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Reservoir petrofacies: a tool for quality characterization and prediction

Abstract

The intrinsic quality of petroleum reservoirs (porosity, permeability) is controlled by depositional structures, textures and composition, by diagenetic processes and products (volume or intensity, habits and distribution), as well as by pore types and distribution. Reservoir petrofacies can be systematically defined by the combination of these attributes. The concept of reservoir petrofacies is useful and operational for the characterization of reservoirs and for the prediction of their quality during exploration. The determination of reservoir petrofacies is initiated by the recognition of preliminary petrofacies through a systematic description of the listed attributes in samples collected along a representative distribution, followed by recognition of the attributes with larger impact on porosity and permeability. The preliminary petrofacies are then checked against petrophysical and petrographic quantitative parameters by using statistical or neural network tools. Threshold values are defined for the influent textural and compositional attributes that constrain the significant reservoir petrofacies. Reservoir petrofacies defined by this methodology are consistent in terms of petrophysical porosity and permeability, seismic and log signatures. Consequently, they can be used for sensible calibrations and for tri-dimensional representations of the quality of reservoirs. Reservoir petrofacies can be linked to stratigraphic and structural framework parameters for the development of coherent models of reservoir quality prediction.

Introduction

The term *petrofacies* is defined in the sedimentary literature by different meanings. The dominant part of the published work defines petrofacies solely in terms of the major detrital composition of sandstones and conglomerates, related to patterns of sedimentary provenance (e.g., Stanley, 1976; Gandolfi et al, 1983; Ingersoll, 1990; Large and Ingersoll, 1997; Trop and Ridgway, 1997; Critelli and Nilsen, 2000; Hendrix, 2000; Michaelsen and Henderson, 2000; Savoy et al., 2000; Dickinson and Lawton, 2001; Marenssi et al., 2002). A few studies refer to petrofacies as the major petrographic characteristics of carbonate, evaporitic or mudrocks (e.g., Kopaska-Merkel and Friedman, 1989; Kulick and Theuerjahr, 1989; Ching and Friedman, 2000; Testa and Lugli, 2000). Even fewer studies define petrofacies solely in terms of petrophysical and log characteristics, totally detached from petrographic characterization (e.g., Watney et al., 1999; Bhattacharya et al., 2005). Our aim here is to redefine petrofacies as a concept for reservoir characterization and modeling.

The concept of reservoir petrofacies

Reservoir petrofacies are defined by the combination of specific depositional structures, textures and primary composition, with dominant diagenetic processes. The combination of primary textural and compositional aspects with specific diagenetic processes and products correspond to defined value ranges of porosity and permeability, as well as to characteristic log and seismic signatures. The concept of reservoir petrofacies is a tool for the systematic recognition of these main petrographic attributes that control the petrophysical and geophysical behaviors, what ultimately define the evaluation of rocks, rock bodies and units during petroleum exploration and production.

Method for the definition of reservoir petrofacies

The recognition of reservoir petrofacies starts with a detailed petrography of representative samples of the area/unit studied. Quantitative modal analysis by counting 300 or more points is important, but not always essential for petrofacies recognition, because in some cases the major patterns can be directly recognized through a merely qualitative description. The samples are separated into groups, first according to sedimentary structures, texture and fabric (grain size, sorting, roundness, packing and orientation). These primary attributes control the original porosity and permeability, which in some cases were not substantially modified after deposition. However, most reservoir successions show important modification of the original quality by diagenesis. Therefore, compositional attributes, such as types, volume and location of primary constituents (which directly affect the diagenetic processes), types, volume, location, habits and paragenetic relationships of diagenetic constituents and processes, and the consequent pore types, location and relationships must also be evaluated. The samples must be thus grouped considering the superposition of depositional structure/texture/fabric attributes with major primary compositional categories, and with the distribution of the most influential diagenetic processes. The attributes with larger impact on porosity and permeability are recognized, and preliminary petrofacies are assigned. The grouping of samples in the same petrofacies assumes that they display similar petrophysical behavior. A same depositional facies may correspond to several different reservoir petrofacies. For example, a facies made of the same cross-stratified, medium to coarse-grained, moderately-sorted braided-fluvial sandstones may be grouped into different petrofacies, e.g., *MetComp* rich in micaceous metamorphic rock fragments, consequently strongly compacted, *QzCem* with a more quartzose composition, but strongly cemented by quartz overgrowths, and *QzPorous* with similar composition to *QzCem* but limited cementation, and consequently porous. The reservoir petrofacies preliminary defined according to the major petrographic attributes are then checked against petrophysical and petrographic quantitative parameters, by using statistical or neural network tools. Threshold values are defined for the influential textural and compositional attributes that constrain the significant reservoir petrofacies.

Examples of reservoir petrofacies application

Uerê Formation, Devonian, Solimões Basin, N Brazil

Devonian sandstones of the Uerê Formation are important oil exploration targets in the Solimões Basin, western Brazilian Amazonia. Sharp-based, progradational sandstones, attributed to a storm-dominated shelf complex formed during an overall transgressive system tract, are overlain by Frasnian-Famennian black shales. The sandstones are very homogeneous in terms of depositional structures, texture, fabric and present-day detrital composition (subarkoses), but extremely heterogeneous in terms of reservoir quality, due to intense diagenesis. Three reservoir petrofacies were recognized, based on the packing, porosity, and types of cementation (Lima and De Ros, 2002). Petrofacies *A*, is represented by porous sandstones (>15 %; up to 28 %; Fig. 1), with porosity preservation due to the inhibition of quartz overgrowth cementation and pressure-dissolution by grain-rimming, eogenetic, microcrystalline quartz or chalcedony (Fig. 1A). Early diagenetic silica precipitation was related to the dissolution of sponge spicules, which were concentrated in storm-reworked hybrid arenites and in interbedded spiculite deposits (Lima and De Ros, 2002). Petrofacies B comprises tight (<10 % porosity), moderately quartz-cemented (< 5 %) sandstones, strongly compacted through intergranular pressure dissolution (Fig. 1B). Petrofacies C comprises moderately porous (10-15 %), conspicuously quartz-cemented (> 5 %) sandstones (Fig. 1C).

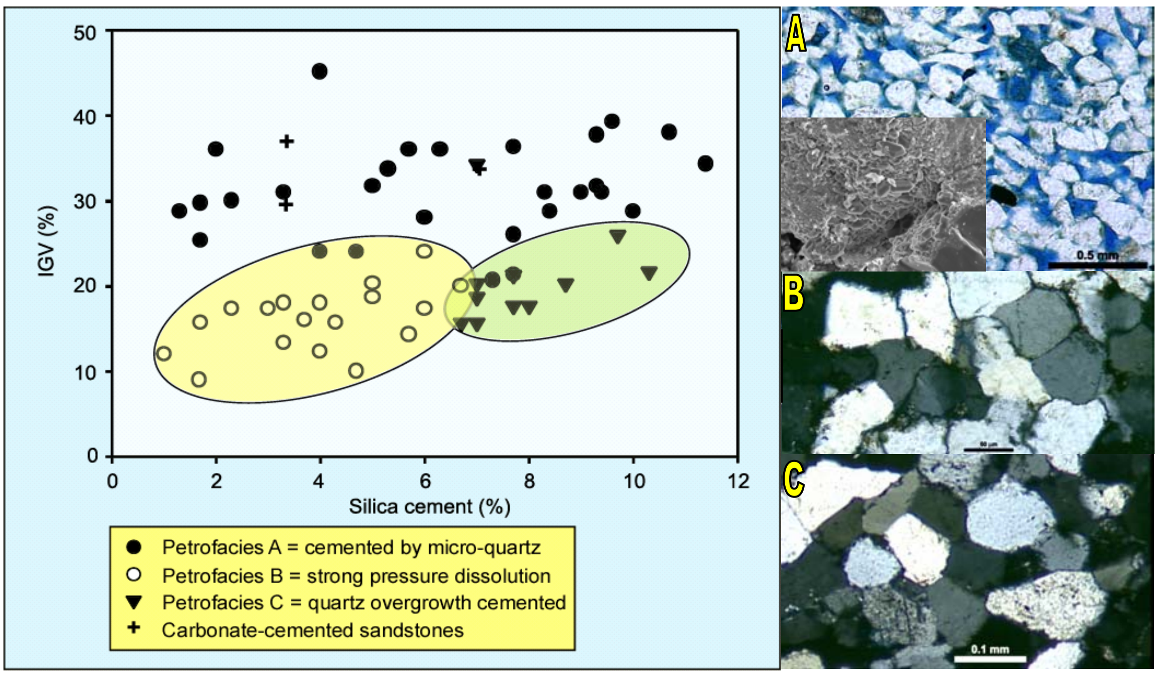

Figure 1: Reservoir petrofacies of Uerê sandstones represented in a diagram of intergranular volume x volume of silica (rims of microquartz, chalcedony and quartz overgrowths).

These petrofacies can be effectively represented in a diagram of intergranular volume *versus* volume of silica cements (Fig. 1), showing different ranges of porosity and permeability and of log parameters. Therefore, they can be used to display tri-dimensionally the quality of the Uerê reservoirs in the oilfields under development, as well as, combined with information on their burial and thermal histories, to predict the quality of equivalent reservoirs in exploration areas (Lima and De Ros, 2002).

Carapebus Formation, Campos Basin, E Brazil

Four major reservoirs petrofacies were recognized in the sandstones and sandy conglomerates of an oilfield of northern Campos Basin (Fig. 2). The sandstones were deposited by high-density turbidity currents in channelized lobe complexes. Petrofacies A comprises medium to coarse-grained, locally conglomeratic, poorly-sorted feldspathic sandstones (arkoses) and sandy conglomerates, which were pervasively cemented by pre-compaction coarsely-crystalline calcite (Fig. 2A). Consequently, their porosity is commonly obliterated totally, except for some dissolution porosity along fractures (average 3.2 %; up to 10 %) and their permeability is very low. Petrofacies B represents the best reservoirs, with good macroporosity (av. 27.7 %; up to 33.3 %) and permeability (up to 1.8 mD), comprising rocks with depositional texture, fabric and composition equivalent to Petrofacies A, but with scarce carbonate cementation, constituted more commonly by blocky to saddle dolomite. Secondary porosity due to dissolution of feldspars is common (Fig. 2B). Petrofacies C includes coarse, commonly conglomeratic, poorly-sorted sandstones and sandy conglomerates rich in mud intraclasts and carbonaceous fragments, with abundant pseudomatrix generated by the compaction of the soft intraclasts (Fig. 2C). Porosity is low (av. 12.1 %; up to 13.3 %), as is the permeability. Petrofacies D is represented by very fine to fine, well-sorted sandstones rich in micas and locally in small mud intraclasts. Macroporosity was heterogeneously reduced by the compaction (8.3 to 26.3 %; av. 18.4 %), but permeability is always low (few tens to fraction of mD). These reservoir petrofacies are easily recognized in logs, and can therefore be used to represent tri-dimensionally the quality and heterogeneity of the reservoirs in the field.

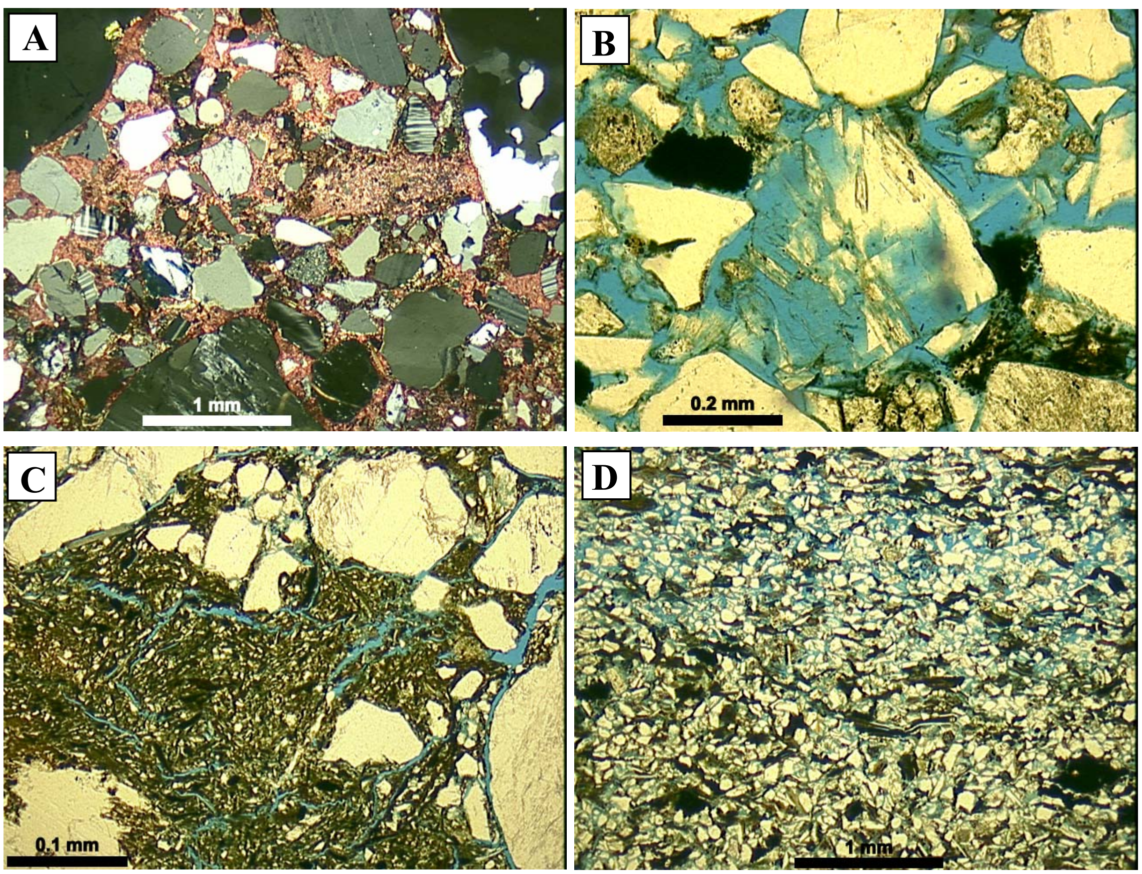

Figure 2: Main petrographic characteristics of the reservoir petrofacies of an oilfield of northern Campos Basin.

Concept Application

Reservoir petrofacies defined by this methodology are consistent in terms of petrophysical porosity and permeability, log and seismic signatures. Consequently, they can be used for calibrating the logs for realistic rock properties. The calibrated logs can then be applied to the representation in 2D sections and 3D models of the true reservoir quality and heterogeneity. Realistic reservoir models constructed through this methodology can then be used in enhanced static and flow simulations during the development and production of the oil and gas fields. Reservoir petrofacies can be consistently linked to sequence stratigraphic, provenance and/or burial history parameters for the development of coherent and operational models for the prediction of reservoir quality during hydrocarbon exploration.

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