PaperID **AU350**
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Estimation of water saturation Sw and cementation exponent m using basic open hole logs in complex carbonate reservoir rock of Western Offshore Basin, Mumbai, India.

Abstract:
A comprehensive study of well log data of the recent wells in Western Offshore Basin (Mumbai) was carried out to compute petrophysical parameters in the carbonate rock. Early to Mid-Miocene limestone rock was one of the objectives. KCL-PHPA mud was used in the borehole for drilling & logging. The petrophysical evaluation of these wells with the basic open hole log suit was impossible to predict the hydrocarbon potential of the rocks. One critical reason was the variation of deep resistivity measurement from as low as1.4 Ω-m to 4-6 Ω-m in a clean section where the density-neutron porosity measurements were almost uniform. Second issue was that the density-neutron logs in hydrocarbon bearing zone didn't exhibit any characteristics of hydrocarbon. The MDT pre-tests & fluid samplings can help in this regard but it has limitation. The conventional Core/ MDT pretest data with CMR logs can assist to the carbonate rock interpretation. But core data collection is not always technically possible. The ultimate option is testing the zone which is not the actual way. In this paper how this complexity can be reduced step by step considerably has been discussed and moved forward towards the goal. The method frequently used in past when no porosity logs were available. The procedure is very simple to compute important petrophysical parameters of a complex carbonate rock. As a result, several pay zones of L-II, L-III of Ratnagiri formation of Early Miocene age were identified as potential hydrocarbon bearing. The MDT samples & testing results are in good agreement with the predictive water saturation in these wells.

Introduction:
The log interpretation of a carbonate reservoir is most challenging. Archie relation is better suited in clean sandstone rock. Its application in carbonate rock is not simple as in sandstone. Of course it works in carbonate rock with coarser primary porosity which is treated same as clean sandstone. A carbonate rock with fine primary & secondary porosities require further study for applying Archie relation. In a carbonate rock with secondary porosity, there is no specific relationship between porosity and pores connectivity. The electrical path depends on how the pores are distributed & interconnected in the rock. That's why the electrical resistivity differs in a zone even porosity is inform. This concludes that the sandstone & the carbonate rocks behave differently for electrical measurements. The interpretation of a reservoir involves the parameters a, m, n, Rw & effective porosity Φe. In normal approach, log data is interpreted with a=1, m & n=2. But m is not always equal to 2 & varies widely in a carbonate rock. Since the Sw depends on m greatly so, the interpretation itself raises doubts & questions for the reliability of the computed Sw. This situation is more complex in oil zone where m≠n. Hence, it is a primary necessity to evaluate m preciously in a carbonate rock to avoid unrealistic Sw. In Fig: 1, the limestone int. XX12-21m with Φe =15-18% (taken from ELAN) produced feeble gas even after acid job indicating that the interval has no actual effective porosity. Hence, evaluation of accurate Φe is also important.

The density-neutron logs are very helpful to detect hydrocarbon in a reservoir rock. But in many cases, the neutron & density measurements are affected by the neutron absorbers & heavy minerals respectively which are available in traces in carbonate rocks. So, the neutron porosity reads high & density porosity reads less. Thus, a carbonate reservoir potentially hydrocarbon bearing will show no cross over in gas zone & the oil zone looks as water bearing. Sometimes, the hydrocarbon in the flushed zone can easily be displaced due to high permeability of the carbonate rock. As a result, the density tool reads only mud filtrate instead of hydrocarbon. In Fig: 2, the limestone int. XX34-37m which has no cross over in the density-neutron logs but the zone produced gas @ 1,11,886m3/day in testing.

The shallow & deep resistivity measurements are very helpful to interpret a complex reservoir. The insight of this paper will elaborate the importance & application of the shallow resistivity log to compute Sw, m & Φ in a complex carbonate rock.

Electrical interpretation of carbonate reservoir:
For the purpose of electric log interpretation, the carbonate porosity is classified into 3 types. Type-A: In this type, the matrix porosity is very fine usually amounts to 1-5% and is almost entirely water saturated. This rock doesn't produce hydrocarbon unless secondary porosity is present. Productive type-A rocks usually have a total porosity between 5 to 15%. Type-C: In this type, the matrix porosity is very fine usually amounts to 20-40%. Sw is very high, frequently greater than 40%. Secondary porosity is rarely present. The production is usually from the low permeability matrix material; sometimes this permeability is not sufficient for hydrocarbon production. These types of rocks have relatively constant capillary water saturation. So, increasing porosity, therefore, will result in a decreasing resistivity. The best possibility of production in this type of rock is from the low resistivity portion. Sometimes Rt reads not more than 2 to 4 Ω-m in the oil zone. Type-B: This type is intermediate between Type-A and Type-C in all respects.

The porosity vs resistivity variation of the three types of hydrocarbon bearing rocks is shown in Fig-3. In type-A, the resistivity first decreasing with increasing primary porosity up to 5% & then the secondary porosity comes at expense of primary porosity, so resistivity increases thereafter. As the coarse porosity contains almost no capillary water, so the resistivity increases. Rocks of the type-A, therefore, are most likely to produce hydrocarbon if resistivity is fairly high of about 100 Ω-m. In case of Type-A, the resistivity is primarily controlled by the changes in water saturation. In the type-C rock, the resistivity depends on the changes of F since the water saturation is fairly independent of porosity. In the type-B rocks represent the intermediate condition.

Estimation of Sw using resistivity logs:

Knowledge of shallow resistivity RXOZ in the completely flushed zone is extremely useful in both qualitative & quantitative log interpretation. The laterolog is generally good provided that the mud has a low resistivity, although in a very high resistivity sections it will also flap-top. For wildcat wells the mud resistivity should be controlled so that Rmf=Rw; the well is then logged with laterolog & the microlaterolog, and the zone where the laterolog reads at least one & one-half to two times higher than the microlaterlog, the hydrocarbon is probably present there. The ratio of these two readings is $(Sxo/Sw)^2$. When the well is drilled with a mud filtrate of salinity adjusted to the formation water salinity & the reliable log data are available, then the shallow resistivity RXOZ & deep resistivity Rt measured by resistivity tool can be used to estimate the water saturation. This water saturation Sw is approximately given by the relation as:

$Sw = RXOZ/Rt$ -- (1)

Note that this Sw does not need any porosity. It also nullifies the conducting mineral effect if it is present in the reservoir. That's why this equation is very useful to compute Sw in a complex carbonate environment. If a well is drilled with mud filtrate salinity other than formation water salinity, then the acquired RXOZ curve needs to be transformed to the shallow resistivity RXOZ' corresponding to formation water salinity. This transformation is done using relation Ro=F*Rw for flushed zone:

RXOZ' = RXOZ × (Rw/Rmf) -- (2)

The ratio (Rw/Rmf) can obtain directly from Rw & Rmf at the formation temperature & this value will remain same as long as salinity of the formation does not change. The ratio (Rw/Rmf) can also find from Rw & Rmf channels generated using Arps' relation (Equation-5 given in Appendix).

When the mud filtrate salinity is different from formation water salinity, the equation (1) is transformed to:

$Sw = RXOZ'/Rt$ -- (3)

The RXOZ measurement may affect due to residual oil in the oil zone. Some local knowledge of residual oil saturation is required at this point. Residual oil saturation in the flushed zone of about 20% is fairly common which means Sxo is about 80%. On the other hand, if the measurement RXOZ is reasonably good, then the RXOZ' must coincide with Rt in a water zone. If both the curves don't match in a water zone, then the chosen Rw is incorrect. In that case the RXOZ' channel must be calibrated to make RXOZ'=Rt (=Ro, resistivity of water wet rock) by adjusting Rw in the water zone. The equation (2) can be used for formation salinity estimation. In an impermeable zone where invasion is not taking place, the calibrated RXOZ' will read higher than Rt.

Computation of porosity using resistivity logs:

The effective porosity Φe in a carbonate reservoir rock cannot be computed directly from any porosity logs including CMR log. It can be computed from CMR log if the T2 cutoff is available from CMR core study. The other means to get the Φe is from the CMR permeability equation using the MDT permeability. So, CMR log is not much helpful in carbonate rock if conventional cores for CMR core study or sufficient MDT data are available. This Φe can be approximately estimated using resistivity logs by the condition:

$\Phi e \geq Rmf/RXOZ$. --- (4)

This porosity occasionally reads less due to higher measurement of RXOX for the residual oil in the oil zone.

Calculation of cementation exponent m:

We'll assume here that the rock behaves like an Archie medium. The cementation exponent 'm' in a clean carbonate rock can be obtained by using the Archie relation in completely flushed zone (assuming a=1) as:

m= ln (Rmf/RXOZ) / ln (Φe) ---------------------------------- (5)

Here, Rmf channel is generated using Arps' relation. RXOZ channel is available from log & Φe is from ELAN. In equation (5), it is assumed that all the pores in the carbonate reservoir are well connected. If the rock has isolated porosity as well, then 'm' will be higher due to overestimated Φe. In oil zone, the RXOZ measurement will read higher due to some residual oil. So, the actual value of 'm' will be smaller than this calculated value in oil zone. In water zone, m is always equal to n but in any HC zone n exceeds m. The computed m by (5) will represent visualized picture of a rock when the formation factor F in the flushed zone does not change.

ELAN interpretation & petrophysical outputs:

The multimineral ELAN plus model is run with the suitable formation components. Once oil, gas or water bearing zones are identified, then propagate the proximate theoretical value of m and use n such that n ≥ m in HC zone in ELAN to make the SDR minimum and to reconstruct each real & theoretical curve. Note that the model is to be geologically right & realistic. Because, minimum SDR & individual curve reconstruction always do not guarantee that the model is geologically robust. Correct lithology & total porosity can be estimated if we incorporate ECS/ Litho-Scanner Logs in ELAN. Work flow of log data interpretation process is given in Fig-4.

Applications:

We have brought four case studies in this paper. The second & fourth cases are taken for estimation of formation water salinity as well. Log data of well-A, B & D were processed with salinity 28,000 ppm and Well-L with 15,000 ppm as NaCl. Proximate value of the theoretical m was considered for ELAN and n was used such that n≥m in HC zone for each well.

In each presentation, the composite logs are presented in standard format from tracks 1 to 4. Dry weight Ca, Si & Fe measurements from ECS logs are plotted in track 5. Effective porosity & fluid saturations and lithology from ELAN are plotted in tracks 6 & 7 respectively. Deep resistivity (Deep_Res) and shallow resistivity (Shallow_Res) corresponding to the formation water salinity are plotted in track-8. The area shaded between them represents the movable HC volume. This gives idea of permeability of the reservoir zone. Sw calculated using resistivity logs (Sw_Res) and ELAN (Sw_Elan) are plotted in track 9. The porosity from resistivity (Phi_Res), sonic logs (Phi_Sonic) and effective porosity from ELAN (Phi_Elan) are plotted in track 10. Theoretical m (m_Theoretical) and m (m_Elan) & n (n_Elan) parameters used in ELAN are plotted in track 11.

Case-1, Well-A: In this well, two distinct units, intervals X614-30m & X651-65m from Ratnagiri formation are taken for our first case study. The upper unit has two layers and the intervals X614-18m & X624-27m from the two respective layers were approved for object-I. In track-8, huge movable HC is clearly seen in the top interval and less movable HC in the bottom interval of this object. But both the layers are interpreted as potential HC bearing using by equation (3) & ELAN. The calculated Sw by ELAN is around 35- 40% in the two intervals of this object. The porosity estimated from sonic log and ELAN are equal against the both intervals, but the porosity from equation (4) is increased in the upper interval & reduced in the lower interval. The theoretical m is around 1.6 in the upper interval and it is higher, more than 2.8 in the lower interval. Hence, the int. X615-18m would have higher permeability than interval X624-27m. So, the top interval would be main contributor than bottom interval in this object. The permeability of this object measured in the reservoir study during testing is as: Kinner=4001.47 md & Kouter=480.17md. Radial distance to discontinuity= 1900 feet & skin is (+ve) 142.5.

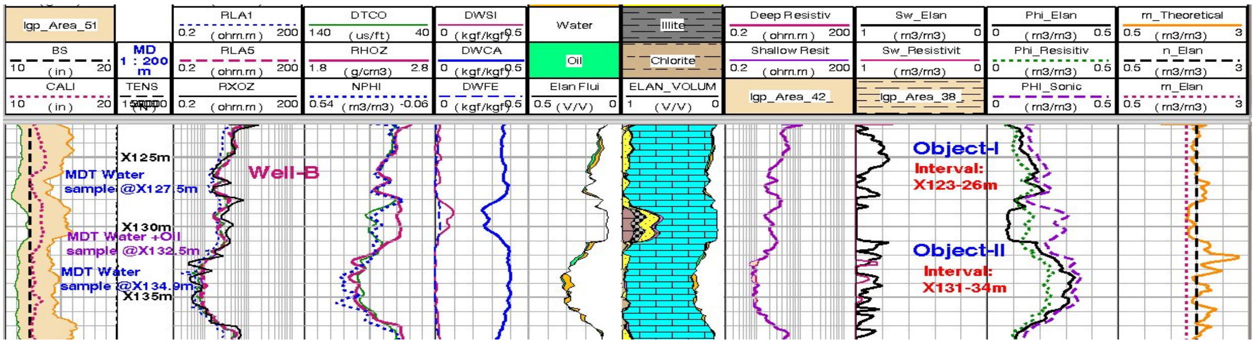
The intervals X652-55m & X662-64m from lower section were approved for the object-II. This object has almost similar characteristics with the reservoir interval X624-29m of the object-I. Only the difference is that the present object intervals have less movable HC than object-I & this reservoir has the moderate value of m. The Sw estimated by equation (3) is relatively high in this reservoir. This type of reservoir has high capillary water along with the bound water in isolated pores leading to relatively low resistivity, low to moderate m and the poor permeability. The dual porosity & permeability characteristics in these two objects have been reported by Sonic-scanner results. The sonic permeability of bottom layer in object-I & the object-II is reduced dramatically than the upper layer of the object-I although the porosity in the both units are about 25-30%. Normally this type of reservoir does not produce without acid frac job. The reservoir in this object looks as type-C porosity rock.

The MDT fluid sample collected @ X626.3m yielded oil in object-I & the MDT FID @ X656m indicated oil in the object-II. The permeability of the object-II (after acid frac job) measured in the reservoir study during testing is as: Kinner=307.9md & Kouter=51.72md. Radial distance to discontinuity= 424 feet & skin is (-ve) 1.899. This well was a discovery well and produced significant & commercial oil & gas. Please see the testing results below.

Objects	Intervals (m)	Bin Size	Qoil(BPD)	Qgas(M3/D)	Qwat(BPD)	Remarks
I	X615-18 & X624-27	5/8”	3,310	17,071	Nil	H2S=Nil & 5% CO2 produced.
II	X652-55 & X662-64		little Oil	little Gas	Nil	Total liquid recovered=67 bbls.
		3/8”	1,273	5,978	567	After acid frac job

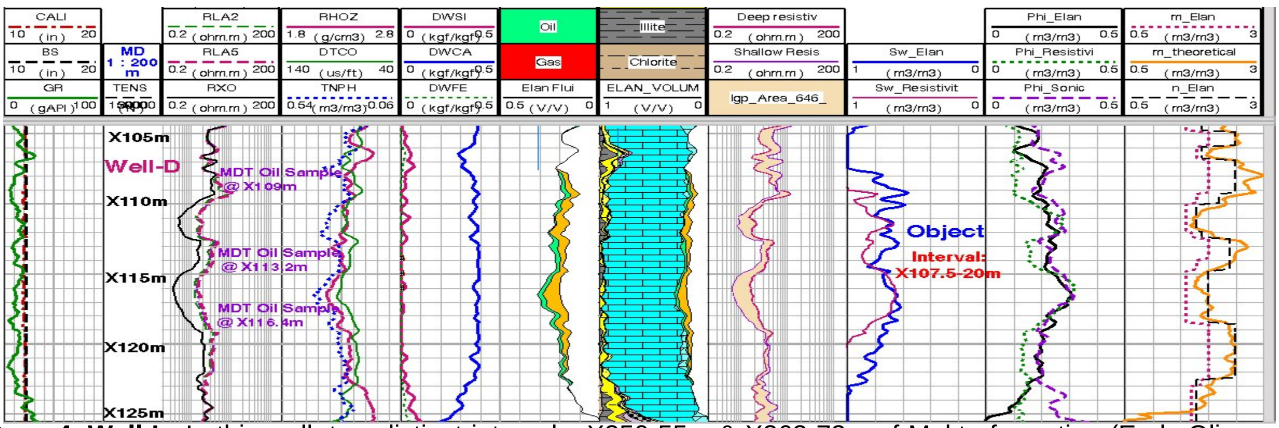
Case-2, Well-B: This well was drilled about 3km away from the discovery well-A to find the extension of its equivalent pays. In this well, limestone int. X123-38m from Ratnagiri formation has taken for case study. It has two separate layers consisting of object-I & II, both are equivalent to two layers of object-I in well-A. This two objects in this well were very important because both the layers in well-A have produced significant commercial oil & gas. This pay zone of object-I & II in well-B is structurally deeper by 4m w.r.t. the well-A.

The upper interval X123-26m was the approved as object-I. The water saturation estimated by equation the (3) is 100% & has no movable HC. The porosity estimated using equation (4) is about 10%. The porosity from ELAN is about 15 to 18% which is slightly less than calculated sonic porosity. The theoretical m is about 2 in this interval. ELAN interpretation shows little oil saturation, Sw> 80% in this interval. The log interpretation of this object using resistivity logs & ELAN saying that this object does not have any movable fluid. This object did not produce even after acid job. (Total contaminated brine collected=60bbls during testing).



The lower interval X131-34m was tested as object-II. The Sw estimated by equation (3) is more than 90% and has no movable HC. The porosity estimated from the equation (4) is about 24% and from ELAN & sonic is 30-32%. The theoretical m lies very close to 2 against the high porosity zone X133-36m where the Rt~0.98Ω-m in the object; else it varies from 2 to 2.4 in the object. ELAN interpretation of this object shows some residual oil and Sw is more than 80%. The object is interpreted as water bearing by both methods. The MDT fluid sample at X132.5m was water + oil & at X134m was water. The object-II produced Oil @ 126 bpd & Water @ 378 bpd via ½" choke in testing. The salinity of the produced water was 26,429 ppm as NaCl.

Case-3, Well-D: In this well, clay free limestone, int. X105-25m from Bombay formation is taken as an example. The interval X107.5-20m was approved for object. In track-8, movable HC is clearly seen against the int. X109-X120m. This interval is interpreted as HC bearing using equation (3). The estimated Sw is high about 60-65%. The lowest resistivity is measured 1.5Ω-m against the highly porous intervals X109-13m & X115-19m and the resistivity increases to 2-3Ω-m at some parts in this object. The theoretical m has the lowest value 1.6 against highly porous intervals X109-13m & X115-19m. The plot of m shows how m varies from 1.6 to 2.5 in the entire object. This oil zone looks like type-C porosity rock. ELAN interpretation also showed oil in the int. X107.5-23m, Sw from ELAN is about 60% & porosity is around 20-30%. The intervals X107-09m, X113-15m & X119-22m have similar petrophysical characters of the object-II in well-A. The MDT fluid samples @ X109m, X113.2m & X115m yielded oil. The zone produced Oil @1189 bpd, Gas @1640m3/d & water is nil via 5/8"choke on testing.



Case-4, Well-L: In this well, two distinct intervals: X350-55m & X363-73m of Mukta formation (Early Oligocene age) have considered for our case study. The object-I belongs to upper interval & object-II belongs to the lower interval. The difference between these two objects is their depositional environments and sediment types. The upper interval is a marine deposit rock & lower one is clastic rock. In Mumbai High, generally the terrigenous sediment in Mukta formation is very rare. The formation water salinity of this clastic sediment was unknown for us. So, the MDT sample was collected @ X373m from the water zone. The water salinity was found 16,500 ppm. This salinity was used in ELAN for the log interpretation in Mukta formation.

The upper int. X350-54m was tested as object-I. This limestone reservoir is different in respect of resistivity & m than any other reservoirs among all these wells. This reservoir is characterized by high resistivity, Rt~60 Ω-m and high m, greater than 3. In this object, the porosity estimated using equation (4) is very low ~ 7% & from ELAN, it is about 20%. The Sw is about 60-65% estimated by equation (3) although it is 40-50% computed by ELAN. All the parameters predicted that the object has poor permeability. The object-I produced Oil @ 1195 bpd & Gas @10,908 m3/day via 5/8"choke only after acid frac job. No water was produced in testing.

The interval X364-67m was approved as object-II. This object is interpreted as oil bearing, Sw~65%, using equation (3). ELAN interpretation also showed oil in the int. X364-67m with Sw around 50-60%. The porosity calculated using equation (4) is 10% but from ELAN it is around 15-20%. We know that the permeability in a clastic reservoir rock has linear relation with the porosity and is expressed by the relation: $\ln(K) \propto \Phi$, where k is permeability of the rock. So, there must be enough permeability in the present object for the fluid movement. In case of limestone, this permeability can be zero even with this porosity range. The vivid example is the object-I in this well & object-II in the well-A. This object interval has very high m around 2.5. The MDT FID carried out @ X373m indicated oil. The object-II produced only Oil @ 2379 bpd & Gas @ 4190 m3/day via 5/8"choke.

Calculation of formation water salinity:

We will estimate the formation water salinity (WS) using Archie relation & equation (2) for the given theoretical m. Let's take the clean water sandstone interval X370-73m in well-D as first example. Here, Φ=27%, Rt=Ro=3 Ω-m (from log) & Sw=1. Using Archie relation for this zone with a=1 & theoretical m=2.3, we get, Rw= 0.147 Ω-m & its equivalent WS=16,021 ppm. We can also estimate this WS using equation (2). In this well, the mud filtrate salinity=51,150 ppm & its equivalent Rmf=0.0528 Ω-m @ 221°F. From log, RMLL (=RXOZ)=1 Ω-m, RXOZ' (=Ro)= Rt=3 Ω-m, then using equation (2), we get Rw=0.158 Ω-m & its equivalent WS=14,789 ppm (Rw & WS are computed using the equations (7) & (8) given in Appendix). The WS estimated with m=2.3 and using equation (2) are much closed to MDT WS in this zone. So, cementation exponent m is 2.3 for this zone and WS of the formation is ~15,000 to 16,000 ppm as NaCl. For 2nd example, let's take the int. X133-35m of object-II in the well-B. Proceeding in the same way and using Archie relation for the int. X133-35m, we get, Rw= 0.1003 Ω-m & its equivalent WS=25,700 ppm. Here we use, Φ=32%, Rt=Ro=0.98 Ω-m (from log) & m=2(avg). This is much closed to the salinity of the produced water i.e. equal to 26,429 ppm. So m is 2 for this zone.

Observations:

The reasons of high m & Rt in HC bearing carbonate rock are (1) less capillary water due to lack of fine primary porosity & (2) presence of large pores with less connectivity results to high tortuosity. The permeability in this case may be low. This is the example of object-I in well-L. A rock with fine pores & with less secondary pores generally has smaller m and low Rt. In this case permeability is low for fluid movement but electrical path suffers less resistivity due to good connectivity through fine pores. In a low resistivity HC bearing reservoir (if no conducting mineral is present) the high water saturation is due to capillary water only. So there is no OWC in that scenario. The example is the well-D. Sometimes m is found high in a reservoir having slightly higher resistivity. In that case the acid frac job is necessary for production. The example is the object-II in well-A. For above cases, the acid job may require for the production if the object does not produce or to increase the existing production from the object. However, water will always be released with oil if acid job is carried out for low resistivity reservoir. We have observed that the test results and the MDT samples/ FID of each well in our case is in good agreement and support with the both ways of log interpretations.

Limitations:

Sometimes, invasion of carbonate rocks can be particularly severe because of high permeability of fractures & connected vugs. So, in a zone of huge mud loss may read the shallow & deep resistivity same. Hence, Sw = $RXOZ/Rt$ will not be applicable. This method will not work in non-conducting-mud also.

Conclusion:

We can have proximate values of Sw, m & Φe without doing ELAN and water salinity of a complex reservoir rock from resistivity logs only. These three parameters when plotted in log with depth, we can clearly visualize fluid type, movable fluid fraction; get an indication of permeability and Φe of a reservoir. The MDT points can be optimized using this Sw. Also, we can have both Φe & Φt for comparison in a reservoir. So, if we consider all these prior knowledge while log data processing in ELAN, then the parameter Sw will have more accuracy.

Acknowledgement:

I'm thankful to Shri D. Gosh, HGOG, Shri A. K. Vinod, COG & Shri M Ayyaduari, ED Basin Manager, WOB, Mumbai for their continuous support & encouragement to write this paper.

References:

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2. Well Logging for Earth Scientists (Springer) by Darwin V. Ellis & Julian M. Singer.

Appendix:

Arps' formula relating resistivity of brine with the temperature is defined as:
$R_{wT2} = R_{wT\,1} \times \left(\frac{T1+6.77}{T2+6.77}\right)$, ----------------------------- (6),

The Rw & its equivalent water saintly (WS) of brine can be obtained from the following relations:
WS @ FT = $400000/FT / (Rw)^{1.14}$, ---------------- (7)
Rw @ FT = $(400000/FT / WS)^{0.88}$ ---------------- (8),

Where T1 & T2 are temperatures in equation (6) and FT represent the formation temperature in equations (7) & (8). All the temperatures are in °F, the resistivity is in Ω-m & WS in ppm.