Characterization of Carbonate Reservoir from Core and Well Logging Data- A Case Study

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Summary

Study of key parameters of reservoir viz, porosity, water saturation, permeability and pore size distribution from well logging data is more complicated in carbonate reservoir due to geological heterogeneities than Clastic reservoir.

In homogeneous reservoir, where the grains are regularly shaped and pore space may be complicated and intergranular, the evaluation and transformation of parameters can be done through empirical equations. But it is very difficult to evaluate these parameters in carbonate reservoir due to post depositional changes i.e. diagenesis, such as recrystallization, dolomitization, cementation, compaction, and dissolution. Crystallization & dolomitization may increase or decrease porosity and permeability, Cementation and compaction, reduces porosity to very low values because of pore size decreases as grain size and sorting decreases, while dissolution/leaching develops vugs and fractures, which may result in large variation in porosity and permeability of carbonate rock.

By integrating available core data with well log data, assessment of rock fabric can be made by Lucia Plot. Pore geometry categories & pore size classes can be analysed from template for calculating rp_{35}, which is based on equation (Aguilera & Aguilera, 2002) and by using Pickett plot techniques, evaluation of range of various reservoir parameters i.e. permeability, pore throat aperture, water saturation, capillary pressure etc. can be made. These parameters can be evaluated effectively. Core permeability Vs porosity data was plotted on the template (Aguilera), which shows that pore size of the reservoir is varying from 0.5 to 10 µm. The same data was also plotted in template of particle size (dp) and rock- fabric number (ë) , which shows that pore size of the reservoir are varying from 0.5 to 10 µm. The capillary pressure data and “J” function shows that the reservoir is having three types of pore geometries. This paper describes such an approach in detail.

Introduction

Clastic rocks develop through the attrition of other rocks and their grains are regularly shaped and pore space though complicated, remains intergranular and are generally undergoes only minor alteration or diagenesis. These rocks form as sediments are transported, deposited and lithified or compacted and cemented into solid rocks; Whereas Carbonate rocks have complex structure of micrite particles and grain illustrates the complexity of pore micro geometry and are chemically unstable & undergo substantial changes such as dolomitization and mineral dissolution etc. The permeability depends on textural parameters like rock fabric i.e. size, sorting, roundness, sphericity, orientation and packing of grain. The carbonate sediments are composed of three textural elements: grains, matrix and cement. Matrix is very fine-grained material, which is lithified mud of deposition, which fills most of the space between grains/ particles. Cement is a crystalline material, which forms in the most of space remaining between grains and matrix or between grains, which binds matrix and grain together.

Carbonate rocks are much more susceptible to post depositional changes (diagenesis) than clastic rocks. Diagenesis can cause dramatic changes in carbonate pore shape and size, which may increase or decrease the porosity and permeability, therefore diagenesis adds further complexity to primary pore space of the carbonate rock. These convoluted pore space of carbonate may be quite different from that found in clastic rocks.

Dunham classified the carbonate rock, which provides some clue to the energy of deposition (fig.1).

The classification is based on relative contents of mud and grains with additional categories for crystalline carbonates and boundstones. Choquette and Pray classified carbonate porosity according to rules shown in (fig.2).

Above classification helps to understand initial oil migration from an underlying source rock into a reservoir by the action of capillary forces, therefore, capillary pressure curves are direct indicators of pore geometry of the rocks that controls permeability. Considering above, the capillary

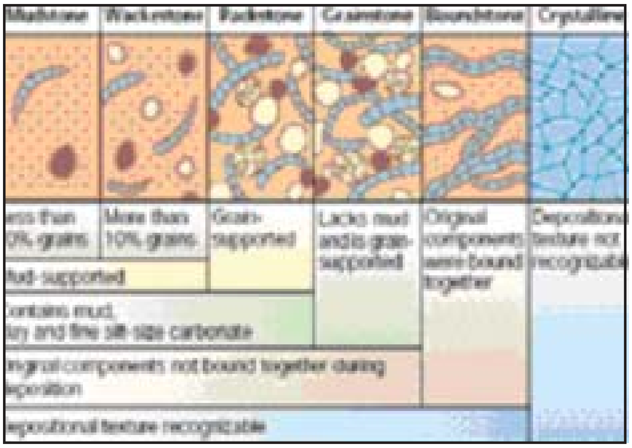

Fig. 1: Dunham classification of carbonate rock.

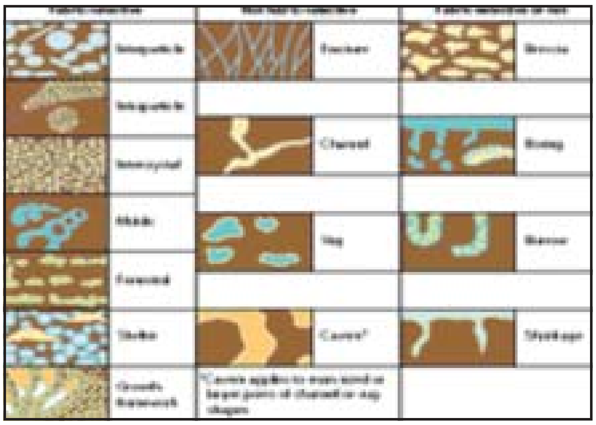

Fig. 2: Choquette and Pray classification of carbonate porosity.

pressure curve is also a good mechanism to predict permeability (k).

In capillary pressure mechanism, the water from potential reservoir forces into the source rock, where it displaces oil droplets; these droplets form a continuous phase and migrate upwards. If the capillary pressure of the oil exceeds the reservoir displacement pressure, oil will replace water from pores and will migrate through the largest pore spaces to the top of reservoir. In this process oil & water move simultaneously in opposite directions. After migration of oil, some water may remain in pores, which is lowest water saturation, called irreducible water, this water saturation will depend upon pore size, and therefore variation in pore size distribution, in reservoir plays an important role in of carbonate rocks. This will result in initial reservoir saturation, which is more complicated in carbonate rocks than clastic rocks.

Carbonate rocks may have pores of all size from micro pores to mega pores (0.5 µm to 10 µm), which behaves, differently in the reservoir. Macro pores are easily filled with oil while micro-pores have retained some water after oil migrates into the reservoir; these micro-pores with retained water also provide a least continuous path for logging current even when the water saturation is very low in the pores. This action, gives low resistivity, which could be interpreted as high water saturation zone, but while taking production from this reservoir, oil will flow only from the macro-pores whereas the capillary-bound-water in micro-pores will retain in microspores.

It is observed in carbonate rocks that porosity-permeability transform generated from core data, shows large variability, which reflects that there is no relation ship between porosity – permeability, this is due to, without inclusion of pore size distribution i.e. pore geometric factors {inter-granular or inter-crystalline pores, isolated vugs and interconnected vugs (touching vugs / fracture)}, which control flow of electrical current and fluid flow in the pore space. The geometry of the inter-particle space is related to the size and shape of the particle and distribution of shale, cement, compaction and inter-particle leaching which reflect in porosity-permeability variation in the reservoir.

Lucia, (1983) Shows that instead of dividing rock fabrics into grain supported and mud supported (Dunham's classification), rock fabrics are divided into grain dominated and mud dominated. He showed that fabrics can be defined using particle size boundaries <20 µm, 20 - 100 µm, & 100 - 500 µm and in terms of 1348 x 'λ' value, corresponding to grain size variation from 4.0 to 0.5, in uniformly cemented non vuggy rocks (fig.3).

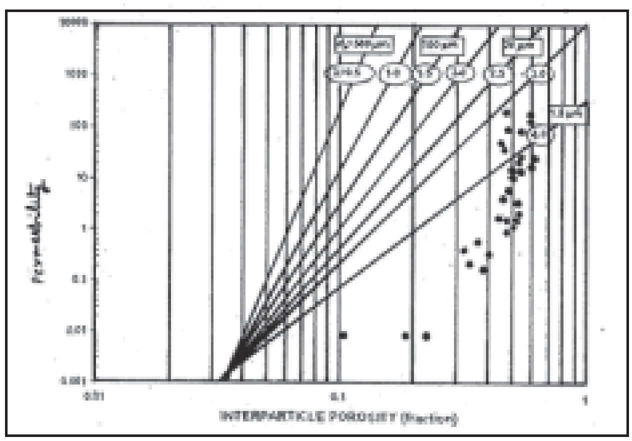

Fig. 3: Lucia plot for rock fabrics from core data.

Methodology

For homogeneous reservoir, the basic equations in formation evaluation are:

$Sw = I^{-1/n}$
$I = Rt / Ro$
$I = Rt / Rw * Rw / Ro, (Rw / Ro = 1/F)$
$I = Rt / Rw * 1/F, \quad Rt = a * Ø^{-m} {}_{* Rw * I}$

Take log on both sides
$\text{Log } Rt = -m \log Ø + \log (a Rw) + \log I$

From above equation a log –log plot of $Ø_e$ Vs Rt with 100% water line, slope "m", intercept "Rw" is drawn and other lines (90%, 65%, 50%, 30%, 10%) are also drawn. Aguilera (1990b) showed that a straight line in Pickett plot would be result of an interval of constant permeability at irreducible water saturation. Different values of Sw, K, Pc, h & r_p values have been drawn and shown in plot (fig 8 & fig.9). The construction of plot is based upon following equations of permeability (1), Capillary pressure (2) height above the free water level (3) :

1. $\text{Log } Rt = (-3n - m) \log Ø + \log [a Rw(250 / k^{1/2})^{-n}]$
2. $\text{Log } Rt = (-m + 2.8125 n) \log Ø + \log [(a Rw) * (1.0961 Pc^{-1.25})^{-n}]$ with straight line slope equal to (-m + 2.8125 n) where m=n=2 and slope of Straight line = 3.625.
3. $h = 0.705 * Pc$

Case Study

For case study an example of "LII reservoir" of Mumbai high field of India has been taken. This is a case of carbonate reservoir. One well of the field is taken for this study. The L-II reservoir is divided into six Zones A (960.2-964.4m), B(964.5-976.0m), C (976.0-982.0m), D (983.8-988.0m),E (988.1-994.0)& F (994.5-997.7m), these Zones are separated by mudstone / shale which may be permeable. The main clay is Montmorillonite, which is identified by NGS log. L-II lime stone facies were deposited in cyclic pattern, due to frequent fluctuation of sea levels; this is characterized by bio-micritic limestone.

At first stage, Core data is taken for study for analysis of rock-fabric and pore throat classes of the well of above field. The pore throat aperture r_{35} at 65% water saturation (standard value used by Winland) can also be calculated by $r_{35} = 5.395 [K^{0.588} / (100 Ø)^{0.864}]$ and rp35 , with Aguilera equation for $rp_{35} = 2.665[k/(100 Ø)]^{0.45}$ by using template (fig. 4) with core data.

Core data analysis

Core permeability Vs porosity data was plotted on template (Aguilera) for calculating rp_{35} values based upon equation (Aguilera), which shows that pore size of the reservoir are varying from 0.5 to 10 µm (figure-4)

The same data was also plotted in template of particle size (dp) and rock fabric number (λ) in which all lines intersect at porosity of 3.5 % and permeability of 0.0015 md. This data also shows that rock fabric number (λ) is below 3.0 and particle size of reservoir below 10 µm (figure-3)

Saturation height method for estimation of pore throat size variation

Laboratory measured capillary pressure data was also used in support of recognizing, variation in pore-size distribution as it is controlled by the pore geometry (porosity and permeability) and reflects the interaction of rock with

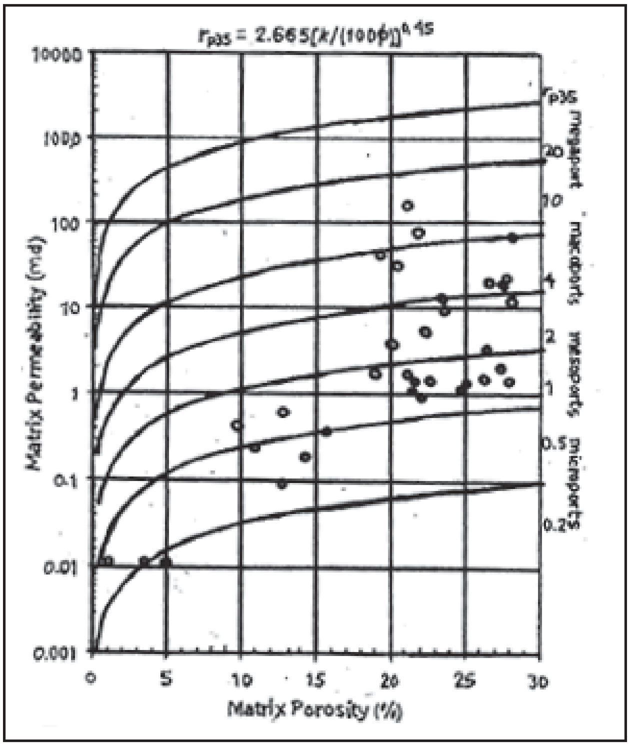

Fig. 4: Aguilera equation for pore throat aperture

fluids; therefore water saturation Vs interval depth (height) profile can also be converted to a pore size variation profile. As reservoir height is increases above free water level (FWL), water saturation decreases to minimum (irreducible level) at the top of the reservoir due to variation of pore size distribution from high at FWL to low at top of reservoir. On analysis of capillary pressure curve, it is observed that in case of higher permeability , lower displacement pressure is required to displace wetting phase by non-wetting phase, (lower side of ideal characteristic capillary pressure curve), flat section of middle portion of capillary pressure curve, indicates that large number of pores have been invaded by the oil and grains of reservoir are well sorted and the slope of the middle portion of the capillary pressure curve will depend on sorting of grains of reservoir i.e. higher slope poor sorting.

This indicates that capillary pressure curves also reflects pore size variation, which is directly related to the permeability, therefore capillary pressure curves for rock samples from the same reservoir having different permeability will be different. For obtaining single representative capillary curve for whole reservoir, Leverett replaced "r" by $(k/Ø)^{1/2}$ (pore geometry factor) in capillary pressure equation and proposed, dimension less, "J" functions, which will be different for different type of rocks.

Capillary pressure Vs Sw, core (fig.5),also shows that three-pore size variations are present in the reservoir, displacement pressure is zero due to high permeability, Swir is 10 ~ 15%.

The "J" function Vs Sw, (fig. 7) indicates that "J" function, correlating group for all measurement of capillary pressure with similar pore geometries.

Evaluation of reservoir from log data by using Pickett plot

Fig. 3& 4 using core data & Fig. 5& 6 using capillary pressure data (measured from core data) reflects pore size variation and useful for evaluating the reservoir from log data. A Log-log graph of porosity Vs Resistivity plot i.e., Pickett Plot is good technique for understanding reservoir characterization in homogeneous, naturally fractured and shaly reservoir. Before evaluating various key parameter of formations from above plot, the value of 'm' (cementation factor) in various pore geometry categories (intergranular, intercrystalline, vuggy and fracture), "n" (saturation exponent), Rw, Log/core relationship and rock properties corresponding to particular environment should be analysed correctly , so that good results could be achieved from above plot.

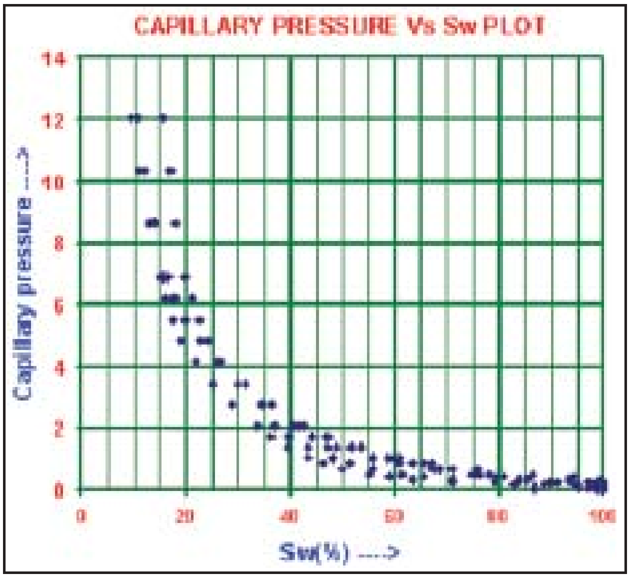

Fig. 5: Capillary pressure Vs Sw plot (core data).

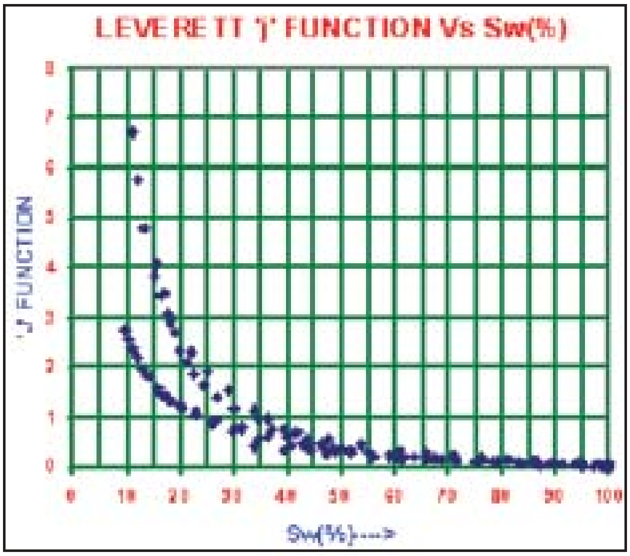

Fig. 6: Leverett 'J' function Vs Sw plot (core data).

Well log parameter Rt & Øe, data of one well of above field are used for constructing Pickett Plot. Rw value is taken 0.106 and slope m=2 for above reservoir. The equation No.1 to 3 (page.2 &3), were used for calculating, permeability "k", Capillary Pressure "P_c", pore throat aperture "r_p" etc. The water saturation lines, permeability lines and Capillary Pressure lines are drawn on the Pickett plot as shown in fig.7 with log data. The same is shown in enlarge view in fig.8 without log data. P_c and r_p are valid between Sw=30% and 90%.From above equations and plot , "r_p" was evaluated equal to ~ 108 / P_c and reservoir height was evaluated equal to ~ 0.705 * P_c.

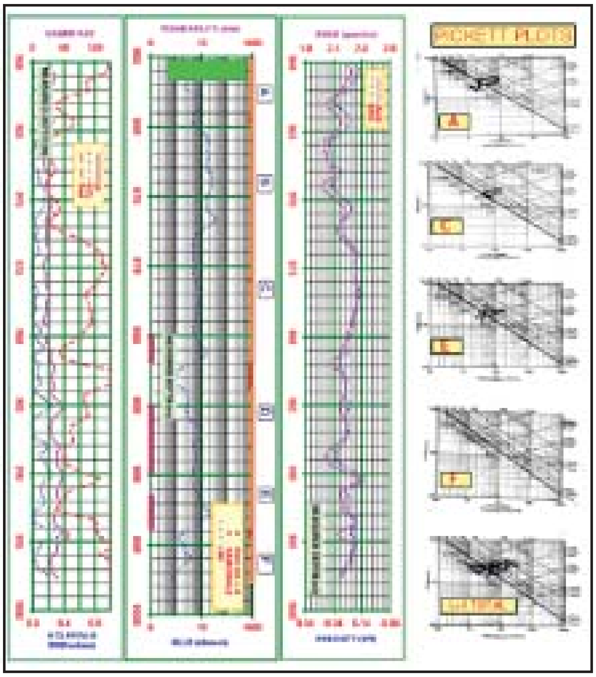

Fig.7: Pickett plot with well log data.

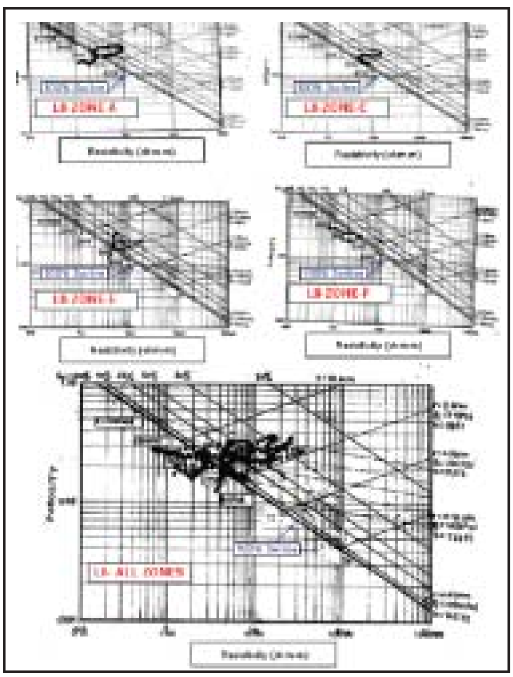

Fig. 8: Pickett plot for LII -Zone-A, Zone-C, Zone-E and All Zones

In Pickett plots, permeability, water saturation, pore size variation etc of L-II reservoir are shown in (fig. 7) along with well log data & Fig.8 with enlarge view. Capillary pressure curve Vs Sw plot shows that there are mainly three types of pore geometries, which are controlling fluid movement. "J" function Vs Sw curve also confirms the same, and shows that two types of pore geometries are representing to whole of the reservoir with third one also have some effect in fluid movement.

Zone A, is gas bearing, pore throat aperture have different pattern may be due to clayey nature and high specific surface area. Water saturation may be high in this zone due to irreducible water saturation which reduces resistivity. The pore size distribution have elliptical pattern due to variation in pore size from 7 ~8 µm and reversing back to 4~5 µm. Permeability is varying from 30 md to 1000md.

Zone C, has pore throat aperture (2µm to 6µm). Permeability is varying from 1md to 100md.

Zone E, has pore throat apertures variation from (2 µm to 6 µm). Permeability is varying 0.1 to 100md range. Pore throat aperture varies in all directions with different permeability values which shows that layer may have multiple pore size distribution.

The zone F, is water bearing, pore throat apertures varies from (5µm to 10µm) and reversing back to below less than 10µm line. Permeability varies from 10md to70md.

Conclusion

- Core permeability Vs porosity data plotted in Aguilera plot shows that pore size of the reservoir is varying from 0.5 to 10 µm .

- Core permeability Vs porosity data plotted in Lucia plot, particle size (dp) and rock- fabric number (ë) shows that particle size of the reservoir are varying from 0.5 to 10 µm.

- Total, L-II reservoir has average pore size variation from 2 µm to 10 µm, permeability varies from 1md to 1000md.
- In zone A, pore size distribution is having elliptical pattern due to variation in pore size from (7 ~8 µm) and reversing back to (4~5µm). Permeability is varying from 30 to 1000md.

- Zone C, has pore throat aperture (2µm ~ 6µm) and permeability is varying from 1md to 100md.

- Zone E, has pore throat apertures variation from (2 ~6 µm). Permeability is varying from 0.1 to 100md. Pore throat aperture varies in all directions with different permeability values which shows that layer may have multiple pore size distribution.

- The zone F, is water bearing, pore throat apertures varies from 5µm to 10µm and reversing back to below < 10µm line. Permeability varies from 10md to 70md range.

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Views expressed in this paper are that of the author only and may not necessarily be of ONGC.

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F. J. Lucia, 1999: Carbonate reservoir characterization (Published book by Springer publication, New York). 1997: Middle East “WELL EVALUATION” Review by Shulmberger. 1989: Petrophysical data book Vol-I, core laboratory, R&P division, KDMIPE, ONGC, Dehradun

Carbonate reservoir production. With an understanding of the carbonate rock formation at the micro and macro scale, specific intervals can also be reopened using hydraulic fracturing techniques. Multistage fracturing. Schlumberger multistage fracturing systems are designed to stimulate multiple stages efficiently and effectively across a well's reservoir section. These systemsâ€"cemented and uncementedâ€"can be used in vertical, deviated, and horizontal wells. Stimulation.Â Carbonate Characterization. Formation evaluation tools necessary to illuminate complex lithology. Q-Borehole.Â Matrix stimulation design software. Integrate reservoir and fluid data to optimize matrix treatments using acid or nonreactive fluids. Kinetix. Reservoir-centric stimulation-to-production software. Download Citation on ResearchGate | Characterization And Geomodeling in a Carbonate Reservoir: A Case Study | Germik Oil Field, which is in the southeastern part of Turkey, was discovered in 1958. While the production decreased in the following years, water cut increased throughout the field and IOR/EOR project has been initiated. Reservior characterization and 3D geological modeling...Â The main reservoir in this structure, is a shallow shelf carbonate with lateral and vertical facies changes due to petrophysical and lithological variations. Before this study, the known fact was that the structure was only limited by the major reverse fault in the south and the oil-water contact surrounding the structure. Well-log evaluation and core analyses provide quantitative measurements of petrophysical parameters in the vicinity of the well bore. The key for quantifying physics models is buildup the relationship between the log data and the core analyses result.Â Rock Typing and characterization of carbonate reservoirs: a case study from South East Kuwait. Society of Petroleum Engineers. 2012, 12. DOI: https://doi.org/10.2118/163294-ms.Â Combining with drilling, seismic data etc., this paper analysis the control factors of karst from 3 aspects that fractures, paleogeomorphy and unconformity surface in this paper. Research shows that the main control factors of karst are fractures and their associated cracks, unconformity surface and karst landforms.