Looking for gas-bearing layers in the Anadarko Basin, Oklahoma
By
Constantin Cranganu
Brooklyn College, Dept. of Geology
A lab activity for *Introduction to Geophysics*, Spring 2007
(This activity is an adaptation of a personal article, *Cranganu 2005*)

Introduction

The Anadarko Basin is the deepest sedimentary basin on the North American craton. Total sediment thickness on the deepest section exceeds 40,000 ft (12 km) and consists of sandstones, limestones, and shales of Cambrian to Permian age (Johnson et al., 1988). The basin covers almost the entire western part of Oklahoma and extends into the northeastern part of the Texas Panhandle (Figure 1).
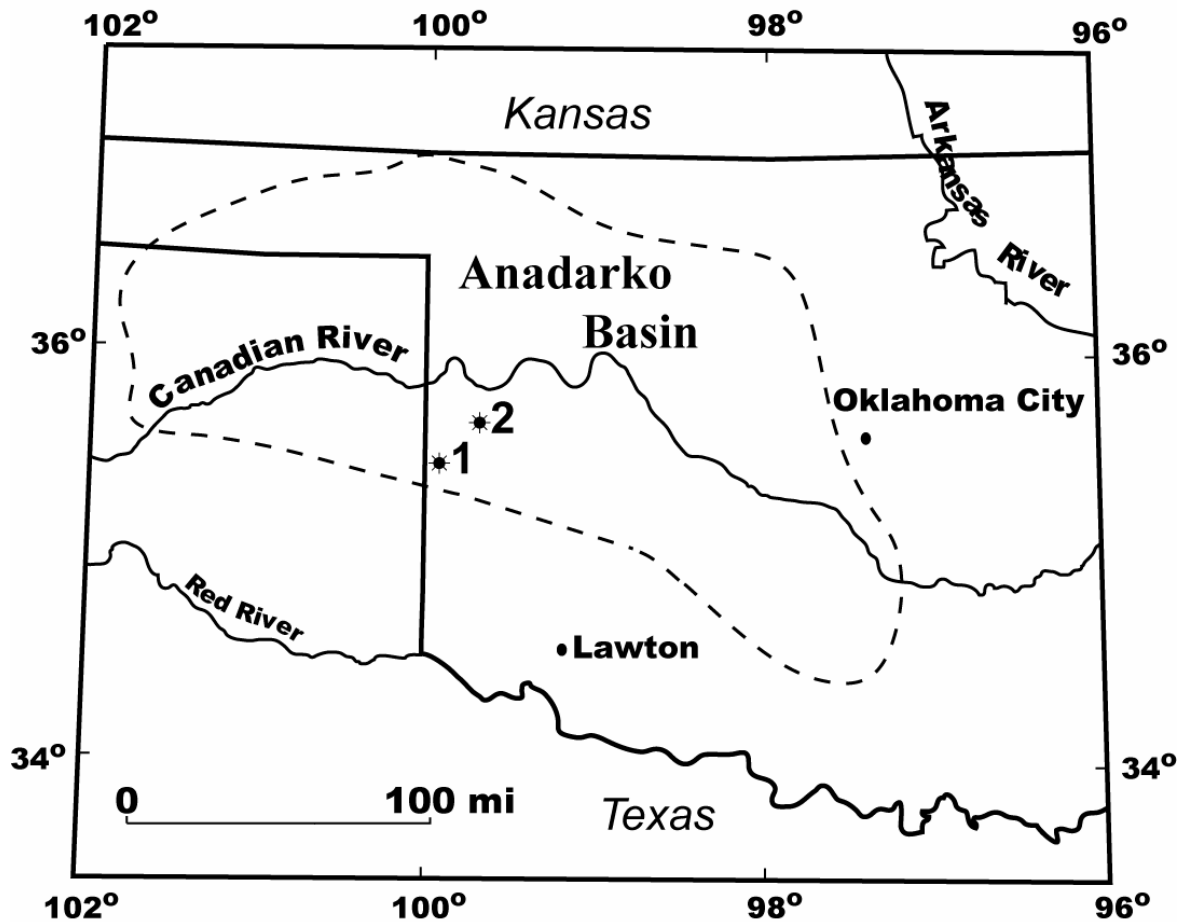

Figure 1. The Anadarko Basin and the two sites of case history discussed in text (1- Wesner 2-1 well; 2- Cobb 2-27 well).

The Anadarko Basin is one of the most prolific natural gas producers in the North American continent. The majority of the basin's gas reserves occur in the basin-scale compartments termed the mega-compartment complex (MCC) (Al-Shaieb et al., 1992, 1994a, and 1994b) and in the

deep basin below the MCC. The upper part of the basin also contains substantial amounts of oil and natural gas. In 1980, the ultimate recovery of natural gas from the Anadarko Basin was estimated at more than 110 TCF (trillion cubic feet) (Hill and Clark, 1980), an amount approximately equivalent to four times the year 2000 production of natural gas from all of North America. Several large (> 1 TCF production through January 2001) gas fields are located in the Oklahoma part of the Anadarko Basin. According to Lay (2001), these fields - Elk City, Putnam, Carpenter, Watonga-Chickasha, as well as portions of the Sooner Trend and Golden Trend fields - have produced about 9 TCF of gas since their discovery and exploitation. The Anadarko Basin is also believed to be the source of gas found in the nearby Panhandle-Hugoton field, the largest gas field in North America. Clearly, the Anadarko Basin still holds large gas reserves that need to be discovered and exploited.

The goal of this paper is to present a synergistic interpretation of various well logs for detecting the presence of gas-bearing layers in the Anadarko Basin. Although the examples chosen for interpretation are from a particular area of the basin (Roger Mills county), there is no impediment in extending it to other areas and, further, to other sedimentary basins holding gas-bearing layers.

Theoretical background

Identifying gas-bearing layers in a sedimentary basin implies a thorough and complex interpretation of information contained in well logs. The detection of gas with open-hole logs is tied primarily to the use of porosity type logs. These are the only logs generally run in open hole that are really influenced by presence of gas versus the presence of oil or water. The gas detected is in the invaded zone close to the borehole wall, or sometimes in the virgin formation if there is little to no invasion. The response of these porosity devices must be understood to fully appreciate the procedures assumed in setting up gas detection systems.

Neutron porosity log
The key to definitive open-hole gas detection is the neutron-porosity log, which responds to hydrogen contained in rock pores. Replacement of liquid by gas in the pore space of rock lowers the hydrogen density of the pore fluid. (Lower gas density predominates over increased hydrogen fraction by weight). As a result the neutron porosity curve, calibrated for liquid-filled porosity, indicates abnormally low porosity. The effect can be large. As an example, consider the zone from 14,035 ft to 14,091 ft in Figure 2: it is a gas-bearing interval with porosity close to 16%, but the neutron log shows an average of about 5%. This implies, as a first approximation, that about two-thirds of the pore space in the invaded zone is filled with gas and one-third is filled with liquid.

The situation is further complicated because the *excavation effect* (Dewan, 1983) must be taken into account. This effect may be defined as the difference, in porosity units or %, between the neutron log reading in a gas-bearing formation and that in a completely liquid-saturated formation having the same hydrogen content. The former will show lower porosity because it will contain less rock matrix, which will allow the neutrons to travel a little further. For example, a 30%-porosity formation with 50% water and 50% air in the pores would not read a porosity of 15%, as might be expected, but 9%. The *excavation effect* would be 6 %, which is not negligible. The reason for the difference is that the air space not been replaced by rock matrix.

Neutron porosity logs record shale as having relatively high porosity. Thus, in most cases, shale response looks like an increase in porosity (Figure 2, depth interval around 14,042 ft or Figure 3, depth interval around 11,335 ft). In other words, a shale response on a neutron porosity log will exhibit an opposite effect than that of a gas response.

Density porosity log

Density log is recorded by a tool comprised of a medium-energy gamma ray source and two gamma ray detectors. When the emitted gamma rays collide with electrons in the geologic formation, the collisions result in a loss of energy from the gamma ray particle. The scattered gamma rays that return to the detectors in the tool are measured in two energy ranges. The number of returning gamma rays in the higher energy range is proportional to the electron density of the formation. For most geologic formations of interest in hydrocarbon exploration, the electron density is related to formation bulk density (ρ_b) through a constant (Tittman and Wahl, 1965), and the bulk density is related to porosity.

The relationship between formation bulk density (ρ_b), formation matrix density (ρ_{ma}), formation density-derived porosity (Φ_D) and the density of the fluid in the pores (saltwater mud, freshwater mud, or hydrocarbons) (ρ_f) can be expressed as:

$$\Phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \tag{1}$$

Using Equation (1), a computer in the logging unit calculates density porosity from the measured bulk density of the formation. The matrix and fluid densities should be define prior to density porosity calculation.

On a density-derived porosity log, gas shows as an apparent increase in porosity (decrease in bulk density) (Figure 2, depth interval 14,035 – 14,091 ft or Figure 3, depth interval 11,253 – 11,368 ft). The effects of changes in fluid saturation are quantitatively predictable on the density-derived porosity log (which is calibrated from the bulk density log) due to the predictable relationship between porosity, formation density and fluid densities (Equation 1).

Shales are generally considered to have a density close to "clean" (shale-free) sandstones. But in some cases, the interstitial clays or inter-bedded shales in the rocks (so-called "dirty" rocks) are less dense than the sandstone grains. Consequently, the presence of clays or shales in "dirty" rocks appears to produce an increase in porosity.

If the formation's actual matrix density (ρ_{ma}) is less than the matrix density used to calculate the porosity [for example, calculating porosity of a sandstone ($\rho_{ma} = 2.644$ g/cm^3) using a limestone matrix density ($\rho_{ma} = 2.710$ g/cm^3)], the log shows a calculated porosity that is higher than the actual porosity of the formation. If the formation's actual fluid density (ρ_f) is less than the fluid density used to calculate the porosity [for example, calculating the porosity of a saltwater-filled formation ($\rho_f = 1.1$ g/cm3) using a freshwater value ($\rho_f = 1.0$ g/cm^3)], the log shows a calculated porosity that is lower than the actual porosity of the formation. Because matrix-density values occupy a wider range than fluid-density values, errors in estimating the matrix density have a stronger impact on the calculated porosity (Asquith and Krygowski, 2004).

It is also important to better know the matrix density (ρ_{ma}) at low porosity (~high ρ_b) than at high porosity (~low ρ_b). For example, at $\rho_b = 2.6$ g/cm^3, derived porosities would be ~3% for sand and ~6% for limestone. These porosities differ by a factor of 2 and could mean the thresh-

old between expecting commercial and noncommercial production since cutoff is often set around 5%. On the other hand, at $\rho_b = 2.2$ g/cm^3, derived porosities would be ~27% and ~30%, which differ by only 3%.

Combined neutron porosity and density-derived porosity logs

When plotted together (at the same scale and using the same porosity units), the neutron porosity and density porosity logs could be used to identify the presence of gas-bearing layers. As previously explained, replacement of liquid by gas in the pore space of rocks reduces both bulk density and hydrogen content. Consequently, in a zone containing a gas-bearing layer, the density porosity log will show higher porosity, while the neutron porosity log will show a lower porosity. In that zone, the two porosity curves will cross over each other. This gives rise to the well-known *crossover effect* on neutron-density porosity logs plotted together or positive values on density-neutron porosity curve (see shaded areas in Figure 2, between 14,035 and 14,091 ft, and in Figure 3, between 11,253 and 11,368 ft). The magnitude of the crossover (the amount of separation between the curves) is rather qualitatively than quantitatively related to the gas saturation.

The true porosity Φ may be estimated either by taking an average of the two log readings or by applying the equation (Dresser Atlas, 1975; Dewan, 1983, Brock, 1986, Labo, 1986, Schlumberger, 1987):

$$\Phi = \sqrt{\frac{\Phi_N^2 + \Phi_D^2}{2}} \qquad (2)$$

where Φ and Φ_D are neutron and density porosities. It has been suggested that the square-root equation is preferable as a means of suppressing the effects of any residual gas in the flushed zone. In the case discussed above (Figure 2, $\Phi_D = 16\%$ and $\Phi_N = 5\%$) this formula gives $\Phi = 12\%$. Thus, we can consider as an assessment rule that in gas-bearing zones the porosity is not midway between neutron and density logs but is about two-thirds of the way from the neutron reading to the density reading.

The *crossover effect* in detecting gas-bearing layers may lead to false predictions in the following situations:

a. Porosity curves are recorded based on limestone matrix ($\rho_{ma} = 2.710$ g/cm^3) but strata is actually sandstone ($\rho_{ma} = 2.644$ g/cm^3). The clue to false gas indication during log examination is a 6-7 % constant difference between the neutron and density logs. When this constant difference is seen, a matrix effect (i.e., the presence of different matrices on the same log) should be suspected.

b. Log is recorded on sandstone matrix ($\rho_{ma} = 2.644$ g/cm^3) and a low-porosity, gas-bearing limestone is penetrated. The crossover effect (due to gas presence) might occur; but if it is less than 6-7 %, it would not cause the neutron log to cross over the density log.

c. Gas is found in a dolomite matrix ($\rho_{ma} = 2.877$ g/cm^3). In contrast to limestone or sandstone recording, dolomite causes the neutron log to read much higher porosity than density log, primarily because of higher dolomite density as compared to limestone or sandstone densities. It is thus possible to suppress crossover effect in gas-bearing zones. In such cases (b and c), it is important to have independent determination of lithology, such as litho-density log.

d. A borehole wall has caverns or washed-out zones, making the use of neutron porosity and density porosity logs invalid. In these cases, the density-porosity tool is measuring drilling fluid

density instead of bulk density and, consequently, the displayed porosity values, as well as *crossover effect*, are anomalously high. These false gas indications can be ruled out by looking at caliper log[1] indications (caverns and wash-out zones are indicated by anomalously high caliper indications).

e. Mud cakes, especially in boreholes drilled with barite-loaded mud, such as wells with overpressures[2], can appear denser than adjacent formations. In such case the density tool will show density too high and porosity too low, and the *crossover effect* may be drastically attenuated. A solution for this problem is checking the caliper readings (which will show a reduction of measured borehole diameter) and density corrections on density log, which can be negative for barite-loaded mud. Such corrections are adequate up to about 0.15 g/cm^3 but not beyond that point.

f. The neutron tool tends to read shales as high in porosity (*the shale effect*). This occurs because the hydrogen that is within the clay's structure and in the water bound to the clay is sensed in addition to the hydrogen in the pore space. The shale effect will offset the effects of gas, which tends to lower the apparent porosity. A shaly gas zone could be interpreted as a clean water zone. Also, drilling fluid invasion into formation may displace gas away from the borehole beyond the depth of investigation of the neutron tool. Thus, even if the zone contains gas, the neutron tool may respond mostly to the presence of filtrate[3]. When such situation (shaly gas zone or drilling fluid invasion) occurs, it requires a thorough analysis of the gamma ray log (GR)[4] and litho-density log[5] to evaluate the shale content of the formation, as well as analysis of electric logs to determine the extent of invasion.

Litho-density (PE) log

The litho-density (PE) tool records the photoelectric factor or photoelectric absorption curve, PE (barn[6]/electron, or barn/e) (Figure 3). This curve reflects the average atomic number of the mineral or rock and is therefore a good indicator of the type of rock matrix. The PE values (in barn/e) for most common found rocks and minerals as follows (Schlumberger, 1987; Hearst et al, 2000): clean sandstone: 1.74; shaly ("dirty") sandstone: 2.70; limestone: 5.08; average shale: 3.42; dolomite: 3.14; quartz: 1.81, barite (a drilling mud additive): 267.

The PE values are influenced by porosity and fluid content (water or gas) (Brock, 1986).

A major impediment in using photoelectric absorption factor PE in determining the lithology and gas presence is encountered in the wells drilled with barite mud. Barite has an extremely high PE (267). If barite-loaded mud intrudes between the PE tool arm pressed against the borehole wall and the formation, as is almost inevitable, the very high PE values of barite swamps the formation value, rendering the PE curve useless. In areas of high formation pressure, where drillers use barite mud to counteract pressure with its weight, there will be severe limitations of use of litho-density log.

---

[1] A caliper log is a well log that measures hole diameter (in inches). It is used in an open hole.
[2] Overpressure is the amount by which the formation or pore fluid pressure exceeds hydrostatic or *normal pressure.*
[3] The drilling fluid that has passed through the mud cake into formation.
[4] A log that records natural (gamma) radioactivity. In sediments, the log mainly reflects shale content because minerals containing radioactive isotopes (the most common of which is potassium) tend to concentrate in clays and shales. For examples, see first panel in Figure 2 and Figure 3.
[5] A log that can distinguish among many minerals and rocks by recording their photoelectric factor (PEF or PE or P_e) (see next chapter).
[6] 1 barn = 10^{-24} cm^2. The probability of interaction of any particle (neutron, gamma, etc.) with a single atom or nucleus is called the *cross section* for that interaction and is normally expressed in barns.

Gamma Ray Log (GR)

Gamma ray (GR) logging tool mainly consists of a Geiger counter or a scintillator that estimates the distribution of gamma ray emitters in rock. Two kinds of tools are used: a total gamma ray tool that counts all gamma rays without discrimination (Natural Gamma Ray log, Figure 2 and Figure 3) and a spectral gamma ray tool that counts the gamma rays whose energy lies in ranges corresponding to windows of uranium, potassium, and thorium. In either case, the effect of attenuation in the rock and in the drilling fluid should be considered.

Shale-free sandstones ("clean") and carbonates have low concentration of radioactive material and give low gamma ray readings. As shale content increases, the gamma ray log response increases because of the concentration of radioactive material (mostly potassium) in shale. However, "clean" sandstones might also produce a high gamma ray response if the sandstone contains potassium feldspars, micas, glauconite, or uranium-rich waters.

Limestones and anhydrites have the lowest reading, 15-20 APIu[7]; dolomites and "clean" sands have slightly higher values, about 20-30 APIu. Shales average about 100 APIu but can vary from 75 to 150. A few very radioactive shales – the Woodford, for example- may read 200-300 APIu (Dewan, 1983). Normally, therefore, the GR log separates "clean" sands and carbonates from shale quite nicely.

Caliper log

Once a hole has been drilled, it is desirable to know its true size and shape. The instrument used for this purpose is called a caliper log. This log's main application is to monitor changes in the diameter of borehole caused by some environmental effects: mud cakes, cavities in the borehole wall, washed-out zones, and fractures. The information provided by the caliper log is then used to validate other wireline logs by checking and evaluating suspect log values.

Borehole environment and its effects on well logging

The purpose of logging is to measure the properties of rocks and fluids contained in them. Yet drilling a borehole causes changes of *in situ* conditions and introduces new material into borehole environment. For example, the drilling fluids, having various compositions, fill the borehole and often invade, at variable lateral extents, the pore space of the rock.

All logs described above are influenced by many factors related to borehole environment and drilling process: borehole size variation, presence of washed-out zones, borehole salinity, formation salinity, mud weight, borehole temperature, mud cake thickness, temperature, lithostatic stress[8], rock pore fluid pressure, effective stress[9], borehole breakouts[10], and borehole wall rugosity. Correction factors need to be applied to log readings before proceeding with interpretation.

---

[7] APIu (American Petroleum Institute unit) is the unit of radioactivity used for natural gamma ray logs. This unit is based on an artificially radioactive concrete block at the University of Houston, Texas, USA, that is defined to have a radioactivity of 200 American Petroleum Institute (API) units. This was chosen because it was considered to be twice the radioactivity of a typical shale. The formation is the primary standard for calibrating gamma ray logs. However, even when properly calibrated, different gamma ray tools will not necessarily have identical readings downhole because their detectors can have different spectral sensitivities. They will read the same only if the downhole formation contains the same proportions of thorium, potassium and uranium as the Houston standard.

[8] The stress caused by the weight of overlying rock.

[9] The difference between the lithostatic stress and the fluid pressure.

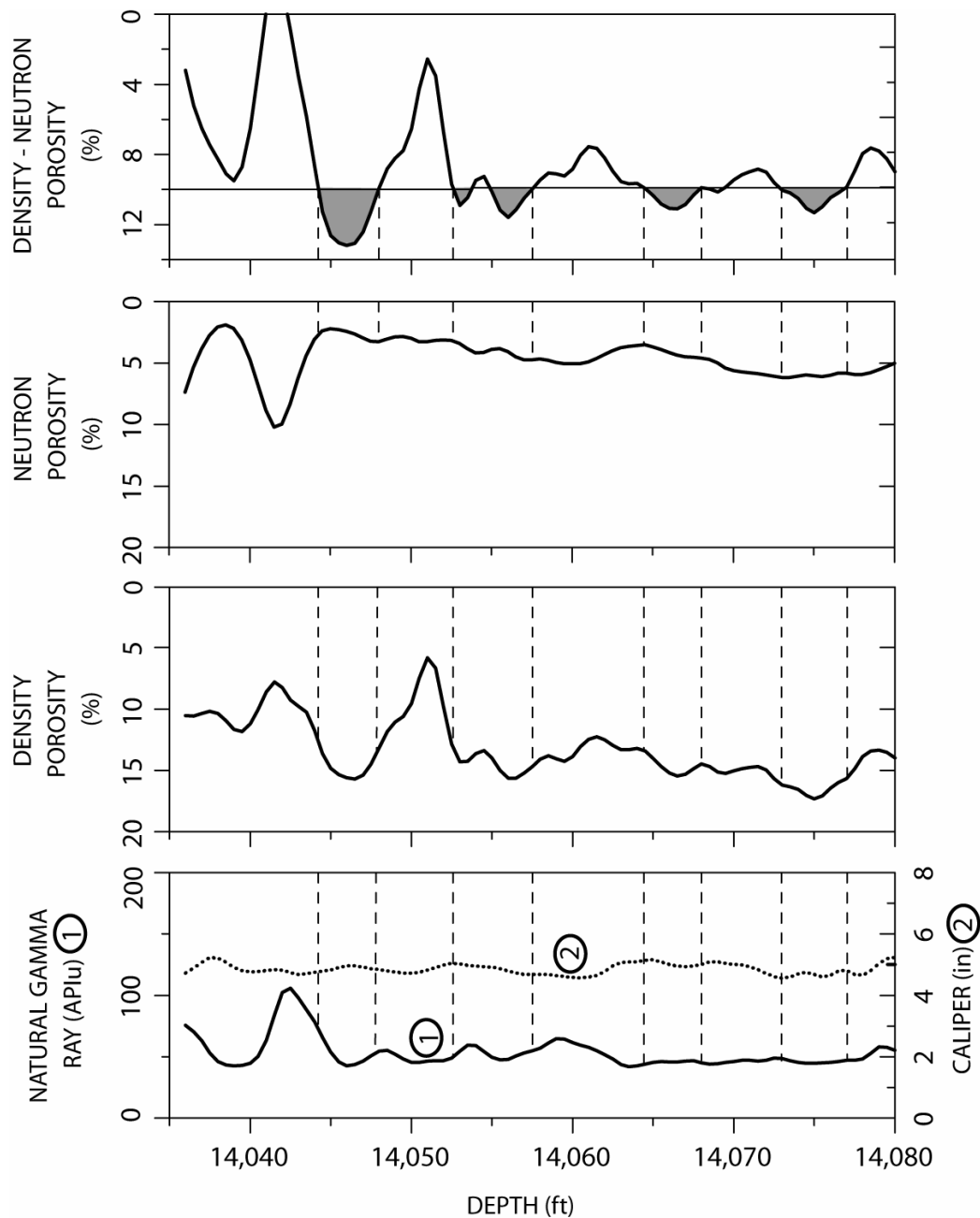[10] Borehole enlargements due to borehole stress concentrations.

Figure 2. Well logs from Wesner 2-1 well, Sec. 1, T 12N, R 22W, Roger Mills County, OK

The drilling company has indicated in completion card that the depth interval between 14,035 ft – 14,081 ft is a gas productive zone (Desmoinesian Granite Wash, Middle Pennsylvanian). The presence of gas is shown by DENSITY – NETRON POROSITY positive values (above +10%). This indication is not a matrix effect, which is, in general, of 6 - 7%. Moreover, natural gamma ray curve, with values between 40 and 60 APIu, indicates that formation is probably sandstone with some shale content in it (a "dirty" sandstone). The granite wash formation, so called by

drillers, is mainly represented by conglomerates eroded from Wichita Mountains (Johnson et al., 1988). Unfortunately, PE curve cannot be used because this well was drilled with barite-loaded mud (see comments above about the litho-density log). This is also true for several other wells, where P_n is higher than 0.5. P_n – normalized pressure- is a dimensionless parameter defined as a function of fluid pressure, hydrostatic pressure, and lithostatic pressure. P_n ranges from 0 (for hydrostatic pressure) to 1 (for lithostatic pressure) (Lee and Deming, 2002). Four or five gas-bearing layers, with thickness ranging between 1.3 –4.3 ft, have been identified (shaded layers in Figure 2). Other comments about this well have been made previously, in discussing the theoretical background of our approach.

Case History: Cobb 2-27 Well, T 15N, R 23W, S 27, P_n = 0.11, Figure 3

Now it's your turn!
Using the model interpretation for the well logs depicted in Figure 2, identify the gas-bearing layers in the Cobb 2-27 well (Figure 3)

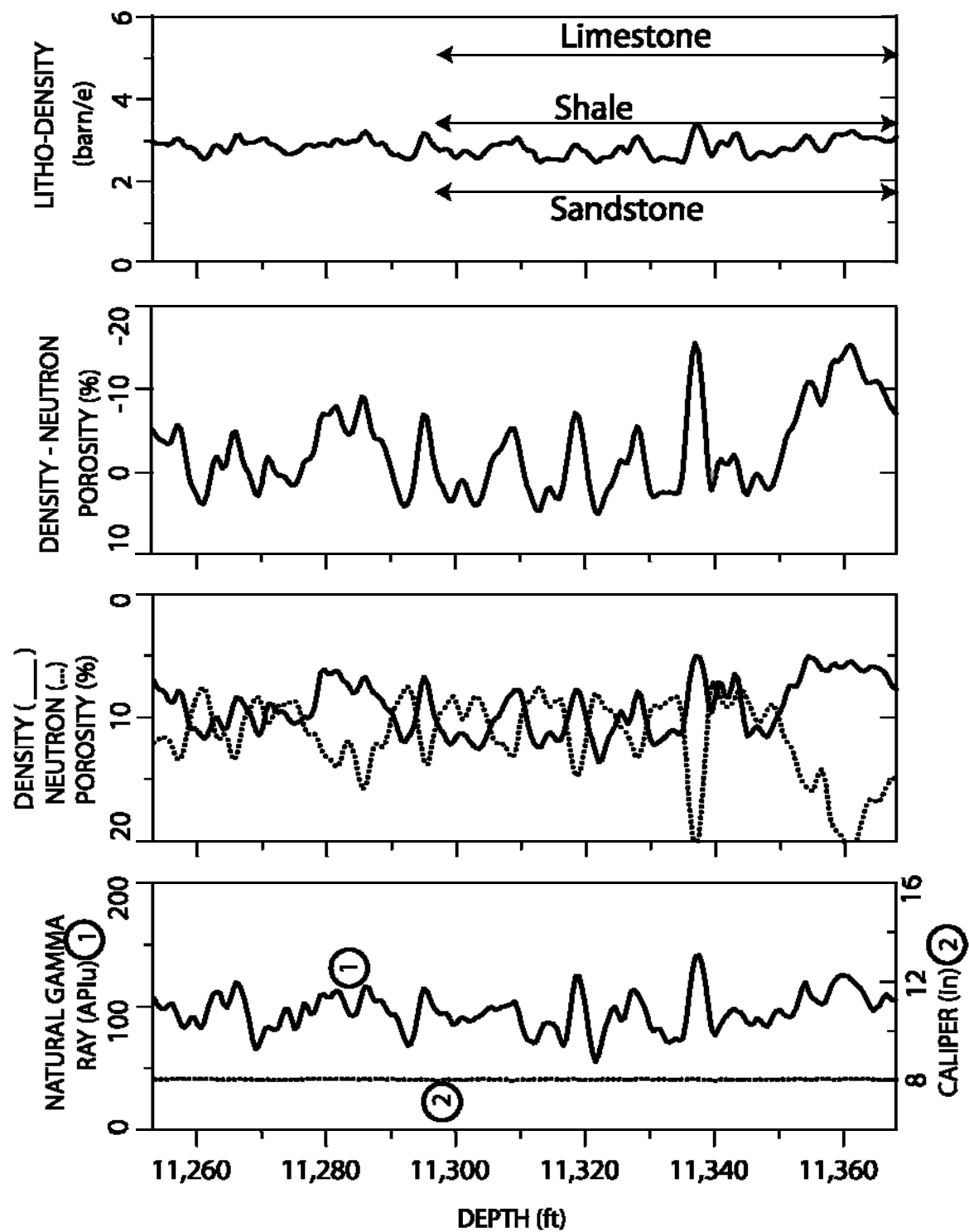Write a short report detailing your approach and your findings.

Figure 3. Well logs in Cobb 2-27 well, Sec. 27, T 15N, R 23W, Roger Mills County, OK (modified from Deming et al., 2002)

Conclusions

A thorough, synergistic analysis of available borehole well logs may represent a valuable approach to identify gas-bearing layers. The suite of well logs should include density porosity and neutron porosity logs that will help detect the presence of gas through crossover effects. Of course, these logs are proxy indicators and side effects (described above in the "Borehole environment…" paragraph) can sometime create crossover effects. Therefore, we were careful to rule out all known alternative interpretations. For example, in sections of a borehole where diameter increases, indicating washed-out zones, crossovers will be created by the presence of drilling fluid in wall cavities. In this instance, the caliper log will reveal the presence of cavernous zones. Other logs, such as natural gamma ray, density, and photoelectric logs, can help to filter out the side effects and yield more reliable information about lithology, which, in turn, enables the interpreter to predict with greater certainty the presence of gas-bearing layers. Finally, an extra checking measure was the comparison between gas-production intervals, as indicated by the drilling companies, and gas intervals, as revealed by the present interpretation.

The procedure described in this paper can be applied in other sedimentary basin where gas-bearing layers are thought to exist, if the proper well logs are available.

Drilling a well does not automatically ensure one will get the oil or gas the well was drilled for. In most cases, one needs to perforate the borehole wall to open the gas-bearing layers and put them in communication with the extraction equipment. But how does one know in advance where to perforate? One possible answer is the present paper.

References

Al-Shaieb, Z., J. Puckette, P. Ely, and V. Tigert, 1992, Pressure compartments and seals in the Anadarko Basin, *in* K. S. Johnson and B. J. Cardott (eds), Source Rocks in the Southern Mid-continent, 1990 Symposium, Oklahoma Geological Survey Circular 93, p. 210 – 228.

Al-Shaieb, Z., J. O. Puckette, A. A. Abdalla, and P. B. Ely, 1994a, Three levels of compartmentation within the overpressured interval of the Anadarko Basin, *in* P. J. Ortoleva (ed.), Basin Compartments and Seals, edited by, AAPG Memoir, v. 61, p. 69 – 83.

Al-Shaieb, Z., J. O. Puckette, A. A. Abdalla, and P. B. Ely, 1994b, Megacompartment complex in the Anadarko Basin: a completely sealed overpressured phenomenon, *in* P. J. Ortoleva (ed.), Basin Compartments and Seals, AAPG Memoir, v. 61, p.55 – 68.

Asquith, G., and D. Krygowski, 2004, Basic well log analysis, 2nd ed., AAPG Methods in Exploration Series, no. 16, Tulsa, Oklahoma, 244 p.

Brock, J., 1986, Applied open-hole log analysis, vol. 2, Gulf Publishing Co., 284 p.

Cranganu, C., 2005, Looking for gas layers in the Anadarko Basin, *Oklahoma Geology Notes,* v. 65, no. 3, p. 72 - 77.

Deming, D., C. Cranganu, and Y. Lee, 2002, Self-sealing in sedimentary basins: Journal of Geophysical Research, 107(B12), 2329 doi:10.1029/2001JB000504.

Dewan, J. T., 1983, Essentials of modern open-hole log interpretation, PennWell Publishing Company, Tulsa, Oklahoma, 361 p.

Dresser Atlas, 1975, Log interpretation fundamentals, Houston, Texas, Dresser Industries, Inc.

Hearst, J. R., P. H. Nelson, and F. L. Paillet, 2000, Well logging for physical properties – A handbook for geophysicists, geologists and engineers, Wiley, New York, 483 p.

Hill, G. W., and R. H. Clark, 1980, The Anadarko basin – a regional petroleum accumulation – a model for future exploration and development: Shale Shaker, v. 31, p. 36 – 49.

Johnson, K.S., T. W. Amsden, R. E. Denison, S. P. Dutton, A. G. Goldstein, B. Rascoe Jr., P. K. Sutherland, and D. M. Thompson, 1988, Southern Midcontinent region, *in* L. L. Sloss (ed.): Sedimentary cover – North American Craton; U. S. Boulder, Colorado, Geological Society of America, The Geology of North America, v. D-2, p. 307 – 359.

Labo, J., 1986, A practical introduction to borehole geophysics, Society of Exploration Geophysics, Tulsa, 330 p.

Lay, M. (ed.), 2001, Annual review of oil and gas production by fields in the Unites States and Canada: International Oil Scout Association, v. 70, p. 173-221.

Lee, Y., and D. Deming, 2002, Overpressures in the Anadarko Basin, southwestern Oklahoma: Static or dynamic?: AAPG Bulletin, v. 86, p. 145 –160.

Schlumberger, 1987, Log interpretation principles/applications, Houston, 198 p.

Tittman, A., and J. S. Wahl, 1965, The physical foundation of formation density logging (Gamma – Gamma): Geophysics, v. 30, p. 106 – 114.