SOLVING FOR RESERVOIR SATURATIONS USING MULTIPLE FORMATION PROPERTY MEASUREMENTS FROM A SINGLE PULSED NEUTRON LOGGING TOOL

David Rose, Tong Zhou, and Pablo Saldungaray, Schlumberger

This paper was prepared for presentation at the SPWLA 58th Annual Logging Symposium held in Oklahoma City, Oklahoma, USA, June 17-21, 2017.

ABSTRACT

Pulsed neutron logging is commonly used to evaluate reservoir saturation through casing based on the ability of neutrons and gamma rays to probe the reservoir rock through casing and cement. Pulsed neutron measurements contain information, which is sensitive to a complex set of different neutron interaction properties such as capture, elastic, and inelastic cross-sections. Conventional cased-hole interpretation methods tend to use a single isolated pulsed neutron measurement complemented by multiple external inputs, often from openhole logs, and assumed formation water salinity to solve for reservoir saturation. The information that can be obtained from pulsed neutron measurements on multiple independent formation properties is often not fully utilized. In the past, some of this information has not been accessible, and conventional interpretation methods have been limited to the use of a single isolated measurement.

A recently introduced pulsed neutron logging tool provides multiple independent formation property measurements, namely sigma, neutron porosity, fast-neutron cross section, and elemental concentrations including carbon from inelastic and capture spectroscopy. All these independent measurements follow linear volumetric mixing laws, and thus are readily accessed in a linear manner by a multimineral and multifluid solver for determination of formation volumes of water, oil, or gas. We detail a new interpretation method using these multiple measurements that can be tailored to many different scenarios encountered in cased-hole logging. The key aspect of the method is to solve for the desired reservoir saturations with proper weighting applied to each measurement, based on its statistical precision and estimated accuracy level. External inputs from openhole logs or assumptions based on local knowledge can also be used coherently with the pulsed neutron measurements. In this case, the multiple independent measurements can be used as a consistency check to validate the underlying assumptions. When external inputs (openhole logs) are not available, multiple measurements from the new pulsed neutron tool make previously underdetermined problems solvable. Log examples illustrate the applications of this method for different scenarios and show that interpretation results from this new method are coherent and robust.

INTRODUCTION

The determination of hydrocarbon saturation in cased holes has been long established using pulsed neutron logs. Most established methodologies focus on using a single pulsed neutron measurement, such as sigma or a detector ratio, to solve for a two-phase hydrocarbon saturation. Some methodologies even extend the solution to using multiple measurements to solve for multiple volumes or fluid phases in the reservoir (Fitz and Ganapathy, 1993; Petricola, 1996; Horkowitz and Cannon, 1997). However, different reservoirs will have different situations, and existing cased-hole workflows may or may not be appropriate for any given situation. Openhole interpretation methods have been developed that take advantage of having multiple independent measurements to solve for multiple unknowns (Quirein et al., 1986).

Recent improvements in cased-hole pulsed neutron logging now make numerous, independent formation property measurements available in cased-hole. In this paper, we propose extending methods available in openhole interpretation to a general cased-hole workflow. Several commercially petrophysical software applications are available that can be adapted to this cased-hole workflow. This workflow can be adapted to any situation to solve for fluid saturations and any other important reservoir unknowns. The main advantages of this workflow is that it can use multiple independent measurements to solve for multiple unknowns, such as multiple fluid phases, or it can use multiple independent measurements as a consistency check to ensure a robust result.

GENERAL METHODOLOGY

The general methodology of this workflow is simple: Develop a system of multiple, weighted, linear measurement response equations where the unknowns are the various formation volume components such as different minerals and fluids. Multiple equations can be included, one for each independent log measurement or externally available piece of information. The weighting of each measurement can be determined based on the confidence in that measurement. Once the series of response equations is complete, the unknown formation volumes can be solved for and fluid saturations can be computed.

This method assumes that the log measurements represent only the formation. In cased-hole interpretation in particular, the raw log measurements can be highly affected by the borehole environment and the completion, including the cement, casing, and borehole fluids. It is important that any log measurement used be fully borehole corrected.

Measurements that follow linear volumetric mixing laws are ideal measurements to use with this methodology because they are simple to deal with and avoid the complicated mathematics associated with nonlinear equations. A new pulsed neutron logging tool (Rose et al., 2015) has been designed to provide multiple, independent, linear, measurements in a single pass from a single tool and is well suited for this methodology. The generalized linear equation series are shown in Equation 1. The variable b_i is the i^{th} measurement. The total number of available measurements is M; therefore, there are M number of linear equations. Note that the sum of all the volumes equal to 1 should be considered as an additional equation, but we can treat it mathematically in the same way as a measurement equation. There are a total of N assumed formation components. The variable v_j is the volume of j^{th} formation component. The variable a_{ij} is the endpoint of the i^{th} measurement for the j^{th} formation component, which is the value that the i^{th} measurement would have assuming 100% of a given j^{th} formation component volume. Each equation represents a response equation or forward model. The unknowns are the formation volumes v_j. The values of b_i are measured at each logging depth in the well. The endpoints a_{ij} are typically determined by computation, modeling, experiment, or in situ determination in known formations. Theoretical endpoint values for some common formation components have been published previously (Zhou, et al. 2016, their Table 3). However, theoretical endpoints may not always be the most appropriate because the actual elemental composition of minerals can vary, and some minerals may not always follow the exact same trends as the calibrated measurement response trends, which are often performed in clean limestone. The field-observed ranges for the mineral groups shown in Table 1 may supplement the theoretical values published previously.

Equation 2 rewrites Equation 1 in terms of matrix operation for simplicity, where A is an M by N matrix containing all the endpoint coefficients, $\boldsymbol{v}$ is an N by 1 vector that contains all the formation volume components, and $\boldsymbol{b}$ is an M by 1 vector containing all the measurements. The solution of these series of linear equations is shown in Equation 3. Of note is that the solution will not exist if the system is underdetermined. Generally, a solvable system requires the number of independent equations to be larger than the number of unknowns. Mathematically, it means the determinant of the square matrix $A^T \cdot A$ must be sufficiently large so its inverse matrix can be computed. When the determinant of $A^T \cdot A$ is close to zero, computing the inverse matrix is like dividing 1 by 0. Any small error in the measurements will be significantly amplified, and the solution will be meaningless.

$$\sum_{j=1}^{N}\left(a_{ij} \cdot v_j\right) = b_i \qquad i = 1,\ldots M \tag{1}$$

$$\overline{\boldsymbol{A}} \cdot \boldsymbol{v} = \boldsymbol{b} \tag{2}$$

$$\boldsymbol{v} = \left(\overline{\boldsymbol{A}}^{\boldsymbol{T}} \cdot \overline{\boldsymbol{A}}\right)^{-1} \cdot \overline{\boldsymbol{A}}^{\boldsymbol{T}} \cdot \boldsymbol{b} \tag{3}$$

A general example of a series of typical linear equations based on available cased-hole pulsed neutron log measurements is shown in Equation 4. In this case, the formation volumes are assumed to be limestone, oil and water, and the available measurements are neutron porosity TPHI and formation sigma SIGM. Equation 5 shows the system in matrix notation. This is a perfectly determined problem.

$$TPHI_{limestone} \cdot v_{limestone} + TPHI_{water} \cdot v_{water} + TPHI_{oil} \cdot v_{oil} = TPHI$$
$$SIGM_{limestone} \cdot v_{limestone} + SIGM_{water} \cdot v_{water} + SIGM_{oil} \cdot v_{oil} = SIGM$$
$$v_{limestone} + v_{water} + v_{oil} = 1 \tag{4}$$

$$\overline{A} = \begin{bmatrix} TPHI_{limestone} & TPHI_{water} & TPHI_{oil} \\ SIGM_{limestone} & SIGM_{water} & SIGM_{oil} \\ 1 & 1 & 1 \end{bmatrix}, \overline{V} = \begin{bmatrix} v_{limestone} \\ v_{water} \\ v_{oil} \end{bmatrix}, \overline{B} = \begin{bmatrix} TPHI \\ SIGM \\ 1 \end{bmatrix} \tag{5}$$

In the discussion above, all equations (or measurements) are treated equally by the linear solver. In reality, it can often be prudent to apply different relative weighting to the different equations for many reasons. Thus, the problem becomes a generic weighted least square regression, as shown in Equation 6.

$$f = \sum_{i=1}^{M} w_{ii} \left[\sum_{j=1}^{N} \left(a_{ij} \cdot v_j \right) - b_i \right]^2, w_{ii} = \frac{1}{\sigma_i^2} \tag{6}$$

The variable f is the cost function that is to be minimized, and w_{ii} is the weight for i^{th} equation (or measurement). The weight w_{ii} is defined as 1 over square of the error, which is σ_i. Since each equation is essentially a forward model, this error is the overall error or confidence level of the forward model. There are many things contributing to the forward model errors. For example, the measurement may have some borehole environmental effects that are not fully corrected or compensated, any nuclear measurement will have statistical noise due to the nature of nuclear counting, the theoretical value of the endpoint for a formation matrix component may not be fully representative, the endpoint of a formation fluid may not be accurate due to unknown salinity/temperature/pressure, and it is usually a simplification to just divide the formation into N number of components. In reality, the weights need to be empirically determined by log analysts. This will be demonstrated in the section showing log examples.

The solution of the weighted least square problem shown in Equation 6 is shown in Equation 7 in matrix form. The matrix W is a diagonal matrix with the diagonal components of w_{ii}.

$$\boldsymbol{v} = \left(\overline{\boldsymbol{A}}^{\boldsymbol{T}} \cdot \boldsymbol{W} \cdot \overline{\boldsymbol{A}} \right)^{-1} \cdot \overline{\boldsymbol{A}}^{\boldsymbol{T}} \cdot \boldsymbol{W} \cdot \boldsymbol{b} \tag{7}$$

It is very important to do a quality check (QC) after solving an interpretation problem. The most direct QC is to use Equation 1. The right side of Equation 1 is a measured variable, and the left side is a reconstructed variable using the solved volumes of formation components. Ideally, one would like to see the reconstructed variable matching the measured one. One can also use the Equation 6 to check the overall error of the solutions. Another important check before solving the problem is to make sure the determinant of the square matrix $A^T \cdot A$ or the one with weights $A^T \cdot W \cdot A$ is sufficiently large, so that the problem is solvable.

ADAPTING THE GENERAL METHOD TO A SPECIFIC PROBLEM

Although the general method shown above is very simple, it usually needs to be adapted to a specific situation to yield the best results.

Assessing the Formation Volume Knowns and Unknowns. The first step is to assess what can be assumed to be known and what is unknown in the formation. Formation volumes can be subdivided into two main components, rock matrix and fluids. When deciding what rock matrix minerals to solve for, it is often useful to limit the volumes to the major components. In reality, the formation matrix can be composed of dozens of different minerals. However, for each mineral volume added to the equation to be solved, a corresponding measurement must be available to solve for it. The best approach is often to keep it simple and only add complexity as needed. In siliciclastics, this may mean limiting the volumes to generic “sand” and “clay” components. The “sand” may not be a pure quartz sand, but a mix of quartz, feldspars, micas, and other minerals. Similarly, the clay may be a mix of different clay types. The endpoints of the response equations can be adjusted accordingly and often the results will be more stable than attempting to break out each individual mineral type.

Similarly, for fluids, each possible fluid present must be added as a volume to be solved. For water, this may include multiple water types. Pulsed neutron measurements respond to the total volume present. Unlike logs such as nuclear magnetic resonance (NMR), clay bound water, capillary bound water, and capillary free water are indistinguishable, assuming they all have the same salinity. Therefore, it is preferable to work in total porosity space when interpreting pulsed neutron logs. What may be important in some reservoirs is the possible presence of waters of varying salinity, such as an oil reservoir with saline connate water that is being waterflooded with less-saline water. Since measurements such as sigma are very sensitive to the water salinity, it may be important to solve for two different water salinity end members. Oil properties may vary across a reservoir, but it is most common to solve for one type of oil with properties that are believed to be most representative of the current reservoir conditions. If two types of oils are present, such as a light and heavy, there must be sufficient contrast in at least one measurement to be able to robustly solve for them. This may be possible in some cases, but is not typical. Gas is similar to oil in that it is most common to solve for a single type gas with properties that are believed to be most representative of the reservoir gas at the time of logging. In highly constrained situations, one may attempt to solve different gas types, such as methane versus CO_2 or original pressure gas versus depleted pressure gas. However, there must be measurement property differences between the two gases for a robust solution.

Assessing the Number of Independent Measurements Available. Once the formation volumes to be quantified have been determined, the next step is to identify the measurements and external information that can be brought to bear on solving the problem. The best starting point is to assess what openhole logs and quantitative volumetric petrophysical interpretation information are available. If a reliable, quantitative openhole interpretation is available, one can use this information as additional measurements in the system of linear equations. Some judgement is required in what can be input, but basically any information can be used as an input if it can be safely assumed that the volume has not changed since the acquisition of the openhole logs. This is usually a safe assumption for lithology and porosity information. Fluid volumes determined at the time of the openhole log should not be relied on as they may have changed with time, and this is typically the goal of cased-hole logging for reservoir monitoring. In some instances, fluid volumes from openhole may be used in the solution if they can safely be assumed to not have changed. This may be a good assumption in some cases. An example of such a case would be assuming the openhole water volume remains unchanged in a dry gas reservoir that is undergoing depletion, with no water influx. In general, it is best to use interpreted volumes and total porosity from openhole rather than openhole measurements, such as density and neutron porosity, because the response of interpreted volumes would not change with changing reservoir fluids where the measurements could have. If available, using volumes from openhole is extremely valuable in a cased-hole interpretation as it allows for more unknown fluids to be solved for with the cased-hole measurements or for a redundancy check if the system of equations is overdetermined. If no openhole logs are available, it may be advantageous in some cases to try to generate pseudo lithology and porosity volumes based on offset wells, if available, and if the formations can be reliably assumed to be laterally homogeneous.

Next, assess the current cased-hole measurements that are available or, if planning an upcoming log, what measurements need to be acquired. Whether certain measurements are needed and useful may depend on the assessments just discussed about what formation volumes need to be solved for and what quantitative information from openhole logs is available.

Pulsed neutron logs are often the most useful and convenient measurements for cased-hole evaluation because they generally work well through casing and can provide a very rich set of independent measurements from a single logging tool. The following is a review of the linear measurements available from cased-hole pulsed neutron logs and some general guidelines in their quantitative use. It is also useful to review the various response endpoints when choosing which measurements are needed by looking at the different unknown volumes and seeing what measurements are sensitive to each of them.

Sigma is most sensitive to differentiating saline water from hydrocarbons and has some contrast between oil and gas. The main complicating factor to using sigma is defining the rock matrix values, which vary with lithology variations. Clay will typically have a relatively high sigma value, and this can be a large source of inaccuracy if its volume, composition and endpoint is not well known, or vary. Acidization is another known source of inaccuracy if a formation has ever been treated because it is known to elevate the formation sigma, and the acid effect can remain for a long time, even after flowing back the well.

TPHI is a pulsed neutron version of a neutron porosity that is similar in response to the familiar openhole dual detector neutron tool. It responds primarily to hydrogen content. While TPHI is not strictly a defined property of a given formation, its response can be estimated with a reasonable degree of accuracy using a modified version of SNUPAR (McKeon, 1989). TPHI is most sensitive to differentiating hydrogen liquids such as water and oil from non-clay rock matrix, which typically contains no hydrogen. It is also very useful for quantifying gas (and CO_2) when the porosity is known because of gas's relatively low hydrogen density compared to liquids. Clay is a complicating factor because clay contains hydrogen and can lead to inaccuracy if the clay volume and clay response are not accurately accounted for.

Fast-neutron cross section (FNXS) is a new formation measurement that has recently been introduced (Rose et al., 2015; Zhou et al., 2016). FNXS is derived from total gamma-ray counts originating from inelastic interactions and is sensitive to the formation's ability to attenuate high energy neutrons. FNXS is effective for differentiating gas (and CO_2) from rock matrix and fluids, such as oil and water. Its response is very different from the TPHI response in that it does not correlate to hydrogen index.

Capture spectroscopy is well suited for use in cased-hole to solve for lithology. Most of the major elements commonly found in sedimentary rocks, such as Ca, Si, S, Fe, and Al can be measured with capture spectroscopy. These elements are typically given as dry weight concentrations that exclude the pore space. These elements can be converted to dry weight mineralogy through various methods such as the method described by Herron and Herron (1996). If lithology is unknown, this measurement is very useful in defining the elemental and mineral composition of the rock.

An alternate way of using spectroscopy information in a series of linear equations is to derive matrix properties such as grain density, neutron matrix and sigma matrix from the dry weight elements (Herron, 2000). This method has been used to generate a continuous FNXS matrix from the elemental dry weights. In this way, one can derive all the matrix properties that vary as a function of logging depth, as does the matrix A in Equation 2.

Inelastic spectroscopy is well suited for two primary formation evaluation applications. The main application is to quantify carbon, which is mostly found in relatively high concentrations in oil, kerogen, bitumen, coal, and carbonate rocks. The other main application of inelastic spectroscopy is quantification of magnesium, which is commonly found in dolomite and to a lesser extent in some clay minerals. The carbon/oxygen ratio (C/O) is often used to solve for oil volumes. Since C/O is not strictly linear, we recommend using a traditional C/O workflow (Scott et al., 1991) to compute a volume of oil from C/O, which can then be used as an input linear equation using this methodology. Since lithology and porosity are an input to this workflow, a two-step, sequential solution may be needed. A gas correction may also be needed in the determination of oil volume from C/O (Badruzzaman, 1998).

This paper will focus on using the pulsed neutron measurements listed above, but other cased-hole log measurements can be added and may be useful. Some other examples are natural gamma ray (GR), spectral GR (Th, U, K), cased-hole density, cased-hole sonic, and cased-hole resistivity. Of these additional measurements, only density follows linear volumetric mixing laws. Natural GR follows linear mixing laws in wet weight space, so it is easily adapted to this method, if available. Sonic and resistivity mixing laws are more complicated, so may fall outside the simple linear method outlined in this paper.

Assessing the Weighting Factor of Each Measurement. It is important to assess the robustness of each measurement before solving the series of linear equations. This information can be used to set the relative weighting of each measurement. Two primary considerations should be assessed when setting each measurement weighting, the statistical precision of the measurement and the accuracy of the measurement (borehole environment correction).

The statistical precision of each measurement is straightforward to assess. Precision of nuclear measurements can be computed from the raw count rate data via statistical error propagation. Precision is determined from the total measured counts, and thus is a strong function of the neutron source output, detector efficiency, logging environment and logging speed. Prior to a logging operation, the precision of the measurements can be predicted through the use of a job planner, and an appropriate logging speed can be determined for a given logging objective in a given environment. Once the logging data are acquired, the statistical uncertainty for each measurement can be calculated and output as a logging curve. This is typically reported as 1 standard deviation. As an example using sigma, the sigma precision curve is computed (SIGM_SIG) where a typical value is approximately 0.2 cu. This would mean that if the SIGM curve at a given depth is reading X, the actual SIGM value for the formation at that depth has a 67% probability to be in the range of X+/– 0.2 c.u. or a 95% probability in the range of X+/–0.4, etc. The statistical precision of a measurement will become worse as the logging speed increases, neutron generator output decreases, or the logging environment degrades.

The second primary consideration for determining the appropriate weighting factor is measurement accuracy, that is, how well the borehole effects are being accounted for and corrected. This is defined as the difference between the mean value of a formation property measurement and its theoretical value. This is a much more difficult thing to predict because in cased-hole we rarely have "ground truth" to assess the various measurement accuracies. In cased-hole, one of the biggest challenges to having an accurate log measurement is compensating the measurement for the borehole completion and borehole fluid. Borehole correction algorithms are generally based on assuming a certain downhole condition and making a correction based on laboratory measurements or modeling. Self-compensated borehole corrected measurements (Rose et al., 2015) are advantageous as they require fewer user inputs or assumptions. Yet in cased-hole, there is often a large number of unknowns that cannot always be rigorously accounted for, such as cement density, composition, and presence; casing and tubing position-eccentering; borehole and annular fluids; borehole size; and logging tool position. The petrophysicist must make a relative assessment of accuracy for each measurement as input to defining a weighting factor, but often without the benefit of the actual accuracy being absolutely definable for a given log. Therefore, some experience and trial-and-error attempts are often needed in assessing this. Measurement accuracy will tend to degrade with increasing complexity of the completion and increasing borehole size. Sigma tends to be one of the more robust measurements in complex completions because it has a relatively deep depth of investigation and a relatively small borehole correction to the raw decay measurement. TPHI is typically less robust than SIGM in complex completions and large boreholes because there can be a very large correction needed to the raw count rate ratio measurement that is the primary raw measurement. FNXS has a relatively shallow depth of investigation compared to the SIGM or TPHI and can have a relatively large borehole effect. Therefore, in complex completions, its response can be dominated by the completion and borehole fluids and may cease to be useable in some cases. Similarly, spectroscopy measurements can be dominated by the completion in very complex cases where most of the signal can come from the borehole and completion rather than the formation.

It is always recommended to assess the accuracy of each cased-hole measurement by comparing with openhole or offset well data, such as comparing histograms over similar formation intervals. TPHI can be compared to openhole neutron porosity and normalized, if needed. Similarly, spectroscopy logs can be compared to openhole spectroscopy logs and normalized, if needed.

When formulating a series of linear equations to solve for unknowns, one must keep this in mind. In favorable borehole conditions, such as a small, brine-filled borehole with single casing, we would expect to have multiple robust independent measurements available. In unfavorable conditions, such as a large borehole in flowing conditions with mixed gas, oil, and water in the borehole and multiple tubulars, only self-compensated measurements such as SIGM and TPHI (Rose et al., 2015) may be available and the accuracy of others may be in question.

Formulating the Equations for a Specific Well. When good-quality openhole logs are available for a given well, it is often best to assume that lithology and porosity are known, and to limit the number of unknown volumes the cased-hole logs must solve for to just the fluids. Some common scenarios for different possible reservoir fluids being present, and the recommended primary measurements to solve the problem, are shown in Table 2. One of the simplest cases is when only two fluid phases are present, such as oil and high-salinity brine, and in this case the sigma measurement is sufficient to solve this system accurately based on the large contrast in sigma between oil and high-salinity brine. Also shown in the table is a column with optional measurements that can be used in an overdetermined system as a consistency check, such as volume of oil from C/O in this first simple case, but with sigma being preferred due to its generally better precision. Using multiple measurements in an overdetermined system with proper weighting factors is a practical way to approach this.

Another interesting case is in a gas reservoir where the fluids are water or gas. In this case, TPHI is generally preferred as the primary measurement because it is self-compensated for the borehole environment and has a large sensitivity between gas and water. Sigma and FNXS can also be used as a consistency check. When clay is present, FNXS may sometimes be preferred as the primary measurement because it has less sensitivity to clay variation, whereas gas saturations from SIGM and TPHI can be significantly impacted if the assumed clay volume and clay measurement response endpoints are not accurate.

A more challenging situation is when lithology and porosity are unknown, such as when no openhole logs exist. Table 3 shows some common scenarios and the measurements needed. With lithology and porosity unknown, more measurements will need to be used as more unknowns require more equations to solve for them. The details are shown in the table. A common theme is that lithology or matrix endpoints will generally be determined from the capture spectroscopy, and porosity must now be determined from the TPHI measurement. When gas is present, TPHI will read less than total porosity as all neutron porosity measurements do, so an additional measurement, FNXS, is needed. Rather than discussing in detail each scenario in the tables, a few are illustrated in the following pages with examples. It should also be noted that the scenarios listed in the tables are not meant to be exhaustive. Many reservoirs will have other unknown fluid volumes such as CO_2, different water salinities, different gas pressures, gas properties, different oil properties, etc. As long as measurements have some contrast, a custom series of equations can be formulated and used.

EXAMPLE 1

Figure 1 shows an example pulsed neutron log from a siliciclastic oil reservoir in a mature field. The well was drilled as a vertical oil producer and is perforated below the zone logged in cased-hole. The borehole size is 8.5 in. with 5.5 in. casing. Openhole triple combo logs are available. The field has been under freshwater and gas injection for many years. In March 2016 the well was logged with an advanced pulsed neutron logging tool to identify fluid contacts and determine water, oil and gas volumes in the various sand reservoirs. The wellbore is filled with oil during cased-hole logging. Some of the significant challenges for cased-hole logging in this field are relatively low porosity (10-15pu), the presence of very fresh water in the formation and the relatively high temperature (296 degf). The fresh water means there is little to no sigma contrast between water and oil. The high temperature causes a challenge to most pulsed neutron spectroscopy tools due to resolution degradation of the detectors with temperature and the finite holding times of flasks, which can delay having the detector temperature reach an unacceptable level.

The lithology and porosity are variable, and can be assumed to be known from the openhole log interpretation. The reservoir fluid could be any mix of oil, water and gas and may have changed since openhole logging, so must be assumed unknown. Spectroscopy data was acquired and a volume of oil was computed from the carbon/oxygen ratio. TPHI should have good contrast between gas and the higher density fluids (oil and water). Mathematically, that is sufficient to solve for the three fluid phases (oil, water and gas) with three response equations from Voil from C/O, TPHI and PHIT from OH. However, two other independent measurements are available that are sensitive to the fluid saturations to some degree. FNXS is sensitive to the volume of gas. Sigma will also have some sensitivity to the volume of gas in this instance. Although formation water is fresh, gas sigma will be several capture units lower than water sigma.

It is always prudent to quality control the input measurements prior to the computation. A good quality control of the SIGM borehole correction is comparing it to the raw apparent sigma from the long spacing (deep) detector from the late time gate (SLDA). SLDA has very little borehole or diffusion effect so reads close to intrinsic formation sigma. Its weakness is that it can suffer statistically due to low count rates and can be erratic in these conditions. In this example the SLDA has good precision, even in the shales. The borehole corrected SIGM matches well with the SLDA over the entire logged interval (see track 2, Fig. 1). A good quality control on the TPHI is to compare it with the openhole neutron porosity. In this example there was an offset compared to the vintage OH neutron, and the TPHI was normalized to the openhole neutron. The FNXS can be compared to the dry matrix FNXS computed from the lithology computed from the spectroscopy mineral fractions. The FNXS should be of a similar value as the matrix except in gas or very light oil zones, which it is the case in this example.

Figure 2 shows the result of the volumetric solver computation and the quality control of each input measurement, including lithology and porosity from openhole, compared to the reconstructed measurement. Ideally, the measured and reconstructed curves should overlay. In this overdetermined case, all measurements and reconstructed curves overlay reasonably well giving a high confidence to the complex, three phase interpretation.

Table 4 shows the response equation parameters and weighting factors used in the solution. Note the extremely small model errors assigned to the openhole mineral volumes. This effectively means the openhole lithology (and porosity) will be strictly enforced in the solution, and not allowed to change from the openhole interpretation. The cased-hole measurements are assigned a higher error, leaving them to effectively resolve the different fluids. In this case, the sigma was not used in the solver, due to its relatively low contrast, but was used as a QC by reconstructing the measurement from the resulting volumes and the response equation.

The high gas saturation zones (A, B & C) are clearly defined and are consistent with three different independent measurements that are sensitive to gas (TPHI, FNXS and SIGM). Having multiple measurements that are consistent with high gas saturation gives confidence to the interpretation. Zone G shows a high water volume. The apparent oil zone immediately above zone C appears in a shale, so was judged to likely be due to a washout with an oil filled annulus and not a prospective productive zone. Three potential reservoir zones with a relatively high oil volume and low water and gas volumes were targeted for reperforation (D, E & F) and produced with no water cut and low GOR, which is consistent with the interpreted volumes.

EXAMPLE 2

Figure 3 shows another example log from a producing gas field in the USA consisting of stacked shaly sands. The well was logged with a triple combo log in openhole. Determination of gas volumes with openhole logs can be challenging with resistivity in this field due to the potential variations in formation water salinity and in some cases deep invasion of fresh water based mud (WBM). To confirm the openhole interpretation, an advanced pulsed neutron log was run in the well after it was cased, but before perforation, about one month after the openhole logs. The bit size was 8.75 in., the casing O.D. was 4.5 in. and the casing was filled with water at the time of the log. However, since the interval of interest (not all shown) was several thousands of feet, spectroscopy data was not acquired and the logging speed was 1800 ft/hr. Both openhole and cased-hole logs are shown in Figure 3. The main potential reservoir sands for this interval are listed (A, B, C and D) and are apparent from the openhole neutron-density and the GR. The resistivity log shows significant invasion of fresh water, particularly in sand D. The quality checks of the cased-hole logs are good with the openhole caliper showing good hole condition. The SIGM matches well with the SLDA indicating the SIGM borehole correction is good. The TPHI matches the openhole TNPH in the shales, but is reading lower in the cleaner sands. This is consistent with an increase in gas volume between the time of openhole logging and the cased-hole logging and is consistent with deep WBM invasion in the openhole that has dissipated at the time of the cased-hole logs. Since no spectroscopy data is available, no matrix FNXS can be computed from spectroscopy, however an approximate matrix FNXS for shaly-sand reservoirs (~7.0 1/m) can be displayed as a qualitative visual flag to identify possible gas zones on the FNXS. The FNXS trend is consistent with the relative amount of density-neutron crossover in openhole.

In this cased-hole evaluation problem, the main unknowns are the gas and water volumes assuming they could have been affected by invasion during openhole logging and that invasion may have dissipated some before the cased-hole logging. The lithology and porosity can be assumed to be known from the openhole interpretation. The cased-hole log has three formation property measurements available that are sensitive to gas and water, SIGM, TPHI and FNXS. One measurement would be sufficient to compute water and gas volumes in this situation so having three measurements means an overdetermined system of equations and the possibility to use each as a redundancy check on the results.

The results of the cased-hole petrophysical interpretation is shown in Figure 4 along with the input measurements and model reconstruct results. The formulation of the set of linear equations for the cased-hole interpretation is shown in Table 5. The openhole lithology volumes were used with a very low interpreted forward model error of 0.001 which has the effect of strictly enforcing the lithology solution to the openhole results. Volumes of illite and quartz are shown. Volume of clay bound water is not shown. In setting each measurement parameter for the lithology volume, we must acknowledge that the formation mineralogy is likely composed of more minerals than pure illite and quartz. So some of the parameters have been adjusted from the theoretical quartz and illite values based on local experience in this field and to improve the model reconstruct when iterating the solution. So for example the SIGM-quartz parameter was raised from the theoretical value of 4.55 c.u. to 8.0 c.u., which is consistent with a sand that may not be pure quartz, but may have some feldspars, micas, and heavy minerals as well. In setting the interpreted forward model error for the three measurements, our approach is to start with balanced interpreted errors. In this case, since we expect to have three good quality measurements in this case, we have used an estimated accuracy of each measurement based on experience, 0.5 c.u. for sigma, 0.05 1/m for FNXS and 0.01 for TPHI.

The model reconstructs are shown in Figure 4. Model reconstructs of measurements used in the solution are shown in brown and model reconstructs of measurements not used in the solution are shown in green. Note that in the first two tracks the volume of gas has increased compared to the volume computed from the openhole logs, which we interpret as the effect of invasion on the openhole logs, with zone D showing the largest difference. The reconstruct of the three measurements gives a consistency check on the computed gas volumes. In zone A, all three model reconstructs match well with the measurements giving a high confidence to the result. In zones B and C, there is some discrepancy between the three. The TPHI and SIGM measurements support more gas than the FNXS measurement. This is consistent with some near wellbore invasion remaining from the time of openhole logging. The FNXS measurement is derived from gamma ray counts resulting from inelastic neutron interactions which have a shallower depth-of-investigation than the SIGM and TPHI measurements that are derived from gamma ray counts resulting from capture neutron interactions. Some of the other possible causes of poor reconstruction are inappropriate model choices, inappropriate measurement parameters and environmental effects on the measurements that were not fully compensated. In this example, multiple measurements and model reconstructs give a more confident interpretation result.

CONCLUSION

A generic linear workflow for cased-hole formation evaluation is introduced using multiple independent measurements provided by an advanced pulsed neutron logging tool. This flexible workflow can be easily tailored or adapted to solve a particular cased-hole application to address complex cased-hole challenges. The interpretation results can be delivered with forward model reconstruction from each measurement as a QC and help assess the confidence level of the interpretation. Several log examples demonstrate the usage and performance of this method.

REFERENCES

Badruzzaman, A., Skillin, R. H., Zalan, T., Badruzzaman, T., Nguyen, P. T., 1998, Accurate oil saturation determination using carbon/oxygen logs in three-phase reservoirs: Paper CC, SPWLA 39th Annual Logging Symposium, Keystone, CO, USA, 26–29 May.

Fitz, D. E., and Ganapathy, N., 1993, Quantitative monitoring of fluid saturation changes using cased-hole logs: Paper XX, Transactions, SPWLA 34th Annual Logging Symposium, Calgary, Alberta, Canada, 13–16 June.

Herron, S.L., and Herron, M.M., 1996, Quantitative lithology: an application for open and cased hole spectroscopy: Paper E, Transactions, SPWLA 37th Annual Logging Symposium, New Orleans, Louisiana, USA, 16–19 June.

Herron, S.L., Herron, M., 2000, Application of nuclear spectroscopy logs to the derivation of formation matrix density: Paper JJ, Transactions, SPWLA 41st Annual Logging Symposium, Dallas, TX, USA, 4–7 June.

Horkowitz, J. P., and Cannon, D. E., 1997, Complex reservoir evaluation in open and cased wells: Paper W, Transactions, 38th Annual Logging Symposium, Houston, TX, USA, 15–18 June.

McKeon, D. C., and Scott, H. D., 1989, SNUPAR—A nuclear parameter code for nuclear geophysics applications: *IEEE Transactions on Nuclear Science*, 36(1), 1215–1219.

Petricola, M. J. C., 1996, Monitoring gas, oil, fresh water and saline water saturations with a single tool: Paper SPE 36222, 7th Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, UAE, 13–16 October.

Quirein, J., Kimminau, S., La Vigne, J., Singer, J., Wendel, F., 1986, A coherent framework for developing and applying multiple formation evaluation models: Paper DD, Transactions, SPWLA 27th Annual Logging Symposium, Houston, Texas, USA, 9–13 June.

Rose, D., Zhou, T., Beekman, S., Quinlan, T., Delgadillo, M., Gonzalez, G., Fricke, S., Thornton, J., Clinton, D., Gicquel, F., Shestakova, I., Stephenson, K., Stoller, C., Philip, O., La Rotta Marin, J., Mainier, S., Perchonok, B., and Bailly, J.-P., 2015, An innovative slim pulsed neutron logging tool: Paper XXXX, Transactions, SPWLA 56th Annual Logging Symposium, Long Beach, California, USA, 18–22 July.

Scott, H. D., Stoller, C., Roscoe, B.A., Plasek, R.E., and Adolph, R.A., 1991, A new compensated through-tubing carbon/oxygen tool for use in flowing wells: Paper MM, Transactions, SPWLA 32nd Annual Logging Symposium, Midland, Texas, USA, 16–19 June.

Zhou, T., Rose, D., Quinlan, T., Thornton, Saldungaray, P., Gerges, N., Noordin, F. B. M., and Lukman, A., 2016, Fast neutron cross-section measurement physics and applications: Paper EE, *Transactions, SPWLA 57th Annual Logging Symposium*, Reykjavik, Iceland, 25–29 June.

"ABOUT THE AUTHOR" SECTION

David Rose is a Principal Petrophysicist and Manager of Interpretation Engineering for Nuclear Answer Products at Schlumberger's Houston Formation Evaluation Center. He holds a BS degree in geophysical engineering from Colorado School of Mines (USA).

Tong Zhou is a Principal Tool Physicist at Schlumberger's Houston Formation Evaluation Center. He holds a PhD in nuclear engineering from North Carolina State University (USA).

Pablo Saldungaray is a Petrophysics Advisor currently based in Buenos Aires, Argentina. Since he joined Schlumberger in 1989, he has held several positions in the field and data processing centers in Africa, Europe, Latin America, and the Middle East. Pablo has a BS degree in electrical engineering from the National South University (1987) and an MBA from the Austral University (1995), Argentina.

Table 1 – Response endpoint ranges for some common mineral groups.

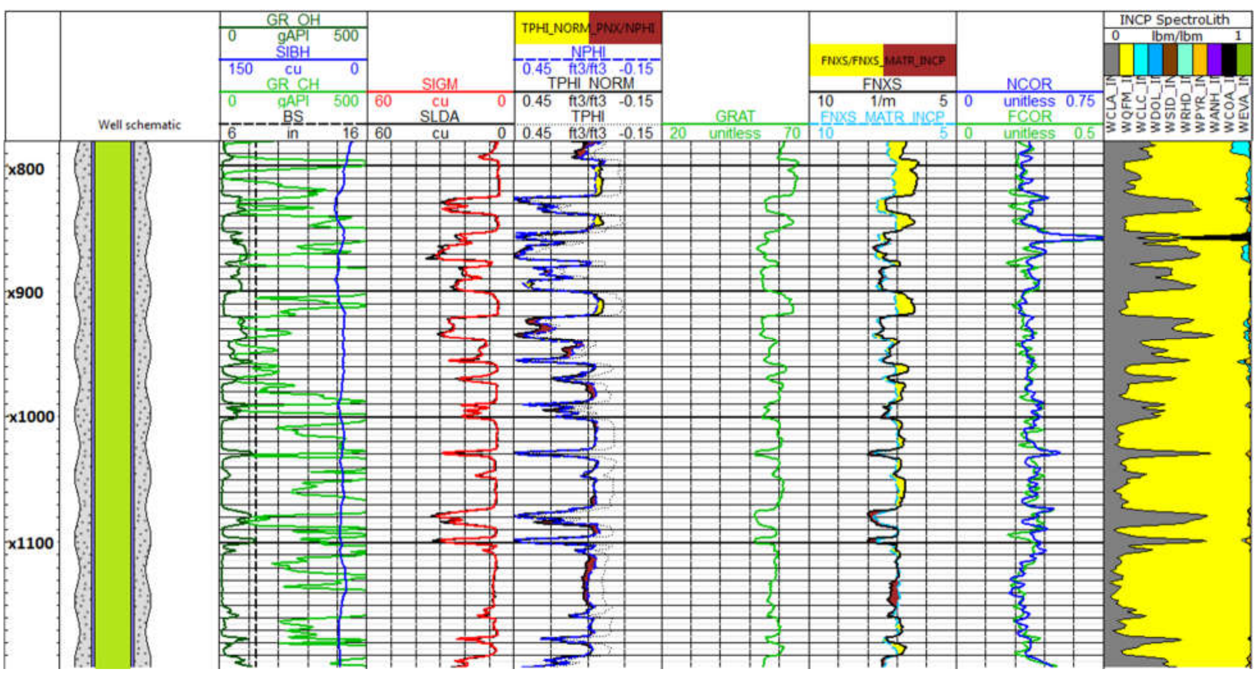
Material	Sigma (c.u.)	TPHI	FNXS (1/m)
Sands	4.55 to 18	-0.05 to -0.03	6.8 to 6.9
Calcite	7.08 to 7.50	0.00	7.51
Dolomite	4.7 to 8.0	0.03	7.5 to 8.0
Anhydrite	15 to 25	-0.03 to 0.00	7.5 to 8.0
Clay Minerals	15 to 60	0.20 to 0.70	7.0 to 8.5

Table 2 – Recommended equation formulation to solve for various combinations of unknown reservoir fluids when lithology and total porosity are known from openhole logs.

Unknown Volumes	Primary Measurements Used	Optional Measurement in Overdetermined System as Consistency Check
oil, high salinity brine	SIGM	Voil from C/O
oil, freshwater	Voil from C/O	
oil, unknown salinity water	Voil from C/O	
gas, water	TPHI	SIGM, FNXS
oil, high salinity brine, gas	SIGM, TPHI	FNXS
oil, freshwater, gas	TPHI, Voil from C/O	SIGM, FNXS
oil, unknown salinity water, gas	TPHI, Voil from C/O	FNXS

Table 3 - Recommended equation formulation to solve for various combinations of unknown reservoir fluids when lithology and total porosity are also unknown, such as when no openhole logs exist.

Unknown Volumes	Primary Measurements Used	Optional Measurement in Overdetermined System as Consistency Check
lithology, total porosity, oil, high salinity brine	capture Spectroscopy, SIGM, TPHI	Voil from C/O
lithology, total porosity, oil, freshwater	capture spectroscopy, Voil from C/O, TPHI	
lithology, total porosity, oil, unknown salinity water	capture spectroscopy, Voil from C/O, TPHI	
lithology, total porosity, gas, water	capture spectroscopy, TPHI, FNXS	SIGM
lithology, total porosity, oil, high salinity brine, gas	capture spectroscopy, SIGM, TPHI, FNXS	Voil from C/O
lithology, total porosity, oil, freshwater, gas	capture spectroscopy, TPHI, Voil from C/O, FNXS	SIGM
lithology, total porosity, oil, unknown salinity water, gas	capture spectroscopy, TPHI, Voil from C/O, FNXS	SIGM



Fig, 1 – Example 1 - A pulsed neutron log from a siliciclastic oil reservoir in a mature field. Several independent cased-hole pulsed neutron measurements are available to solve for the unknown fluid volumes that could be fresh water, oil or gas in this field. Formation property measurements include sigma (SIGM), neutron porosity, fast-neutron-cross-section (FNXS), C/O from near and far detectors (NCOR, FCOR) and lithology from capture spectroscopy. Zones where FNXS<matrix FNXS computed from spectroscopy (FNXS_MATR_INCP) is shaded yellow and a visual gas indicator. GRAT is the raw gas ratio from which the FNXS is computed.

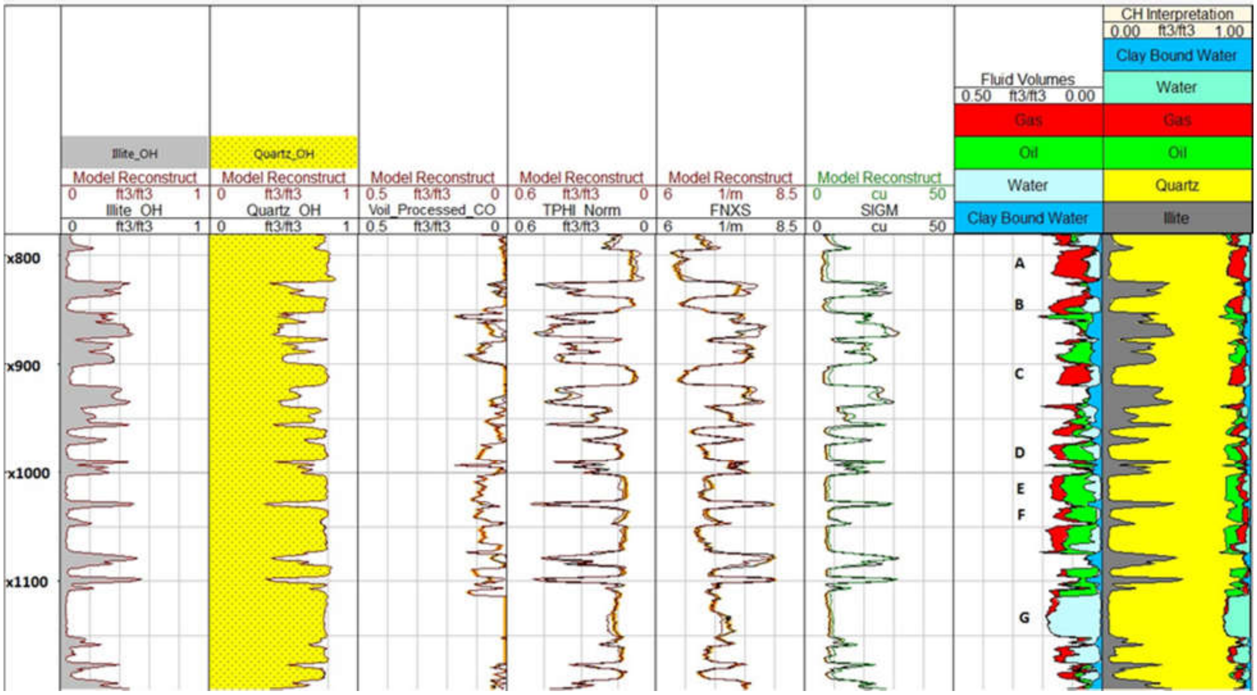


Fig. 2 Example 1 - Volumetric solver computation and the quality control of each input measurement, including lithology and porosity from openhole, compared to the reconstructed measurements (brown and green) with generally good agreement, which gives confidence to the solution. High gas saturation zones (A, B, & C) and high water volume zones (G) were identified and not perforated. High oil volume zones (D, E & F) were perforated and produced oil with no water cut and low GOR, consistent with the interpretation.

Table 4 - Example 1 linear model assumed volumes and input equations from cased-hole (CH) logs, C/O, and openhole (OH) logs.

Measurements	Interpreted Forward Model Error (σ in Eqn. 6)	Quartz	Illite	Water	Oil	Gas
SIGM from CH PN	Not used in solution	4.30	50.00	22.00	18.00	5.00
FNXS from CH PN	0.05	6.85	8.80	7.85	7.30	1.34
TPHI from CH PN	0.01	-0.03	0.80	1.00	1.00	0.08
Oil Volume from C/O	0.01	0	0	0	1	0
Quartz from OH	0.001	1	0	0	0	0
Illite from OH	0.001	0	1	0	0	0

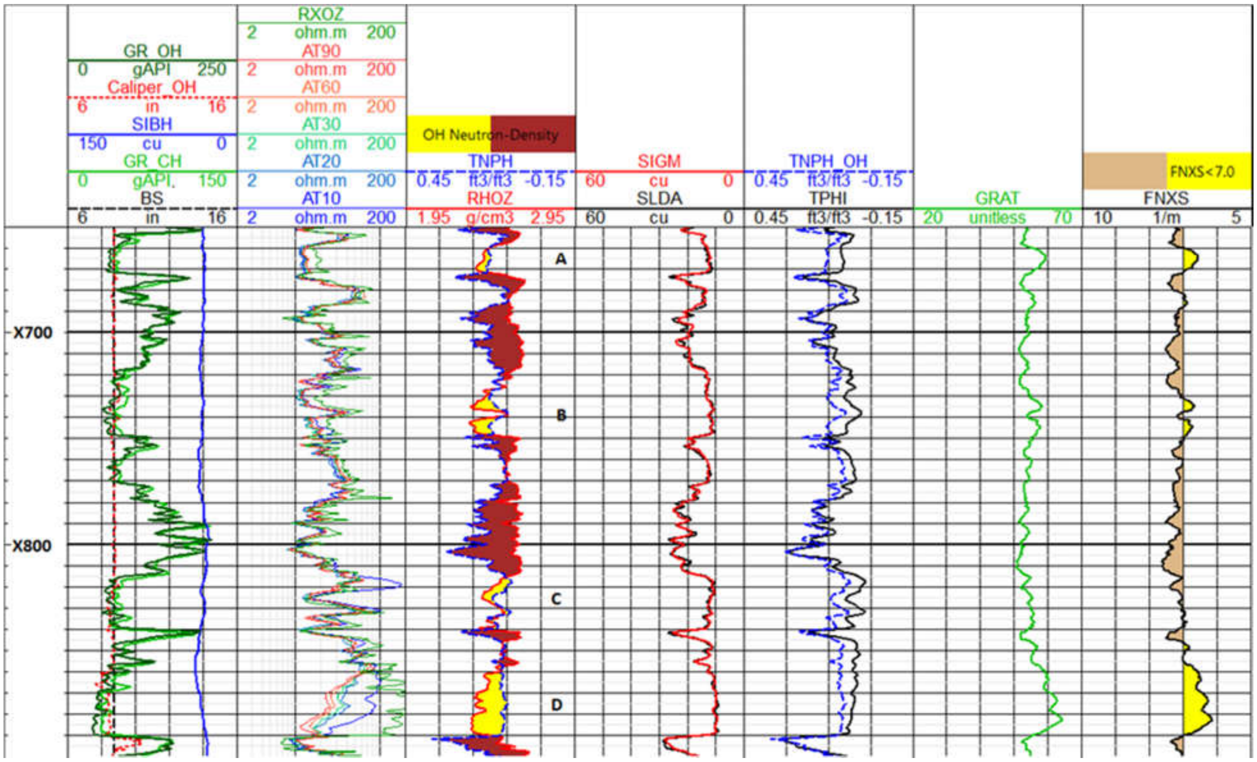


Fig. 3 Example 2 – Openhole logs and a cased-hole pulsed neutron log from a producing gas field in the USA. The openhole resistivity indicates possible invasion. The openhole TNPH – cased-hole TPHI difference is consistent with invasion dissipation between openhole and cased-hole logging. SIGM and FNXS are also sensitive to gas saturation.

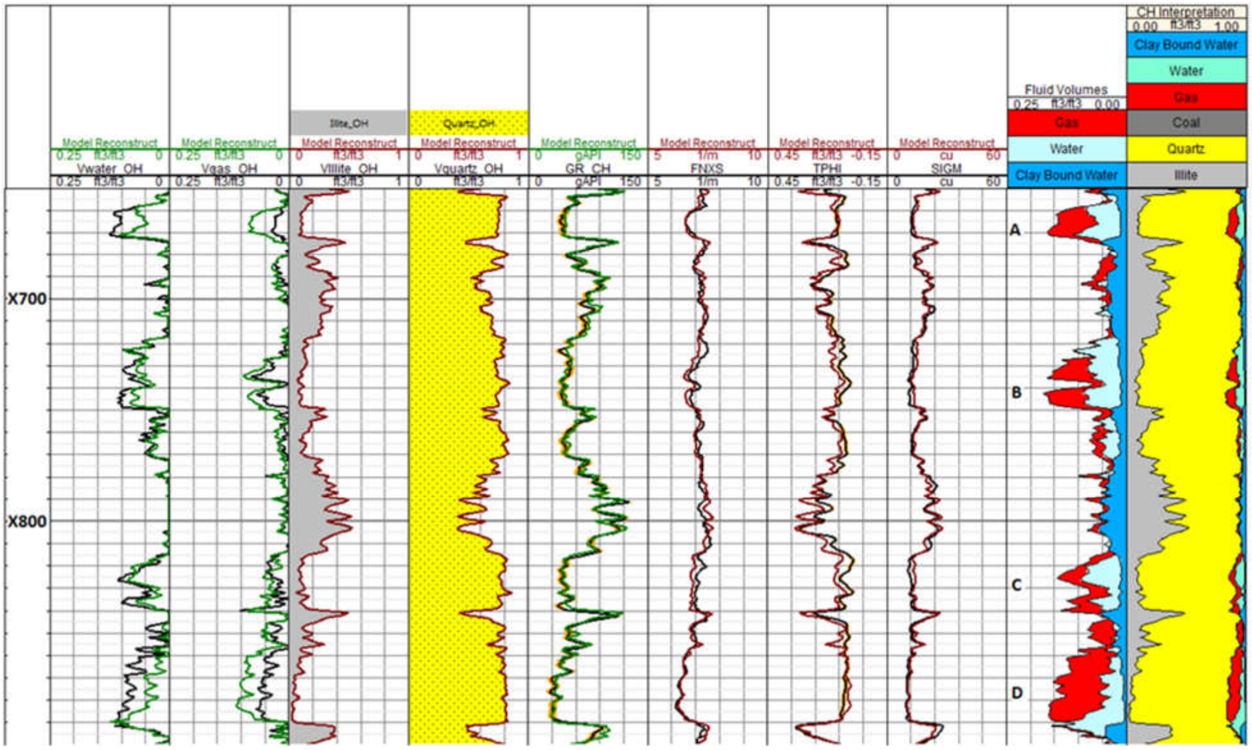


Fig. 4 Example 2 - Volumetric solver computation and the quality control of each input measurement. The lithology and total porosity is from the openhole logs and the three redundant measurements (SIGM, TPHI and FNXS) are solving for gas and water volumes. Computed gas volume is generally higher for the cased-hole log than the openhole log thought to be due to invasion dissipation. The reconstruction of the three measurements is good overall, but in zones B and C, there is some discrepancy between the three. The TPHI and SIGM measurements support more gas than the FNXS measurement, which has a shallower depth-of-investigation. This is consistent with some near wellbore invasion remaining from the time of openhole logging.

Table 5 - Example 2 linear model assumed volumes and input equations.

Measurements	Interpreted Forward Model Error (σ in Eqn. 6)	Quartz	Illite	Coal	Water	Gas
SIGM from CH PN	0.5	8.00	42.00	20.00	40.00	2.50
FNXS from CH PN	0.05	6.85	8.50	7.20	7.85	0.67
TPHI from CH PN	0.01	-0.03	0.50	0.37	1.00	-0.05
GR from CH	Not used in solution	25	200	60	25	25
Coal from OH	0.001	0	0	1	0	0
Quartz from OH	0.001	1	0	0	0	0
Illite from OH	0.001	0	1	0	0	0
Vwater from OH	Not used in solution	0	0	0	1	0
Vgas from OH	Not used in solution	0	0	0	0	1