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Missed pays in carbonate reservoirs

Bachelor thesis

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Anotace

Složité sítě pórů a heterogenita karbonátových rezervoárů představují zvláštní potíže pro průzkum a těžbu ropy a zemního plynu. Zmeškaná platba je typickým problémem v karbonátových nádržích a může být náročné najít platební zóny s komerčními zásobami uhlovodíků. Tento přehled literatury si klade za cíl prezentovat souhrn typických důvodů zameškaných plateb v karbonátových nádržích, včetně systémů s dvojitou pórovitostí, vrstevnatých útvarů, zlomů, vodivých minerálů, nesprávných měření měrného odporu, mikroporéznosti, plísňové a hrubé pórovitosti, bariér propustnosti a odpadních zón. Kromě toho se článek zabývá řadou metod, včetně protokolů z vrtů, analýzy jádra, seismických dat a simulace nádrží, které se používají k lokalizaci platebních zón v nádržích s uhličitanem. Společnosti zabývající se průzkumem a těžbou mohou zvýšit svou úspěšnost v nádržích s uhličitanem tím, že pochopí důvody promeškaných plateb a techniky pro lokalizaci výplatních zón.

Annotation

The intricate pore networks and heterogeneity of carbonate reservoirs provide special difficulties for oil and gas exploration and production. Missed pay is a typical issue in carbonate reservoirs, and it can be challenging to locate pay zones with commercial hydrocarbon reserves. This literature review aims to present a summary of the typical reasons for missed pays in carbonate reservoirs, including dual porosity systems, layered formations, fractures, conductive minerals, incorrect resistivity measurements, microporosity, moldic and vuggy porosity, permeability barriers, and waste zones. Additionally, the paper looks at some methods, including well logs, core analysis, seismic data, and reservoir simulation, that are used to locate pay zones in carbonate reservoirs. Companies engaged in exploration and production may increase their success rates in carbonate reservoirs by comprehending the reasons for missed payments and the techniques for locating pay zones.

Klíčová slova: Zmeškaná platba, zásobník uhličitanu, Střední východ, platová zóna s nízkým odporem

Keywords: Missed pay, Carbonate reservoir, Middle East, Low resistivity pay zone

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Declaration

I declare that I have prepared the bachelor's thesis myself and that I have stated all the used information resources in the thesis.

In Olomouc, May 8,2023 ……………………………………………

Rawchi Chalabee

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1. Introduction

Evaluation of carbonate reservoirs has long been a top concern for scientists and oil and gas companies, but the difficulties faced by these incredibly varied rocks appear unsolvable. To generate the most reserves from the subsurface, geoscientists, petrophysics, and engineers work from the early phases of discovery to the mature production stages. Reservoirs need to be evaluated before drilling or anything else, sometimes the evaluation that is used for sandstone successfully will fail for carbonate reservoirs. It is important to calibrate and check engineering data against geological data to provide an accurate estimate of effective porosity, water saturation, and hydrocarbon potential. A carbonate reservoir that shows very high-water saturation on the logs may sometimes produce oil that is water-free because a significant portion of the water in the reservoir is irreducible water that is bonded by dispersed clays in microporosity. This circumstance, which ordinarily results in Low Resistivity on logs and hydrocarbon Presence, is Ignored. Conventional log interpretations must be calibrated with geological information at the microscopic level to address this major issue.

Common Causes of Missed Pays in Carbonate Reservoirs:

Dual porosity system: Carbonate reservoirs frequently include a dual porosity system in which smaller holes are filled with water and bigger pores are charged with hydrocarbons. As a result, hydrocarbon reserves during exploration and production may be misinterpreted.

1. Layered formations: Carbonate rocks frequently consist of layered sections of rocks with different pore sizes, such as large grainstone and small micrite. Incorrect identification of pay zones and missed pay may result from this.
2. Fractures: Oil-filled and water-filled fractures can be found in carbonate rocks, which frequently have them. If these fractures are not correctly detected, it could lead to missed pay zones.
3. Conductive materials: Carbonate rocks may include conductive minerals, which may interfere with the measurements of the resistivity of hydrocarbon-bearing zones and result in the identification of the pay zone being erroneous.

4. Incorrect measures of resistivity: wrong measurements of resistivity, such as high invasion, might result in the identification of hydrocarbon-bearing zones being incorrect.
5. Microporosity: Carbonate rocks may include microporosity, which, if incorrectly identified, can result in missing pay zones.
6. Moldic and Vuggy Porosity: Carbonate rocks may have moldic and vuggy porosity, which, if not properly diagnosed, can result in missed pay zones.
7. Permeability barriers: Permeability barriers in carbonate rocks can restrict the movement of hydrocarbons and cause missed pay zones.
8. Waste zones: Carbonate rocks may contain waste zones, Waste zones have limited porosity and permeability, and if they are not correctly recognized, they might result in missed pay zones.

1.1 Low resistivity pay zone

A low resistivity pay zone occurs when wireline resistivity methods are failed to identify the hydrocarbons and show that the reservoir is water-bearing. Most documented examples describe LRP zones as having great porosity and extremely low resistivity. low resistivity pay zones are only found in the capillary transition zone, which also contains water and hydrocarbons. Low resistivity pay zone in carbonates has been attributed to the presence of conductive minerals, microporosity, deep, high-saline mud invasion, or a combination of these factors, as well as an anisotropic impact from drilling high-angle wells in thin reservoirs. very tight carbonates are frequently impacted by conductive mud's deep infiltration, and filtrate, which therefore affects the measurement of deep resistivity. To establish the optimum approach for evaluating the reservoir characteristics and to capture the uncertainty range, it is critical to identify the primary sources of LRP. A reservoir-specific in-depth analysis is necessary to determine the primary reason for the discrepancy between the resistivity-derived saturation and other sources. LRP is reported to have various causes. Most of the world's proven reserves are in carbonate reservoirs, however, LRP and other issues make it extremely difficult to characterize these reservoirs.

Development geologists and engineers who are focused on the efficient development of hydrocarbon accumulations are particularly interested in various aspects of carbonate porosity evolution and distribution. These factors are relevant not just to the quality and extent of a reservoir, but also to the interpretation and evaluation of logs and tests when deciding on well completions.

1.1.1 Microporosity

LRP intervals are thought to be caused by several factors, one of which is the occurrence of bimodal pore networks in carbonates. In this sense the movable hydrocarbons, while micropores, which have higher entry pressures, hold immovable, highly saline formation water. According to Hassan and Kerans (2013), who investigated the geological effects of LRP in carbonate reservoirs, microporosity makes up over 70% of the total porosity in all the analyzed facies from 14 core plugs. They concluded that the capillary-bound formation brine present in these microporous zones offered an uninterrupted channel for electrical current. As a result, the amount of accessible hydrocarbon was concealed, which significantly underestimated the genuine oil saturation. Archie parameters sensitivity analysis employs core-measured cementation exponent (m) and saturation exponent (n) if no deep invasion was found as one of the suggested solutions. Over the whole carbonate reservoir, the Archie equation cannot be used, because formation parameters (m, n) depend on variations in pore geometry, wettability, clay content, pore tortuosity, and formation pressure, carbonate reservoirs presumably don't behave like Archie rocks. Since the water saturation in LRP reservoirs is usually high, Archie is working in an area where the effect of "n" is minimal.

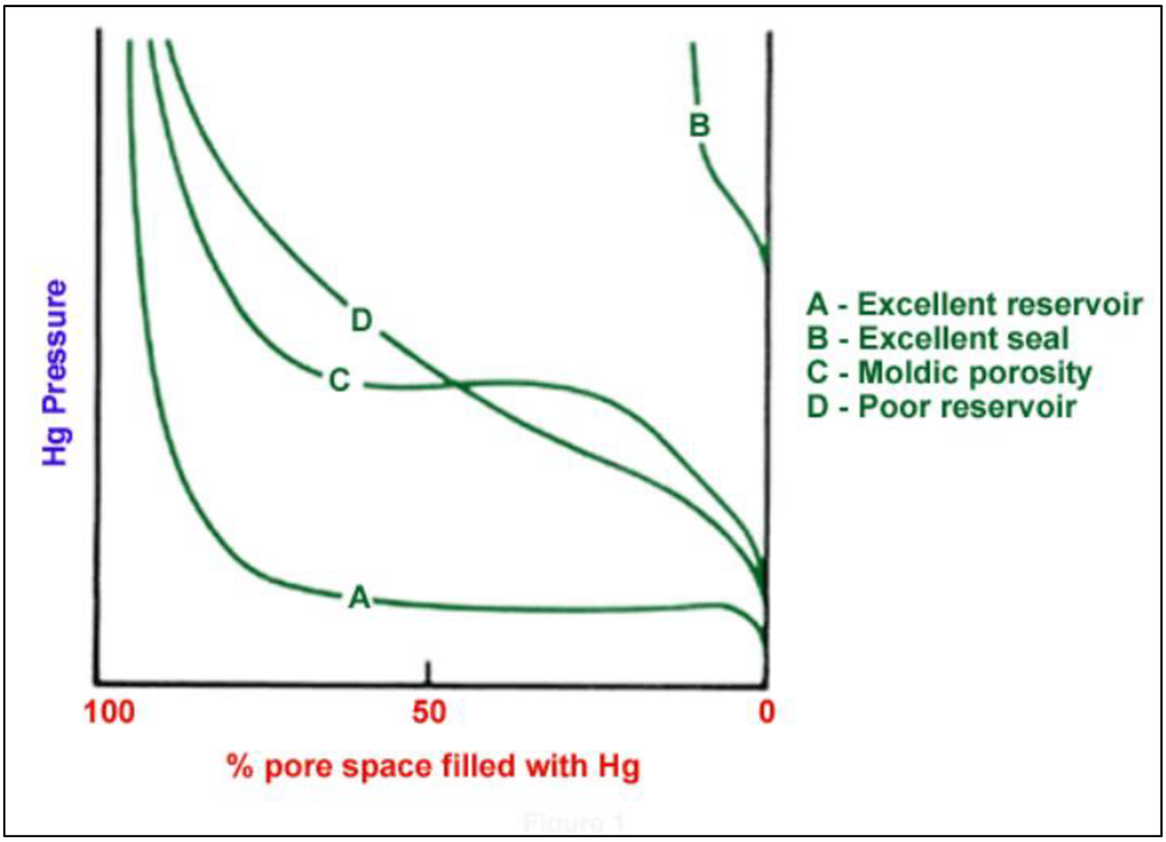

Figure 1 Schematic mercury-injection curves of typical carbonate rocks: A=excellent reservoir, B=excellent seal, C=moldic porosity, D=poor reservoir. (Keith, B.D. and E.D. Pittman)., 1983.

Microporosity is, however, an important component of total porosity in some carbonates, e. g. microsucrosic dolomite tidal flatstones, chalkite or pyricritized grainstones, and depositional phosphate rocks. The water from these micropores cannot be moved, so if hydrocarbons are brought into the reservoirs, it is difficult to remove them; otherwise, they will remain highly saturated unless there is a strong hydrocarbon column. There are also reservoirs with high intergranular grain-stone porosity as well as considerable microporosity inside the grains (intragranular porosity). This rock will produce hydrocarbons without water, although a simple log analysis may indicate that there is up to 65 % water saturation.

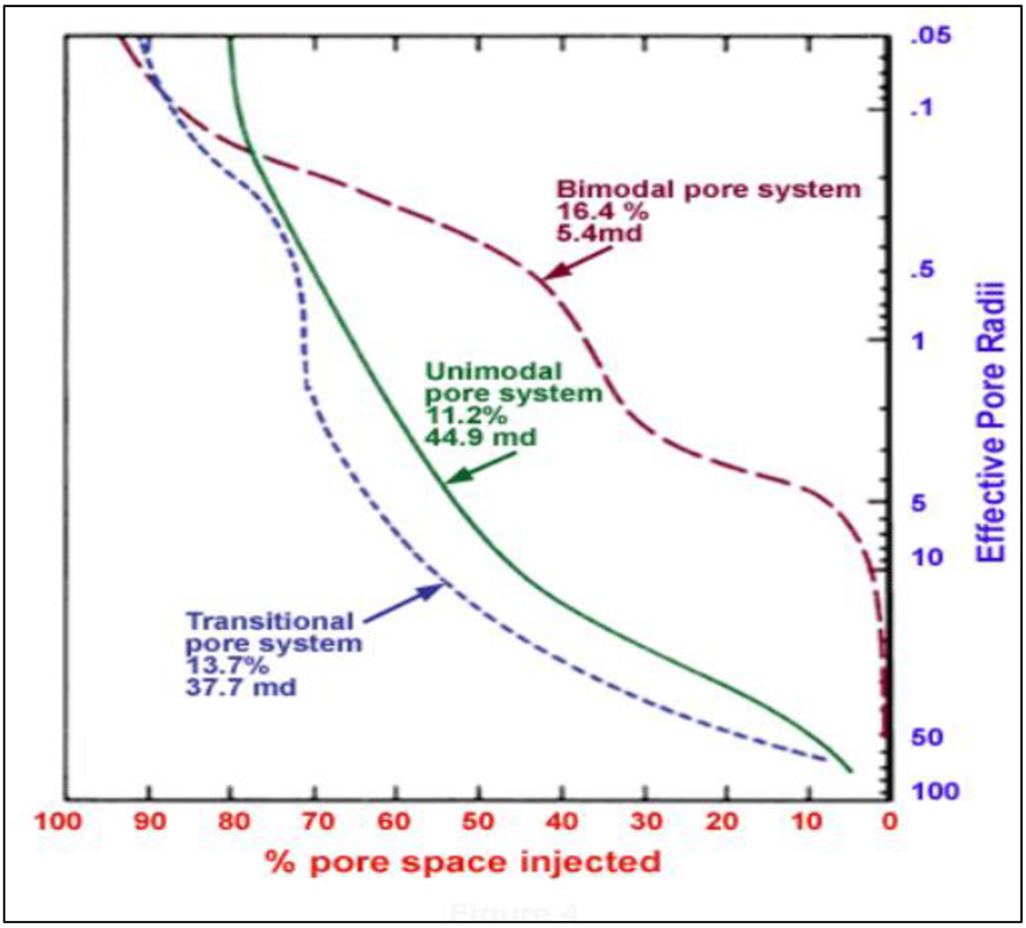

Figure 2 An example from the Lower Cretaceous Rodessa buildup in East Texas. The product is made from ooid-skeletal grainstones. (Keith, B.D. and E.D. Pittman, 1983).

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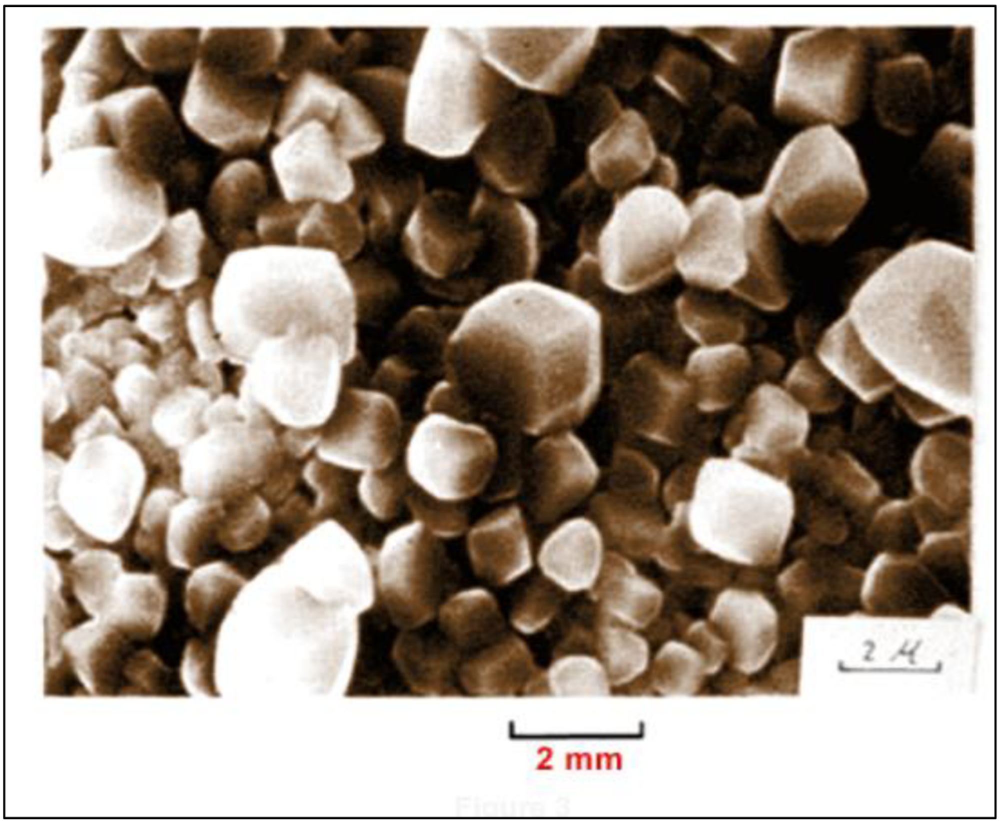

Figure 3 This microporosity maintains water content in the oolitic portion of the tank, making it more obvious that there is a saturation with water. This oolite also produces water-free gas. (Keith, B.D. and E.D. Pittman, 1983).

The reservoir is made up of skeletal and oolitic grainstones with high intergranular porosity. Both are in the gas column; however, log analysis shows that the oolitic part has a high-water saturation and hence would not be considered pay.

However, SEM photos and mercury injection curve data reveal an appreciable intragranular microporosity in the ooids.

During drilling the ome micropores are absorbing water which is displacing hydrocarbons in the vicinity of the borehole. Drillstem tests with low volume recovery may recover water with hydrocarbons, suggesting high water saturation when, in fact, away from the borehole the zone may have very low water saturation.

In response to differences in the depositional facies and diagenetic background, the distribution of microporosity may be variable vertically as well as laterally within the same continuous pore network. It is no surprise that water up dips from oil, or irregular fluctuations of water into the same reservoir, are found in such systems.

1.1.2 Moldic and Vuggy Porosity

Special problems in the evaluation include fungal and vuggy porosity. Common porosity logs shall record the total porosity of the rock as it exists, although the sonic log may indicate slightly less porosity than the neutron or density log because the sound waves pass through the rock framework more slowly.

Even though the pores have a high-water saturation because there is no well-connection between those isolated chambers, resistivity readings will often indicate very high levels of resistivity. It may be assumed that such a high porosity combined with an increase in resistivity would constitute pay, but this is not the case.

Cores from moldic or vuggy rocks can also be misleading. At first glance, it would be an exciting sight to see a twenty-foot core covered in 30% porosity leaking oil on the rig floor. The fact that the oil has been stored in the pores throughout the corrigendum operation suggests to me a very poor gas permeability and, if necessary, fungal, or vegetative porosity.

1.1.3 Permeability Barriers

The carbonate porosity networks are the result of complicated deposition and diagenesis interactions, as has been explained in previous sections. Such complex interactions may occur within a carbonate body, which can be thought to consist of an entire reservoir system, such as the carbonate platform or pinnacle reef. The internal variability may lead to a permeability barrier defining the various traps within this carbonate body. In either case, the Internal Barriers would have a significant impact on Primary and Secondary Recovery Programs.

1.1.4 Waste Zones

The types of rocks that are not good reservoirs or good seals can be attributed to the great variation in pore size, shape, and interconnections because of carbonated rock. These are permeable rocks that may be trapped with hydrocarbons but do not produce hydrocarbons in commercial quantities. The effect is much like it was found in a normal reservoir where there are zones of transition from high water levels too high hydrocarbon levels at the bottom of an oil column. But at any of the reservoirs, it may also be possible to find such strange rock samples, even on top of an oil column. These rocks are referred to as waste zones because some part of the hydrocarbon column has been drained from rocks with no productive properties. It may be necessary to recognize these waste areas.

The prospect could be lost because of poor productivity if wildcat wells were drilled into a waste zone at the crest of an architectural structure or its up-dip edge in a stratigraphic trap. Off-structure or downdip of the pore structure might improve within the hydrocarbon column, resulting in commercial production.

In the Williston basin of the Red River dolomite, Showalter and Hess (1982) described such a situation, where a crested well on a structure had been abandoned as uneconomical, even though it had a good amount of oil. In combination with water saturation measurements, mercury injection curves confirmed that an oil column was likely to extend down the flank of the structure.

2. Literature Review

In the literature review, we used two different papers that aimed to investigate the causes of low pay resistivity in different fields.

2.1 Rock fabric characterization in a low resistivity pay zone from a Lower Cretaceous carbonate reservoir in the Middle East:

The first paper we will review on it which is prepared by Ahmed Hassan and Charles Kerans, The University of Texas at Austin. The studied reservoir is in Abu Dhabi, United Arab Emirates, and it is produced from a Lower Cretaceous, an extremely porous unit of the Lekhwair Formation. In this paper two main causes were identified for low resistivity pay zones, the first one is thin-bedded formations (Worthington et al, 2000) and dual and triple pore systems existing in a single rock type (Keith and Pittman, 1983). The occurrence of bimodal pore distributions is the second frequently occurring source of LRP in carbonates. Intergranular macropores that contain and create mobile hydrocarbons next to micropores that contain immobile formation brines are a typical illustration. They combine typical thin-section photomicrographs with data on porosity, permeability, measured wireline resistivity, and mercury injection capillary pressure (MICP) from 14 core plugs.

They used existing data from a vertical well in an onshore anticlinal field in Abu Dhabi, United Arab Emirates, that is currently producing hydrocarbons from Lower Cretaceous Lekhwair carbonates. With an average water saturation of 78% determined using Archie's approach and a resistivity instrument that measured 2 ohm-m throughout the whole 15.5-meter-thick reservoir, negative hydrocarbon estimations were produced.

Three primary facies are represented in the Lekhwair LRP data, with the first being the misunderstanding bacinella wackestone-floatstone, which makes up the thickest units (3.3-3.9 m thick), Ooid Bacinella grainstone, which forms the thinnest units (0.8-1.4 m thick) and Peloidal burrowed packstone with an intermediate thickness of between 0.8 and 2.7 meters. The data consists of measured permeability, porosity, geological descriptions that are currently accessible, measurements of deep resistivity from well logs, and mercury injection capillary pressure (MICP), which aims to characterize the distribution of pore throat widths. They classified the distribution of pore throat sizes into microporosity, mesoporosity, and macroporosity for each depositional facies using MICP data. Here, pore throats with diameters of less than 1 m, between 1 and 3 m, and larger than 3 m are referred to as microporosity, mesoporosity, and macroporosity, respectively.

A complicated triple pore throat size distribution for ooid bacinella grainstone and bacinella floatstone is shown by mercury injection capillary pressure data. The average porosity of ooid bacinella grainstone is composed of 51% microporosity, 34% macroporosity, and 15% mesoporosity. This most likely shows that hydrocarbons make up around a third (34%) of the total pore space in grainstone facies. Microporosity with pore throat widths smaller than 1 µm makes up more than half (51%) of the pore space in the grainstone facies. These micropores are present in the exceedingly microscopic ooids, and they most likely contain the capillary-bound formation water that lowers the resistivity. Mesoporosity of 15% is likely like pore throats between smaller ooid grains. If the capillary pressure is strong enough to replace the formation water that now exists, the mesopores may be filled with oil.

From the overall measured porosity, Bacinella wackestone-floatstone facies show an average of 58% microporosity, 36% mesoporosity, and 6% macroporosity. The presence of what appear to be rebuilt pieces of micritic bacinella grains along with micritic matrix and inside micritic grains is the major cause of the 58% microporosity. Mesoporosity makes up more than one-third (36%) of the overall porosity. The low 6% macroporosity in these facies may be explained by the inclusion of covered grains and result in changes as minor grains.

Peloidal burrowed packstone facies exhibit no macroporosity and a preponderance of 98% microporoisty and 2% mesoporosity. Viewing their thin section, these facies appear intriguingly macroporous and grain supported. It shows that only tiny pore throats (less than 1 m in diameter) link the interparticle pore space.

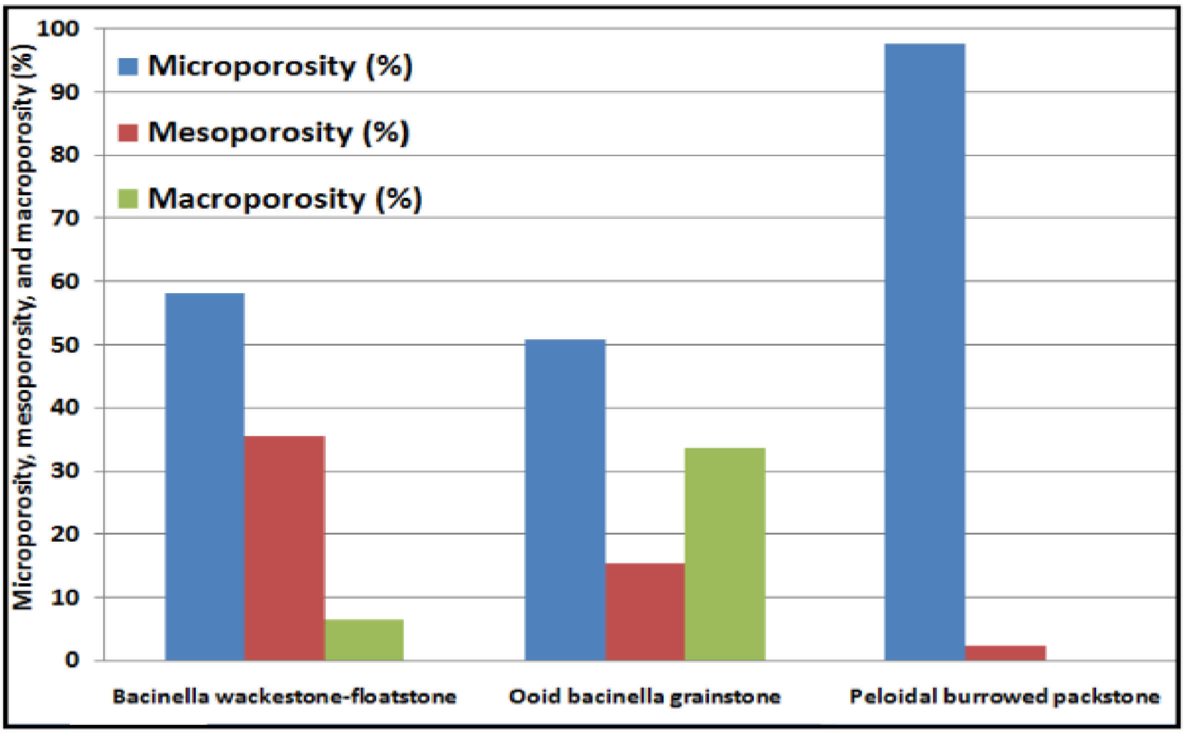

Figure 3 shows the distribution of the three mentioned facies' microporosity, mesoporosity, and macroporosity. (Hassan, A. and Kerans, C, 2013).

Both the ooid bacinella grainstone and the bacinella wackestone-floatstone exhibit triple pore systems with microporosities of greater than 50%. It is thought that a significant portion of the capillary-bound water in this microporosity is what drives the resistivity response.

To better understand a low resistivity, pay zone that comes from the Lower Cretaceous Lekhwair Formation, they combined petrographic and petrophysical studies. The resistivity instrument produces extremely high-water saturations since it reads an average of 2 ohm-m over the whole reservoir. Dry hydrocarbons were present. To determine the source of the LRPZ, the measurement of the pore throat size distribution is helpful. In this case study, it is obvious that a complicated multi-modal pore system is the main cause of the obtained extraordinarily low resistivity values. The micropores are present in all three of the above facies and account for around 70% of the total average porosity. These microporous zones have formation brine that is capillary-bound, which frequently acts as a continuous conduit for the electric current and conceals the presence of economic hydrocarbons.

2.2 Reservoir Characterization of Carbonate in Low Resistivity Pays Zones in the Buwaib Formation, Persian Gulf:

The second paper we will review on it which is prepared by Bita Arbab, Davood Jahani, and Bahram Movahed, the Department of Geology, Islamic Azad University in Tehran, Iran. The Buwaib formation is located in the Salman field which is divided into three reservoir zones. These reservoir zones show low resistivity characteristics and high levels of fluid saturation. Thin section X-ray diffraction (XRD), Pulse Neutron Neutron (PNN), and laboratory measurements of the petrophysical characteristics have been used together. The reservoir was split into the BL1, BL2, and BL3 sections. Geological research led to the definition of eight facies, with the porous, lithocodium-bearing facies displaying the greatest reservoir quality. Magnetic minerals, like pyrite, can lower the log resistivity reading.

The formation of lithocodium mound facies, together with moderate to high porosity interbeds, generally has little impact on the reservoir potential of the Buwaib Formation. According to the XRD study, the two primary clay varieties with the highest CEC and greatest influence on lowering resistivity are montmorillonite and kaolinite. The Lonoy method was used to characterize the pore systems of rocks with mudstone microporosity associated with lithocodium mound facies and uniform interparticle at class 3 Lucia, where pore size ranges from 0.2 to 10 micron.

The Salman Field is 142 kilometers south of Lavan Island in the Persian Gulf and sits the oval-shaped dome structure known as the Salman Field. The field is shared by Iran and Abu Dhabi and crosses the international boundary. About 3/4 of the field is within the Iranian border, while 1/4 of the field is within Abu Dhabi's territorial waters and is named Abu Al Bukhoosh.

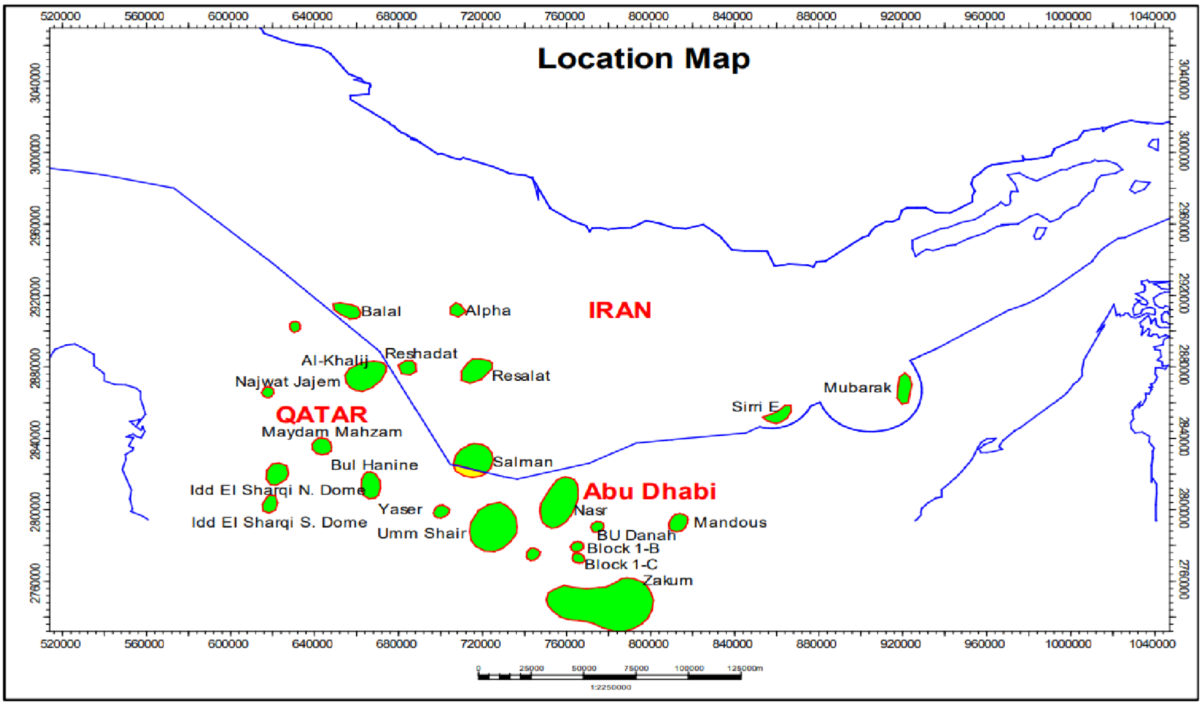

Figure 4 Location map of Salman field in the eastern part of the Persian Gulf. (Arbab, B., Jahani, D., and Movahed, B, 2017).

The research is based on 195 thin sections, 60-meter-long core samples, and petrophysical logs. Six samples were analyzed to determine the primary clay types in the reservoir for clay typing using XRD. 150 samples were subjected to a CT scan to identify the key elements that significantly affect the resistivity response. 180 samples of core plugs were also analyzed in the core lab for standard and unique core analyses for Porosity and permeability measurements. Based on their sedimentological and diagenetic properties, thin sections were investigated and categorized. Facies are identified and interpreted in accordance with sedimentological criteria by comparison to the established facies models, Sigma logs and capillary data have been utilized to accurately analyze water content in low resistivity pay zone to evaluate water saturation. Different diagenetic procedures with varying strengths were applied during formation. The quality of the reservoir is affected by digenetic processes such as pyritization, micritization, and bioturbation. micritization, cementation, replacement (pyritization), and burial compaction are the steps that led to the discovery of identified diagenetic.

Dunham's classification uses petrographic research to show how different digenetic events affected that reservoir. To evaluate the faunal contents and the rock's textures, thin portions were described. This helped to clarify the properties of the examined reservoir's pore networks and diagenetic overprint. Seven microfacies, from Wackeston and Packstone to Floatstone, were defined. Large benthic foraminifera, a wide variety of algae, and echinoderm are the principal faunal components in these facies.

Based on the XRD study and Thorium, Potassium cross plots of petrophysical standards, the reservoir contributes Illite, Montmorillonite, and Kaolinite as main clay types, and conductive minerals like pyrite are most reasonable for the LRP reservoir. Pore throat diameters with interparticle uniform microporosity, chalky limestone, and mudstone microporosity are addressed using the Lonoy approach. Pore systems are categorized as Lucia class 3 and range in size from 0.5 to 20 microns. Mudstone micropores typically have very tiny pore sizes of a few micrometers in diameter. The Petrophysical Interpretation Full-set logging tools (bulk density, neutron porosity, and resistivity) were used to core the wells and log them. The reservoir is 81 feet thick, very heterogeneous, and has permeabilities ranging from 0.1 mD to more than 11 mD along with moderate to excellent porosity of up to 25%. Multiple methods were used to predict the water saturation, which was visible in the resistivity-based saturation log. Water saturation was defined by using Full set logs, Sigma logs, and various petrophysical factors as constraints. High water saturation was indicated by the calculated log saturation. To get reliable water saturation, several restrictions were established. In BL1, BL2, and BL3, the water saturation levels are, respectively, 42%, 34%, and 40%.

3. Methodology

As the aim of the study is to focus on the microporosity in carbonate reservoirs as the main cause of the low resistivity pay zones, reviewing and investigating the avaliable data of this study: **Saturation evaluation of microporous low resistivity carbonate oil pays in Rub Al Khali Basin in the Middle East.** To find the issue that conventional logging makes it difficult to find low resistivity pays (LRPs), Displacement resistivity experiments simulating the process of reservoir formation and production, along with data from thin sections, mercury injection, and nuclear magnetic resonance experiments, were used in the Rub Al Khali Basin, Middle East, to analyze the variation of fluid distribution and rock conductivity during displacement. The resistivity of the LRPs in the investigated region is less than 1 m, matching or even significantly falling below that of the water layers. According to geological studies, the LRPs are formed in low-energy depositional environments and are typical microporous LRPs since their reservoir spaces are governed by tiny pore throats with an average radius of less than 0.7μm. With cementation index values of 1.77–1.93 and saturation index values of 1.82–2.03, respectively, which is 0.2–0.4 lower than conventional reservoirs, Archie's formula may be used to interpret saturation in LRPs.

Oilfield A in East Rub The typical carbonate microporous LRPs with a pyrite content of 2% to 4% and no cracks or encrusted particles are found in the Al Khali Basin in the Middle East. The carbonate microporous LRPs were generated in a medium-low energy depositional setting. They are identified by their small pore throats and resistivities between 0.4 and 0.7 m, which are equal to or even slightly lower than the water layer below. Identification of oil layers has been successfully accomplished using the Dean-Stark experiment in coring wells using RST casing logging in production wells. The accuracy of saturations determined by nuclear magnetic resonance (NMR) logging, the oil column height method, and the methodology for conventional reservoirs are poor. Because carbonate microporous LRPs differ from standard pays in terms of saturation interpretation parameters, the Archie Formula can be used to calculate saturation for these materials.

According to the oil testing and production data of 8 wells in the study region, the resistivity of LRP is not larger than 1 m. The resistivity of rock at 70% water saturation is not larger than 1 m, which is the second definition condition. The third definition condition is assumed to be the resistivity of water-saturated rock no larger than 0.5 m. The resistivity index of LRP is often less than 2. Additionally, the information on pore throat structure obtained from rock thin section, mercury injection, and NMR tests is used for screening and verification, with the characteristics of a microporous reservoir serving as an auxiliary definition criterion. The samples of the rock resistivity experiment are sorted into three groups based on the above definition criteria: possible LRP samples, non-LRP samples, and low porosity (15%) samples, which are then compared and evaluated.

3.1 Archie Formula

Worthington and Ayadiuno say that the following reservoir criteria must be met to determine saturation using the Archie Formula:

1. The reservoir is homogeneous, has a simple mineral composition, and contains little clay minerals, silt, or mud.
2. It is water wet, with a high salinity of electrolyte and low resistivity information water.
3. It has a single pore throat system that is mostly made up of intergranular pores.
4. It doesn't contain or have any negative effects from conductive minerals.

The reservoir in the research region mostly comprises calcite, with little to no clay minerals, and less than 4% pyrite, which has a minimal effect on rock conductivity. Intergranular pores and intergranular micropores, both of which have a simple pore throat system, occur in the reservoir space and the LRP, respectively. With a formation water salinity of more than 170 mg/g and a water resistivity of around 0.013 m, all LRPs are water wet. The potential LRP samples, non-LRP samples, and low porosity samples all meet the law of Archie Formula.

To determine the water saturation of LRP, using Archie's Formula follows the parameters of the saturation interpretation Model, cementation index, and saturation index.

3.1.1 Cementation Index (m)

First, the parameters that affect water-saturated rock resistivity (Ro) are examined. Ro is positively correlated with porosity and decreases as porosity increases. Ro is less than 1 m for high porosity reservoirs with porosity of more than 15%, while Ro of the probable LRP samples is less than 0.5 m.

With an increase in average pore throat radius, Ro of high porosity reservoirs rises. Potential LRP samples have pore throat radius that are typically smaller than 0.7 m. The conductive route is thought to get more complicated as the size of the pore throat increases. The permeability and porosity of high porosity reservoirs are well correlated, and rise as permeability does. Potential LRP samples' permeability is lower. Ro is significantly influenced by wettability. The Ro of an oil-wet sample in high-porosity reservoirs is larger than 0.5 m, but the Ro of a water-wet sample is less than 0.5 m.

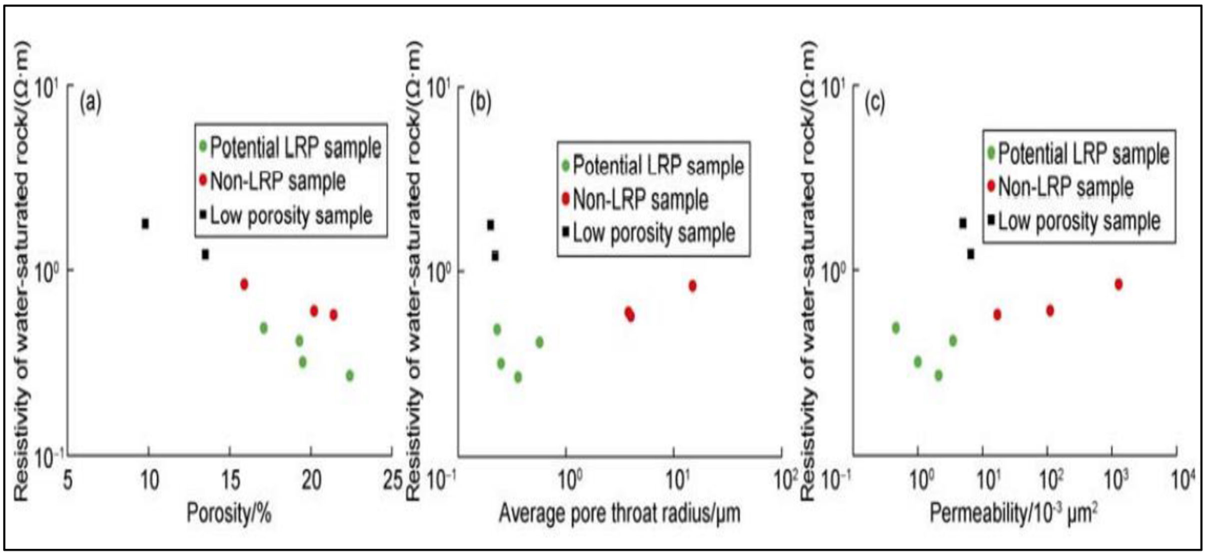

Figure 5 Influencing factors for resistivity of water-saturated rock. (Yongjun, W.A.N.G., Yuanhui, S.U.N., Siyu, Y.A.N.G., Shuhong, W.U., Hui, L.I.U., Min, T.O.N.G. and Hengyu, L.Y.U, 2022).

In conclusion, the Middle East's development of carbonate microporous LRPs must satisfy the basic geologic requirements of high porosity, low permeability, tiny pore throat, and wet water content.

When the permeability exceeds 1000×10–3 μm2, the reservoir is referred to be a high permeability strip (abbr. HPS), and its m value decreases slightly, reflecting the reservoir's improved free water conductivity. The m value is significantly high when the permeability is less than 0.5×10–3 μm2, which is associated with decreased conductivity because of smaller pore throats.

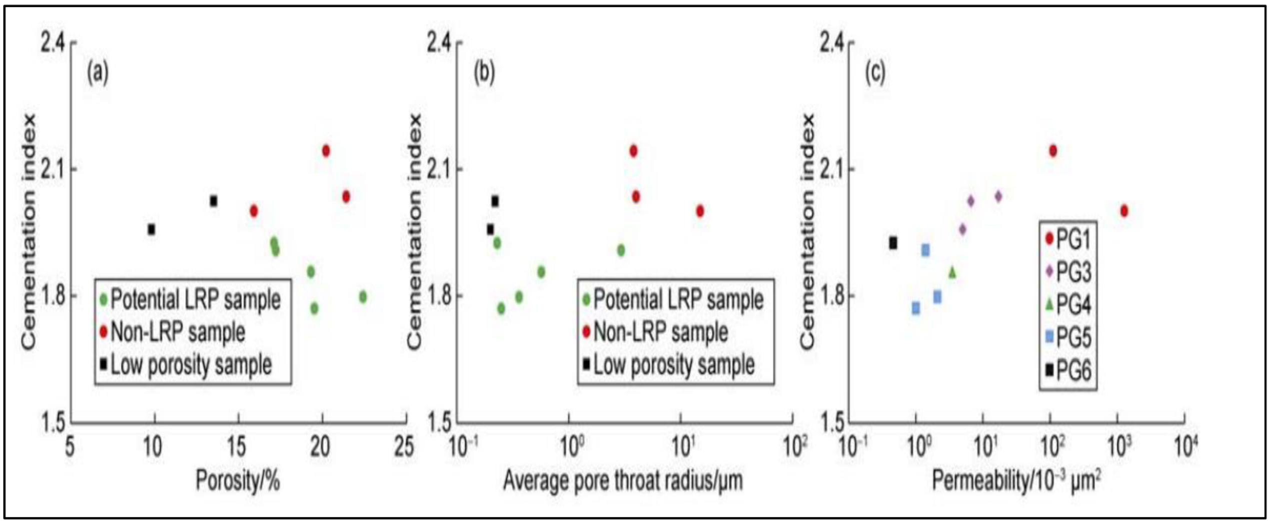

Figure 6 Influencing factors for cementation index. (Yongjun, W.A.N.G., Yuanhui, S.U.N., Siyu, Y.A.N.G., Shuhong, W.U., Hui, L.I.U., Min, T.O.N.G. and Hengyu, L.Y.U, 2022).

The petrophysical group classification method was used for petrophysical research on carbonate reservoirs by using capillary pressure curves which are proposed by Thomeer and Baker for classifying rocks.

Reservoirs in the research region are classified into 6 groups of PGs, with PG1 representing a large-scale pore throat system and the other PGs decreasing in size according to the size of the pore throat. Potential LRP samples have a m value between 1.77 and 1.93, which is often lower than that of non-LRP samples (2.00 to 2.14), as well as low porosity samples (1.96–2.02). This further shows the minimal conductive channel tortuosity and high conductivity of microporous LRPs. The m value is calculated by taking the average value in accordance with the PGs classification to estimate the saturation interpretation parameters according to the reservoir types.

The m value for the LRP is 1.85, whereas it is 2.20 for PG1, 2.1 for PG2, 1.96 for PG3 and PG4, 1.77 for PG5, and 1.93 for PG6. Using the LRP as an example, the calculated water saturation (Sw) is 55%, 59%, and 63% depending on the formation water resistivity (Rw), n, porosity, and rock resistivity (Rt) values which the water resistivity (Rw) as 0.013 Ω·m, n as 1.9, porosity as 0.2, rock resistivity (Rt) as 0.7 Ω·m. When m is taken as 1.77 (lower limit), 1.85 (average), and 1.93 (upper limit), respectively. if m is used as the average value. The highest error, 4%, is reasonable and controllable.

3.1.2 Saturation index (n)

The displacement resistivity experiment is used to examine how the dispersion of oil and water affects rock resistivity. There are 8 steps to the oil-wet sample experiment:

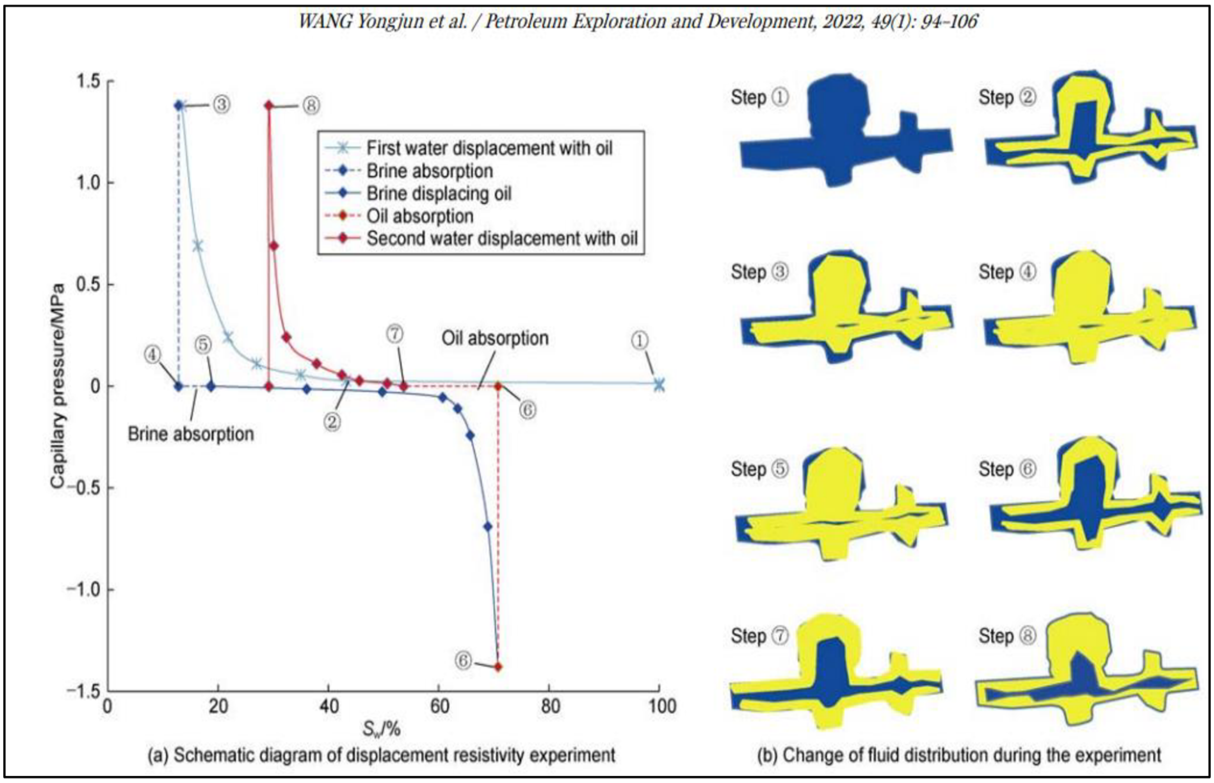

Figure 7 Displacement resistivity experiment method and steps of the oil-wet sample. (Yongjun, W.A.N.G., Yuanhui, S.U.N., Siyu, Y.A.N.G., Shuhong, W.U., Hui, L.I.U., Min, T.O.N.G. and Hengyu, L.Y.U, 2022).

1. Samples that have been soaked in brine with a salinity of 170 mg/g to simulate the formation process.
2. To simulate the early reservoir formation stage, the main drainage cycle replaces water with oil at low pressure, using formation water as membrane-bound and linked free water.
3. The primary drainage cycle, which replaces oil for water under increasing pressure to simulate the stage of reservoir development with membrane-bound water.
4. Oil layer is replaced by some of the water layer, increasing wettability.
5. Natural brine imbibition using connected and scattered free water to simulate the early stages of reservoir recovery or damage.

6. A cycle of brine imbibition under negative pressure that replaces oil with brine to simulate the process of reservoir recovery or damage, with connected free water eventually evolving.
7. Using spontaneous oil imbibition to represent the early stages of secondary reservoir development and a predominance of connected free water.
8. The second drainage cycle replaces water with oil once more to simulate the formation of a secondary reservoir, with scattered and connected free water being the most.

The experiment shows a large change in the distribution of oil and water during the reservoir formation and recovery process. To assess the wettability of rock samples, the Amott-Harvey index and applicable criteria are employed. The sample's Amott water and oil indices are 0.144 and 0.443, respectively, as seen in Fig., and this results in an Amott-Harvey index of -0.3. As a result, it is found that the rock sample is oil wet in terms of wettability. Some membrane-bound water in the samples' oil-water distribution disappears once the wettability of their oil-wet core samples is restored.

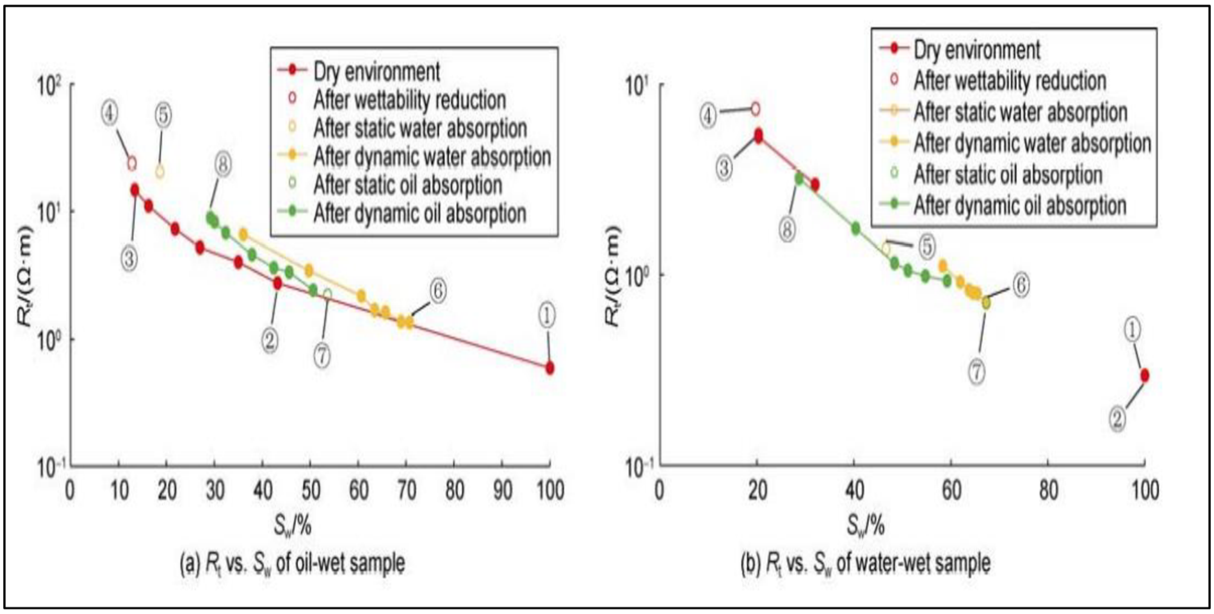

Figure 8 Displacement resistivity experiment of oil-wet and water-wet samples, shows the results of two different rock sample tests. (Yongjun, W.A.N.G., Yuanhui, S.U.N., Siyu, Y.A.N.G., Shuhong, W.U., Hui, L.I.U., Min, T.O.N.G. and Hengyu, L.Y.U, 2022).

Figure 9a is an oil-wet sample of grainstone with a porosity of 20.2% and permeability of 114.0×10–3 μm2. Comparing the two numbers demonstrates that. The sample in Figure 9b, is a water-wet sample of wackestone, with a porosity of 19.5% and permeability of 1.7×10–3 μm2. The two statistics are analyzed, and it is shown that:

1. The resistivity of a water-wet sample reaches the LRP requirement when saturated with brine.
2. The oil inlet pressure is low for the oil-wet sample and high for the water-wet sample at the beginning of the primary drainage cycle.
3. The irreducible water saturation of the oil-wet sample is around 13% after the first drainage cycle, whereas it is 20% for the water-wet sample.
4. The resistivity of both samples increases to their greatest value upon wettability restoration, however, the increase of the water-wet sample is minimal.
5. The reduction in oil saturation following spontaneous brine imbibition is 6% for an oil-wet sample and 27% for a water-wet sample.
6. After a brine imbibition cycle, both samples had about the same levels of saturation.
7. The increase in oil saturation following spontaneous oil imbibition is 17% for an oil-wet sample and none for a water-wet sample.
8. Two samples had the same levels of saturation following the secondary drainage cycle.

By contrasting the resistivity value under the same saturation, the changing trend of rock resistivity is examined. The primary drainage cycle shows the oil-wet sample's resistivity at its lowest, and the secondary drainage cycle sees it at its greatest, after wettability restoration. The resistivity change trend for the water-wet sample is stable and very slightly lowers during the secondary drainage cycle.

This shows that the oil-water distribution of an oil-wet sample gradually becomes more complicated throughout the displacement process, but the distribution of a water-wet sample is more stable since the water is still bound to the membrane.

During the experiment, the oil-water distribution gets complicated, and the n value typically rises, with a maximum change of 0.85, showing that the oil-water distribution has a significant influence on rock conductivity. The n value of an oil-wet sample increases with increasing water saturation and tends to stabilize in the secondary reservoir formation stage. It is greater in the exploitation stage than in the reservoir-forming stage. The stable distribution of the bound water film and the oil-water relation may be the cause of the little overall change in the n value of the water-wet sample. The n value is substantially lower in the process of reservoir development, making the possible LRP samples similar to water-wet samples.

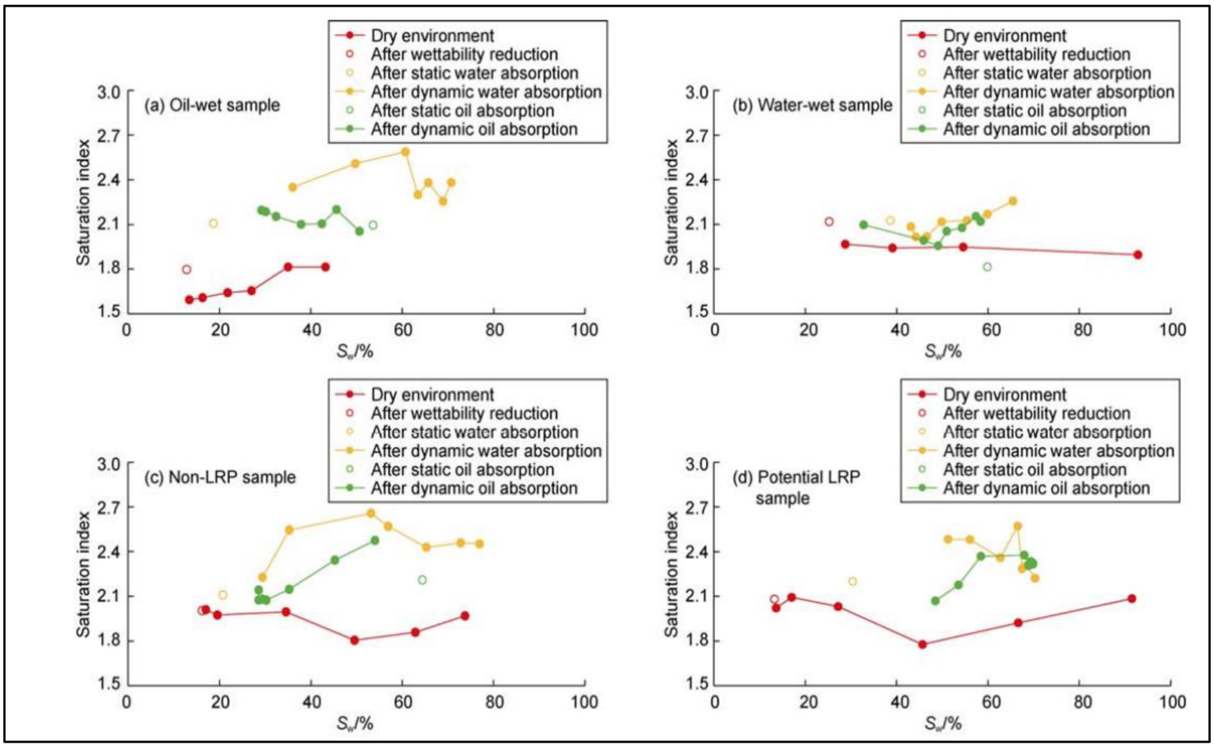

Figure 9 Saturation indexes of different types of reservoirs in three rounds of absorption and displacement experiments. (Yongjun, W.A.N.G., Yuanhui, S.U.N., Siyu, Y.A.N.G., Shuhong, W.U., Hui, L.I.U., Min, T.O.N.G. and Hengyu, L.Y.U, 2022).

The n value increases with improved PGs, pore throat size, and permeability, and the n value decreases while the increase in porosity. Potential LRP samples have an n value between 1.8 and 2.03, which is often lower than that of non-LRP samples and comes under the category of low porosity samples. The n value is found to be 1.9 for possible LRP in the research region, 2.10 for PG1 and PG2, 2.00 for PG3 and PG4, and 1.85 for PG5 and PG6.

The computed Sw value for the LRP, using the same reservoir parameters as in Section 4.1, is 57%, 59%, and 61%, respectively, when m is 1.85 and n is 1.82, 1.90, and 2.03, respectively.

When comparing the average n to the upper limit n and lower limit n, the calculation error of saturation is at most 2%, which is fair and within control.

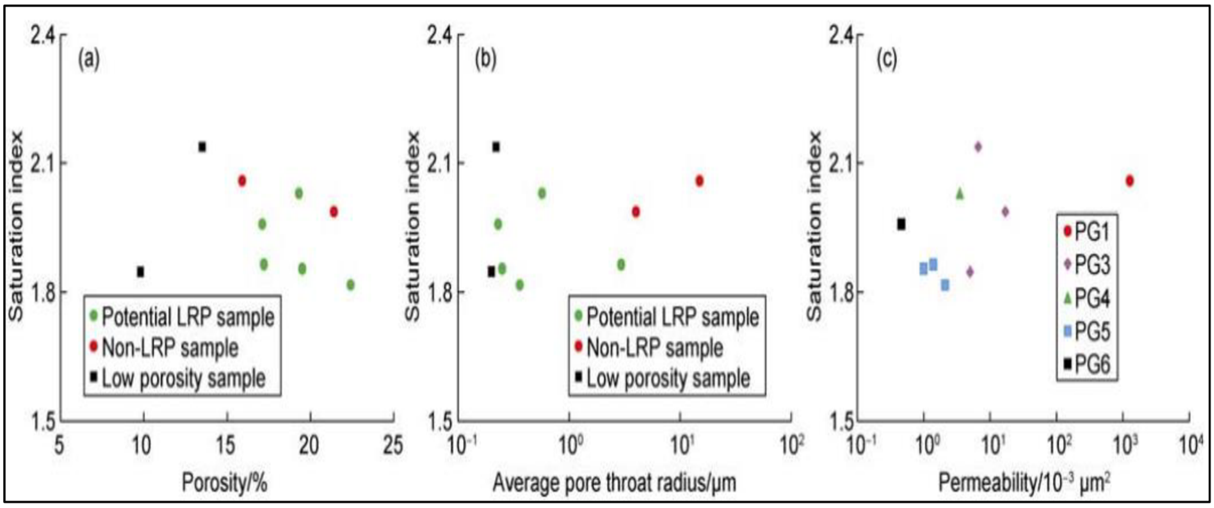

Figure 10 Influencing factors for saturation index and characteristics of saturation index of low resistivity pay (LRP). (Yongjun, W.A.N.G., Yuanhui, S.U.N., Siyu, Y.A.N.G., Shuhong, W.U., Hui, L.I.U., Min, T.O.N.G. and Hengyu, L.Y.U, 2022).

4. Results & Discussion

The LRP is qualitatively detected in a single well based on the above experimental analysis as well as the genetic process, defining criteria, and formation circumstances of LRPs in the research region. Then, using LRP saturation interpretation technology, the reservoir saturation is quantitatively determined. The interpretation findings are then confirmed by Dean Stark, RST (reservoir saturation testing), dynamic test, and real production data.

4.1 Result

In column 8 of Figure 12 well A, the qualitative identification findings are displayed.

At a depth of 2998.6-3002.3 m, the LRP in Well A is developed and primarily made up of Bacinella Floatstone. The lower nearby layer is a high-permeability belt of Ooids Bacinella Grainstone With a water avoidance height of just 1.5 m. A thin layer separates the formation from the aquifer.

At 3033.4-3034.0 m and 3034.9-3035.6 m, respectively, the LRPs of Well B are developed. They are made of BF and have a 3.4 m water avoidance height. The reservoir's physical characteristics between LRP and the aquifer are poor.

With the method introduced by the article, the oil saturation of LRP is understood to be 30%–50%, which is 15% higher than that read by the conventional method but is consistent with the previous irreducible water saturation shown by field production. The calculation's result is considered possible given that the LRP's oil column height is low and the reservoir is managed by micropores. Column 7 of Fig. 12a.

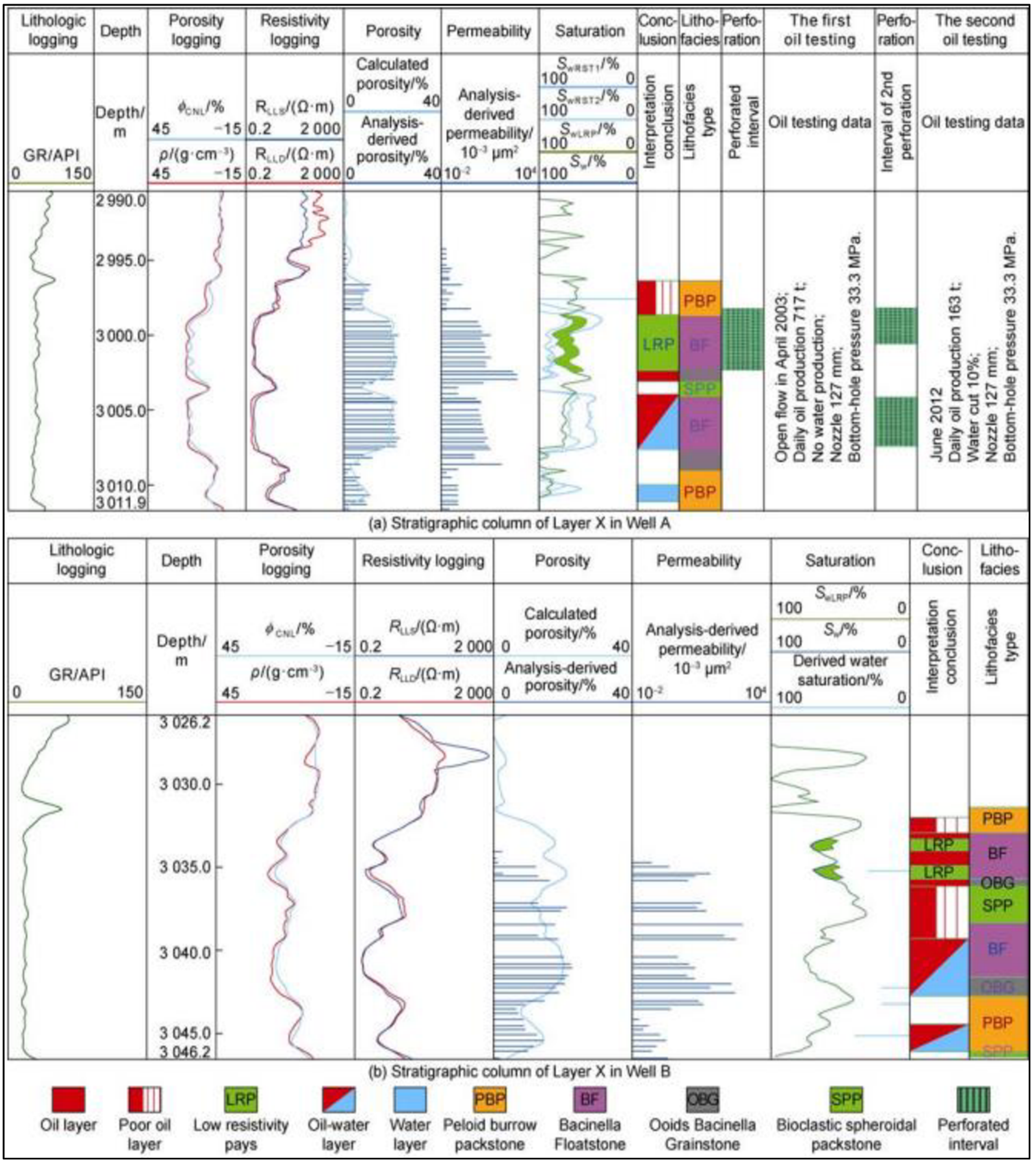

Figure 12 Logging interpretation for saturation of X in Wells A and B in the study area, the qualitative identification findings are displayed. (Yongjun, W.A.N.G., Yuanhui, S.U.N., Siyu, Y.A.N.G., Shuhong, W.U., Hui, L.I.U., Min, T.O.N.G. and Hengyu, L.Y.U, 2022).

Dean Stark data is used for assessment. Well B has Dean Stark saturation data, but no oil saturation data is obtained. Column 7 in Fig. 12b shows that the alteration in water saturation determined by logging corresponds with the results of the study (light blue bar in the picture). The Sw value computed by logging is more than that recorded from core, which is connected to experimental data measurement loss (typically (Sw+So)100%). The oil saturation measured by the new approach in the LRP is greater than that computed by the previous method. The discrepancy between the new interpretation method's conclusions and the experimental data is less than 15%, and the interpretation performance is increased.

RST data is used for validation. RST logs are present in Well A. The two test findings varied significantly because of the impact of borehole conditions and fluids (Column 7 in Fig. 12a). The interpretation outcomes from traditional technology are closer to the second RST in the top half of LRP, whereas the interpretation results of the novel approach are among the two RSTs. Two RSTs in the lower part of LRP reveal low oil saturation, and traditional method interpretation findings are equal to RST. The new method's interpretation of oil saturation is much greater than the test findings. It is believed that the interpretation results of analyzing the electric characteristics and oil-water relationship of the upper and lower parts of LRP are concerning the interpretation results of the new study is more study.

Well test data is used for validation. In April 2003, the LRP and its beneath HPS in Well A were perforated (Column 10 in Fig. 12a). Trial runs were carried out using a 127 mm oil nozzle. The well produces 717 t of oil per day with a bottom-hole fluid pressure of 33.3 MPa and no water. Although its resistivity is low (0.4-0.7 m), it has been determined that this region is not an aquifer. The associated section in well B is not perforated. However, based on the oil-water relationship of the entire reservoir, adjacent wells, and the vertical layers of well B itself, the 3033.4-3034.0 m and 3034.9-3035.6 m sections are all low resistivity pays rather than aquifers. Production data is used for validation.

The investigation demonstrates that the HPS is associated with the high output of crude oil and subsequently water production, thus the HPS has been sealed and the lower section at 3004.0-3007.5 m was perforated in 2012 (Column 12 in Fig. 12a).

The average daily liquid output was 180 m3 at the start of the test, with water reduced by 10%. The consistent output was maintained till 2013.

The bottom perforated part is verified to be an aquifer, whereas the top perforated portion is an LRP. The novel approach is widely used in the research domain. The coincidence rate is determined to be more than 90% after oil evaluation and production confirmation of 15 wells, confirming the practicality of this technology. The findings of the study offer the groundwork for quantitative evaluation and large-scale successful development of LRPs in the studied region.

4.2 Discussion

Low resistivity pay zones form an important challenge to oil and gas development and production in carbonate reservoirs. The most frequent reasons for missed pay in carbonate reservoirs have been investigated, along with the techniques for pore system characterization in these formations. According to the research, dual porosity systems, layered formations, fractures, conductive minerals, and improper resistivity measurement are the five main reasons for low resistivity pay zones in carbonates.

Missed pay zones in carbonates are most frequently caused by the dual porosity system. tiny holes in the reservoir rock may be filled with water while the bigger pores are charged with hydrocarbons due to the distributed large and tiny pores. If various pore types can't be recognized and distinguished from one another, hydrocarbon saturation levels may be misinterpreted, which might result in missed pay zones.

Another frequent reason for low resistivity pay in carbonates is layered formations. The holes in these formations are laminated and vary in size, with grainstones having larger pores and micrites having smaller pores. Because it can be difficult to differentiate between various pore diameters, hydrocarbon saturation levels may be misinterpreted, and missed pay zones.

In carbonate reservoirs, fractures, whether oil- or water-filled, can also result in missed pay zones. Fractures can improve the formation's permeability and facilitate the movement of hydrocarbons. However, if the fractures are not well defined and diagnosed, they risk being ignored and leading to missed pay zones.

Rare conductive minerals like pyrite and siderite are the reason behind carbonates' low resistivity pay zones. These minerals may hide the presence of hydrocarbons due to their high electrical conductivity, leading to inaccurate interpretations of the formation.

Finally, although uncommon, inaccurate resistivity measurement might result in missing pay zones in carbonates. Excessive invasion or other variables that cause inaccurate measurements of the formation resistivity might cause this.

The Lønøy approach and the Lucia approach are two of the several techniques that have been developed to precisely detect and describe the pore systems in carbonate reservoirs. The Lønøy approach relies on a multiscale study of the reservoir rock to detect the various forms of porosity by evaluating various pore sizes and shapes. Contrarily, the Lucia technique concentrates on identifying and characterizing the matrix porosity and its contribution to the formation resistivity.

5. Conclusion

In conclusion, oil and gas exploration and production in carbonate reservoirs are severely limited by low resistivity pay zones. Dual porosity systems, layered formations, fractures, conductive minerals, and incorrect resistivity measurement are the five most typical reasons for missed pays in these formations. The Lny approach and the Lucia method are two of the several techniques that have been developed to precisely detect and describe the pore systems in carbonate reservoirs. The development of novel techniques for locating and describing the pore systems in carbonate reservoirs should be the main focus of future studies. This might involve the application of modern imaging methods like nuclear magnetic resonance (NMR) imaging and micro-CT scanning. Research should also concentrate on enhancing the accuracy of resistivity measurements and creating novel methods for locating and describing fractures in carbonate deposits.

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