Developing best practices for evaluating fluid saturations with pulsed neutron capture logging across multiple active CO₂-EOR fields

Amber Connera,*, David Chaceb, Jehad Abou-Salehb, Yonghwee Kimb, Caitlin McNeil, Jacqueline Gerst, Mark Kelley, Matt Place, Rick Pardinici, and Neeraj Guptaa

*a Battelle, 505 King Avenue, Columbus, Ohio, 43201, USA
b Baker Hughes, 2929 Allen Parkway, Houston, Texas, 77019, USA
c Core Energy, LLC, 1011 Noteware Drive, Traverse City, Michigan, 49686, USA

Abstract

The Midwest Regional Carbon Sequestration Partnership (MRCSP) is leading an extensive study and monitoring effort of large-scale carbon dioxide (CO₂) injection and storage during enhanced oil recovery (EOR) in depleted oil fields in the Michigan Niagara Reef Trend. Detailed monitoring of caprock and reservoir zones is vital for understanding oil, gas, and water saturations and potential migration of CO₂. Baseline and repeat pulsed neutron capture (PNC) logs were collected as part of the monitoring effort and study for these storage sites. An overview of the development and enhancement of best practices for PNC logging in complex EOR fields is presented.

© 2017 The Authors. Published by Elsevier Ltd. Peer-review under responsibility of the organizing committee of GHGT-13.

Keywords: Pulsed Neutron Capture Logging; PNC Log; MVA Best Practices; MRCSP; CO₂ storage

1. Introduction

As the demand for carbon dioxide (CO₂) mitigation increases, the process of geologic carbon sequestration has attracted increasing interest. Large-scale, long-term CO₂ storage projects require detailed monitoring, verification, and accounting to understand CO₂ storage mechanisms and potential migration of CO₂ [1]. The U.S. Department of Energy has funded regional carbon sequestration partnerships to study geologic CO₂ sequestration and all aspects of CO₂ storage, including monitoring of injected CO₂. The Midwest Regional Carbon Sequestration Partnership (MRCSP), (www.mrcsp.org) program includes assessment of CO₂ injection and storage during enhanced oil recovery (EOR) in depleted oil fields in Michigan’s Niagara Reef Trend [2,3]. The targeted reefs discussed in this paper are highly
depleted reef oilfields that have undergone significant CO₂-EOR and those undergoing active CO₂-EOR for enhanced recovery. Porosities in these reefs have high levels of variability that can range as high as 30%, with average porosities of less than 3%. Complex phase distributions within the CO₂-EOR reservoirs and a wide range of formation porosities in these reefs present challenges for monitoring, analyzing, projecting, and understanding CO₂ injection, migration and permanent storage.

Pulsed neutron capture (PNC) logs have been used for assessing fluid saturation levels in oil and gas production in the past, however the tools’ development for distinguishing between oil, gas, and water in cased oilfield wells was not adequate for comprehensive and accurate CO₂ monitoring. Recent development of new pulsed neutron measurements to provide enhanced sensitivity to CO₂, coupled with advancement in log analysis and modeling using comprehensive geochemical analyses are being used to apply this existing technology directly to CO₂ plume monitoring and fluid saturation analysis during CO₂ storage or storage during CO₂-EOR. The MRCSP program and the Niagara Reefs within the study undergoing CO₂-EOR provide an optimal testing site for exploring PNC logging as a monitoring tool and developing best practices when using PNC logging in existing CO₂-EOR fields. As part of the MRCSP program, PNC logs have been run and analyzed in multiple reefs, including those with low porosity injection/production reservoirs, salt plugged formations, and other operational constraints. The collection of these logs and experience gained in acquisition and analysis has been used to develop effective methods to apply PNC logging as a tool for CO₂ monitoring. This paper will focus on the best practices and lessons learned from the MRCSP PNC logging monitoring program.

2. Pulsed Neutron Capture Log Technology

PNC logging is used to identify the presence of reservoir fluids near the wells and can be used to aid in monitoring the migration of injected CO₂. PNC logs operate by generating a pulse of high energy neutrons, subsequently measuring the neutron decay over time and across a wide energy spectrum. The PNC tool measures the ability of an element to capture thermal neutrons and generates a log of this value, known as the thermal neutron capture cross section, or Sigma [4]. Thermal neutron capture measurements are compared to referenced values of common downhole fluids and formation matrices. A higher sigma value equates to a greater ability of a particular element to capture, or absorb, the neutrons. Formation brines, oil, natural gas (i.e., methane (CH₄)), and CO₂ all have distinctive sigma values which can be used for determining fluid saturations at various depths surrounding the borehole.

The primary PNC analysis technique, also known as Sigma analysis, uses a material balance equation which defines the measured formation sigma as the weighted sum of the component sigma responses for fluids and lithology within the measurement volume. The equation can be solved for water and hydrocarbon (gas or oil) saturation using inputs of porosity, shale volume and representative sigma values for the specific fluids present in the formation.

For the graphical presentation (on the log plot basis), this consists of plotting the capture cross section response of the formation against theoretical capture cross section values of the defined lithology and porosity saturated with either liquid or gas. The comparison of the measured sigma to these two theoretical sigma curves shows the presence of gas when the formation capture cross section curve migrates from overlaying the theoretical water curve towards the theoretical gas curve [4].

A ratio-based capture analysis uses the ratio of capture gamma rays between the short-spaced detector (1st detector) and the extra-long-spaced detector (3rd detector) on the logging tool. This ratio is called RATIO13 [4]. Monte Carlo simulation modeling is used to develop the theoretical response curves for liquid or gas filled lines, then the measured log results are compared to the theoretical curves. The log measurements are normalized to fit within the theoretical curves and to account for the presence of shale, not considered in the Monte Carlo simulation modeling. Through processing, the modeling combined with the log data provides quantitative formation gas saturation values.

Well-specific modeling and proprietary analysis techniques can analyze and compute multi-phase saturations, including oil, gas and water saturation in cased wells. The models utilize the Monte Carlo N-Particle (MCNP)
simulations that predict RATO13 responses of formation fluid components to establish quantitative interpretations for CO₂ saturations. RATO13 is sensitive to formation water salinity and shale volumes. It provides a dynamic envelope for porosity and salinity changes and is insensitive to lithology variations between limestone and dolomite in low porosity formations [5].

3. Geology Background for PNC Logging

There are approximately 700 reefs in the northern Niagara Reef Trend. Stratigraphically, these encapsulated reefs are situated below evaporates and carbonates creating a finite reservoir area. The carbonate reservoirs are internally complex and range from dominantly dolomite, closer to the barrier reef, to limestone, more basin-ward, containing well-developed intercrystalline and/or vugular porosity. The reservoir facies primarily consist of porous and permeable dolostone and limestone. Some reefs are completely dolomitized, while others are primarily limestone. Dolomitization of reefs increases as the reefs become more shallow (i.e. updip from the center of the basin), while salt and anhydrite plugging of porosity is more prevalent in the deeper reefs [6]. The primary reservoir target for hydrocarbon production and potential CO₂ storage in these reefs, within the MRCSP study, is a carbonate formation known as the Brown Niagara (or Guelph Dolomite). In certain locales along the Trend, the overlying A-1 carbonate has additional storage reservoir potential. Target reservoir intervals with ideal effective porosity for CO₂-EOR within the reservoir range from only a few feet to several hundred feet, varying from reef to reef. Porosity values range from 0 to 30%, but typically have an average from 3 to 12%; the best porosity and permeability are associated with dolomitized reef core and flank facies.

The seals for the Niagara reefs consist of a series of evaporites and salt-plugged carbonates that encase the flanks of the reefs and form impermeable regional seals over the entire reef complexes. These evaporites show rapid changes in composition, from carbonate to evaporites (halite and anhydrites) and are problematic for geologic interpretation and effectively estimating CO₂ storage capacity for a couple of reasons. These thin and sporadically changing intervals between carbonates, halites and anhydrites are difficult to analyze using traditional density log analyses. These complex evaporite and carbonate layers create false porosity indicators in traditional neutron porosity and bulk density logs which complicate understanding and mapping reservoir porosity, seal integrity, and CO₂ migration modeling. In many cases of these developed CO₂-EOR reefs, wells are historic and cased off, which makes traditional triple combo logging impossible if historical logs are not available.

The fields being studied by MRCSP are in different stages of their production life-cycles: highly depleted fields that have already undergone significant CO₂-EOR in the past and are being used solely for CO₂ storage (no production) and those currently undergoing CO₂-EOR. These complex carbonate and anhydrite layers, combined with low average porosities and EOR production life-cycles affords a unique opportunity to test and assess PNC logging technology in tracking fluid saturations and understanding the behavior of CO₂ as it is being stored during and after EOR.

4. PNC Log Data Analysis and Modeling

Within the MRCSP monitoring program, workflows were developed for PNC logging and modeling analyses. They consisted of: 1) data acquisition using wireline logs and operational information (production rates), 2) well condition data collection, to understand the cement bond conditions and verify well configurations such as casing and tubing sizes, 3) fluid properties analyses, including water salinities and gas densities, and 4) modeling simulation (Fig. 1). Each workflow step is a necessary input in the modeling and Monte Carlo simulations. This workflow was then utilized across multiple reefs in the Niagara Reef Trend. One of the fields in this study, a late-stage production reef, was initially used to test the application of PNC logging for CO₂ monitoring. Initial PNC models constrained data to two phase saturation, gas and liquid. The analysis of these two-phase data sets presented gaps in the saturation analysis of the CO₂-EOR system. Oil saturation information is required in order to provide a comprehensive analysis of initial saturation levels and time-phased changes in the CO₂-EOR fields as CO₂ is injected and oil is produced. In order to provide a three-phase solution—oil, gas/CO₂, and water—an enhanced, proprietary, interpretation methodology was
utilized based on triangulation of two PNC measurements [7]: a thermal neutron capture cross section (i.e., sigma) and a ratio of capture gamma ray count rates between the first and the third detectors (i.e., RATO13).

Monte Carlo modeling generates theoretical pulsed neutron tool responses for the given logging conditions [5]. Inputs for the modeling process are formation lithology; formation fluid compositions and in-situ densities; sizes of hole, casing, and tubing; quality of cement; and properties of wellbore fluids. Each of these factors are used to develop effective saturation estimations in the PNC log data analysis. There are several considerations that can potentially impact PNC modeled results, a few examples are as follows:

- Changes in formation lithology can cause slight underestimation or overestimation of fluid saturations,
- Low salinities decrease the sensitivity factors in low porosity fields,
- Formation fluid chemistry understanding is needed to determine salinity equivalence to formation fluids,
- The presence of CH₄ and CO₂ together can be difficult to distinguish, and
- Cement bond can impact log analysis results by showing false positive gas saturation in areas of low cement volume.

Simulated Monte Carlo models are used for data post-processing. An example of Monte Carlo modeling responses for RATO13 is presented in Fig. 2(a). RATO13 responses of salt water, downhole condition oil (0.8 gram per cubic centimeter [g/cc]), and CO₂ (0.68 g/cc) were modeled with respect to effective porosity. RATO13 is sensitive to gas versus liquid as well as oil versus salt water. As porosity increases, the sensitivities between different fluid types increase. In a low porosity range, RATO13 reveals good sensitivities between oil and gas.

Material balance-based sigma responses are presented in Fig. 2(b). Sigma is predominantly sensitive to salt water but has poor resolution between oil and CO₂. The depth of investigation of sigma is slightly deeper than that of RATO13; sigma measurement is less affected than RATO13 by any borehole effects such as hardware and fluid conditions.
A combination of Monte Carlo and material balance models and measured RATO13 and sigma using triangulation method allows for a comprehensive examination of the three formation fluid components (i.e., salt water, oil, and CO₂). One of the reasons that RATO13 and sigma are an optimal combination for this analysis algorithm is that these measurements have sensitivities between different fluid types in a low porosity range. Typically, a conventional carbon/oxygen (C/O) log is adopted to calculate oil saturation, but its use in a low-porosity formation has limitations; however, RATO13 and formation sigma reveal enough sensitivity in a low-porosity formation to perform reliable saturation analysis. In addition, these two capture measurements are much less sensitive to the variation of lithology types between limestone and dolomite.

The triangulation method incorporates modeled and measured responses of RATO13 and sigma to simultaneously solve three formation fluid saturations [8]. Fig. 3 illustrates how a triangle is constructed at a specific depth interval. In this example, at 20% porosity, three theoretical fluid points (i.e., water, oil, and CO₂ points) are mapped on the crossplot of RATO13 and formation sigma. The points represent theoretical points of fully saturated water, oil, and CO₂ formations at the corresponding depth. The measured RATO13 and formation sigma are also plotted (the yellow point on the triangle in the top left plot of Fig. 3. The relative distance between each theoretical fluid point to the measured data point determines the saturation of each fluid type. As the distance from the measured data point to the theoretical point becomes shorter, the corresponding saturation becomes higher.
Fig. 3. An illustration of a triangle creation and the position of measured data from RATO13 and sigma combination; this is an example of a triangulation construction using RATO13 and sigma at one specific depth and porosity in a given completion geometry. The top left figure is the crossplot of RATO13 and sigma at 20%; the CO$_2$ point is red, the oil point is green, the water point is blue, and the normalized log measurement is in yellow. The top right figure is the sigma model, and the bottom left figure (rotated 90 degrees) represents RATO13 models for salt water, downhole condition oil, and CO$_2$. 
The size of a triangle is related to the uncertainty of calculated saturations. As the size of a triangle increases, the uncertainty in calculated saturation decreases. In general, as porosity increases, the size of the triangle increases and uncertainty decreases. The main factors that determine the size of the triangle in this application (given the low porosity for Niagara carbonate formations) is formation water salinity and borehole fluid. As water salinity increases, salt water responses of RATO13 and sigma increase and a larger triangle is obtained. Formation water for one case study well was known to include boron concentration, and water salinity was in a range of 400,000 parts per million (ppm) sodium chloride (NaCl) equivalent. A liquid-filled wellbore (preferably water-filled) conditions are desirable for PNC logging because a hydrogen-rich environment inside the borehole ensures higher sensitivities among the three formation fluid components.

5. Well Configuration and Operational Considerations

A single casing string is usually best for PNC logging, however, field management often requires the use of more complicated completions allowing selective access to different intervals within the formation. This can present challenges for PNC logging due to, for example, potential trapping of fluids in annular regions near packers. In the course of the extended logging program, different completion scenarios were encountered and studied, resulting in an understanding of the completion design best suited for monitoring within the constraints of field operation. A preferred tubing configuration should have tubing and packer in the well. The packer should be set above the perforations with the tubing extended through the logged interval with enough tailpipe to ensure the toolstring is secure within the tubing during the logging run. This tubing should have communication with the perforations in order to effectively collect fluid samples using wireline/slickline deployed tools prior to or directly following PNC logging runs. This configuration allows for efficient PNC logging and formation fluid (liquid or gas) sampling for chemical characterization.

Wellbore fluid is another factor to be considered for CO₂ monitoring in time lapse logging program. Pulsed neutron log responses are affected by wellbore fluid properties [5]. Depending upon the wellbore fluid types (water, oil, CO₂, or a mixture of two or three components) and measurement types (inelastic versus capture), the degree of impact from changes of wellbore fluids on different log runs varies. The depth of investigation of capture measurements (e.g., RATO13 and sigma) is deeper than that of inelastic measurements (e.g., RIN13, a ratio of inelastic gamma ray count rates from the first and the third detector, and C/O); thus, capture measurements are less sensitive to wellbore fluid. Changes of wellbore fluid types between multiple log runs may augment the complexity of the saturation interpretation (e.g. liquid vs. gas). It is preferred to maintain the same or similar fluid types in multiple log runs.

6. Detection of Salt Plugging

In addition to the primary task of monitoring saturation, pulsed neutron logs are also useful for identifying salt plugs (salt-filled porosity) in the target reservoirs. The sigma measurement is one of the most robust sources to delineate the salt plugs. Chlorine in halite formations readily absorbs thermal neutrons resulting in high sigma response. Apparent sigma for halite is around 748 capture units (c.u.), and that for dolomite is around 8 c.u. Because sigma of halite is so high compared to dolomite (or other common formation lithologies), sigma is very useful for identification of salt plugs. The RIN13 response of the salt matrix is less than that of the dolomite matrix, and RIN13 decreases if salt plugs exist. RATO13 increases as salt volume in the formation increases. A log example of salt plugs is shown in Fig. 4. The interval from the top of the log to depth ‘A’ was identified as a salt plug interval; RATO13 and formation sigma increase abruptly above depth ‘A’ and RIN13 decreases at the same depth. The average porosity for the reservoir with salt plugs was around 7% and porosity has been reduced or eliminated due to plugging.

Detection of salt plugging is important to identify the potential reduction in formation porosity and potential storage capacity. When analyzed, these salt plug signatures can potentially be correlated with three-dimensional (3D) seismic and log cross-section data to produce 3D static earth models.
Fig. 4. Overlays of time lapse data; logs in red are baseline logs from 2012 acquisition, and those in blue are repeat logs from 2016 acquisition. From left track to right track, gamma ray count rates are in track (a); casing collar locator is in depth track; borehole sigma logs are in track (b); formation sigma logs are in track (c); RATO13 and RIN13 are presented in track (d) and (e), respectively.

Borehole sigma logs in the salt plug interval were generally unchanged because wellbore fluids of two log runs remained almost the same; a slight difference (around 143 g/l) in brine density did not change borehole sigma values. This result confirms that the differences of any other logs between two runs are associated with formation fluid changes.

7. Time-Lapse PNC Logs and CO₂ Saturation Quantification, A Case Study

Time lapse PNC log acquisitions were performed at the injector in 2012 and 2016. The key measurements are compared in Fig. 5. Formation sigma logs repeat very well (as shown in track (b) of Fig.5). This suggests that the formation water saturation remained unchanged before and after CO₂ injection. Since formation sigma does not have high sensitivity between oil and CO₂, a good overlay of two sigma logs does not provide information on changes of formation oil and CO₂ volumes. Like sigma, RATO13 is sensitive to salt water versus hydrocarbon, however, RATO13 is also very sensitive to the presence of oil versus gas, especially CO₂. RATO13 is observed to decrease in several intervals of the log data, indicating a change in the volume of CO₂. Individually, sigma or RATO13 can be used to compute two-phase saturations. Both sigma and RATO13 can be used to determine water vs. gas or water vs. oil saturation. In order to determine three-phase saturations, both measurements must be used in combination.
The triangulation method, which combines RATO13 and formation sigma data, was used to simultaneously quantify three-phase saturations. Water sample tests from the subject and nearby wells revealed concentrations of boron and total dissolved solids, and confirmed that water salinity was close to 400,000 ppm. The in-situ densities of oil and CO₂ were set to be 0.8 g/cc and 0.68 g/cc for the analysis. The same RATO13 models were used for two data sets as wellbore conditions were maintained almost the same (only a minor difference in brine density in the wellbore was observed). Gas saturation is mainly identified by RATO13, and water saturation is effectively determined by formation sigma in the triangulation method. Sigma values for salt water, oil, and CO₂ used in the material balance model were 200 c.u., 20 c.u., and 0.03 c.u., respectively.

Time lapse saturation results are presented in Fig. 6. On track (b), Monte Carlo modeled RATO13 responses for salt water, oil, and CO₂ are presented, and baseline and repeat RATO13 logs are plotted. RATO13 from the repeat log run (shown in black) is lower than that from base log (shown in yellow), and the relative position of the repeat log is
less than theoretical oil response. This confirms the increase of CO₂ saturation. On track (c), formation sigma logs and modeled responses are presented.

Computed saturation profiles using triangulation method from baseline and repeat data are presented on track (d) and (e). It was observed that water volume remained at a similar level yet CO₂ saturation increased before and after CO₂ injections.

Triangles corresponding to depth ‘A’, ‘B’, and ‘C’ are illustrated in Fig. 7. In each crossplot, theoretical data points for salt water, oil, and CO₂ are in blue, green, and red, respectively. Measured data from the baseline log are in purple; data from the repeat log are in yellow. The saturation is determined based on how close the measured data point is to the theoretical fluid points.
Fig. 6. A composite log presentation of pulsed neutron data analysis using a triangulation method of RATO13 and sigma combination; track (a) shows gamma ray count rates; track (b) presents modeled responses of RATO13 (water in blue, oil in green, and CO₂ in red) and 2012 and 2016 measured RATO13 (2012 RATO13 in yellow and 2016 RATO13 in black); track (c) presents formation sigma models (salt water in blue, oil in green, and CO₂ in red) and measured formation sigma logs (2012 sigma in yellow and 2016 sigma in black); and tracks (d) and (e) illustrate three-phase formation fluid saturation profiles from 2012 and 2016 data, respectively. Track (f) shows volumes of shale and matrix and low effective porosities through the entire interval. On the depth track, casing collar locator log and perforation intervals are presented.
Crossplot (a) in Fig. 7 clearly shows that the relative positions of measured data points from the baseline log (in purple) and repeat log (in yellow) on the same triangle changed. As the measured data point laterally moved closer to the water-CO$_2$ side of the triangle, CO$_2$ saturation increased with almost the same water saturation.

The measured data points on crossplot (b) moved along the water-CO$_2$ side of the triangle, and the data point from the repeat log was located closer to theoretical water point. This indicated a slight increase of formation water saturation at depth ‘B’. The difference of triangle sizes between the one from depth ‘A’ and the other from depth ‘B’ is attributed to the porosity difference. As porosity increases at given formation fluid properties, a larger triangle is created.

In crossplot (c), there is no significant change in the positions of the measured data points, which indicated similar fluid saturations before and after CO$_2$ injections.

8. Conclusions

Lessons learned from the logging program in the study wells were used to build “best practices” to implement logging in a pre-EOR reef in the MRCSP study region. Key findings with PNC logging and modelling include:

- High salinity formations, like the Niagara reefs, presented salinity factors that provided enough sensitivity to compensate for low porosity fields.
- To decrease modelling uncertainties better characterization and acquisition of modelling inputs are needed. Some of these factors include:
  - Analysis of surrounding well logs and cores can better define lithology and porosity factors in the field.
  - Geochemical analysis of formation fluids conducted prior to PNC logging assist with defining in-situ densities and salinities
  - Chemical analyses of brine fluids in the tubing and annulus determine if salinities are similar to or greater than formation fluids
- Optimal wellbore conditions are necessary for effective PNC logging. These conditions include but are not limited to:
  - Quality cement conditions
  - Running the PNC logging tool through tubing, full of water (similar to the formation water salinity), with liquid in the annulus, and cement behind casing.
  - There should be tubing and a packer in the well,
The packer should be set above the perforations with the tubing extending through the full logged interval and enough tailpipe to ensure the entire toolstring stays within the tubing while logging.

Hardware allowing communication between the tubing and annular space, e.g., perforated put joint or sliding sleeve, minimizes trapped fluids in the annular space and facilitates model development based on known fluid types.

- Triangulation of sigma and RATO13 allows simultaneous solution of water, oil, and CO2 saturations, overcoming the limitations of the use of sigma alone (which only provides 2-phase saturations).
- In addition to the primary task of monitoring saturation, PNC logging is also useful for identifying salt plugs (salt-filled porosity) in the target reservoirs. Detection of salt plugging is important to identify potential reduction in formation porosity and potential storage capacity.

Advances in modeling of pulsed neutron responses, log analysis technique, and “Lessons Learned” in logging operation have substantially decreased uncertainties in saturation estimations. These advancements provide effective PNC logging and enhanced CO2-EOR production and monitoring.

Acknowledgements

MRCSP is led by Battelle and supported by U.S. Department of Energy National Energy Technology Laboratory under Cooperative Agreement no. DE-FC26-0NT42589 with co-funding from several other partners. Core Energy, LLC. and its staff are acknowledged for providing access and field implementation support for the large-scale test. Significant contributions were also provided by Autumn Haagsma and Lydia Cumming of Battelle.

References


