Determination and distribution of petro physical parameters (PHIE, Sw and NTG) of Ilam Reservoir in one Iranian oil filed

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Abstract: In this study geological-reservoir zonation has been developed based on petrophysical logs and then petrophysical parameters such as porosity, Water saturation and NTG have been determined, evaluated and distributed throughout of the field. Ilam Formation is subdivided into three zones and two subzones. This zonation has been extended and correlated to 4 nearby oil fields. In order to populate the petrophysical properties into the reservoir, structural model and 3-D geocellular grid of the field has been constructed using required geological and geophysical data. Each zone includes some layers depending on the petrophysical/lithological heterogeneity. Based on porosity and water saturation distribution, 2 rock types including a good rock with a connate water saturation of 25% and poor rock type with a connate water saturation of 50% have been determined. Water saturation cut off has been determined upon to modality of water saturation distribution plot and based on intercept of 2 groups of sw frequencies, porosity cut off was defined. PHIE=2% and Sw=76% have been identified as cutoff criteria for NTG. Petrophysical modeling has been carried out using deterministic approach. Trend maps indicate that, PHIE parameter decreases from western toward eastern of the field, in all zones.
[V. Mehdipour, B. Ziaee, H. Motiei**. Determination and distribution of petrophysical parameters (PHIE, Sw and NTG) of Ilam Reservoir in one Iranian oil filed**. *Life Sci J* 2013;10(8s):153-161] (ISSN:1097-8135). http://www.lifesciencesite.com. 21

Keywords: Ilam, zonation, petrophysics, modeling, PHIE

1. Introduction:

The studied field is located in Dezful Embayment of Zagros fold belt in SW of Iran. As a matter of surface exposure, the structure is expressed as a monocline with a NW-SE trend and covered by Agha Jari Formation. Ilam Formation and overlying formations have been generally cut by two reverse and three normal faults (Figure-1). The structure is an asymmetrical anticline and its axial surface is oblique. Reservoir zonation and porosity modeling are the major parts of this study.

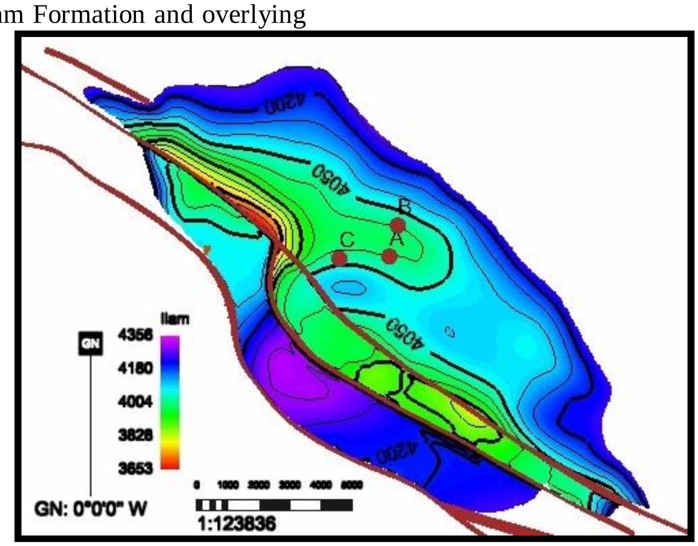

Figure-1 UGC map of Ilam Formation

2. Material and methods:

In this study about 200 thin sections were studied. Petrophysical evaluation was implemented using MULTIMIN module of Geolog software. Average of petrophysical parameters have been exported from Geolog and imputed to Irap-RMS to be modeled. Core data and DST results have been also used for petrophysical evaluation.

3. Geological setting:

Stratigraphy description of Ilam Formation will be explained as follows:

Type section of Ilam Formation was studied in northwest of Kabirkoh by James & Wynd [1]. This formation consists of limestone with shaly layers. In fact, it is comprised of cream-light grey, type I, hard and fossiliferous limestone with hard and dark shaly layers. It contains a lot of bentonitic fauna of echinoids and algal debris. It has good reservoir characteristics and is suitable for hydrocarbon accumulation. This formation overlays Surgah Formation and mainly composed of both shallow and deep water carbonates with thin beds of shale [2]. Its upper contact with the Gurpi Formation is continuous. Age of the Ilam Formation is Santonian to Campanian (Upper Cretaceous). Ilam depositional environment is neritic in this oil Field.

4. Discussion:

4.1 Zonation of Ilam Formation:

Geological zonation of the reservoir has been carried out based on petrophysical logs including GR, NPHI, RHOB and DT. Geological zonation was done in one appraisal and then all top zones have been identified and correlated with other 2 vertical wells. Ilam Formation is subdivided into three zones and two subzones (Figure-2). It contains Il-Z1, Il-Z2, Il-Z3-1 and Il-Z3-1. The average thickness of Ilam Formation (TST) is 92.32m.

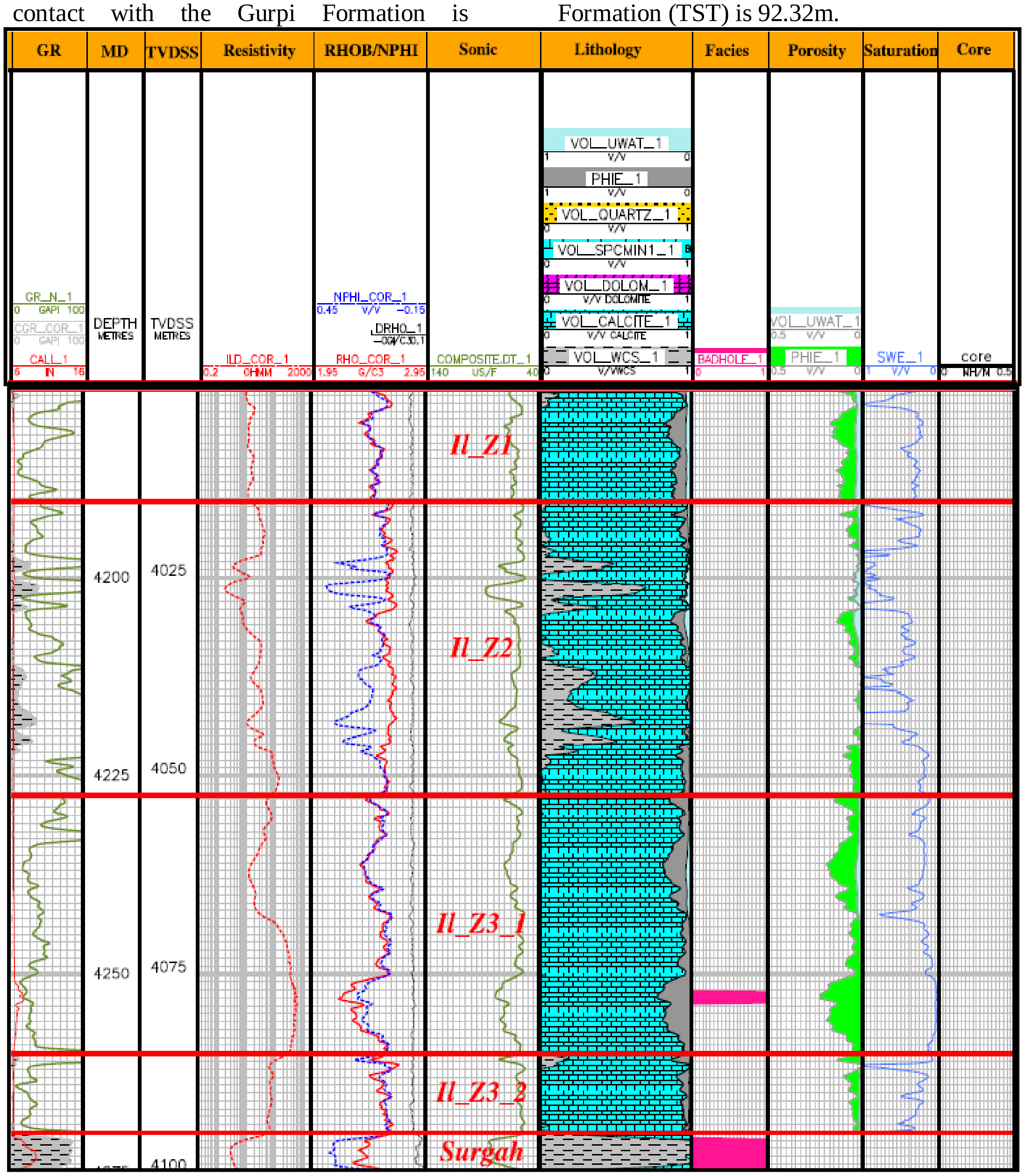

Figure-2 Ilam zonation on evaluated petrophysical log

4.1.1 Il-Z1

Based on thinsection study, the lithology of Il-Z1 is argillaceous limestone (mudstone, wackestone and minor packstone) with slightly Shal. It includes mudstone, wackestone and packstone respectively. Its constituents mainly include fossils and intraclasts. There are also some glauconitic grains, opaque and dolomite crystals in this zone. Intraparticle and vuggy are the main pore types in the zone. Some of the fractures are opened, whereas others are filled by calcite or dead oil. The average thickness of this zone is 13.36m (Figure-3). This zone has the lowest thickness value in the central area of the field and increases gradually from crest to flanks. The average effective porosity is about 10 percent increasing from the northeast to southwest of the field, the average ratio of net to gross is 0.94 and the average effective water saturation is 32.95 Percent.

4.1.2 Il-Z2

This zone mainly consists of argillaceous limestone (wackestone, mudstone and some packstone) and shale. Similar to Il-Z1 its constituents include fossils, intraclasts, glauconitic grains, opaque and dolomite crystals. There are some intraparticle, moldic and vuggy pores and fractures (opened or filled by calcite and dead oil) in this zone. Clay percentage has been increased in this zone. The average thickness of the zone is 37.74m increasing from northern to southern part of the field (Figure-3). The average effective porosity is 5.5 percent, average ratio of net to gross is 0.54 and its average effective water saturation is 35.57 percent. The porosity is increased from east to west direction.

4.1.3 Il-Z3-1

This zone is comprised of argillaceous limestone (mudstone to wackestone) and shale. Main particles are fossils and peloids and main pore types are intraparticle and vuggy. Glauconitic grains, opaque, quartz and dolomite crystals also are found in this zone. There are many opened and cemented fractures in this zone. Based on petrophysical evaluation, this zone has good reservoir quality. The average thickness of this zone is 32.83m decreasing from south to north of the field (Figure-3). The average effective porosity is about 10.5 percent, the average ratio of net to gross is 0.96 and its average effective water saturation is 13.81 percent. Generally, porosity decreases from west toward east.

4.1.4 Il-Z3-2

Il-Z3-2 zone consists of argillaceous limestone and shale. The rock constituent includes of fossils, peloids, glauconitic grains, opaque and micro dolomite crystals. The intraparticle and vuggy pores are main pore types, which some of them are filled by calcite. There are a few opened fractures in this zone. The average thickness of this zone is 11.31m (Figure-3). It increases from the northwest to southeast of the field. The average effective porosity is 5.4 percent, the average ratio of net to gross is 0.87 and its average effective water saturation is 24.6 percent. Similar to Il-Z3-1 zone, porosity decreases from west to east in this zone.

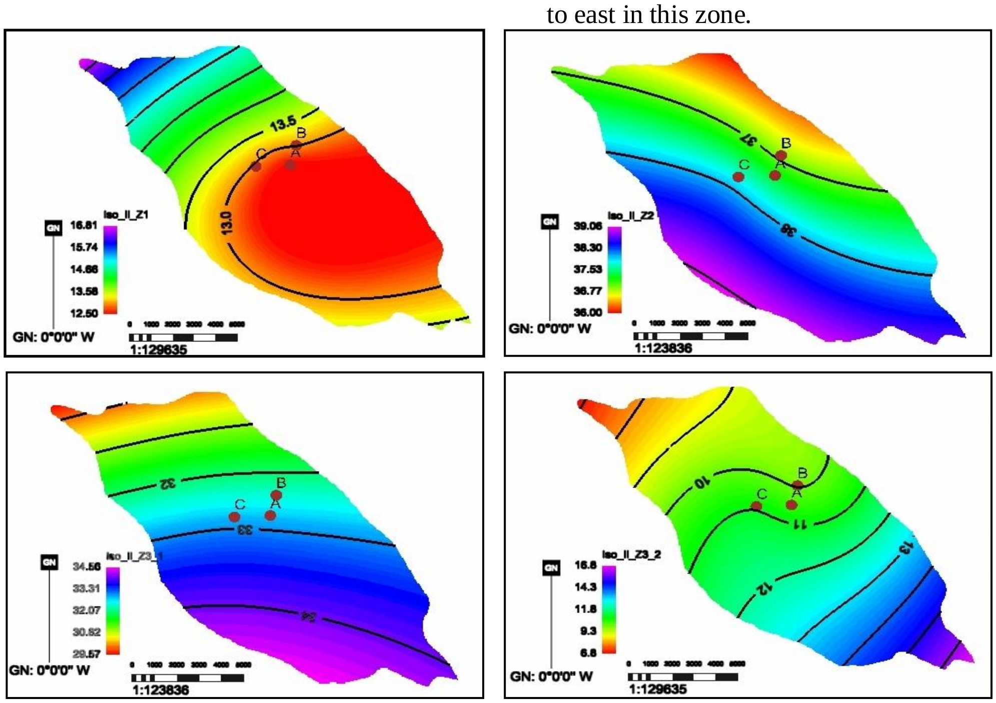

Figure-3 Isopach map of Ilam Zones

4.2 Petrophyscial evaluation:

The reservoir petrophysics e.g. porosity and water saturation are the most important properties that control qualitatively and quantitatively the reservoir performance. The petrophysical model was constructed by data which are taken from petrophysical log interpretations such as porosity, water saturation, net/gross thickness. Petrophysical evaluation was implemented using multimin module of Geolog software. Available core analysis results and geological data (Graphic Well Log) were used to control petrophysical evaluation results and to improve models. Also, Lateral variation of petrophysical evaluation results in different wells was evaluated using frequency, graph and correlation charts. Mineral composition of Ilam Formation was investigated from following 3 approaches.

- Petrophysical cross plots (MID plot, MN Plot, RHO-NPHI …)
- Core description
- Thinsection description

Petrophysical cross plots are presented in Figures 6 to 25. Based on these plots, Ilam Formation composed of argillaceous limestone and Shale.

Since argillaceous limestone is the main rock type of all zones, it is necessary to determine type of clays during parameter picking process in order to estimate possible clay problems. Based on this study, illite and montmorillonite are the main clay type in this formation. They can plug pore throats as the former locate on grain surface in the form of bridge and the later causes drilling problems and influences reservoir quality. The clay content greatly accelerated the rate of porosity loss in limestone reservoir [3].

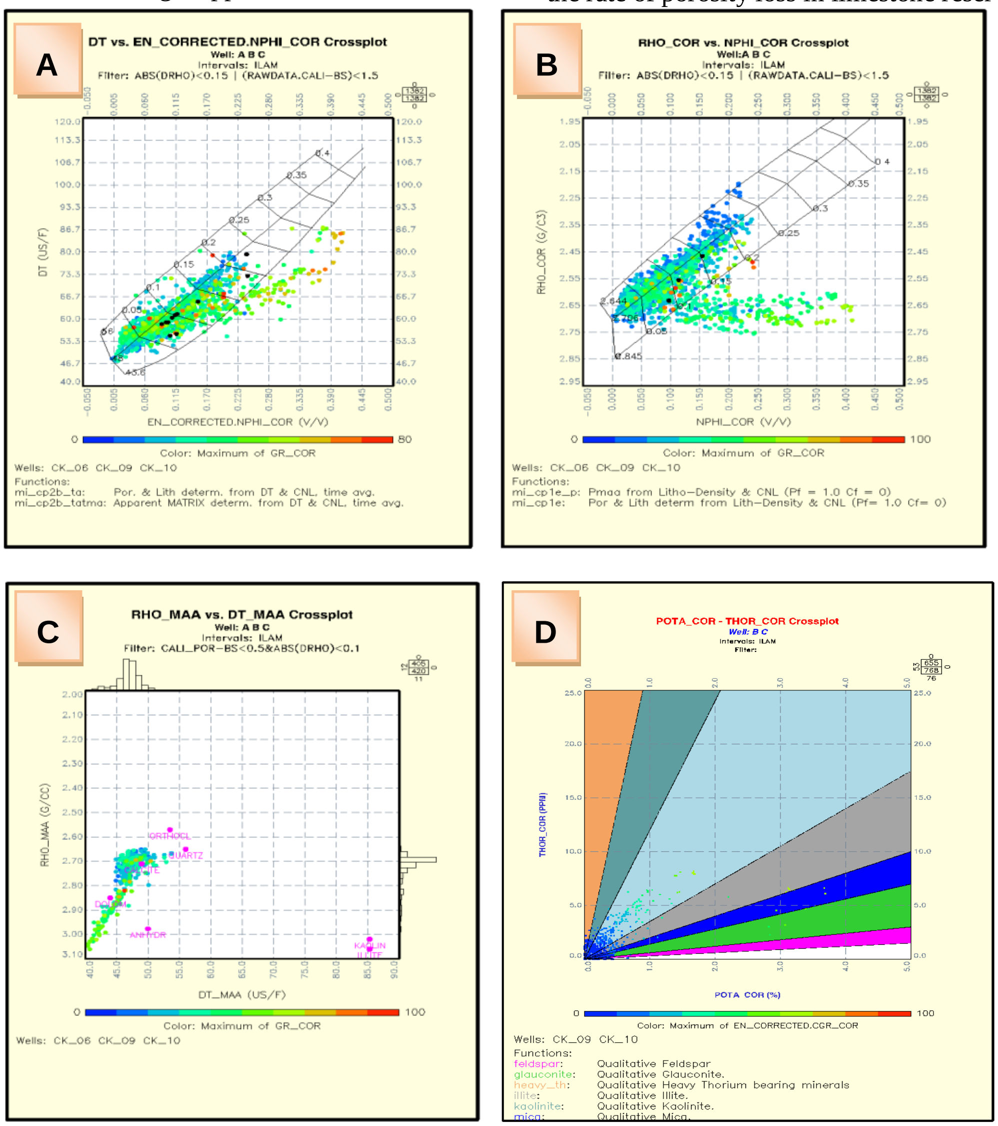

Figure-4 Determination of lithology by A) DT-NPHI plot B) and RHO-NPHI plot C) MID plot, and D) Clay mineral type in Ilam Formation

4.3 PHIE modeling:

Porosity is the key and primary parameter to evaluate the amount of hydrocarbon in a reservoir. Porosity of this formation was determined using multimin approach from all conventional logs such as sonic, CGR, SGR, resistivity, neutron and density. Porosity average has been provided in both net and gross formats. Average gross PHIE data from 4 nearby wells have been imported as a single point data into the model and were implemented for parameter mapping. Generally, PHIE parameter decreases from western toward eastern of the field, particularly in porous zones (Figure-5). Then trend modeling of all zones and subzones have been done to build different PHIE parameter models. Finally, these PHIE parameters have been used in volumetric calculations.

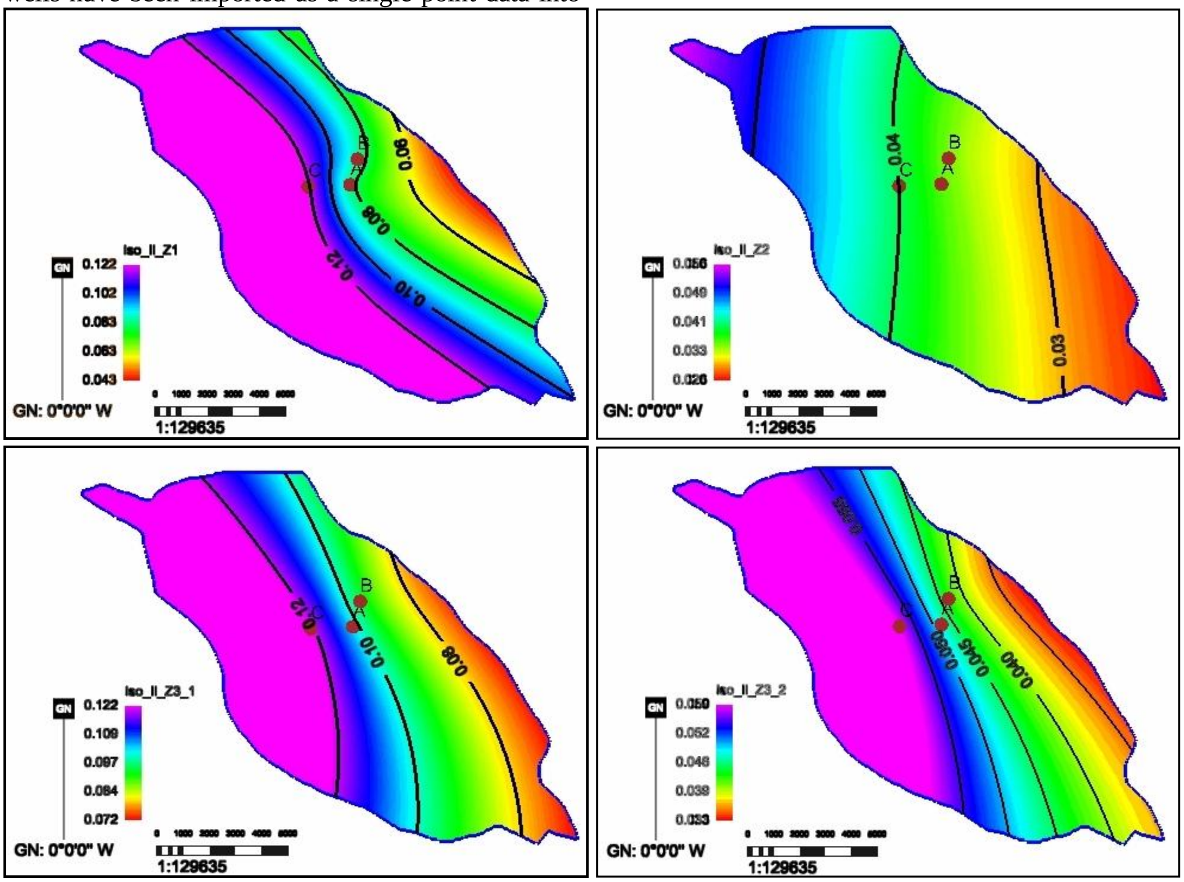

Figure-5 PHIE trend maps of Ilam

4.4 Sw modeling and rock typing:

Water saturation is one of the most important parameters in reservoir characterization procedure. This parameter can be either predicted from core data, well logs, or seismic attributes directly or can be estimated from an intermediate parameter such as shale volume in sand stone reservoirs.

Water saturation parameters (m, n, a) were determined using core data in Ilam Formation.

Cementation factor is slope of formation Resistivity Factor versus porosity in a log-log scale plot. This plot is demonstrated in Figure-6A. To improve the cementation factor, core data should be categorized based on texture controlling parameters. Porosity is most important parameter which effects on cementation factor. Modified Borai model has been applied in order to determination of cementation factor which is demonstrated in Figure-6B. As shown in this figure, cementation factor slightly increases by increasing porosity [4].

Subsequently, tortuosity constant (a) was forced to one. This approach is addressed force fit. Data scattering is observed in the force fit plot and correlation coefficient of the fitted equation is not appropriate and the resulting cementation factor bears a degraded order of accuracy.

There is a linear relationship between water saturation and RI in a log-log scale plot ND saturation exponent could be derived from this plot. This plot is presented in Figure-6C. As shown in this figure, saturation exponent in Ilam Formation is 2.2 and correlation coefficient of fitted line to this data is appropriate. Resulted Saturation Exponent from this approach was used in petrophysical models of Ialm Formation. Porosity and saturation distribution plots of wells are presented in Figure-6D. Based on this plat all samples could be divided 2 groups which identified 2 rock types as described in following text.

A good rock with a connate water saturation of 25% which includes Ilam1, Ilam 3-1 and Ilam3-2. The poor rock type has a connate water saturation of 50% and is assigned to Ilam-Z2 based on low porosity, high water saturation value and high shale volume. Due to lack of reliable measurements, capillary pressure curves are constructed based on log interpreted water saturation profile. By capturing the saturations from the log at any height and converting to pressure, one can get the overall shape of the Pc providing that the effect of variation of rock fabrics and distance from free water level are considered. Figure-7 shows water saturation interpreted log used for the good rock. The resulting Pc curve is shown in Figure-8. Finally Sw trend maps of Ilam have been mapped using Irap-RMS which Il-Z3 Sw trend maps have been illustrated in Figure 9.

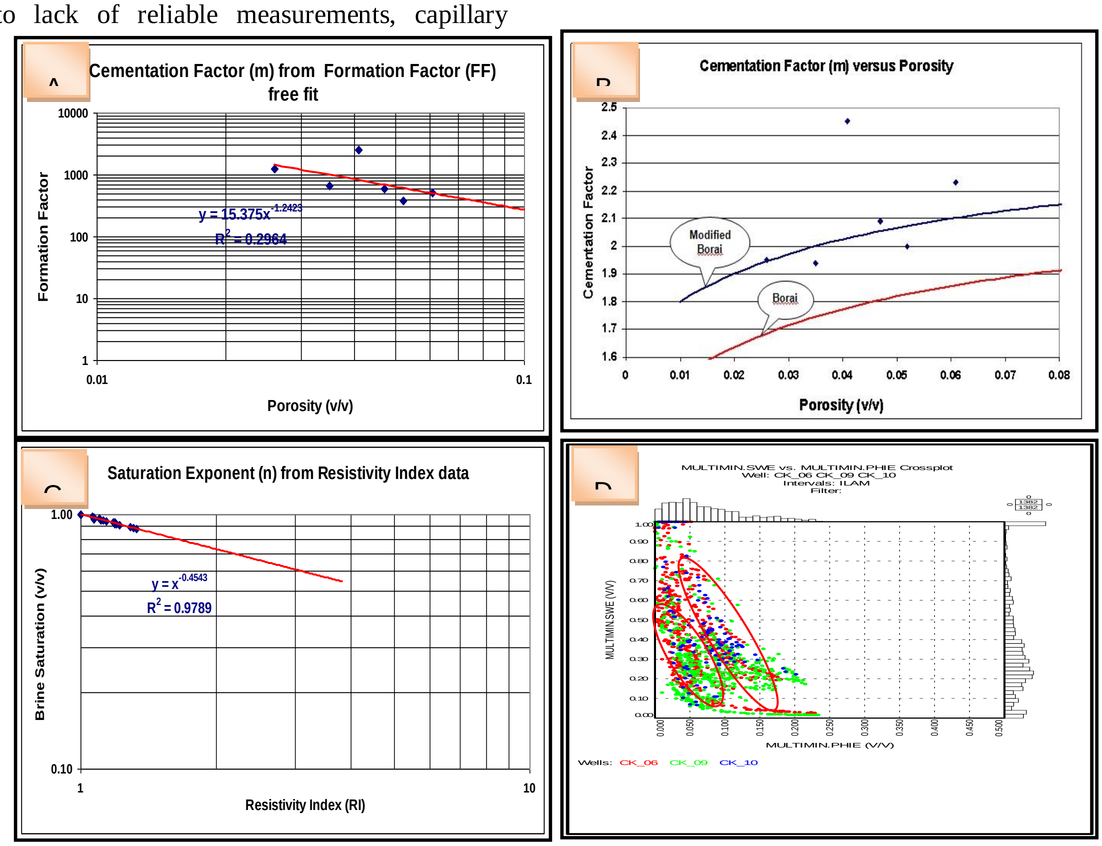

Figure-6 A) Determination of cementation factor (m) from SCAL data, B) Cementation Factor (m) versus Porosity (Borai) C) Saturation exponent determination from core data and D) Porosity Vs. Saturation

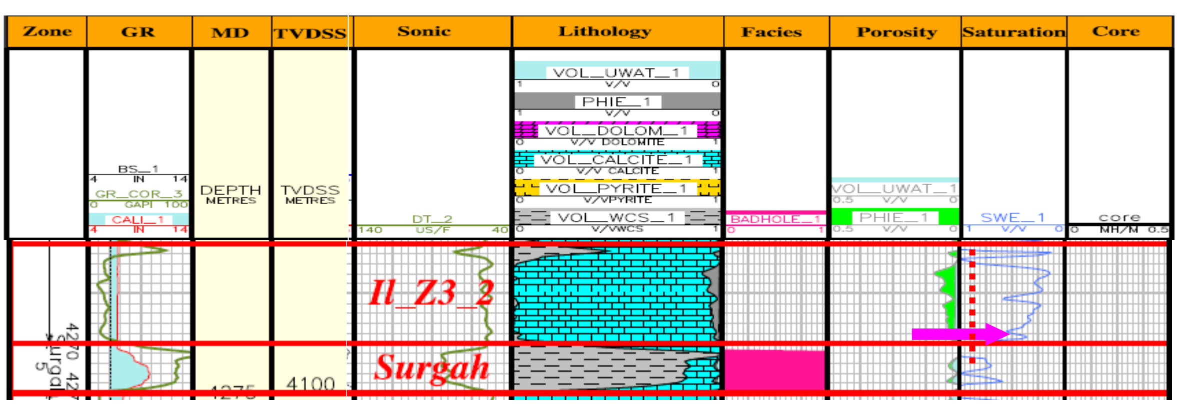

Figure-7 Saturation log used for definition of good rock capillary pressure

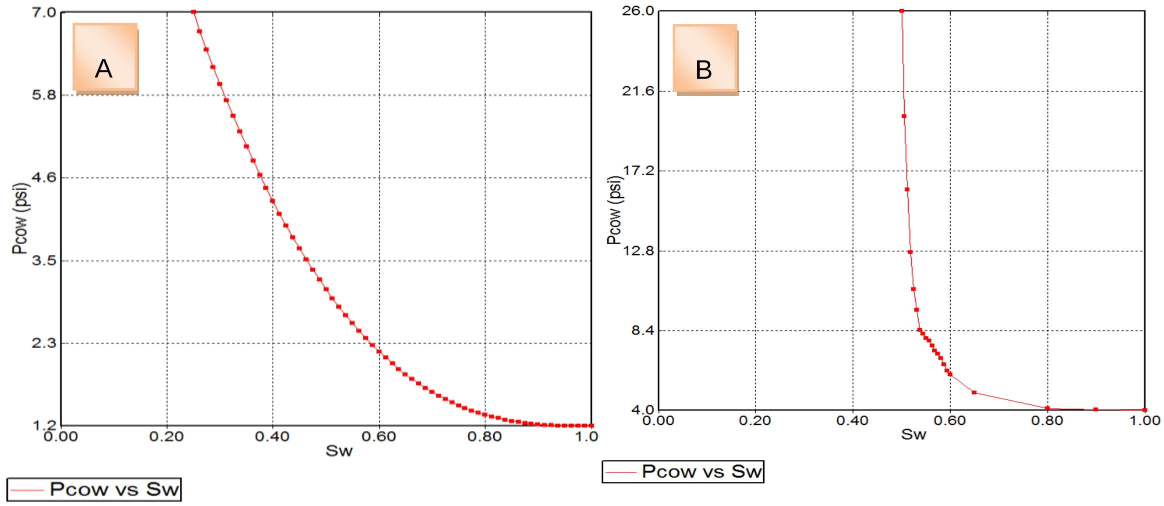

Figure-8 Capillary pressure curve for good rock and B) Capillary pressure curve for bad rock

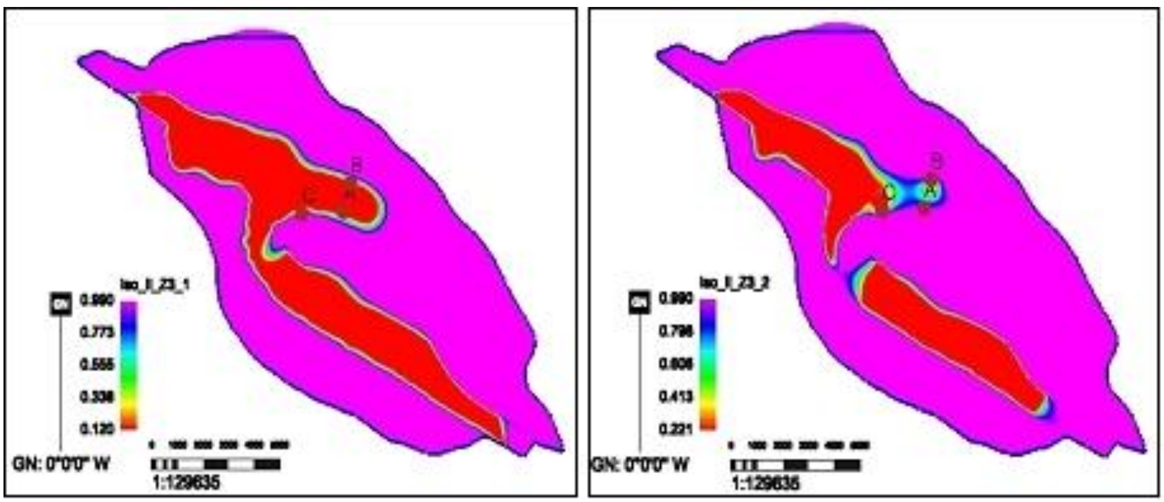

Figure-9 Sw trend maps of Il-Z3

4.5 NTG modeling:

Definition of good rock and the reason for using cut off values in reservoir studies is of prime importance. Good rock is determined by applying cut off values for porosity and water saturation. Frequency of water saturation and porosity from petrophysical evaluation results were plotted for this formation. Water saturation cut off was defined upon to modality of water saturation distribution plot (Figure-10A). Subsequently, porosity data were divided in two categories (Net & Gross) by applying water saturation cut off, and then Intercept of these two frequencies was recognized as porosity cut off (Figure-10B). Therefore PHIE=2% and Sw=76% have been determined as cutoff criteria for NTG. Also, effect of determined cut off criteria on hydrocarbon column was investigated using S-Curves (Figures-10C and 10D). NTG parameter was generated based on cut off criteria of Sw and PHIE for, Ilam Formation. Eventually PHIE, Sw and NTG have been used to calculate oil in place and bulk volume of the reservoir.

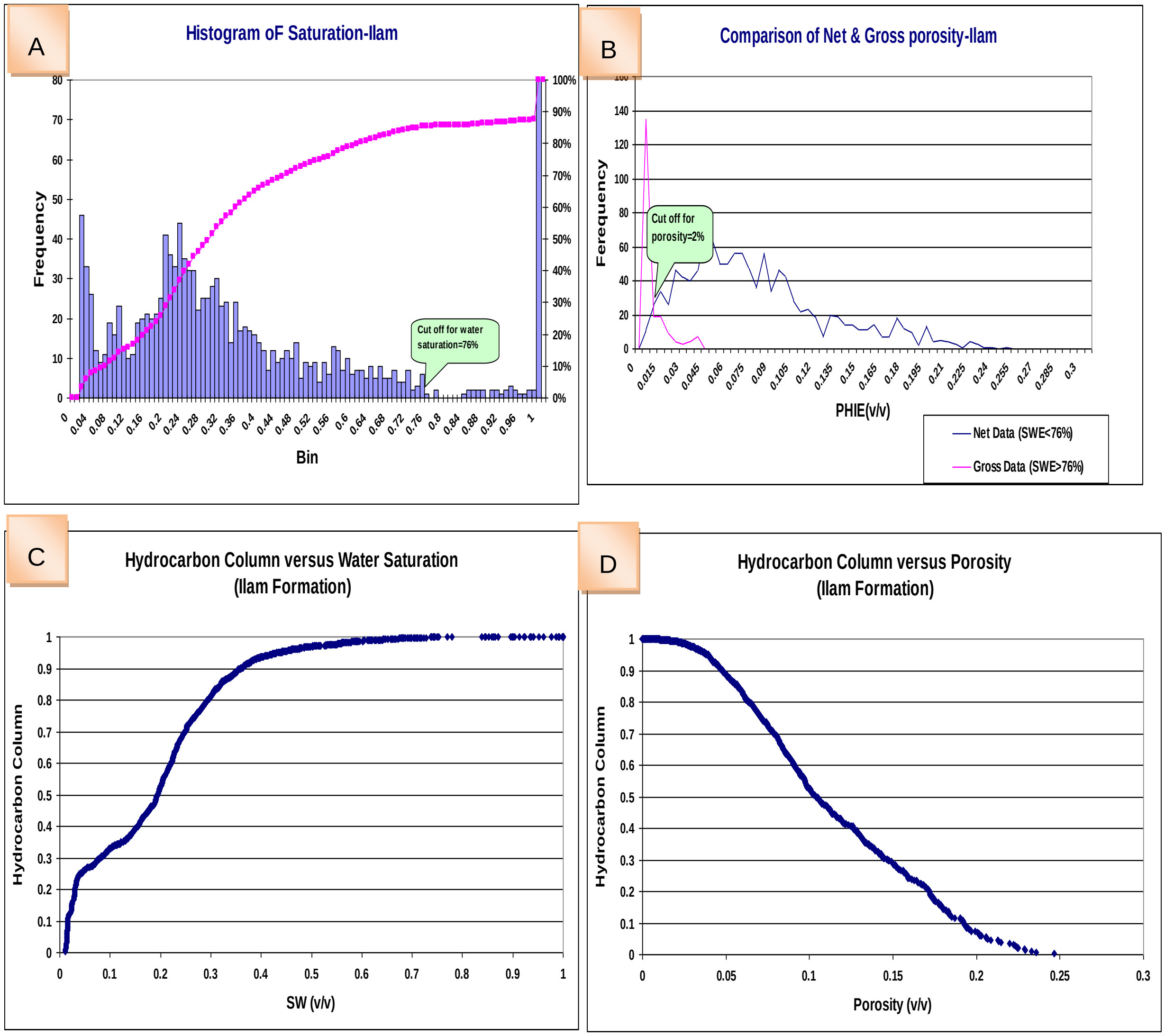

Figure-10 A) plot of water saturation distribution modality, B) categories of porosity distribution and C-D) effect of determined cut off criteria on hydrocarbon column

5. Conclusions:

In this study, Ilam Formation is divided into 4 zones and subzones. This zonation has been extended and correlated to 4 nearby oil fields. Based on porosity and water saturation distribution 2 rock types including a good rock and poor rock type have been determined. Water saturation cut off has been determined upon to modality of water saturation distribution plot and based on intercept of 2 groups of Sw frequencies, porosity cut off was defined. PHIE=2% and Sw=76% have been identified as cutoff criteria for NTG. Generally, Il-Z1, Il-Z3-1, Il-Z3-2, have better-defined reservoir properties in this field and can be considered as potential reservoirs. Trend Petrophysical maps show that, PHIE parameter decreases from western toward eastern of the field, particularly in porous zones.

6. Acknowledgements:

The authors are thankful of ICOFC for easy accessibility of logs and core data and permission to publish the results of this study. Also there must be appreciated Mr. Vahid Farajpour as Geologist from ICOFC for providing s. Authors also acknowledge KPE Company for creation of a peaceful environment to complete this study.

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4/2/2013