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A Review of Petrophysical Challenges in Pre-Salt Carbonate Rocks Requiring Sympathy, Synergy and Synthesis*

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Search and Discovery Article #70364 (2018)**
Posted October 1, 2018

*Adapted from extended abstract based on oral presentation given at AAPG 2018 Annual Convention & Exhibition, Salt Lake City, Utah, United States, May 20-23, 2018
 DOI:10.1306/70364Corbett2018

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Abstract

Reservoir quality in Pre-salt carbonate rocks from the South Atlantic is of major importance. These deposits, largely discovered in the last decade, are characterised by several petrophysical challenges, as might be expected with any carbonate reservoir, but also compounded by relatively little industry experience with non-marine, essentially lacustrine, carbonate facies. Drawing largely on outcrop analogue materials and the limited publications, we have investigated several key issues that we wish to emphasize here:

- Understanding of how pore topology affects the porosity-permeability relationships, rock typing schemes and resistivity pathways. We illustrate this in series of plug-scale measurements of coquinas (one of the Pre-salt reservoir facies, Barremian Age) with combination of resistivity index measurements, micro-CT and numerical pore scale models. Resistivity anisotropy is documented.
- The role of representative volume scale in the rocks that demands consideration of what scale/volume should be measured and associated upscaling challenges as these volumes change. This can be illustrated by consideration of the coquina and shrub facies (another of the Pre-salt reservoir facies, Aptian Age) examples incorporating outcrop scale models and running flow simulation to calculate effective metre-scale properties.
- How variability of rock types is present in single beds over the metre-scale, as illustrated by NMR measurements on coquina plug data and assessing the relative contributions of macro-, meso-, microporosity – microporosity appears to be a minor component of these rocks.
- Evidence for metre-scale lateral variability of Pre-salt coquina facies and modelling the impact at the inter-well scale.
- Comparison of effective well test permeability with permeabilities averaged from core plug data (across various Pre-salt carbonate facies) and from various models for permeability prediction from logs quantifies the importance of ‘missing’ permeabilities in statistically under-sampled (by plugs), highly heterogeneous, rocks.

Several studies have been conducted over the last few years by the authors and co-workers leading to insights that are relevant to the understanding the variation of reservoir properties in these highly heterogeneous reservoir facies. We emphasise the need for sympathy with the petrophysical challenges, and synergy between different measurements (i.e., scale of measurements) and subsurface disciplines and the need for careful synthesis of all geological and engineering data, as it is possible and cost-effective to obtain, in order to predict reservoir performance.

The Sympathy, Synergy, Synthesis Mantra

This was introduced by Sir Patrick Geddes (1854-1932) who is widely credited as the founder of environmentalism and civic planning and for such sayings as "Think Global, Act Local". He started out as a botanist (after a period studying geology under Huxley) and ended up as Professor of Sociology and Civics having worked to break down interdisciplinary barriers all his life. His "three bird" mantra "Sympathy, Synergy and Synthesis" is used in Urban Planning to address a similarly complex challenges as those presented (albeit in a different context) in the characterisation of carbonate reservoirs.

Sympathy

The fluid in a reservoir will flow where it is easiest to go. This is not always clear in carbonate reservoirs – in clastics this tends to be between the grains and the pore throats are clearly defined. In carbonates, any science or engineering approach to their study has to have sympathy with the fluid. It would seem likely that carbonate petrographers, because of the nature of the material they deal with, have more sympathy with the rock than the fluid. Herlinger et al. (2017) note the connectivity of porosity at the thin section scale through diagenetic processes and its impact on permeability.

To illustrate this paradox, we describe the study of a single coquina sample from the Morro do Chaves Formation (Barremian, Sergipe-Alagoas Basin, E Brazilian Continental Margin) to give us an understanding of how complex pore topology effects the porosity-permeability relationships, rock typing schemes and resistivity pathways. A series of plug-scale measurements of coquinas with combination of resistivity index measurements, micro-CT and numerical pore scale models (Figure 1). Resistivity anisotropy is documented (Corbett et al., 2017). This suggested the flow through these core plugs was being controlled by a critical pore or group of pores.

As well as understanding the critical pore throat, there is role of representative volume scale in the rocks that demands consideration of what scale/volume should be measured and associated upscaling challenges as these volumes change. This can be illustrated by consideration of both coquina and shrub facies examples incorporating outcrop scale models and running flow simulation to calculate effective metre-scale flow properties. If the rock has holes (pores, moulds, vugs, caverns) that are so big that core plugs are impossible to recover and measure, the fluid will seek these out, in preference to the rock and find pathways that can be sampled in core and in the lab. There is a well-documented 'missing' permeability data issue in Pre-salt carbonates (de Jesus et al., 2016) where well test permeability is higher than core plug data.

Synergy

This is often defined as the output of individuals working in a team is greater than the sum of the individual efforts. This is often assumed in the subsurface to mean that teams of geologists, petrophysicists, geophysicists and engineers will also produce “better” models of the reservoir than any working on their own. How do the disciplines decide if the model is useful in answering relevant questions. This can be done in many ways by the different disciplines. To the geologist, does the model look like more-familiar and better-exposed analogues. For Pre-salt rocks in the South Atlantic, the Morro de Chaves Formation (Cretaceous coquinas), Shark Bay (Holocene coquinas and stromatolites) and Yacoraite Formation (Paleocene stromatolites, Salta Basin, Argentina) are considered suitable analogues (e.g., Kinoshita, 2010; Terra, 2012; Corbett et al., 2016). Shrub facies are believed to be of microbial for some workers (q.v. Dias, 2005) whereas others believe they are strongly influenced by chemical precipitates, and tend to go for travertine analogues (q.v. Wright and Barnett, 2015; Claes et al., 2017). Carbonate reservoirs usually have tectonic overprints, so structural geologists are looking for faulted/fractured analogues (viz. Crato Formation, Aptian, onshore NE Brazil, cf. Catto et al., 2015; Santos et al., 2017). For the petrophysicist, the comparison might be more in the realm of porosity–permeability cross plots or rock types present in analogues and subsurface reservoirs. For the reservoir engineer the match to production or well test data from the fields in question will be important.

We consider various aspects of Morro de Chaves Fm., Shark Bay, Yacoraite Fm. and Crato Fm. analogues, along with comparisons with the petrophysical data of the Pre-salt, and the well test signatures from simulation models and the subsurface, to consider what might be the appropriate ‘best model’ for fluid flow in Pre-salt reservoirs. In the Morro de Chaves Formation, variability of rock types is present in single beds over the meter-scale, as illustrated by NMR measurements on coquina plug data (Luna et al., 2016).

The relative contributions of macro-, meso-, and microporosity (microporosity appearing to be a minor component of these rocks) are apparent over short distances (Figure 2). Evidence for metre-scale lateral variability of Pre-salt coquina facies was also observed in the permeability data (“low permeability” coquina with average 17.5 mD and “high permeability”, 240 mD) from outcrop in the Morro do Chaves Fm. (whilst the porosity data is relatively uniform, 13–15.6%) (Corbett et al., 2016). The Holocene coquinas of Shark Bay show fabric heterogeneities that can be used to modelling the impact of coquina fabrics at the inter-well scale. The connectivity will be constrained by the lower permeability facies (Figure 3) where the connectivity is poor and the effective permeability of the system will lie between the geometric average and the harmonic average (Corbett et al., 2016).

Synthesis

Subsurface teams are required to synthesize all the data at their disposal to produce a series of believable subsurface model. How to they do this when, essentially “All models are wrong, but some are useful”. If all the information can come together in a single preferred model(s) then these models should perhaps be considered the most useful. A model derived from the data on the ground (“Place, Work, Folk” was another Geddesian mantra) rather than one from somewhere else (Geddes’ civic model for Mumbai was based on what he encountered already in Mumbai rather than involving pre-existing European models) should be preferred.

We consider a model that combines information from analogues, and data from the subsurface to indicate how a stratigraphically constrained, fault-related diagenetic model might be appropriate for consideration. Limited subsurface data is available to our team, so this model cannot be used to explain all fluid flow phenomena experienced in the Pre-salt. However, we put forward a “three pronged” model as a useful approach to tackling the problem. The complexities of depositional model(s) for Pre-salt rocks, the diagenetic changes particularly in relationship to dissolution episodes that allow fluid movement through these rocks, and the depositional/diagenetic/structural frameworks that are required to provide useful models for the long-term recovery and optimization of hydrocarbon field development.

A well test from the Pre-salt in Brazil shows 110 mD from a radial flow period (Figure 4). The arithmetic average of the core data over the same intervals is 21 mD (between 11 mD and 30 mD allowing for statistical sufficiency). Clearly there is a significant mismatch and this is termed “missing permeability” reflecting the ability of fluid to find higher permeability pathways, if they exist. Usually in carbonates, this mismatch is explained by the presence of fractures. However, in this case, the well test response (Figure 4) shows no evidence for fractures (see for comparison a fractured carbonate well test from carbonate in Brazil described in Nogueira et al., 2013).

So what could give rise to the higher permeability – simply better quality rock that has not been sampled in the core? Consideration of a laminated carbonate system at outcrop, the Crato Fm (Figure 5) shows how lateral, layer-bounded, fault-related dissolution occurs in layered carbonates, probably reacting to subtle primary variations in permeability in the layers. This process may be invoked to explain the missing permeability in our subsurface example. The outcrop based models (Figure 3) for the ‘matrix’ suggests that the effective permeability should be between the geometric and harmonic average (1.3 and 0.005 mD respectively, in this case). With these permeabilities the well would not be flowing!

Comparison of effective well test permeability with permeabilities averaged from core plug data (across various pre-salt carbonate facies) and from various models for permeability prediction from logs quantifies the importance of ‘missing’ permeabilities in statistically under-sampled (by plugs), highly heterogeneous, rocks. Using the well test data (which does not see major fractures) and a permeability prediction from image log data, we can identify the location and magnitude of the missing permeabilities. Image logs show dissolution and this can be invoked to explain the well test/core plug differences.

Conclusions

Understanding connectivity at the pore, bed, tectonic scale is key to understanding permeability pathways and effective permeabilities in complex carbonate reservoirs found in Pre-Salt reservoirs and analogues. A geological model combining the key analogues (i.e., depositional, diagenetic and structural aspects) is proposed. This current model, based on very limited data, is a stratigraphic/structural controlled dissolution model. Taking team-working models from other disciplines tackling cross-disciplinary, complex problems might be the key to unlocking the ultimate potential of Pre-Salt hydrocarbon reservoirs

Acknowledgements

Thank you to Petrobras and Shell for permission to publish this worked that has been funded and inspired by them. Particular thanks to Jorge André Braz (Petrobras) who introduced Patrick Corbett to the Crato Formation with colleagues from the Federal University of Rio Grande do Norte (Brazil).

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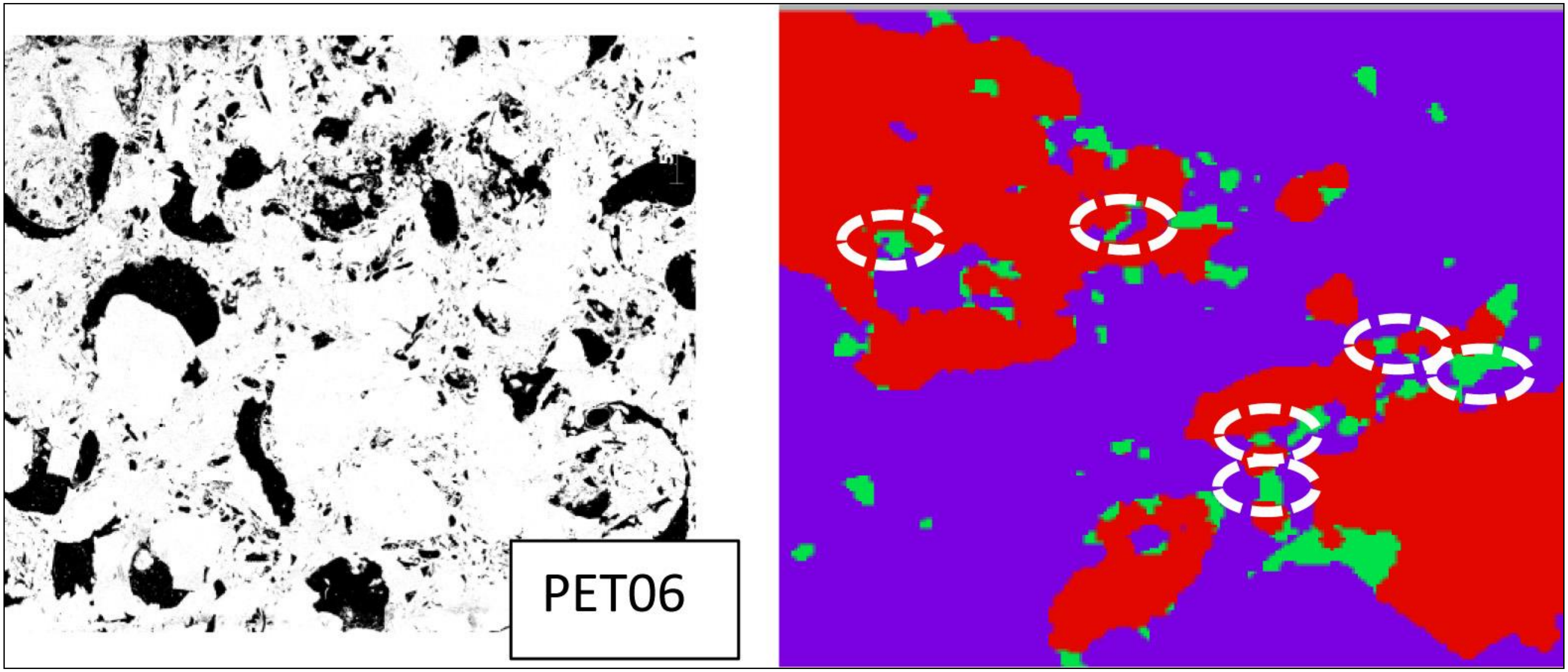


Figure 1. Porosity at the pore scale. Image from a coquina sample and an analysis of critical pore connectivity (the circled pores) in a coquina sample from the Morro do Chaves Formation (Barremian, Sergipe-Alagoas Basin, E Brazilian Continental Margin). (Sample PET 6; 10.23 µm/pixel size; porosity of 19.87%; refer to Corbett et al., 2017).

Figure 2. Pore distribution from a short NMR profile in the Morro do Chaves Fm (from De Luna et al., 2016).

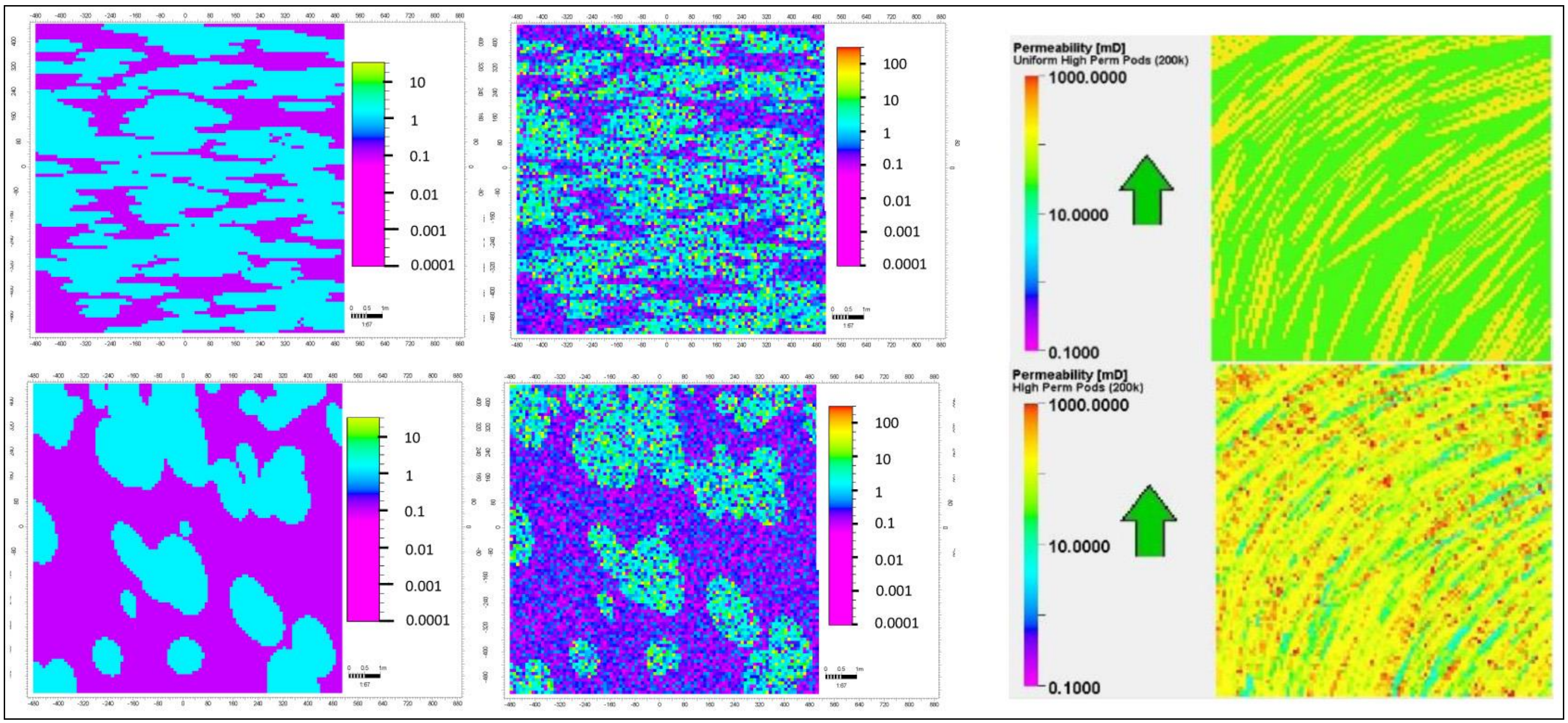
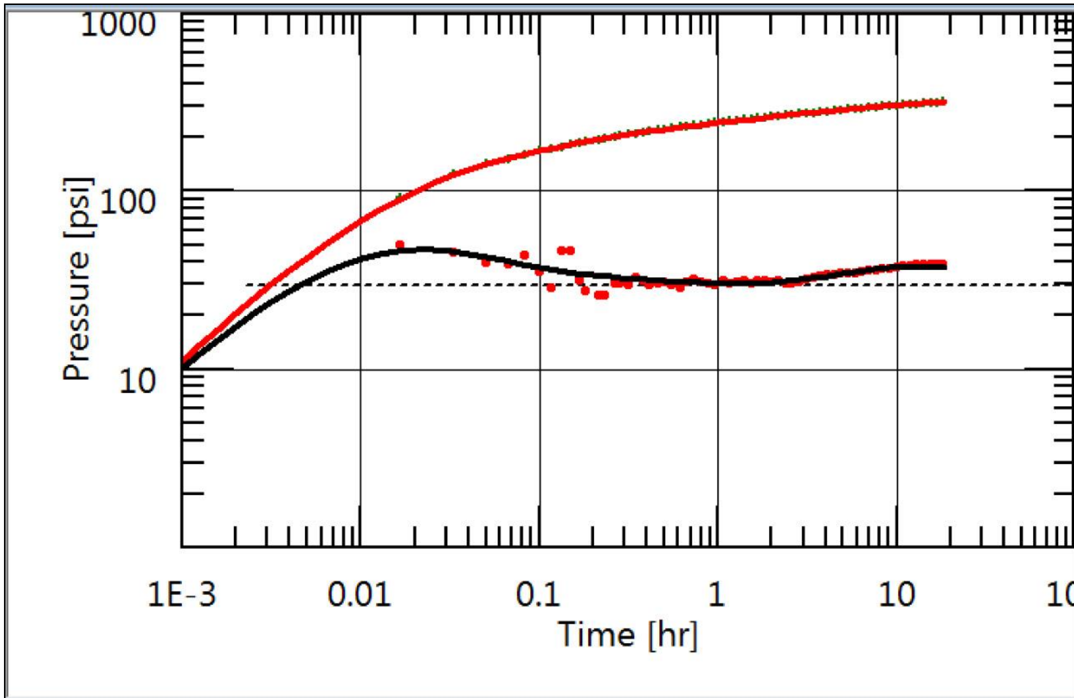


Figure 3. Permeability models at the decametre to kilometre scale. Left: Areal views of permeability models for stromatolites system based on Shark Bay and Yacoraite Fm. analogues (Rattanakit, 2016). Right: Permeability models of a coquina bank from Shark Bay analogue (arrows refer to increasing permeability, Corbett et al., 2017). Critical facies are those one that lie between the stomatolite build-ups or the coquina higher-permeability lenses.



Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	Leaky fault
TMatch	220 [hr]-1
PMatch	0.0169 [psia]-1
C	0.0366 bbl/psi
Total Skin	-3.84
k.h, total	13700 md.ft
k, average	116 md
Pi	7558.396796 psia
C	0.0366 bbl/psi
Skin	-3.84
Pi	7558.396796 psia
k.h	13700 md.ft
k	116 md
L	1730 ft
Leakage	0.539139
Delta P (Total Skin)	-227.8165517 psi
Delta P Ratio (Total Skin)	-0.7241919309 Fraction

Figure 4. Well test interpretation of a carbonate section from the Pre-salt offshore Brazil. It shows radial flow with 116 mD permeability. There is no evidence for finite/infinite conductivity or double porosity fracture signatures.

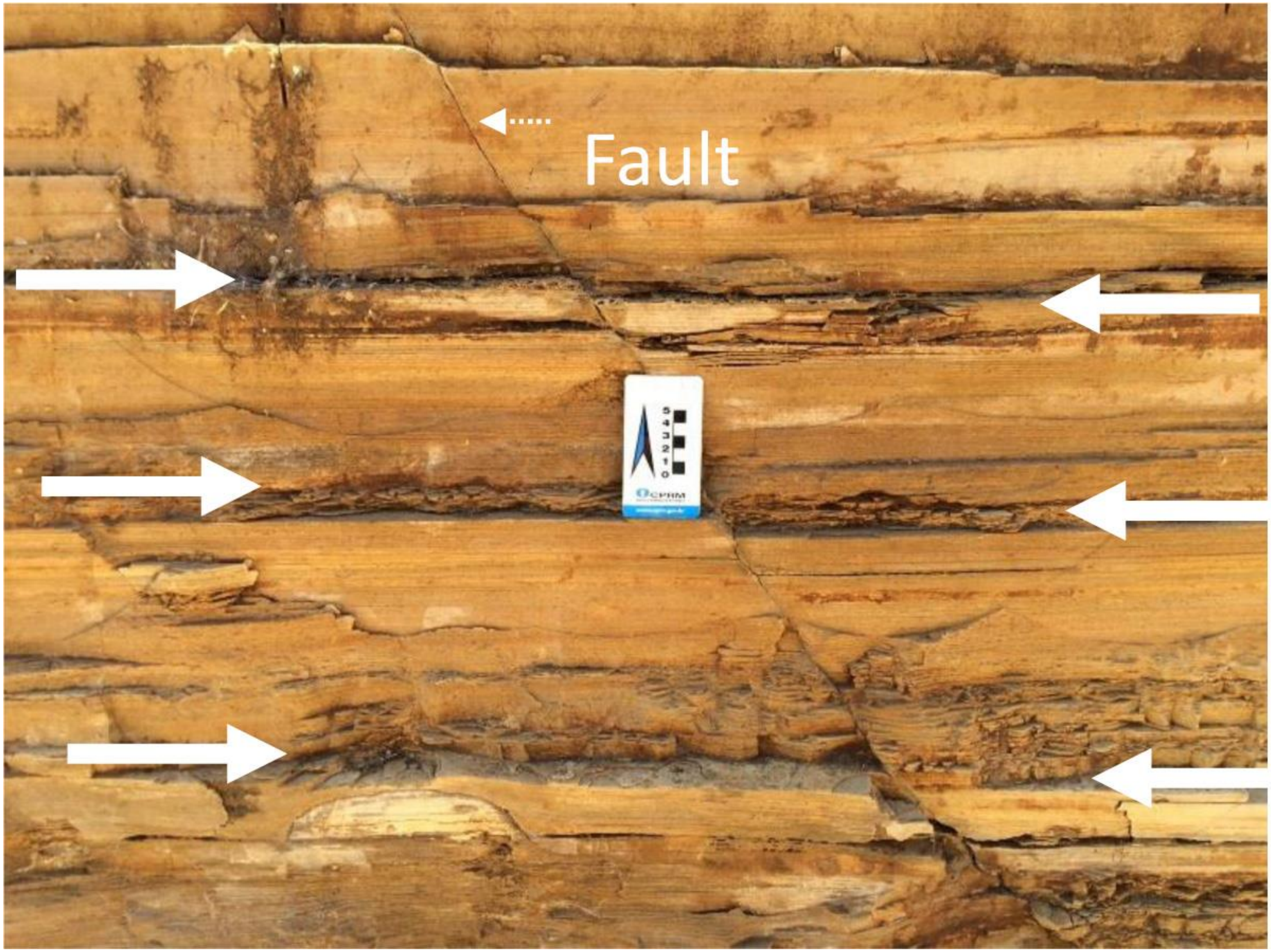


Figure 5. Outcrop of the Crato Formation (Aptian, Araripe basin, onshore, NE Brazil) showing layer-bounded, fault-related dissolution in laminated mudstone/marl couples.