Multidimensional Petrophysical Analysis in the Reservoir Description Division

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ABSTRACT

During the recent development of Shaybah, a number of wells were cored and logged with a routine open-hole suite of tools (density-neutron, sonic-resistivity), and then later (but pre-production) logged with a pulsed neutron tool. Selected wells were also evaluated with wireline formation pressure measurements and nuclear magnetic resonance. Laboratory core data includes both routine core porosity/permeability/grain density and capillary pressure/electrical properties/NMR measurements, in addition to CT scans, x-ray diffraction and fluorescence mineralogy and visual core descriptions. The routine core analyses validate wireline porosity and permeability estimates within both a multiwell fieldwide composite and depositional facies context. With this basic confidence established, capillary pressure concepts are used to investigate reservoir continuity.

Fig. 1. Shaybah field, the Empty Quarter

Horizontal wells, bounded by two cored vertical wells, are observed to cross a distinct boundary, across which the petrophysical attributes transcend from those of one neighbor to the other. Variations in reservoir quality from one foot to the next can be quantified with the so-called Archie cementation exponent, a direct indicator of porosity tortuosity. When formation water composition is known and electrical resistivity is measured, it is possible to calculate this exponent in the water interval of the well and compare both visual core descriptions and independent laboratory measurements. This parameter, which has a direct impact on formation evaluation, is dependent upon both the original depositional environment (deep water, lagoon, etc.) and diagenesis. Thermal neutron decay rates are measured, and contribute to both reservoir surveillance and characterization of the cementation exponent.

Laboratory measurements of the respective component capture cross-sections — Σ_{oil}, Σ_{brine} and computer-simulated (based upon XRD-XRF mineralogy) Σ_{matrix} — allow one both to monitor water influx in the hydrocarbon interval and to calculate the cementation exponent in the water leg. This approach is supplemented with the (less common) nuclear magnetic resonance tool. In all cases, we observe zonal variations in the implied Archie cementation exponent: the remaining challenge is to properly assign Archie exponents in the hydrocarbon column.

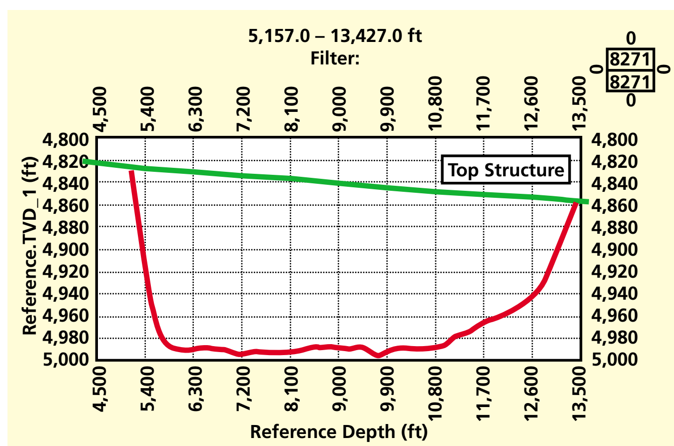


Fig. 2. Identifying the size of the reservoir with directional drilling. The reservoir was encountered at 5,200 ft MD, a long horizontal section was then drilled for production purposes and the wellbore then deliberately steered upwards to penetrate the top formation and thereby quantify the lateral extent of the accumulation. The Reservoir Description evaluation was thus multidimensional from the very beginning.

INTRODUCTION

The Shaybah field was discovered and delineated in the late ’60s and early ’70s, but not developed until the mid ’90s. The remote Empty Quarter location, with its harsh environment, made the development particularly challenging and the successful accomplishment even more rewarding. To produce the current 500,000 barrels per day, Saudi Aramco first had to first overcome daunting physical obstacles at the surface (fig. 1), and then acquire and analize subsurface data from which the best field development plan could be determined.

About 35 vertical wells were drilled and cored during the delineation phase, and initial formation evaluation algorithms developed. We thus had, going into the development phase, an overview of what to expect.

Development drilling was in two phases:

1) Additional vertical wells, which were cored and served to further define the field boundaries and interpretation techniques.
2) Horizontal wells, which were generally located and drilled to allow efficient reservoir depletion. Upon occasion, these wellbores were deliberately steered so as to produce a commercial wellbore and even further delineate the reservoir (by intersecting the top formation) (fig. 2).

The formation interval of both vertical and horizontal wells was subjected to a multitude of measurements (radioactive, electrical, acoustical, nuclear magnetic spin and others) by lowering specially designed tools on wireline into the wellbore. In the case of horizontal wells, gravity is insufficient to pull the tools into the outer reaches of the well. The tools must be attached onto the end of the drill string and the assembly pushed out into the well. Finally, in selected wells, special logging-while-drilling (LWD) tools were used that made it possible to measure key petrophysical attributes and actually visualize the wellbore (fig. 3).

In addition to tool-based measurements in the reservoir, a considerable effort was made to analize the core (rock) recovered from vertical wells. The rock grain density (indicative of the mineralogical composition), porosity and permeability (fluid-flow capacity) were measured every 15.24 cm (6 in). At selected locations, special core (SCAL) tests were done to characterize the electrical properties of the fluid-filled pore system and the capillary pressure behavior (which controls the oil-water percentages within the reservoir).

There are a multitude of measurements available representing many different disciplines and spanning a time frame that has seen the industry undergo an unprecedented evolution in procedures and capabilities. It is the Reservoir Description Division’s responsibility to take all of this data into account and to deduce the best possible formation evaluation algorithms (fig. 4).

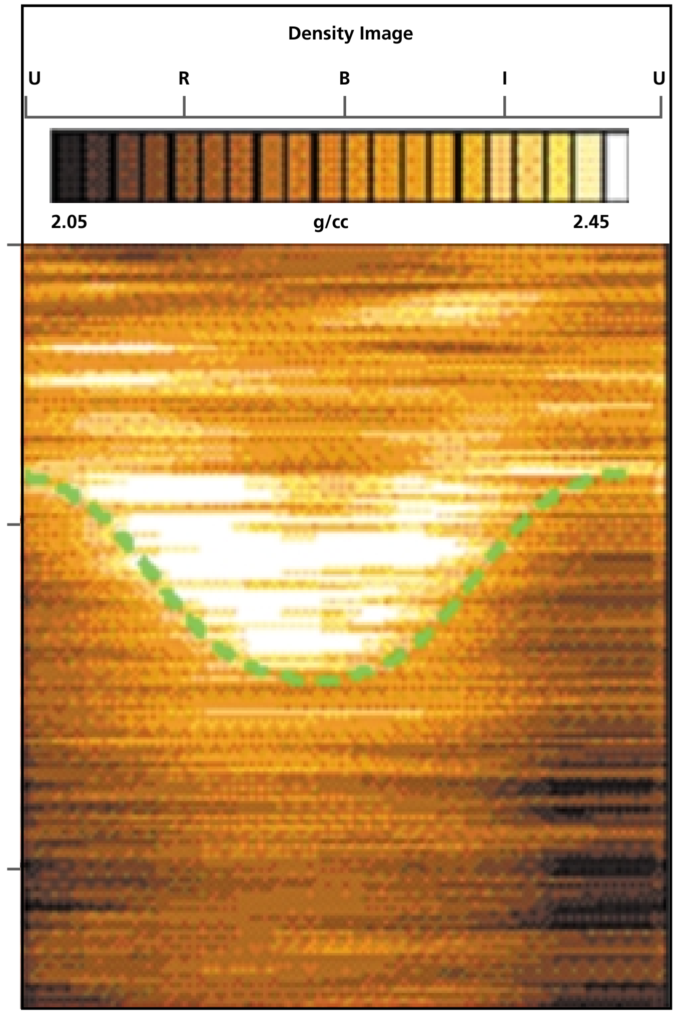


Fig. 3. Formation density images, obtained while drilling with the latest LWD technology. Based upon electron scattering principles, this tool is able to measure the bulk density (in grams per cubic centimeter) of the formation rock, then, provided the rock composition is known, able to calculate the amount of porosity (void space, filled with oil) that is present. When mounted on the end of a rotating drill assembly, the measurements made at the various azimuths (up - left - right - bottom) are used to construct an image of the formation at the wellbore. When reservoir attributes vary along bedding planes, and that bed intersects the wellbore at an angle, a sinusoidal pattern results (highlighted in green). Trigonometric considerations can be used to deduce the local reservoir geometry, an extremely variable attribute, and reservoir quality, even as the well is being drilled.

MAIN BODY

The typical vertically oriented well was drilled to delineate the field and as a source of core (rock samples) which are analyzed in the laboratory. Wireline data is acquired immediately after drilling, and includes borehole caliper, natural gamma ray activity, thermal neutron capture detection, electron scattering and a variety of electrical resistivities (sampling at different radii of investigation, into the formation). From this information, it is possible to estimate the reservoir porosity (void space, filled with either hydrocarbon or water), the hydrocarbon saturation (fraction of the porosity that is filled with hydrocarbon) and the formation permeability (fluid-flow capacity).

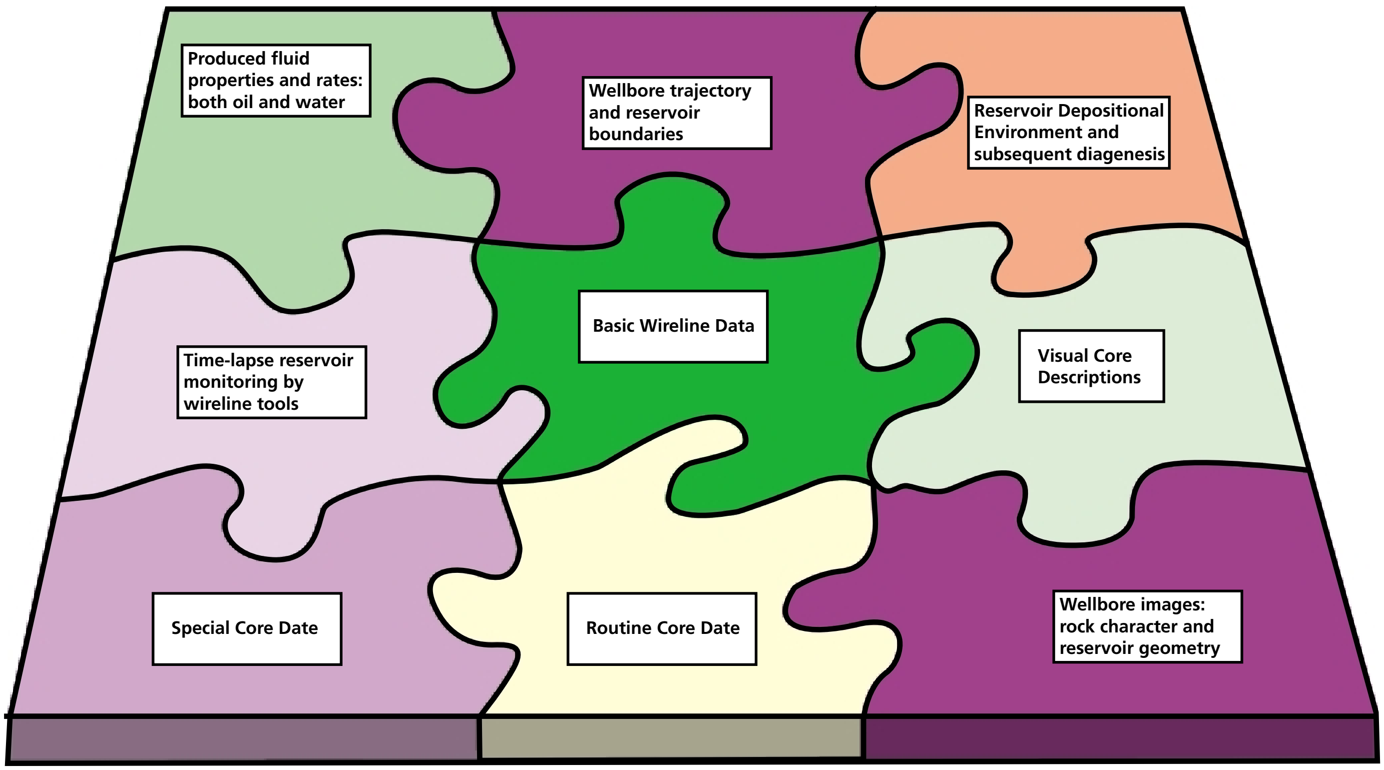


Fig. 4. Multidimensional petrophysics is where it all comes together

The rock bulk density measurement, based upon electron scattering measurements, is a common method of measuring pore volume (normally quoted as either a volumetric percentage or decimal fraction) according to the following equation:

$$\rho(\text{bulk}) = \phi\ \rho(\text{fluid}) + (1 - \phi)\ \rho(\text{rock}) \tag{1}$$

ϕ reflects the volumetric void space, which is fluid filled, while $(1 - \phi)$ is the rock volume fraction. At 100 percent porosity, $\rho(\text{bulk}) = \rho(\text{fluid})$, and at 0 percent porosity, $\rho(\text{bulk}) = \rho(\text{fluid})$, so that this is in fact an interpolation between the possible reservoir endpoints: 0 percent and 100 percent porosity. Intermediate (and obviously the most common) porosities are calculated by

$$\phi = [\ \rho(\text{rock}) - \rho(\text{bulk})\ ] \ /\ [\ \rho(\text{rock}) - \rho(\text{fluid})\ ] \tag{2}$$

In principle, only a single, average bulk density measurement is required for porosity calculation, but in fact today's modern tools (fig. 3) can measure this important attribute in an azimuthal (around the wellbore) dimension.

The porosity-filling fluid is either hydrocarbon (a nonconductor) or water (normally containing sufficient salt to make it a relatively efficient conductor of electricity), so the most common method of distinguishing hydrocarbon from water is based upon electrical measurements. Archie, of Shell Research, first quantified this important relationship more than 50 years ago.

$$S_w^{\,n} = R_w \ /\ (\phi^m\ R_t) \tag{3}$$

R_w is the resistivity of the local formation water, ϕ is pore volume, R_t is the resistivity of the fluid-filled formation and m and n are the Archie exponents. The end result is the water-filled fraction of the porosity (S_w) from which one can also deduce the quantity of actual interest: the hydrocarbon-filled fraction, $S_o = (1 - S_w)$.

While our real target is always hydrocarbon, we are also able to acquire important supplemental information from the water intervals, for here the water saturation is 100 percent and the equation reduces to

$$R_w = \phi^m\ R_o \tag{4}$$

with R_o designating the formation resistivity opposite a water-filled interval. When water properties are known from either geochemical information, a direct resistivity measurement or pulsed neutron decay data, we are able to directly solve for one of the important Archie exponents:

$$m = \log\ (R_w \ /\ R_o)\ /\ \log\ (\phi)^{\sim} \tag{5}$$

This value, which is often available across hundreds of feet of reservoir, may be compared to laboratory measurements, which are much more limited in extent (due to the time-consuming nature of the lab work). Common ranges for both m and n are 1.8 – 2.0, though drastically different values

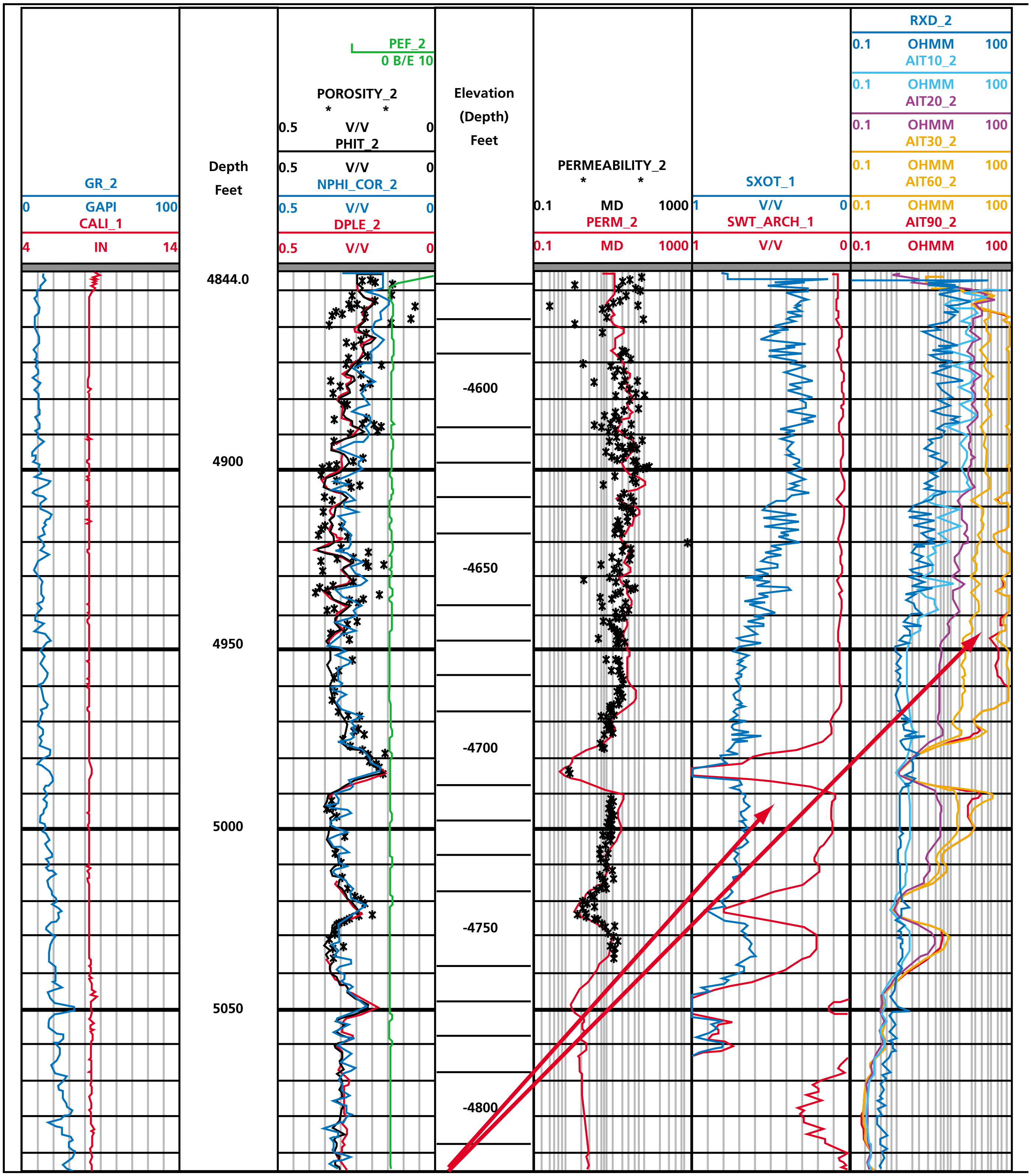


Fig. 5. Modern resistivity tools sample the formation at a variety of radii, away from the wellbore. Here measurements correspond to 90, 60, 30, 20 and 10 in, plus the Rxo, which is about 6 in. This multitude of readings makes it possible to calculate the water saturation, both near (Sxo) and far (Sw), from the wellbore. Any difference across the hydrocarbon interval is the result of mud filtrate invasion and is an indicator of fluid-flow potential.

do occur in special circumstances. Both this direct, empirical technique and laboratory analyses are important components of a complete reservoir description.

Basic formation evaluation

With the equations at hand, one is able to perform basic formation evaluation and would indeed be able to identify many of the Saudi Arabian oil-filled reservoirs (though more sophisticated ________ would naturally give more precise estimates).

Core is subjected to both routine (porosity and permeability) and special (mineralogy, electrical measurements, capillary pressure) analyses, with the routine data being delivered first. Upon receipt of the routine data we immediately review our previous calculations, compare wireline estimates to laboratory measurements (fig. 5) and (in partnership with both Reservoir Management and Geology) identify any additional data requirements. An important aspect of multidimensional petrophysics is the time domain: We try to be one step ahead in identifying and acquiring the necessary data for future needs.

Special core work

X-ray diffraction/x-ray fluorescence (XRD-XRF) mineralogy is an example of subsequent special core work that might be requested, with the objective of achieving better porosity estimates. As noted above, reservoir pore volume can be calculated from both thermal neutron capture and electron scattering measurements. Since the tool response is a function of rock mineralogy, porosity and pore-filling fluid, an independent measurement of any one of the three will eliminate one variable from the equation. XRD-XRF results can be reported as either mineral percentages or as equivalent rock (or grain) densities (fig. 6), and in the Shuaiba reservoir are found to peak strongly around the known limestone value of 2.71 gm/cm^3. With a benchmark porosity known from the routine core measurement, and mineralogy determined from XRD-XRF, formation evaluation analyses can be performed with even more confidence.

In the "real world" of hydrocarbon reservoirs, rock quality is not constant in either the vertical or horizontal dimensions. As data is acquired and analyzed, well locations are planned with an ever-increasing amount of knowledge available, better estimates of the reservoir properties result, and more efficient-economic depletion is achieved.

Reservoirs are charged with hydrocarbon because, basically, hydrocarbon floats on top of water. Rock, on the other hand, will usually display an affinity for water, as opposed to oil, and a competition takes place, known as capillary pressure. The reservoir was originally deposited in a water environment, has a natural affinity for water and is later exposed to hydrocarbon that seeks to displace the water.

Within the pores (void space) of the rock, oil and water are at different pressures and experience different affinities for the rock surface, with each trying to displace the other. This pressure increases with height, in a manner similar to what a

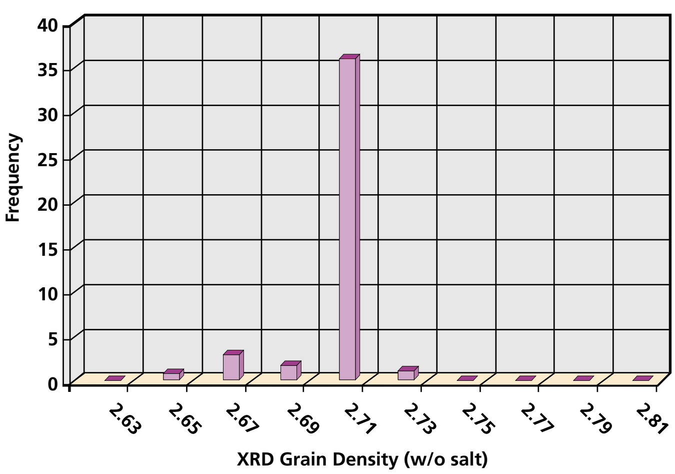


Fig. 6. X-ray diffraction and x-ray fluorescence measurements, made at Saudi Aramco's LRDC Lab, reveal that the Shuaiba is strongly dominated by limestone, with a grain density of 2.71 gm/cm^3.

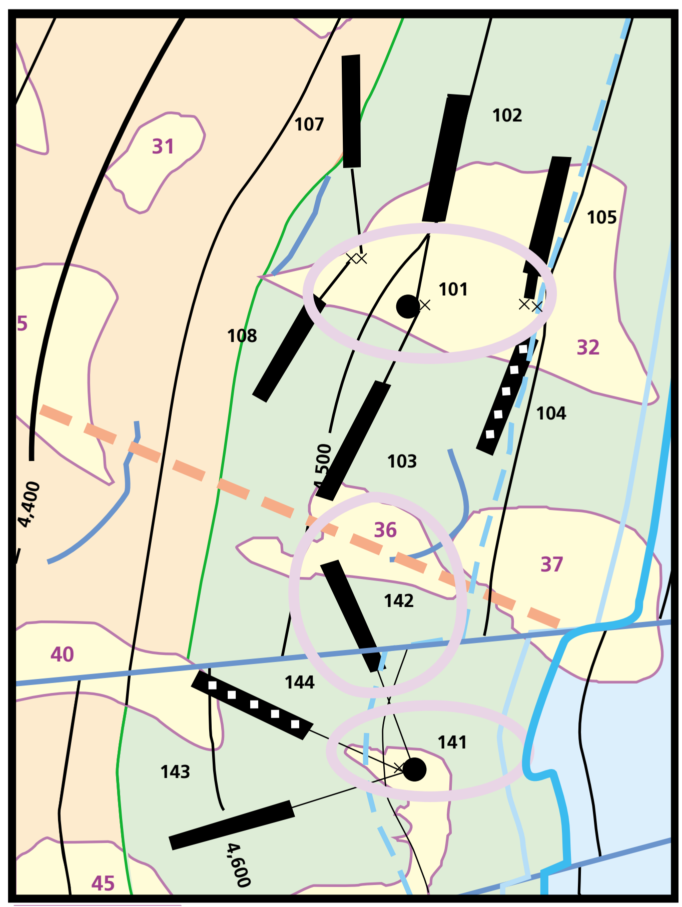


Fig. 7. Each newly drilled well is compared to its neighbor, as both a quality control and reservoir description technique. In some areas, reservoir properties are uniform, with only slight changes, whereas in others the intermediate well (C) is found to cross a sharp boundary, with the two halves of the well resembling the opposing neighbors.

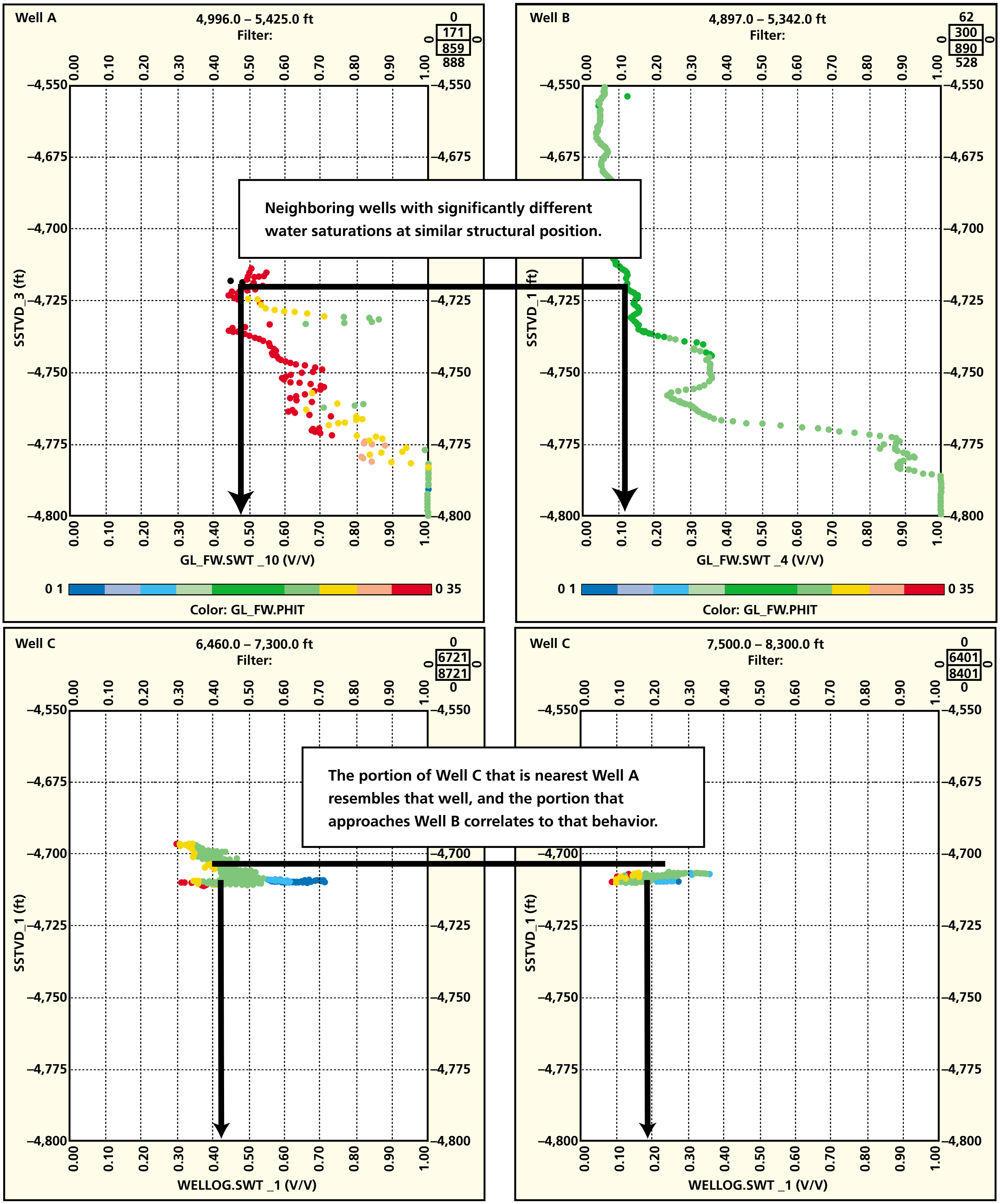


Fig. 8. Wells A and B, neighboring vertical wells, have distinctly different height-saturation relations (an indicator of rock quality). The intermediate well (Well C) has two relations, each of which resembles that of the closest vertical neighbor. Reservoir description is an ever-evolving process, with each new measurement contributing to a better understanding.

swimmer's ears feel when diving into a pool. At a given position, the better-quality (higher-porosity) rock will allow the oil to displace the water more efficiently. One way of comparing rock quality in one location to that in another (fig. 7) is with plots of fluid (either hydrocarbon or water) saturation versus height (fig. 8).

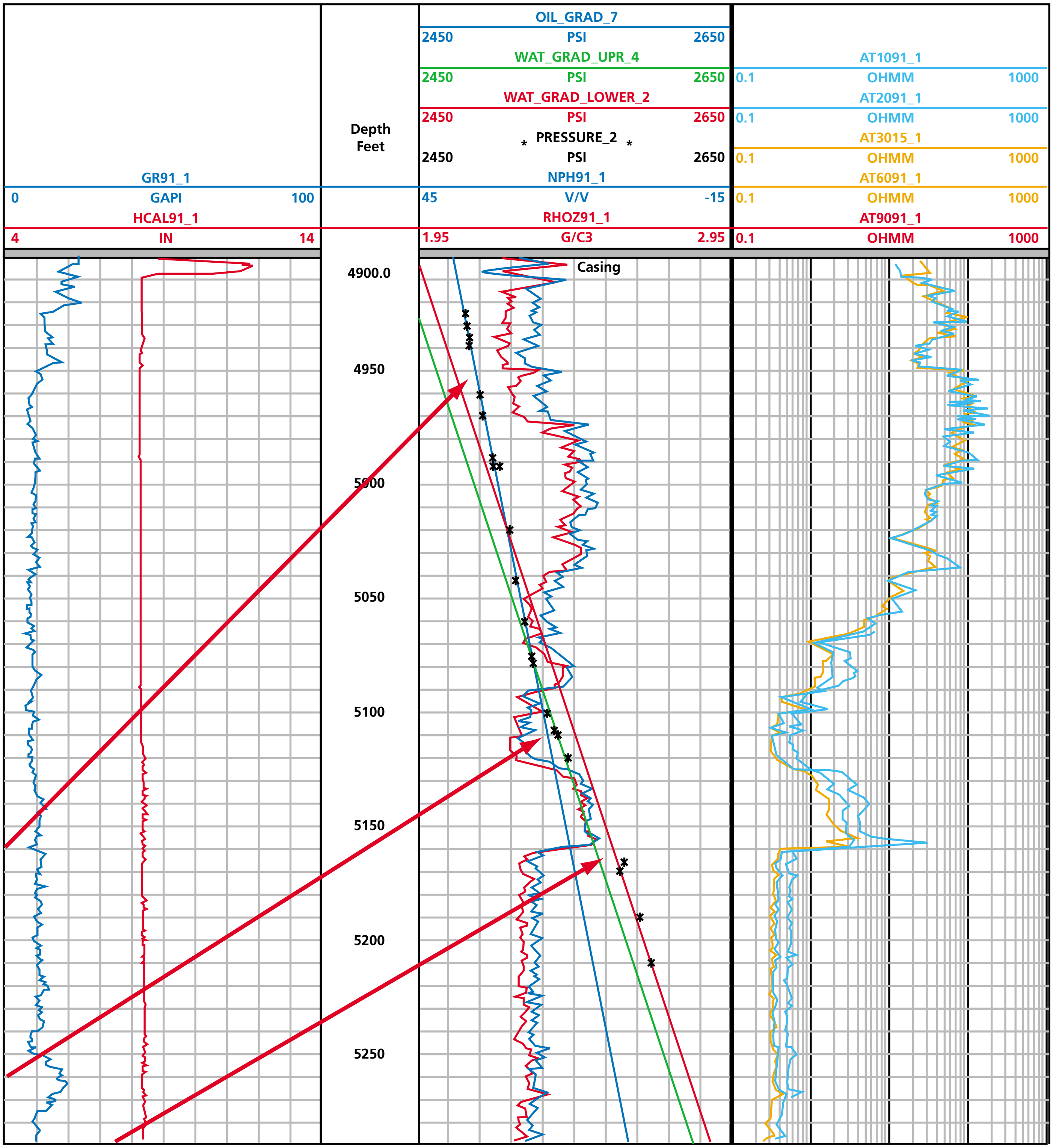


Fig. 9. With today's wireline testing tools, it is possible to measure the local formation fluid pressure and even recover samples of that fluid. When subsequent fluid pressures are displayed versus depth, the linear trend defines a gradient, which is characteristic of that specific reservoir fluid, be it hydrocarbon or water. If one interval is hydraulically separated from another, the trend will suddenly shift at the boundary.

Well C is horizontal, and bounded by Well A (vertical) on the south and Well B (vertical) on the north. When fluid saturation versus height is compared for these two end points, it is clear that, at a specific elevation, hydrocarbon saturations in Well B are significantly higher than those of Well A — the rock in well Well B is of much higher quality. The initial reservoir interval of Well C behaves like that of the neighbor to the south (Well A) and then crosses a distinct boundary, beyond which the behavior correlates with that of the neighbor to the north (Well B). Horizontal wells serve many useful purposes, and as can be seen here, one is a lateral definition of reservoir quality.

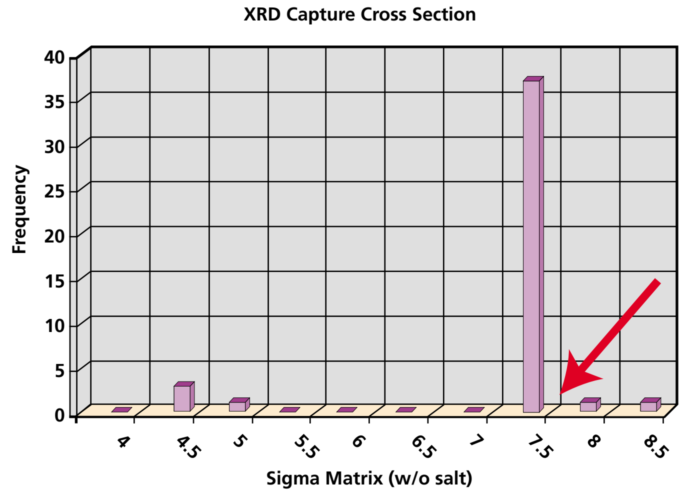
Continuity a consideration

While reservoir quality is an obvious concern, continuity is an equally important consideration and one that can be sometimes addressed in a direct manner. The basic wireline data is first correlated from one well to the next, and similar intervals are identified (as above).

Since the reservoir dimensions in Saudi Arabia are typically much larger than those elsewhere in the world, the interwell distances are also greater and there is a corresponding loss of resolution in the correlation. They remain invaluable, but the simple fact is that even if we are able to precisely identify boundaries (as above), we remain unable to comment on reservoir drainage efficiency across the boundary. Supplemental information can make an important difference: reservoir fluid pressure.

In addition to characterizing reservoir rock quality and identifying the amount and type of fluid in place, it is also common to directly measure the pressure of that fluid. When a series of these measurements are made across a vertical range, a pressure gradient is defined that will, by itself, identify the fluid type: gas-oil-water. When these measurements cross a rock quality boundary (such as a low-porosity interval), it becomes possible to determine if this is a limited constraint or a more widespread phenomena.

Fig. 9 displays density-neutron porosity and electrical resistivity measurements, in addition to discrete pressure points. The upper section is hydrocarbon bearing, as can be seen by the relatively high resistivities (hydrocarbon does not conduct electricity, while the salty Shuaiba brines are good conductors), while the lower reservoir is water filled. Pressure points (black) fall along a gradient that corresponds to oil (blue) at the top of the well and along water gradients (green and red) at the bottom. Simple enough, oil over water, but why don't all the water points fall along the same line? The lower-quality rock from 5,130 to 5,160 feet constitutes a barrier: the water above and below has the same density (gradient), but the lower zone is offset to a higher pressure.



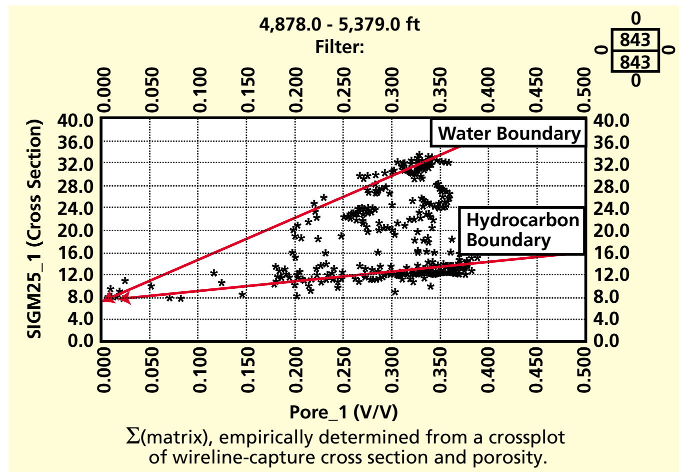


Fig. 10. Crosschecks are routine in the reservoir description discipline: one well against another, lab data against field results. The puzzle must fit together at the end of the day.

Discontinuity considerations

Consider the implications of similar pressure behavior (discontinuity) in an oil zone. Ideally, one would like to draw oil from only the uppermost portion of the reservoir, allowing water to rise from the bottom, pushing the oil above and nicely sweeping the reservoir free of oil. If a boundary is present, however, then there will not be a uniform sweep and hydrocarbons will be left behind. A complete reservoir description must address not only reservoir quality, but also the crucial question of reservoir continuity.

Providing the necessary reservoir description to develop and bring a giant, remote field like Shaybah on-line is a tremendous achievement, but in fact is only the beginning of our obligation, for an equally important task remains: surveillance as the field is depleted.

Surveillance takes advantage of many physical principles and technologies, with one common method being pulsed neutron (PN) decay measurements. Of the various naturally occurring elements in reservoirs, chlorine (present in the brine as NaCl) is a particularly good neutron absorber and will result in a rapid decay rate. This differs from the neutron capture porosity measurement, which detects the capture of thermal neutrons because of collisions with hydrogen nuclei (typically associated with hydrocarbon and water molecules) and can be thought of as a "hydrogen" log.

If the only time-dependent reservoir change is replacement of produced hydrocarbon by brine, then a PN (chlorine) log run prior to depletion and one run during depletion will differ when water has replaced oil. It is then possible to monitor where oil has (and has not) been produced, and development plans and production strategies may be altered as required.

In some circumstances, such as in the Shu'aybah, it is possible to do even more with the PN data, for as noted earlier, the Shu'aybah rock is strongly dominated by limestone, which has a specific neutron-capture cross section (typically denoted as $\Sigma_{(\text{matrix})}$): fig. 10, upper. This information can be applied (and tested) directly in the interpretation of data from the field.

The neutron-capture cross section measured by a PN tool will range from the fluid value at 100 percent porosity to the matrix value at 0 percent porosity. Thus, in plotting $\Sigma_{(wireline)}$ versus the independent wireline porosity, a clear trend is expected along the water boundary, intersecting the vertical axis at a cross section equal to that measured in the lab: fig. 10, lower. The consistency of field and lab data establishes the validity of this technique. Because of this capability, bypassed oil and water fingers can both be identified and remedial action taken.

Pulsed neutron data

Pulsed neutron data also contributes to reservoir description in the water leg of a well (where hydrocarbon depletion surveillance is not an issue). The basic equation that describes tool response within a water-bearing formation is

$$\mathbf{\Sigma(log) = (1 - \phi)\, \Sigma(rock) + \phi\, \Sigma(wat).}$$

Σ*(log)* is measured by the PN log, Σ*(mat)* is known from matrix mineralogy information and from the routine porosity evaluation, leaving Σ*(wat)* to be calculated from the data.

R_w can be calculated from Σ*(wat)*, leaving us in the position of being able to calculate Archie's *m* exponent, from yet another direction (as opposed to the geochemically determined R_w).

Illustrative results from an actual Shaybah well are seen in fig. 11, where there is a clear correlation between the inferred exponent (track 1 – green) and the visual core descriptions of depositional environment (SM = Medium Slope, SS = Shallow Slope, DOP = Deep Outer Platform, etc).

The importance of this variation is seen in the far right track, where water saturation (S_w) varies from the expected (this is a known water interval) 100 percent to more than 120 percent (an artifact, resulting from use of an "average" exponent value). A similar, but much reduced, misestimation of water saturation will occur in the hydrocarbon interval. A remaining challenge for Shu'aybah petrophysics is identification of facies and assignment of proper exponent values from the basic wireline (not core) data.

CONCLUSION/SUMMARY

Saudi Aramco's reservoir description begins with planning the logging job in the first well and does not conclude until the last well has been depleted. The petrophysicist is a multidisciplinary professional who understands not only the basic tool-measurement principles and formation-evaluation techniques, but also appreciates the contribution his colleagues can make. As the reservoir passes from discovery to delineation to development and depletion, tools and techniques change.

At each phase, Reservoir Description acquires measurements that offer the "biggest bang for the buck," taking into account both present and future needs. Since the typically large field has a long lifetime, documentation becomes important to avoid "reinvention of the wheel." Multidimensional petrophysics within the Reservoir Description Division seeks to provide the best possible description, with supporting documentation, at each step in the journey.

ACKNOWLEDGMENTS

A multidimensional effort such as was conducted with Shaybah draws upon the expertise of many people. Key contributors to our effort were Geology, Reservoir Management and the Core Laboratory. We should further recognize the early pioneers, who had the foresight to acquire and document the initial data that allowed us to step into field development with more confidence, and who developed the early interpretation algorithms that remain usable to this day. As an example: *Permeability from Well Logs – Shaybah Field*, presented at the 1977 Society of Professional Well Log Analysts Symposium by Al Brown and Sadad Husseini. No alternative wireline algorithm has yet been found which better matches the core, and this equation remains in use to this day.

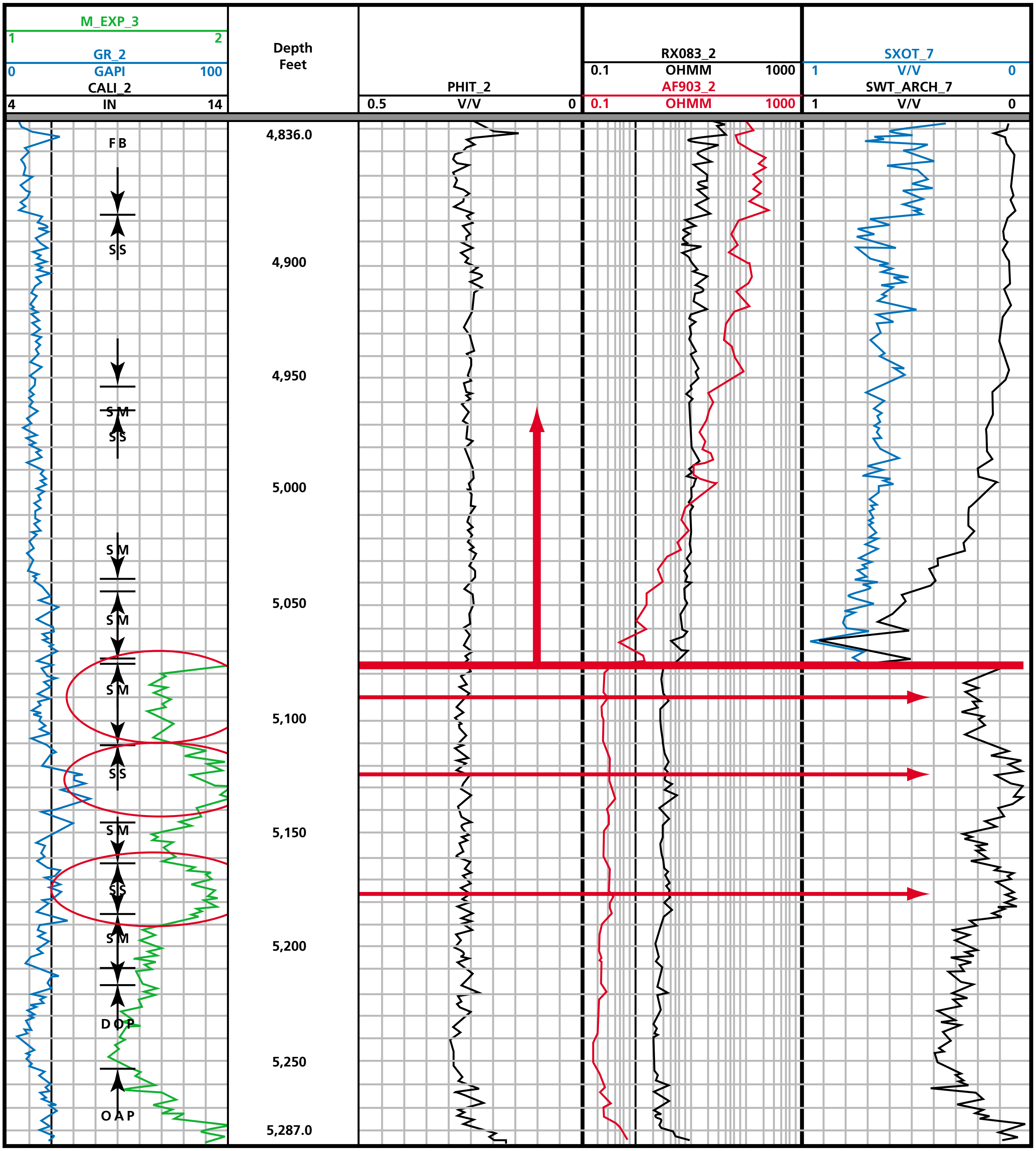


Fig. 11. Identification of facies from well log data is a remaining challenge. If water composition is known, it is possible to calculate the inferred *m* exponent in the water leg. Here we find a good correlation with independent core described facies. An improved formation evaluation would clearly result if one were able to identify facies and assign the appropriate exponent with only the log data.