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THE EFFECT OF FRACTURE LENGTH AND CONDUCTIVITY ON FLUIDS PRODUCTION - CASE STUDY, BLOCK 8 – SUDAN

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ABSTRACT: *Recently, natural gas reservoir exploration has become one of the most important priorities which countries are competing; most of these reservoirs are low-permeable and tight formations or so-called shale gas formations which are need special techniques to produce the hydrocarbons. Hydraulic fracture is a well stimulation technique in which a pressure-induced fracture to form a conductive path for trapped fluids in low permeable zone; it is also applied to unconsolidated high permeable zone to control the movement of formation sand toward the wellbore. The production through this fracture is a function of two factors, fracture length and fracture conductivity. The current work presented, the effect of fracture length and conductivity in well productivity for low-permeable formation of Hossan -1 through Block 8- Sudan. Using the default shally sand properties combined with 3 D reservoir simulation software (CMG), series of scenarios were performed under different fracture lengths and dimensionless conductivities. Dimensionless conductivity of 1, 2, 3, 5, and 10 and fracture lengths of 300, 500, 700, 900, and 1000 ft were studied; with constant fracture width of 0.05 ft. The results presented that a fracture length of 700 to 900 ft is the optimum length to achieve good gas production; length less than 700 ft can case production restriction; while an unfavorable job can be achieved with length greater than 900 ft due to water production. The recommended dimensionless fracture conductivity (FCD) is 1.0 to 2.0 to avoid massive water production. Using Fracture with these parameters, the recovery factor can be increased from 0.82% to more than 3.0% with a daily gas production of $0.3*10^6$ ft^3/day, while a cumulative gas can reach 0.52 MMM ft^3 with 12000 bbl of water.*

KEY WORDS: hydraulic fracturing; gas production; fracture conductivity; fracture length; reservoir.

INTRODUCTION

Unconventional gas reservoirs such as shale, coalbed and tight sands have become an important source of natural gas and it requires special stimulation technique such as hydraulic fracturing this is because the gas is highly dispersed in the rock, rather than occurring in a concentrated underground location. With the first industrial application of hydraulic fracturing in 1949, the technology has widely been used as a well stimulation techniques for low and moderate-permeability reservoirs. The technique induced fracture into a target rock formation through the injecting of a certain fluid with a pressure exceed the formation break down pressure to bypass formation damage and to form conductive path for fluid to flow toward the well. The technique also was appeared as a useful well completion technique to control sand production from unconsolidated formations (Parker et al. - 1994). The application of the technique on injection well to increase the injectivity was also presented (Ajay et al. - 2010).

The efficiency of the fracture depends on two steps: receiving fluids from formation and transporting the received fluid to the wellbore; the efficiency of the first step depends on fracture dimensions (length and height) while the efficiency of the second step depends on fracture permeability or conductivity. Generally, low permeability reservoirs, leading to high-conductivity fractures, which would benefit greatly from fracture length; on the other hand, high-permeability reservoirs, naturally leading to low-conductivity fractures, require good fracture permeability and width. The optimization of the fracture parameters such as fracture conductivity and Fracture length is the major factor for a favorable fracture job. Numerous studies investigated the effect of fracture conductivity and length on the well productivity based on either analytical or numerical simulation methods (Elyezer et al. - 2003; Mohan et al. - 2006; Wei et al. - 2009).

When modeling a fracture job, the first requirement is to estimate the desired fracture length and height based on geological conditions, well pattern, well spacing and well density using of 3D reservoir simulation model. Secondly, fracture simulation models will be used to estimate the pad volume, the time to start the main slurry stage; the time to end the mean slurry stage and the proppant concentrations for the given time. To increase the net present values of the fracturing job, Hydraulic fracturing designs are required which includes the selection of fracture size (length) and proppant concentration. Smith et al.(2014) presented statistical-based hydraulic fracturing design methodology based on constructing and calibrating a basic geological model, incorporating geo-statistics and forecasting production for alternate fracturing treatments.

Pang et al.(2016) presented the requirements for Fracture design which includes a carrier fluid with a suitable leakoff coefficient, initial reservoir pressure and permeability, the closure-stress in the formation and in the bounding formations, and rock properties (Young's modulus and the Poisson's ratio). When key parameters are left unknown, the hydraulic-fracture stimulation is likely to be severely suboptimal.

The presence of natural gas in Sudan was investigated to evaluate the source rock in Abu Gabra, based on the main key parameters she used to evaluate shale gas in Marine basins there is high feasibility of shale gas in Lacustrine basin. Moreover, White Nile Petroleum Operating Company WNPOC discovered significant amounts of dry, non-associated natural gas in block 8 in Sudan Maimona Washie (2012) a geochemical evaluation. The Block is situated in the eastern central of Sudan; it is around 300 km SE Khartoum, covers an area of 60,000 km2. It is mainly consists of Blue Nile Basin; which in turn consist of three Sub-basins. Dinder I, Dinder II and Dinder III. A high peak of total gas (143,048 ppm, 14.3%) is recorded in Lower Dinder II formation at 1827.5 m MD. Total of six wells have been drilled in this Block, Hosan-1 is the first well drilled in the field No oil shows observed while drilling, and Gas shows observed through the log Chromatograph Data.

No work was conducted to analyze the effect of fracture on the well productivity for these type of reservoir in Sudan; Although, some studies were conducted to evaluate the uses of Sudanese materials in hydraulic fracture job (Elham et al. 2014 and Elham and Faried - 2016). This study analyze the effect of fracture on well productivity for low permeable zone in Block 8 in Sudan through numerical simulation. Based on gas and water flow rates and the cumulative production and using 3D reservoir simulation software of Computer Modeling Group (CMG - IMEX black oil simulator); optimization of fracture parameters was presented under constant fracture width with different fracture half-length and conductivity without considering the Net present Value for the job.

WORK PROCEDURES AND MODEL INITIALIZATION

General Simulation Model

Based on the available petro-physical information and the field geological model, with the target sands of Dindier II, a geological study and reservoir analysis was first conducted with Petrel simulation software. The obtained static and dynamic models was converted to reservoir

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simulation software (Computer Modeling Group - CMG) to create different strategies for well production with the different fracture length and fracture conductivity. a Geological model of grid number 91×128×80 with total cells of 931840 was conducted. The average cell sizes in X and Y directions are 24.25 ft with an average cell thicknesses (DZ) of 12.26 ft. Cartesian coordinate and corner point geometry was used to perform the analysis; the dry gas model simulation was started with one vertical well (Hossan -1) which completed with 7″ production casing (Fig. 1).

The Rock and Fluid Relative Permeability default table for shally sand was used to generate the relative permeability curve as recommended by the original model creators as no SCAL data are available for the field.

The PVT were calculated using Petrel simulation program and Reference pressure, Reservoir temperature, minimum and the maximum pressure. The properties were calculated based on old known PVT correlations.

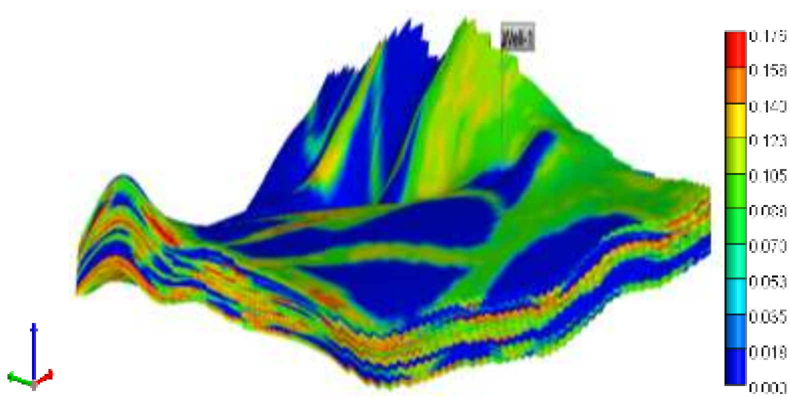

Fig. 1 Schematic Diagram for Formation and Sub- layers for the Model

History Matching:

As histories match allowing making accurate predictions and evaluating alternative production scenarios, history matching was carried out manually, standard procedures were used to achieve a technically acceptable match. The available data for matching is only for the period from Jan. 1, 2008, till Feb 9, 2008; therefore, the simulation have been run with a well start production on same period; the totally produce crude gas $1.1*10^6$ scf with initial oil saturation of 0.65.

The history match plots of oil production rate and Bottom-hole Pressure (BHP) of the well are shown through Fig. 2 and Fig. 3 respectively. After a good history match was achieved; the simulation was run to predict the performance of the wells for 16 years. The well was re-

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perforated to produce from Dinder II formation at depth of 1510 to 1520 due to the shale barrier under the despite with the pretty good barrier above. The simulation was started at 1/1/2016 using IMEX as simulator type and single porosity as porosity type to predict the performance of the well before fracturing. The permeability, and saturation distribution for the model at the beginning of the simulation was presented in Fig. 4 and Fig. 5 respectively.

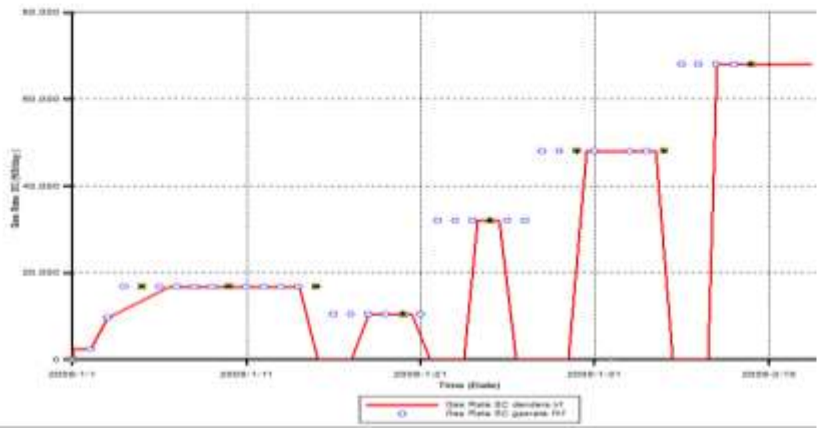

Fig .2 Gas Production History Match Plots of Hosan 1

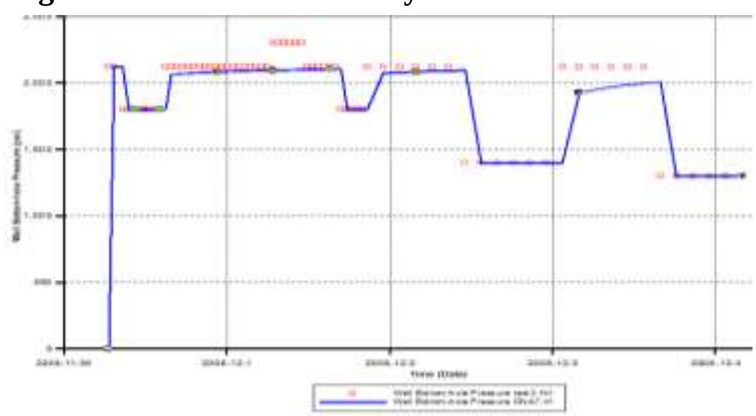

Fig. 3 The Bottom-hole Pressure History Match of Hosan 1

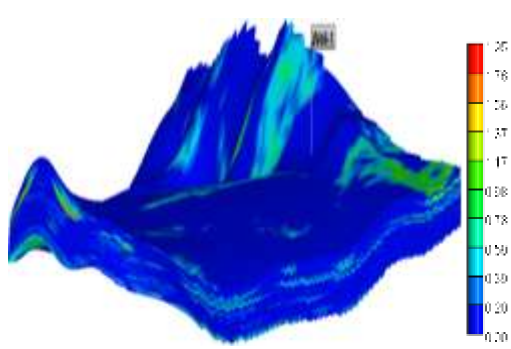

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Fig. 4 3D Viewer of Permeability Distribution at the Beginning of Simulation

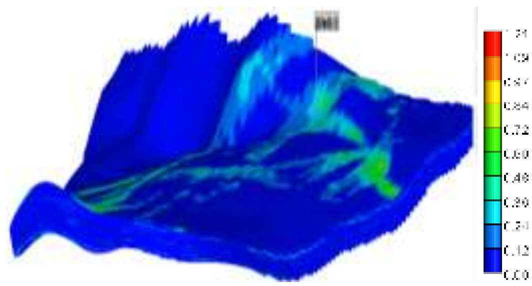

Fig. 5 3D Viewer of Gas Saturation Distribution at the Beginning of Simulation

Local Grid Refinement

Well Hossan-1 is located in the central of grids No. 51 in the X direction and grids No. 48 in the Y direction as presented in Fig 6. A fully three-dimensional, extremely finely grid is used to accurately model near well-bore and to perform fracture on the formation. The total number of the grids after LRG increased by 1233. The width of the fracture was taken as 0.05 ft to allow the high proppant concentration to inter the fracture.

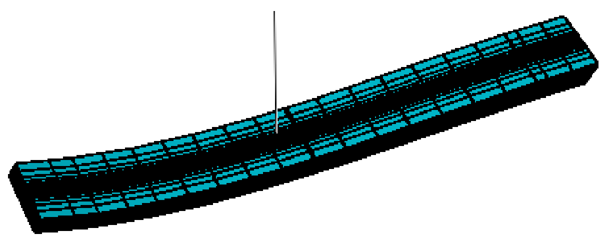

Fig. 6 3D Viewer for Parent Grid and Child Grid of the LGR Model

Optimization of Fracture Length and Conductivity

The simulation software was run to study the effect of fracture length on gas production depending on the resulting gas production; when the increases of those parameters is not followed by considerable production to cover the cost of treatment and provides a considerable NPV, the increment is then unfavorable; fracture length of 300-1000 ft, was used to address the effect of the fracture length under constant fracture conductivity and width.; while fracture conductivity of 1, 2, 3, 4, 5, and 10 was studied under constant fracture length and width; the fracture conductivity was calculated according to Agarwal (1979) as presented in equation 1

$$FCD = \frac{k_f w}{k L_f} \quad \text{...} \quad (1)$$

Where

K_f = Fracture permeability (md).

W =Fracture width (ft).
L_f = Fracture half length (ft).
K_r = Reservoir permeability (md)

RESULTS & DISCUSSIONS

The Effect of Fracture Length

The effect of fracture length on the daily gas production and cumulative gas under constant conductivity and width was presented in Fig.7 and Fig. 8 respectively. While the same effect was presented for water phase in Fig.7 and Fig. 8 g for the daily and cumulative production respectively.

Fig. 8 presents that by the end of 2030, the cumulative gas production with no fracture is only 136 MM ft^3. An increment to 397 MM ft^3 will take place if a fracture with half length of 300 ft is created; as well as 462,502,537,550 MM ft3 will be achieved with a fracture half length of 500, 700, 900 and 1000 ft respectively; with a none lianer increments. Fig. 9 presents that the dially prodution rate increses as fracture length increses up to fracture half lenth of 900 ft and no increses was observed with a fracture length of 1000 ft; again the figure presents a none linear increments in production with fracture length.

On the other hand, the cumulative water production for the well with no fracture is 4948 bbl compared with 7660, 9283, 10905, 11486 and 11790 bbl with fracture half length of 300,b500, 700, 900 and 1000 ft respectively as presented through Fig. 10. The dailly water rate also increses with fracture lengh as observed through Fig. 9; therefore, it is concluded that the long fracture is not the best one and the reasnable fracture length is of 700 to 900 ft to achieve the best gas production and the recovery factor was reached 3.0% and more instead of 0.82 %.

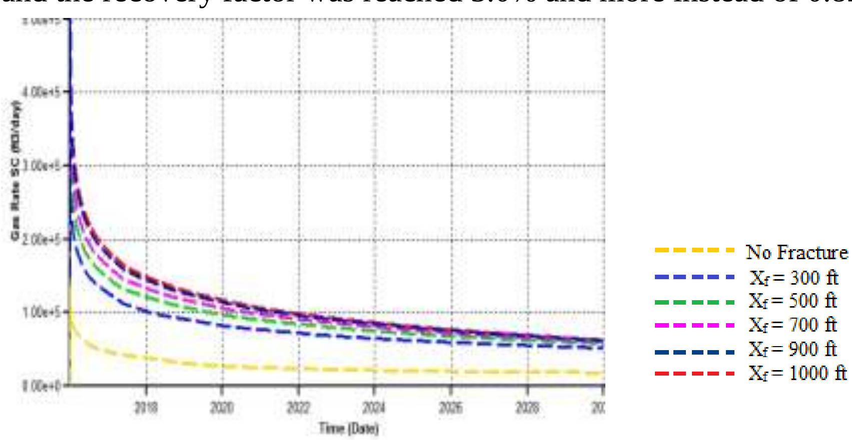

Fig 7: Effect of Fracture Half Length in The Daily Gas Production rate, (FCD = 1)

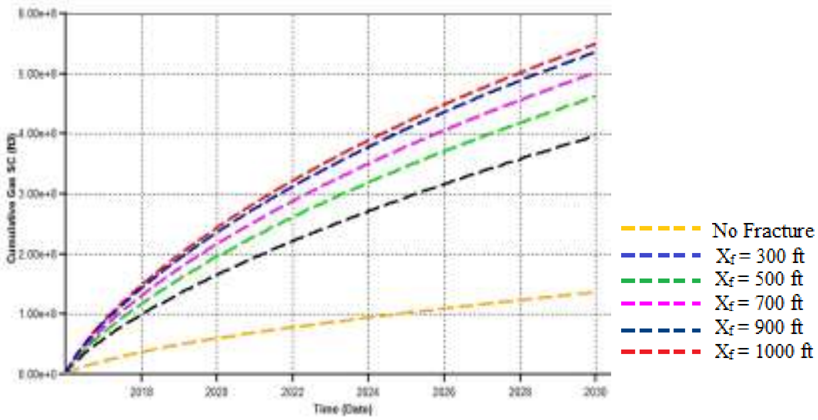

Fig 8: Effect of Fracture Half Length in The Cumulative Gas Production (FCD =1)

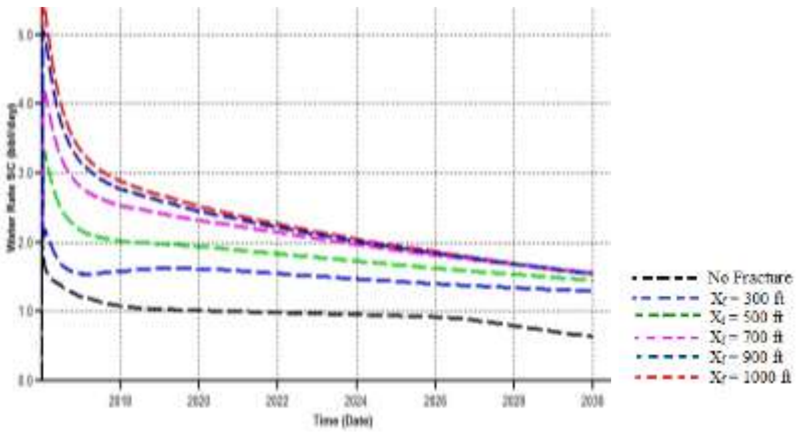

Fig. 9 The Effect of Fracture Half Length in Water Production Rate (FCD =1)

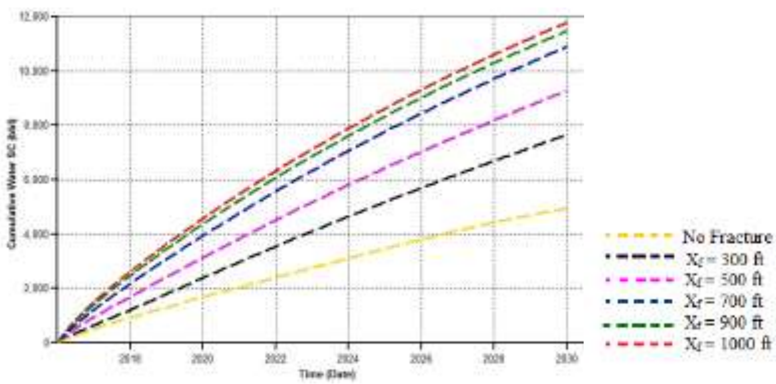

Fig 10: Effect of Fracture Half Length in Cumulative Water Production (FCD =1)

The Effect of Fracture Conductivity

The dialy gas and water production for 14 years simulation period were presented through Fig. 11 and Fig. 12 recpectively for dimensionless conductivities of 1, 2, 3, 5 and 10. The figures

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show that the increses in the dimensionless conductivities has a little effect on the gas production rate, and the effect on water production rate is bigger. The dimenssionless conductivety (FCD) depends on the fracture permeability which is depends on the proppant size and the type; any increses in FCD requiere an incresess in the total cost due to the requiered proppant quality; therfore, it is better to work with FCD of 1 to 2 for productivity enhancments.

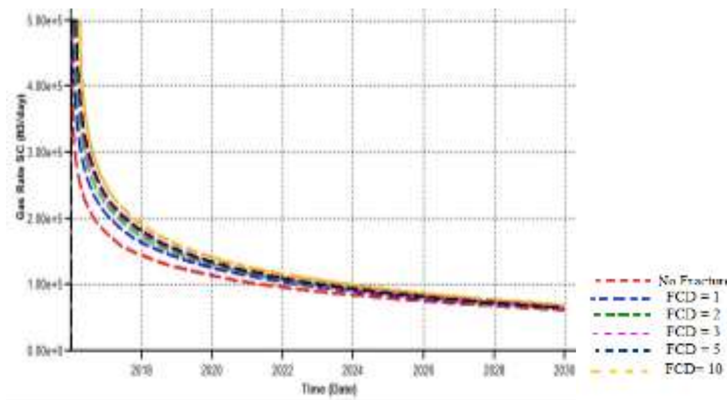

Fig. 11 The Effect of Dimensionless Conductivity in Gas Production Rate (X_f =900 ft)

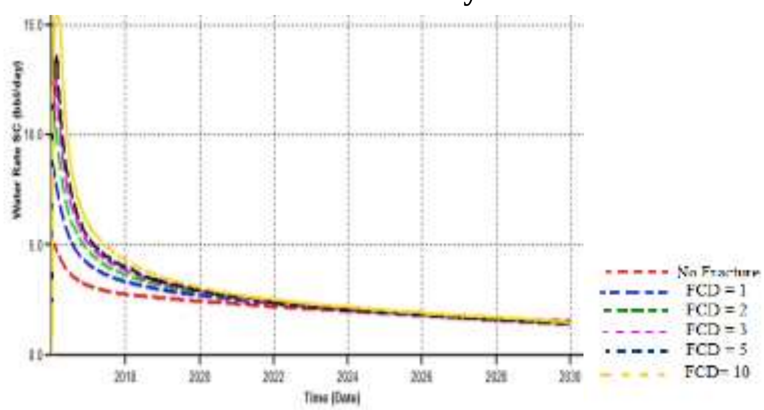

Fig. 12 Effect of Dimensionless Conductivity in Water Production Rate (X_f =900 ft)

CONCLUSION

This study addressed the effect of fracture length and conductivity on well production for well Hosan-1 in Block 8 in the eastern central of Sudan.

For the well under study, the fracture half-length is strongly affect the fluid production in the early production time. A fracture length of 700 and 900 ft is the optimum length to achieve good gas production; length less than 700 ft can case production restriction; while an unfavorable job can be achieved with length greater than 900 ft due to water production.

The recommended dimensionless fracture conductivity (FCD) for this well is 1.0 to 2.0 to avoid massive water production.

The recommended fracture half-length and dimensionless conductivity were selected based only on fluid production, future cost calculations and optimization based Net Present Value are required.

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