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Optimization of Field Development Scheduling, East Unity Oil Field, Sudan

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Abstract: In order to improve the reservoir performance in East Unity oil field Sudan, the studies focused on characterization, modeling and simulation of the actual performance and future development. A model was constructed using a three-phase, three dimensional, black oil simulator (ECLIPSE). In this study a data from East Unity oil field Sudan started production at July 1999 was used to perform the optimal oil rate and designing the best location of the new operating wells. Cumulative oil production, oil production rate, Water cut and recovery factor were used as key criteria to see if adding new wells in the area under study are economic risk.

Key words: Reservoir Simulation, Production Profile, Validity of the Model, Well Placement

INTRODUCTION

The main task of a reservoir engineer is to develop a scheme to produce as much hydrocarbon as possible within economic and physical limits. The solution of this kind of problem encompasses two main entities: the field production system and the geological reservoir properties. Each of these entities presents a wide set of decision variables and the choice of their values is an optimization problem. In view of the large number of decision variables it is infeasible to try to enumerate all possible combinations. Analysis tools encoded in computer programs can spend hours or days of processing for a single run, depending on their sophistication and features. Also, it can be costly to prepare the input data if many hypotheses are going to be considered and if it is desirable to allow the parameters to vary. A typical reservoir development problem involves many variables that affect the operational schedule involved in its management. These variables are usually used as input to a reservoir simulator that generates a forecast of the production profile. Using this forecast, the production engineer has to consider several hypotheses to achieve the best strategy for the field development problem. Also, each hypothesis can generate other ones and so, the overall process is one of generating a hypothesis tree.

Optimization of oil and gas reservoir development requires integration of quantitative geological and geophysical analysis with appropriate flow models to assess alternative development and completion schemes and their relative economic values. It is critical to make optimal development decisions in order to obtain the maximum profit from the future oil and gas production [1].

The case study and the data that used in this paper is a Sudanese field data (Unity oil field) and the Sudanese oil fields are new, was never subjected for study or publication before, all the past work in this field is for the companies that working in the area and all (are) confidential which was let the data collection very difficult.

Geological Description of Reservoir: The area selected for study is East Unity oil Field, located in the Muglad basin, Sudan. The sediments of the Muglad Basin consist of a monotonous succession of sand, sandstones, shale, clay and silts [2]. Each formation is likely to contain varying amount of each facies and massive sandstone beds are rarely found. Reservoirs in Unity oil field are resulted of fluvial and lacustrine deposition. Sands formations are characterized by good porosity and mid to high permeability. Geological correlation of reservoir zones is complicated by about (five) faults [2]. The area is strongly heterogeneous even in each reservoir zone, where the oil viscosity varies. The reservoir can be divided into two productive Members.

Aradeiba Formation: Relatively thick mudstones dominated sequences potential reservoir horizons, notably in the upper part of the formation.

The thickness and field wide lateral extent of these impermeable barriers preclude any connection between the main reservoir zones. Mainly gray shale, siltstone interbedded with sand stone layers.

Bentiu Formation: Dominantly gray-white, massive sand, interbeded with thin silts and shale. Grain size of sand varied greatly with modicum pyrite and coal.

Reservoir Fluids: Oils within East Unity oil field are of medium gravity, low shrinkage and waxy [2]. Oil gravity varies from 28.9 to 36.2 API°. The oils contain

Table1: Reservoir Fluid Properties

Reservoir pressure (bar)	208.8
Bubble point pressure (bar)	7.6
Oil formation volume factor at reservoir pressure (m^3 m ^{3})	1.051
Oil formation volume factor at bubble point (m^3 m ^{3})	1.072
Stock tank oil density (kg m ^{3})	843.8
Oil viscosity at reservoir pressure (cp)	5
Oil viscosity at bubble point (cp)	3.73
Gas density at surface condition (kg m ^{3})	0.997
Density of stock tank water (kg m ^{3})	1000.9
Water formation volume factor (rm^3 sm ^{3})	1.03
Water viscosity (cp)	0.34
Water compressibility (/bar)	4.42E-5

Table2: Reservoir Properties of 3D Model

Reservoir properties	Reservoir regions					
	1	2	3	4	5	6
Reservoir average thick (m)	13.8	10.3	13.7	11.2	20	1000
Oil water contact (m)	2165	2390	2291.5	2384.3	2401.4	1000
Reservoir pressure at datum depth (bar)	209	227.6	220.9	229.8	231.5	98
Average K (K_x=K_y) (md)	935	2605	280	190	33.2	500
K_z/ K_x	0.1					
Type of oil	Oil with little dissolved gas					
Original oil in place (M^3)	29.96×10^6					

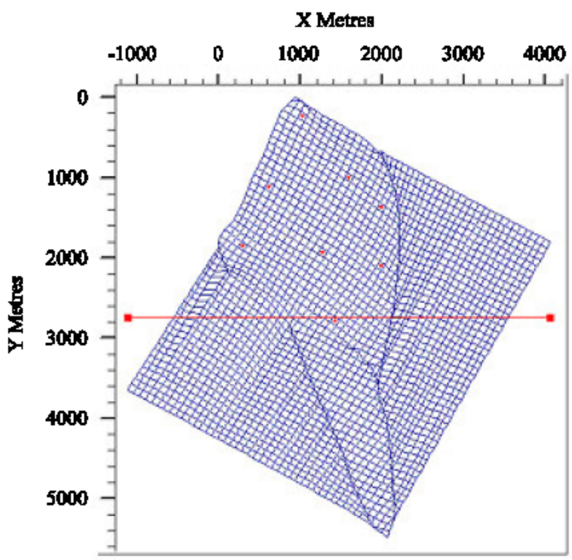


Fig. 1: East Unity 2D Grid Control

little gas and consequently the bubble point pressure and the formation volume factor are low. PVT data used in this study were summarized in Table 1.

Reservoir Sand Properties: Predictions of reservoir performance often require the availability of a reservoir simulation model in which rock properties such as porosity and permeability are specified at all block locations [3].

Reservoirs in East Unity oil field are strongly heterogeneous. Porosity and permeability were widely varied. Porosity varied from 0.50 to 0.1. Permeability in the x direction is varied from less than 10 md to more than 6000 md. Permeability in y and z directions taken to be 1.0, 0.1 respectively times the permeability in the x direction. Net thickness is varied from 0.3 m to 13 m in some blocks in Ab zone. 6 regions were subjected for this study with no active block in region 5, as well as; region 1 and 6 are the inactive top and bottom zones. Table 2 summarized the reservoir sand properties for all the regions.

Well Data: Additional well information required for the model such as the perforations, hole size, Production and injection data, were defined separately for the wells. The completion intervals in the model were checked to ensure that they did not make well connection in void grid blocks, or in no-flow zones.

Grid Selection: 3D reservoir model was constructed. The Reservoir model consists of 51744 [X (i) $\times$ Y (j) $\times$ Z (k) = 49 $\times$ 44 $\times$ 24]. Figure 1 shows the 2D grid for the area under study.

Validation of Reservoir Model: The goal of a numerical-model study is the prediction of reservoir performance in more detail and with more accuracy than is possible with simple techniques such as extrapolation. It is intuitively evident that for a model to

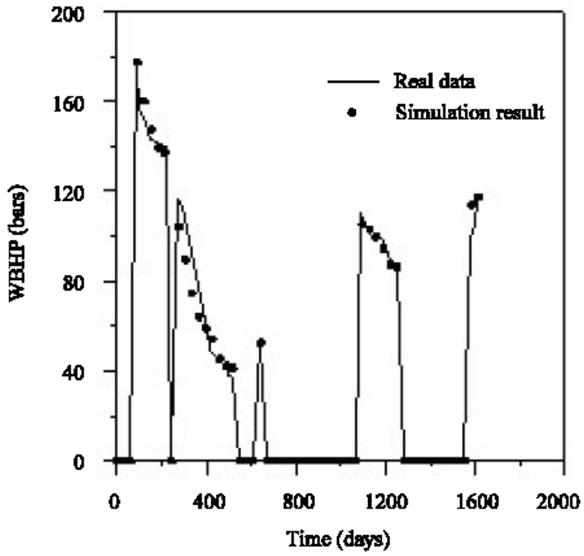


Fig. 2: Well Un10 BHP, Real Data and Simulation Results

behave like the reservoir it must be conceptually similar to the reservoir. Significant differences between the data defining the reservoir in the numerical model and the actual values of the parameters governing the reservoir performance will cause correspondingly significant errors in the simulation.

The most useful-and usually the only available-way to test the model, is to simulate the past performance of the reservoir and compare the simulation with actual historical performance. In the case of East Unity sandstone reservoir models, this was done with the aim to demonstrate an adequate match in terms of water cut development and overall field recovery. The key criteria used for comparing the reservoir past performance and detailed reservoir simulator results, were pressure, water cut, cumulative oil and liquid production, field oil and liquid production rate.

Reservoir Pressure: Reservoir pressure is probably the most important type of data used to monitor reservoir conditions, obtain reservoir descriptions, develop recovery schemes and forecast reservoir performance [4]. The changes in the reservoir pressure due to alteration of the production conditions are characteristic of reservoir properties themselves. Therefore, the reservoir properties can be inferred by matching the pressure response to a reservoir model. The inferred reservoir model can then be used for future reservoir management [5].

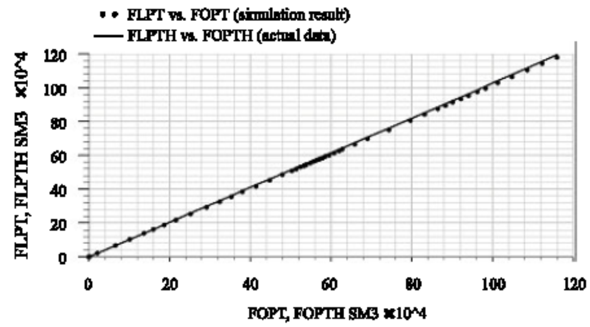
The actual well bottom hole pressure is calculated from the available historical data for dynamic fluid level and casing pressure using the equation [6]:

BHP = Casing Pressure + Depth of Liquid Column × Average Gradient of Liquid

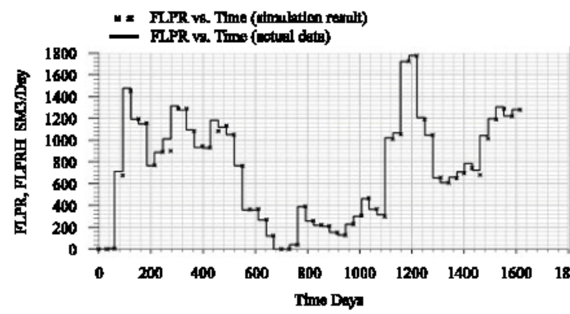
Where:

BHP = Bottom Hole Pressure, psi

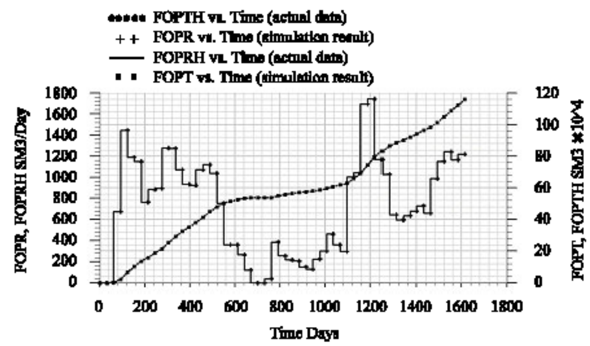
Depth of Liquid Column = (Mid Perforation – DFL), ft



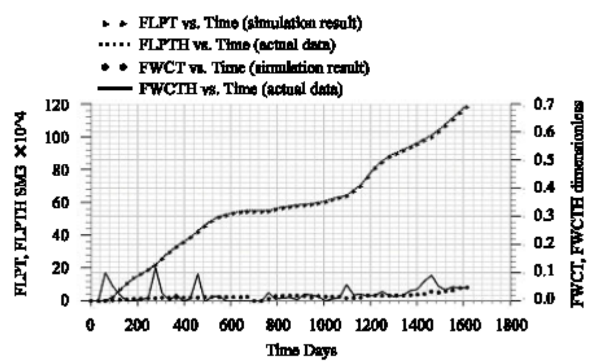
a. Cumulative Liquid Production vs. Cumulative Oil Production



b. Field Liquid Production Rate vs. Time



c. Field Oil Production Rate and Cumulative Oil Production vs. Time



d. Field Cumulative Liquid Production and Water Cut vs. Time

Fig. 3a-d: Comparison Between Simulation Result and Past Performance Data

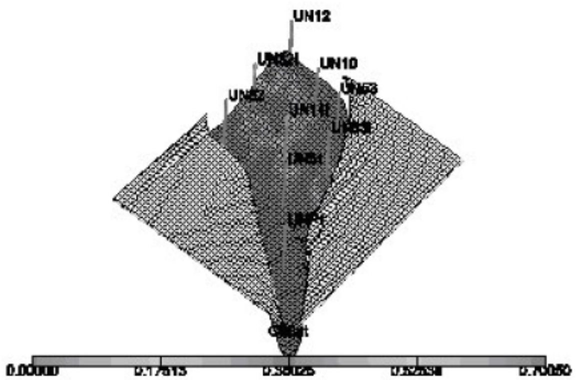
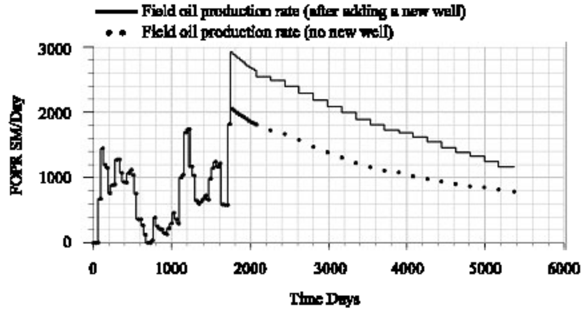


Fig. 4: The Location of the New Well Unp1 in Ab Zone

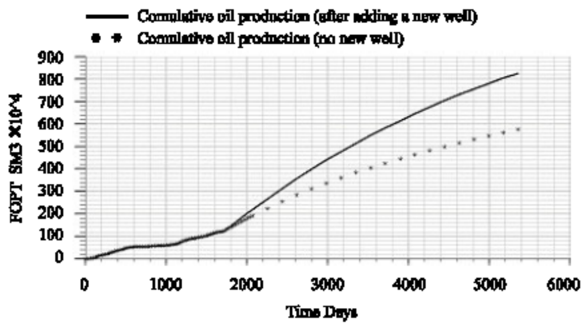
DFL = Dynamic Fluid Level, ft
Oil Gradient = 0.32 per foot
Water Gradient = 0.45 per foot
The past performance BHP match for 4 wells of all the 8 wells in East Unity oil field was done to compared with simulation result.
Figure2 shows the match between BHP past performance and simulated BHP for well UN10.

Production: Matching historical WOR's, GOR's [1] is usually the best way to confirm the validity of estimates of effective zonation and zonal continuity. Unfortunately these data are not available for this study, so after comparing the original oil in place that resulted from the geological model with the simulation result and matching the well bottom hole pressure; the production past performance was matched with simulated production rate, cumulative production and water cut. Figure 3a-d shows the match between the past performance production and simulated production rate, cumulative production and water cut development predictions over field life.

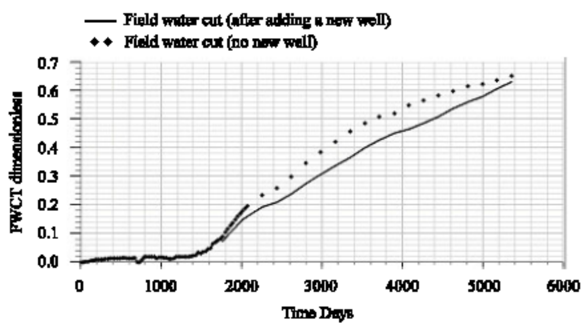
Prediction Cases: Most reservoir simulation studies require that forecasts of future performance be made under different operating conditions or with two or more equally probable reservoir conditions. Predictions give the engineer a chance to visualize the future performance of a well or of a reservoir under different operating strategies.
In this study, simulation run for 3 cases well liquid production rate. The cases chosen depend on well past performance match. Reservoir volume water injection rate controlled by the total reservoir volume injection rate of the field equals to its production voidage rate times 3.
Simulation shows; 400-500 $M^3 d^{-1}$ is suitable liquid rate for all the 5 production wells in East Unity oil field. The oil rate for all the wells is more than 380-450 $M^3 d^{-1}$ at the first 5 years and 220-230 $M^3 d^{-1}$ for the last 5 years.



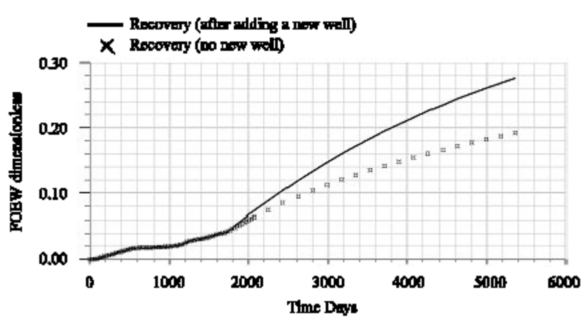
a. Oil Production Rate



b. Cumulative Oil Production



c. Water Cut



d. Recovery

Fig. 5a-d: Comparison Between the Field After Adding a New Well and Before

The cumulative oil production after these 10 years is $5.76 \times 10^6 M^3$ (36.23×10^6 bbl). Injection rate for the entire field is about 2270 $M^3 d^{-1}$ (Fig. 5).

Table3: Comparison between Oil Recovery at Several Times

Time, days	OIP 10^6 M^3	Recovery%
Before start production	29.96	0
1614	28.80	3.8
5359 (before adding new well)	24.20	19.22
5359 (with new well)	21.70	27.56

Design and Optimization of Well Pattern: Determination of the location of new wells is a complex problem that depends on reservoir and fluid properties, well and surface equipment specifications and economic criteria [7].

East Unity is already having 8 wells, 5 of it are production wells and the rest are injection wells. Simulation shows 3.8% of the original oil in place was produced during the past 4 years. Prediction performance shows after 10 years using all the 8 wells the field recovery will be 19.2%. Zone Ab (region2) is full of hydrocarbon and there is a big area have large a mount of oil with no well drilled or planned. Considering the characteristics and status of East Unity field, well pattern is chosen according to the following principles:

* All existing wells should be used in the design.
* Each well covers sand bodies as more as possible to get high oil production rate.

Simulation was run several times with several new well location design to raise the efficiency of wells and to reduce the numbers of the new development wells. The result is: only one well is needed in the area specified above (Fig. 4 shows the location of the new well UNP1). Simulation showed drill this new well in this area at the beginning of the proposed 10 years to produce from Ab zone; will lead to 27.5% field oil recovery. In other words; this new well will produce in 10 years production time, 8.34% of the in place of oil with oil rate more than 900 M^3 d^{1}. (Table 3). Also this new well will decrease the field water cut and increase the field oil rate and consequently cumulative oil production

Figure 5a-d shows the comparison between oil production rate, cumulative oil production, water cut and field recovery after adding the new well and before.

CONCLUSION

The major conclusions can be drawn as follows:

* Reservoir simulation is an effective tool in analyzing several production forecast for East Unity oil field.
* Due to low gas-oil ratio and not enough reservoir aquifer, artificial lift is needed in this field.
* Oil reserve in East unity oil field is about (29.96×10^6) m^3.
* Production wells open for liquid rates 400-500 m^3 d^{1}; oil rate can be more than 380-450 m^3 d^1.
* Layer Ab has large a mount of oil only 5 production wells open in it is uneconomic.
* Simulation showed add only one new well is economically enough to produce from Ab.
* Add a new well to produce from Ab will increase oil recovery in the field by 43.4%.

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