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Multi-scale Imaging Process for Computations of Porosity and Permeability on Carbonate Rocks*

Abraham Grader[1], Amos Nur[1], Chuck Baldwin[1], Elizabeth Diaz[1], and G. Li[1]

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[1]Ingrain, Inc., Houston, TX (diaz@ingrainrocks.com)

Abstract

Reservoir rock material collected during drilling is one of the main sources used to derive reservoir fluid transport and rock mechanics properties. Carbonate reservoirs may have heterogeneities that create multi porosity/permeability systems that are very difficult to describe, and to determine their flow properties. They may contain micritic, sparic, and much larger grain and pore structures, all in one reservoir and in close proximity. Conventional methods use laboratory procedures to perform experiments that yield directly or indirectly required rock properties. Some of these procedures, such as the determination of relative permeabilities, may take several months to perform.

Yet, as reservoir characterization is becoming ever more important for oil and gas production, a much larger portion of reservoir rocks, from cuttings to full cores, will need to be analyzed than what are currently evaluated. This paper offers an example of the use of digital rock physics to determine porosity, permeability, and relative permeabilities for a carbonate sample using multi-scale imaging. Digital rock physics using the Lattice Boltzmann (LBM) for fluid dynamic calculations is at a point where for a proper digital pore space the resulting flow properties calculated are reasonably correct. The main issue facing digital rock physics is the need to up scale the computed properties to the scale of the core.

The process presented in this paper includes sample preparation, imaging, image processing, property computations, and property integration to the core scale. The sample is subjected to a descending scale of x-ray CT imaging, along with physical sub-sampling of the core. The descending size of scanning leads to increased resolution of the three-dimensional digital core, keeping the sample volumes registered in place. The resulting digital rocks are segmented and the pore structure is determined on the x-ray CT grid system. The resulting three-dimensional pore structure, that is the same as the actual pore structure subjected to resolution limits, is used as the input grid system for direct fluid dynamic computations that are second order accurate representation of the Navier-Stokes fluid flow equations. These computations yield porosity, absolute permeability, relative permeabilities, and capillary pressure. In this paper we focus only on porosity and permeabilities.

References

Vanorio, T., 2008, Emerging methodologies to characterize the rock physics properties of organic-rich shales: Leading Edge, v. 27/6, p. 780-787.

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MULTI-SCALE IMAGING PROCESS FOR COMPUTATIONS OF POROSITY AND PERMEABILITY ON CARBONATE ROCKS

A.S. Grader, A. Nur, C. Baldwin, E. Diaz*, G. Li

(Ingrain Inc, Houston, TX, USA)

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INTRODUCTION

- Determination of fluid flow properties in carbonates is strongly affected by heteogeneity: Case study offered for a Middle East carbonate sample.
- Through multi-scale x-ray CT imaging (***core panoscopy***), a base flow unit is selected in the sample for property computations.
- 3D volumes scanned at different resolutions are spatially registered and presented.
- Using digital rock physics, proper transport properties of the core are determined.
- The flow unit is a bio-sparic portion of the sample that fills the space between large solid carbonate fragments.
- High-resolution micro-CT images provide a digital rock that is the basis for calculating porosity, permeability, and relative permeability using Lattice Boltzmann fluid dynamics method.
- The results are in good agreement with the laboratory measurements released by the field operator.

Notes by Presenter: Carbonate reservoirs may have heterogeneities that create multi porosity/permeability systems that are very difficult to describe and to determine their flow properties. They may contain micritic, sparic, and much larger grain and pore structures, all in more reservoir and in close proximity.

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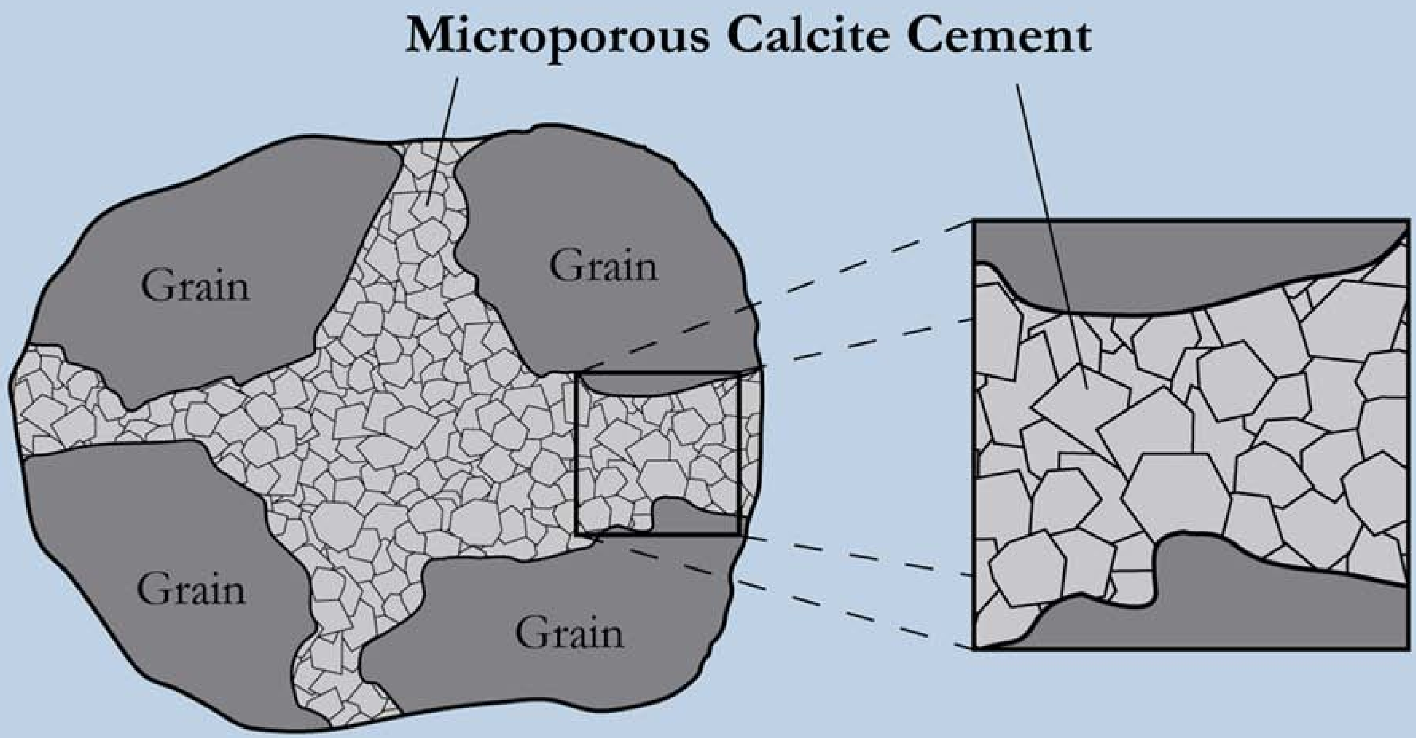
Microporous Cement



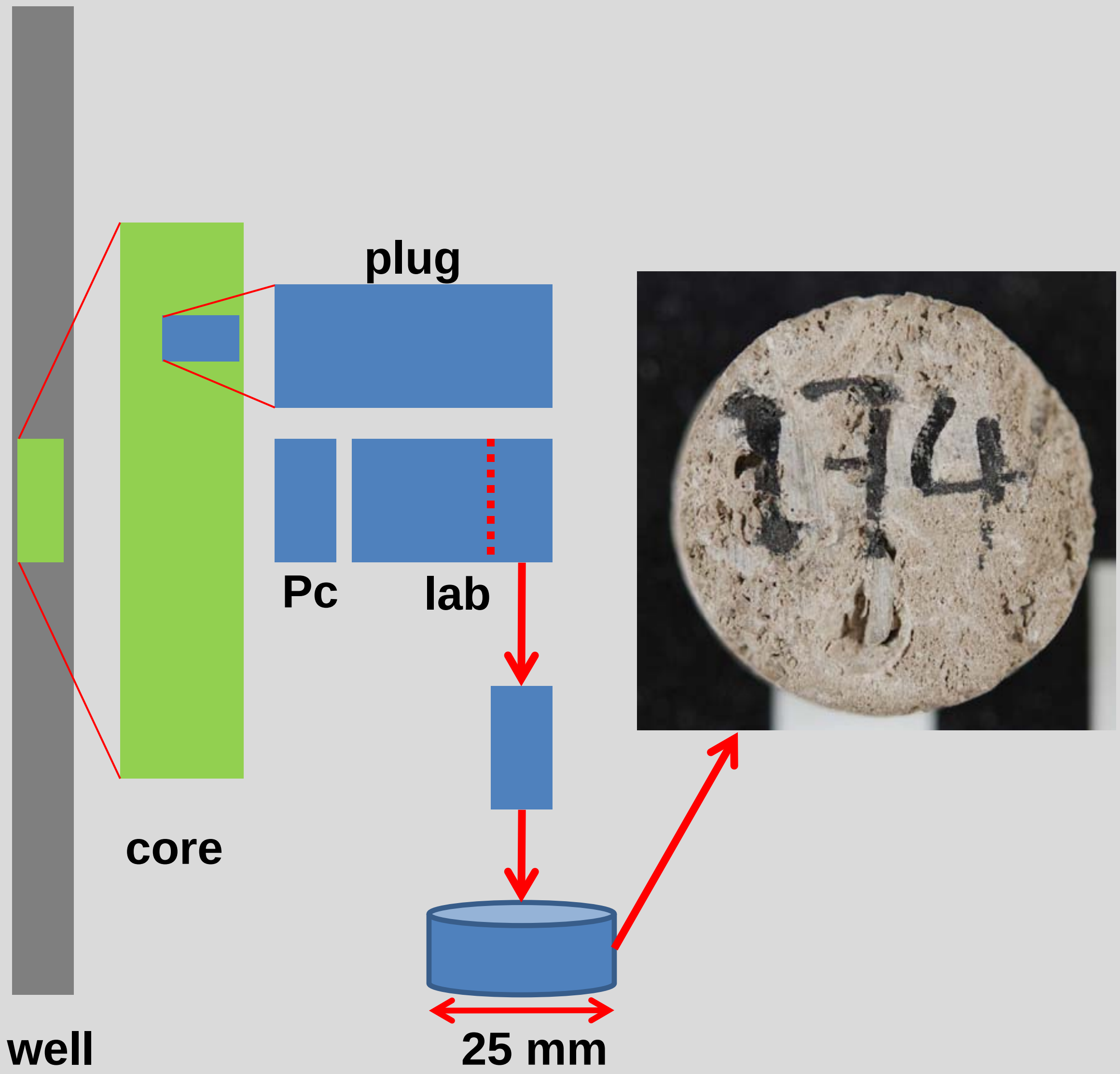
(Tiziana Vanorio, 2008, Stanford Univeristy)

Definitions

Macro-porosity: associated with largest grains and pores observed in rocks.

Micro-porosity: associated with micrite (**micr**ocrystalline calc**ite**), pore throat ≤ 1 μm

Sparic-porosity: associated with sparite (**spar**ry calc**ite**), crystals > 4 μm



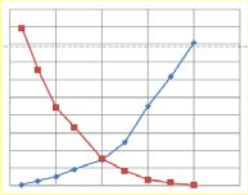
The Challenge

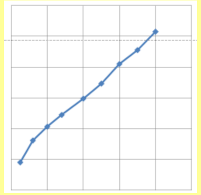
Identify porosity structure
Macro / Sparic / Total

Estimate Porosities
0.19 / 0.21 / 0.20

Permeability
1.2D / 1.2D

Sparic relative permeabilities





Within only 7days!

Notes by Presenter (for previous slide): The sample is subjected to a descending scale of x-ray CT imaging, along with physical sub-sampling. The descending size of scanning leads to increased resolution of the 3D digital core. The low-resolution/large-field-of-view images guide decisions about the location and size of higher-resolution/smaller-field-of-view scans and physical sub-sampling. This process allows consistent registration of samples and images of different size and resolution, i.e., we know where the high-resolution volume is located inside the low-resolution one.

The resulting digital images are segmented and the pore structure, which is the same as the actual pore structure subject to resolution limit, is used as the input grid system for direct fluid dynamic computations, representing the Navier-Stokes fluid flow equations to the 2^{nd} order of accuracy. They yield absolution perm, relative perm and capillary pressure.

Mutiple scale imaging permits the estimation of properties at the core scale.

The core sample we use is from a Lower Cretaceous lithofacies of a coated grain, skeletal rudstone-floatstone limestone in the Middle East.

A plug (25mm diameter, 50 mm length) was taken. A disk from one end of the plug was used for thin section work. The rest for perm and rel perm measurement in a physical lab.

A small portion of the sample was sent to Ingrain to estimate the flow properties of this rock portion that is made up of small calcite crystals and skeletal remains on the order of 100 microns, and to relate this information to larger scales of the core.

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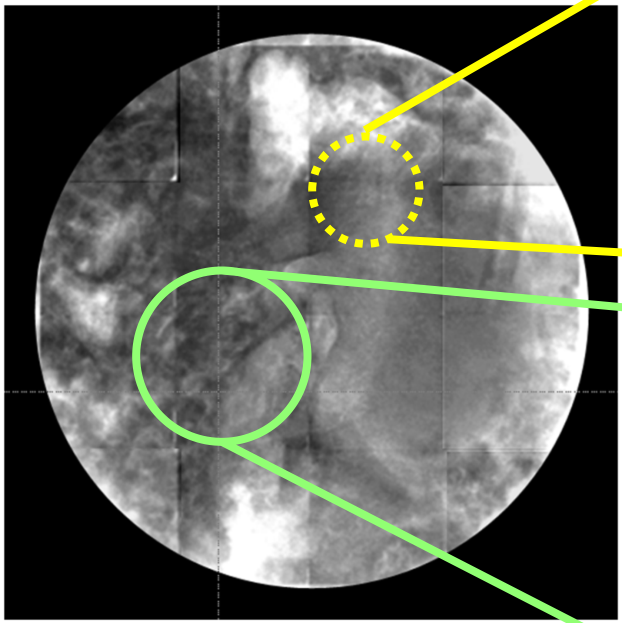
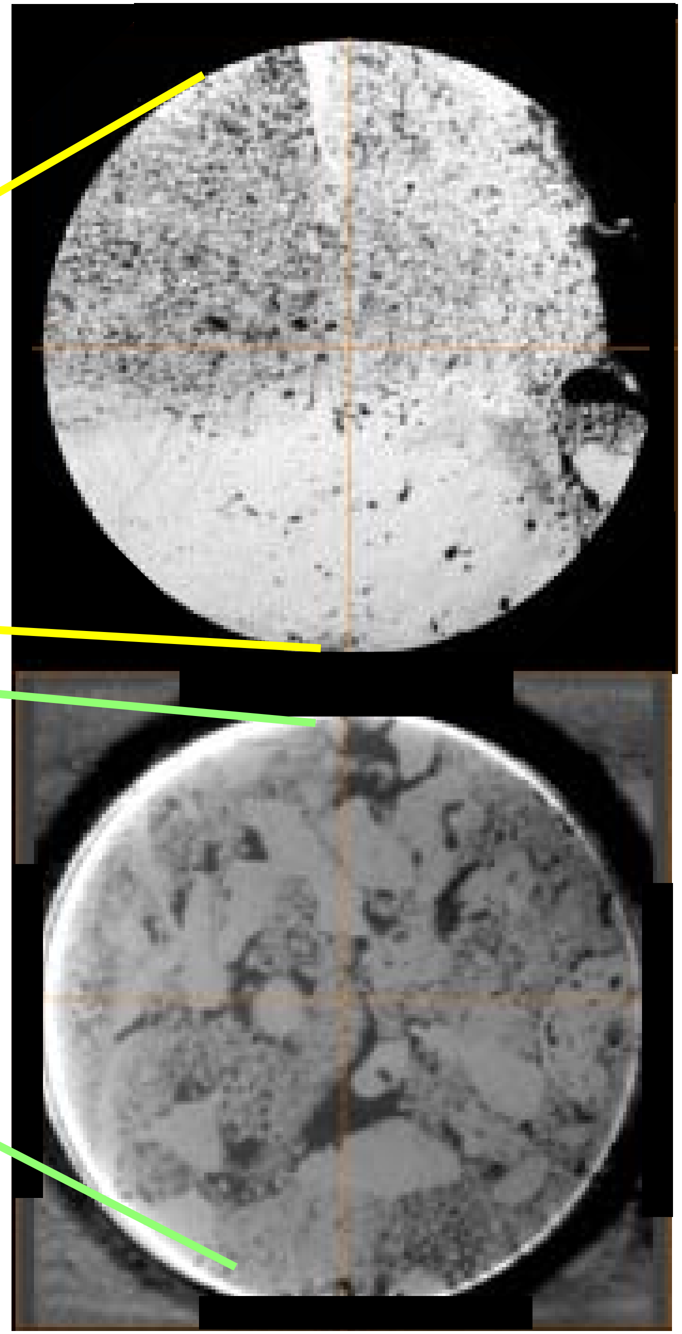
Process

2-D projection



25 mm



Granular region

Vuggy region

8 mm

Low res (8)

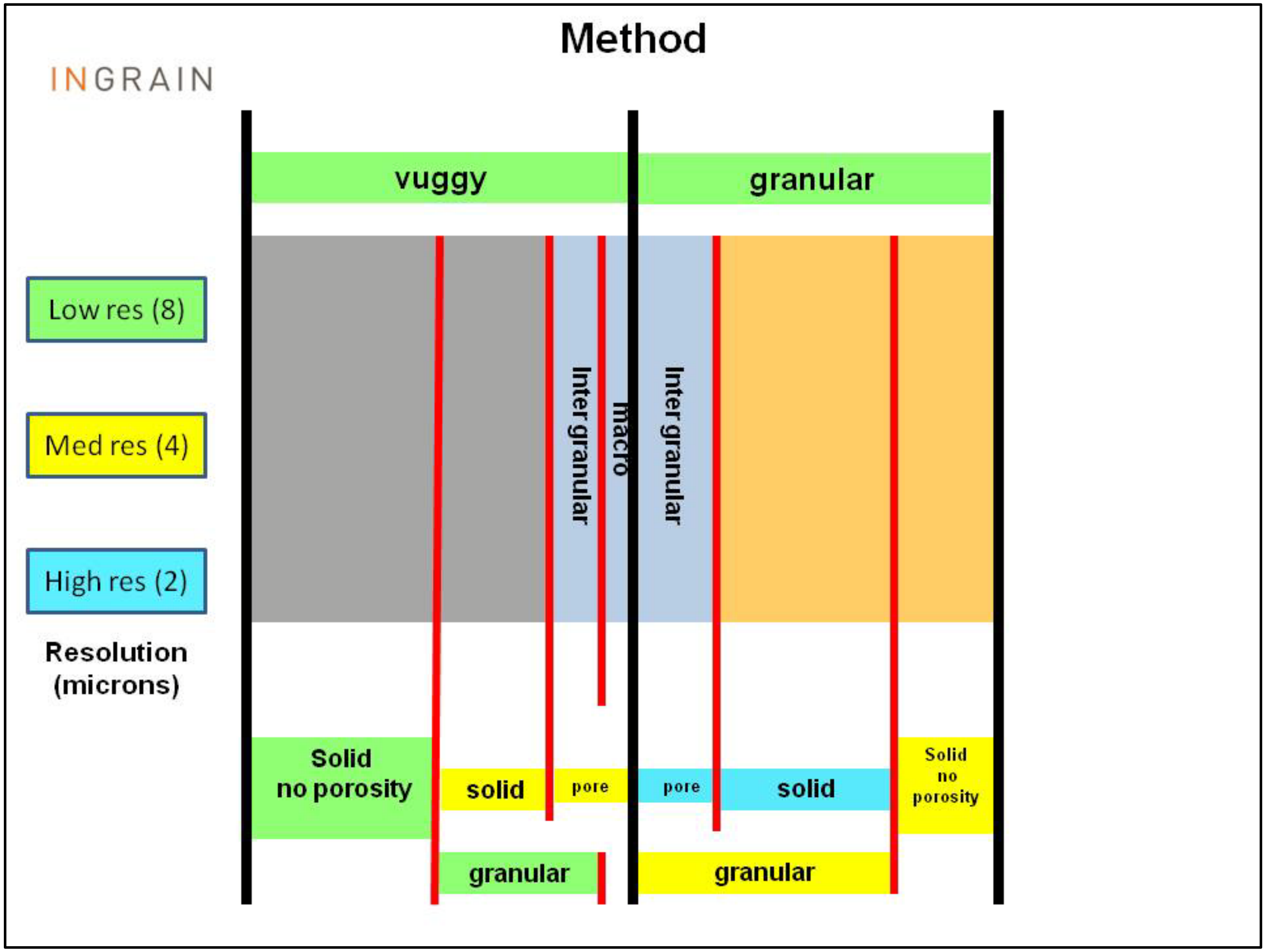
Med res (4)

Resolution (microns)

Notes by Presenter (for previous slide): The cylindrical sample 12 mm long (on left) was scanned using a low-resolution MacroCT (8 microns). This 2D projection was acquired in order to decide what part of the core should be selected for microCT. It is in reverse gray scale color scheme where dark areas represent higher density and light gray areas represent low density. It shows two distinct regions: a low density rather homogeneous region, or a Granular region (in yellow), and a high density heterogeneous region, or a Vuggy region (in green).

The Vuggy region, at a resolution of 8 microns, show three main structures: large dense shell fragments, large pores that are isolated from each other, and high porosity regions with grains and fragments about 100 microns in size. In the Granular region at a resolution of 4 microns, half of the space is occupied by solid grain, and the other half is high porosity substance that is filling some of the inter-shell volumes, similar to the porous areas within the Vuggy region. Both scans were performed in sub-volume mode without cutting the sample.

Higher resolution scans (not shown here) were performed when small pillars were physically sub-sampled.



Notes by Presenter: This way we are able to characterize the multiple porosity/permeability system in this rock sample. In the case of vuggy region, we can image macro pore space at low resolution (8 microns) and its inter-granular porosity at medium reoslution of 4 microns, in addition to the solid non-porosity areas. In the Granular area, we image the inter-granular porosity, solids within the intergranular porous areas, in addition to the overall solid non-por

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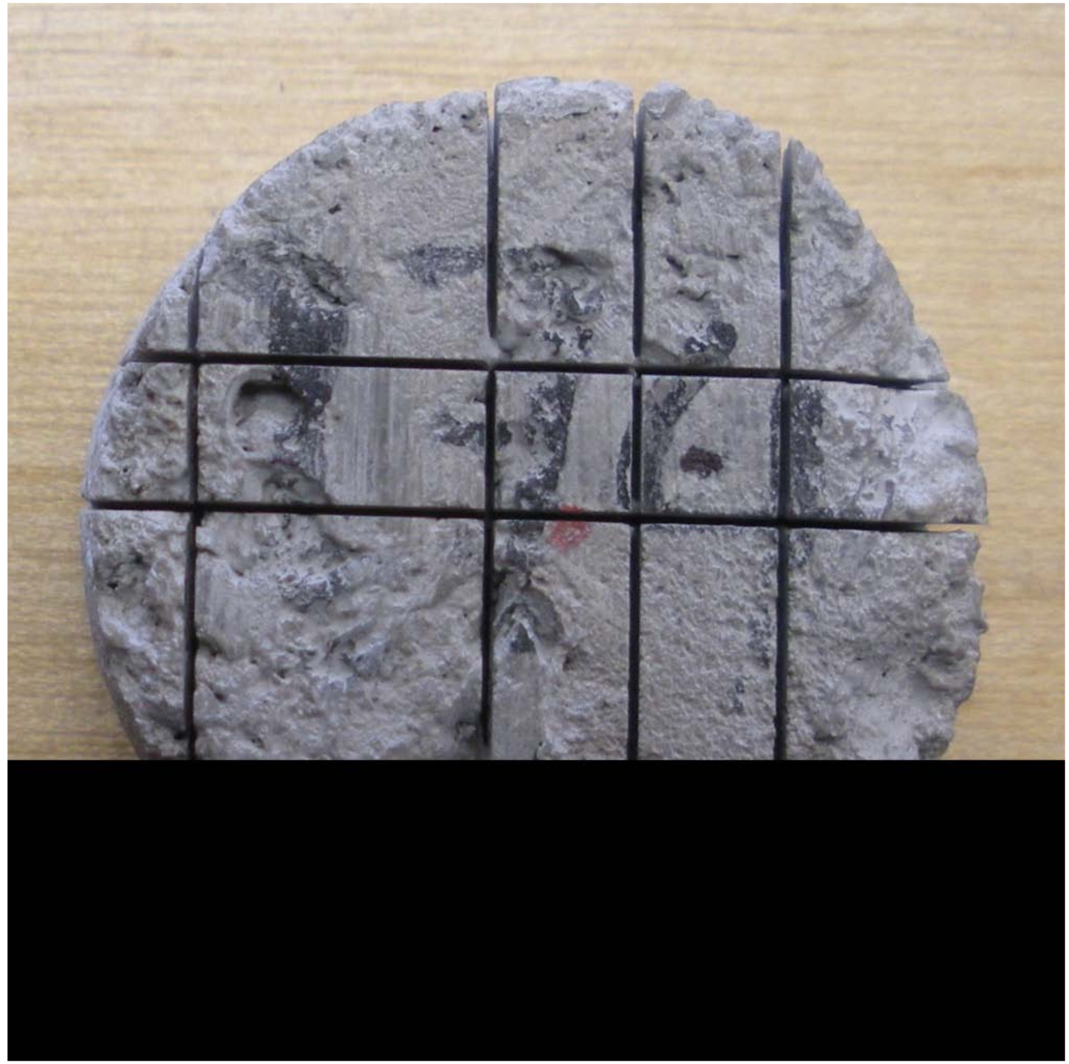
Process



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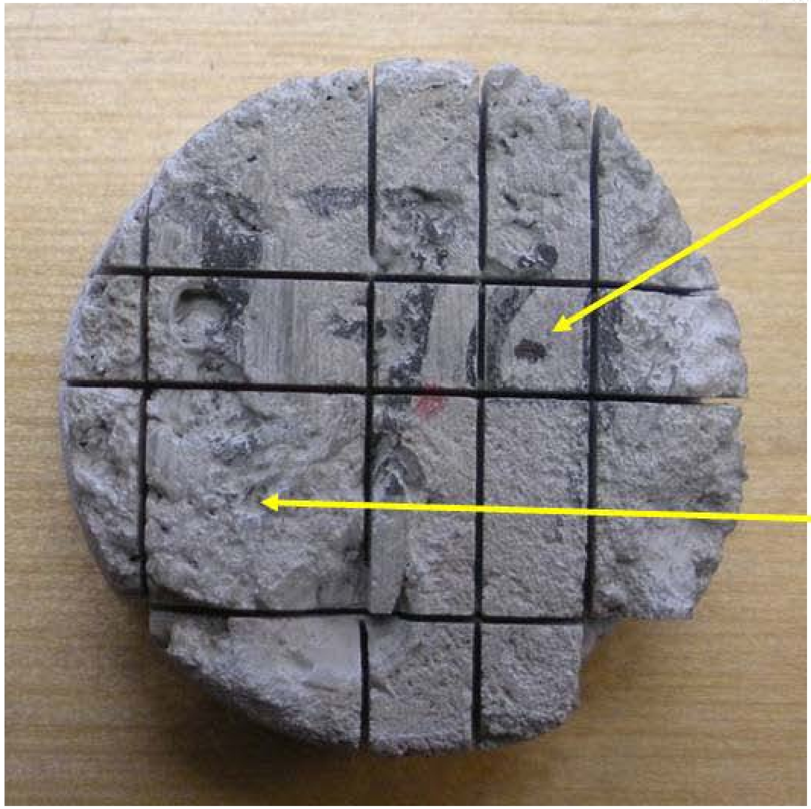
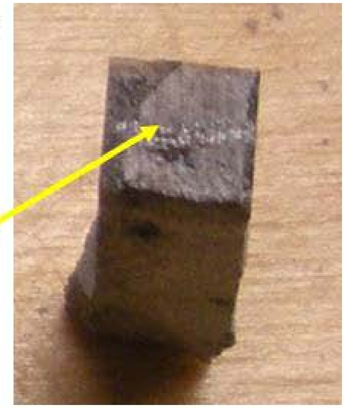
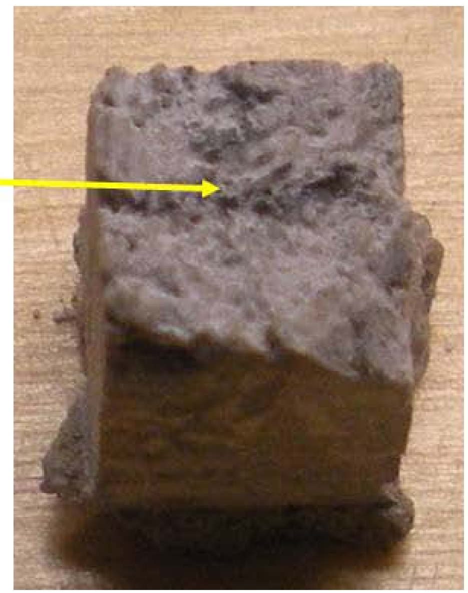
Process



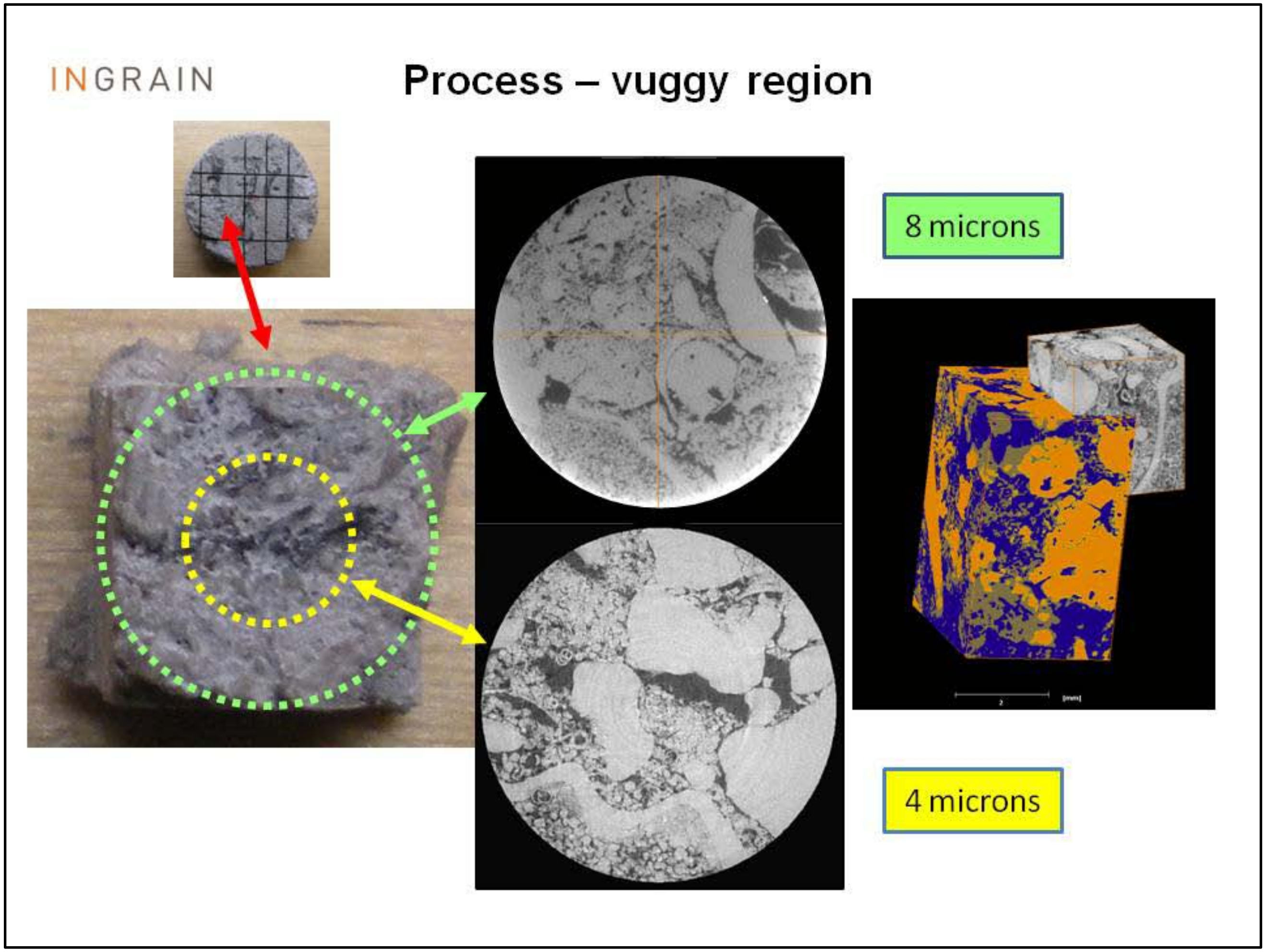
Granular region





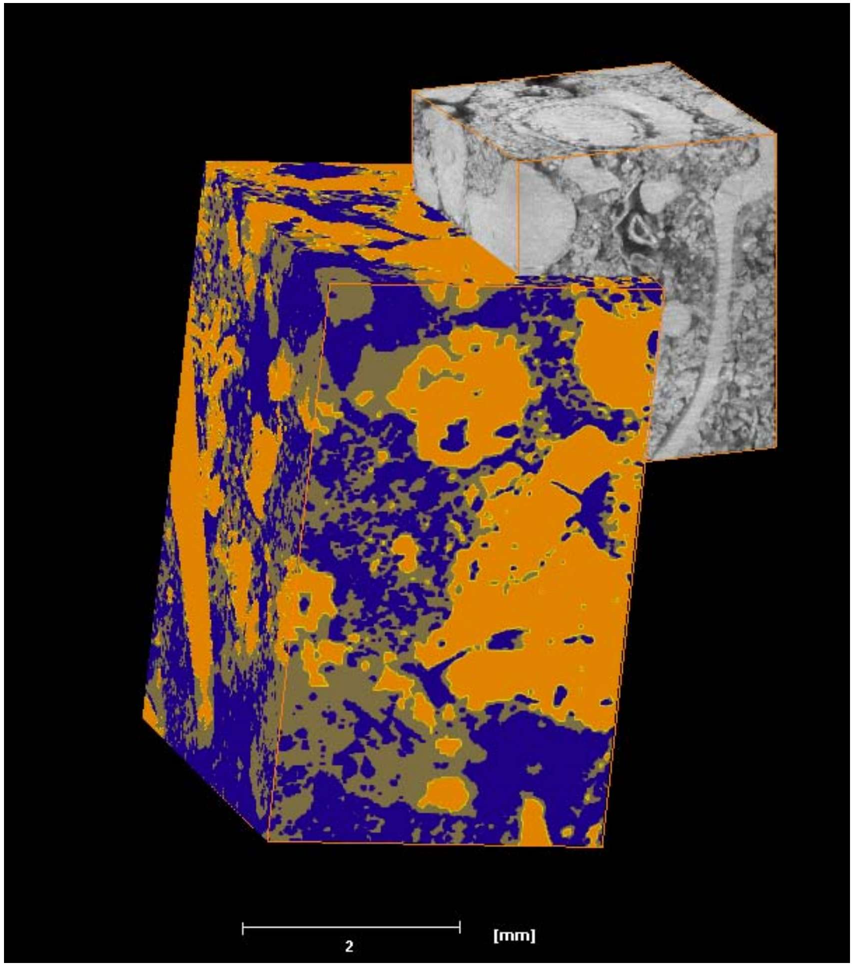
Vuggy region

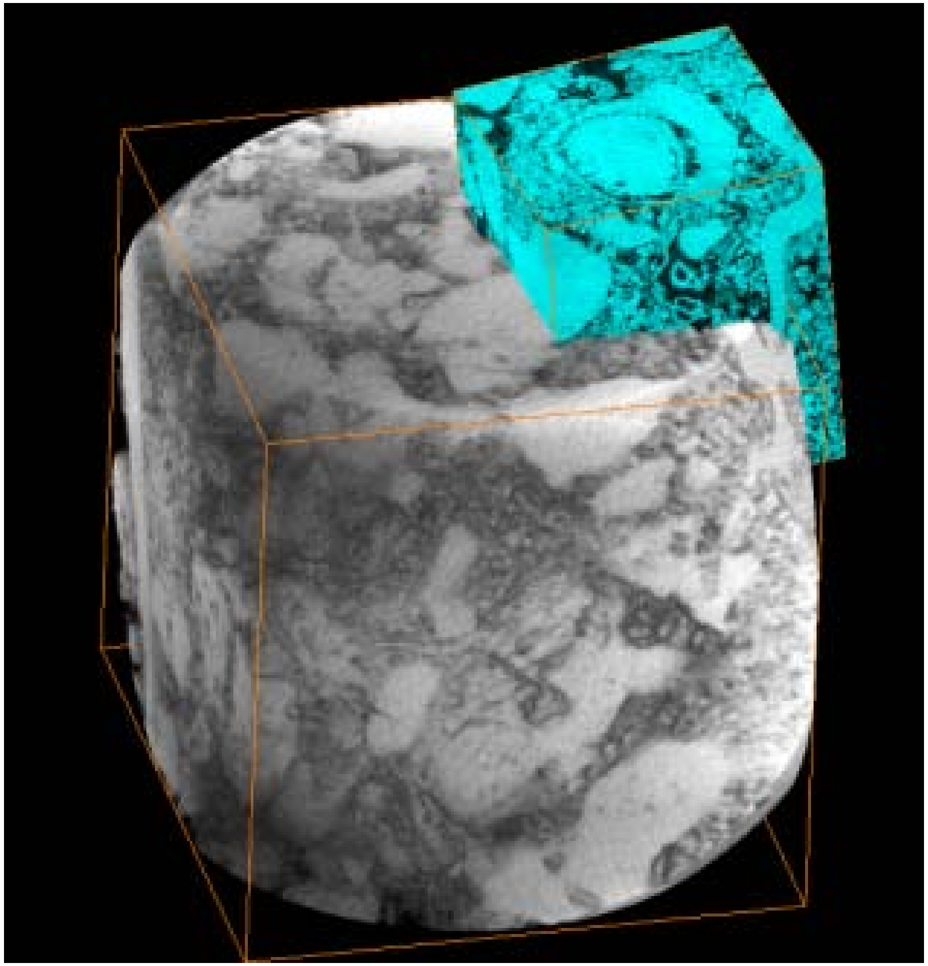
Notes by Presenter: Vuggy region: a 8 mm x 8 mm pillar. Granular region: a 4 mm x 4 mm pillar



Notes by Presenter: Vuggy region: scanned twice at different resolutions: at 8 microns and 4 microns. And then they were registered in 3D volumes. The medium resolution 4 micron scan was used in porosity/permeability calculations while the lower resolution scan was used to determine the fractions of the large vuggy porosity, the porous granular material and the solid high density shell fragments.

Process – vuggy region





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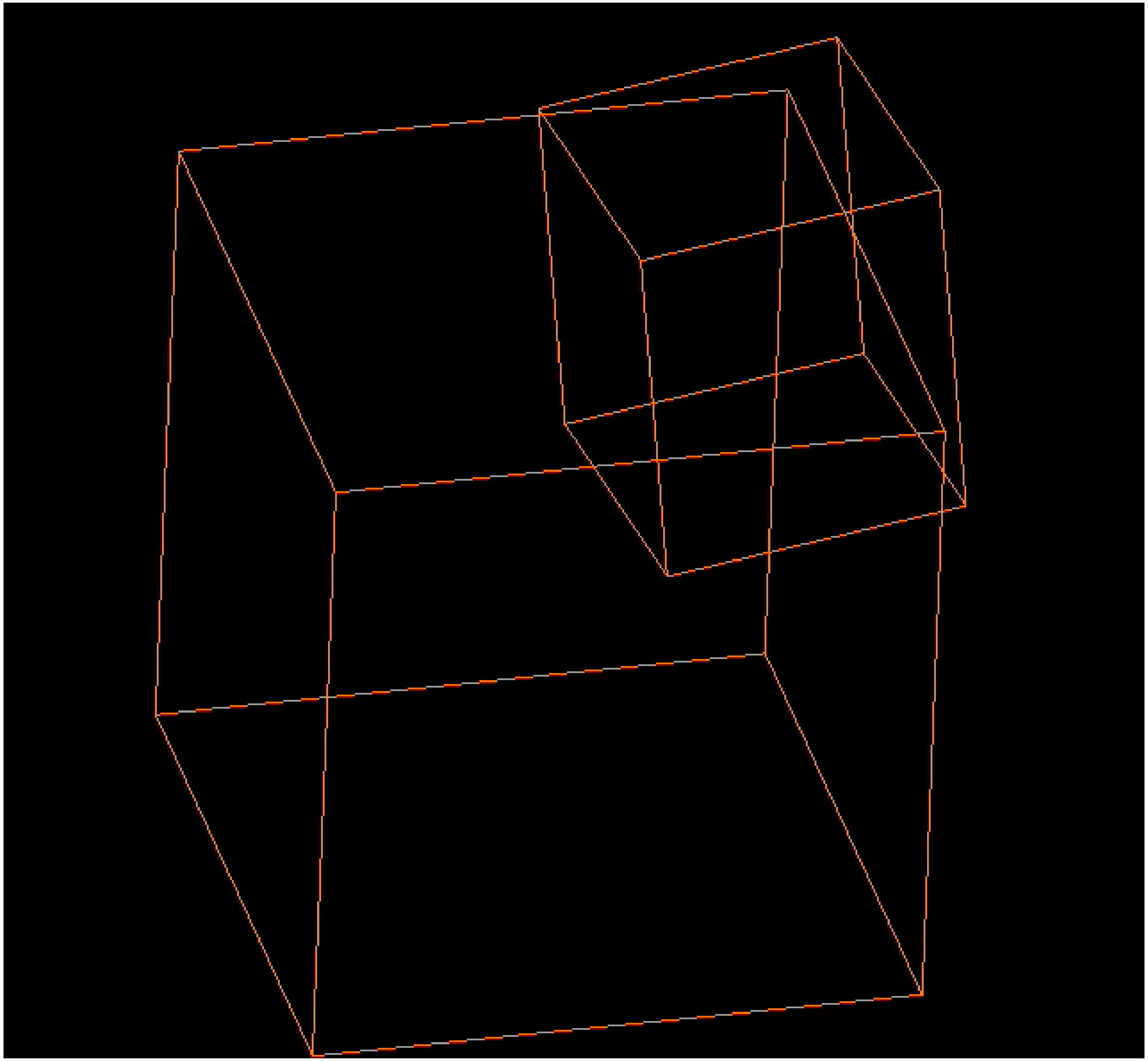
Process – vuggy region



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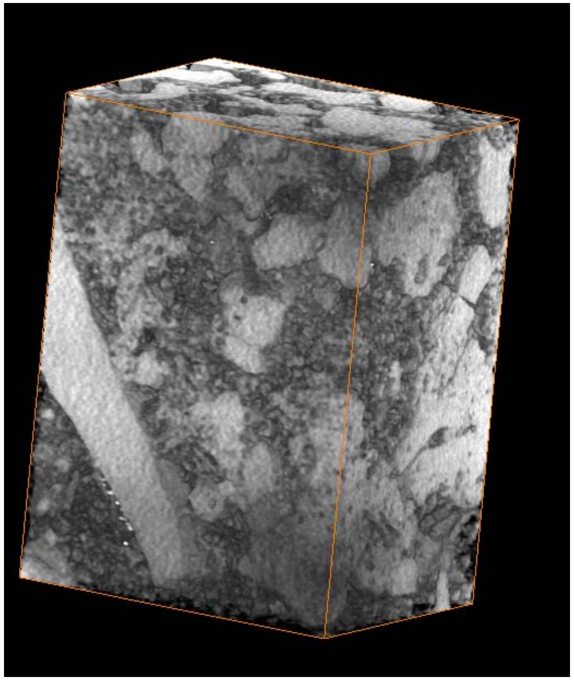
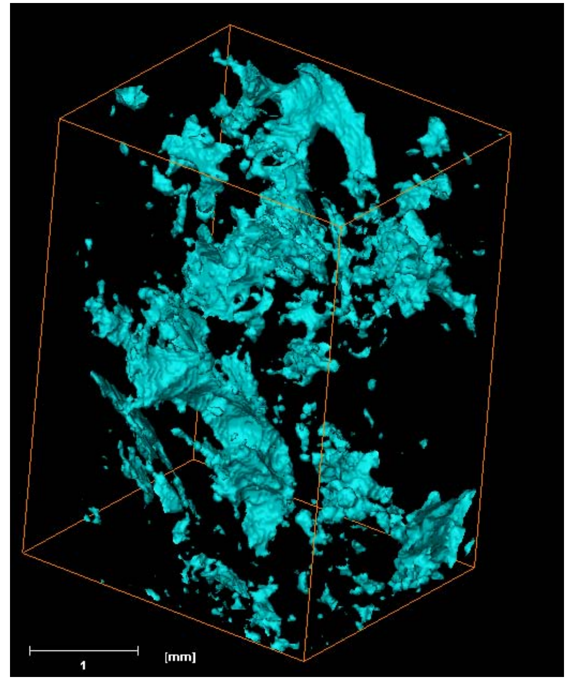
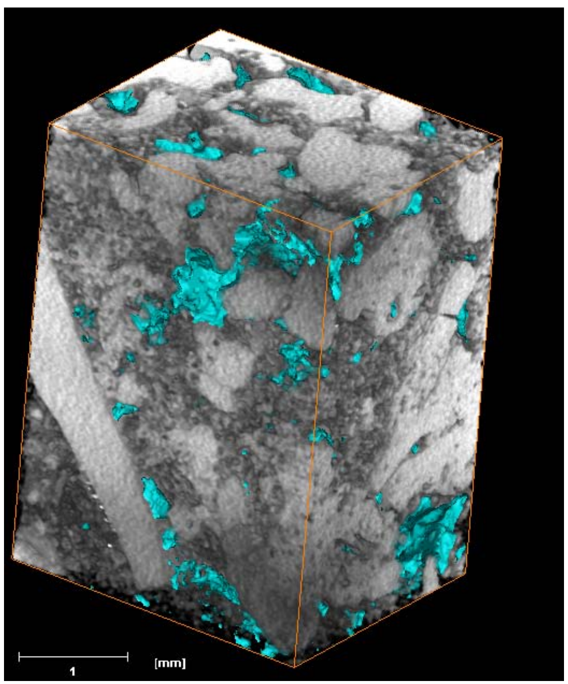
Low res vuggy porosity volume

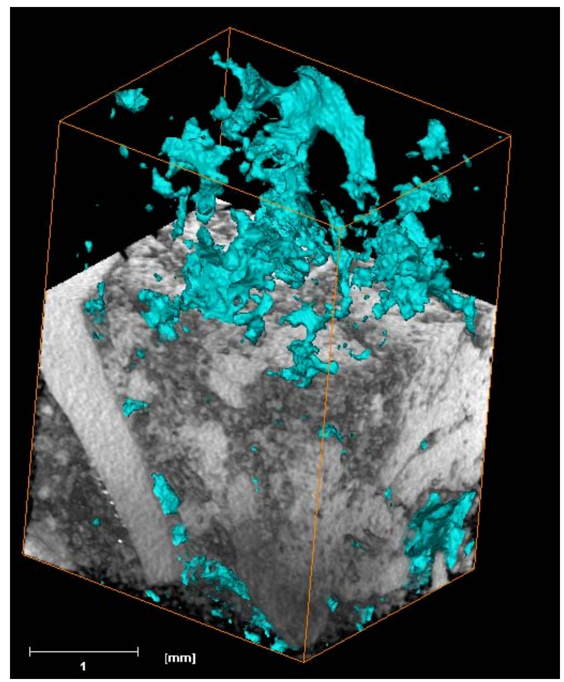




Low res vuggy large non-connected pore structure

Low res vuggy large non-connected pore structure and the calcite matrix





Low res vuggy large non-connected pore structure partially exposed above the calcite matrix

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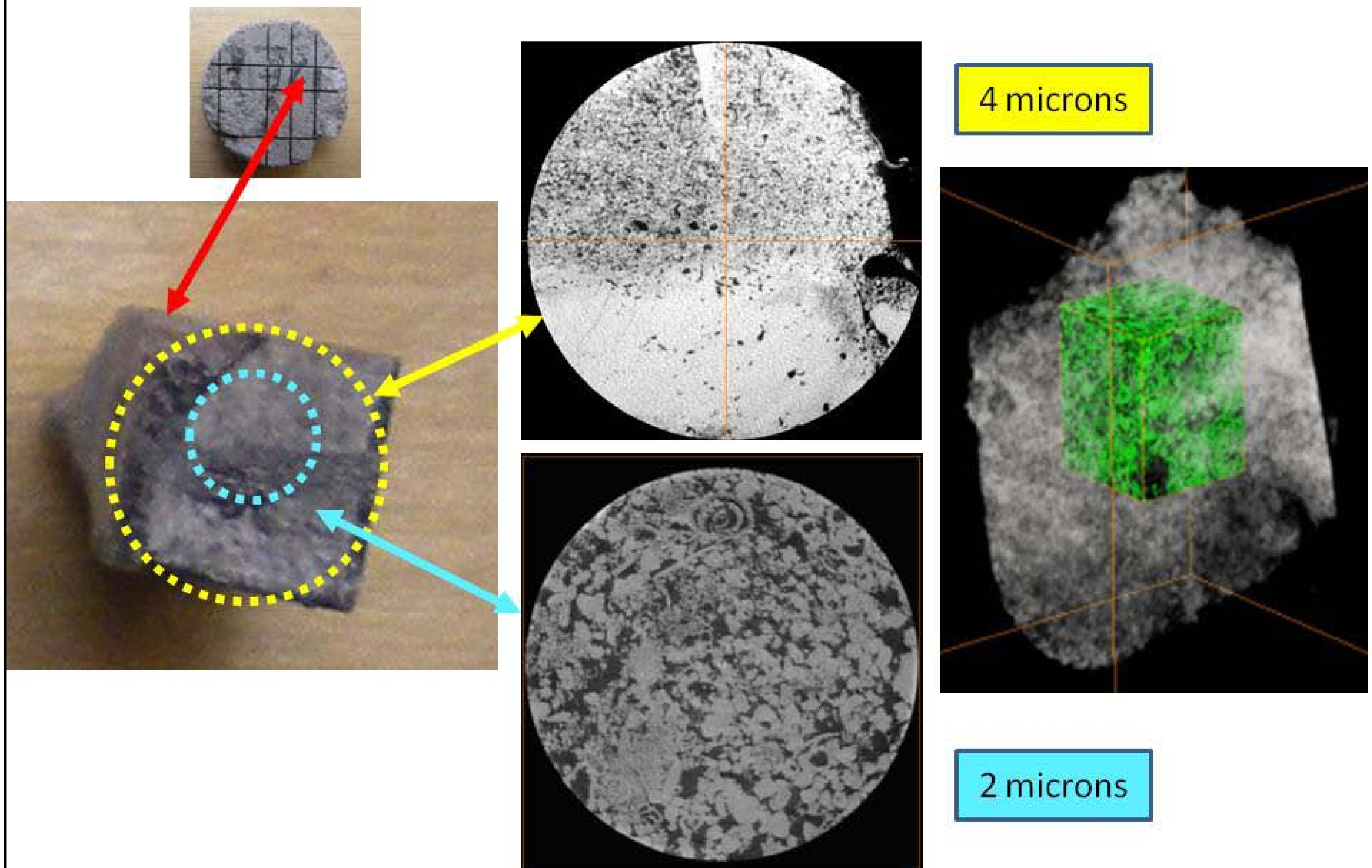
Process – granular region



Notes by Presenter: Granular region scaned at medium resolution (4 microns) as well as higher resolution (2 microns), both registered in 3D volumes on the RIGHT side.

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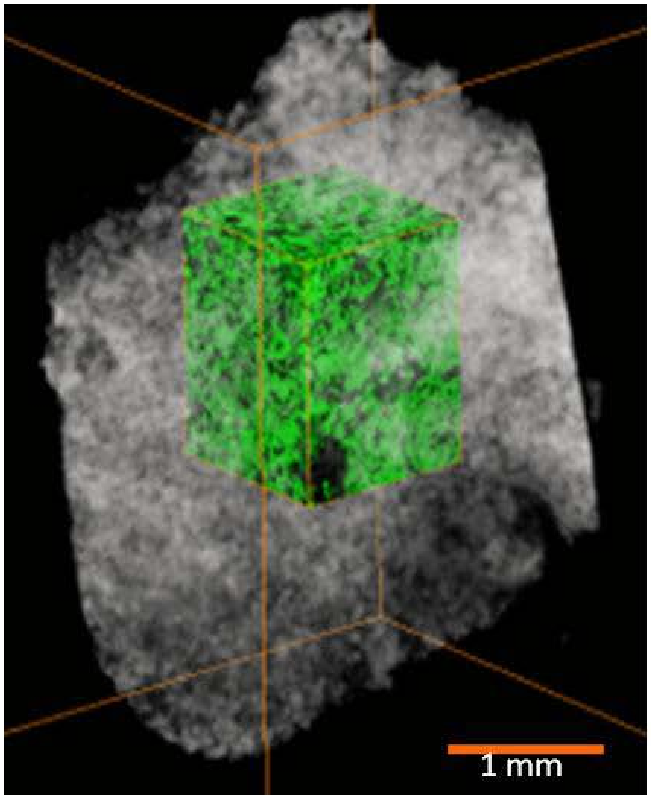
Process – granular region



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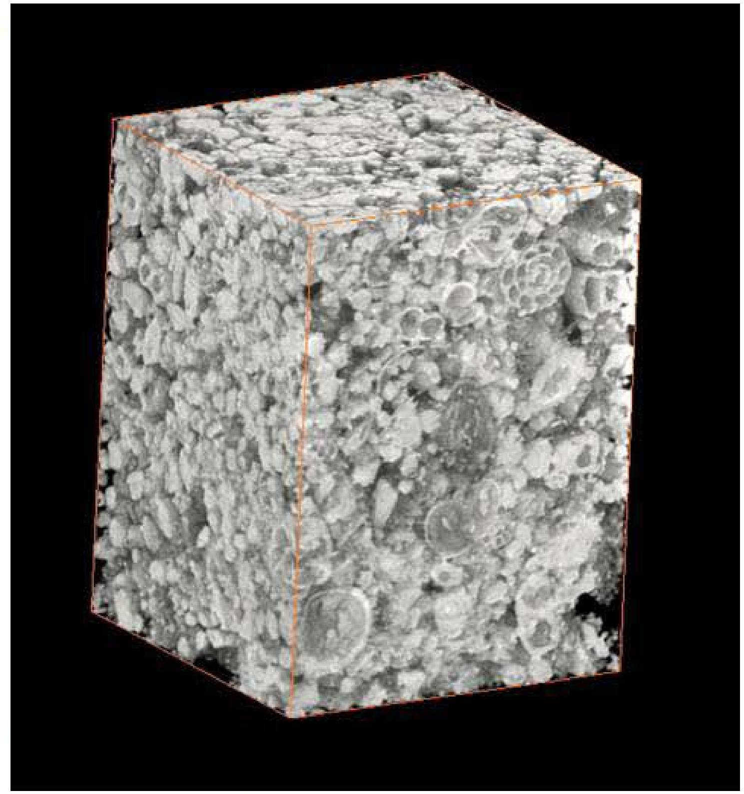

0.5 mm

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Notes by Presenter: The higher resolution image maximizes the fraction of the granular filling porosity.

Porosity and permeability results

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Granular

0.290

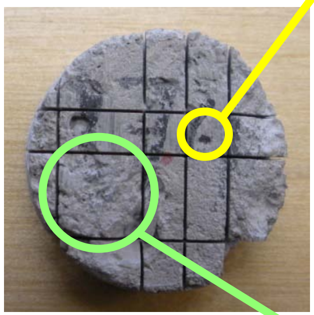
0.700

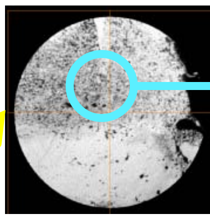
Solid large calcite material

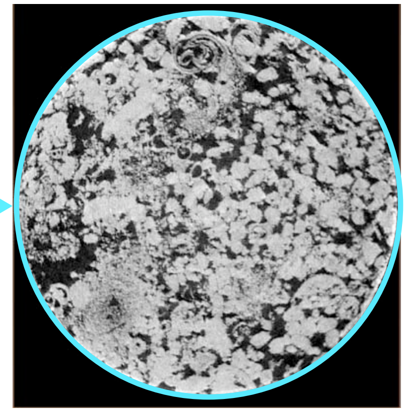
0.300

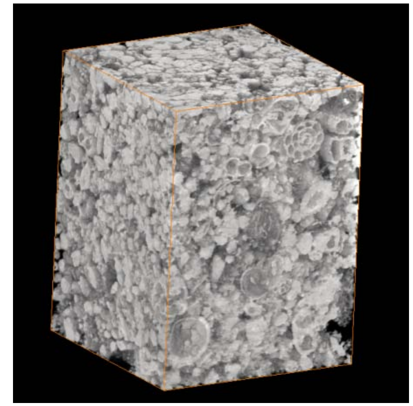
$0.700 \times 0.290 = 0.21$

High Res micro-CT (V = 2 microns)



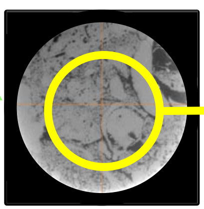


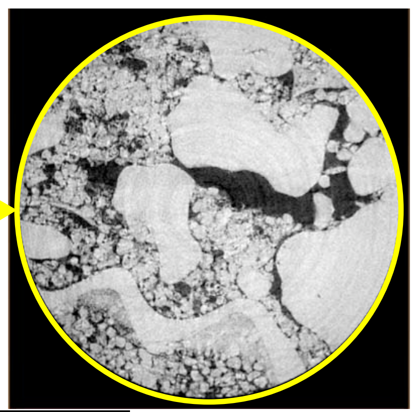


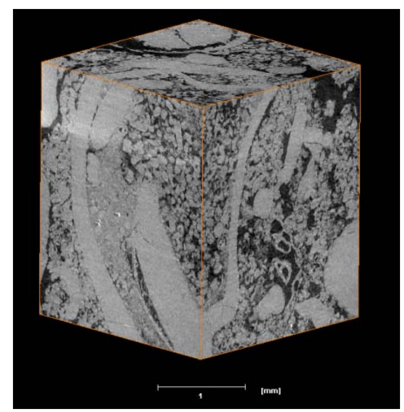


K = 1.19 D

Por = 0.21







K = 1.24 D

Por = 0.19

Medium Res micro-CT (V = 4 microns)

Solid large calcite material

0.500

Large open pores

0.065

Sparic calcite

0.435

$0.435 \times 0.290 + 0.065 = 0.19$

Notes by Presenter (for previous slide): The average porosity of the sample under study is about 20%.

The MICP data on another portion provided a porosity of 21%. The porosity of the entire plug was 25%, as determined by an external lab.

The permeabilities were calculated by using the LBM in single-phase mode. The Granular region has a perm of 1.19D, while the Vuggy volume yields a perm of 1.24D.

The total core perm from the external lab was measured at 0.44D.

Key Point: The permeability of the granular material controls the system.

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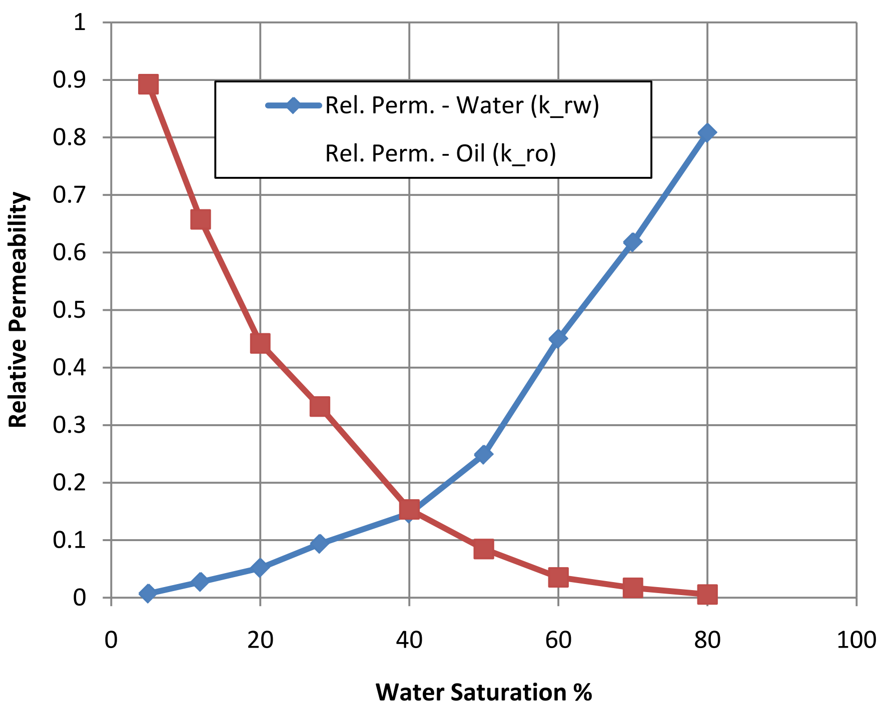
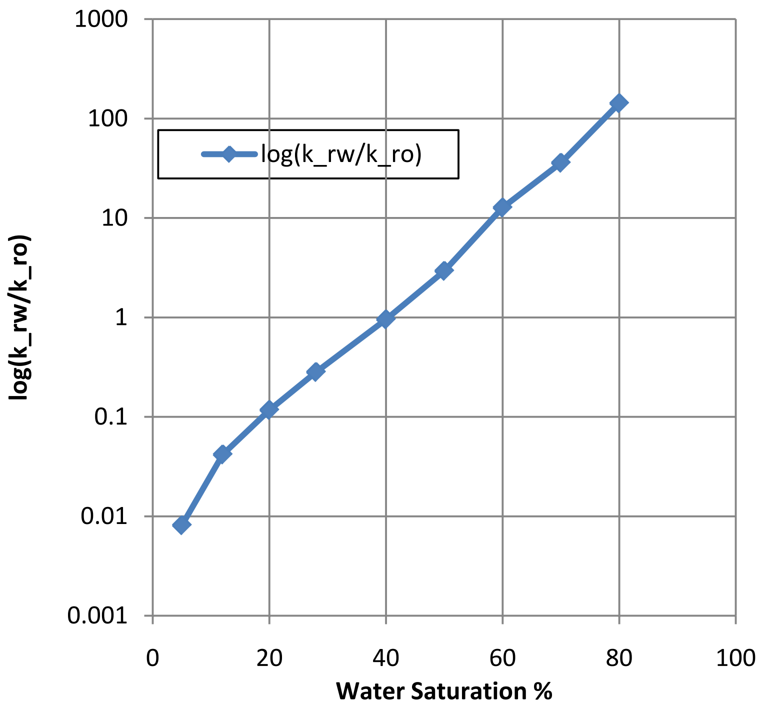
Relative Permeabilities results (For sparic volume)

Sat(water) %	kr(water)	kr(oil)	kr(water)/kr(oil)
5	0.0073	0.89	0.0081
12	0.028	0.66	0.042
20	0.052	0.44	0.12
28	0.094	0.33	0.28
40	0.15	0.15	0.95
50	0.25	0.085	2.93
60	0.45	0.035	12.7
70	0.62	0.017	35.8
80	0.81	0.0057	142.2

Relative Permeability : Viscosity Ratio 0.667/1, Interfacial Tension = 1.15 dynes/cm, CA=135 Degrees



Permeability Ratio



Notes by Presenter (for previous slide): The Granular volume was used to compute the rel perm using LBM in two-phase mode.

Reservoir fluid properties and reservoir wetting characteristics were used directly on the CT-derived pore structure, including viscosity ration, interfacial tension, and contact angle.

The relative perm curves on the LEFT, and permeability ratio curve on the RIGHT. The initial water saturation and residual oil saturation were computed through CT imaging/LBM to be 5% and 80%, vs 4% and 85% from the Client's simulation model, which used SCAL data.

Please also note that the relative perm was computed at a much fast speed than the lab measurements, in this case, less than 7 days.

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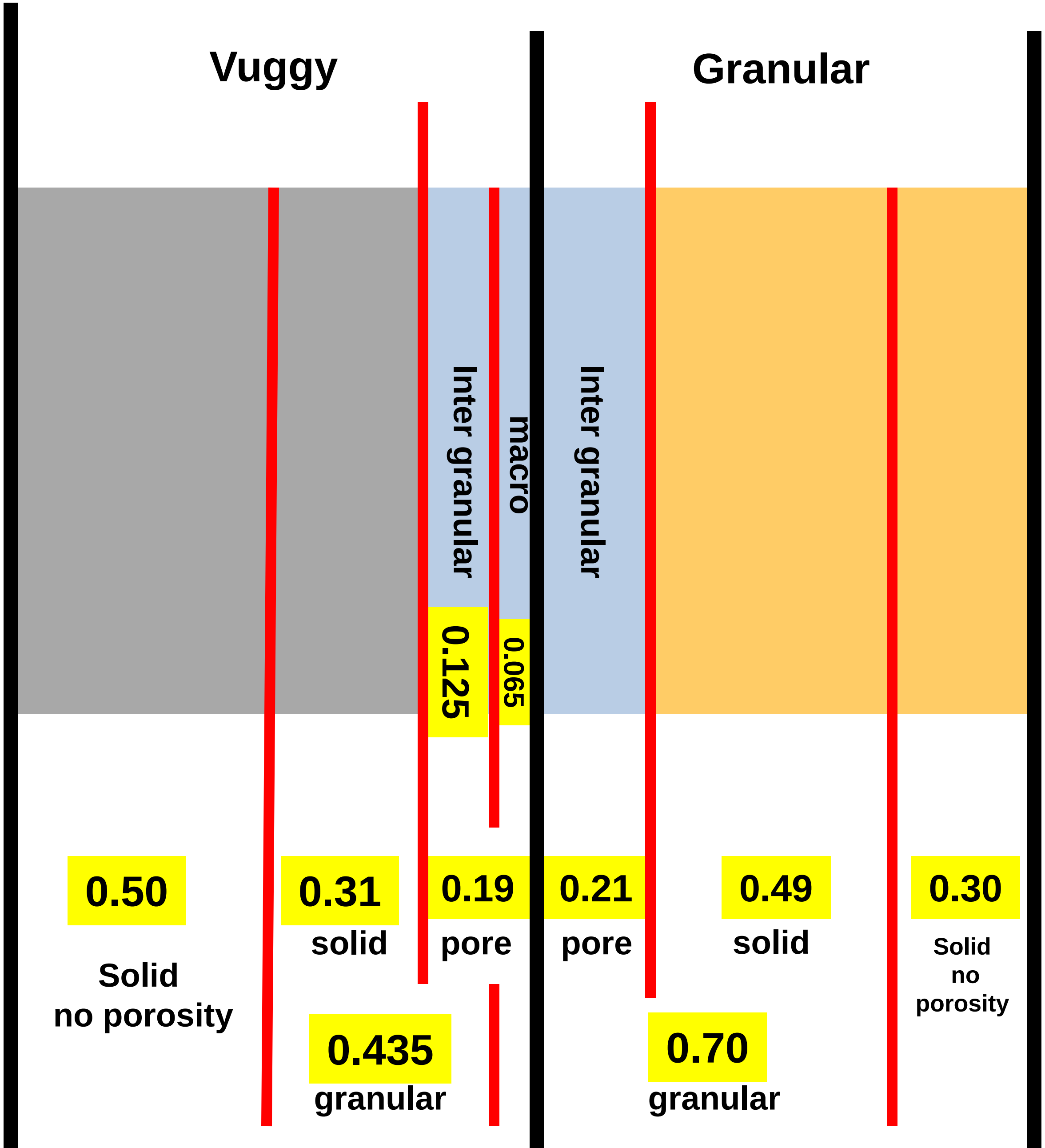
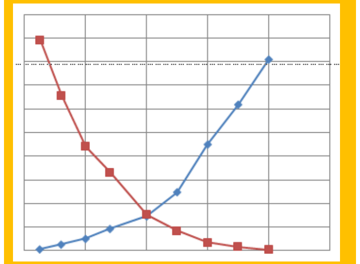
Summary



Por = 0.20

K = 1.2 D

Kr



Seven days

Notes by Presenter (for previous slide):

To summarize:

Using Core Panoscopy or multi-scale CT imaging, we are able to reliably and quickly characterize complicated carbonate rocks, better understand and QUANTIFY its multiple porosity/permeability systems, and the dominant fluid flow control features, and compute the important rock physics values.

In this case study, we distinguished the vuggy-type pore region from the granular-dominating pore region, BOTH present in the same rock sample, and calculated their porosity, permeability and relative permeability. We compute the relative perm within 7 days, while it might take several months or even longer to obtain from a traditional physical lab measurement.

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Thank You for Your Attention

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