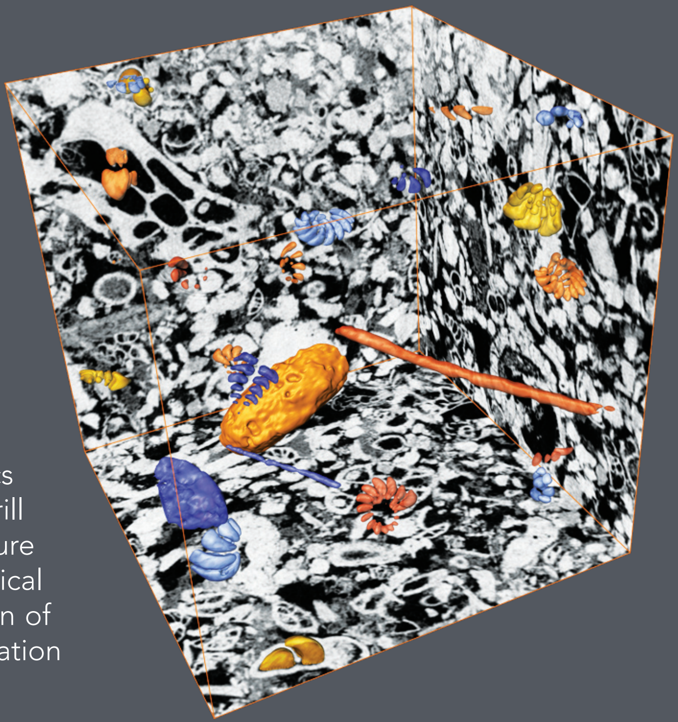
Ingrain Digital Rock Physics Lab

go digital

Ingrain's revolutionary digital rock physics lab computes the physical properties and fluid flow characteristics of oil and gas reservoir rocks. We use advanced 3D imaging to create vRock™ digital reservoir rock samples. A vRock™ is a 3D digital capture of the rock fabric, grain structure and pore-space geometry at resolutions from 1 micron down to 5 nanometers.



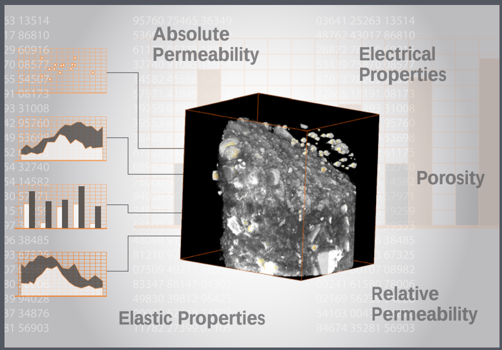
gain control

Ingrain can deliver our suite of digital rock physics measurements using sidewall cores. We can use drill cuttings where cores are not available. We measure rock properties in formation types that defeat physical core analysis methods. Ingrain can offer the option of guaranteed results in 30 days (regardless of formation type).

get the facts

Every Ingrain analysis includes

- Porosity (Vv/Vt, % total, connected and isolated)
- Permeability (mD) in three axes
- Formation factor (S/m) in three axes
- Elastic properties: Bulk modulus (K) compressional velocity (Vp), Young's modulus (E), Shear modulus(G), Shear velocity (Vs), Poisson's ratio
- Grain Statistics



At your option, we will compute two-phase relative permeability and capillary pressure. Our reports include detailed images that reveal your reservoir rocks from the inside.

invest in the future

Ingrain delivers lasting value that physical core analysis labs can't match. By investing in vRock™ digital reservoir rocks, you create assets that are available for the life of your field. Each vRock™ is safeguarded in a digital rock physics database that is available online and ready for additional analyses. This database allows for new "what if" approaches to understanding fluid flow, and creates the potential for using new rock properties computations in the future.

INGRAIN
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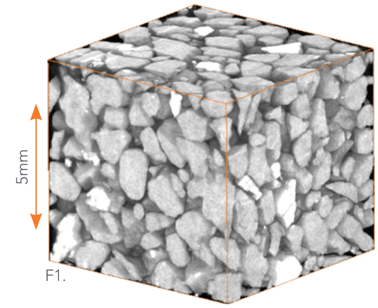
porosity

Ingrain computes porosity directly from high-resolution 3D digital images of reservoir rock samples. This calculation is the ratio of the number of voxels that fall into the pore space (black and dark-gray) to the total number of voxels in a 3D image.

The task of separating the pores from grains in such 3D objects is called image segmentation. The main technical challenge in image segmentation is the gradual transition from dark to light shade of gray at the edges of the pore space. Ingrain uses proprietary image-processing algorithms that include statistical analysis of the gray-scale images. As a result, the pore space is accurately separated from the mineral matrix and the porosity is computed.

F1. High-porosity sand (Porosity 0.39)



F1.

F2.

Permeability

Flux

$$\vec{k} = -\mu \frac{\vec{U}}{\nabla P}$$

Pressure head

absolute permeability

Ingrain complements and vastly expands laboratory permeability data sets by numerically simulating fluid flow through a direct digital representation of a real pore space obtained by high-resolution 3D imaging. Such imaging and simulations can be rapidly and massively conducted on physical samples of irregular shapes and sizes that are impossible to handle in the physical laboratory.

The absolute permeability is computed in a manner analogous to a laboratory measurement: a pressure head or body force is directly applied to a digital sample. The resulting fluid flux is then computed and permeability is calculated according to the Darcy's equation.

F2. Darcy's equation and definition of permeability

electrical conductivity

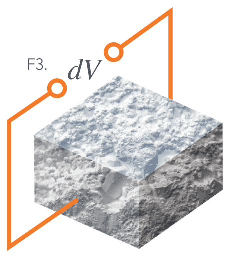
Ingrain uses the finite element method (FEM) to solve the Laplace equation for the electric potential field inside a digital sample for a specified potential difference at the boundaries.

The electrical current field in the pores is computed and then summed-up to obtain the total current through the sample. The effective conductivity of the sample is simply the ratio of this current to the potential drop per unit length.

F3. Electrical potential applied to a tight sandstone digital sample

F4. FEM solves the Laplace equation in complex pore space

F3.



F4. Electrical potential

$$\nabla(\sigma \nabla V) = 0$$

Local conductivity

F5.

Compressional modulus

Shear modulus

$$M = K + \frac{4}{3} G$$

Bulk modulus

elastic properties

Ingrain determines elastic moduli by simulating a static deformation experiment on a 3D digital rock sample.

The application of stresses to the faces of the sample generates strains in the rock frame that are computed locally using the finite element method (FEM). The resulting effective deformations of the sample are related to the stresses applied at the boundaries to calculate the effective elastic moduli. This application assumes linear elasticity laws are valid within the sample. Therefore, the elastic moduli thus obtained can be converted into the elastic-wave velocities.

F5. FEM is used to compute the effective bulk and shear moduli of a digital sample

relative permeability

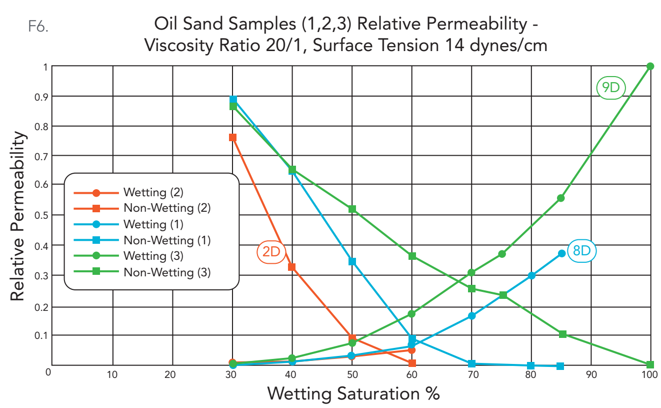
Relative permeability is the ratio of effective permeability of a particular fluid at a particular saturation to the absolute permeability of that fluid at total saturation.

Ingrain simulates the slow multiphase viscous flow needed for relative permeability estimates using the lattice Boltzmann method (LBM). LBM mathematically mimics the equations of multiphase viscous flow by treating the fluid as a set of particles with certain interaction rules between the particles belonging to the same fluid, different fluids, and the fluids and pore walls.

LBM directly simulates static and dynamic configurations of the contacts between the fluid phases and the pore walls by taking into account surface tension and contact angles. It allows for the estimation of irreducible water and hydrocarbon saturations.

F6. Relative permeability curves in oil sand samples

F6.



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