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PRIMARY RECOVERY FACTOR CORRELATIONS FOR THIN OIL RIMS WITH LARGE GAS CAPS

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Abstract

Simple correlations have been developed for evaluating the primary recovery factor for thin oil rims with large gas caps prior to detailed reservoir simulation. The correlations are based on oil recovery factor estimates obtained from three dimensional, three-phase black oil reservoir simulation models for saturated reservoirs with overlying gas caps at their initial state, which capture spatial effects and the dynamics of oil rim and gas cap production. Dominant factors (oil rim thickness, horizontal permeability, gas cap size, oil viscosity, gas cap offtake, aquifer strength and reservoir dip) that affect oil rim and gas cap production were obtained using foldover Plackett-Burman screening designs. Response Surface Models (correlations) were then developed using Box-Behnken experimental design to obtain oil recovery estimates under conventional development and concurrent development at gas cap production up to 15% of the free gas initially in Place per annum. The oil recovery factor correlations for conventional development were validated using actual oil rim field production data while the models for concurrent development were validated using history-matched reservoir simulation results. The oil recovery factor estimates from correlations presented in this study are in good agreement with the field data with a mean average percentage error of 2.5% for oil rims developed conventionally and a mean average percentage error of 4% for oil rims and their gas caps developed concurrently. The developed correlations can be applied to reservoirs with oil columns less than 100 ft underlying large gas caps with a good degree of confidence.

Keywords: Correlations, Experimental design, Large gas caps, Recovery factor, Thin oil rim.

1. Introduction

Oil rims are reservoirs with small to medium oil columns sandwiched between an overlying gas cap and basal aquifer. Randle and Marchal [1] defined a thin oil rim as an oil zone that appears as a ring or a part of a ring around, and in communication with, a relatively large gas cap providing primary energy support.

Irrgang [2] provided case studies of thin oil column reservoirs in Australia and summarised the production methods, well performance and recovery efficiencies. The recovery efficiency of these reservoirs are particularly sensitive to horizontal permeability, vertical permeability, oil column thickness, stratigraphic dip, well spacing and oil viscosity. A correlation was developed for estimating the ultimate recovery per well, which is stated as:

$$N_{pw} = \frac{\varnothing(1 - S_{wc} - S_{or})k_h h_o^{2.5} R_{ng}^{1.5}}{\mu_{oi} B_{oi} 10^6} \tag{1}$$

The derived mathematical relationship was validated empirically for several thin oil columns in Australia.

Weber and Dronkert [3] evaluated the non-technical criteria for delineating remaining oil based on reservoir architecture. They analysed data from 29 oil rim reservoirs, in formations with fairly high vertical conductivity, wells spaced between 600 and 800 m with variation in thickness from about 15 to 50 m. No clear correlation could be established between the oil recovery factor and oil rim thickness. Based on the detailed simulation of a reservoir in the Niger Delta, recovery factors were obtained and fit to the trend of the 29 reservoirs by iteration. The estimates from the theoretical model developed under-predicted actual oil recovery factor.

Kabir et al [4] developed two simple oil recovery factor correlations based on Experimental Design for quick evaluation of thin oil rim exploitation via the proposed depletion strategy. A three-step approach was used, which entailed first screening a large number of reservoir, fluid and process variables using a 2-level Plackett-Burman design, which captured only linear effects to identify major variables, which influence oil recovery. Subsequently, variables within 95% confidence interval were selected for 3-level D-optimal design based on which, flow simulations were run, which captured the linear, non-linear effects and interactions between the variables. Response surface models were then generated using multivariate nonlinear regression by fitting a polynomial to the flow simulator runs. The correlations were tested and validated using independent experimental and published field datasets.

Olamigoke and Peacock [5] carried out an assessment of the performance of 35 oil rims developed in the Niger Delta and established based on field performance near-linear trends in oil recovery. Though individual good performance varied significantly in these oil rim reservoirs, a clear trend was established between average oil rim recovery and thickness of the oil rim for each drainage point considered. Departure from this trend is attributed to the interplay of the reservoir and production-related factors. It was observed that the conditions most favourable for optimal oil rim development include formations with minimal geological complexities, highly permeable, bearing low viscosity oil, with strong aquifer support and oil rim thickness exceeding 20 ft. Mathematical models were obtained for each development strategy using Response Surface Methodology based on the key factors identified to influence oil recovery. Subsequently, oil recovery forecasts were obtained over a specified range of subsurface conditions and production constraints. The correlations were presented for ultimate oil recovery per good estimates under conventional recovery and concurrent oil and gas recovery (5% FGIIP and 10% FGIIP produced per annum respectively). The correlations developed were also presented in graphical form to assess the effect of variation in permeability, oil gravity and other parameters on ultimate oil recovery per well. Thus, an oil recovery range can be obtained for thin oil rims as a function of parameter uncertainty. The estimates for oil recovery per well all are based on horizontal good development.

Obah et al. [6] developed three models based on decline curve analysis for forecasting oil production from oil rim reservoirs. Factors with significant impact on oil production forecasts were identified with a variable Plackett-Burman design. Reservoir simulation results were regressed using the least square method and then fit an exponential decline curve. Probabilistic production forecast models were generated using a Monte-Carlo simulation approach. This method enables the generation of a probabilistic range of forecasts that can then be used in decision making. Arjun and Prasad [7] used a feed-forward back propagation artificial neural network model to find the most economical scenario to maximize ultimate oil recovery and forecast oil production performance for reservoirs underwater injection. Arinkoola and Ogbe [8] analysed three families of screening designs and four response surface modelling methods to quantify uncertainty in production forecasts for reservoir management. Box-Behnken method was found adequate for determining production forecasts for a Niger Delta oil reservoir exhibiting the least estimation error. Davarpanah and Mirshekari [9] investigated the migration pattern in the gas cap expansion reservoir along the oil-gas interface using a one-dimensional displacement test. A logarithmic relationship was found between the morphological factors defining the oil-gas interface and displacement velocity. Zifei et al. [10] presented charts, which provide guidance for concurrent production involving development scenarios involving depletion, barrier water injection and barrier plus pattern water injection via by reservoir numerical simulation. In their work, the oil and gas recovery was related to the injection-production ratio.

Existing oil recovery forecasting models for thin oil rims overlain with gas caps are limited due to the narrow range of oil rim parameters over, which the models are applicable. In addition, most of the models require a transformation of input variables thus making them cumbersome to use. Simple mathematical models developed based on experimental design and reservoir simulation are presented in this study for preliminary evaluation of technical feasibility of oil rim development either conventional or concurrent production from the oil rim and gas cap prior to extensive reservoir modelling and simulation.

2. Development of Recovery Factor Correlations

The workflow for developing the recovery factor correlations is presented in this section. A base three dimensional, three-phase black oil reservoir simulation model for saturated reservoirs with overlying gas caps at their initial state was built. The model captures spatial effects and production near the contacts while anisotropy is accounted for via the ratio of vertical to horizontal permeability, which influences oil rim recovery. The dominant factors that influence oil rim and gas cap production were screened from eleven parameters identified from previous studies by Olamigoke and Peacock [5] and Cosmos and Fatoke [11] using Plackett-Burman foldover screening designs. The screening designs set the number of reservoir simulation runs required for capturing the main and interaction effects influencing oil recovery factor from the simulation models. Response Surface Models (correlations) were then developed by fitting non-linear regression models to oil recovery estimates obtained from reservoir simulation runs determined using Box-Behnken experimental design for conventional development and concurrent development at gas cap production of both 5% and 10% of free gas initially in place per annum.

The base reservoir simulation model used in the experimental design is described briefly in *Appendix A*.

2.1. Definition of potential key oil rim development parameters

A combination of subsurface and operational parameters was assessed to identify the key parameters necessary for developing response surface models (correlations), which would be useful in estimating oil recovery from oil rims either under conventional or concurrent development. The parameters and their ranges are given in Table 1.

Table 1. Oil rim parameters and ranges.

	***L*(-1)**	***M*(0)**	***H*(1)**
Oil rim thickness, h_o (ft)	20	60	100
Horizontal permeability, k_h (millidarcies)	100	1300	2500
Oil viscosity, μ_o (centipoises)	0.2	1.2	2.2
m-factor, m	1	5	9
Dimensionless aquifer radius, r_{eD}	2	6	10
Perforation position, *perfpos*	0.25	0.5	0.75
Permeability anisotropy, k_v/k_h	0.005	0.25	0.495
Gas cap offtake, q_{gi} (%)	0	7.5	15
Oil rim offtake, q_{oi} (%)	10	15	20
Reservoir dip, θ (degrees)	1	8	15
Gas oil ratio constraint, multiples of initial Gas Oil Ratio, GOR	3	10	17

2.2. Generic reservoir simulation

Each reservoir simulation model was built to honour the properties for each simulation run. Each model has a grid size length of 4,000 ft (1,220 m) in the *y*-direction while the length in the *x*-direction is dependent on the dip angle, oil column thickness and the gas cap size. The aquifer was modelled analytically using the finite Carter Tracy water influx model.

Constant rock properties (porosity and NTG) were used throughout the model. PVT properties (formation volume factors, gas-oil ratio, oil compressibility and fluid viscosities) have been calculated using published correlations by Standing [12], Glaso [13], Beggs and Robinson [14]. Gas cap production is via a dedicated gas well in each case. These reservoir simulation models have been used to investigate oil rim development under both conventional and concurrent production from the oil rim and gas cap.

2.3. Initial screening design

The foldover Plackett-Burman designs as demonstrated by Miller and Sitter [15] are very efficient for screening parameters when main effects alone are of interest. The main effects of these designs are not heavily confounded with two-factor interactions. Thus, a 24-run Foldover Plackett-Burman design was used to identify the parameters with the most influence on the development schemes from the eleven parameters listed in Table 1. Figures 1 and 2 show the pareto charts, which rank the effect of the eleven parameters for concurrent and conventional development respectively. The key parameters identified from the screening study for both development schemes are oil rim thickness, gas cap size, oil viscosity, horizontal permeability, dimension aquifer radius and reservoir dip. In addition, gas cap offtake and vertical anisotropy were identified as main effects for concurrent development while oil rim offtake was identified as the main effect for conventional development. Perforation position (or well placement) in the oil rim, oil rim offtake, and gas-oil ratio constraint accounted for only 5% of total main effects for concurrent development while vertical anisotropy, perforation position (or well placement) in the oil rim and gas-oil ratio constraint accounted for only 8% of total main effects for conventional development.

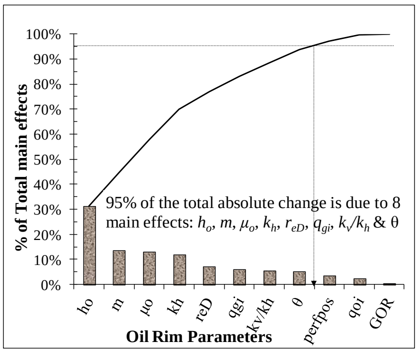

Fig. 1. Pareto chart for concurrent development.

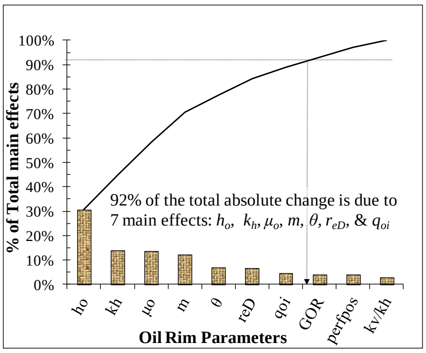

Fig. 2. Pareto chart for conventional development.

2.4. Response surface modelling (correlation development)

The Oil Recovery Factor (RF) can, therefore, be expressed as a function of the subsurface and operational parameters X_1, X_2, X_3, ..., X_k, which can be represented as follows:

$$RF = f\left(X_1, X_2, X_3, \ldots\ldots\ldots\ldots\ldots\ldots, X_k\right) \tag{2}$$

where f = response function due to x (input variables); k = number of variables.

Equation (2) can also be expressed in the form of the main linear, linear interaction effects and quadratic effects as follows:

$$RF = \beta_0 + \sum_{i=1}^{k} \beta_i X_i + \sum_{i=1}^{k} \sum_{j=2, i<j}^{k} \beta_{ij} X_i X_j + \sum_{i=1}^{k} \beta_{ii} X_i^2 \tag{3}$$

Box-Behnken designs are used in this paper for response surface modelling using the main parameters identified through the screening design, which is the basis for the oil recovery factor correlations. Three oil recovery factor correlations have been developed in this work. The first correlation, shown as Eq. (4), is a generalized oil recovery factor correlation, which is applicable to both conventional and concurrent oil and gas development using vertical wells. This correlation accommodates annual gas cap offtake from zero to 15% of the FGIIP. The second correlation, shown as Eq.

(5), gives estimates of oil recovery factory under conventional oil development only using vertical wells. The third correlation, shown as Eq. (6), is a generalized oil recovery factor correlation, which is applicable to both conventional and concurrent oil and gas development using horizontal wells.

$$\begin{aligned}RF &= 0.733 + 0.24h_o - 18.0\mu_o + 0.0058k_h + 0.6m - 0.2r_{eD} - 0.385q_{gi} \\ &+ 10.0\left(k_v/k_h\right) + 8.0\times10^{-5} h_o k_h + 2.3\times10^{-4} m k_h + 3.0\times10^{-4} r_{eD} k_h \\ &- 1.42\times10^{-4} q_{gi} k_h - 0.048 m q_{gi} - 0.02h_o^2 + 2.0\mu_o^2 - 1.2\times10^{-6} k_h^2 \\ &- 0.08m^2 + 0.05r_{eD}^2 + 0.024q_{gi}^2 - 20.0\left(k_v/k_h\right)^2\end{aligned} \tag{4}$$

$$\begin{aligned}RF &= 8 + 0.14h_o - 9.356\mu_o + 2.34\times10^{-4} k_h + 0.346m + 0.314r_{eD} \\ &- 0.738\theta - 0.0689q_{oi} + 5.692\times10^{-4} m k_h + 4.679\times10^{-4} r_{eD} k_h \\ &+ 6.465\times10^{-4} h_o \theta\end{aligned} \tag{5}$$

$$\begin{aligned}RF &= 4.8 + 0.19h_o + 3.1\times10^{-3} k_h - 0.5m + 0.4r_{eD} - 1.9\mu_o + 1.8\left(k_v/k_h\right) \\ &+ 0.1\theta + 4.87q_{gi} + 3.0\times10^{-5} h_o k_h + 0.01 m h_o + 0.01 h_o r_{eD} + 5.5 m k_h \\ &- 0.06 h_o \mu_0 - 5.5\times10^{-3} h_o q_{gi} - 3.0\times10^{-4} k_h r_{eD} - 1.3\times10^{-4} k_h q_{gi}\end{aligned} \tag{6}$$

3. Validation and Verification of Correlations

To ensure the validity and accuracy of the correlations, estimates from correlations are compared to recovery factors from three oil rim reservoirs in the UA Field, Niger Delta. The correlation for conventional development was validated using actual field production data from the oil rims while the correlation for concurrent development was validated using history-matched reservoir simulation results. The UA oil rims had thicknesses, reservoir dip, horizontal permeability, and oil gravity ranging from 25 – 45 ft (7.6 – 19.8 m), 1 – 3 degrees, 750 – 2500 md (7.4×10^{-13} – 2.47×10^{-12} m^2) and 27 – 33 API respectively. The key oil rim parameters for the three UA oil rim reservoirs are shown in Table 2.

Figure 3 shows the comparison between the oil recovery factor estimates from correlations in this current study and the actual field recovery efficiency data for UA oil rims. The oil recovery efficiency (the ratio of cumulative oil production to stock tank oil initially in place) for each oil rim was compared to the oil recovery factor estimates from the generalized correlation for vertical well conventional recovery. Figure 3 shows that the oil recovery factors are in good agreement with the field data with a mean average percentage error of 2.5%. The mean average percentage for E1, E2 and E3 oil rims is 6.0%, 1.5% and 0.14% respectively.

A comparison of the oil recovery factor estimates obtained under concurrent oil and gas production (5% FGIIP/year) as compared to results from reservoir simulation for UA oil rims is shown in Fig. 4. The oil recovery factors are in very good agreement with the field data with a mean average percentage error of 4%. The plots showing the field match of the simulation models to their respective production history data is presented in *Appendix B*.

Table 2. Test model specifications and test conditions.

	***E*1**	***E*2**	***E*3**
Oil rim thickness, h_o (ft)	25	38	45
Horizontal permeability, k_h (md)	2500	1500	750
Oil viscosity, μ_o (cp)	0.9	0.43	0.45
m-factor, *m* (dimensionless)	4.8	1.7	1.7
Dimensionless aquifer radius, r_{eD}	6	10	5
Permeability anisotropy, k_v/k_h	0.01	0.01	0.01
Reservoir dip, θ (degrees)	1	2	3

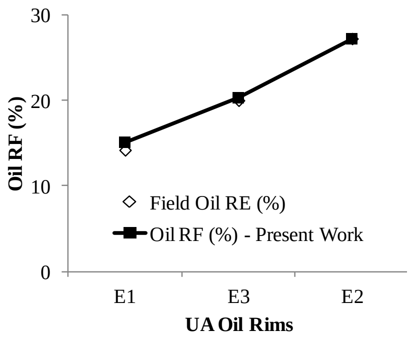

Fig. 3. Actual vs. estimated oil recovery for UA oil rims.

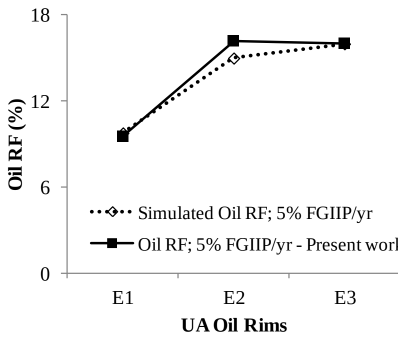

Fig. 4. Simulated vs. estimated oil recovery for UA oil rims.

4. Results and Discussion

The correlations presented in this work have been shown to provide good oil recovery estimates from oil rims in the UA field. Wider application of these correlations, comparison to Kabir's correlation and the potential for prediction of oil recovery in reservoirs produced with either vertical or horizontal are discussed in this paper.

4.1. Application to oil rims produced with vertical wells

The generalized oil recovery factor correlation for vertical wells was applied to obtain estimates of the oil recovery factor for 20 oil rims, which were produced primarily with vertical wells. The oil rim data was obtained from published papers on different oil rims around the world. These oil rims include Snapper N-1 reservoir [16], Obagi level IX [17], Soku oil rims E55X and F1X [11] and the UA oil rims used in validating the correlations.

The oil recovery factor estimates obtained using Eq. 4 have been compared to actual oil recovery efficiency for these oil rims produced with vertical wells. The standard error of the estimate is 3.53% while the regression coefficient of determination obtained is 0.86 (see Fig. 5).

4.2. Application to oil rims produced with horizontal wells

The generalized oil recovery factor correlation for horizontal wells was used to obtain oil recovery factor estimates for nine oil rims, which have been produced primarily with horizontal wells. The oil rim data was obtained from published papers on oil rim development, which include Oseberg Gamma North oil rim [18], Immortelle Sand 22 [19], Mahogany Sand 21 FBIV [20] and Gbaran D7X [21].

The oil recovery factor estimates obtained using Eq. 6 for oil rims produced with horizontal wells have been compared to actual oil recovery efficiency for each oil rim. The standard error of the estimate is 1.55% while the regression coefficient of determination obtained is 0.90 (see Fig. 6).

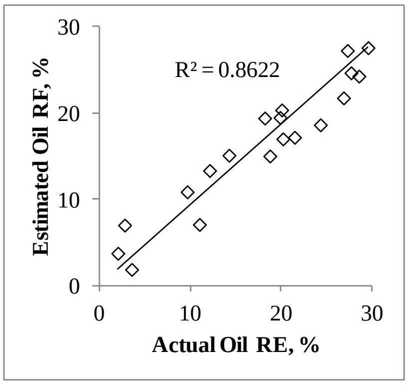

Fig. 5. Actual oil RE vs. estimated oil RF for oil rims produced with vertical wells.

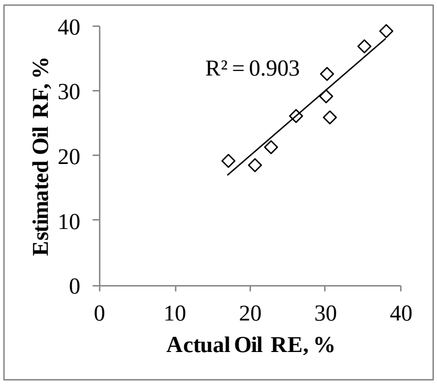

Fig. 6. Actual oil RE vs. estimated oil RF for oil rims produced with horizontal wells.

4.3. Comparison of estimates from correlation for oil rims produced with horizontal wells to estimates from Kabir's correlation

The correlation oil recovery factor estimates for oil rims produced with horizontal wells have been compared to actual oil recovery efficiency for five of the oil rims referred to in the previous section with oil rim thickness less than 50 ft thick. This is because Kabir's correlation was developed for thin oil columns less than 50 ft. As shown in Fig. 7, Kabir’s correlation estimates are much lower the actual recovery efficiencies while the estimates from the correlation presented in this study more closely match actual oil rim recovery for the five oil rims.

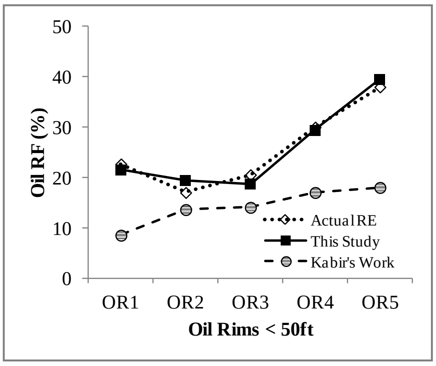

Fig. 7. Comparison with Kabir's correlation.

5. Conclusions

Correlations for evaluating the primary recovery factor for thin oil rims with oil rim thickness from 20 to 100 ft overlain with large gas caps have been developed in this paper. This is done using three dimensional, three-phase black oil reservoir simulation combined with experimental design methodology. Some concluding observations from the study are given below:

- The dominant factors that influenced concurrent oil rim and gas cap production under obtained using foldover Plackett-Burman screening designs were oil rim thickness, gas cap size, oil viscosity, horizontal permeability, dimension aquifer radius, gas cap offtake, vertical anisotropy, and reservoir dip while the other factors perforation position (or well placement) in the oil rim, oil rim offtake, and gas-oil ratio constraint accounted for only 5% of total main effects.
- The oil recovery factors estimated using the correlations for conventional development are in good agreement with the field data with a mean average percentage error of 2.46% while the oil recovery factors estimated using the correlations for concurrent development are in very good agreement with the simulated data with a mean average percentage error of 4%.
- The oil recovery factor estimates for oil rims produced with horizontal wells compared to actual oil recovery efficiency yielded a standard error of the estimate is 1.55%.
- Thus, the developed correlations can be applied to oil rims with oil column thickness less than 100 ft and dimensionless gas cap size from 1 to 9 with a good degree of confidence.

Nomenclatures

B_{oi}	Initial formation volume factor, bbl/stb
h_o	Oil rim thickness, ft
i, j	Integer increments
k_h	Horizontal permeability, md
k_v	Vertical permeability, md
M	Ratio of gas cap pore volume to oil rim pore volume (m-factor)
N_{pw}	Ultimate oil recovery per well, MMstb
perfpos	Vertical good perforation position within the oil rim relative to the gas-oil contact at 0 and the oil-water contact at 1
q_{gi}	Gas cap offtake, %
q_{oi}	Oil rim offtake, %
RF	Oil recovery factor, %
R_{ng}	Net-to-gross ratio
r_{eD}	Ratio of aquifer radius to total reservoir radius
S_{or}	Residual oil saturation
S_{wc}	Connate water saturation

Greek Symbols

Θ	Reservoir Dip, degrees
μ	Oil viscosity, cp
$\varnothing$	Effective porosity

Abbreviations	
FGIIP	Free Gas Initially in Place
GOR	Gas Oil Ratio
RE	Recovery Efficiency

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Appendix A

The Base Case Reservoir Simulation Model

The base reservoir model is a three-dimensional box model, with isotropic rock properties and grid refinement for resolving saturation change and contact movement in thin oil rims. There are two vertical or horizontal wells (one dedicated to oil rim production and one to gas cap production) in the model. However, the initial oil production rate dictates the actual number of oil wells. Local grid refinement is applied near the oil wellbore to properly capture coning behaviour while keeping runtimes manageable. The 2D and 3D simulation grids are shown in Figs. A-1 and A-2.

The base reservoir model has a grid size of 2,946 ft × 10,000 ft areally and the model is 50 ft thick as shown in Fig. A-1. The reservoir has a dip angle of 8 degrees in the *x*-direction. Porosity is constant throughout the model. Horizontal permeability in the *x*- and *y* directions is 1,300 md, i.e., $k_x = k_y = 1300$ md, while vertical permeability, k_z is 325 md. Average porosity is 25%. The pressure-volume-temperature and viscosity data were generated using published correlations. The relative permeability parameters have been calculated as a function of horizontal permeability, porosity and wettability index. The aquifer modelling approach is analytical with a boundary Carter-Tracy aquifer. Aquifer activity is sensitized via the dimensionless radius. The reference model has a dimensionless radius of 6 ($r_{eD} = 6$).

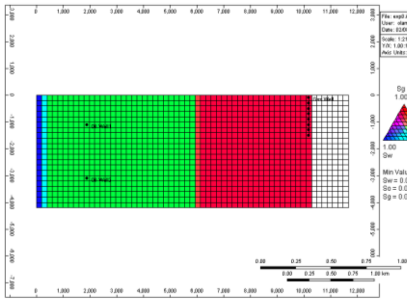

Fig. A-1. 2D base model reservoir grid for concurrent development.

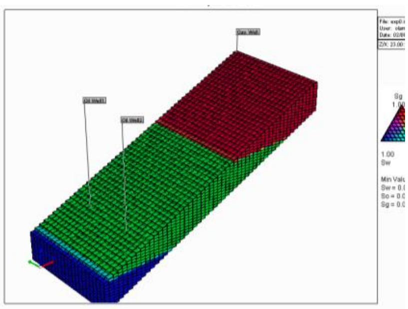

Fig. A-2. 3D base model for concurrent development.

Appendix B

History Match Performance Plots for E1, E2 and E3 oil rims

The correlation for concurrent development, Eq. (6), was validated using history matched reservoir simulation models for three reservoirs in the UA Field, Niger Delta. The history matched performance plots for oil production rate, cumulative oil production and average reservoir pressure on a reservoir basis are shown in Figs. A-3, A-5 and A-7 for oil rims E1, E2 and E3 respectively. The history matched performance plots for gas-oil ratio and water cut on a reservoir basis are shown in Figs. A-4, A-6 and A-8 for oil rims E1, E2 and E3 respectively. The model output is depicted in lines while the actual production and pressure history is depicted with markers.

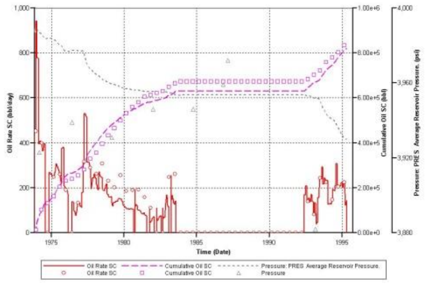

Fig. A-3. Oil production and average reservoir pressure history match for E1 oil rim.

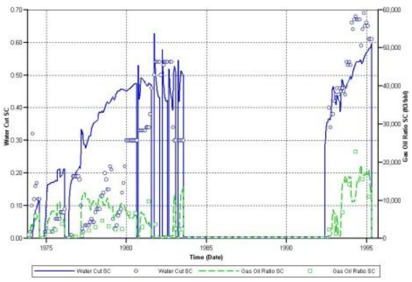

Fig. A-4. Gas oil ratio and water cut history match for E1 oil rim.

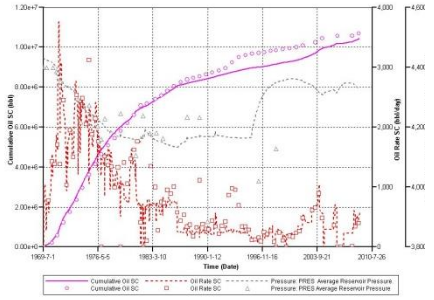

Fig. A-5. Oil production and average reservoir pressure history match for E2 oil rim.

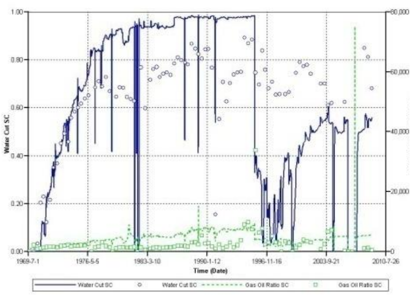

Fig. A-6. Gas oil ratio and water cut history match for E2 oil rim.

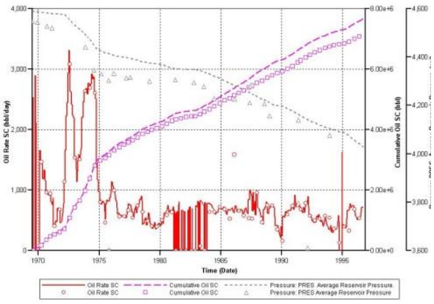

Fig. A-7. Oil production and average reservoir pressure history match for E3 oil rim.

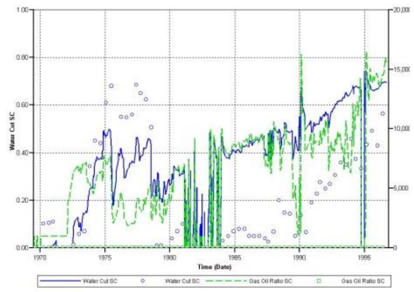

Fig. A-8. Gas oil ratio and water cut history match for E3 oil rim.