Log Interpretation Strategies in Gas Wells

This discussion is excerpted from a roundtable conducted on June 24, 1990 in Lafayette, Louisiana, USA during the SPWLA 31st Annual Logging Symposium.

Initial Analysis

MODERATOR

SCOTT JACOBSEN

Does your logging suite differ depending on whether you’re looking for oil or gas?

JOHN WATSON

In some areas, what we’re looking for alters the logging suite, particularly which neutron tool we might use. In north Louisiana, for example, the neutron tool has a much greater depth of investigation than the density. In the main gas producing zones, the neutron sees beyond the invaded zone and reports very low porosity, almost zero. The neutron is so low we can’t correct it back. In this environment and others where lithology also depresses the neutron reading, the sidewall neutron porosity tool, with its shallower depth of investigation, provides a better match with the density. This is especially true when we want to characterize lithology and porosity instead of just identifying gas with the neutron and determining porosity with the density.

CORNELIS VAN BAAREN

If we know lithology and porosity, have shallow invasion, and can see the gas effect on the neutron, we might run only the neutron to distinguish gas from oil. As an exception, Canada has a lot of low-porosity carbonates with fairly deep invasion, which masks the gas effect.

MODERATOR

What are the basic logging tools for optimum evaluation of low-porosity gas sands?

VAN BAAREN

Onshore western Canada has mixed lithology—dolomites, limestones and anhydrite—and very low porosity, about 5 percent. We usually run the sonic to cope with the low porosity, and the density-neutron to determine lithology, porosity and, if possible, fluid type.
LOUISE LEVIEN

Onshore Thailand also has low-porosity carbonates, but our holes are often in poor shape. The neutron-sonic gives a better representation of porosity because bulk density seems to read low, possibly because of rugosity or hole enlargement.

MAGGIE SULLIVAN

And what is your basic logging suite for high-porosity gas sands?

VAN BAAREN

I start with the gamma ray to distinguish sands and shales, reservoir from nonreservoir. Next, I examine lithology in detail. Is it argillaceous sandstone or not? Third, I check the porosity. In high-porosity sandstones, unconsolidated or friable, I find the density measurement the most reliable porosity indicator.

Fourth, I quantify saturations, and fifth, I locate and characterize fluid contacts—gas/oil or oil/water and the free water level.

I have had to work hard to convince some partners that the RFT tool does not give an ideal measurement in high-porosity, high-permeability gas sands. The build-up measurement basically yields a lower limit of permeability, causing underestimation of productivity. We're not sure why the RFT gives low values, perhaps because of local variations in permeability or permeability reduction around the probe. Sidewall cores provide even lower permeability values because of alteration of the grain structure during sampling. Drillstem or production testing, minus skin, gives the best indication of reservoir quality.

MAGGIE SULLIVAN

Is there a difference in approach when deciding whether to complete an oil well versus a gas well?

LEVIEN

There probably is. You would most likely use a lower porosity cutoff for gas than for oil. With gas, you might set pipe and test at 1- or 2-percent porosity, which you would rarely do with oil. The higher productivity of gas can be attributed to both fracturing and mobility differences between gas and oil.

VAN BAAREN

Whether to set pipe often has nothing to do with log interpretation. Sometimes there are regulatory requirements, sometimes it depends on the objectives for the well. If our main objective is oil and we find gas, we might decide not to complete if the economics are bad—we need proximity to distribution and a significant volume at a sustainable rate. Sometimes we set pipe based on safety. We once unexpectedly found enormous amounts of gas in the Arctic and had to set pipe earlier than planned to protect ourselves.


**Invasion and Porosity Corrections**

**MODERATOR**

A significant problem in gas reservoirs is accounting for the effect of invasion because it displaces some gas beyond what the neutron tool can detect. How do you tell if you have deep invasion?

**LEVYEN**

We have a deep gas well in a crossbedded eolian sandstone in Mobile Bay (offshore Alabama, USA), in which the challenge is to distinguish whether log effects are due to invasion or a transition zone. To quantify reserves, we need to determine the depth of the gas/water contact. By “contact” I mean a 20-foot [6-meter] interval above which we could say “this is gas” and below which “this is water.” The problem was that most tools failed because of the high temperature—400°F [204°C]—and evaluation was complicated by the formation being open for a long time. Only the sonic correlated with core porosities. The sonic porosity log indicates an increase in porosity with depth (below).

There is very little separation between the deep and medium resistivity, suggesting either no invasion or deep invasion. We also know that we don’t have a very good mudcake because the high temperature reduces viscosity of the water-base mud, contributing to deep invasion. In the zone below X540 feet, porosity is greater than 5 percent and permeability is in the 100-millidarcy (md) range. Using the deep induction for true resistivity \( R_t \) with a tornado chart correction, the logs still indicate hydrocarbon, known to be gas from production history.

**VAN BAAREN**

If you had a water-bearing zone, what would you expect to be the resistivity of the water-bearing formation \( R_t \)?

**LEVYEN**

We calculated \( R_t \) from measured \( a \) and \( m \) from core.\(^3\) We then plotted \( R_t \) and \( R_t \) to try and see where they came together. They converged, indicating a contact at X810 feet; other data indicated a contact at X855 feet. So the question is because there isn’t a well-defined contact, are we in a long transition zone because of poor permeability, or in a zone that goes from less to more invasion, masking the contact? Resistivity increases at X710, X725, X739, X751 and X760 feet are due to tight strings—evidenced by a decrease in sonic interval transit time—and are not hydrocarbon-related.

**CHARLES NEUMAN**

Perhaps you can determine the contact only by setting casing and running a pulsed neutron log. Then deep invasion should have dissipated into the formation, and you might see gas around the casing.

**LEVYEN**

Some wells in Mobile Bay were drilled with oil-base mud (OBM), and the contacts are obvious. I think we can see them because OBM maintains its viscosity at high temperature and prevents deep invasion. But we can’t diagnose the depth of invasion because the resistivity curves are lying on top of each other.

**MODERATOR**

Has anyone tried to determine the diameter of invasion using analytical methods, such as resistivity tool modeling?

**VAN BAAREN**

We’ve tried but the answers are not easily obtained. For sandstone with moderate porosity and permeability, a step-like invasion profile, or piston-like invasion, is assumed. This is not the invasion profile used to construct the tornado chart, so its corrections of resistivity are invalid. If we have very high permeability—0.5 darcy to 40 darcies—and therefore shallow invasion, we just assume the induction log reads \( R_t \). Such high-porosity formations have very short vertical transition zones and well-defined hydrocarbon and water zones, with very high hydrocarbon saturations—85 percent or greater.

Another problem is knowing whether hydrocarbons are present, so we know which fluid type to use in the porosity correction. Fortunately, we normally calibrate porosity logs against core. And since we know the vertical distribution of porosity—from core and averaged over the response function of the relevant porosity tool—we make separate core-log calibrations of porosity correction for gas, oil and water. But if we don’t have core, we have to be careful. Chartbook porosity corrections often can’t cope with a strong gas effect in high-porosity sands. In this case, we go to the same section in an offset well where the sand is water-bearing and we can easily calibrate porosity. The key issue here is knowing lithology, depositional environment and diagenetic history. This has worked for us in Cabon and Nigeria. Alternatively, we sometimes assume a residual gas saturation—say, 30 percent—and base our calibrations on that.

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\(^3\) An invaded zone or a long transition zone? There are several interpretations for this gas well in Mobile Bay, offshore Alabama, USA. On the sonic log at X550 feet, a 60-microsecond transit time equals 5 porosity units (p.u.). (Courtesy of Ocean Corp.)
WATSON
In thick, high-porosity sands with a definitive gas/water contact, we find that a good quality check on hydrocarbon corrections is to look at the final computed porosity below and above the contact. When they're different, we know the hydrocarbon correction is incorrect.

VAN BAAREN
Calculated grain density provides another good quality check on the hydrocarbon correction. An unexpected jump in grain density across a contact indicates something is wrong with the hydrocarbon correction. This is why understanding of lithology is so important—to know whether grain density jumps around for a good reason. We wonder whether the GLUT tool may be able to replace core for this application, but so far, unfortunately, it has not. We think there are still uncertainties in the translation of elemental yields into mineral compositions, and then to lithology.

MODERATOR
Can the density-neutron be used quantitatively in open hole to define gas saturation?

NEUMAN
Certainly, using chartbook corrections. First we correct the neutron for temperature, if needed, then apply the Segesman and Liu excavation correction. Because the density log reads close to the wellbore, we assume it reads only liquid, that the gas has been flushed. We've tried using sophisticated computer programs, like SNUMPAR, but they give us the same answers as the old-fashioned way when lithology is known.

WATSON
The biggest problem we have in determining gas saturation, in open or cased hole, is the shale content—especially in shaly sands. The thermal neutron component of the CNL tool is strongly affected by the clay matrix, which complicates the computation. If the clay correction is off, the gas saturation will be also. Clay evaluation is probably the most difficult thing we do.

Hydrocarbon Effects

MODERATOR
Let's take a scenario where you have a gas/oil contact (GOC) that you can define on the logs, despite some invasion. Is it important to characterize the downhole gas/oil ratio (GOR)?

VAN BAAREN
It would be fantastic if you could. I was investigating this in the North Sea and came back to John's [Watson] point: the density-neutron separation is affected by so many factors that are often unknown—lithology, porosity and fluid.

NEUMAN
I'm convinced there's another reason you can't characterize downhole GOR, at least in the US Gulf Coast. We see strange hydrogen contents of crude oils. I encountered one well with an interval of large density-neutron crossover that produced oil above, and another well with an interval at 970-980 feet with

3. In the Archie expression,$$ F = \frac{R_s}{R_w^m} $$

F is formation resistivity factor (resistivity of the water-saturated formation divided by resistivity of the saturating brine), a is cementation factor (a constant varying with lithology), \( \phi \) is porosity and m is the cementation exponent. Both m and a are determined empirically.


5. Excavation effect decreases neutron porosity below that expected based on the hydrogen indices of the formation. It results from the presence of a formation fluid with a hydrogen index lower than that of water. See Segesman F and Liu C: "The Excavation Effect," Transactions of the SPE-AIME 12th Annual Logging Symposium, Dallas, Texas, USA, May 2-5, 1971, paper N.


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no crossover—which could mean invasion—that produced gas with no oil (left). The large crossover that produced oil indicates that we don't have a full understanding of the effect of the hydrogen content of crudes.

**VAN BAAREN**

Could you possibly have a very light oil? Even an oil of 50° API gravity² could give you a separation if the hydrogen index is different.

**NEUMAN**

No, we produced low-GOR oil so the anomalous behavior must be due to something else. In the extreme case (page 25), there is a large separation and we produced essentially gas-free oil. The top of the hydrocarbon-bearing zone, at X010 feet, has almost 30 units of separation. The GOR from sustained production at X030 to X060 feet was below 700 scf/bbl. Note that the TDT-K near/far count rate separation also indicates oil, not gas.

A less extreme case is more typical (next page), where the crossover starts at about 462 feet and continues down for about 40 feet (12 meters). This well was more important because we didn't want to set casing if it produced only gas. Ultimately, we cased the well because there was some oil produced from this sand in an offset well. The entire sand was perforated and produced oil.

Unfortunately, I don’t have a solution to this. All it tells us is to watch out—that you can produce oil despite a density-neutron crossover.

**WATSON**

In our experience, we produce oil despite a density-neutron crossover in about 10 percent of wells, especially in homogeneous limestone in the Middle East, with porosities of 20 to 22 percent. It’s Arabian light, in the 40° to 55° API range.

**VAN BAAREN**

Some oils have strange properties. We have seen very pure, light oils that start with C₁₀.⁸ And we have seen very heavy oils that start with C₂ or C₃. In a significant number of instances chartbook corrections don’t work, and we need to be able to recognize these.

**NEUMAN**

My first example seems to shoot down the anomalous oil explanation (page 25). The density-neutron crossover from X008 to X050 feet changes dramatically from 30 to 10 units. No oil could undergo such a large hydrocarbon density change in only 42 feet (13 meters). A measurement of neutron capture cross section (2) was not run at the same time as the density-neutron, and there was probably some production preceding it, but it also changes drastically.

**VAN BAAREN**

This kind of crossover in an exploration well strongly indicates gas to me, regardless of the other information. Fortunately, 90 percent of the time, you’re right. But in the other 10 percent, the only way to find out is by an RFT or a drillstem test.

**LEVIE**

Can you also look at fluorescence for a gas indication or a lot of C₃?

**VAN BAAREN**

In our experience, this works only about half the time. Sometimes the mud log shows only about half the reservoir interval. We have had this problem in Denmark and in western Egypt. The key to handling these problems is identifying API gravity and fluid type.
Using Irreducible Water Saturation

MODERATOR
Assuming you identify fluids, get a good handle on porosity and $R_p$, what about irreducible water saturation $S_{wirr}$? Do you calculate it, and what do you use it for?

VAN BAAREN
We almost always use capillary pressure from core instead of $S_{wirr}$ from logs. The exception is when you have a fairly clean rock with high porosity—at least 30 p.u.—and high permeability and you make the calculation far above both the free water level and the contact. As permeability declines, this approach becomes less certain.

BOB EVERETT
Do you try to relate $S_{wirr}$ to a permeability?

VAN BAAREN
Yes, using core, which has risks. It can be off by two orders of magnitude. Direct assessment of permeability from core and RFT measurements can give only a minimum value.

MODERATOR
We’ve had some recent success in the Gulf Coast showing that a model using electromagnetic propagation logging does indeed give $S_{wirr}$. Our model, which has been tested only in the US Gulf Coast, is this: Even in the shallowest part of the invaded zone, capillary-bound water occurs in shaly sands. This is water in addition to that bound to the clays. This capillary water does not move during invasion, so some water is left even in the zone of investigation of the EPT-D or EPT-G tool. The electromagnetic propagation log measures a salinity that is therefore between that of the filtrate and of this capillary-bound water. If there is sufficient contrast in salinities, you can distinguish these two waters. This works in the Gulf Coast because the mud is fresh and the water saline. Has anyone tried this?

NEUMAN
I haven’t tried it but would argue against it because there is always sufficient time for diffusion to take place between mud filtrate and capillary-bound water. On the other hand, I have successfully used the EPT measurement for residual oil.

LEVIE
In my experience, 90 percent of boreholes aren’t in good enough condition to run the EPT tool. In unconsolidated sands, it’s probably more than 90 percent.

EVERETT
Another problem is the matrix effect on the EPT log, which can be high enough to invalidate EPT porosity when only a quartz matrix is used to calculate porosity.

LEVIE
For the method to work you would need silt or a very fine grain sand to have enough capillary force to hold the capillary-bound water. It would also have to be clean enough to avoid complications associated with varying lithology. [General agreement.]
Tight Rock Evaluation

VAN BAAREN

A typical problem in low-permeability, low-porosity, gas-bearing reservoirs—1 to 100 md and 3 to 10 p.u.—is determination of $R_s$ for calculation of saturations (below). This well is in a vuggy, fractured, heterogeneous carbonate reef. A problem is that vugs, which constitute the reservoir, occupy thin limestone and anhydrite streaks, with a thickness of 10 to 20 centimeters (cm) [4 to 8 inches] (3250 meters subsea depth). It's a complex setting—both tight and permeable sections.

Our means of separating hydrocarbon from water is $R_s$, usually in the tight streaks. But with the present generation of tools, we can't get $R_s$ in formations thinner than 1 meter [3 feet]. Ideally, we need a high-resolution, deep-reading tool, if possible.

We've marked the gas/water contact transition zone beginning at 3250 meters. Here we have several questions. What is the real free water level? It can be hundreds of meters deeper, so you still don't know whether or not this is gas. What are the water and gas saturations? Will it produce and what will it produce—gas alone, water alone or a mix? Typically, we test and see what comes out.

Another problem is determination of $m$. We rely heavily on core analysis, and in the past we used atmospheric porosity, permeability and formation resistivity factor. Recently, we've started with whole-core analysis under in-situ conditions and we get different parameters. In the past, $m$ based on log analysis was about 3, but under in-situ conditions it's 2.3 or 2.4. The value of $m$ declines because the core is distorted, with tiny fractures. Most core analysis is done on the matrix rather than the vugs, so $m$ does not increase, as you might suspect.

We have found complex invasion patterns. The matrix, with porosity about 3 percent, has a permeability of about 1 md. The vugs have much higher permeability, and if they are well-connected, invasion can be extreme. We'd like to predict how the vugs are connected, but today we have no tools for that.

MODERATOR

What does the change in the water saturation ($S_w$) log interpretation at 3250 meters mean?

VAN BAAREN

Knowing these rocks, I would say above 3250 meters is about 80-percent hydrocarbon saturation. Based on the capillary pressure curves for this type of rock, I would expect gas another 100 meters [330 feet] down. Whether we can produce this economically, because of distribution of vugs and fractures, is another matter. The lower resistivity below this interval is an invaded zone. The question is, in the face of probably deep invasion, should we test? Above 3240 meters, where we have curve separation, there is still gas close to the wellbore. The microlog works like a charm as a permeability indicator in this kind of rock—about 10 percent porosity. You get good separation if you have good matrix porosity or poor matrix porosity with a high concentration of vugs. But if you have a low concentration of vugs without matrix porosity, the microlog will not tell you whether or not you have a reservoir.

The density-neutron [not shown at left] did not show any gas below 3250 meters because invasion was deep and porosity was too low. We are considering alternatives such as borehole gravimetry, but it has limitations because it reads so deep. You know lithology near the wellbore, but lithology can change dramatically just 10 feet [3 meters] away, especially in reefs.

[General agreement].

LEVIEI

Our Thailand wells are much less porous, around 5 percent. In one of these wells, the laterolog was useless for saturation determination—in many zones it was pegged at 40,000 ohm-meters (ohm-m). There was little evidence of fractures but the well tested at a very high flow rate.

In the Thai field, if log porosities agree somewhat with core porosities, I'm quite happy. I pick contacts where $S_w$ in the relatively porous zones—greater than 5 percent porosity—goes from consistently low to consistently high. In some wells, we don't appear to have contacts—everything is in vertical communication. But in others, contacts are very clear, although production tests are ambiguous. We use log porosities to calculate reservoir volume, but log error is significant so we test based on mud gas, drilling breaks and kicks. Log analysis usually breaks down because porosities are so low.

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Finding $R_s$ for accurate saturation calculation in a low-porosity, low-permeability reservoir. Logs are, from left, gamma ray, microlog (normal and inverse), porosity bulk volume, an indicator of where whole core was taken (the solid dark column), laterolog shallow and deep, and two computations of water saturation. The black profile is based on $m$=2.4 and $\alpha$=1; then gray is based on $m$=2.72 and $\alpha$=0.44. (Courtesy of Shell Canada Limited.)
Shaly Gas Sands

LEVIEH
As with high-porosity sands, a common question in shaly sands is whether you are seeing hydrocarbon or water. These wells are from the same block in offshore California (below). Well A produced a lot of gas during a 2-hour test between 40 and 282 feet, where there's no density-neutron crossover. Well B was tested over a similar interval (23 to 277 feet) and produced water. The lithology varies widely: 10 to 50 percent plagioclase—a lot of which is altered—25 to 35 percent quartz, 15 to 20 percent K-feldspar, 0 to 10 percent laumontite9 and 5 to 20 percent biotite.

NEUMANN
Good separation of the medium and deep induction logs suggests there is enough invasion to prevent the density-neutron from seeing gas—that the gas has been flushed.

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9. Laumontite ([CaAl₂Si₃O₁₀·4H₂O]) is a white zeolite mineral. It occurs in veins in schist and slate and in cavities in igneous rock.
EVERETT
I think the density-neutron is seeing gas. The high neutron reading is due to a thermal absorber, such as a lot of boron in the formation. I see a difference in the density-neutron separation of well A compared with that of well B, which I think shows gas. In well B, if I put the density log on top of the neutron and normalize them in the bottom shale, they overlay as you come up. If I do exactly the same thing for well A, normalizing it on the bottom, there is crossover as you come up. So I think all I'm doing is amplifying the difference between the neutron-density on the gas well—there is more crossover on well B than on well A after the logs have been normalized.

WATSON
In this setting, where positive separation hinders the ability to find gas, has anyone seen any benefit from using the CNT-G?

NEUMAN
No, unfortunately. Every time I run one in shaly sand, by the time we correct everything, the epithermal and thermal measurements tell us the same thing.

LEVIE\n
In this well, the density log gave the best estimate of core porosity, using grain density from the core rather than a constant matrix value. We could have used a similar approach for the neutron. If you have SNUPAR, it's not difficult to go from core density and mineralogy to a matrix correction on the neutron. But when these logs were made, this was not done.

NEUMAN
You could make the SNUPAR calculation to correct the neutron for matrix effects if you know mineralogy and $\Sigma$, but you don't have either. Besides, in California, you get so much $\Sigma$ from gadolinium, samarium and boron that it is almost impossible to reconstruct $\Sigma$ from mineralogical analysis.

WATSON
You can if you have a GLT log. It measures gadolinium, which is related to samarium and boron. And a GLT log gives you a $\Sigma$ measurement—not a perfect one, but better than none.

A GLT gives you a $\Sigma$ measurement—not a perfect one, but better than none.

Cased Hole Logging

MODERATOR
A challenge in cased hole logging is using pulsed neutron techniques to distinguish gas sands from liquid-filled "tight" sands—those with porosity low enough to be mistaken for gas. How do you deal with this?

NEUMAN
Wet sands that look like gas can have porosity as high as 20 percent, at least in the US Gulf Coast. If we have 30-Percent porosity confidently determined from openhole logs, and the pulsed neutron log reports 20 percent—because $\Sigma$ and the near/far ratio are low—we generally produce gas. Yet, there are places with genuinely low porosity without gas. I consider distinguishing these two an unsolved technical problem.

Chevron has dealt with this problem in a cemented, cased well in the US Gulf Coast (above and next page). The resistivity has three excursions to the right, at 933, 960 and 969 feet. The obvious interpretation of the density-neutron is gas in the top two lobes and none in the bottom.
In cased hole, distinguishing tight sands from gas sands. Porosity from the pulsed neutron log (TDT-P) is much lower in all three lobes than in the wet sand below, indicating gas. However, the inelastic signal from the far detector shows no deflection, suggesting a brine-filled sand. This interval produced 9.5 MMcF/D and 360 barrels of condensate per day. The DT log (previous page) provided evidence that the interval was porous. Often, however, sands like this in the US Gulf Coast are evaluated only with pulsed neutron and old electrical survey (ES) logs. (Courtesy of Chevron USA.)

Despite the lack of separation in the bottom sand, the pulsed neutron \( \Sigma \) could indicate about the same amount of gas as in the upper two sand lobes. How do we tell whether this lower sand is low porosity or gas-bearing? One guide we have in the Gulf Coast is the inelastic curve [a measure of inelastic neutron scattering], which moves left in gas. But here the inelastic curve is dead and fails to distinguish gas from low porosity. Another guide is the sonic log, which here shows the same porosity in all three sands. The interval containing the two lobes was perforated and produced mostly gas, some condensate and no oil.

**WATSON**

The inelastic can help confirm the presence of gas but tends to require both a high gas saturation and high porosity. In medium or low porosity, the inelastic is never going to help. It's a very shallow measurement.

**VAN BAAREN**

No one has mentioned cement. I would assume that the cement significantly affects the pulsed neutron measurement.

**NEUMAN**

Although I used to advocate that, today it would surprise me—unless you have an annulus of at least 3 inches [8 cm]. But if the annulus is an inch or less, neutrons will diffuse fast enough to reach the casing and be absorbed before they can influence the measurement.

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The effect of borehole environment on pulsed neutron response is illustrated in a classic TDT-P example (right). This very gassy North Sea well was logged flowing. The inelastic curve is tremendously sensitive to the borehole environment. Once gas hits the borehole, the inelastic curve almost saturates, and its primary response is to the borehole environment. Gas in the formation is a secondary response. The key gas indicator is the fairly constant Σ curve through this zone, except at the fluid contact at 8970 feet.

Another example, from Schlumberger's dry test well in Rosharon, Texas, USA, shows the basis for using an inelastic curve to distinguish a tight streak from gas (below, right). The tight zone from 4905 to 4915 feet is 15-p.u. limestone on top of Fri sand. Normal interpretation based on count rates would be gas. But the inelastic is straight, indicating no gas.

The third example (next page) shows that a low-pressure formation can enhance the inelastic response and help confirm the far count rate. This is a Canadian high-porosity sand-shale with a gas-bearing zone at 4690 to 4710 feet and tight streaks at 4540 and 4595 feet. Because the producing zone is a low-pressure gas, the inelastic curve moves left and confirms the far count rate indication of gas.

Another consideration in gas detection is pulsed neutron tool output. For example, the near/far count rate overlay, used for gas detection, is not as easily distinguished on the new TDT-P as with the older TDT-K.

I'm glad to hear you say that. Some of my colleagues laugh at me because I take raw data from the TDT-P and make a TDT-K out of it.

It would be better to go to a whole new telemetry system with a 256-channel analyzer for each detector. This would allow you to break down the response into 10-microsecond bands. Then you could effectively model the TDT-K count rate almost exactly.

I think I disagree. I can fit a decay curve very well to the 16-gate response of the TDT-P. I don't need 256 channels. By knowing how the TDT-P works, you can take the response curve and work backward to what a TDT-K would give you.

Let's talk about fresh water. What cased hole log measurement do you use then? Is the pulsed neutron the only tool you can run?

Fresh water itself in a high-porosity gas sandstone is not much of a problem. The Carrizo formation of south Texas has drinking quality water in places with a gas cap. The Σ measurement has a little wobble that might aggressively be interpreted as gas. But the gas shows clearly when pulsed neutron porosity and count rate techniques are used together. The measurement isn't quantitative, but you can qualitatively pick perforation intervals.

Sonic logs have had some success. In south Texas, in the Fri sandstone and some of the older formations, even carbonates, the t compressional interval transit time has been successful, and a sonic-neutron overlay has worked quite well. The technique seems to work even in poorly cemented casing but has some difficulty with more than one string of casing or un cemented casing, or both.
MODERATOR
How do you evaluate zones that have gas inside casing, such as in northeast Texas and north Louisiana?

WATSON
There's more to the problem than gas response characterization—there's no hydrogen in the borehole to moderate the neutrons and you effectively saturate the detectors. Dead-time losses are considerable. When you try to subdivide the $\Sigma$ measurement, 80 percent is from the borehole and 20 percent is from the formation. This also occurs in the openhole environment when you have a low $\Sigma$ and fresh borehole fluids because there is no iron in the casing to boost the borehole $\Sigma$.

The $\Sigma$ computation can be improved by placing a fluid excluder sleeve around the tool, which unfortunately is not generally available. Schlumberger has had success using the GST sleeve on the pulsed neutron tool. No lab-type calibration with the sleeve is needed. The sleeve contains boron, which greatly increases the apparent borehole effect, so you can easily distinguish borehole from formation $\Sigma$.

Where Does Gas Well Evaluation Stand?

VAN BAAREN
The key issue in gas is that an awful lot is overlooked. I've been in North America only two years, and I find most companies extremely cautious—they look only at hydrocarbon above the transition zone. They aren't interested in average water saturation and the volume below the transition zone. This is surprising because in some fields, 90 percent of reserves are in the transition zone.

NEUMAN
But as far as equity is concerned, anything below the transition zone just doesn't count.

VAN BAAREN
That's where many people make a big mistake. Some fields can't be produced at all if you look only at the good stuff. The standard rule is that formations with less than 50 percent hydrocarbon saturation won't produce a lot of gas. It's not true, but it's the rule followed by many small companies.

EVERETT
Lithology determination is constantly brought up as a problem. In gas, we've centered our attention on tools that look at the fluid or gas content. When porosity gets very low, we're therefore trying to measure something that's getting smaller and smaller. We can gain an advantage by looking at the part that's getting bigger and bigger, the solid part of the rock.

LEVYIEN
Certainly you're trying increasingly to pull the signal out of the "noise," that is, the lithology. So the more you know about the noise, the more likely you'll be able to subtract it from the signal.

MODERATOR
Given the economics of gas today, are you having to defend your interpretation more vigorously?

LEVYIEN
Yes. Someone has always imposed a limit, like "we're not going to produce from any formations with gas saturation less than 10 percent." The gas bubble has made that cutoff very high. Since gas is far less economic than oil, you need to have a lot of it before you start thinking about completions and pipelines.

The question of equity is more difficult. In tight reservoirs that produce gas from fractures, how do you determine equity? By how many fractures you have or how much structure? We may have much to learn from studying how coalbed methane fields are handled.1

We increasingly find ourselves as partners so we must be vigilant in defining equity from the very first exploration well. This often entails negotiating agreement on the baseline logging program and subsequent cased-hole monitoring. It's not sufficient to say "use the triple combo for all gas wells." We have to think in the longer term and with an eye to equity agreements. If you own your block and someone else owns the abutting block, the sooner you coordinate your logging programs, the better for both of you.

EVERETT
Does the equity question encourage you to be as quantitative as possible in your evaluations?

LEVYIEN
Rather, it encourages you to make good decisions about the next well, such as how much core you take. You have to start thinking about how to produce the well. In the US, this means thinking about allowables1— in the context of not just what is best for you but what is best for everyone in the field. —JMK


12. An allowable is the amount of hydrocarbon that a well or leasehold is permitted to produce, per unit time, under provision by a regulatory body.
Moderator's Commentary

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As our roundtable participants see it, state-of-the-art gas well evaluation revolves around basic logging suites, judiciously compared with or calibrated to available core data. In the openhole setting, core-adjusted density log data are commonly used for porosity. This information is combined with deep induction or laterolog resistivity to establish a saturation model to estimate hydrocarbon volume. Neutron-density porosity curve separation is then interpreted for gas recognition, usually qualitatively.

In the cased hole setting, pulsed-neutron devices are most commonly employed. When combined with a porosity value, either from the pulsed-neutron tool or another input, the formation Σ measurement is used to infer the presence or absence of hydrocarbons.

Methods in both open and cased hole rely on the physics of neutron tool response to help determine the type of hydrocarbon present (oil or gas). The formation evaluation examples presented, which are the rule rather than the exception, highlight the inherent pitfalls of relying on neutron tool response.

The difficulty involves two phenomena. The first is the relationship between the volume investigated by standard neutron tools and the borehole environment, which can occupy a significant part of that volume. In openhole cases, this amounts to the effect of mud filtrate invasion, flushing gas beyond the depth of the tool's response, usually unpredictably. Invasion was considered in the analysis of every openhole example.

In the cased hole examples, invasion is thought to be less of a problem. But taking its place is a perhaps more complex combination of variables—borehole fluid and casing and cement condition—perturbing the pulsed-neutron tool measurement. An additional hindrance in cased hole is that the critical porosity parameter for saturation determination must often be estimated from the pulsed-neutron measurement itself, which is already disturbed by gas and environmental effects.

The second phenomenon is the lithology dependence of the neutron porosity measurement. If lithology is poorly understood, the resulting answer suffers greatly (this includes the effect of neutron absorbers, such as boron, in the formation matrix). Louise Levien put it succinctly: "Certainly you're trying increasingly to pull the signal out of the 'noise,' that is, the lithology. So the more you know about the noise, the more likely you'll be able to subtract it from the signal."

What can be done? These problems are not new, and our panel indicates that gas well interpretation hasn't advanced significantly since the introduction of the CML measurement. Taking an optimistic view, however, there is hope on the horizon:

- Investigation of invasion mechanisms is suggesting better ways to characterize invasion in terms of formation parameters. These parameters can be gleaned from resistivity measurements made while drilling or at "wireline time" with standard induction tools or new multiple depth of investigation resistivity imaging tools.

The hope is to define the extent of the flushed zone within the neutron response geometry.

- GLT measurements provide a key to addressing the lithology-dependence issue. This "mineral-based" interpretation technique has helped build formation interpretation models for large portions of the US Gulf Coast and is being extended to other, more complex lithologies.

- Porosity information from full waveform sonic velocity measurements in cased holes is proving reliable in many cement conditions. Logs of several test wells show that combining sonic with Dual-Burst pulsed neutron data gives an accurate gas interpretation for reclamation decisions.