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Critical Success Factors Identification to Develop Unconventional High Porosity Low Permeability Shallow Limestone Reservoir of Apollonia Formation, Western Desert, Egypt

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Abstract

The Apollonia reservoir is one of the unconventional highly porous and low permeability gas opportunities in Egypt that was not previously properly studied and is currently being appraised by Shell/BAPETCO. The characterization and evaluation of the Apollonia carbonate reservoir in well BED 9–3, of BED 9 field, Western Desert, Egypt was accomplished by integrating a multi-disciplinary dataset with production data to ultimately approach the key controlling indicators for future Apollonia reservoir development plans.

Critical success factors for the Apollonia reservoir development in the BED 9 field are identified and assessed by using/integrating the openhole dataset (including triple combo, borehole micro-resistivity imaging data, mineralogical data, and nuclear magnetic resonance data). This information is calibrated with core data analysis, X-ray diffraction (XRD), and petrography analysis. This study was performed throughout three primary disciplines: geological interpretation (depositional rock fabric and textural analysis, fracture analysis, diagenetic processes, pore system identification and classification, and clay typing and its effect on reservoir quality), petrophysical evaluation (fluid typing, distinguishing moveable from immovable water, and hydrocarbon saturation), and production performance data.

The Apollonia formation grades from clean chalky limestone to marl with occasional mudstone streaks, expanding on the lithofacies identification. The petrographic analysis shows that the Apollonia carbonates are generally classified as a mud-supported texture that commonly ranged between wackstone to mudstone; it also shows that reservoir properties are dominantly influenced by depositional processes, in accordance with the clearly identified original rock fabric and bioclasts with little diagenetic and fracturing influences. The pore system identification and classification shows that porosity is generally high with very poor connectivity (low permeability) in which the majority of pore spaces are microporous. The formation includes considerable amounts of smectite, kaolinite, and illite, generally identified using XRD analysis and scanning electron microscope (SEM) analysis that affect porosity and permeability.

Extending the geological and petrophysical evaluation performed over the Apollonia formation, neither natural flow nor small scale fracture jobs were efficient enough to provide for commercial production rates; consequently, BAPETCO has performed large scale foam fracturing operations to maximize the well productivity and to improve the project economics. These fracture operations were considered to be the first

successful implementations of foam fracturing in North Africa, as well as the second largest ever in terms of proppant volume. The well showed a significant improvement in productivity of more than 40 fold after the treatment. The Apollonia reservoirs in the BED 9–3 well were produced at a commercial and sustainable rate, after the reservoir properties were understood, using the optimum/convenient production job design.

The fracturing work is considered to be required as a critical success factor for the Apollonia reservoir.

Introduction

The BED 9 field of the Apollonia reservoir is a tight gas chalk field located in the central Abu El-Gharadik basin in the Western Desert of Egypt. Fig. 1 shows the field location.

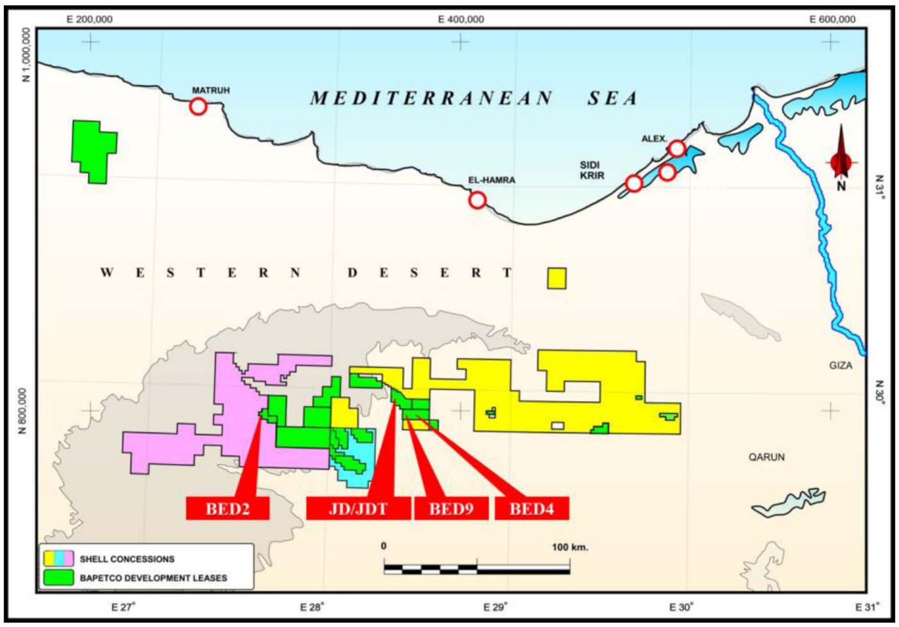

Figure 1—BAPETCO concession map showing the location of BED 9 field.

The Apollonia formation of the Paleocene-Mid Eocene age is a pelagic chalk characterized by high porosity/low permeability. It was subdivided into four members from base to top: Apollonia D, Apollonia C, Apollonia B, and Apollonia A members.

The Apollonia A and C members are composed of thick, massive limestones with thin marly streaks, and Apollonia B and D are thinner members dominated by shales, marls, and thin limestone streaks. Most of the porous intervals and hydrocarbon-bearing zones are in the Apolonia A and C members.

The generalized stratigraphic column of the Abu Gharadig basin (Fig. 2) shows that the Apollonia formation is overlain by Dabaa shale, which is considered to be an excellent top seal; this thick shale provides good sealing quality and is encountered by all wells. Stratigraphically, the Apollonia A and B members and top part of Apollonia C belong to the Middle Eocene, whereas the Lower Eocene top lies more or less in the vicinity of a top chert (or C20) interval within the Apollonia C member.

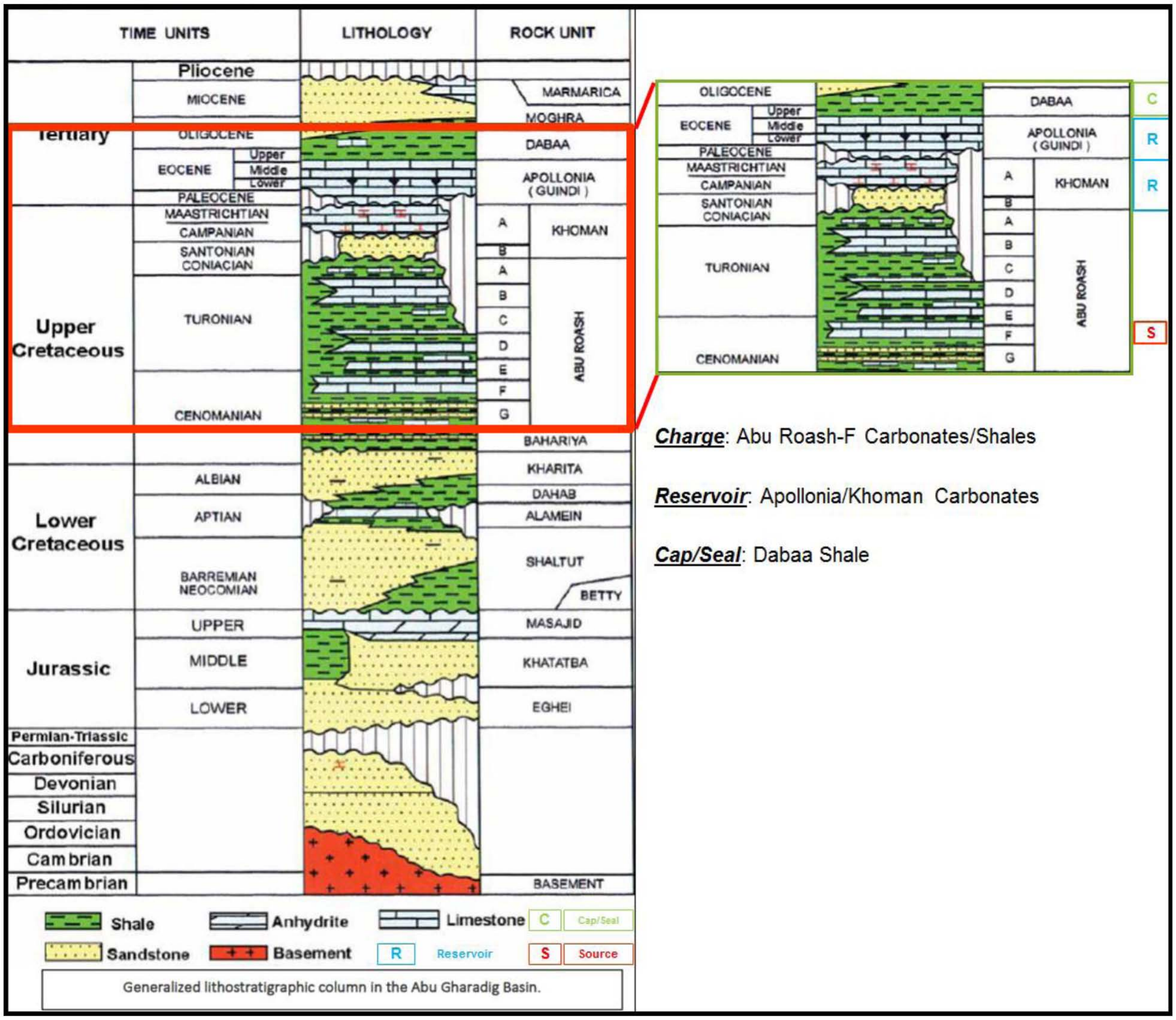

Figure 2—Generalized stratigraphic column of the Abu Gharadig basin. The enlarged frame shows the Paleocene-Eocene Apollonia formation and its stratigraphic disposition with the Late Cenomanian source rock (Abu Roash-F carbonates/shales of Late Cenomanian) and the Late Eocene-Oligocene regional seal (Dabaa shale).

BED 9–3 was a key well drilled as a vertical appraisal producer well targeting the Apollonia A and C members in BED 9 field. Integrated comprehensive suites of logs, such as sonic, NMR, borehole image, and a geochemical element tool, have been acquired to assist the geological interpretation, petrophysical evaluation, and reservoir heterogeneity identification.

Seven cores were cut in the BED 9–3 well with approximately 250 m total core length to cover the subunits in Apollonia A and C. Routine core analysis (RCA), special core analysis (SCAL), and sedimentological studies were performed on BED 9–3 cores with the primary objectives of determining initial water saturation, delineating irreducible and movable fluids, and defining the porosity type and reservoir permeability. Those results were used to calibrate wireline logs and to correlate with uncored intervals or uncored wells.

Apollonia A and C members in the BED 9–3 well were tested and fractured. The production results with the acquired data are then integrated to identify the critical controlling factors for developing the Apollonia formation.

Workflow

The workflow implemented (Fig. 3) was designed to enhance data management, inputs, outputs, and the results of each tool measurement during the Apollonia study, and to provide a more organized data integration result. The following workflow shows three primary steps that were defined to evaluate the Apollonia reservoir:

1. Perform the geological interpretation of the borehole image log and geochemical elements log, then integrate the results with core data thin section, XRD, and SEM results to define the depositional texture, rock fabric, pore system type, and clay type, and their distribution.
2. Perform the petrophysical evaluation of the Apollonia reservoir, using core calibrated standard logs and NMR data to delineate reservoir properties, such as porosity, permeability, and gas saturation, and to distinguish bound from movable fluids.
3. Assess the reservoir properties by perforation, production tests, and fracturing to determine the reservoir production performance.

The goal of including various disciplinary data in this workflow was to define the primary critical success factors that will affect the Apollonia development concept.

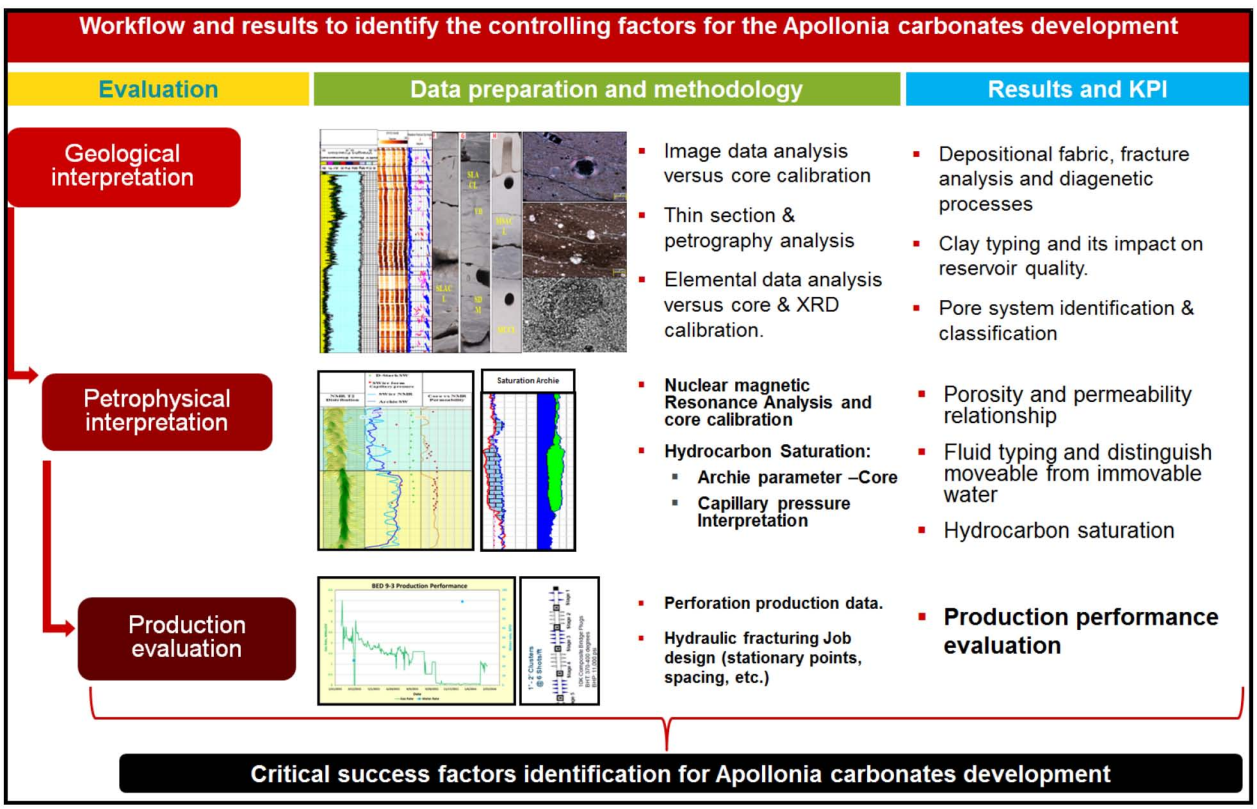

Figure 3—Workflow followed to identify the controlling factors for the Apollonia carbonates development using integrated tools and disciplines.

Geological Interpretation

Geological core description, petrographic/XRD analysis, and log analysis are preformed to explain the effects of the depositional, diagenetic rock fabric, and pore system on the Apollonia reservoir.

Carbonate classification is controlled by the depositional processes, diagenetic processes, and mechanical fracture. Carbonates can experience these three processes in various degrees; the dominance of one on another will greatly contribute to the resultant present-day rock texture, fabric, and pore-system, and will consequently affect reservoir quality.

Geological core description, petrographic analysis, and XRD results are integrated to calibrate the available openhole logs (image log and elemental data log) to ultimately appraise the effect of the rock texture, fabric, pore system, and clay types/distribution on the reservoir quality, and then characterize the carbonates of the Apollonia formation into geologically and petrophysically related sub-rock units.

The geological core description performed over the entire BED 9–3 well shows that the Apollonia formation is dominantly recognized with a chalky limestone that grades to marl with occasional mudstone. The sedimentary structures and lithological description have been identified along the studied interval. Fig. 4 shows most of the dominant lithofacies recognized.

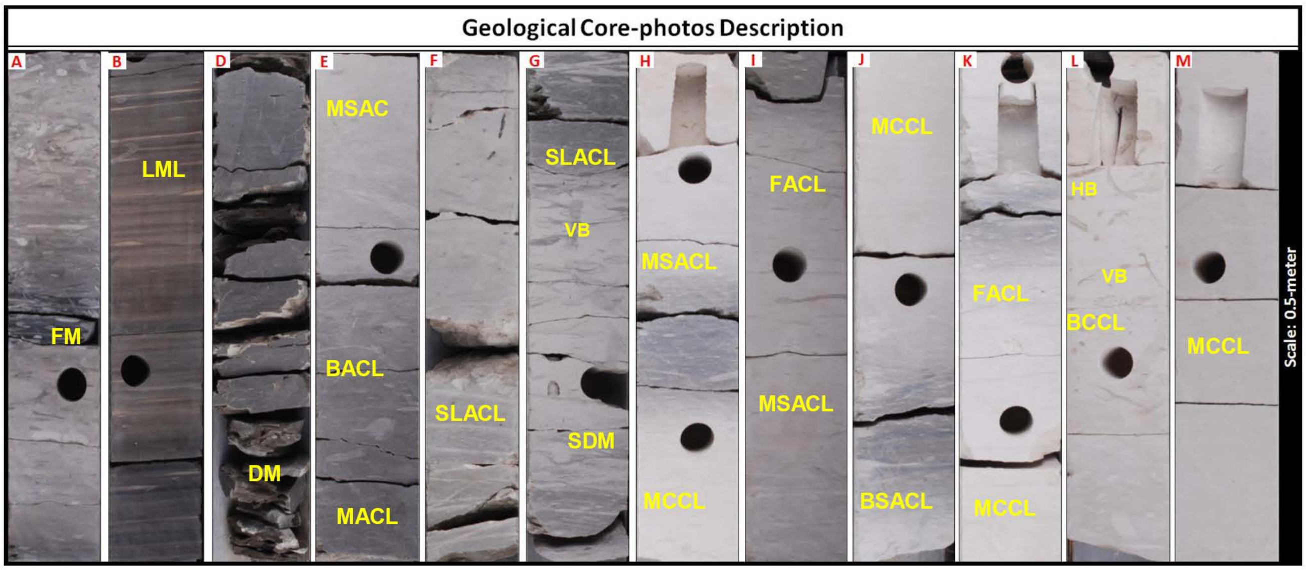

Figure 4—Representative core photos (scale 0.5 meter) of the different and most common identified lithofacies among the studied interval of Apollonia formation in well BED 9–3, where it generally grades from clean chalky limestone to marl and occasional mudstone from core-M to core-A. These photographs show various common lithofacies, including massive clean chalky limestone (MCCL), bioturbated clean chalky limestone (BCCL) with horizontal (HB) and vertical (VB) burrows, massive slightly argillaceous chalky limestone (MSACL), bioturbated slightly argillaceous chalky limestone (BSACL), massive argillaceous chalky limestone (MACL), slightly laminated argillaceous chalky limestone (SLACL), bioturbated argillaceous chalky limestone (BACL), slightly deformed argillaceous chalky limestone (SDCL), laminated lime/mudstone (LML), massive marl (MM), bioturbated marl, fossiliferous marl (FM), and slightly deformed marl (DM).

A petrographic analysis of this well shows that the Apollonia formation overall has experienced few diagenetic events and fracturing processes; the main contribution to the rock fabric and pore system is the depositional processes that is preserved with its significant original fabric, as shown in Fig. 5, plates 1 and 2. The less dominant diagenetic and fracturing processes have been observed and characterized with their effect on their reservoir quality.

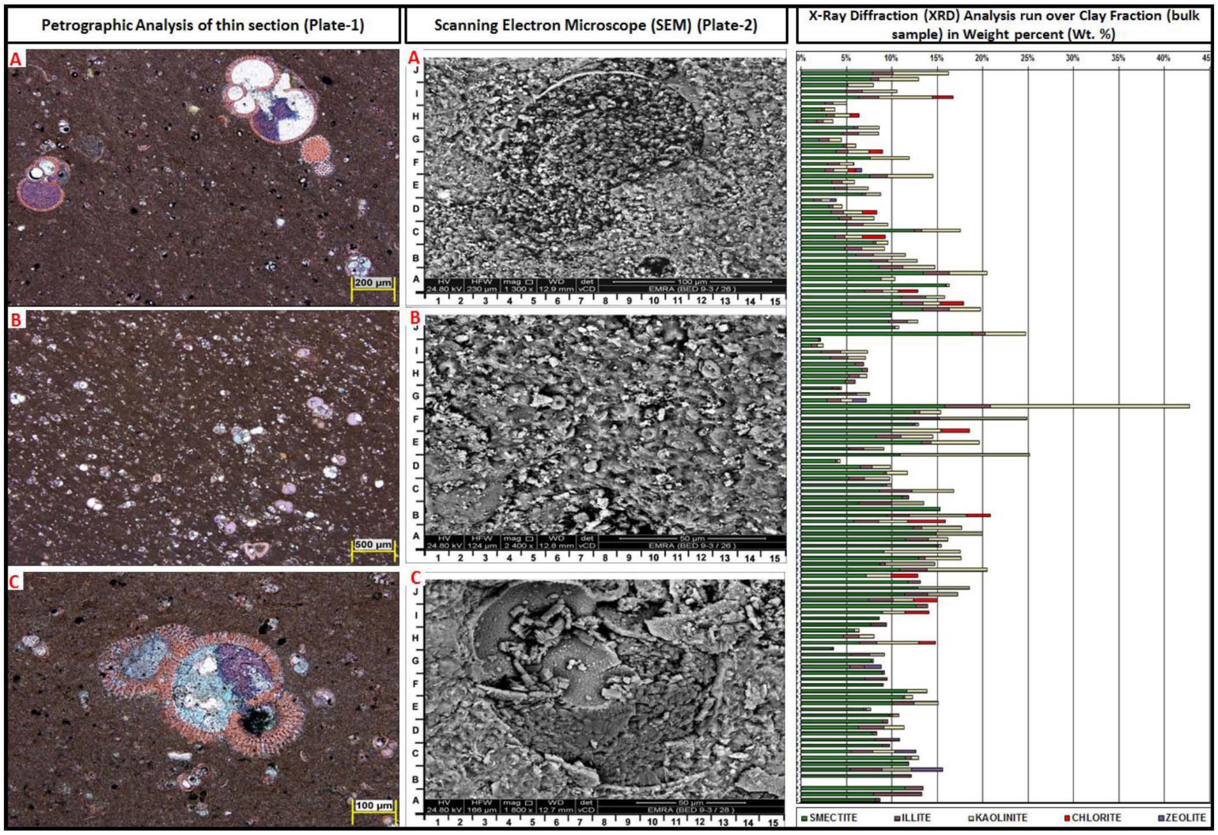

Figure 5—Common and representative photographs of the results from petrographic analysis, SEM, and XRD analysis.

The cementation and fabric selective dissolution are two diagenetic events recognized from the petrographic analysis; the cementation, as shown in Fig. 5, plate 1, has been partially recognized with cementing material of ferroan calcite, various clay minerals, black pyrite, secondary silica, and scattered finely-crystalline euhedral non-ferroan/ferroan dolomite rhombs. The cementation diminishes the porosity and reduces the quality of the reservoir to a considerable extent. The uncommon/rare partial dissolution of calcite crystals has been observed, which generates intercrystalline porosity, as recognized from the SEM analysis shown in Fig. 5, plate 2.

Although compaction diminishes the porosity and reduces the reservoir quality to a considerable extent, the Apollonia reservoir has been exposed to mild compaction, which is indicated by the preservation of the fragile coccoliths (Fig. 5, plate 2, Photo B: D3).

The XRD results and the elemental analysis logging tool show various types of clays with changeable weight percent along the Apollonia formation. As shown in Fig. 5, the XRD analysis over the clay fraction shows amounts of smectite, kaolinite, illite, chlorite, and zeolite in a descending order. Each of these clay mineral types dramatically affects the reservoir quality. For example, the identifiable fibrous hair-like structure of illite damages the permeability to a significant percent, and the kaolinite booklet-like structure reduces the porosity.

The petrographic analysis generally shows the Apollonia formation as mudstone to wackstone chalky limestone, with a pervasive micritic/microsparitic matrix, and a moderate amount of terrigenous clays.

In Plate 1 of Fig. 5, a petrographic analysis shows chalky wackstone, with abundant amounts of micritic/ microsparitic matrix and moderate amounts of terrigenous clays. Skeletal grains that commonly constitute amounts of planktic foraminifera (globigerinoides and heterohelix) are present. Rare amounts of benthic foraminifera, echinoderms, and ostracods are evident. The poorly visualized porosity is primarily classified as intergranular and occurs within skeletal grains with very poor connectivity.

In Plate 2 of Fig. 5, SEM analysis shows that the majority of the porosity is microporosity located between terrigenous clays or the coccolith discs and platelets, and minor primary intragranular pores occur within some planktic foraminifera chambers with poor connectivity (Photo A: G2, G7, A-B10; Photo B: G5–6, I11, C-D6–7, I-J9–10; Photo C: D2, E14).

In Plate 2 of Fig. 5, SEM analysis reveals that Apollonia was affected by minor diagenesis processes; mild compaction in accordance with the preservation of the fragile coccoliths and uncommon partial dissolution creates intercrystalline porosity (Photo A: B5, I13–14; Photo B: E-F10, G6, I-J9–10; Photo C: B3, H-I14).

In Plate 2 of Fig. 5, SEM and XRD analyses show a considerable amount of clays that is visually recognized in the SEM (kaolinite booklets filling foram chambers and traces of hair-like illites locally replace terrigenous clays) as shown in Photo A: D12, D-E4, F8–9, H9–10; Photo B: C14, H5, I8, D9, H7; Photo C: C9–10, E-F11, H5–6. This is also semi-quantitatively identified in the XRD histogram that represents the different types of clay minerals along the studied Apollonia formation in descending order to be smectite, kaolinite, illite, chlorite, and zeolite.

Fracture characterization has been analyzed using the available dataset grading among the scales of various tools, including borehole micro-resistivity imaging, core, and thin sections, as shown in Fig. 6. The fracture intensity of the Apollonia formation is considerably low, although it shows relatively moderate intensity at certain intervals. The analyzed fractures are also classified as either partially cemented or cemented with low contribution to the reservoir quality.

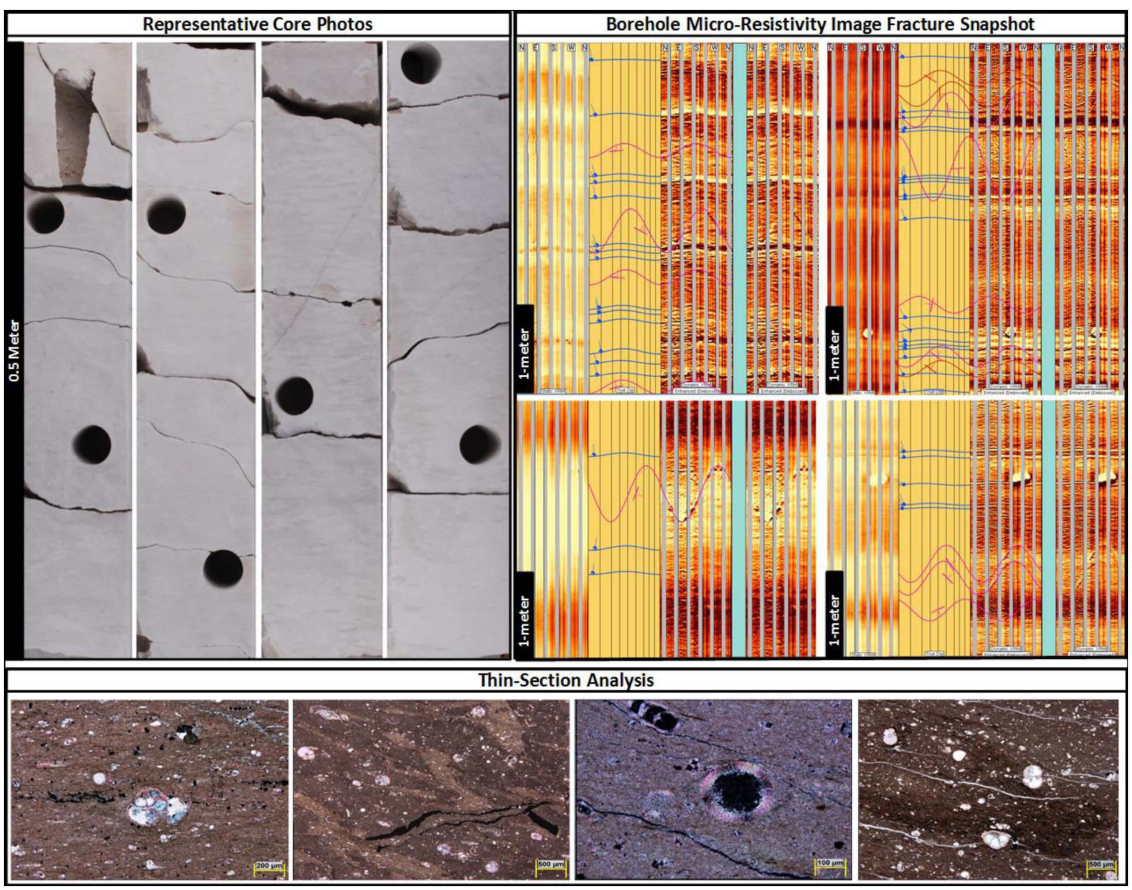

Figure 6—Data integrity analysis for fracture identification and classification in the targeted zone of the Apollonia formation. Fracture intensity along the entire Apollonia formation is considerably low, although at some intervals where fractures localized, fractures are relatively moderate and recognizable using scales of various tools, including core photos, micro-resistivity image logs, and thin sections. Thin sections show microscopic fractures that are partially to totally cemented, with some uncommon light brown hydrocarbon stains and residual hydrocarbons. The core image logs show fracture intensity at some intervals that are partially cemented to cemented.

As described by Lucia (2007), in mud-dominated packstones, wackstones, and mudstones, the size of the micrite particles and the amount of interparticle porosity in the mud controls the pore-size distribution. The small pore size is often referred to as microporosity and is visible with SEM. Lucia classifies intragrain microporosity as a type of separate vug because it is located within the particles of the rock. Mud-dominated fabrics may also contain grains with microporosity, but they present no unique petrophysical condition because of similar pore sizes.

SEM analysis in the Apollonia formation shows that a large majority of pores are micropores located between terrigenous clays, kaolinite booklets, and within the coccolith discs and platelets, in which primary intragranular pores occur within some skeletal grains with very poor connectivity.

In the BED 9 area, Apollonia includes typically tight, microporous, chalky carbonates that have been proven to contain movable hydrocarbons. As described by Lucia (2007), if the depositional characteristics are dominant but somewhat modified by mechanical fracturing and minor diagenetic attributes, then depositional facies remain reliable proxies for porosity. As shown by well BED 9–3 in the Apollonia formation, little diagenetic and mechanical fracturing has occurred; consequently, additional complete facies mapping analyses are required in the spatial distribution to identify the reservoir map of the BED 9 area.

The identified facies/micro-facies are then tied to the conventional logs to assist in the subdivision of this carbonate interval into separate geological and petrophysically related units. In the BED 9–3 well, the entire analyzed Apollonia formation is subdivided into three Apollonia members (C, B, and A members) that display different reservoir properties/potentiality.

The reservoir potentialities of the recognized subdivisions are then evaluated in terms of reservoir properties to concentrate additional analyses on the good/high potential reservoir (HPR) units and ignore bad/low potential reservoir (LPR) units of the Apollonia carbonate in the BED 9–3 well. The three analyzed Apollonia A, B, and C members are discriminated into Apollonia A and C reservoirs and Apollonia B as a non-reservoir unit. Apollonia A is subdivided into A1, A2, A3, A4, and A5; Apollonia C is subdivided into C12, C13, C14, C15, C16, and C17, based on reservoir quality.

The conventional logs were analyzed side-by-side with the borehole static/dynamic image, interpreted dip, and fracture density along the recognized subdivisions of the Apollonia carbonate, as shown in Fig. 7, to evaluate the potential reservoir units. The figure shows that the fracture density along the Apollonia formation is considerably low except at some intervals against Apollonia A and C reservoirs, where the fractures are localized and relatively moderate. The interpreted fractures are classified into closed and partially open fractures.

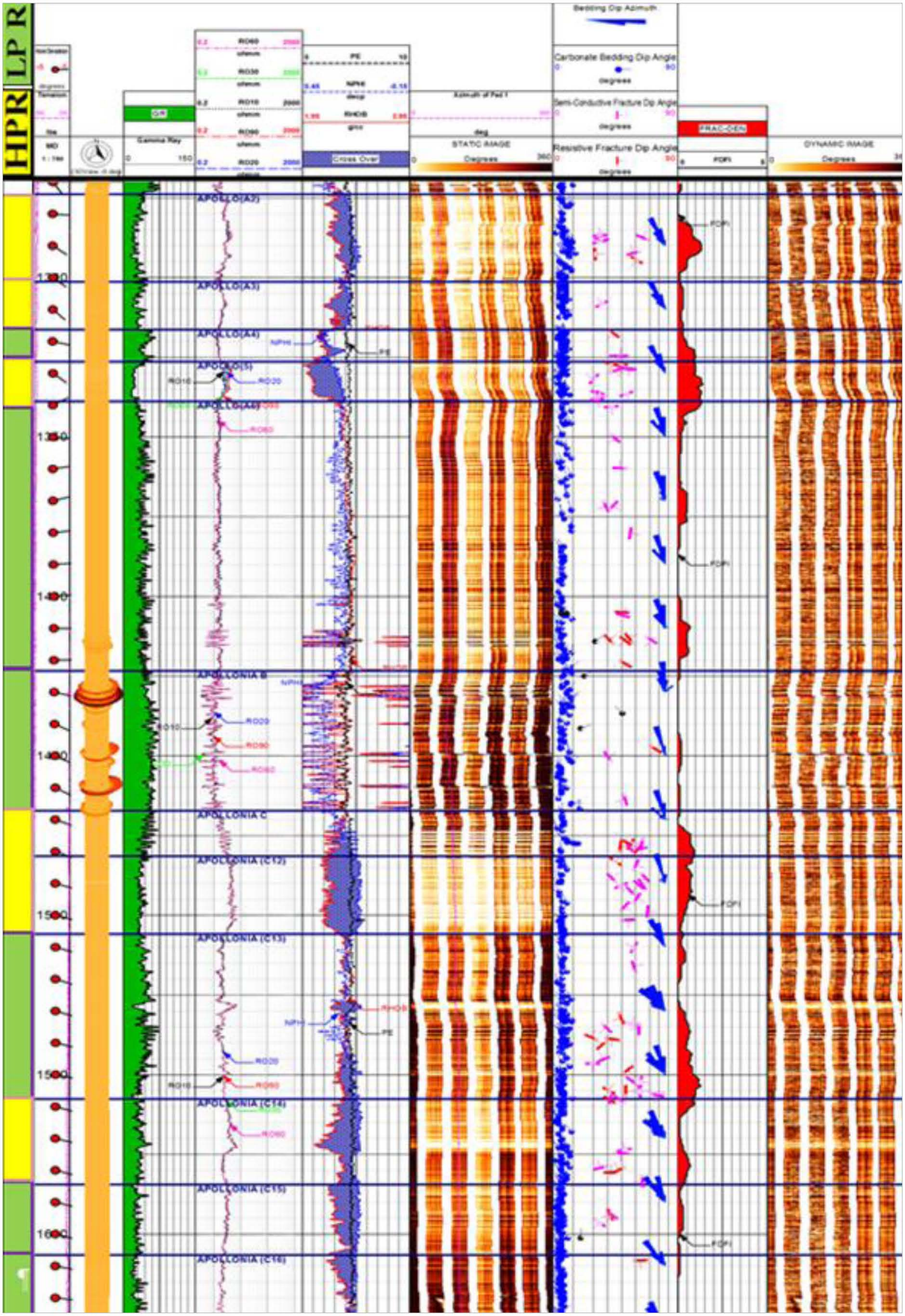

Figure 7—Conventional and image logs along the subdivided rock units of the Apollonia formation and their fracture distribution. Image-core calibrated interpretation reveals that fracture density is generally low except for some intervals against the Apollonia A and C reservoirs.

Petrophysical Evaluation

The petrophysical evaluation of the Apollonia reservoir includes identifying the lithology, determining the porosity permeability relationship, fluid typing, and distinguishing between moveable/bound water. The hydrocarbon saturation along the potential reservoir units of Apollonia formation is calculated.

Apollonia Rock Typing

Increasing reservoir complexity demands an accurate understanding of formation composition and minerology. In well BED 9–3, a detailed mineralogical analysis was conducted on a 250 m cored section. This data validated the elemental concentration logs obtained by using a geochemical element tool that is capable of measuring ten formation elements performed over the same interval.

XRD analysis reveals that the three main predominate mineralogical components in Apollonia A and C include calcite, quartz, and smectite, with the presence of minor dolomite (Fig. 8 and Fig. 9).

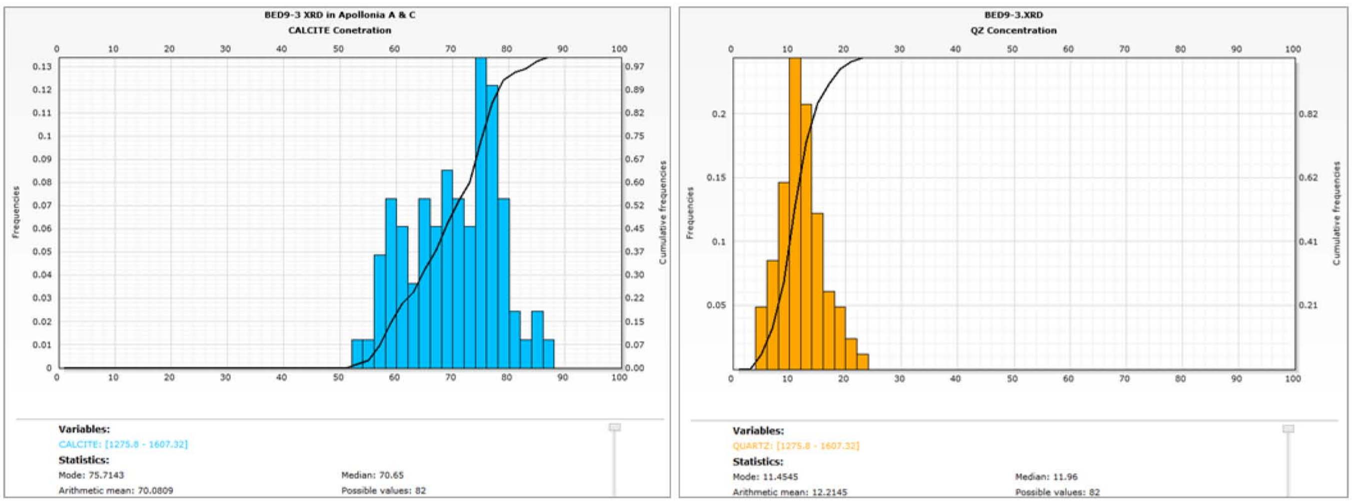

Figure 8—(A) The XRD calcium concentration histogram with arithmetic mean measures 70%; (B) The XRD quartz concentration histogram with arithmetic mean is measuring 12%.

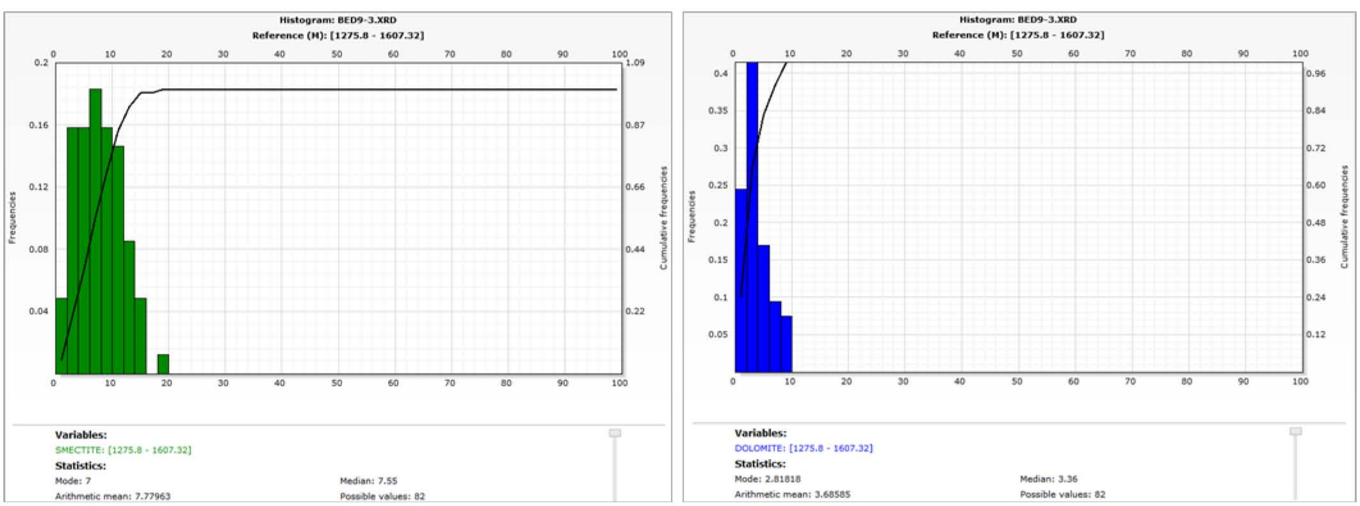

Figure 9—(A) The XRD smectite concentration histogram with arithmetic means measures 8%; (B) The XRD dolomite concentration histogram with arithmetic mean is measuring 3.5%.

The elemental weight fractions measured by the tool are represented as elemental concentration logs, and then compared/validated with those analyzed from the core (used for validation only, but not for calibration). As shown in Fig. 10, there is a very good match between the core and log elemental measurements/values that are presented in weight fraction. The log data is displayed as solid red lines, and the core data is displayed as black dots.

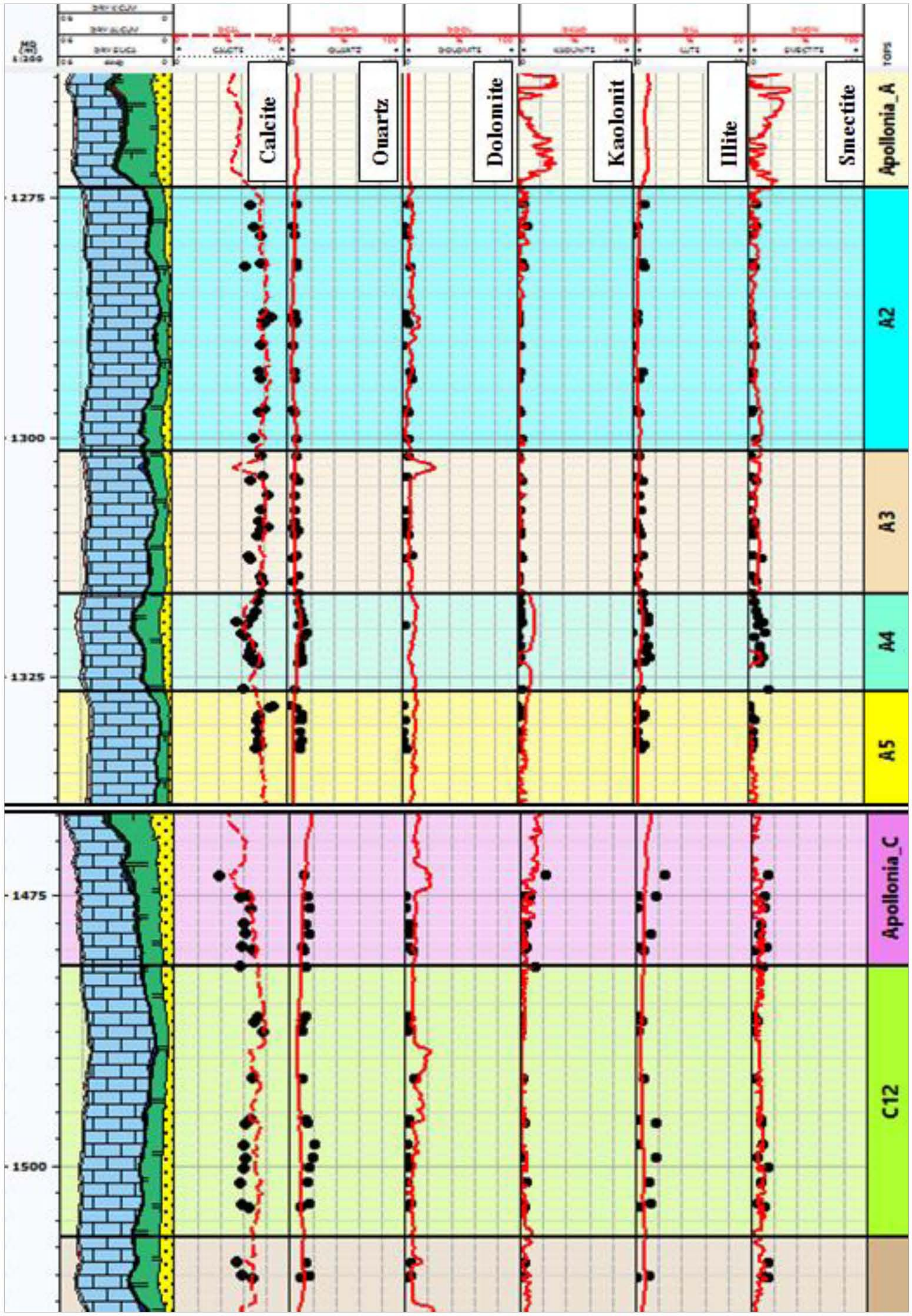

Figure 10—Comparison of the elemental weight fractions measured by the tool (red lines) to those derived from core analysis (black points). The track to the right of the depth track shows the minerology. A very good match exists between the core and log for all elemental concentrations.

The previously mentioned Apollonia A and C members are the reservoirs in Apollonia formation. Apollonia A is subdivided into A1, A2, A3, A4, and A5, and Apollonia C is subdivided into C12, C13, C14, C15, C16, and C17, based on reservoir quality. The clay distribution, especially the smectite and illite, along each of the reservoir units plays an effective rule in determining the reservoir quality. An inverse relationship has been recognized between the reservoir quality and the presence of smectite and illite; the A5 reservoir unit represents the best reservoir quality (in terms of porosity/permeability), and it has been noted from the geochemical elemental tool calibrated with the core that it is characterized by a low presence of smectite and illite, as shown in Fig. 11.

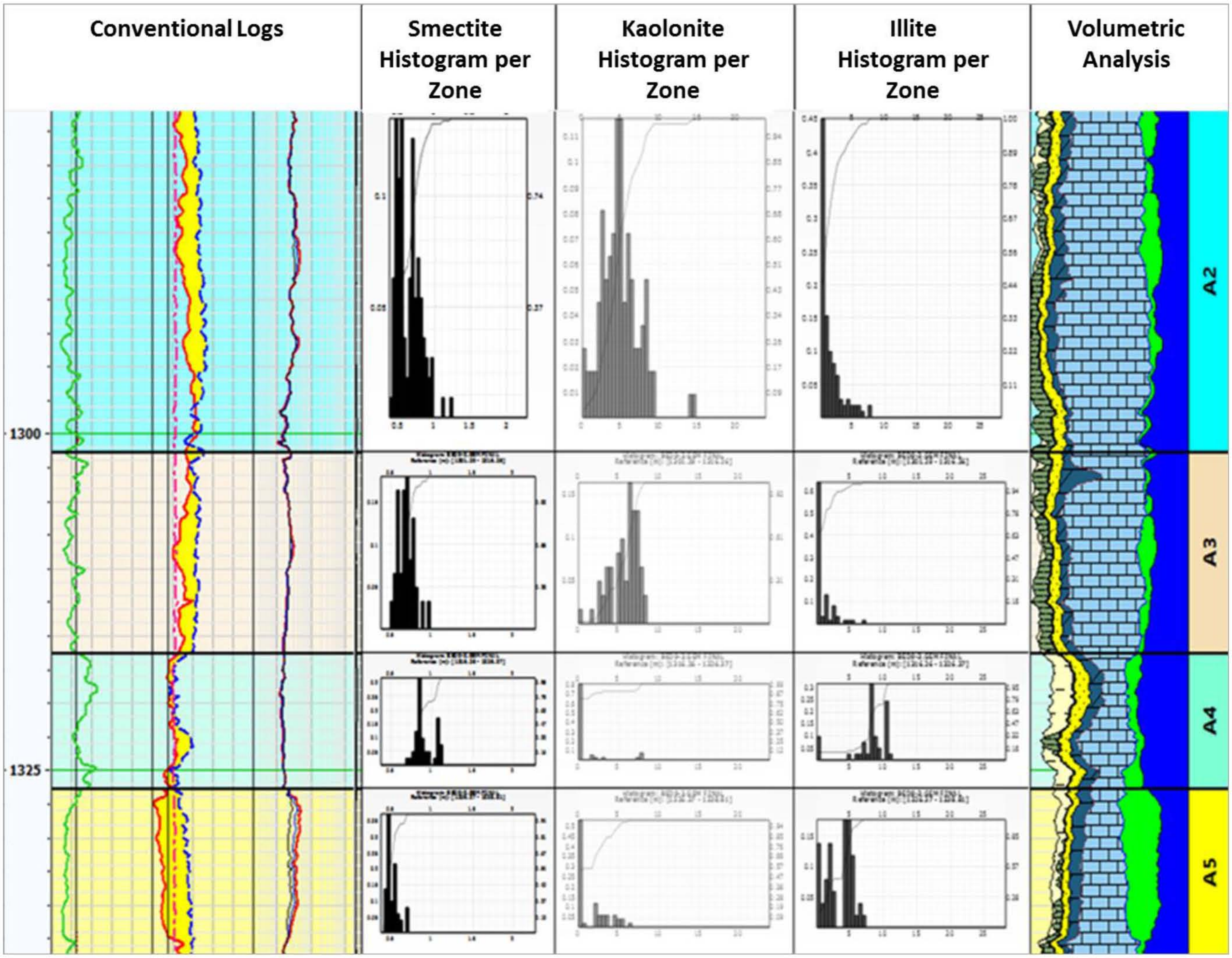

Figure 11—Conventional logs along with the smectite, kaolinite, and illite volume histograms obtained from the elemental tool in the Apollonia A reservoir. A volumetric analysis shows gas, water, calcite, dolomite, quartz, illite, smectite, and kaolinite volumes from right to left in order.

The XRD data interpretation and the geochemical element tool interpretation demonstrate a uniform distribution of minerology along most of the Apollonia formation. The primary mineralogical components that predominate in the Apollonia A and C members are calcite, quartz, dolomite, and clays (smectite and kaolinite) associated with the minor presence of illite as another type of clay.

Apollonia A5 and C12 show relatively good reservoir quality porosity and permeability and higher gas saturation, as compared to other Apollonia subunits that are interpreted to have a low presence of smectite and illite, as illustrated in Fig. 11.

Apollonia A2 to A4 and C13 to C17 are classified as low potential reservoir quality; they generally show relatively higher argillaceous content than that identified in A5 and C12 units.

Pore Throat Size Distribution of the Apollonia Reservoir

Capillary pressure curves can be used to investigate pore-size distribution. These measurements of pore throats can then be related to porosity and permeability, after the data is normalized (Lucia 1999). The pore throat sizes of the Apollonia reservoir are measured using the capillary pressure curves, which are converted to a distribution profile of pore throat sizes.

In the BED 9–3 well, the pore throat size distribution along the cored interval in the Apollonia reservoir subdivision has been studied and reveals that the predominant pore throat is the nanopore size of less than 0.1 micron; only units A2 and A5 contain the micropore size, which ranges from 0.1 to 0.5 micron, as shown in Fig. 12.

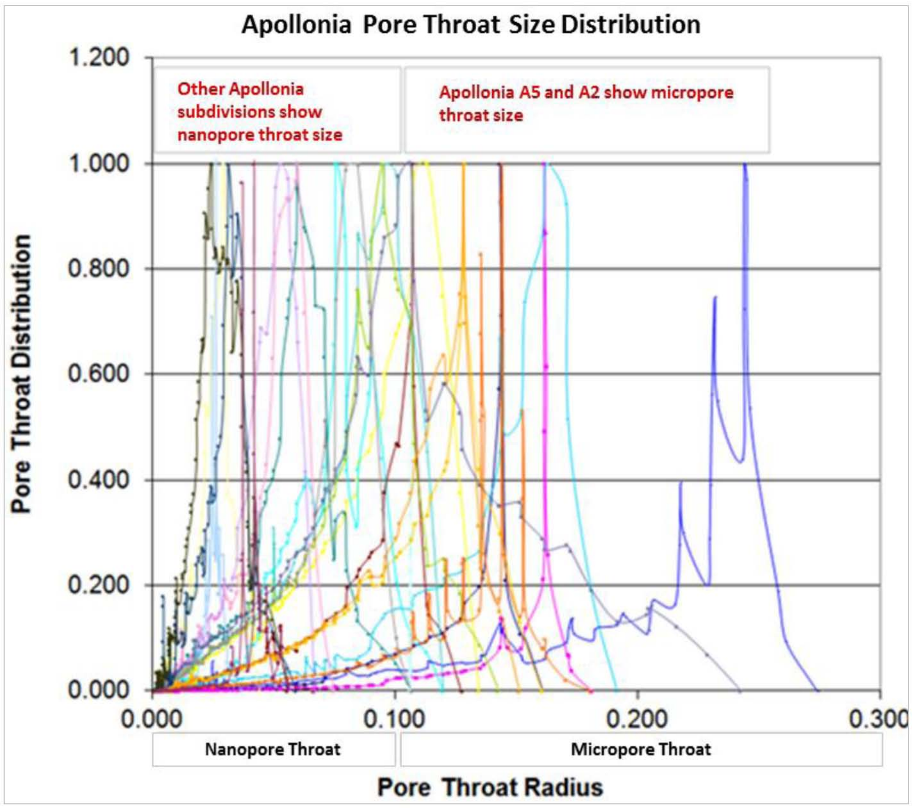

Figure 12—Pore throat size distribution along cored interval in the Apollonia reservoir. The dominant size is nanopore, and only A2 and A5 show micropores, which could be considered as sweet spots.

The analyzed pore throat size distribution along the subdivision shows that majority of pores in A5 and A2 are micropores located within/between the coccolith discs and platelets. The pores of the remaining Apollonia rock units are primarily nanopores located between terrigenous clays and within the coccolith discs and platelets, which is also recognized from the visual inspection of SEM and thin section in A5 and A3, as shown in Fig. 5.

Apollonia Fluid Distribution (Centrifuge, NMR, Dean-Stark, Archie)

Various methods were used to estimate fluid distribution in the Apollonia reservoir, including conventional Archie core calibrated, NMR free fluid, irreducible water saturation from capillary pressure, and Dean-Stark water saturation.

In the BED 9–3 well, the Halliburton MRIL-XL™ tool was used in Apollonia reservoir with the primary objective of discriminating between formation gas and liquids. Dual weight time activation was selected to match reservoir properties and objectives. The NMR cutoff was selected on the basis of the following core measurements:

- Clay-bound water-filled porosity (CBW) T2 cutoff is 5 ms.
- Capillary-bound water-filled porosity (BVI) T2 cutoff is 50 ms based on the NMR core analysis, and it represents the majority of the total porosity. The same T2 cutoff used for free fluid.

Core plugs were studied using the Dean-Stark water saturation and centrifuge capillary pressure to obtain representative irreducible water saturation, enabling the Archie and NMR water saturation to be calibrated. The Dean-Stark water saturation measurement completely disagreed with the other water saturation measurement sources; however, the irreducible water saturation from capillary pressure, NMR, and Archie matched very well.

Overall, Apollonia A5 shows less irreducible water saturation "high gas saturation" from all water saturation measurement sources. Fig. 13 shows a good match between the conventional Archie water saturation in A5 along with irreducible water saturation from the capillary pressure and the NMR tool.

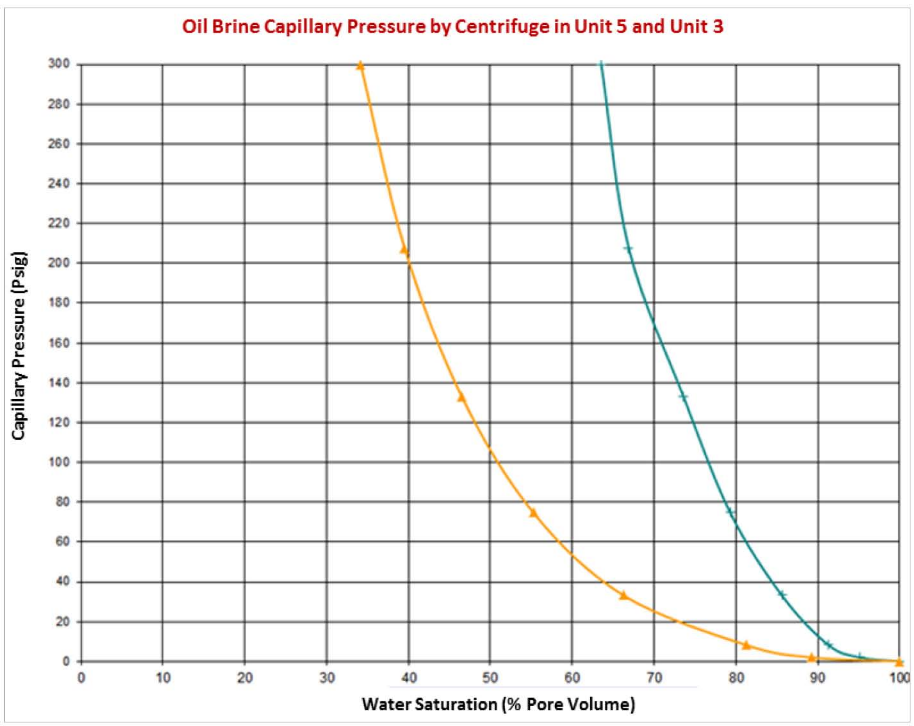

Figure 13—Example of capillary pressure of the Apollonia reservoir A5 and A3 units; A5 indicates less SWirr, but A3 shows a high Swirr, which is matched with NMR results.

NMR permeability was estimated using the Coates methods and calibrated with the stressed core permeability; it provides a very good match, as shown in Fig. 13. The Apollonia reservoir permeability ranges from 0.1 to 1 md/sp.

Capillary pressure data indicated that the entry pressure of hydrocarbon in the Apollonia reservoir is high; the irreducible water saturation is high and ranges from 35% (relatively good quality) to 60% (poor quality). Fig. 13 shows two centrifuge capillary pressure examples in the A5 and A3 subdivisions.

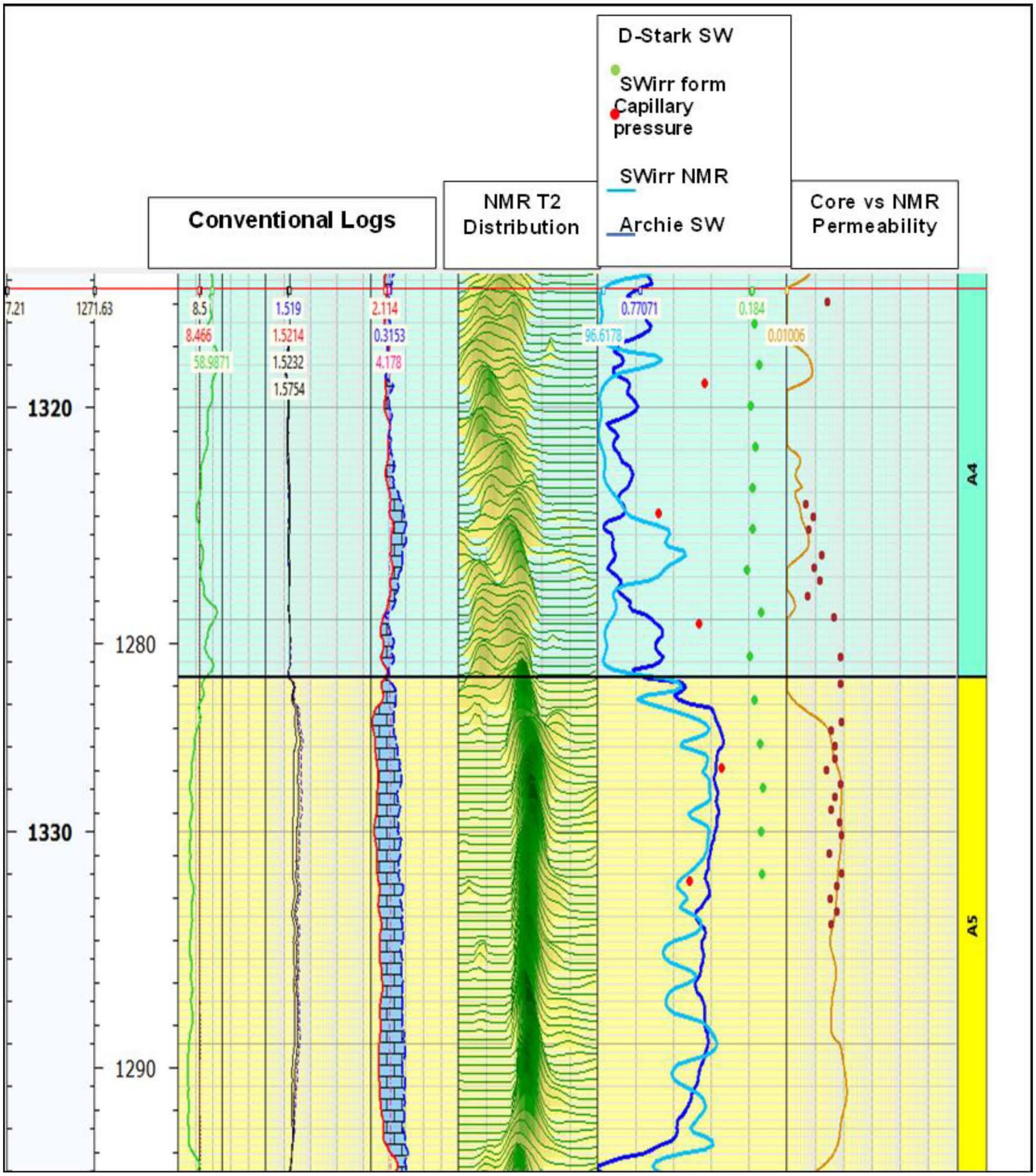

Figure 14—Good match between Archie core calibrated total water saturation with capillary pressure and NMR water irreducible water saturation against the Apollonia A5 reservoir, which confirms that the high water saturation from the conventional log is irreducible water saturation.

Production Assessment

Reservoir production performance was analyzed after the natural flow and the relatively small scale fracture jobs, then a simulation job was perfectly designed to match the previously characterized reservoir properties.

Apollonia Testing and Fracturing

The Apollonia reservoir is one of the tight gas opportunities in Egypt that is currently being appraised by Shell. It is a shallow chalk reservoir (800 to 1,600 m TVDS) that has low permeability (0.01 to 1 md) with very weak etching and low reservoir pressure (1,500 to 2,500 psi). Despite the large in-place gas volumes, the development of this tight reservoir encounters serious economic challenges at the current commercial terms as a result of low productivity and low recoverable volumes of the wells.

The most challenging target to develop the low pressure, shallow, tight Apollonia reservoir in the current market conditions is to approach the best simulation job design and best production performance. Previous attempts to evaluate the Apollonia development have relied on either natural flow or relatively small-scale fracture jobs that have had only limited contact with the reservoir and, consequently, poor productivity.

In early 2012, BAPETCO performed large-scale foam fracturing operations on two Apollonia wells in the BED concession of the Abu Gharadig basin to maximize the well productivity and to improve the project economics. Approximately one-fourth to one-third of the foam volume is liquid, and the remainder of the volume is gas. With this composition, there is less liquid available to contact the formation downhole, minimizing any damage to the formation.

These fracture operations were considered as the first successful implementations of the foam fracture in North Africa, as well as the second largest ever in terms of proppant volume. The wells showed a significant improvement in productivity of more than 40 fold after the treatment (0.15 MMscf/d pre-treatment up to 6.5 MMscf/d post treatment).

The massive foam fracturing was designed to have a long half-length of approximately 300 m and dimensionless conductivity of 10 using 12/18 proppant size, and the foam quality was increased from 25 to 45%. This foam fracturing is carefully designed to decrease the damage by decreasing the pumped volume of frac fluid, provide faster well cleanup, and improve the fracture conductivity by increasing the effective propped half-length. The well was tested after fracturing with 6.5 MMscf/d against flare condition and 4 MMscf/d against plant condition with a flowing wellhead pressure of 500 psi. No initial water production was produced from Apollonia.

Conclusion

Effective exploitation of carbonate reservoirs requires knowledge of the distribution of geological/petrophysical properties, porosity, capilliarity, and permeability (Lucia 2000). The challenge in carbonate reservoirs is that a wide range of reservoir controls must be identified and characterized before well test results and performance histories are understood, matched, and modeled (Cerepi et al. 2003).

Geological carbonate facies and micro-facies analysis are identified/classified using openhole logs, core, and petrographic analysis to reveal that the Apollonia carbonates are dominantly influenced by depositional processes. Dominant depositional processes are still preserved in accordance with the clearly identified original rock fabric and bioclasts that were slightly influenced with later diagenetic and mechanical fractures processes. The fracture density of the Apollonia reservoir is very low; they are either closed or partially open, and they do not contribute to production.

The Apollonia carbonates are generally classified as mud-supported and commonly range from wackstone to mudstone. The majority of porosity is identified as microporosity. The pore throat size ranges from the dominant nano size to the uncommon micro size found only in the sweet spot areas. The Apollonia carbonate could be generally described as a relatively homogenous rock unit with high porosity and very low permeability.

The Apollonia carbonate rock unit is classified into good/high potential to bad/low potential reservoirs units. It is subdivided into separate rock units, in which the A5 reservoir unit could be considered as a sweet spot in the Apollonia reservoir because it has high porosity/relatively higher permeability, low presence of illite and smectite, and shows less irreducible water saturation with high gas saturation.

A petrophysical evaluation using the conventional and advanced log calibrated with the core data reveals that the irreducible water saturation ranges from 40 to 80% along the analyzed gas-bearing reservoir units. Smectite and illite play an effective role in controlling the reservoir quality and can be predicted by conventional logs.

Reservoir production performance was analyzed after the natural flow and the relatively small scale fracture jobs; consequently, fracturing the Apollonia reservoir units is essential to produce a commercial and sustainable rate. The fracturing is the key success factor for developing the Apollonia reservoir. The Apollonia reservoir could be developed through drilling low spacing vertical wells with proper fracturing or horizontal wells with multistage fracturing.

The integrated core-log analysis performed on the Apollonia carbonates provides reservoir quality identification and classification based on the reservoir properties (porosity-permeability relationship and hydrocarbon-bearing). These identified reservoir qualities are then best classified into separate intervals in which each of the identified intervals are then evaluated for development plans.

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