

Digital rock physics analysis in complex carbonates

Using CT scanners and specialized image processing, a pilot project delivered accurate special core analysis in about an eighth of the time required for physical test results.

■ ZUBAIR KALAM and TAHA AL DAYYANI, Abu Dhabi Company for Onshore Oil Operations; AVRAMI GRADER and CARL SISK, Ingrain

Initiatives by Abu Dhabi Company for Onshore Oil Operations (ADCO) to increase hydrocarbon recovery from its existing fields require the capability to quickly and accurately conduct reservoir simulations to evaluate different scenarios for improving oil recovery. These numerical simulations require input parameters such as relative permeabilities, capillary pressures, and other rock and fluid porosity-versus-permeability trends. These parameters are typically derived from special core analysis (SCAL) tests. Laboratories have traditionally provided SCAL through experiments conducted on core plugs. Depending on a number of variables, SCAL experiments can take a year or longer to complete and often are not carried out under in-situ reservoir conditions with live reservoir fluids.

With the goals of improving the quality and reducing the turnaround time of SCAL data on its complex carbonate formations, ADCO conducted a pilot study of a suite of cores using Ingrain's digital rock physics (DRP) technology to determine SCAL and petrophysical parameters. DRP uses specially designed computerized tomography (CT) scanners and image processing (typically called "segmentation") to create a highly accurate 3D digital rock sample, which the company refers to as a "vRock." Numerical simulations are then performed on each digital rock sample to compute SCAL and petrophysical properties.

The chosen core samples were obtained from a prolific but mature onshore oil-producing carbonate reservoir in Abu Dhabi, United Arab Emirates. Physical SCAL tests were initially conducted on core samples comprising different reservoir rock types with varying levels of heterogeneity. These SCAL lab tests formed the baseline for later comparisons with SCAL results using digital rock physics. Several of these same core samples were used in the DRP study to evaluate water-oil relative permeabilities, capillary pressures, Archie's cementation exponents (m), Archie's saturation exponents (n), and elastic parameters such as compression and shear wave velocities.

The comparison demonstrated an overall satisfactory match between data obtained by DRP and physical lab methods. Furthermore, the digital rock physics SCAL work required three months to complete, whereas the equivalent physical tests took over two years. ADCO has concluded that DRP has the poten-

tial to significantly improve the quality and schedule of reservoir characterization studies, including assessment of petrophysical groups/reservoir rock types in carbonate formations.

MATERIALS AND METHODS

Digital rock physics investigates and calculates the physical and fluid flow properties of porous rocks. In this approach, high-resolution images of the rock's pores and mineral grains are obtained and processed, and the rock properties are evaluated by numerical simulation at the pore scale.

Comparisons between the rock properties obtained by DRP studies and those obtained by other means (laboratory SCAL tests, wireline logs, well tests, etc.) are important to validate this new technology and use the results it provides with confidence.

Characterization of core samples. The blind validation study was conducted on core plugs representing four Lower Cretaceous carbonate reservoir rock types (RRTs), as defined by the operator. The RRT definition was based mainly on the sample's porosity, permeability and mercury injection capillary pressure measurements. This characterization was also linked to a standardized ADCO lithofacies description and assumed environment of deposition.

Four RRTs are described below, using some of the core plugs, classified by porosity and permeability, for illustrative purposes.

RRT-2. Samples S9 and S18 are examples of coated-grain, algal, skeletal rudstone to floatstone (CgASR) lithofacies. The measured porosity for S9 was 32%, and the water permeability was 164 mD. For S18, the measured porosity was 30% and the water permeability was 240 mD. The CgASR lithofacies implies deposition in a shallow sub-tidal, high-energy open platform above fair-weather wave base, upper ramp, near shoal crest.

RRT-3. Samples S14 and S21 were examples of skeletal, peloid grainstone (SPG) lithofacies. The measured porosity for S14 was 27%, and the permeability was 47 mD. For S21, the measured porosity was 32.5% and the permeability was 57 mD. The SPG lithofacies implies deposition in a shallow sub-tidal to intertidal, high-energy open platform above fair-weather wave base, possibly upper ramp beach, near shoal crest and near inner shoal.

RRT-4. Sample S22 was an example of skeletal, peloid packstone (SPP) lithofacies. The measured porosity for this plug was 35.2%, and the water permeability was 21.8 mD. The SPP lithofacies implies deposition in shallow sub-tidal to intertidal, moderate-energy restricted and open platform above fair-weather wave base, possibly inner shoal and upper ramp.

RRT-6. Sample S33 was an example of orbitolinid, skeletal wackestone (OSW) lithofacies. The measured porosity for this plug was 24.3%, and the water permeability was only 0.82 mD. The OSW lithofacies implies deposition in low-energy, open platform below fair-weather wave base, possibly middle ramp.

Fig. 1. a) A single 4-mm CT slice showing pores and calcite, with total sample porosity of 22.6%. b) A 1-mm 3D cube showing porosity in blue. c) The full pore structure of the cube.

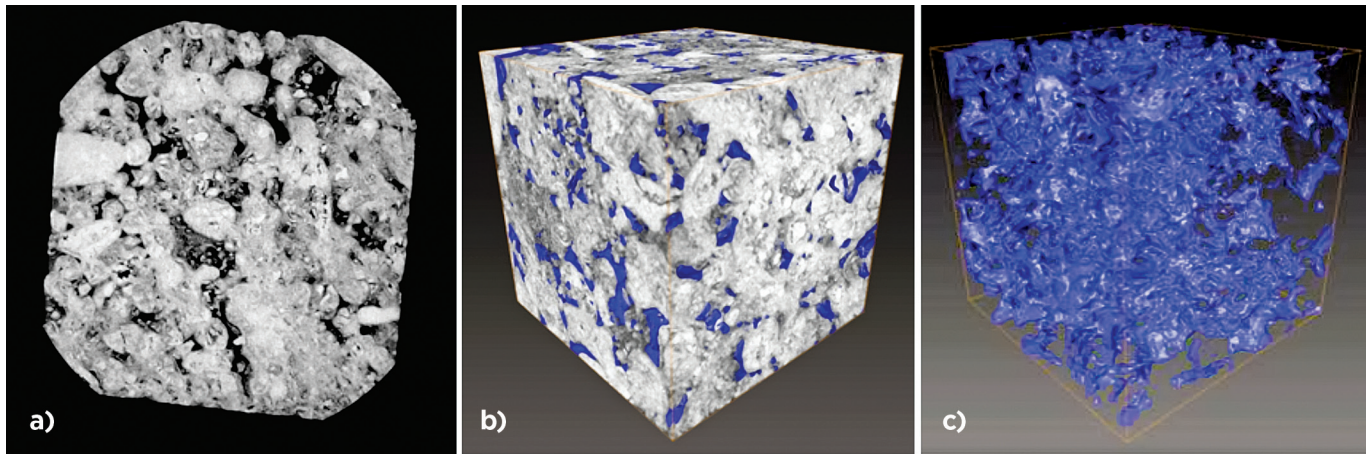
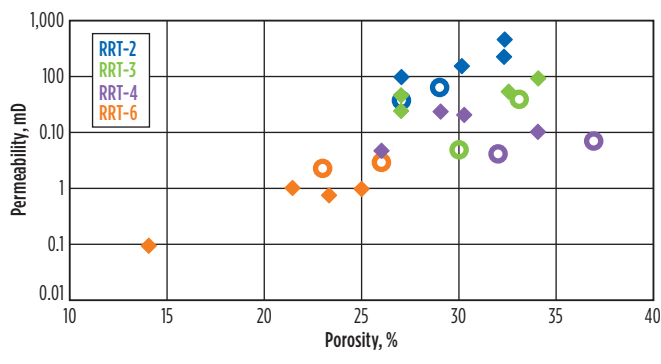


Fig. 2. Semi-log plot of permeability versus porosity resulting from lab tests (solid diamonds) and DRP (open circles). Open circles display permeability-porosity trend for RRT-6, obtained by sub-sampling the digital rocks. Different colors identify rock types.



Laboratory tests. The lab test data used in this study were accumulated by the operator in the course of several years. The tests were performed on cores from the same rock type and formation, but not necessarily on the same cores, used in the DRP study. A number of commercial and research labs were involved in testing, and they used a variety of SCAL methods, including centrifuge, porous plate, steady state and unsteady state.

Laboratory SCAL studies, especially those involving steady-state and porous plate methods, may take over two years to complete.

DRP methods. Three-dimensional digital samples were obtained using X-ray CT with resolutions ranging from 100 nm to 40 μm . The digital samples were processed (segmented) to identify locations in the rock occupied by various minerals and pores. The result of this process is a segmented digital rock—i.e., a 3D matrix of the same size as the CT image, where each cell is either a solid or a pore, and is assigned elastic properties and conductivity accordingly to the mineral or fluid occupying the corresponding location in the rock sample. **Figure 1** shows a) a sample 2D slice, and a 3D cube showing b) porosity in blue and c) the pore structure itself.

The lattice Boltzmann method (LBM) was used to simulate the laminar flow of single or multiple fluids through the digital rock.¹ The 3D pore structure defined by high-resolution CT im-

aging forms the grid system for using the LBM method to compute fluid transport properties: absolute permeabilities, relative permeabilities and capillary pressures. The capillary pressure simulations also provide fluid (e.g., oil/water) distributions throughout the digital rock, which are then used to assign conductivities to the pore cells in the course of estimating the resistivity index and determinations of Archie's saturation exponent (n). The computational parameters—including fluid viscosities, interfacial tensions and contact angles—were selected to match the experimental conditions in the lab tests. Experimental constraints such as fluid flow velocities and aging were also considered in determining two-phase oil/water relative permeabilities.

The elastic properties of the rocks were estimated from simulating small elastic deformations in the digital rock. The rock's conductivity and related formation resistivity factor, resistivity index, cementation and saturation exponents (m and n , respectively) were estimated from numerical simulation of the electric current in the rock.

RESULTS

Figure 2 compares the porosity and permeability results obtained by DRP and from lab tests. RRT-4 (orange) and RRT-6 (purple) are mainly uni-modal structures, and they form an almost continuous trend. The blue points represent RRT-2, which has a bi-modal structure and higher permeabilities than the other rock types. The total porosity of the samples included porosity that can be directly defined by the CT data and micro-porosity in the micro-crystalline (MC) phase. The porosity in the MC phase was determined either by nano-CT imaging or by linear phase segmentation of the micro-CT data. The typical contributions of micro-porosity were 50–60%, 60–70% and 70–90% of total porosity for RRT-2, RRT-4 and RRT-6, respectively. The determination of the micro-porosity phase and its properties plays a significant role in determining the elastic properties and the formation factor/resistivity index, as well as in determining original oil in place and reserve estimations.

Figure 3 compares the formation resistivity factor results obtained by DRP and from lab tests. The DRP data form a continuous trend that merges well data with lab data, which are not for the same samples used in the DRP studies. In some lab tests, resistivity factors were not measured. **Figure 4** compares

Table 1. Cementation exponent m values

Rock type	Lab min.	Lab max.	DRP avg.
RRT-2	1.96	2.21	1.99
RRT-3	1.92	2.12	1.83
RRT-4	1.89	2.07	1.75
RRT-6	1.77	2.15	2.01

Table 2. Saturation exponent n values

Rock type	Lab min.	Lab max.	DRP avg.
RRT-2	1.88	2.09	1.95
RRT-3	1.91	2.07	2.45
RRT-4	1.87	1.98	2.10
RRT-6	1.54	1.75	2.74

the resistivity index results obtained by DRP and from lab tests, demonstrating a reasonable match. Moreover, the trend for the micritic samples of RRT-6 shows a good match even along the changing n value (related to the slope of the curve through the data) at lower saturation. **Tables 1 and 2** compare the DRP and lab SCAL results for m and n , respectively. The high value for the DRP RRT-6 value stems from the draining of the micritic phase in a capillary process, which increases the resistivity of the sample and the value of n . Drainage of the micritic phase may not have been complete in the experimental case.

The cementation exponent m was computed by obtaining the formation factor and the porosity of several digital rock samples from the same plug. The effect of the saturated micro-porosity on the formation factor was taken into account by assigning a specific conductivity to the micro-porous phase based on either direct DRP computations on the samples in the study, or by using comparable DRP data from other samples from similar Middle East carbonates. The saturation (drainage) exponent n was determined by computing the formation factor for several saturation maps obtained during the primary drainage capillary pressure DRP simulation and generating diagrams. Only saturation maps in which the oil had arrived at the outlet end of the sample were used in the computation of n . In the case of a bimodal structure, such as in RRT-2, the combined drainage capillary pressure (P_c) data (micro- and macro-porosities) were used.

No lab tests of compression (V_p) and shear (V_s) velocities were performed on the cores included in this study. For comparisons (**Fig. 5**), we used the values obtained from lab tests on cores from the same and adjacent wells, as well as values from a published study of velocities in carbonate outcrops (green triangles and diamonds).² The velocity values provided by DRP agree well, in general, with those obtained in the lab tests conducted under reservoir conditions. The dynamic elastic moduli (not shown) calculated from these velocities are also in good agreement with the lab data.

The comparisons of relative permeability values obtained by DRP and conventional lab SCAL tests are presented in **Fig. 6**, for each of the four rock types considered. In all cases, relative permeabilities were scaled by relative permeability to oil (K_{ro}) at irreducible water saturation, and all DRP-derived relative permeabilities were computed at imbibition steady-state conditions. The DRP data overlay reasonably well with the lab SCAL data.

Figure 7 (for RRT-4) shows that the drainage capillary pressure is controlled by macro-porosity. The residual water saturation at the end of primary drainage is between 8% and 12%. The lab results are on the same rock type (RRT-4) but different core plugs. All the lab results approach a similar range

Fig. 3. Formation resistivity factor/porosity results from lab tests (solid diamonds) and DRP (open circles).

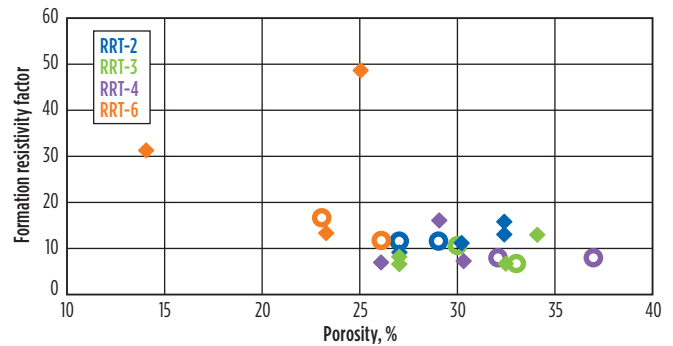


Fig. 4. Resistivity index/water saturation trends resulting from lab tests (solid diamonds) and DRP (open circles).

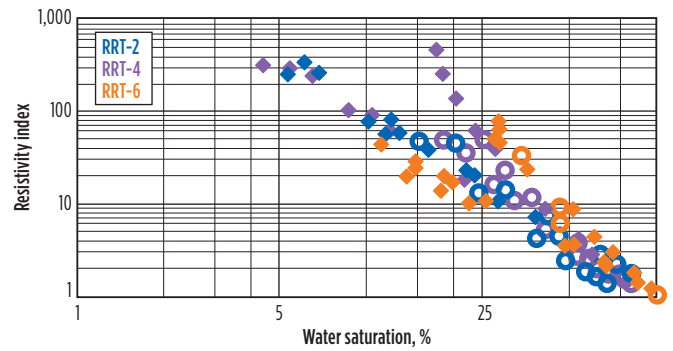
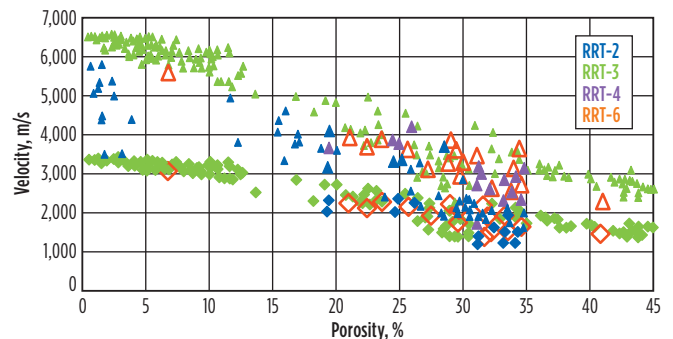


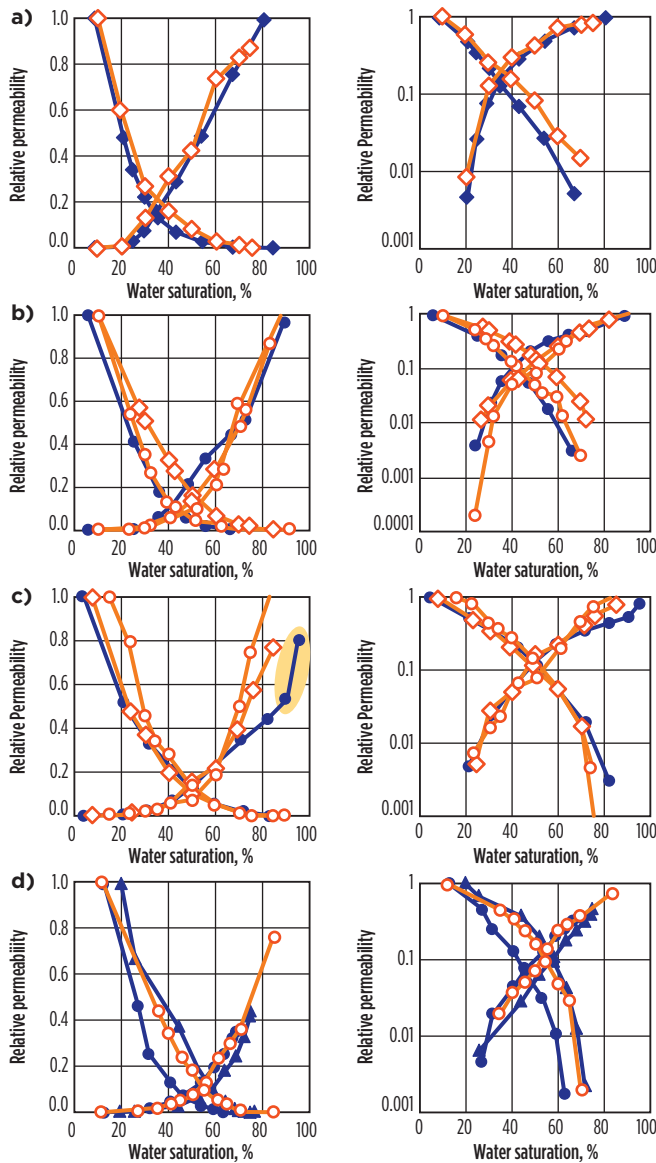
Fig. 5. Pressure and shear velocity/porosity trends. Diamonds represent V_s values; triangles, V_p . Open symbols represent DRP results, while solid symbols represent lab tests at different effective stress conditions (ambient, 7 MPa, 30 MPa and 44 MPa). The small green triangles are data that were collected for carbonate outcrops.



of residual water saturation. The uppermost curve (open diamonds) represents a tight portion of the sample and exhibits a drainage plateau at a pressure of about 2 bars, after which pressure begins to drop rapidly again. It represents a small fraction of the rock bulk volume and can be added to the curve denoted by the open circles, which experiences a similar capillary pressure plateau at a lower value. There are five lab-derived capillary pressure curves for the same rock type. Four of these match the DRP curve (open circles) quite well.

The DRP work was done in three months, whereas the physical lab work took almost 24 months. DRP offers an opportunity to use dynamic data (relative permeability and capillary

Fig. 6. Cartesian (left) and semi-log plots of relative permeability curves for a) RRT-2, sample S9, b) RRT-3, c) RRT-4, sample 22 (orange diamonds) and sample 1V (orange circles), and d) RRT-6. Open orange symbols represent DRP results; solid black symbols represent results of steady-state lab testing on a composite core of the same rock type. For RRT-4, the yellow oval denotes injection-rate bumping at the end of waterflooding.

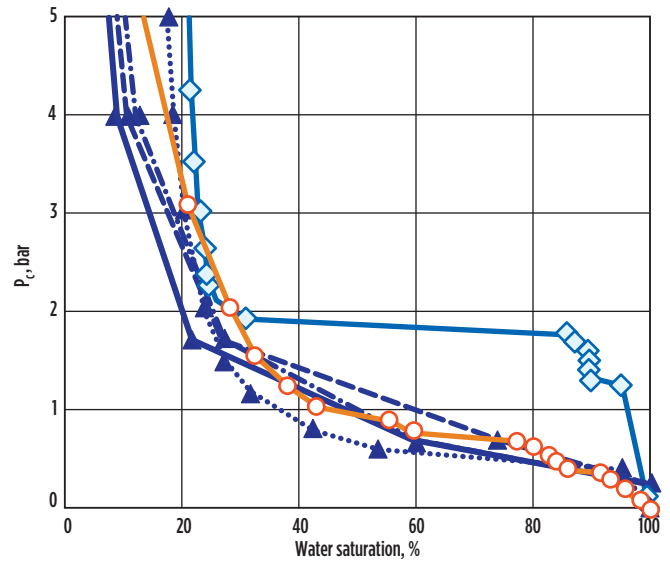


pressure resistivity index) in early rock typing procedures and provide essential data for reservoir simulation about one year earlier than current laboratory methods.

CONCLUSIONS

The DRP validation study presented in this article describes the first substantial work involving carbonate reservoir rock types. This technology is a breakthrough for oil and gas companies that need large volumes of accurate results faster than the current SCAL labs can normally deliver. Operators can use this information as input to numerical reservoir simulators, fracture design programs, investigation of pressure transient analysis and other reservoir characterization tools, which will improve reserve forecasts, production rate forecasts, well placement

Fig. 7. Drainage capillary pressure data resulting from lab tests (solid symbols) and DRP (open symbols) for RRT-4. Orange circles show macro-porosity response with relatively flat capillary pressure at a high value. Blue diamonds show micritic response with a high value of relatively flat capillary pressure.



and completion designs. The information can also help operators evaluate options for improved oil recovery, with sensitivity analysis of various options considering the actual pore scale rock fabric of each reservoir zone. [W/O](#)

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ZUBAIR KALAM is a Discipline Expert in special core analysis for Abu Dhabi Company for Onshore Oil Operations, with 25 years of petroleum industry experience. After completing his BSc and PhD degrees at the University of Manchester and post-doctoral research at the University of Oxford, he joined BP, where he was involved in novel core analysis research involving nuclear magnetic resonance and magnetic resonance imaging, as well as single-phase and multiphase fluid flow. / mkalam@adco.ae

TAHA AL DAYYANI is a Senior Carbonate Reservoir Development Geologist for ADCO. He earned a BS degree in geology from United Arab Emirates University in 1999. Mr. Dayyani's expertise extends to operational geology and geosteering, reservoir characterization and static modeling. / taldayyani@adco.ae

AVRAMI GRADER, Chief Scientist for Ingrain, is an expert on multiphase flow in porous media and formerly a professor at the Pennsylvania State University. He has provided consulting services in the field of X-ray CT imaging and image processing and analysis in Germany, Brazil and the US. Dr. Grader holds a PhD in petroleum engineering from Stanford University. / grader@ingrainrocks.com

CARL SISK, Chief Reservoir Engineer for Ingrain, is an expert in numerical simulation of oil and gas reservoirs. After 32 years of combined service with Amoco/BP, Sisk joined Ingrain in June 2009, where he is heavily involved in the upscaling aspects of digital rock physics and is a member of the management team. / sisk@ingrainrocks.com