

UNCONVENTIONAL TIGHT OIL RESERVOIRS: A CALL FOR NEW STANDARDIZED CORE ANALYSIS WORKFLOWS AND RESEARCH

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ABSTRACT

Recommended Practices for Core Analysis is firmly established in the American Petroleum Institute's RP 40 Second Edition, February 1998 document. Standardized workflows for the core analysis of unconventional shale reservoirs are deeply rooted in analytical techniques that were originally developed for coal bed methane, shale gas and tight gas reservoirs. These techniques were researched and developed by the Gas Research Institute (GRI) and are outlined in the GRI final report: GRI-95/0496, "Development of Laboratory and Petrophysical Techniques for Evaluating Shale Reservoirs." These methodologies were extremely successful in evaluating cores from gas shale reservoirs. As operators shifted their development focus from gas shale reservoirs to unconventional oil producing reservoirs, these same gas core analytical techniques were used to analyze unconventional tight oil cores.

This paper will discuss the results of tests and experiments that were made on core from the Bakken petroleum system's Middle Bakken and lower Three Forks formations. These series of tests were made following a very poor core-to-log data water saturation comparison. The core analysis measured 40% to 60% water saturation, and the logs showed the reservoir to be 100% water saturated.

This investigation started by looking closely at the solvent extraction methods with Dean and Stark [3] using toluene followed by chloroform/methanol azeotrope extraction. Preliminary tests focused on the possibility of anhydrite dissolution, which would have created excess porosity, thus making the core analysis incorrect. Additional investigation of the problem included measurements with nuclear magnetic resonance (NMR), retort extraction methods and possibilities of errors in the computations due to extremely high water salinities. While this investigation has resulted in applying some new protocols in the analysis of tight oil cores, it has also demonstrated that more research is needed and new standard core analysis workflows need to be developed for unconventional tight oil reservoirs.

INTRODUCTION

One of the most important aspects in the development of unconventional reservoirs is a comparison of core measurements with wireline logging measurements. This comparison primarily accomplished by cutting whole core and completing extensive wireline logging in pilot hole wells, is particularly important in the development of unconventional tight oil reservoirs. Unconventional tight oil reservoirs typically have a porosity of less than 10% and a permeability of less than 0.01 mD.

The Bakken petroleum system, one of the largest tight oil deposits in the world, is situated in the Williston Basin [Fig. 1]. The Bakken petroleum system is generally considered a hybrid type of unconventional tight oil reservoirs: it consists of two layers of organic-rich shale (the Upper and Lower shales) sandwiching a dolomitic-siltstone interval called the Middle Bakken [Fig. 2]. Included in the Bakken petroleum system below the Lower shale is the Three Forks formation, composed of laminations of dolostone and dolomitic-mudstone. Developing large acreage positions in the Bakken petroleum system to maximize hydrocarbon production requires a thorough understanding of the reservoir parameters across the play and an understanding of the individual reservoirs of the system.

To evaluate the production potential more accurately, a series of five wells [Fig. 3] were cored and logged in the Bakken petroleum system starting at the end of 2013 and through 2014. The wells were positioned over a broad section of leases that represented the acreage being developed. During this process, routine core analysis (RCA) saturation data from parts of the middle Bakken and the lower Three Forks formations were compared with wireline logging data. The workflows recommended by API RP 40 [1] were implemented to acquire the RCA saturation data. The comparison revealed obvious discrepancies between the core and log data sets.

Advanced logging measurements using dielectric and NMR logs had been run and analysed over these formations. The NMR logging tools measure total porosity, while the dielectric logging tools measure the total water-filled porosity. Therefore, by plotting the NMR total porosity with the dielectric water-filled porosity, the difference between the two measurements is a hydrocarbon-filled porosity. A plot of the porosities from the log measurements is shown in Fig. 4 in the second log track from the right, labeled "Porosity." The dark green shading between the two curves represents oil-filled porosity. The teal blue color represents water-filled porosity. The maroon dots are core porosity measurements.

Due to these log measurements, there was a high level of confidence that log data in the lower portion of the Three Forks formation indicated 100% water saturation, as represented in Fig. 4 by the blue curve in the middle log track labeled "Water Saturation." In the same intervals, water saturations from the RCA data, shown as maroon dots, largely ranged from 40% to 60% and as such were highly questionable.

This discrepancy triggered an inquiry into its sources, with a focus on the core data. The authors started with the core service company working on the core in which a large discrepancy in the data sets was observed; a second inquiry began into other cores from the same formations in process at a second core service company. Additionally, the authors examined historic core data. It was concluded that this was probably not the first time that a discrepancy between the data sets existed.

Research into the reliability of the core data led, over time, to a more comprehensive understanding of analytical procedures and lab workflows for data acquisition from the Bakken petroleum system. A series of lab visits, detailed discussions with lab analysts and a review of industry-accepted protocols were all-necessary to define the scope of the problems and develop tests to address analytical procedures and lab workflows. The authors' focus has been on the following:

- Solvent extraction procedures during RCA on both core plugs [1]; as well as crushed rock using the GRI method [2], or a modified version of GRI (following a proprietary lab workflow that diverges from the original GRI workflow), which itself was developed for characterizing reservoir properties of gas shales.
- NMR as an independent check of plug porosity and fluid saturations.
- The possibility of anhydrite dissolution during solvent extraction. In the absence of resolution to this investigation, processing of previously unanalyzed core materials has been suspended. Cores 1 and 2 had already been analyzed, Core 3 had had plugs cut and Dean Stark had been started on some, and Cores 4 and 5 were being evaluated for sampling intervals. [Fig. 3]

DISCUSSION

Solvent Extraction

Cleaning of core materials was undertaken on both 1.5 x 2-inch core plugs and on material that was crushed. Cleaning of the core plugs followed the procedures originally developed by Dean and Stark [3] and a workflow outlined in API RP 40 [1]. For both Dean Stark and GRI, the samples are subjected to extraction using toluene at 110°C. Questions were raised regarding the efficacy of the Dean Stark workflow because it was developed for conventional reservoir rocks, but applied here to the Bakken and Three Forks formations, considered unconventional tight oil reservoirs [4].

A quick test of the Dean Stark method was made on six plug samples of Bakken and Three Forks rocks from Core 4 [Fig. 3]. Core plugs were first subjected to RCA and Dean Stark cleaning. Lab protocols for cleaning required no measurable increase in water level in the extraction apparatus after at least 24 hours. Upon completion of the cleaning process, the plugs, still saturated with toluene, were removed from the extractor and immediately crushed. The crushed material was placed back into the extractor, and additional hydrocarbons and water were removed during this second episode of extraction [Figs. 5A and 5B]. Preliminary results from this quick test indicate that as much as 15% more water was removed from the crushed material, which would suggest

that there was incomplete cleaning of the core plugs through the normal RCA Dean Stark process. Additional testing is currently underway to confirm the degree to which the Dean Stark procedures on the Bakken and Three Forks rocks are inadequate to fully clean core plugs, and to verify the volume of water left in the core plugs after the normal RCA workflow.

While attempting to understand the efficacy of RCA on plugs from the Bakken and Three Forks formations, an unexpected error was uncovered in calculating water saturations from the volume of extracted distilled water using Equation 1:

$$S_w = (V_{DW} * V_{Brine} / V_{Pure\ Water}) / V_{Pore} \quad (1)$$

Where the brine volume is calculated as follows:

$$V_{Brine} = [(V_{Pure\ Water} * \rho_{Pure\ Water}) / \rho_{Brine}] [1,000,000 / (1,000,000 - C_{salinity})] \quad (2)$$

(S_w , water saturation; V_{DW} , volume of distilled water; V_{Brine} , volume of brine; $V_{Pure\ Water}$, volume of pure water; V_{Pore} , pore volume; ρ , density)

In the absence of client guidance, two labs used different default salinity values in Equation 2 to calculate water saturations in Equation 1: one lab applied a default salinity value of 50,000 ppm (density of ~1.03 g/cc); and the second lab applied a default salinity value of 30,000 ppm (density of ~1.02 g/cc). Pore waters in the Bakken petroleum system are extremely saline, with salinities measured on produced waters at the surface ranging up to 360,000 ppm (density of ~1.29 g/cc) or greater. As a result, using the correct values for water salinity resulted in as much as a 15.34% difference in the calculated water saturations, especially in rock intervals that are dominantly water-wet. Therefore, the simple matter of using correct values for pore water salinity allowed for a significant change in calculated saturation values, and thereby ‘corrected’ core data to match log data more closely. Use of the appropriate salinity affected saturation calculations for samples subjected to either RCA or GRI. Fig. 6 is a plot of water saturation for 350 core plugs. The blue line is computed water saturation assuming a formation water salinity of 50,000 ppm; the red line is computed water saturation assuming a formation water salinity of 350,000 ppm.

Given the extreme salinity of formation waters in the Bakken petroleum system, there was a suspicion that salt (halite) precipitation was a possibility in core material. Analysis confirmed the presence of halite occluding pores in core material [Fig. 7] as well as in at least some X-ray diffraction analyses. The authors now believe that the halite precipitated after the core was brought to the surface and subjected to ambient conditions. (Formation temperatures are approximately 250°F, and pressures are as high as 7,000 psi.) The halite not only occludes pores but also occurs as a partial coating on diagenetic minerals in the rocks. This conclusion corroborates the assumption that the halite is a ‘contaminant’ formed after the cores were retrieved. The presence of halite in the rocks calls into question whether salt can be completely removed during the chloroform/methanol azeotrope and subsequent methanol cleaning steps of RCA, especially given that

incomplete cleaning of water and hydrocarbons during RCA toluene extraction had been observed [Figs. 5A and 5B]. Further, because the GRI protocol as written [2] does not include either a methanol/chloroform or methanol cleaning after toluene extraction, incomplete removal of halite can be expected in crushed rock analyses. Indeed, initial lab tests showed that both post-toluene cleaning steps are required on crushed rock samples to remove the ‘contaminant’ halite completely from the rocks; the methanol/chloroform azeotrope cleaning proved insufficient to remove all halite, and a methanol cleaning was required. Because incomplete removal of halite will affect subsequent measurements of materials, it is likely that the core measurements are in error from the lack of thorough salt removal. The significance of this source of error is being evaluated.

Comparison of Nuclear Magnetic Resonance and Extraction Saturation Analysis

Core NMR measurements were run to attempt an independent analysis of the core saturations without using an extraction method. The NMR measurements required a 1-inch diameter core plug. This was accomplished by under coring preserved 1.5-inch diameter plugs that were twins to original core analysis. These 1-inch plugs were measured in native saturation using a high field 20 MHz NMR spectrometer by acquiring both T2 and T1 datasets. From these measurements, porosity, oil and water saturations were calculated. Following NMR measurements, the 1-inch plugs were placed in Dean Stark apparatus and normal Dean Stark measurements were made on the plugs. The remnants from this core were used to make retort extraction analysis measurements. Table 1 shows a comparison of the retort, NMR and Dean Stark measurements for porosity, oil saturation, and water saturation. The water and oil saturations calculated from Dean Stark uses water salinity of 360,000 ppm and oil gravity of 45 API.

Fig. 8 contains plot of all of the data in Table 1. Fig. 8A is a plot of porosity and shows that Dean Stark and NMR porosities are similar whereas Retort porosities are generally lower in value. Fig. 8B is a plot of oil saturations for all of the methods and shows that Retort gives lower values, Dean Stark the highest values and NMR is generally in between the other two. Fig. 8C, is a plot of the water saturations and shows that Dean Stark has the lowest saturation values, Retort the highest and the NMR saturations values varying both higher and lower when compared to the other two methods. Therefore, the variation in the results of this data would seem to indicate that there is uncertainty as to which method is more accurate in determining saturations in unconventional tight oil.

It should be mentioned that the current version of API RP 40 protocol for retort procedures does not include a brine-density volume correction factor as required in the Dean Stark procedures using Equations 1 and 2. Additionally, this protocol does not have any procedures for the removal of salts from the sample during the test.

Anhydrite Dissolution

Early in the deliberations about possible sources of error in core measurements, the likelihood of gypsum dissolution by methanol during RCA was discussed. This question arose from the observation that the interval where the difference in log and core saturations was occurring started where anhydrite was appearing in the log mineral analysis. Although little or no indication of gypsum was observed in the samples,

anhydrite is present, particularly in the Three Forks. That gypsum is methanol soluble is expected based on relevant literature [5, 6]. Although lab experiments have shown that anhydrite solubility is higher than that of gypsum [6], it was unclear whether some of the anhydrite in the Three Forks rocks was dissolving during the cleaning process when methanol was used. Thus, the service labs were instructed to perform bench top tests; anhydrite from the Three Forks was carefully weighed and then bathed in methanol. After approximately two weeks, the samples were carefully removed from the beakers, dried and reweighed, with little to negligible weight loss from the beginning of the experiment. From these test results, the concerns regarding anhydrite dissolution during the Dean Stark cleaning process seem unfounded.

CONCLUSION

An ongoing evaluation to understand possible reasons why core data are mismatched to log data from the Bakken and Three Forks formations has uncovered several issues that are being considered as sources of errors in the original core data. Most notable is the problem with core analysis that may have roots in the salinities of the pore waters in these rocks. The very high salinities require special attention in the calculations of water saturation. In addition, salt precipitation in the cores on retrieval to the surface can lead to porosity occlusion and therefore to incomplete cleaning during routine core and crushed rock analysis. The salt precipitation may be considered a principal hurdle to overcome when performing lab tests on either core plugs or crushed samples. Diligence is required to inform core service labs of formation water salinity and produced oil density values before commencing lab work, and to ensure that errors are minimized in calculating water and oil saturations.

The characteristically low porosity and permeability of Bakken and Three Forks rocks, coupled with the concerns regarding salt precipitation, calls into question the use of existing core analytical approaches and workflows to obtain accurate core data from unconventional tight oil rocks. Existing methods were developed for conventional reservoir rocks (RCA) and gas shales (GRI). Consequently, the authors propose research and development of analytical protocols and workflows specific to unconventional tight oil reservoirs (low porosity/permeability) and associated rocks. Finally, our studies suggest that the API RP 40 is due for a review and revision, and should be updated to include detailed analytical techniques suitable for unconventional reservoirs.

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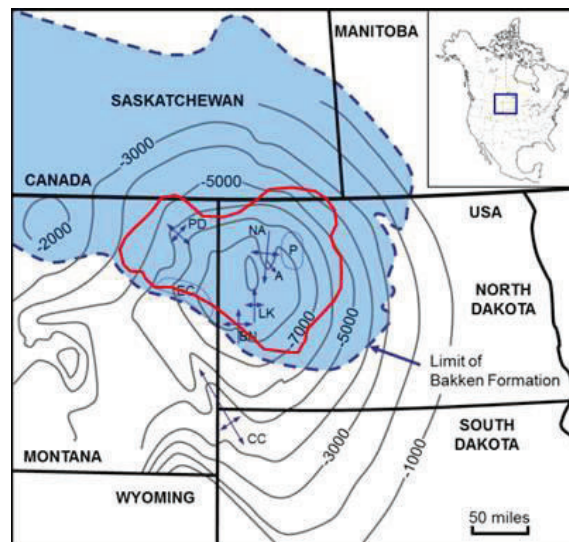


Fig. 1 - Map showing Williston Basin (outlined in red) in North America

PERIOD	Group	Formation
MISSISSIPPIAN	Big Snowy	Otter
		Kibbey
	Madison	Charles
		Mission Canyon
		Lodgepole
DEVONIAN		Bakken
		Three Forks
	Jefferson	Birdbear
		Dupero
	Manitoba	Souris River
		Dawson Bay
	Elk Point	Prairie
		Winnipegosis
		Ashern

Fig. 2 - Generalized stratigraphic column of the Williston Basin

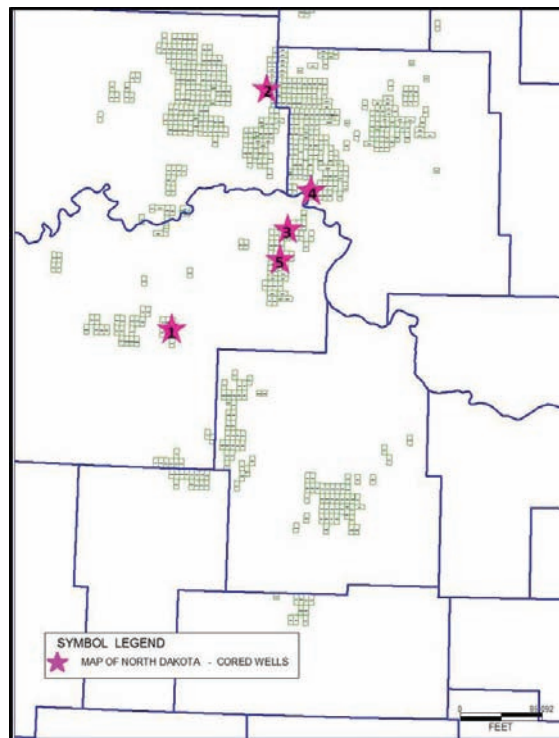


Fig. 3 - Map showing the location of five cored wells in the Bakken petroleum system taken in 2013 - 2014

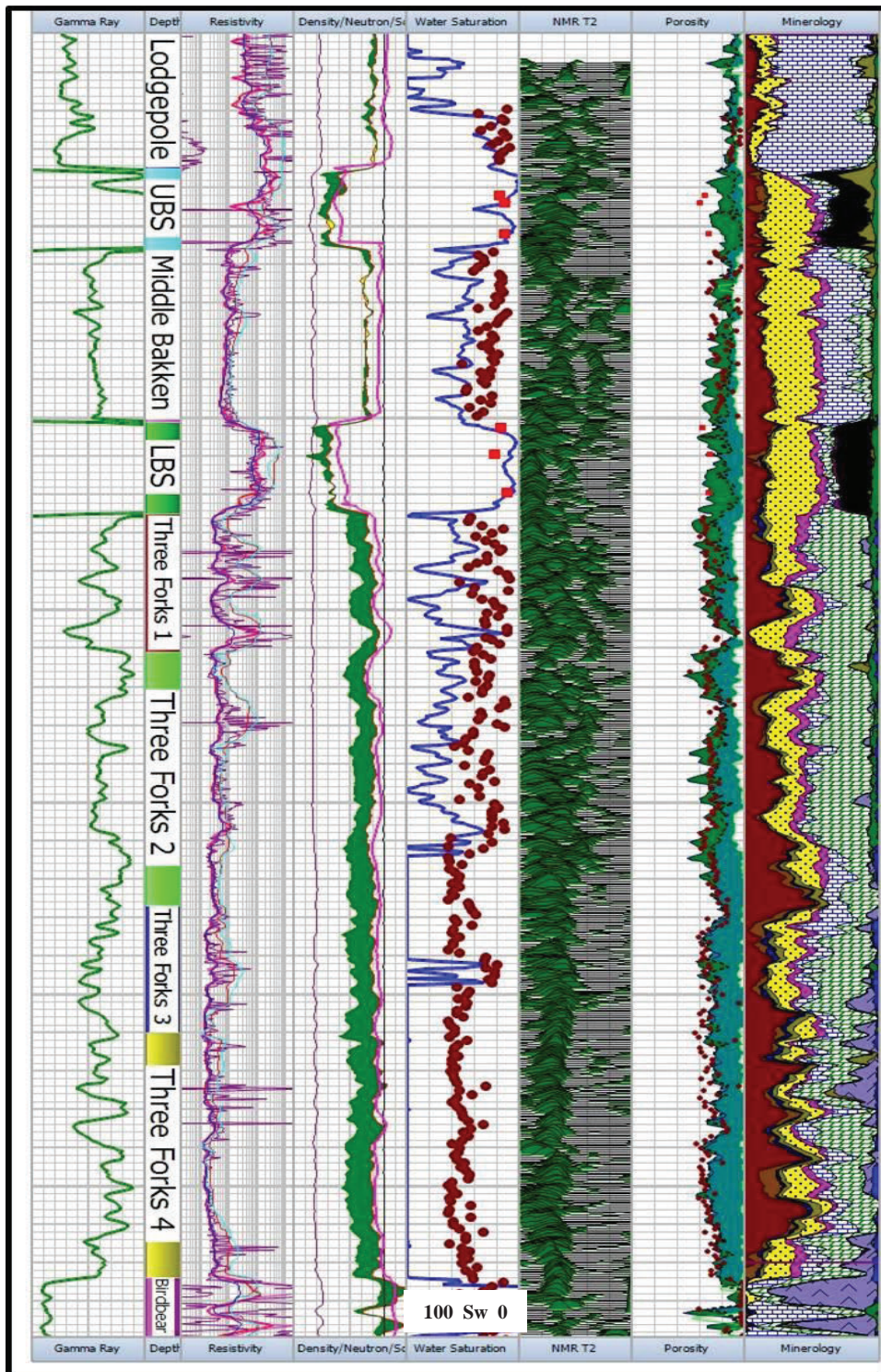


Fig. 4 - This example shows a poor log to core water saturation comparison in the middle water-saturation log track, primarily over the Three Forks Zones 3 and 4



Fig. 5A - Dean Stark extraction apparatus showing orange discoloration of toluene in boiling flask. The discoloration resulted from hydrocarbons released after crushing a core plug that had already been subjected to RCA Dean Stark cleaning



Fig. 5B - Water level in the calibrated receiver of the Dean Stark extraction apparatus. This additional water was extracted from the sample after crushing a core plug that had already been subjected to 'complete' RCA Dean Stark cleaning

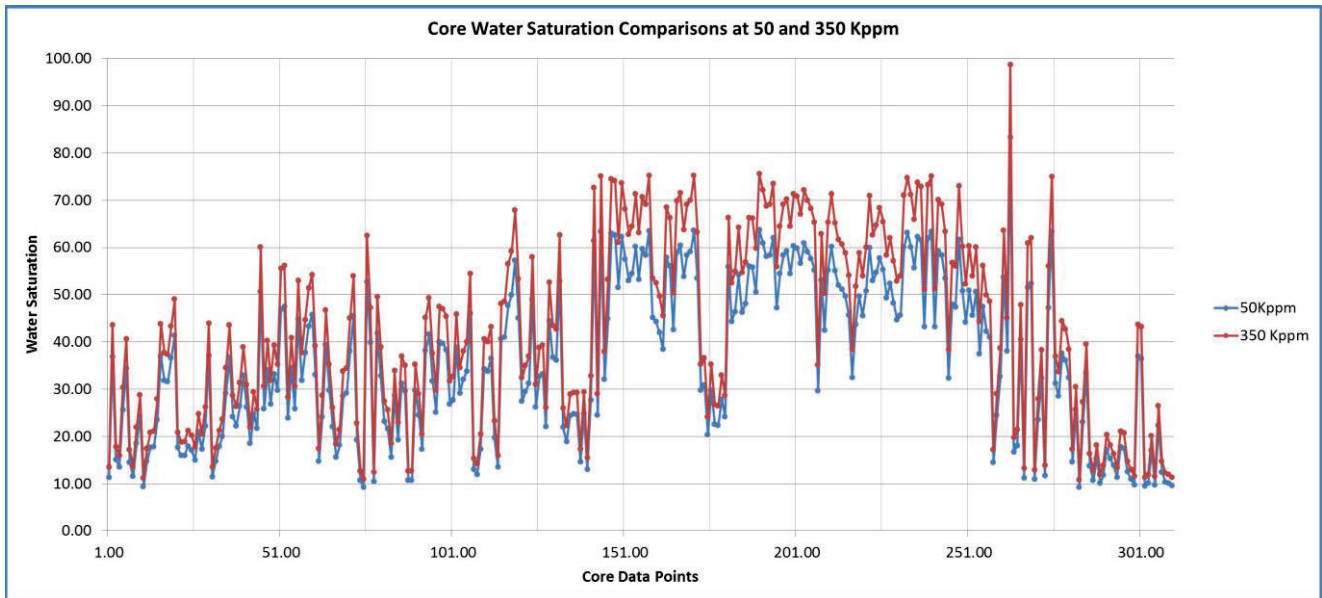


Fig. 6 - Comparison of 350 RCA cores, changing formation water salinity from 50,000 ppm to 350,000 ppm

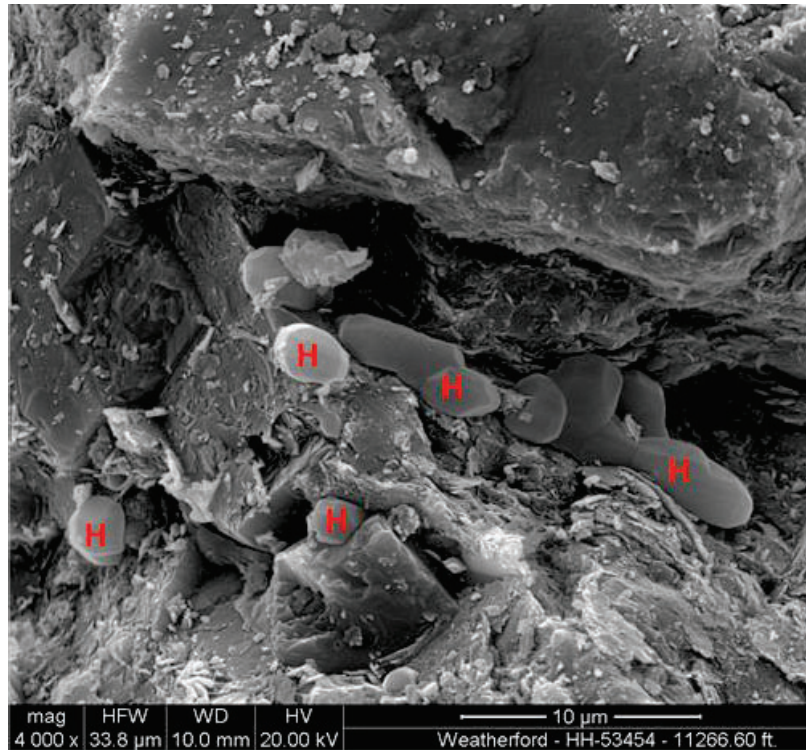


Fig. 7 - Scanning electron micrograph showing halite crystals (H) that partly occlude pores and coat diagenetic minerals

	Porosity			Oil Saturation			Water Saturation		
	Retort	NMR	DeanStark	Retort	NMR	DeanStark	Retort	NMR	DeanStark
Sample	Porosity	Total				360K & 45API			360K
Number		Porosity	Porosity	Oil	Oil	Oil	Water	Water	Water
	%	%	%	% PV	% PV	% PV	% PV	% PV	% PV
30Rb	2.14	2.2	1.94	0.00	9.4	28.7	52.45	42.7	21.3
48Rb	3.22	4.9	4.91	4.48	13.9	20.1	77.87	32.5	31.2
53RB	4.60	6.0	5.58	13.57	18.3	27.3	68.91	52.8	43.5
58RB	2.58	2.5	1.98	12.67	18.4	9.7	44.33	69.0	44.5
62Rb	6.45	8.4	8.74	19.62	18.0	11.3	71.39	25.7	39.7
84Rb	4.69	6.1	7.20	0.00	10.6	10.1	79.88	40.3	56.0
108Rb	3.46	4.6	5.54	3.64	14.2	11.0	76.97	22.6	33.4
139Rb	2.82	6.4	7.89	3.67	19.5	20.2	58.47	18.8	8.2
161RB	5.75	5.4	4.91	2.71	3.5	41.5	85.08	94.9	69.0
183Rb	5.86	4.6	10.69	0.00	2.6	9.2	80.46	48.6	54.9
195RB	3.09	3.8	4.26	0.00	5.6	29.6	72.58	90.3	63.4
207Rb	3.91	1.2	2.25	0.00	10.2	20.2	72.58	36.9	50.8
216Rb	6.59	4.7	6.29	2.71	6.7	17.7	66.17	44.2	42.6
241RB	5.72	7.0	6.84	2.95	2.7	17.9	90.37	74.3	58.2
247Rb	4.95	4.9	3.88	0.00	6.0	12.8	76.06	45.5	28.9

Table 1 – Comparison of porosity, oil saturation and water saturation measured on preserved core plugs using three different analysis techniques. Values in the green columns were from retort extraction methods; values in blue were from a 20 MHz lab NMR spectrometer; and values in yellow were computed from Dean Stark solvent extraction methods

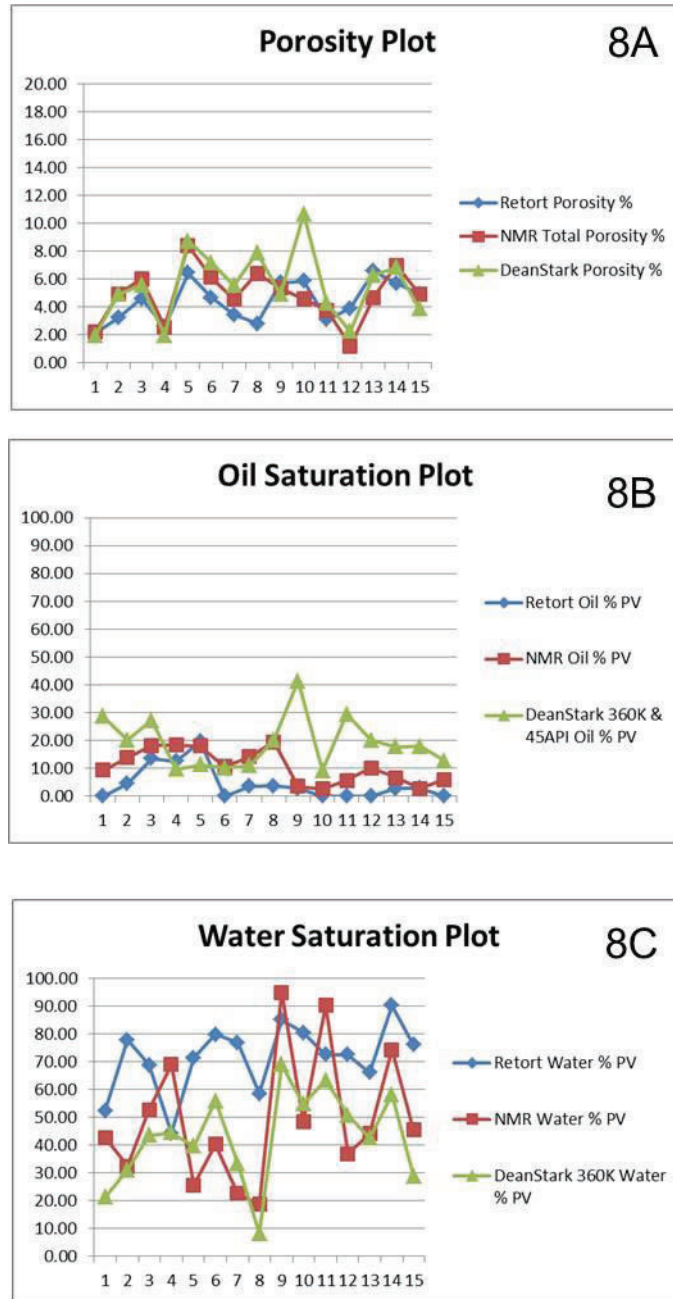


Fig. 8 – Porosity, Oil and Water Saturation plots from Retort, NMR and Dean Stark