CARBONATE COMPLEXITIES AFFECTING HYDROCARBON RECOVERY AND OVERVIEW OF RECOVERY OPTIMIZATION TECHNIQUES

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ABSTRACT

Carbonate reservoirs possesses around 60% of world's total oil and accounts for comparatively larger proportion of gas. The lithological complexities bounded with the carbonate reservoir systems makes them of cardinal interest of the geologists and reservoir engineers to characterize the well or field, which is very challenging as compared to sandstone reservoirs. The petrophysical properties such as porosity, permeability, saturation and other parameters are hard to determine in carbonates as they greatly possess lateral heterogeneities varying largely across the field and thus affects the recovery of hydrocarbons. In order to understand the complexities possessed by the carbonate rocks, their origin, deposition and diagenetic history is a fundamental pre-requisite to be known that affects the texture, pore size and internal rock structure of the rock which greatly affects the reservoir properties in a field. The source of carbonate rock formation can be biogenic, deep water accumulation or precipitation which are greatly affected by the post depositional conditions and are subjected to chemical and mechanical reactions. The carbonate sediments are generally not transported far from their source and hence the depositional characteristics like sorting, size and shape are not ascertain as in case of sandstone. Their deposition undergo chemical and biological diagenetic processes which tend to produce compounds which can either help to aggrandize the storage capacity of hydrocarbons in the reservoir (porogenesis) or can deteriorate the same (poronecrosis). The paper deals in understanding the lithological complexities that affects the production trends and provides an overview of production techniques for recovery optimization citing cases from different fields.

INTRODUCTION

Carbonate rocks accounting near about 15% of the sedimentary rocks are generally limestone, which is composed of calcium carbonate i.e calcite ($CaCO_3$) and dolostone, which is composed of calcium magnesium carbonate ($CaMg(CO_3)_2$). These carbonate minerals have a greater tendency to dissolve in acids which accounts for the dual porosity/permeability systems in the carbonate reservoirs. Porosity and permeability are the major characteristic petrophysical properties which are pre-requisites for original oil and gas in place determination. Unlike in sandstone reservoirs where these parameters are generally uniformly distributed across the fields (ignoring a few uncertainties), it is not the same in case of carbonate reservoirs. There is a wide array of heterogeneities possessed by them which can be well understood looking into the depositional history which explains about the source of sediments, type of depositional environment influencing the sedimentation and diagenetic history which explains the post depositional changes affecting the porosity and permeability of the reservoir.

CARBONATE COMPLEXITIES

Carbonates can be genetically reframed in accordance with three different processes namely Depositional, Diagenetic and Fractured oriented. The interplay of two or more of the processes forms the hybrid* poro-perm system (After Wayne M. Ahr et al.) altering the original morphology of the carbonates

(Fig1). Depositional processes varies in particular with the environment, the carbonates formed due to the mechanical sedimentation of the detrital deposits that possess the original texture and fabric framework while in the reef complexes the biological processes affect the texture and fabric of the carbonates that are different than the mechanically formed loose sediments. Diagenesis alters the carbonate rocks through processes like dissolution, cementation, compaction, recrystallization and replacement. These processes greatly affect the porosity of the rock by either reducing or enhancing the original porosity or might end up in creating new pores that induces a significant impact on the flow units of the carbonate reservoirs. Fracture networks can be formed mechanically in effect with the in-situ stresses that cause alteration of porosity and permeability of the carbonate reservoirs and affect the hydrocarbon flow paths in a producing field. These three end processes discussed are independent in nature but never the less in a carbonate reservoir hybrid genetic nature exists; the porosity and permeability is produced by occurrence of two or more processes together. Due to increased affinity towards chemical processes of carbonates, the post depositional sediments are altered due to diagenetic processes that form Depositional- Diagenetic hybrid system of porosity and permeability affecting the original oil in place and flow paths. Similarly Depositional- Fractured Hybridized system may exist due to mechanically produced fractured altering the original depositional system. All three end processes may be present in a reservoir creating intense complexities, for example a reservoir is subjected to diagenesis forming dolomite after replacement. Dolomites are more brittle in nature as compared to limestones which with induced stresses possesses fractures. Understanding the pore types of the rocks formed/altered genetically by these processes is essential as they influence the bulk- rock properties and can significantly cause erroneous results if misinterpreted (Fig2).

OVERVIEW OF RECOVERY TECHNIQUES

The recovery factor for carbonate reservoirs is generally low as compared to siliciclastic reservoirs. In order to maximize the recovery various IOR/EOR techniques are adopted to optimize the production including repressurization through water or gas injection, stimulating the reservoir with acid or using EOR approach like Microbial enhanced Oil Recovery etc. Proper understanding of the reservoir's petrophysical properties is a prerequisite to choose an apt method of recovery optimization. Two cases with different recovery approaches are given below:

CASE 1: CARBONATE RESERVOIR ACID STIMULATION TECHNIQUE- Mumbai High

With the depleting production rates various techniques were adopted to re-establish the initial production curves. IOR techniques like water flooding were used to regain the reservoir pressure and increase the recovery factor. The most effective method adopted to set back the initial flow regimes is the Viscoelastic Self Diverting Acid Stimulation.

Well Name: Z

Characterized by three pay zone intervals with contrasting permeability from 5-500mD

Well Location: Bombay High

VSDA Formulation:

15% Hydrochloric Acid

3% Viscoelastic Srufactant and standard additives

The following conclusions were drawn:

- The post treatment production analysis of the well treated with VSDA showed significant oil gain (Fig3)
- Real time plots showed elevation of treating pressure after injection of VSDA indicating effective diversion of acid from high permeability to low permeability streaks (Fig.4)

CASE 2: MICROBIAL ENHANCED OIL RECOVERY (MEOR) IN CARBONATE RESERVOIRS-Saskatchewan, Canada

The principles outlining the classification of MEOR is that the production of acid due to microbes facilitates in dissolution of rock matrix which leads to increase in the porosity and permeability, whereas in gas production the gas produced with the help of microbes helps to reduce the viscosity and pressurize the reservoir. In solvent, it directly acts as an extractant which decreases the interfacial tension leading to increase in oil mobility. The surfactant production decreases the interfacial tension and improves microscopic displacement efficiency. Selective plugging enables blocking of dominant flow channels within the reservoir which enhance the sweep efficiency.

An example for MEOR in carbonate reservoir can be taken from a mature waterflooded reservoir in Saskatchewan, Canada (SPE 124319). The field was at 95%watercut when an In-situ Microbial Response was performed to mitigate the problem.(Fig.5)

Location: Saskatchewan, Canada

Procedure: Analysis of reservoir was done for specific crude oil, water and microbes that were indigenous. Based on laboratory and field test a nutrient was designed and released into the reservoir via water injectors.

Response: The average decrease in water cut was 10% and 200% more oil production was observed.

Pre Treatment Flow rate: 1.2 m^3/day
Post Treatment Flow rate: 4.1 m^3/day

CONCLUSION

The following conclusions can be drawn:

- Carbonate reservoirs possesses dual porosity/permeability systems due to interplay of depositional diagenetic and fracture processes.
- The processes affecting the petrophysical properties, in particular porosity and permeability are likely to occur more than once and are must of be characterized properly to understand the reservoir framework properly
- Diagenetic processes distort the original sedimentation framework of rocks many times during burial history that greatly affects the OOIP estimations.
- Recovery methods are adopted aptly after characterizing the complexities of the carbonate reservoir to optimize production

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FIGURES

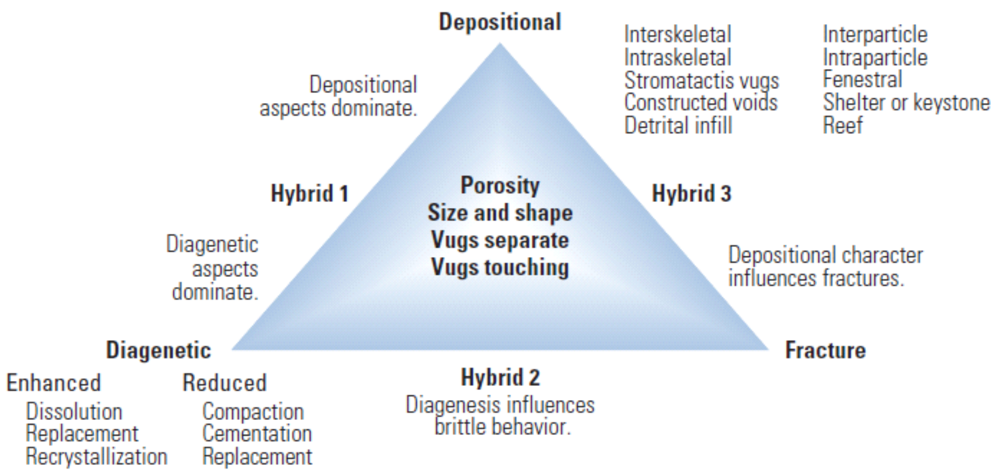
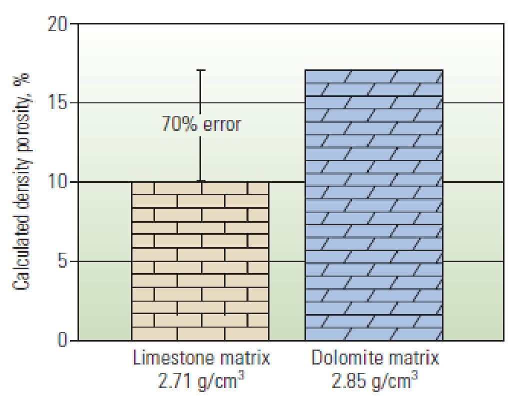


Fig1: Genetic Classification of Carbonate Rocks Porosity/ Permeability (after Wayne M. Ahr)



$$\phi_{density} = \frac{\rho_{matrix} - \rho_{bulk}}{\rho_{matrix} - \rho_{fluid}}$$

$\phi_{density}$ = density porosity

ρ_{matrix} = matrix density, or grain density

ρ_{bulk} = bulk density measurement

ρ_{fluid} = fluid density

Fig2: Change in Matrix Causing Erroneous Results in Bulk Rock Property

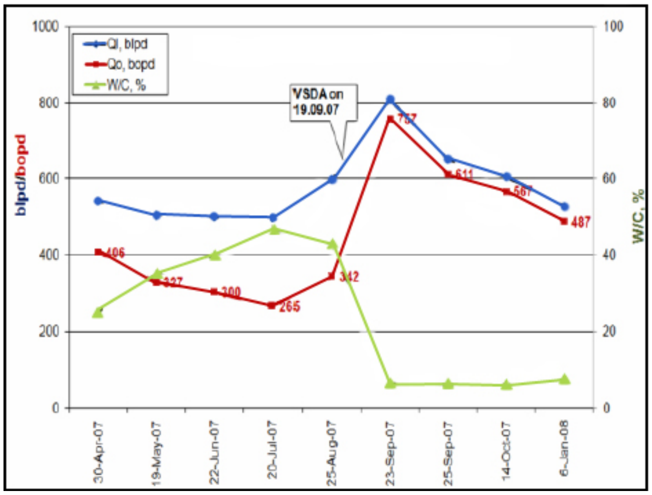


Fig3: Plot showing elevation of treating pressure after injection of VSDA showed effective acid Diversion

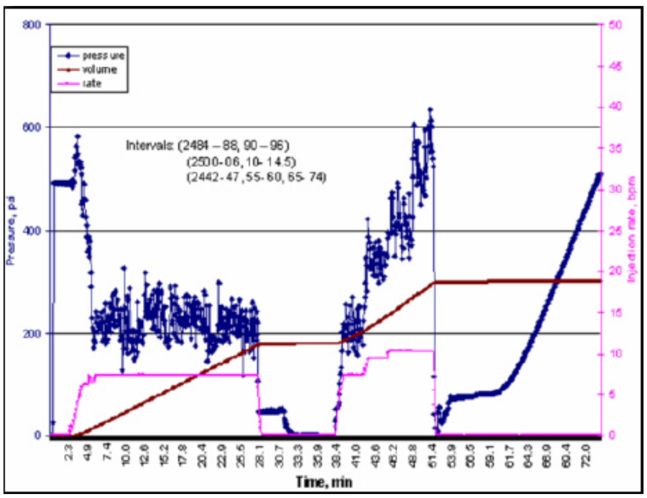


Fig4: Production Performance of Candidate Well after VSDA job done on 19.07.2007

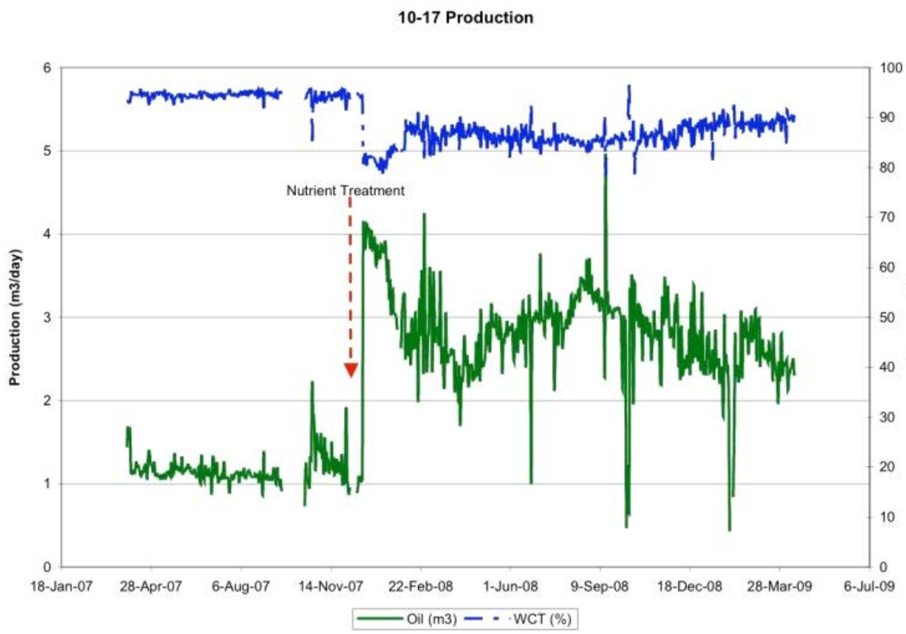


Fig5: Production plot showing post treatment significant oil gain and reduced water cut