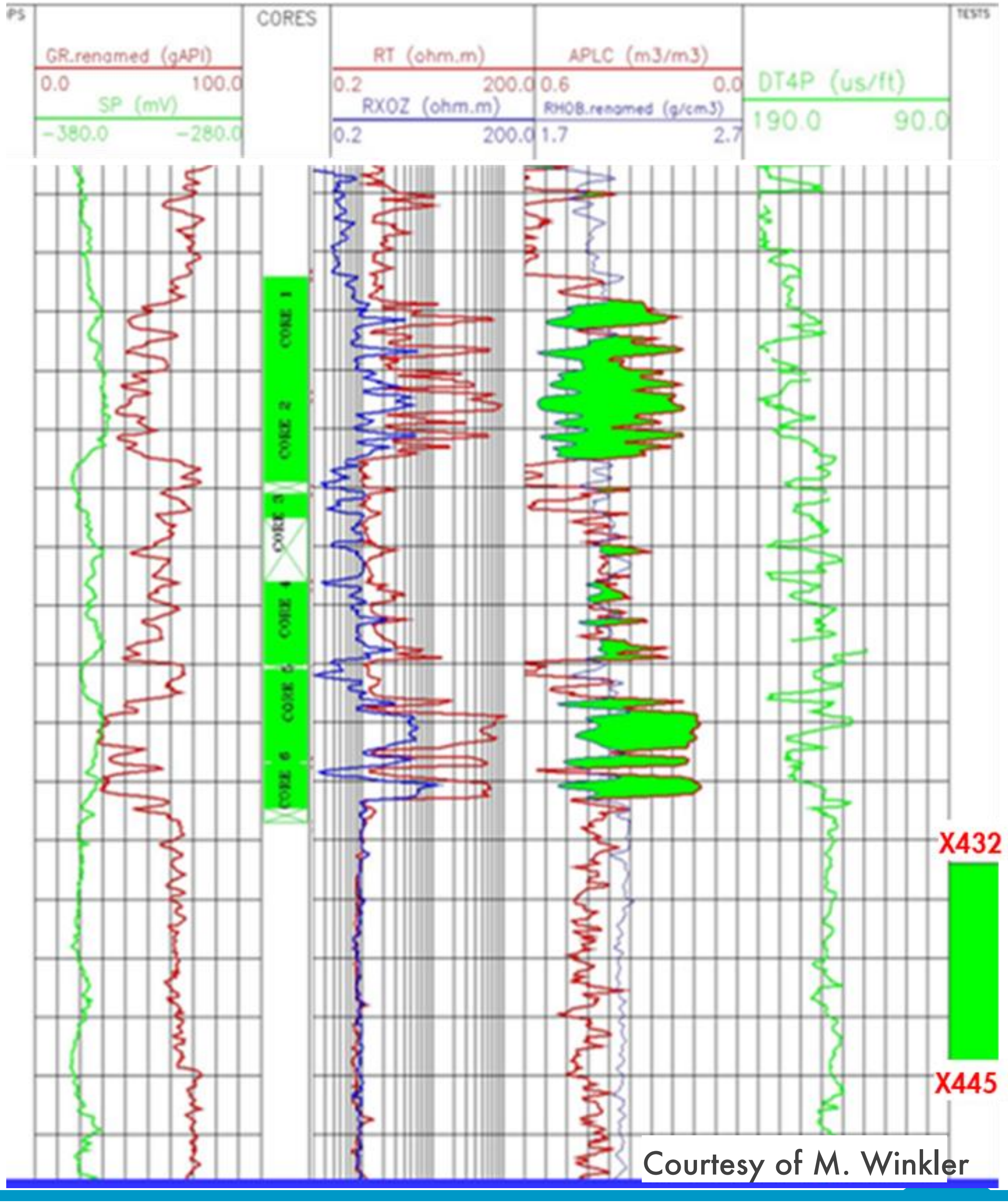
Courtesy of M. Winkler

THIN BEDDED LOW RESISTIVITY PAY

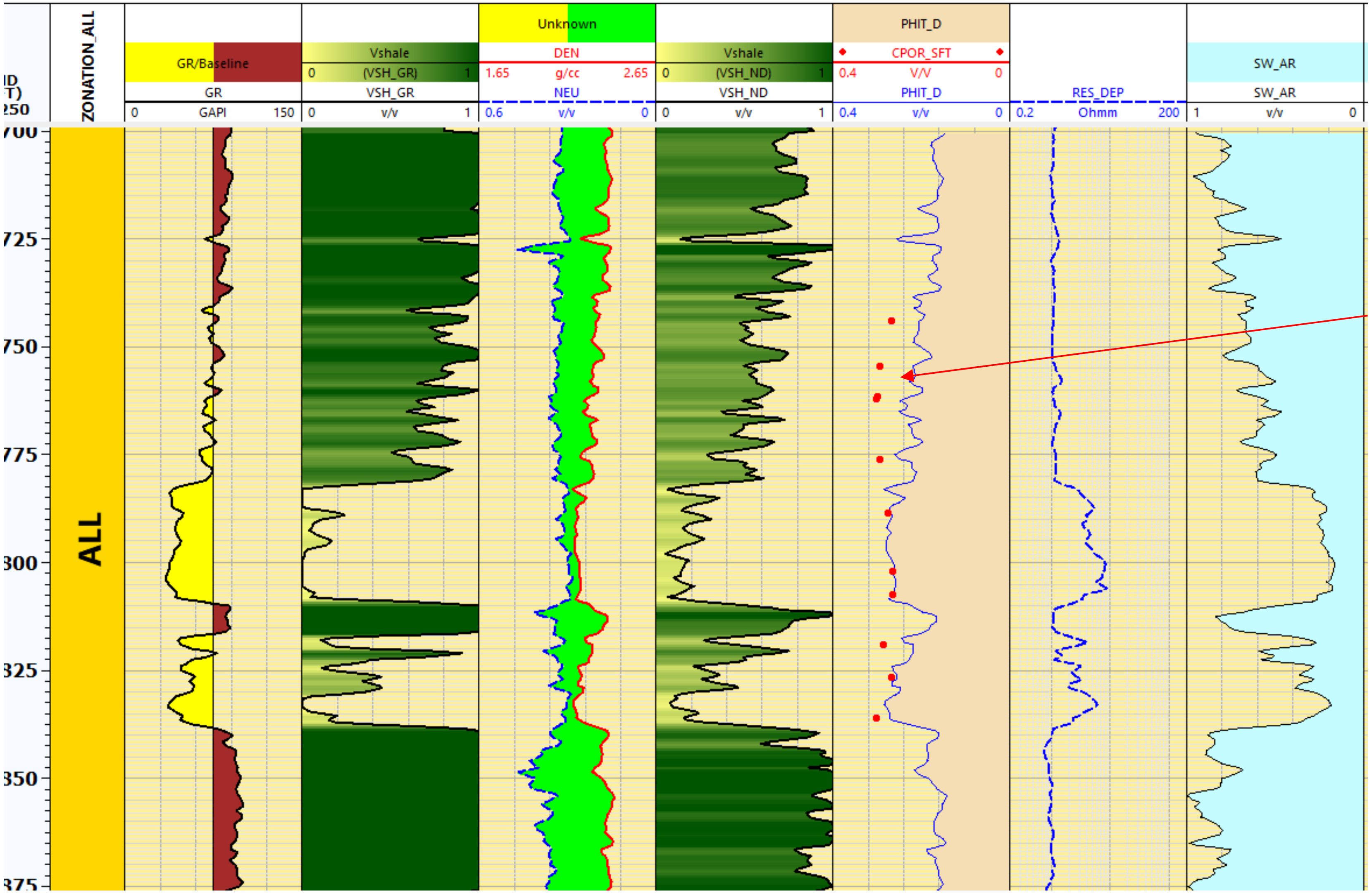
Test results: 23 MMscf/day

Geological settings: overbank facies

Standard log responses and simple evaluation models can give you incorrect estimates of the well's productivity.

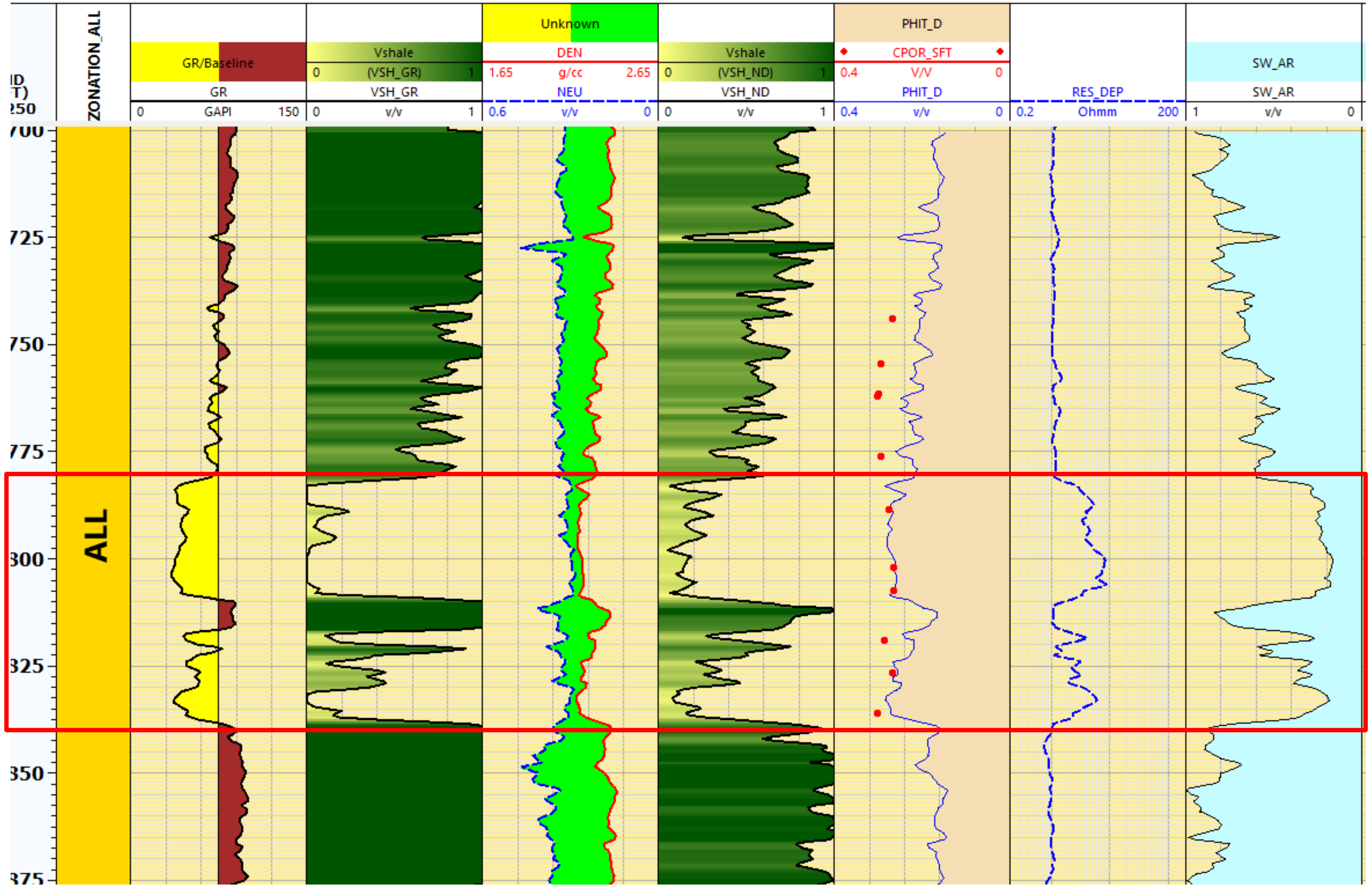


CONVENTIONAL INTERPRETATION FINING UPWARDS SEQUENCE



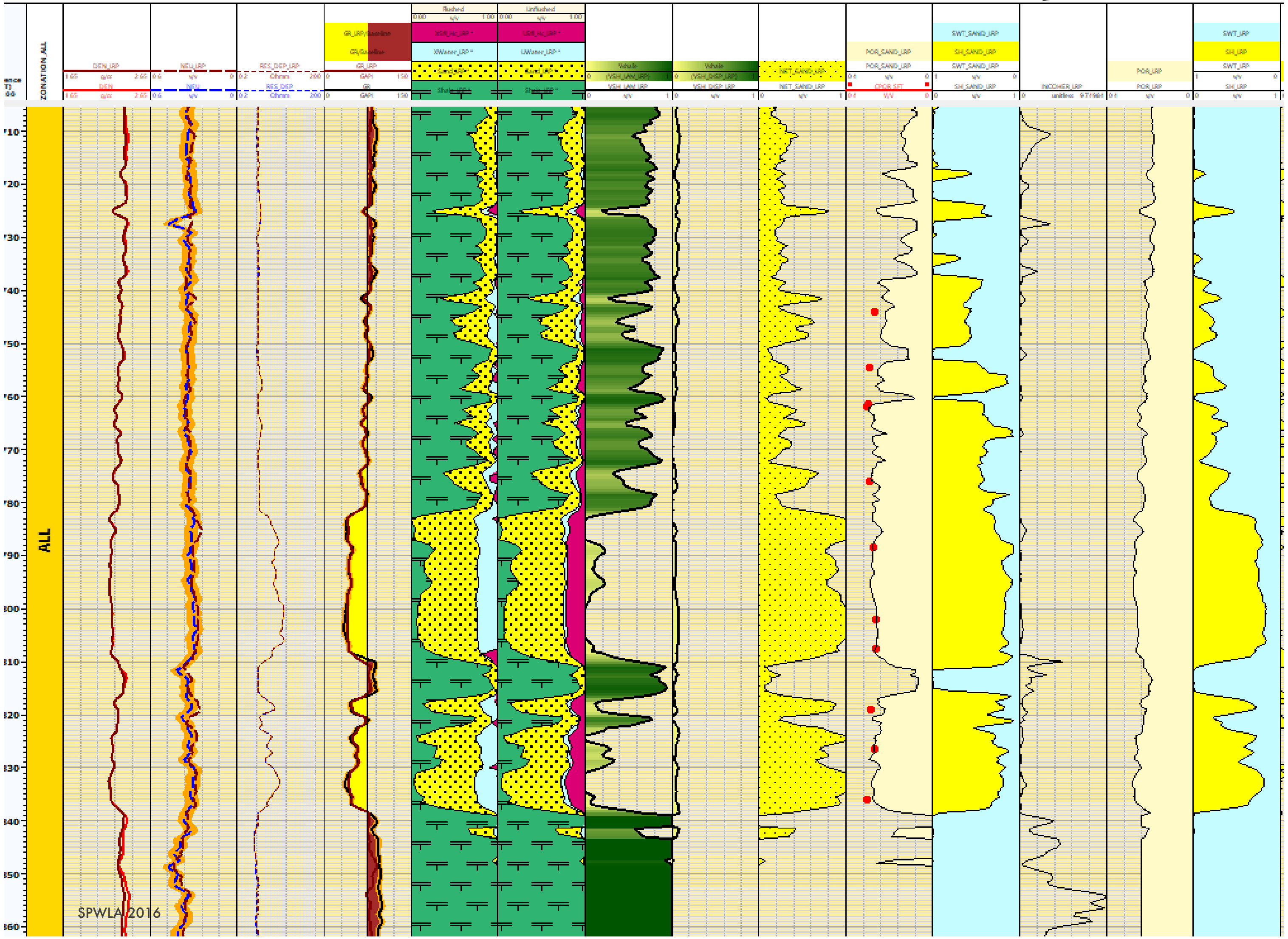
Porosities do not match the core porosities, unless thin bed analysis module LowReP is utilized.

CONVENTIONAL INTERPRETATION FINING UPWARDS SEQUENCE

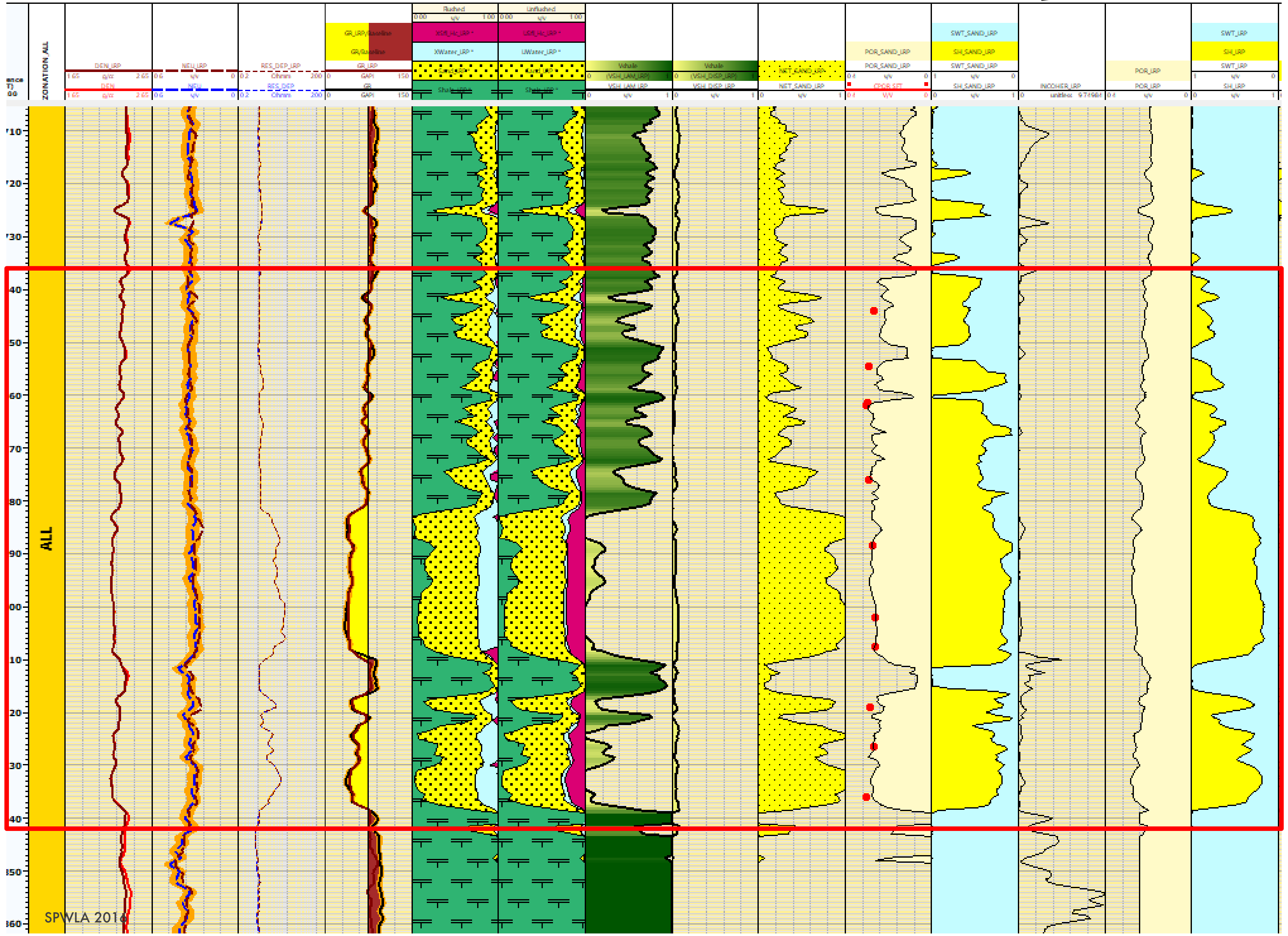


Interval for completion, based on conventional interpretation results.

LOWREP THIN BEDDED FINING UPWARDS SEQUENCE



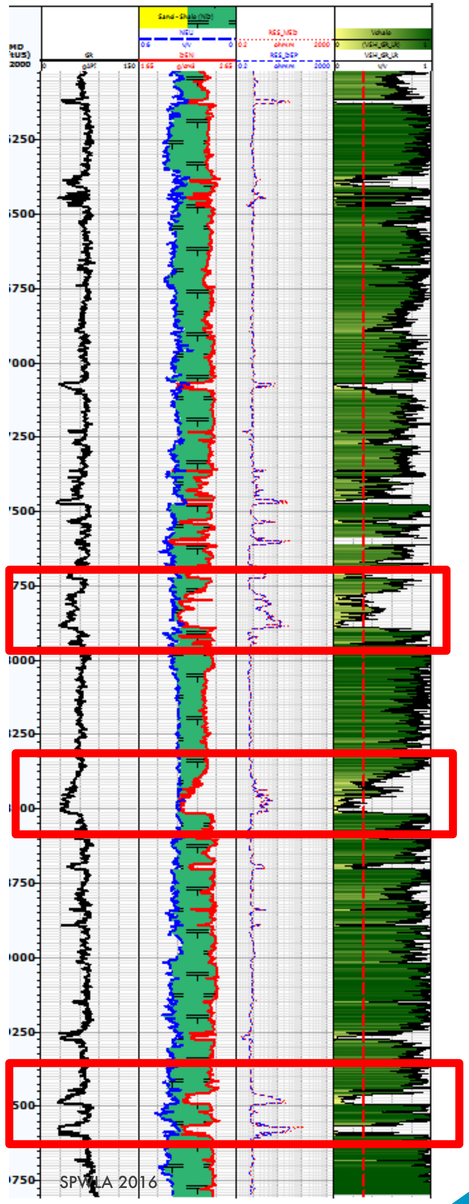
LOWREP THIN BEDDED FINING UPWARDS SEQUENCE



Interval for completion, based on thin bed analysis interpretation results.

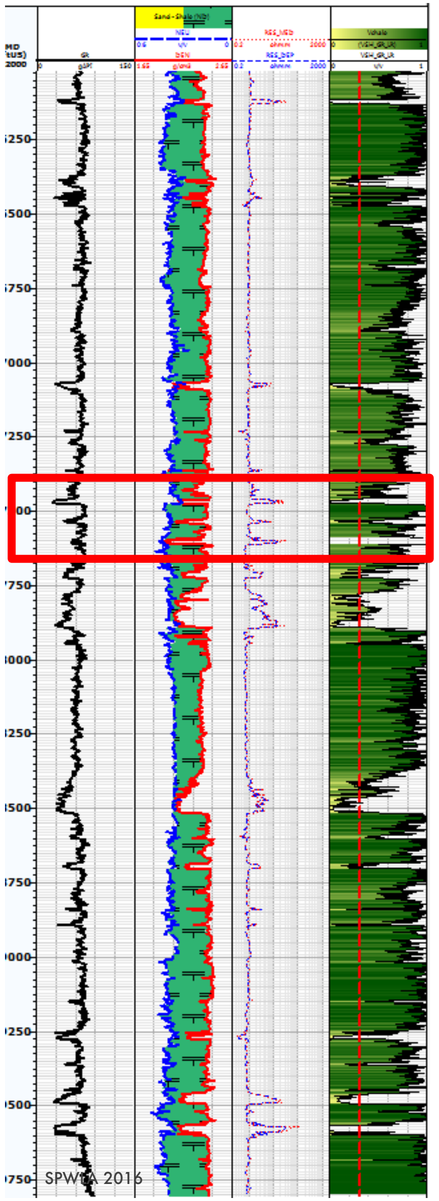
GoM WELL RANGE FROM 16,000 TO 20,000 FT

Best possible intervals for perforation, based on Vshale cut-off.

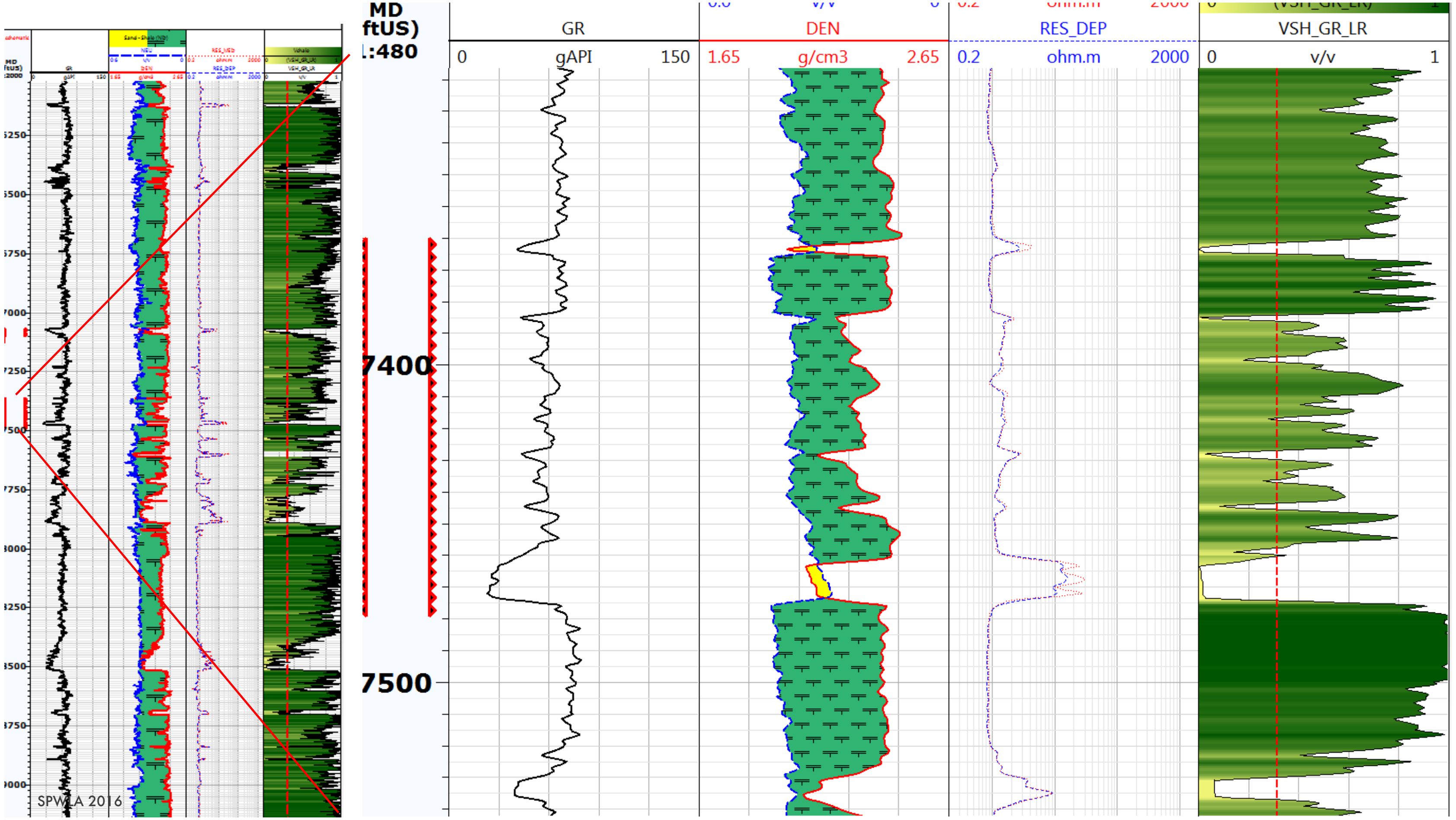


GoM WELL RANGE FROM 16,000 TO 20,000 FT

Actually perforated interval

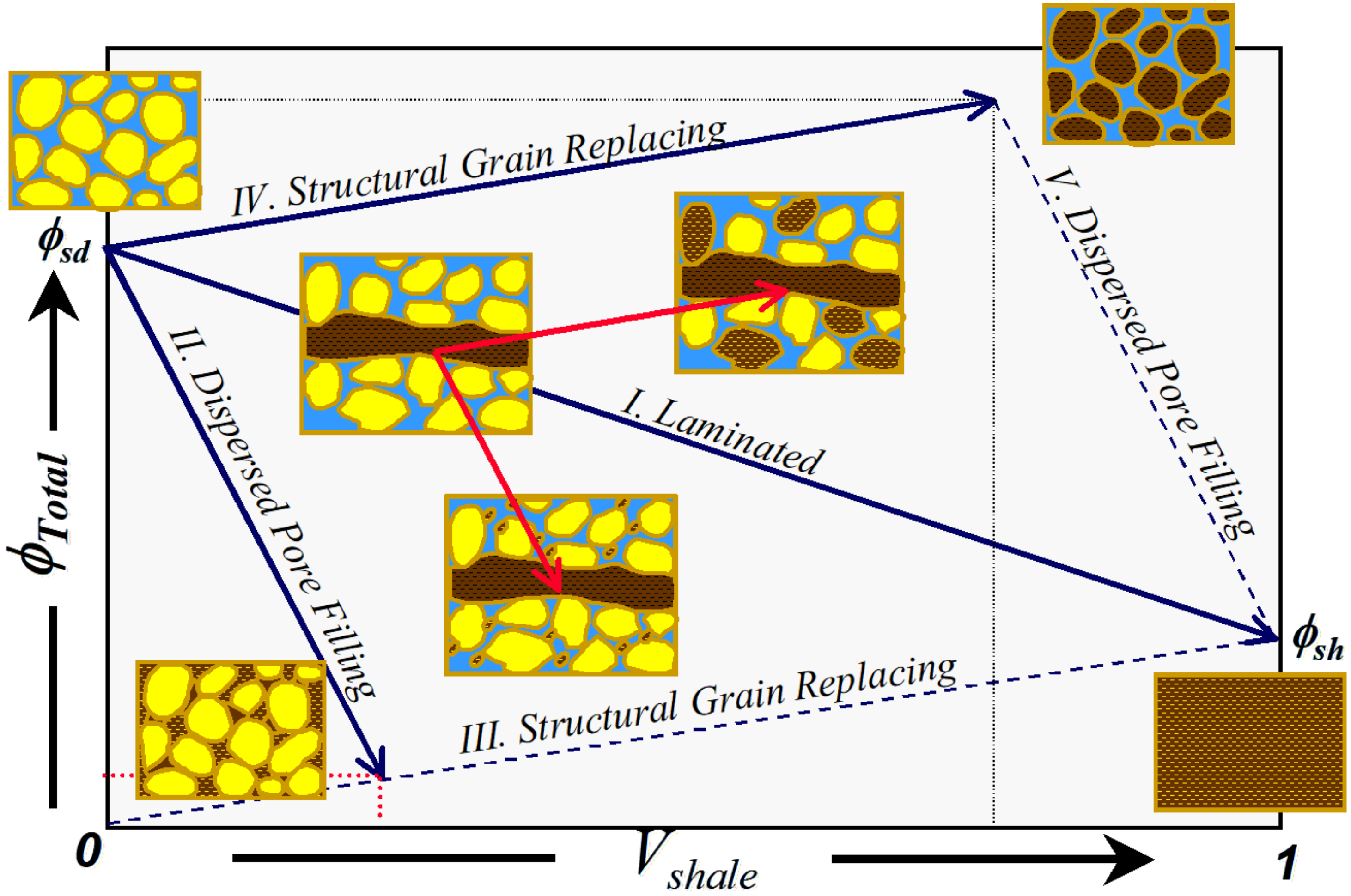


GoM WELL CUMULATIVE PRODUCTION > 40 MMBBLS

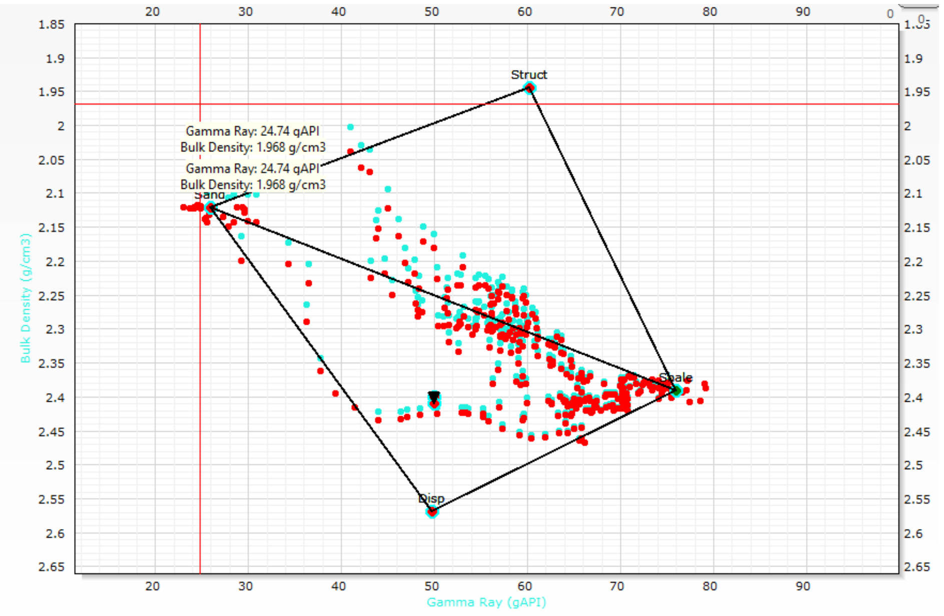


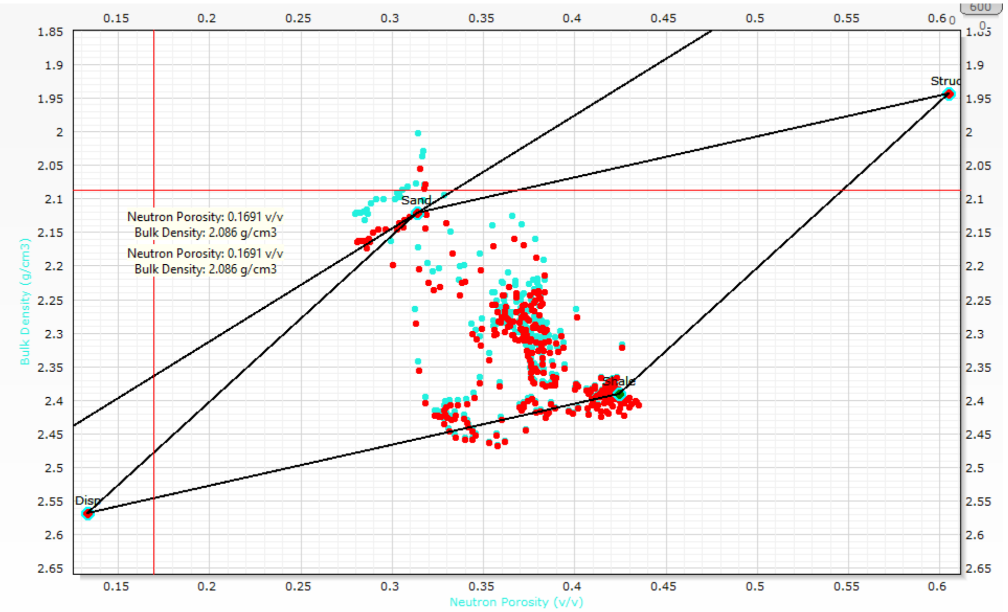
This is second to the best well in Gulf of Mexico. Mostly thin beds with high reservoir properties. If standard cut-off V_{shale} = 0.3 would be used, this well would be never perforated.

THOMAS – STIEBER CROSSPLOT (DIAMOND/TRIANGLES)



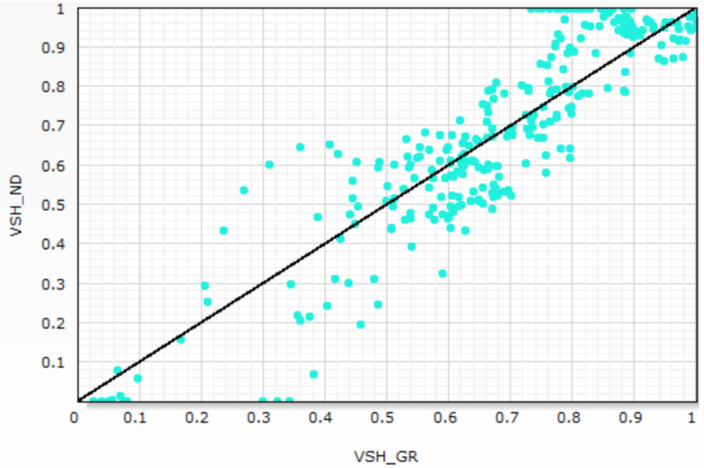
LOWREP CROSSPLOTS



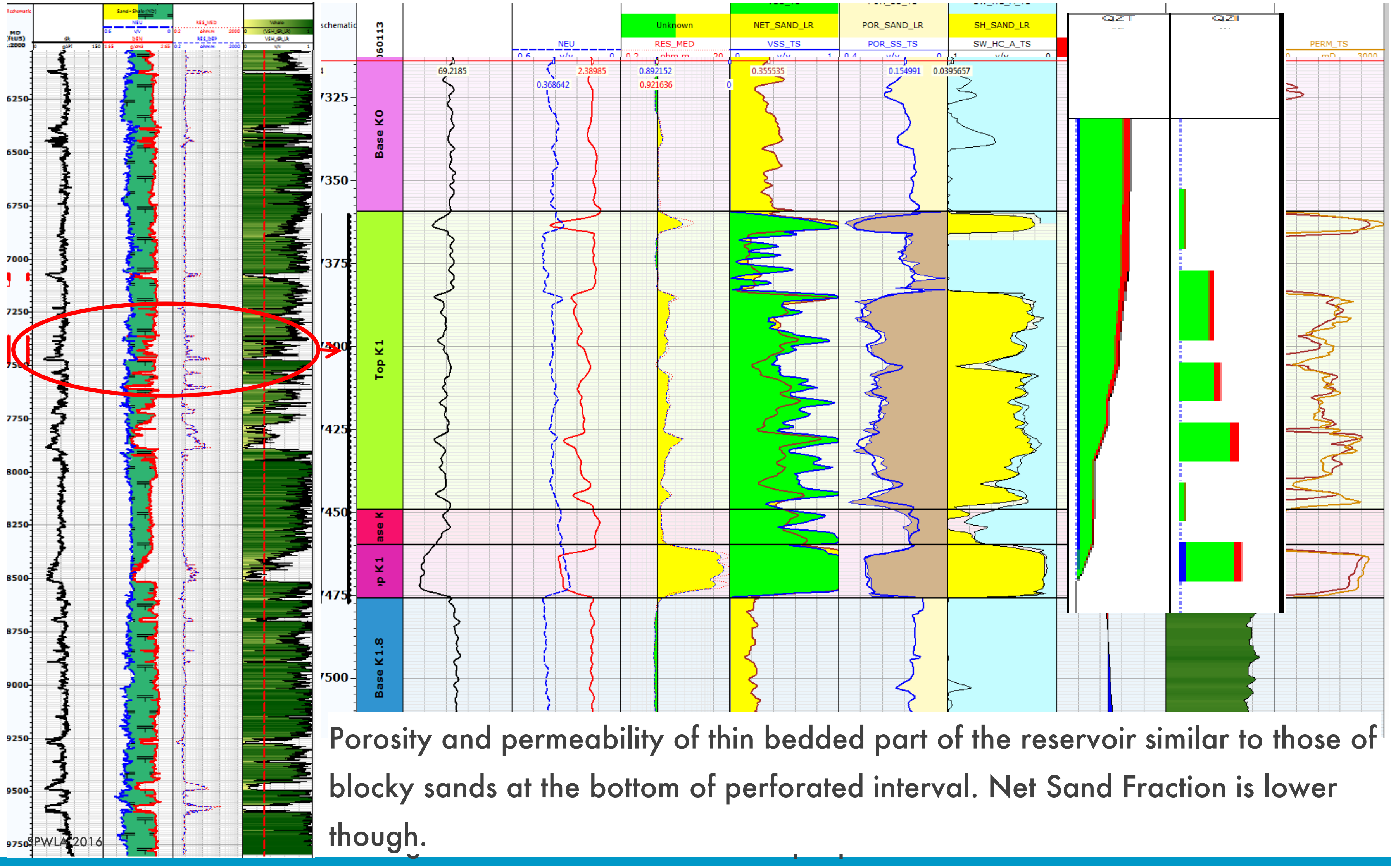


VSHALE -> VSH_DISP, VSH_LAM, VSH_STRUCT

TPOR -> POR_SAND & NET-TO-GROSS



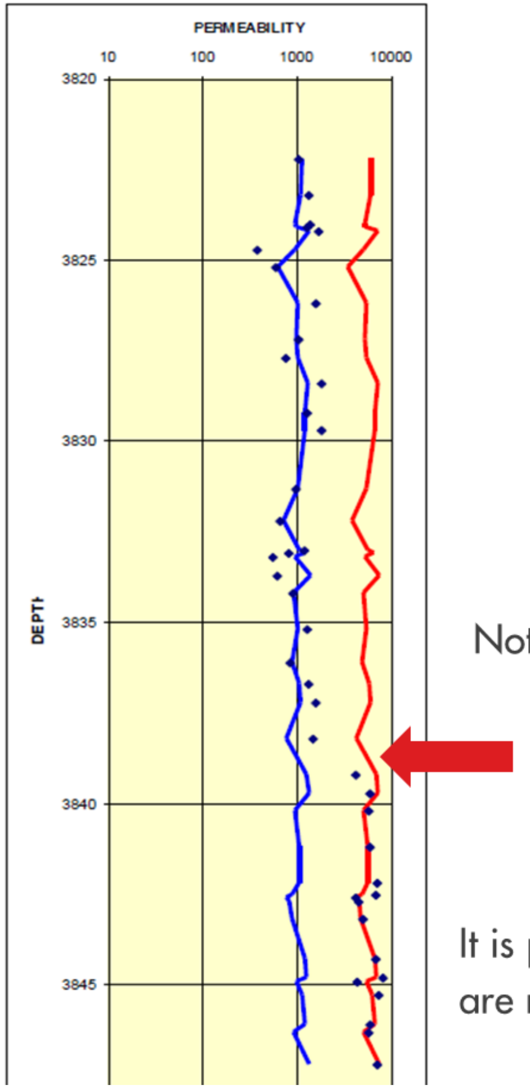
GoM WELL – HIGH RESERVOIR PROPERTY THIN BEDS



Porosity and permeability of thin bedded part of the reservoir similar to those of blocky sands at the bottom of perforated interval. Net Sand Fraction is lower though.

PLT logs show that thin beds inflow is proportional to Net Sand Fraction

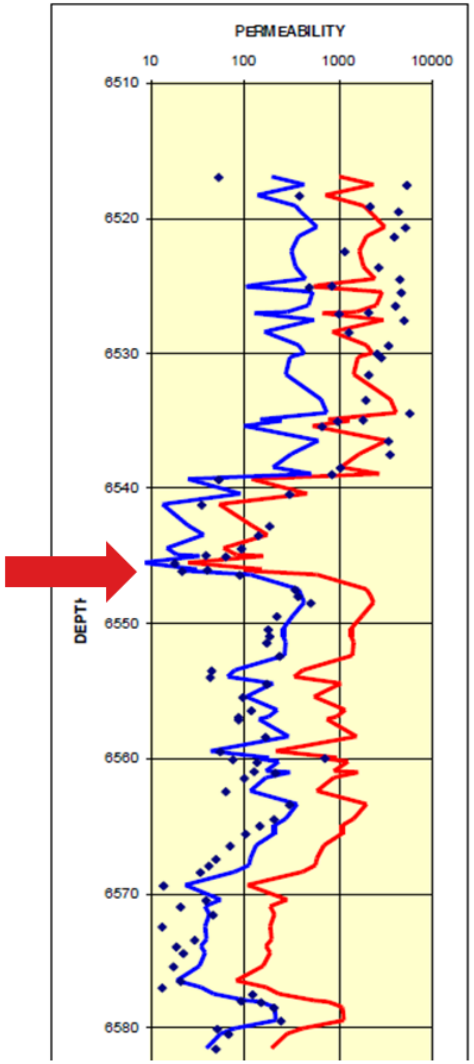
BOTH ROCK TYPES ARE PRESENT IN EACH CORED INTERVAL



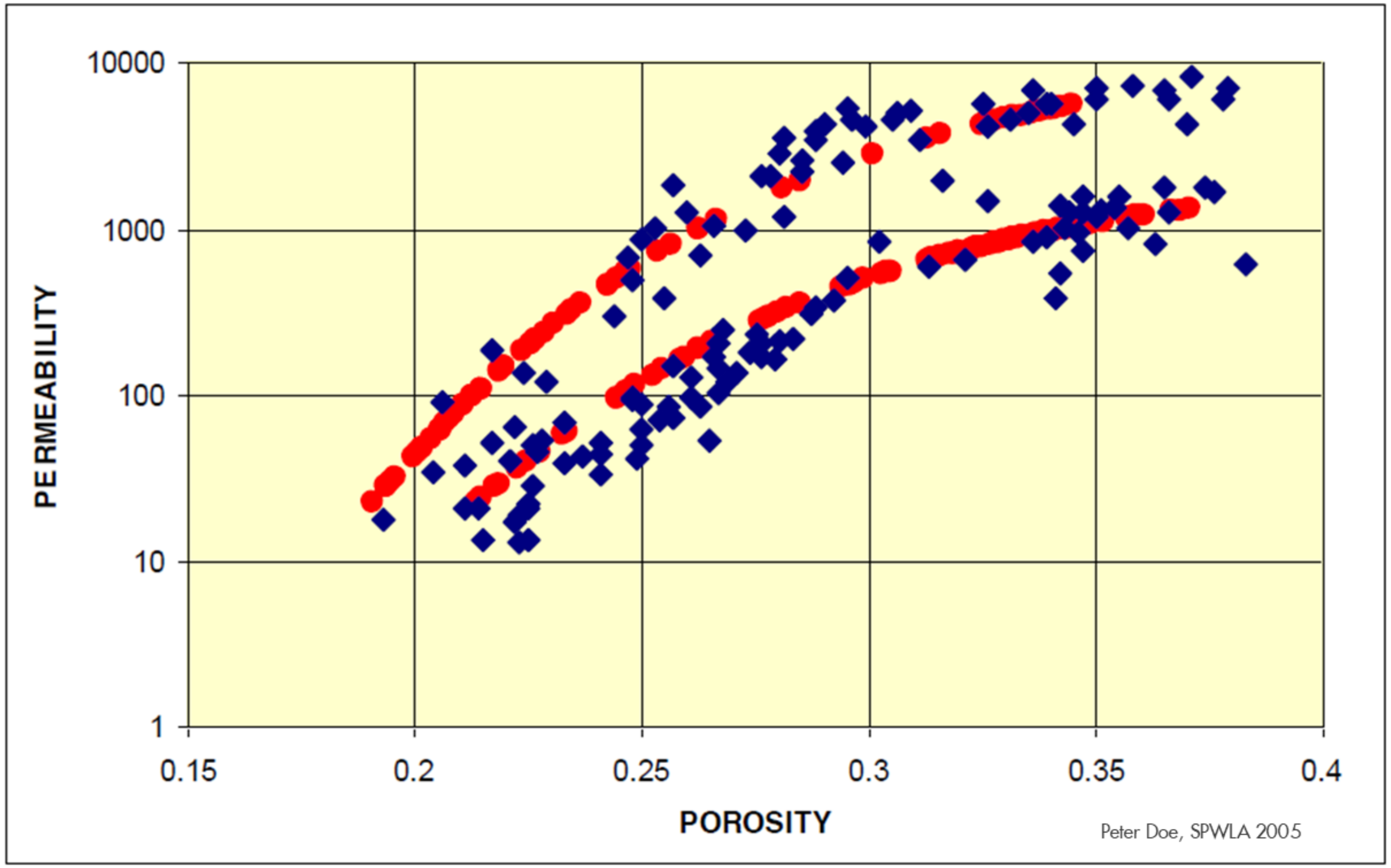
- Points – Core Permeability
- Red – High Permeability Trend
- Blue – Low Permeability Trend

Note rock type change at depth of arrows.

It is pretty obvious that constant cut-off values are not applicable to these rocks. Peter Doe, SPWLA, 2005

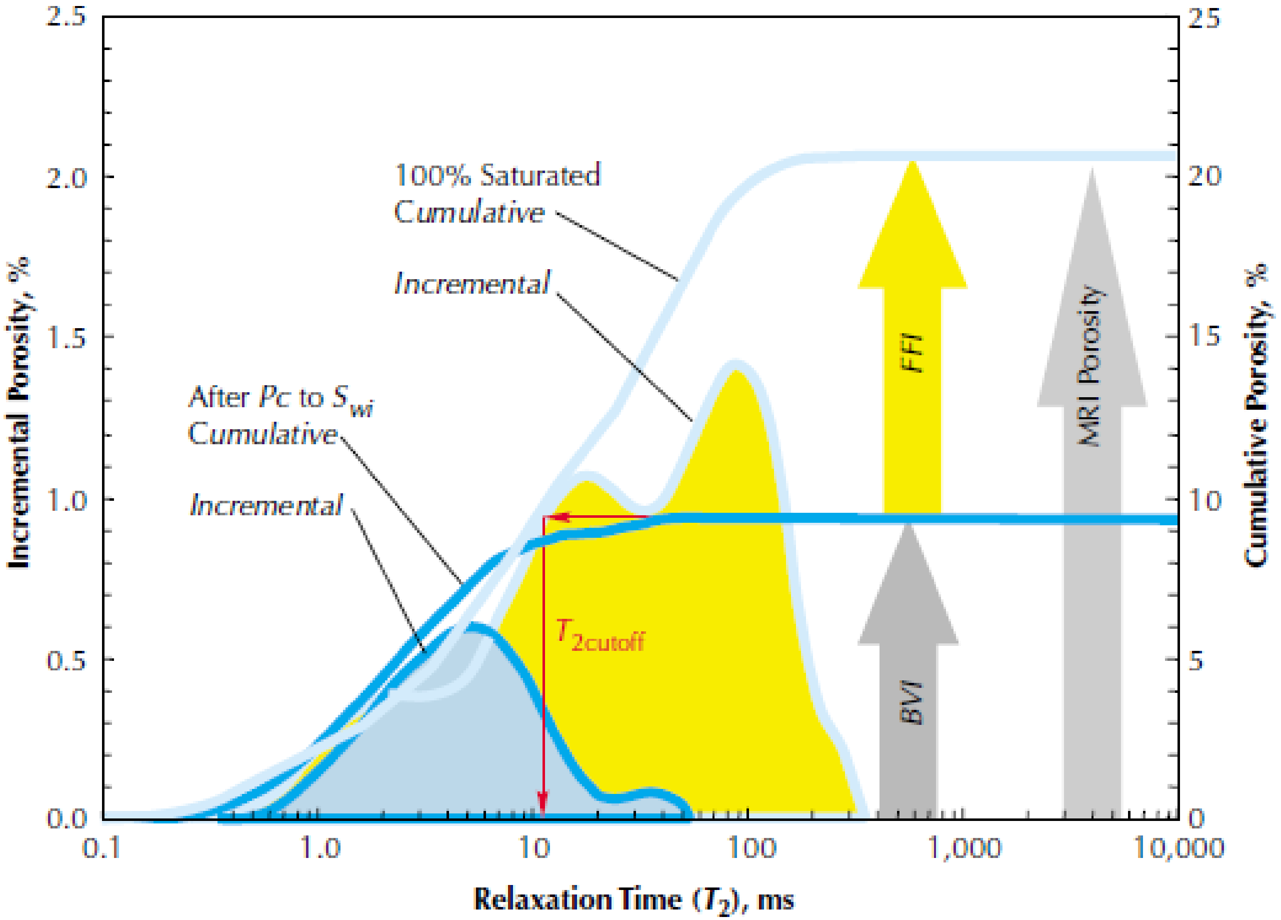


TWO ROCK TYPES IN A SINGLE RESERVOIR



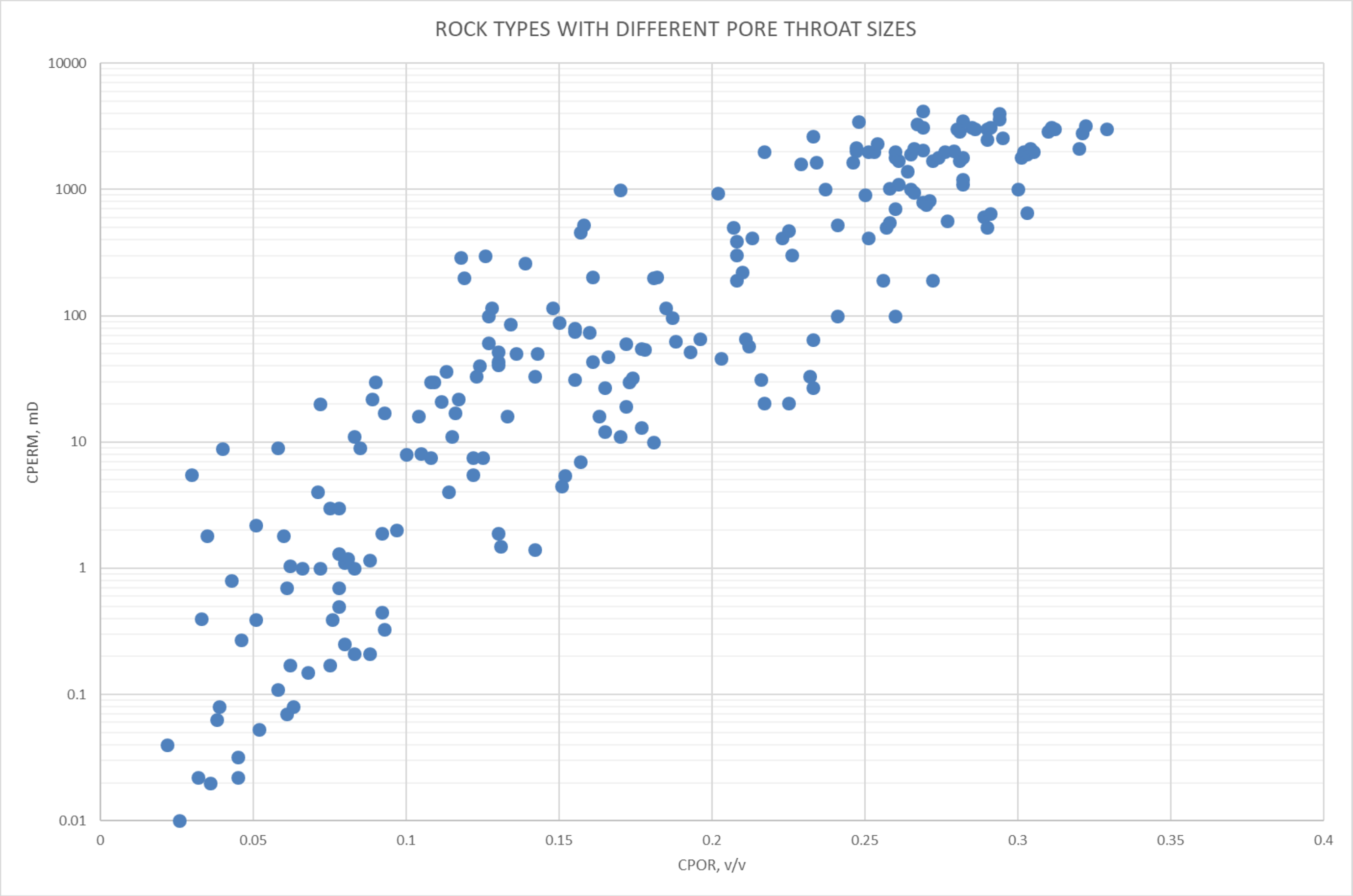
- Core Porosity- Permeability data indicates two lithologies
- Range of data extends down to 15 mD
- Two reasonable poro-perm trends can be developed
- What cause it?

NMR T2 CUTOFF DEFINITION FOR FREE FLUID INDEX



"NMR Logging Principles and Applications"
George R. Coates, Lizhi Xiao, and Manfred G. Prammer
Halliburton Energy Services, Houston 1999.

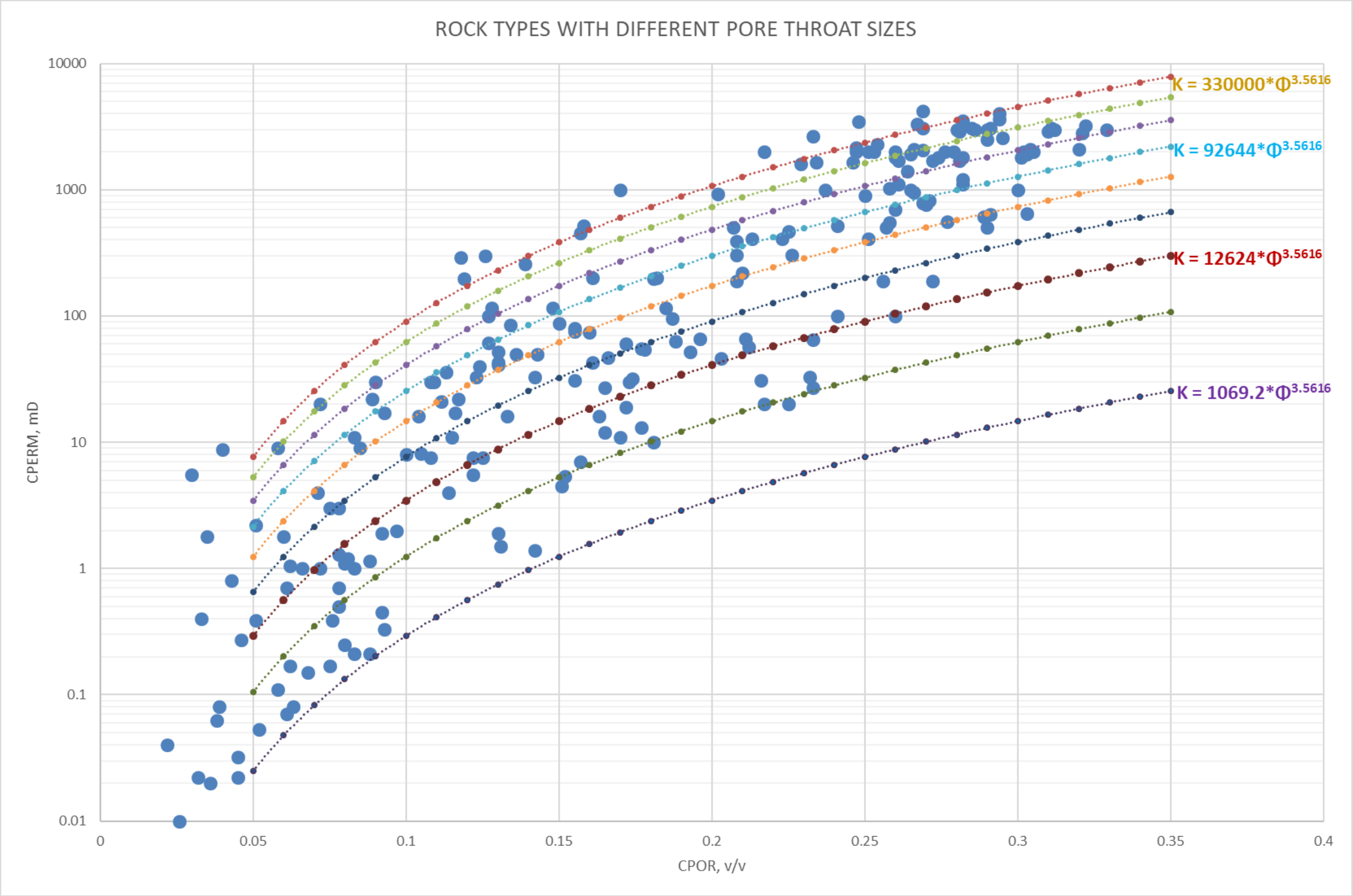
CORE MEASURED POROSITY - PERMEABILITY



Core measured stressed porosity and permeability relation shows high variability. Permeability at 20 p.u. stretching from less than 10.0 to greater than 1000 mD (>2 magnitudes). Total porosity has poor relationship with permeability due to significant development of microporosity and clay bound water. Most of the time it is extremely difficult to break total porosity – permeability relationship into separate rock type groups based on log response. One of the reasons is similar log response and whole suite of data is not always available.

Different pore throat size for each rock type is caused by different grain size, sorting, amount of clay content and microporosity. Microporosity resigns in lithic fragments, leached grains, structural grains etc. It doesn't provide any conduit for fluid flow, but it also not contribute to water cut due to capillary bound nature of fluids residing in micropores.

CORE MEASURED POROSITY - PERMEABILITY



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CONCLUSION ON SEM ANALYSIS AND THIN BED ANALYSIS

Thin bed evaluation provides higher porosity, saturation and permeability and net-to-gross aligned with core derived net-to-gross.

Total porosity should to be used only for estimation of total water/HC saturation from resistivity measurements.

Free Fluid Index from NMR is the best way to calculate volume of mobile fluid.

Total porosity is not representative parameter for permeability and transmissibility characterization.

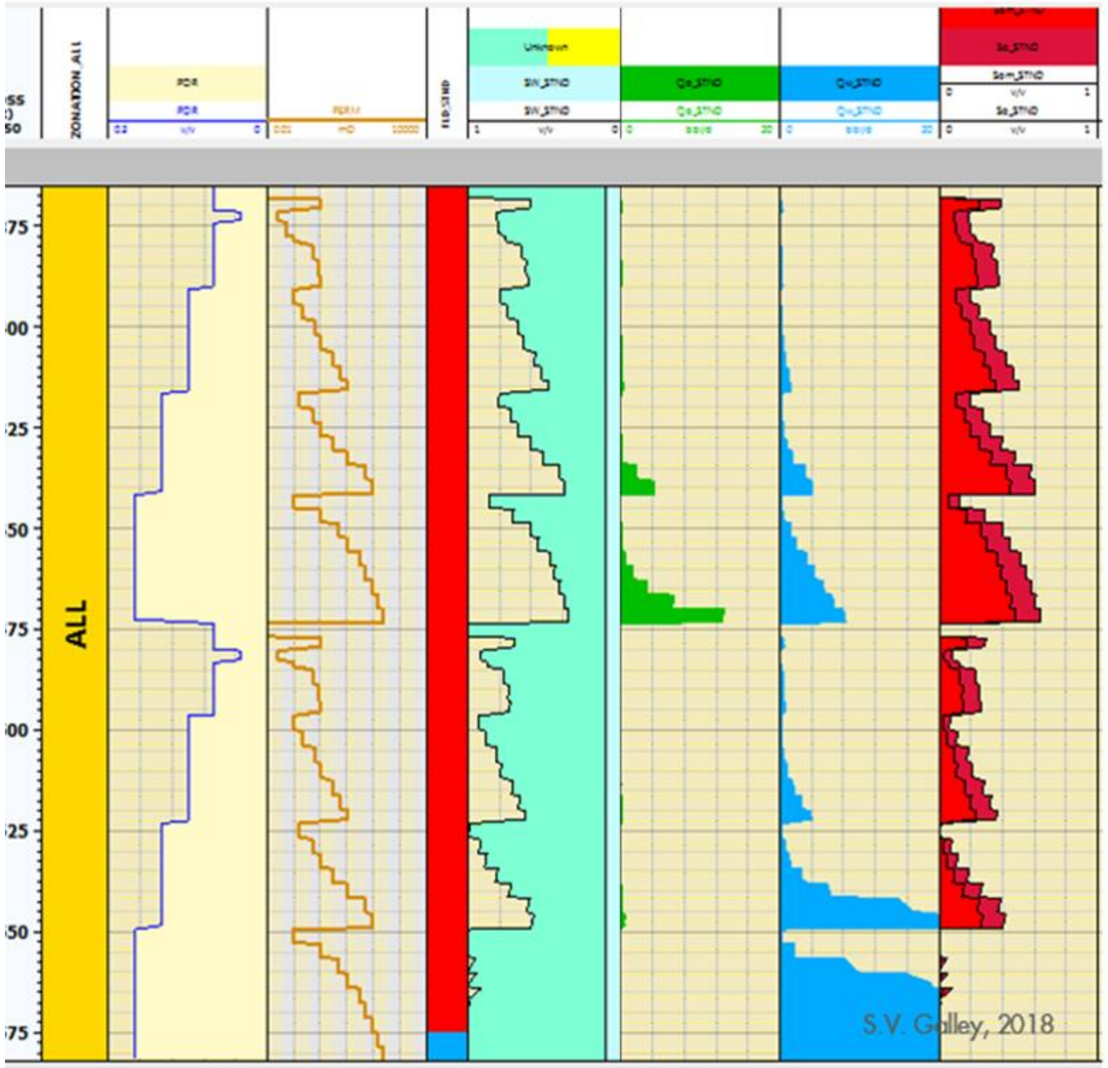
Besides shale related microporosity there is significant amount of microporosity associated with leached albite, lithic fragments, weathering and dissolution of rock grains.

Microporosity with pore size less than 1μm should be deducted from total porosity for usage in porosity - permeability transform.

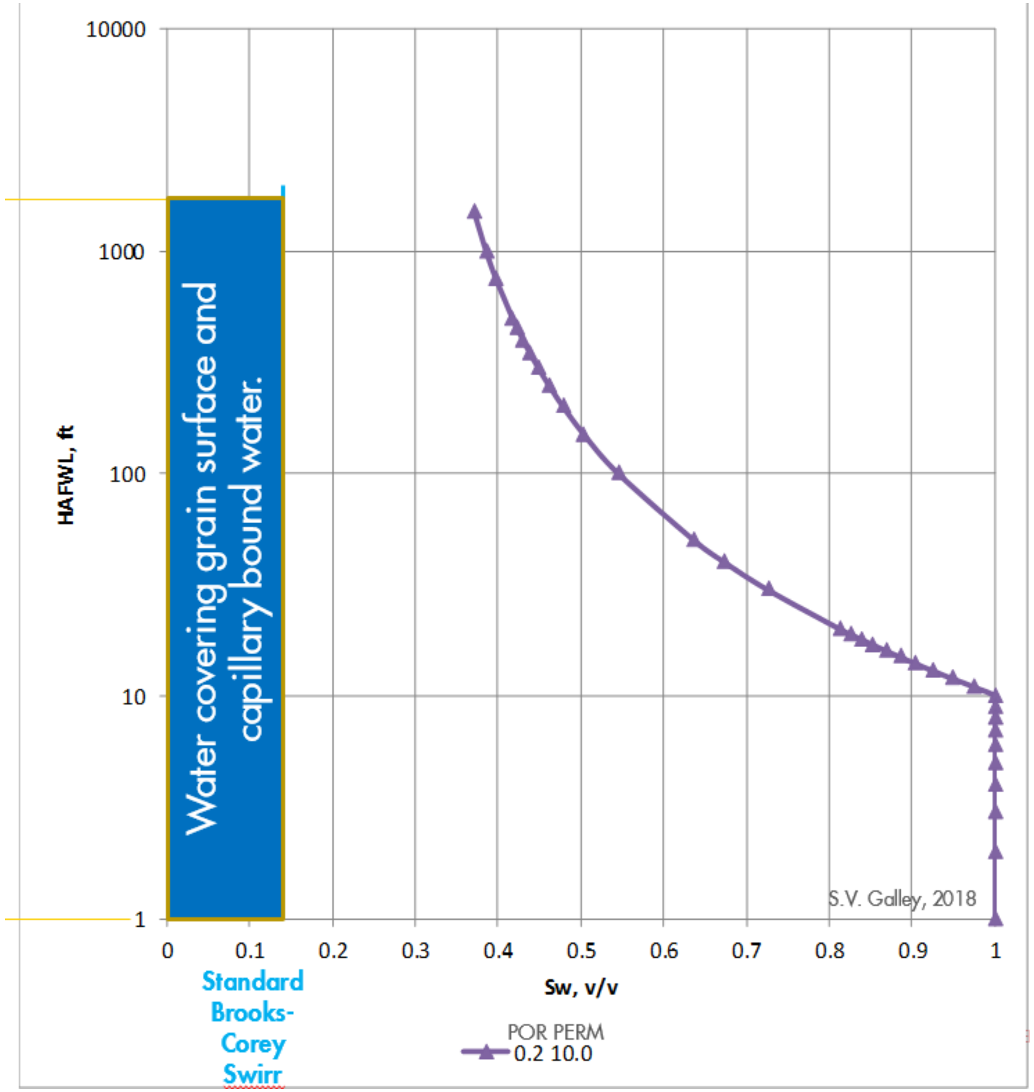
Free Fluid Index from NMR is the best way to calculate log derived permeability.

TEST DATASET STANDARD WORKFLOW

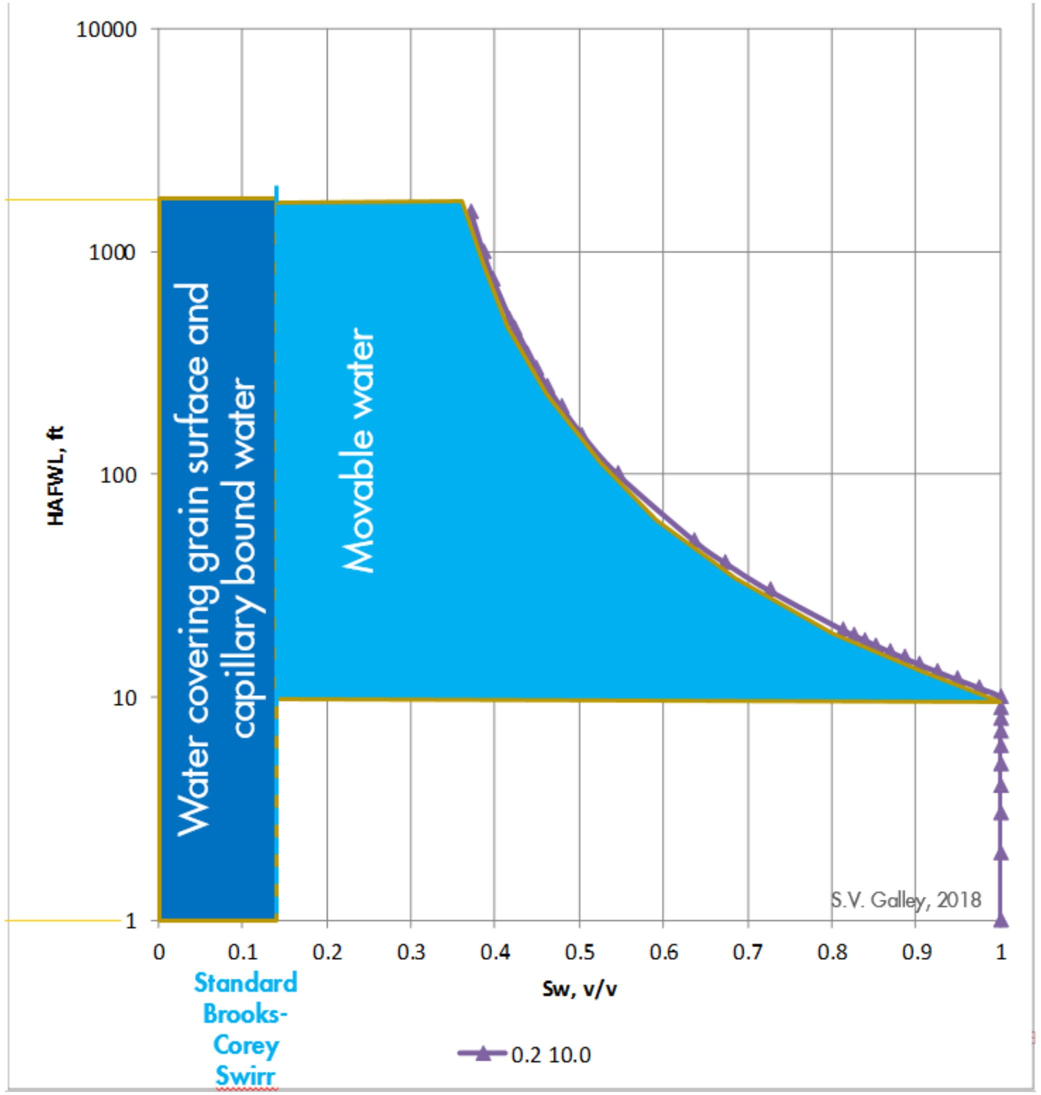
Irreducible water saturation, calculated by Brooks – Corey saturation height model is insensitive to any microporosity and it is almost constant. So, amount of movable water is very high, which contradicts with production results. Water residing in microporosity space is not movable and will not flow into wellbore. Most of the movable water is in transition zone. New saturation height function shall be developed in order to take microporosity residing water into account.



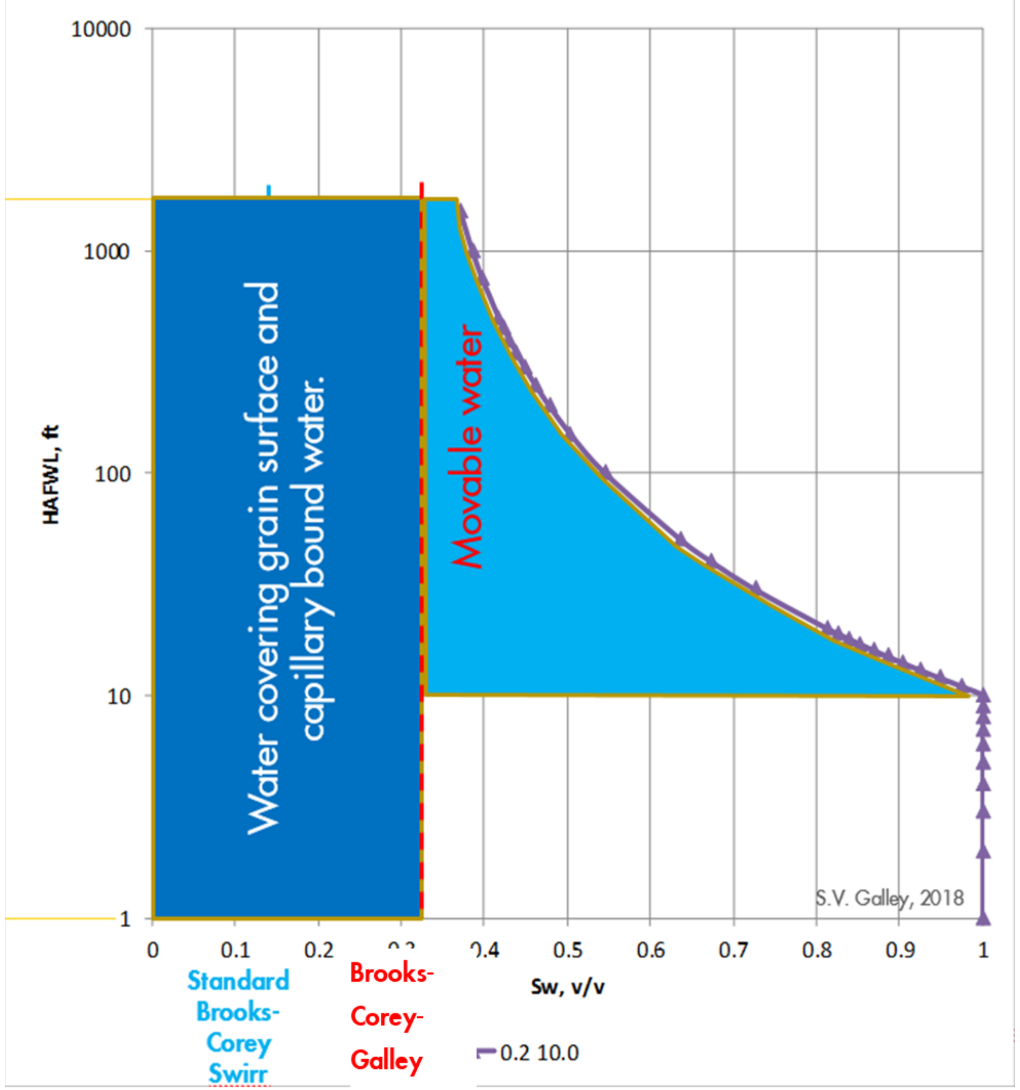
STANDARD BROOKS – COREY MODEL



STANDARD BROOKS – COREY MODEL



MODIFIED MICROPOROSITY BROOKS – COREY - GALLEY MODEL



BROOKS – COREY – GALLEY SATURATION HEIGHT MODEL

PC_IFT1 = (HAFWL * 0.3048 * (DEN_W – DEN_HC) * 0.0980665 * (1.0 / (σ * cos(Θ))))

Swi = min(1,max(0,((POR - ((PERM / A) ** B))/ POR)))

PCe = (C1 * pow(sqrt(PERM / POR), C2))

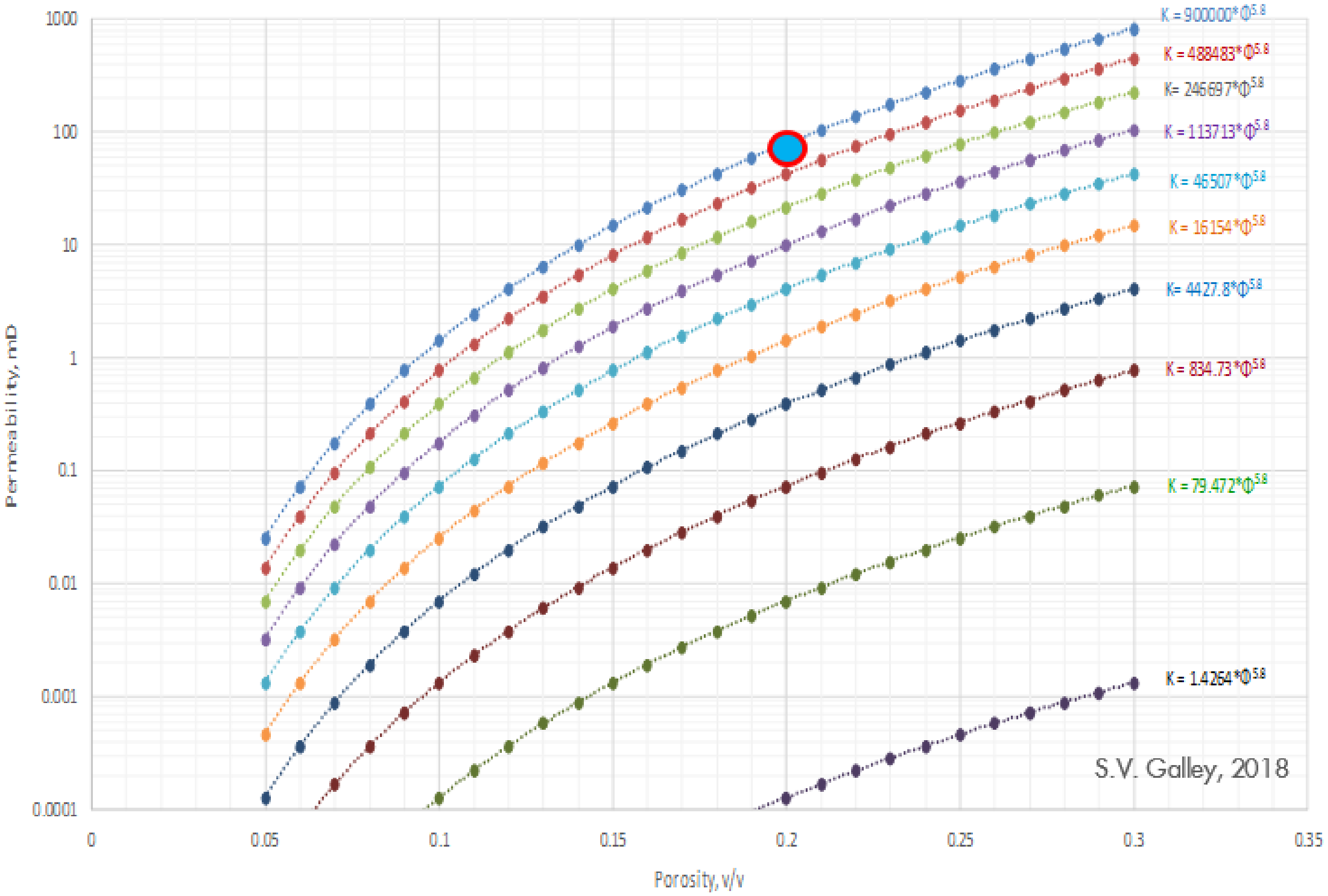
N = (D1 * pow(PERM, D2))

SW = min(1, max(0, SWi + (1 - SWi) * (PCe / PC_IFT1) ** (1.0 / N)))

*Where A and B are coefficients in porosity – permeability relationship PERM = A * POR* ^{B}

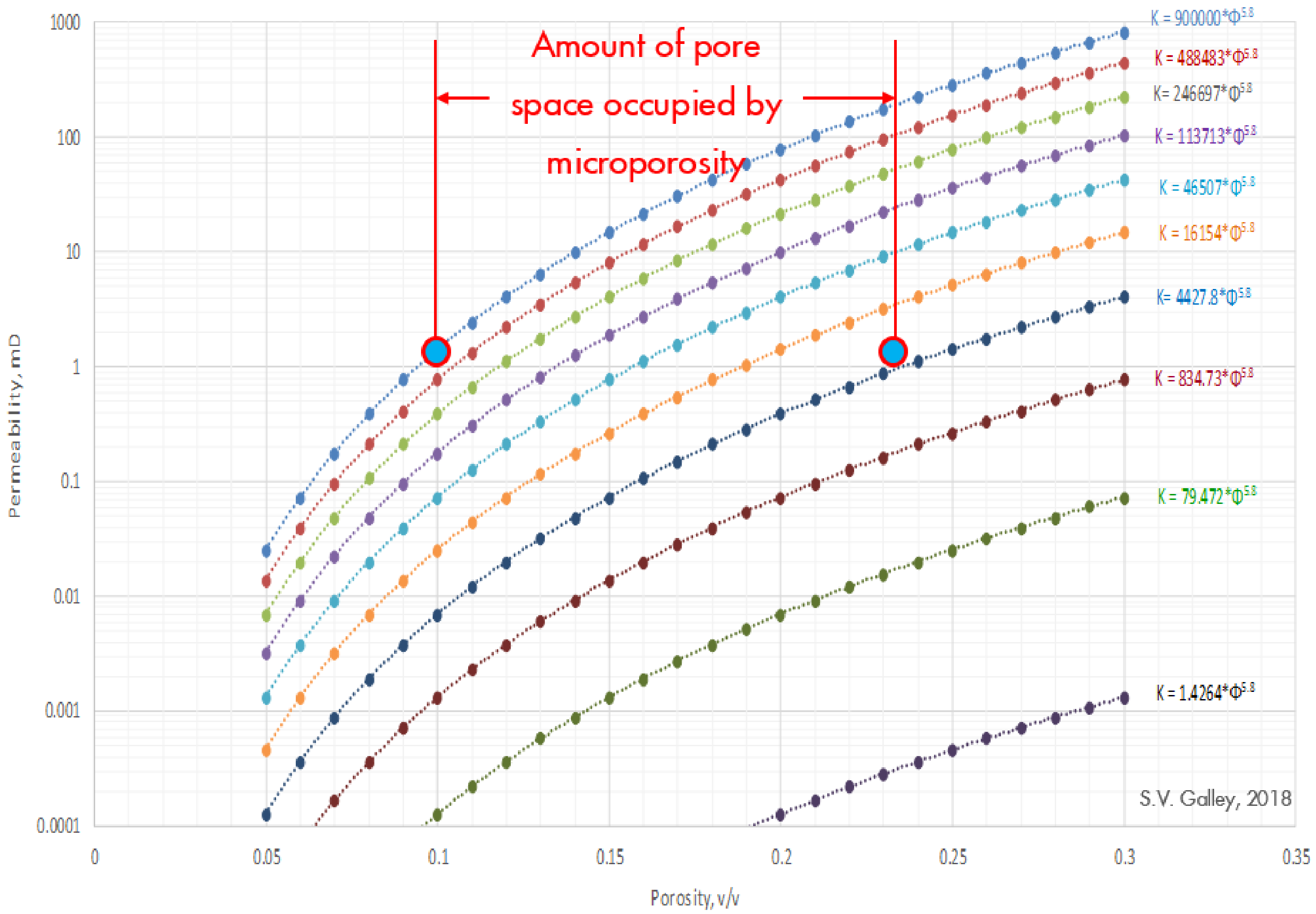
C and D are constants in saturation height model

POROSITY – PERMEABILITY VS MICROPOROSITY



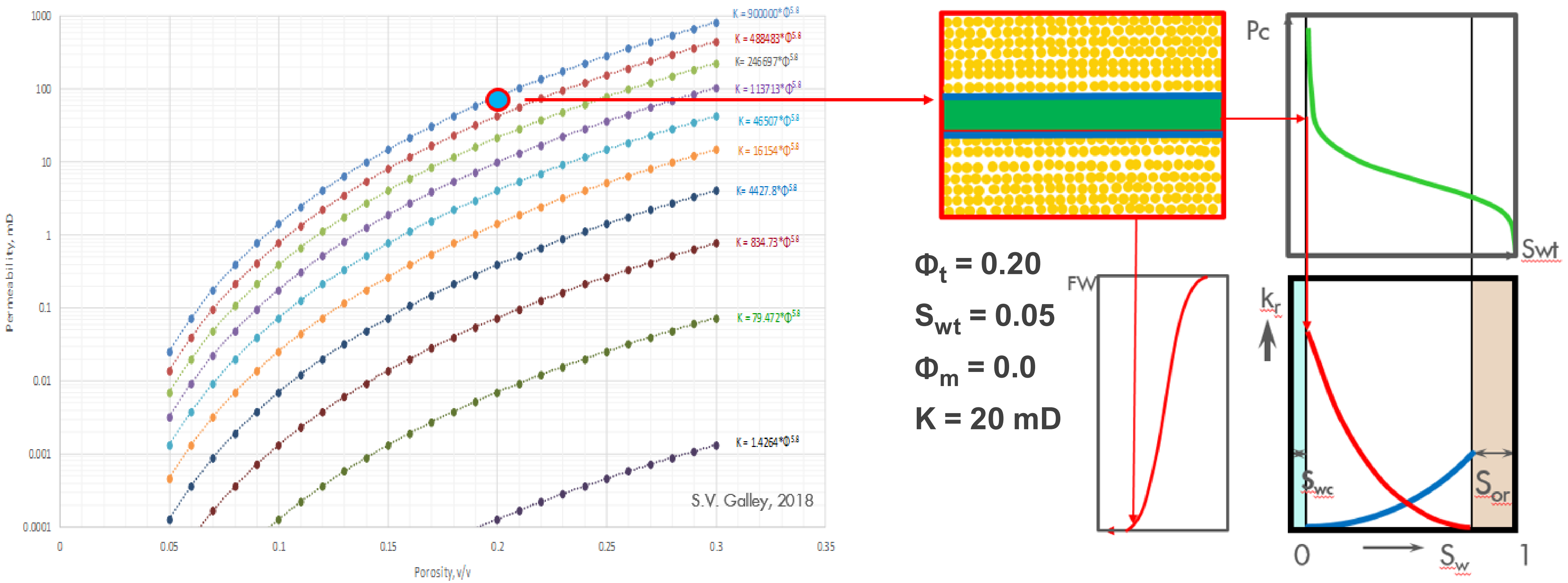
Position of porosity and permeability point on this chart is also controlled by amount of microporosity.

POROSITY – PERMEABILITY VS MICROPOROSITY



Two points with same permeability have different porosity, which means that difference between these two is amount of microporosity, holding all other variables constant. This microporosity is added on top of connate water calculated by standard Brooks – Corey saturation height model.

POROSITY – PERMEABILITY VS MICROPOROSITY



$\Phi_t = 0.20$

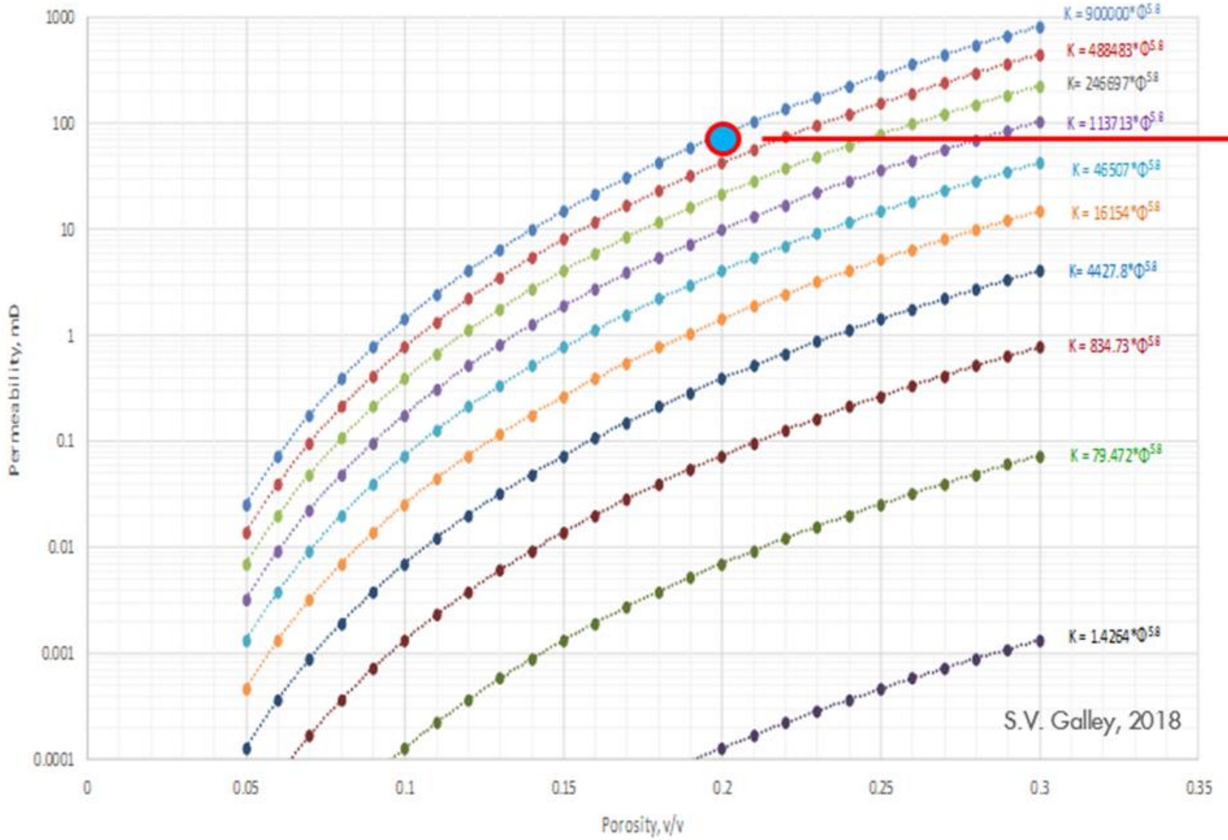
$S_{wt} = 0.05$

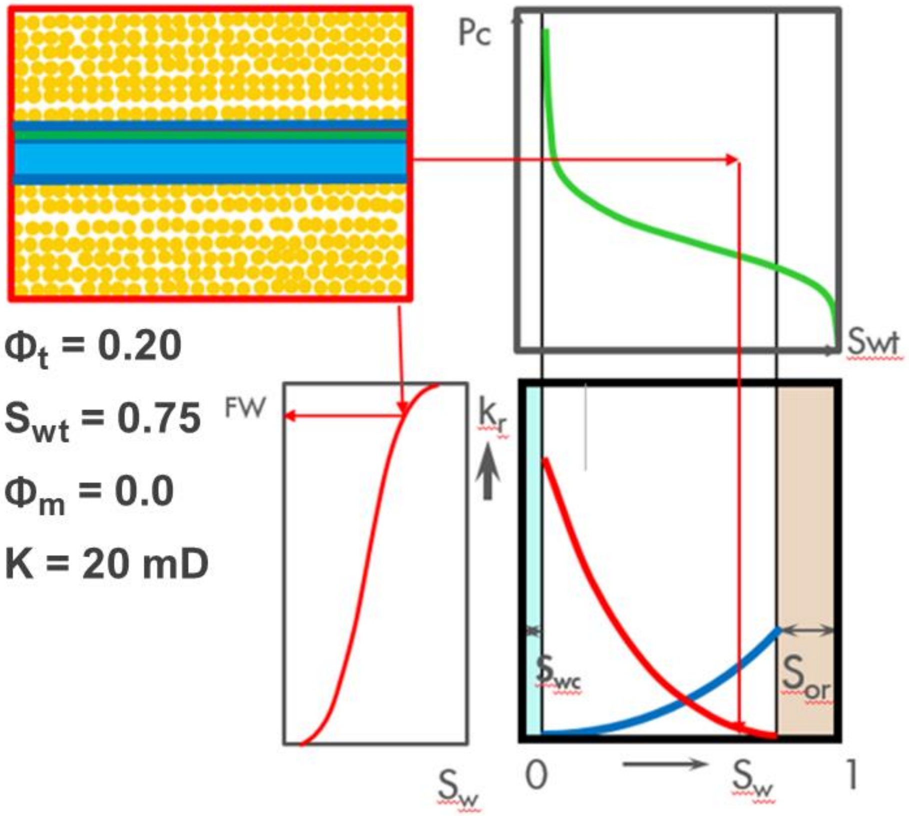
$\Phi_m = 0.0$

K = 20 mD

Clean sandstone end member has irreducible water saturation, defined by cap pressure curve, which is water covering grain surfaces (water wet rock).

POROSITY – PERMEABILITY VS MICROPOROSITY





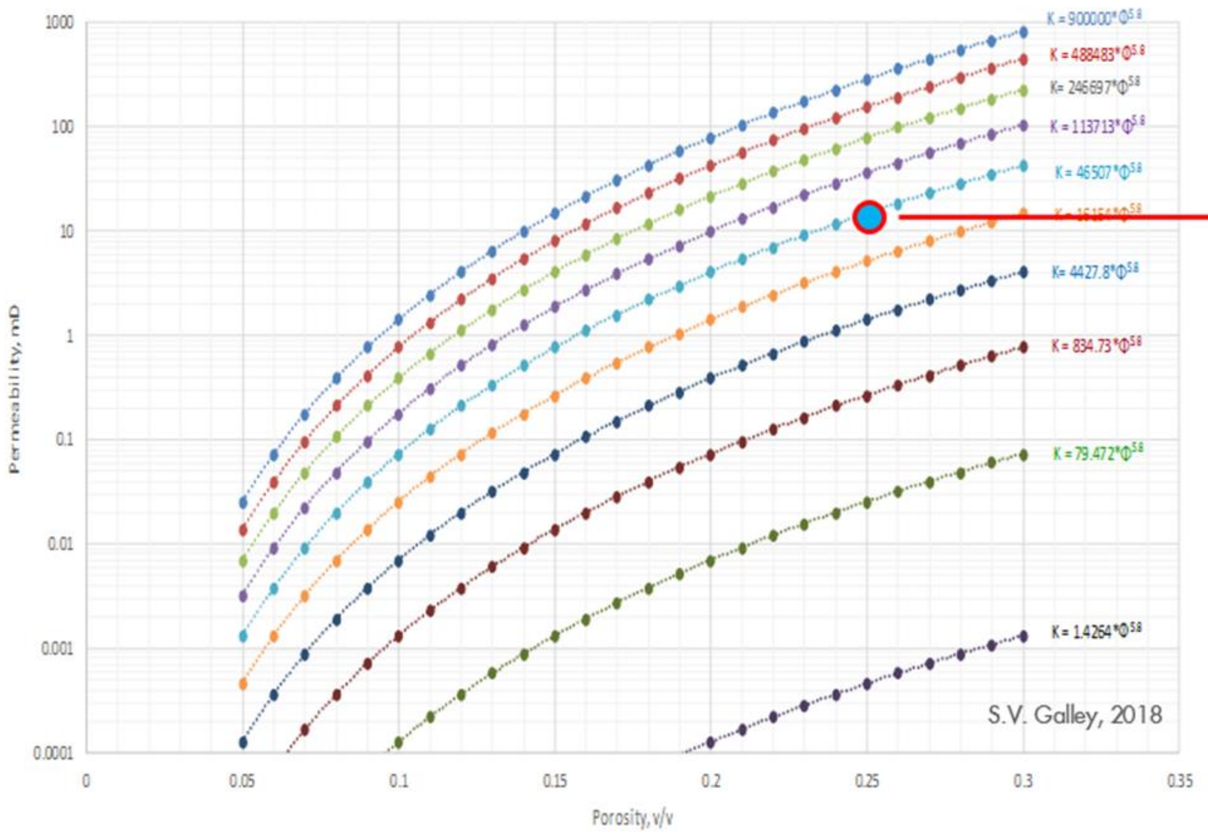
$\Phi_t = 0.20$

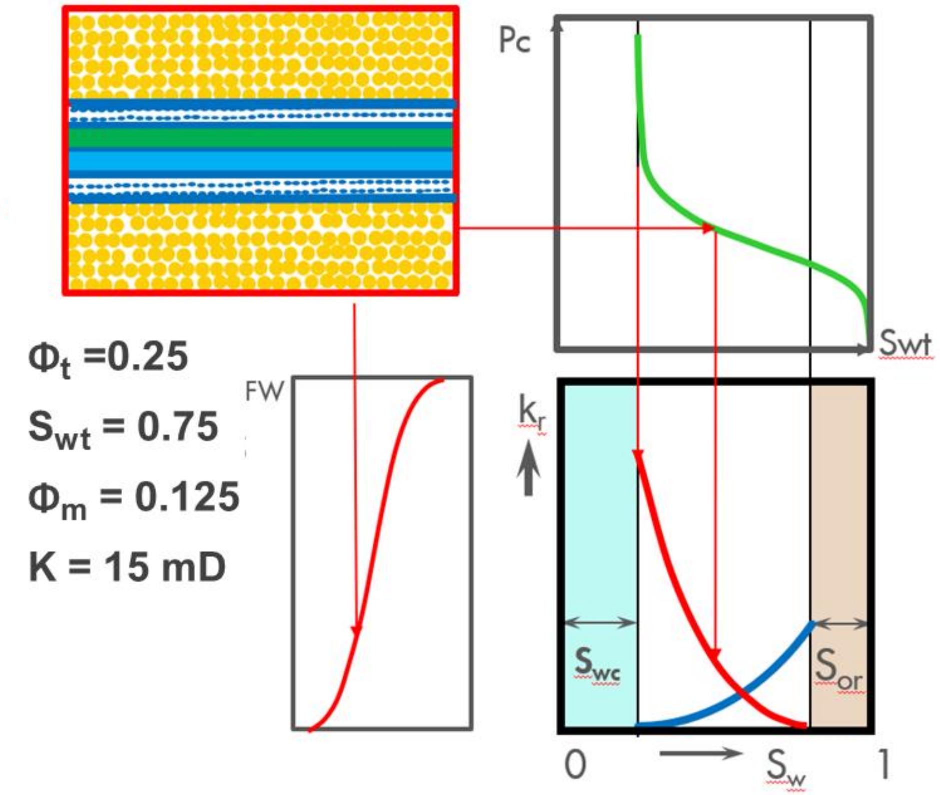
$S_{wt} = 0.75$

$\Phi_m = 0.0$

K = 20 mD

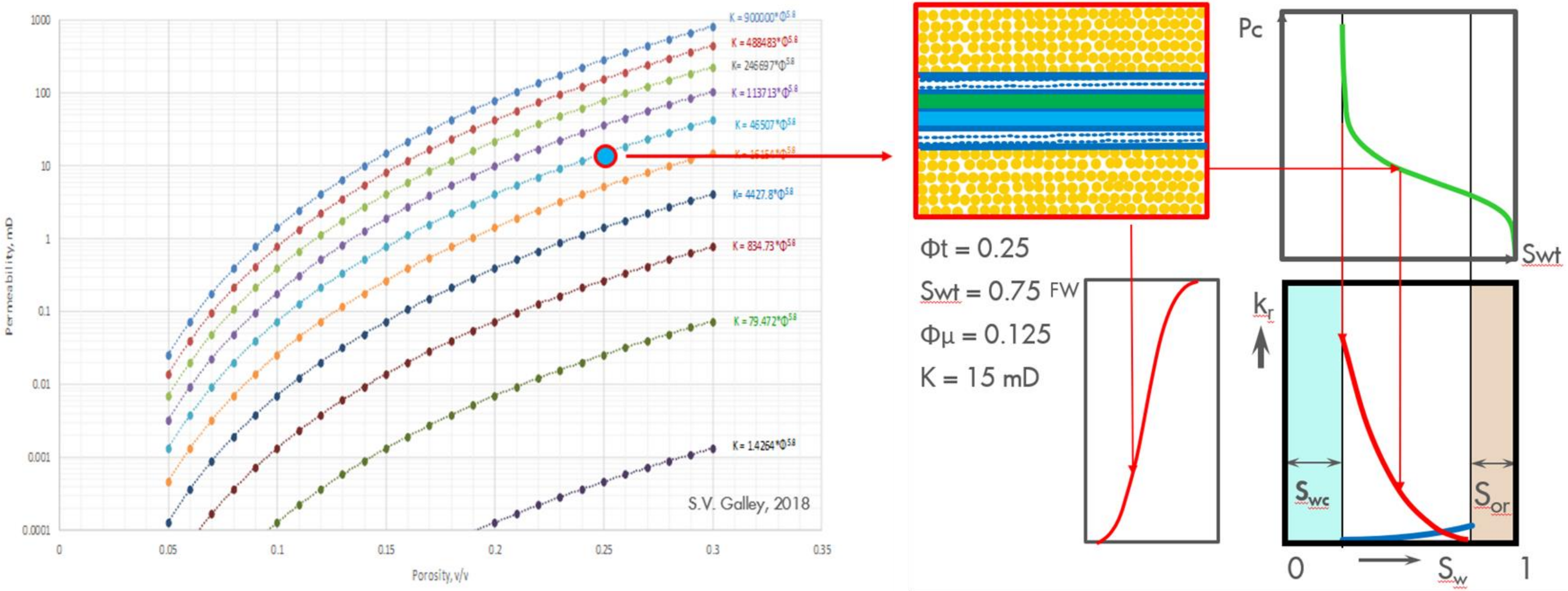
POROSITY – PERMEABILITY VS MICROPOROSITY





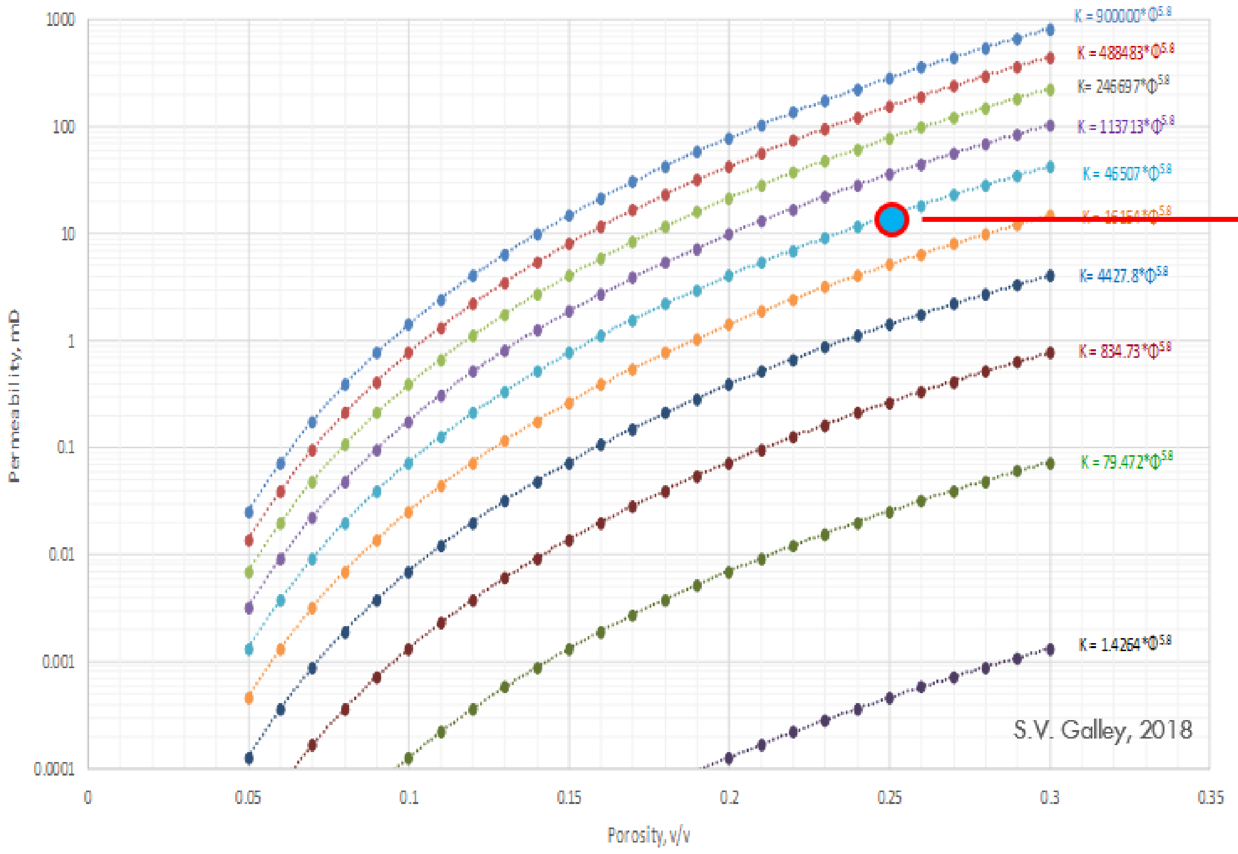
In this case irreducible water occupies 50% of total porosity which is located sufficiently high above free water level (FWL), so amount of movable water is negligible. If reservoir engineer uses standard Brooks – Corey equation, connate water saturation will be about 18% and rock will produce 50% water cut. Obviously such high water cut contradicts production data, which has about 4% water cut. So what reservoir engineer do?

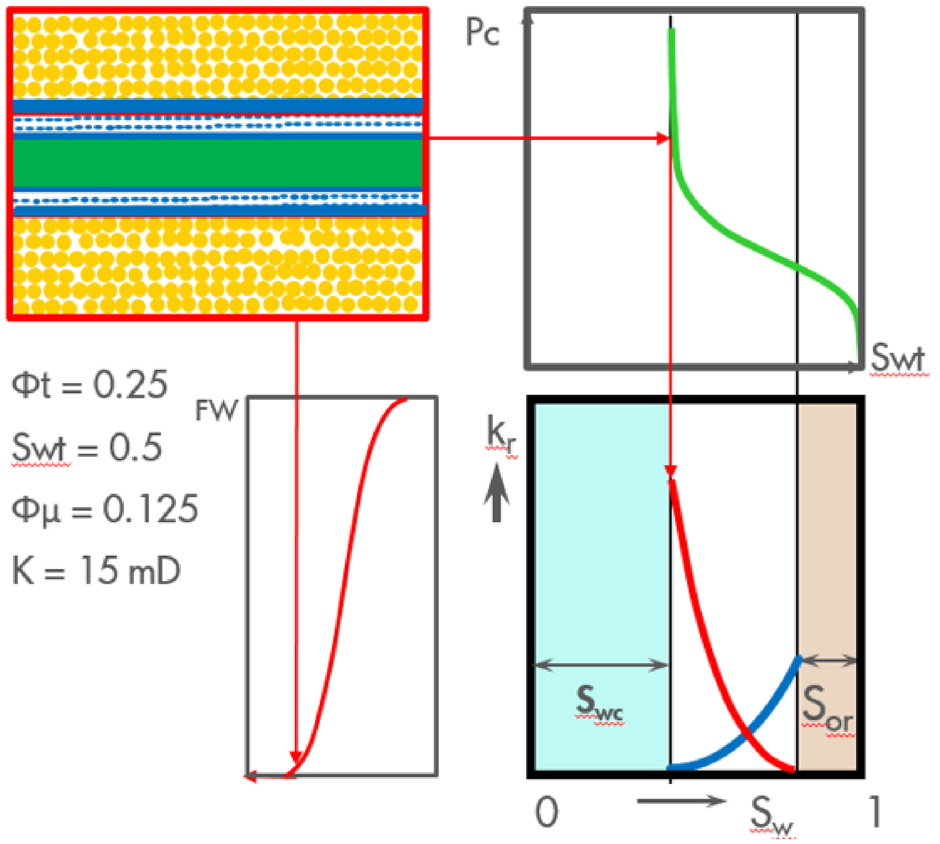
POROSITY – PERMEABILITY VS MICROPOROSITY STANDARD SHM



Reservoir engineer increases water Corey exponent and suppress water flow. However, water relative permeability is rather unphysical, it could be possible only when water viscosity is significantly higher than oil viscosity.

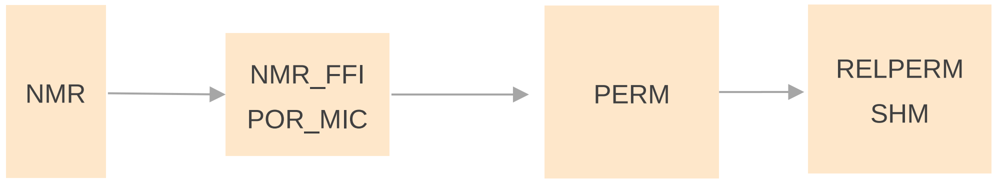
POROSITY – PERMEABILITY VS MICROPOROSITY MODIFIED SHM

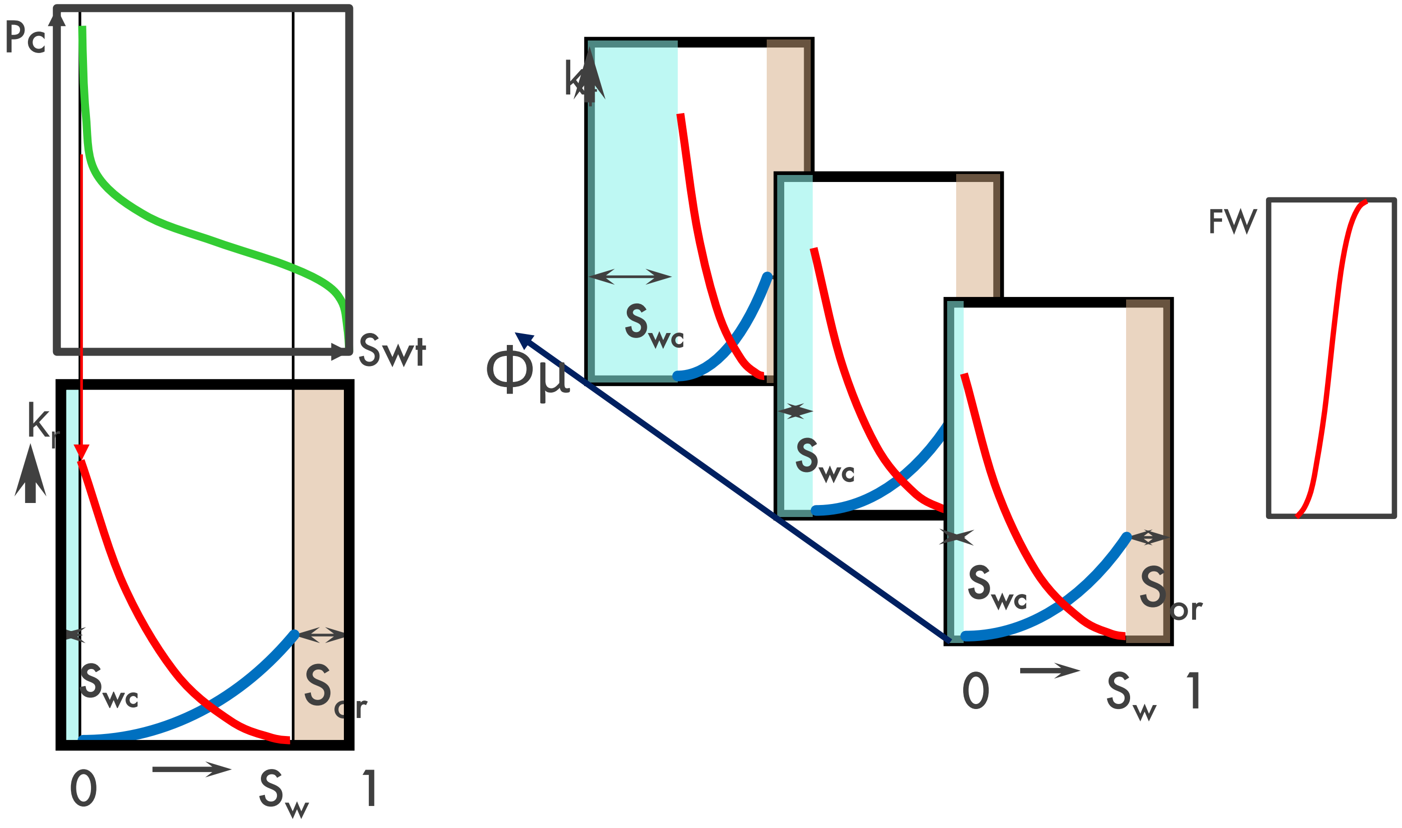




Relative permeability end points are shifted to match position of connate water saturation point. Corey oil and water exponents matching core derived value and production is water free, assuming this interval is sufficiently high above FWL.

LOGS – STATIC – DYNAMIC MODEL





CONCLUSION

It is recommended to use thin bed analysis for robust evaluation of reservoir properties and net sand evaluation. Free fluid or effective porosity should be utilized for calculation of permeability but its utilization for calculation of saturation is associated with significant uncertainties. Development of saturation height model or relative permeability model in effective porosity domain is associated with even higher uncertainties and should be discouraged.

Modified for microporosity Brooks – Corey - Galley saturation height model (SHM) allows reservoir engineers utilization of reasonable Corey water exponents and match production data. Proposed methodology for integration of petrophysical properties and reservoir engineering parameters is equally applicable to clastic and carbonate reservoirs, where microporosity development is rather norm than exception.

Authors are thankful to Shell management for permission to publish this paper and Marc Varner (Reservoir Engineering), who was driving force behind whole this work and Rakesh Kumar for his support.

Questions and Answers

Q&A

APPROVALS