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Production Optimization in the Duke Field Using the IPM Suite

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Abstract

This project focuses on building a reservoir sub-sea network model for a condensate field in the gulf of Guinea, the Duke Field. It integrates the five developed Duke reservoirs, development wells and subsea network using the Petroleum Experts' Integrated Production Model suite of software, (IPM) which is widely used in the E&P industry especially for integrated forecasting, surveillance and production system optimization that require integration of surface and subsurface models.

Following the acquisition and quality control of data from other teams working on the Duke Field, a network model which integrates the five Duke reservoirs, their associated wells and subsea network up to the production separator was built. The model was initialized and used to predict full field performance under different scenarios.

Finally, a water injection allocation sensitivity study was performed and the results were analyzed both technically and economically. From the technical point of view, the option to reallocate 10 kbwpd from reservoir U to reservoir P-upper North and another 10 kbwpd from Reservoir ST to reservoir Q-Lower brought about the optimum recovery. This was also supported by a simple economic analysis. It was then recommended that additional water injectors be drilled in P-Upper North and Q-Lower to unlock an additional 8.4 MMSTB of reserves resulting from higher sweep efficiencies and better pressure maintenance.

Introduction

Duke Reservoirs

The Duke Field is located offshore the Niger Delta in Nigeria. The reservoirs in DUKE are deepwater fans of distal turbidite origin, deposited in submarine channels and lobes. **Trapping** in DUKE Central comes from a **combined structural / stratigraphical** mechanism (four way dip anticline) whilst in DUKE East trapping is partly stratigraphic to the West.

There are **five major accumulations** or reservoirs in the Duke Field which have been identified by initial free water levels, (FWL), pressure trends and fluid properties. They are Reservoirs; P, Q, R, ST and U as shown in figure 2 below.

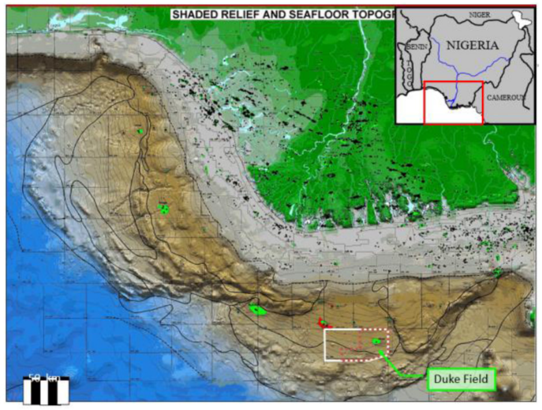

Figure 1—Location of the Duke Field offshore Nigeria

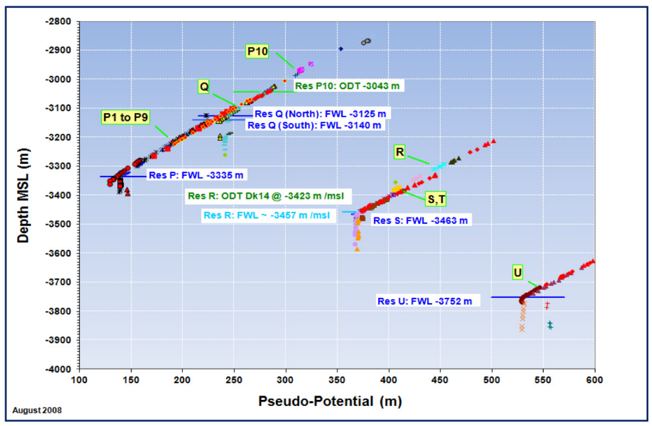

Figure 2—Initial Pseudo-Potential Plot showing the five Duke Reservoirs

Hypothesis

The general material balance equation for a hydrocarbon reservoir is shown below;

$$N\left\{(B_t - B_{ti}) + mB_{ti}\frac{(B_g - B_{gi})}{B_{gi}} + (1+m)B_{ti}\frac{(C_w S_{wi} + C_f)}{(1 - S_{wi})}\Delta P\right\} + W_e = N_p * B_t + \left(R_p - R_{soi}\right) * B_g + B_w W_p \quad 1$$

The terms on the right hand side account for the cumulative production (oil, gas and water), while those on the left provide the energy required for production in form of liquid expansion, gas cap expansion, pore volume contraction and connate water expansion and aquifer influx.

The material balance suite, MBAL uses the above principle to match the historical pressures by running production simulations using the actual production history and then it generates average tank pressures and saturations based on the results of the simulation. Parameters which are uncertain, such as the initial oil in place, rock compressibility and aquifer parameters can be regressed upon to improve the match. To be acceptable, the result of the regression must be realistic considering other information such as geology and geophysics. Following attainment of a suitable match, the model can now be used for production prediction and as an input in the network model, GAP.

The performance of any water flooding scheme is governed by several factors which are lumped into equation 2 below.

$$Recovery\ Factor, RF = E_D E_A E_V \quad 2$$

$$Displacement\ Efficiency, E_D = \frac{Volume\ of\ Oil\ at\ Start\ of\ Flood - Remaining\ Oil\ Volume}{Volume\ of\ Oil\ at\ Start\ of\ Flood} \quad 3$$

From equation 2, it can be seen that the overall recovery factor, RF is a function three key parameters: the displacement efficiency, E_D, the areal sweep efficiency, E_A, and the vertical sweep efficiency, E_V. The displacement efficiency (equation 3) is the fraction of movable oil recovered from the swept zone. In the Duke field, E_D obtained from core flooding ranged from 50-65% of the initial oil in place. This coupled with other factors made the development team of the Duke field to select waterflooding as the preferred option. The areal sweep efficiency, E_A, is the fraction of the area enclosed by a pattern which is contacted by the advancing floodfront. It is affected by the mobility ratio, M, the flood pattern and the cumulative water injected, W_{inj}. Equation 4 shows the mobility ratio as a function of the relative permeabilities and viscosity ratios. The mobility ratio for the flooding in the Duke reservoirs ranged from 0.2 to 0.4 which is rather preferred.

$$M = \frac{Mobility\ of\ the\ displacing\ fluid}{Mobility\ of\ the\ displaced\ fluid} = \frac{K_{rw}\mu_o}{K_{ro}\mu_w} \qquad 4$$

In the Duke Field, the injection pattern selected is the pheripheral system with the injectors completed some few feets below the oil water contact (OWC). It is anticipated that the as production preceeds, the OWC would rise more or less uniformly, displacing oil in the process.

$$VRR = \frac{B_{winj}W_{inj} + B_{ginj}G_{inj}}{B_oN_p + B_wW_p + B_g(R_p - R_s)N_p} \qquad 5$$

It is common practice in the petroleum industry to speak of the performance of a waterflooding scheme in terms of the cumulative voidage replacement ratio, VRR. The VRR refers to the extent of replacement of the produced reservoir oil, gas and water with comesurate injected fluids (oil and gas) as presented in equation 5. For the Duke field, the target is to keep the VRR as close as possible to 1.0, that is to replace all produced reservoir fluids. This is achieved by water injection.

Methodology

The methodology which has been adopted for this project is a four-step process as shown in the figure below. Each step is briefly introduced and subsequently applied to the Duke reservoirs in the proceeding sections.

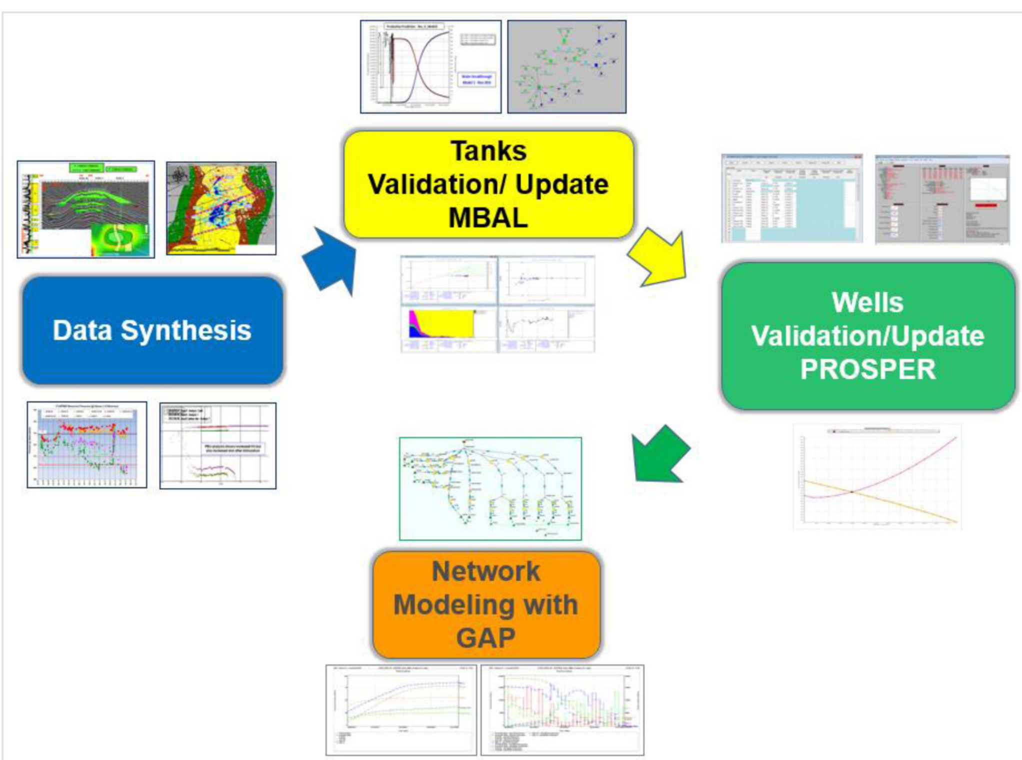

Figure 3—Workflow Chart

Data Synthesis

This dealt with analysis of both static (geology, geophysics) and dynamic data (static pressure history, production/injection history, well tests, 4D seismic..) for each Duke reservoir with a view to properly identify flow units and understand compartmentalization/ connectivity issues in each reservoir as this is vital for representative MBAL modeling.

Review and Update of Existing MBAL and PROSPER Models

Here, quality check was performed on the existing MBAL models by integration of the information derived from the data synthesis in order to ensure model representativity. Quality check was also performed on the Prosper models and they were then updated to match current well test data.

Modeling with GAP

At this stage, integration of the entire production system using GAP's platform was done and it linked the Duke reservoirs (MBAL Models) with their wells (PROSPER) and the sub-surface network up to the separator on the FPSO. This was done by coupling the MBAL models of reservoirs P-Upper, Q-lower, R, ST and U and their corresponding producers and the subsea network up to the Duke FPSO as shown in Figure 4 below. In the network solving mode, the chokes are calibrated to ensure that the wells produce at the current rates. Following attainment of representative rates, the production prediction is carried out first by assuming 100% Voidage replacement by water for all the tanks except reservoir R where the Voidage replacement is by gas injection. Next, sensitivity on water injection allocation is performed and then the results are analyzed in terms of increased recovery and also economics.

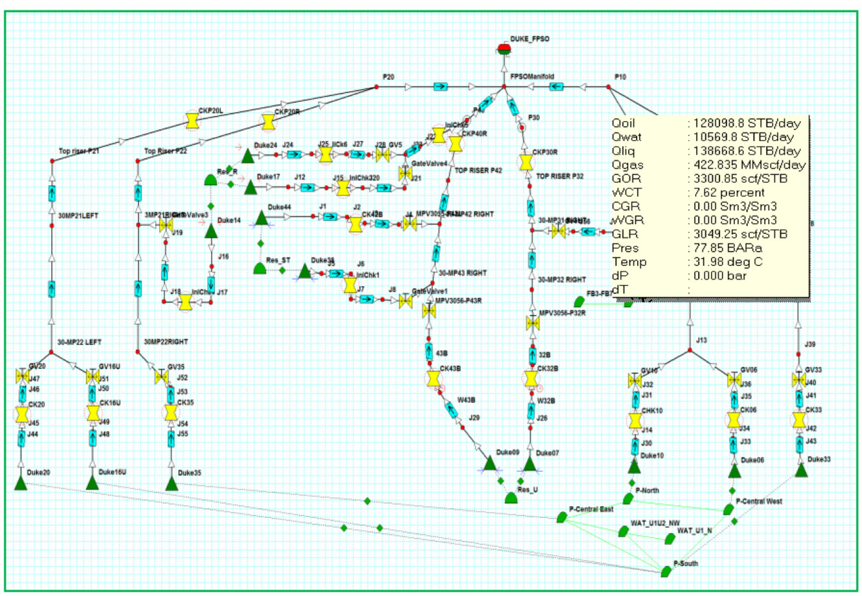

Figure 4—Network Model Layout for the Duke Field

Production and Injection Optimization

The main energy for production in the Duke Field is from water injection in four of the Duke reservoirs and miscible gas injection in the remaining one. The essence of this secondary recovery is to:

- Maintain the reservoir pressure above the saturation pressure thus ensuring that the gas remains in solution in the reservoir, thus preserving the energy for production and also maintaining the productivity of the wells by minimizing two phase flow around the wells as much as possible
- Ensuring better sweep efficiency, thus resulting in increased recovery,
- Gas management strategy to minimize flaring.

Production Optimization by Water Injection Allocation Sensitivity

The maximum injection capacity of the Duke FPSO is 301,700bwpd. There are currently no plans to upgrade this in the near future. The interest of this study is to optimally allocate the available 301,700 bwpd of injection water to the reservoirs so as to improve the recovery while maintaining the reservoir pressures above their respective saturation pressures and delaying water breakthrough and water cut evolution. Tables 1 and 2 below show the water injection allocation for each case.

Table 1—Water Injection Allocation *-Increased, *-Reduced Injection and *-Modified Split compared to base case)

	Water Injection Allocation, kbwpd						
Reservoir	Base Case	Case I	Case II	Case III	Case IV	Case V	Case VI
P-Upper	140.2	150.2	140.2	150.2	160.2	140.2	160.2
Q-Lower	12.3	12.3	12.3	22.3	12.3	12.3	12.3
ST	87.5	87.5	97.5	77.5	77.5	87.5	77.5
U	61.7	51.7	51.7	51.7	51.7	61.7	51.7
Total	301.7	301.7	301.7	301.7	301.7	301.7	301.7

Table 2—P-Upper Water Injection Allocation Breakdown

	P-Upper Water Injection Allocation Breakdown, kbwpd						
Tanks	Base Case	Case I	Case II	Case III	Case IV	Case V	Case VI
P-North	70.2	80.0	80.2	80.2	90.2	90.2	90.2
P-South	70.0	70.0	70.0	70.0	70.0	50.0	70.0
P-Upper Total	140.2	150.2	140.2	150.2	160.2	140.2	160.2

Results and Discussion

The result of the sensitivity on injection water allocation shows that Case II which allocates more water injection to reservoir ST gives the highest expected ultimate recovery, EUR. However, comparing Case II with Case III which allocates water injection from Reservoir U and ST to Reservoir P-upper North and Q-Lower, it can be seen from the simple economic analysis that the present value at 2013, PV from case III is the highest as the recovery from Case III is obtained faster than for Case II. **Hence Case III is the optimal case**. This is in line with what is currently being observed, as the injector on P-Upper North is currently limited by the fracture pressure of the rock. It would be interesting to drill an additional water injector in P-Upper North or re-enter Duke-15 with a side track to improve the injectivity index of this well to ensure better sweep efficiency of the northern and central region. Also, the Q-Lower reservoir needs an additional water injector to ensure better pressure maintenance and reservoir sweep.

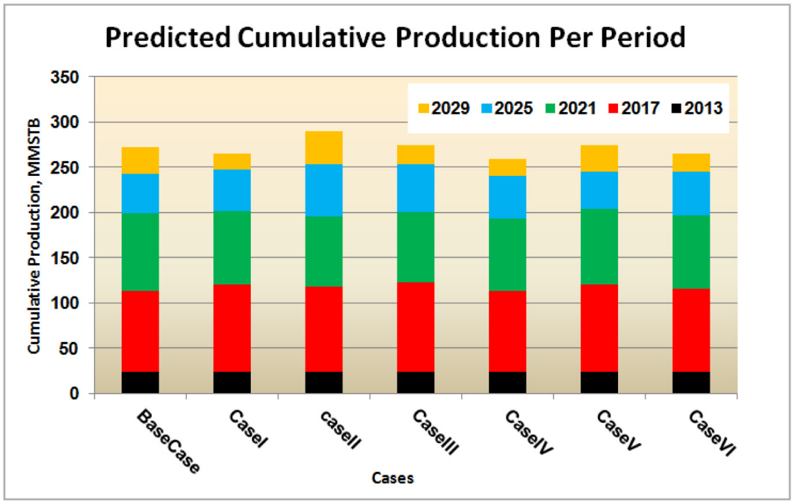

Figure 5—Predicted Cumulative Production per Period per Case

Economic Analysis

The results of the water injection allocation sensitivity show a rather close array of estimated ultimate recoveries. In order to select the optimal case, a simple economic analysis is performed on the production profile for the different cases and the one that yields the highest present value (discounted value of the cash flows arising from the yearly predictions), is ranked as the optimal case.

The table below shows the assumed parameters used for the economic analysis.

Table 3—Assumed Economic Parameters

Assumed Economic Parameters	
Crude Price, $/bbl	30
Interest Rate	15%
Inflation Rate	7%

Table 4—Impact of Injection Water Allocation on Cumulative Production (*-sum of the P-Upper tanks)

Estimated Ultimate Recovery, EUR, MMSTB							
Tanks	Base Case	Case I	Case II	Case III	Case IV	Case V	Case VI
P-North	25.1	25.5	27.1	26.0	28.7	25.9	23.4
P-Cen. West	33.4	36.8	36.5	38.7	32.0	36.3	35.0
P-Cen. East	25.7	24.6	27.6	25.6	25.1	26.5	27.9
P-South	57.7	56.2	59.0	56.7	57.7	57.7	57.7
P-Upper*	141.9	143.1	150.2	147.0	143.6	146.4	144.1
Q-Lower	17.5	12.4	18.5	21.0	13.9	17.8	16.0
Res. R	116.3	116.2	114.8	112.9	112.2	118.1	115.6
Res. ST	82.1	80.7	81.8	82.9	81.8	82.5	81.3
Res. U	83.9	82.0	85.2	86.3	83.9	84.5	81.8
EUR, MMSTB	441.7	434.4	450.5	450.1	435.4	449.3	438.8
PV @ 2013, B$	2.943	2.994	2.985	3.037	2.889	2.966	2.980

Conclusion and Recommendations

The MBAL models for the Duke reservoirs have been updated following dynamic data synthesis, production predictions have also been carried out and the results which have been obtained are comparable to those obtained using the 3D simulator, Eclipse. Also, well models have been updated. The network model has been built by integrating the updated MBAL models for the Duke reservoirs, their corresponding producers and the subsea network up to the FPSO.

Production/ Injection optimization has been performed and an optimal case has been obtained which reallocates injection water from Reservoir U and ST to reservoir P-Upper North and Reservoir Q-Lower in order to unlock 8.4MMSTB of additional reserves by better pressure maintenance and sweep.

Following the results of the optimization studies, it is recommended that an additional water injector each be drilled in P-Upper north and Q-Lower in order to effectively maintain pressures and to obtain a better sweep.

Due to the assumptions and limitations of MBAL, the results are more qualitative than quantitative. Hence, it is recommended that a 3D simulator which accounts for the heterogeneities in turbidite reservoirs is used in place of MBAL to carry out this study in order to compare the results quantitatively.

In conclusion, network modeling with Integrated Production Modeling suite, GAP is a rather simple approach that yields results which are useful for the prediction and optimization of full field performance.

Nomenclature

3D	= *Three Dimensions*
4D	= *Four Dimensions (Time Lapse)*
Bgi, Bg	= *Initial and current formation volume factor, rbbls/scf*
Bging	= *FVF for gas injected, bbl/SCF*
Bo	= *Single phase oil formation volume factor, rbbls/stb*
Bti, Bt	= *Initial and current Phase oil formation Volume factor, rbbls/stb*
Bw	= *Water formation volume factor, rbbls/stbw*
Bwinj	= *FVF water injected, bbl/STB*
Cf	= *Pore volume compressibility, Psi-1*
Cw	= *Compressibility of formation water, psi-1*
DeltaP	= *Current pressure drop, Psi*
E_A	= *Areal Displacement Efficiency*
E_D	= *Microscopic Displacement Efficiency*
EUR	= *Estimated Ultimate Recovery*
E_V	= *Vertical Displacement Efficiency*
FPSO	= *Floating, Producing, Storage and Offloading*
FW	= *Reservoir Water Cut*
GAP	= *Network Modeling Suite of Software by Petroleum Experts*
Ging	= *Cumulative gas injected, MMSCF*
GOR	= *Gas Oil Ratio*
Gp	= *Cumulative gas produced, MMSCF,*
GSR	= *Geosciences and Reservoir*
H	= *Net thickness contributing to production, ft*
IPM	= *Integrated Production Modeling*
K	= *Effective permeability to oil at the sand face, md*
kro	= *End-point relative permeability to oil*
krw	= *End-point water relative permeability*
m	= *Ratio of initial reservoir gas cap to reservoir oil in place, dimensionless*

MBAL	= *Material Balance Suite of Software by Petroleum Experts*
MMSTB	= *Million Stock Tank Barrels of Oil*
N	= *Original oil in Place, STOIIP, STB*
Np	= *Cumulative Oil Production, MMSTB*
PI	= *Productivity Index, stb/day/psi*
PROSPER	= *Well modeling Suite by Petroleum Experts, PETEX*
PV	= *Present Value, $*
PVT	= *Pressure Volume Temperature (Fluid Properties)*
Qginj.	= *Gas Injection Rate, MMSCF/D*
Qwinj.	= *Water Injection Rate, Kbwpd*
Rbbls	= *Reservoir Barrels*
Re	= *Reservoir radius, ft*
RF	= *Recovery Factor*
Rp	= *Producing Gas oil ratio, scf/stb*
Rs	= *Solution gas oil ratio, scf/stb*
Rsoi	= *Initial solution gas oil ratio, scf/stb*
Rw	= *Wellbore radius, ft*
S	= *Skin, dimensionless*
STB	= *Stock Tank Barrels*
STOOIP	= *Stock tank original oil in place, MMSTB*
Swi	= *Connate water saturation, %*
U	= *Oil Viscosity, cp*
VRR	= *Voidage Replacement Ratio*
We	= *Cumulative Water influx, rbbls*
Winj	= *Cumulative water injected, MMSTB*
Wp	= *Cumulative water Production, Stb*

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