

Predicting the Effect of Well Trajectory and Production Rates on Concurrent Oil and Gas Recovery from Thin Oil Rims.

¹Olabode Oluwasanmi; ²Egeonu Gerald; ³Ojo Temiloluwa; ⁴Oguntade Tomiwa; ⁵Bamigboye Oreofeoluwa

^{1,2,3,4} Department of petroleum engineering covenant university, ota, Ogun state, ⁵ Department of management information systems, covenant university, ota, Ogun state
E-mail address: Oluwasanmi.olabode@covenantuniversity.edu.ng

Abstract Thin oil rim reservoirs are those with less than a 100 ft. of oil thickness underlain and overlain by an aquifer and gas cap respectively. Irrespective of the sizes of the aquifer or gas cap, oil rims productivity is usually low due to excessive coning of water and gas. Production optimizations are usually carried out before recovery schemes are initiated. One of such is a concurrent oil and gas production which is used in comparison with sequential production in this study in conjunction with production rates and well geometry to ascertain the extent of recovery and to improve the overall field development plan. Production of gas is slightly restricted to meet gas demands and also to prevent an adverse effect on oil production. A case study of an oil rim from the Niger delta was studied by running reservoir simulation using Eclipse software to check the effect of production schemes, well type and production rates on oil recovery. From the studies, concurrent production using a horizontal well and a production rate of 1000 stb/day is desired for an appreciable incremental oil recovery. Further studies on limiting oil rim movements and thusly increasing oil recovery can be done by initiating secondary and enhanced oil recovery schemes.

Key words; oil recovery, horizontal well, vertical wells, concurrent production, sequential production

1. Introduction

Due to the reservoir, geological and operational uncertainties of oil rims, production challenges as described by the coning of water and gas are inevitable. In 2012, Masoudi described the pros and cons of the strategies of developing oil rims. A gas cap blow down will ultimately mean production of oil is ignored, sequential production neglects the early production of gas, swing development offers cyclic production of gas and a low oil recovery factor and concurrent oil and gas production which might suit both investor and host country[1]. The conventional way to exploit oil from a thin oil rim is to produce from the oil column while keeping the gas cap in place as a drive mechanism or pressure support. For reservoirs with gas cap expansion as the dominant drive mechanism, a concurrent oil and gas development is less attractive. It is however feasible and should still be considered. With increased focus on LNG in the world, we are faced with the challenge that some key gas reservoir that are crucial for the timely LNG supply have underlying oil rims. Concurrent oil and gas production involves the simultaneous production of oil and gas from the same reservoir from the start of production through either separate conduits (i.e. by separate wells or dual string completion) or through a single conduit (i.e. by commingling or with a smart completion).

In 2011, Ibukun described some of the major challenges facing the performance of simultaneously producing oil and gas especially for this case study includes: the size of the gas cap, the presence, activity, and size of the aquifer, production rates, well geometry, geometry of the reservoir, fluid properties, reservoir heterogeneities, phase behaviors and gas off takes just to mention a few[2]. It is also of importance to make mention or to understand the movement of the oil over the life of the field which is typically determined by two dominant drives:



- Water drive (the aquifer)
- Gas cap expansion drive (ie the size of gas cap)

Reservoir simulation has demonstrated the ability of concurrent wells to enable simultaneous oil and gas production with minimal impact on oil recovery. The proposed concept can significantly impact the portfolio of available gas reservoirs by delivering a cost effective technology solutions. As a result significant cost benefits can be realized (i.e. one concurrent smart well can potentially replace two conventional dedicated oil and gas wells).

The applications of horizontal well technology in developing hydrocarbon reservoirs have been widely used in recent years. One of the main objectives of using this technology is to improve hydrocarbon recovery from water and/or gas-cap drive reservoirs. The advantages of using a horizontal well over a conventional vertical well are their larger capacity to produce oil at the same drawdown and a longer breakthrough time at a given production rate. Reduced water and gas coning because of reduced drawdown in the reservoir for a given production rate, thereby reducing the remedial work required in the future and Increased production rate because of the greater wellbore length exposed to the pay zone.

Sensitivity analysis have majorly been carried out by changing parameters and evaluating their effects on estimated oil recovery. In 2005, Wanye developed a qualitative set of screening criteria for sequential and concurrent development of oil and gas resources in thin oil reservoirs by sensitivity analysis on gas cap size and oil rim thickness. Their suggestions are summarized as:

- M-factor > 2 and $H_o > 30$ ft : concurrent oil and gas development is feasible
- M- factor < 2 and $H_o > 30$ ft : delay gas development till the end of oil development
- For all m- factor and $H_o < 30$ ft. : gas development only oil development is not feasible[3]

In 2012, Iyare and Marcelle estimated oil recovery by initiating sensitivity analysis by combining the effects of gas cap, aquifer sizes and optimal well locations for oil rims[4].

In 2008, Sascha and Marc proposed the concurrent production of oil and gas from oil rim reservoirs through a single well conduit smart well (intelligent well). Using a case study, the authors postulated that a smart well solution to concurrent production of oil and gas from oil rim reservoirs results in significant costs benefits (reduction in costs), as one concurrent smart well can potentially replace 2 conventional dedicated wells[5].

An oil rim reservoir in the Niger delta region of Nigeria is used to analyze the effects of production rates on vertical and horizontal wells on concurrent and sequential production strategies on oil recovery in oil rim reservoirs.

2. Methodology.

An oil rim reservoir from the Niger delta is used in this study to verify the effects of oil flow rates and well configurations on oil recovery. The subsurface map of the reservoir is seen in figure 1 while figure 2 is the discretized sub surface map showing the 5 producing wells. The eclipse software was used to build a black oil model by incorporating Pressure, Volume and Temperature properties as well as solution properties from the software manual for the active cells in the grid. Table one describes the reservoir properties of the oil rim.

2.1. Model Construction

The GridSim Module was used to build the reservoir grid model. The reservoir lies between 10000 to 10450 feet. The Cartesian grid is set into 75 x 50 x 20 grid-cells with 74000 cells set active by boundary definition and shaped according to the cross-sections drawn across the reservoir sand map in both X and

Y directions. There are 32420 active cells and 41580 inactive cells. GridSim was also used to assign the petro physical properties (arrays) such as horizontal permeability (PERMX), porosity (PORO), active grids (ACTNUM), net-to-gross (NTG) ratio, and the initial water saturation (SWATINIT) to the reservoir grid model. The model was assumed to be homogenous, so average values were used to populate the grid model.

There are five producing wells named: “04L/E2”, “06L/E2”, “09L/E2”, “10L/E2, and “ -13L/E2,” located at I, j coordinates: (62, 34), (50, 22), (27, 13), (49, 38) and (40, 33) respectively on the grid model. All wells penetrate the grid blocks in Z-direction and were set as producers. Analytical (Fetkovich) aquifer system was connected at the eastern flank of the grid



Fig. 1 Subsurface map of E2 reservoir

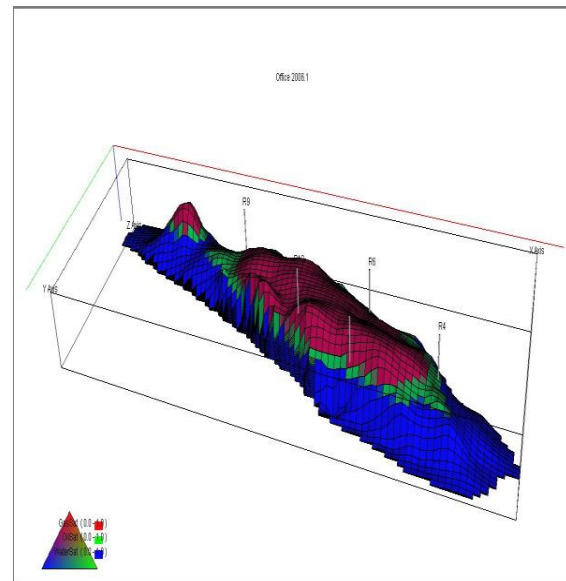


Fig. 2 Discretized sub surface structure of E2 showing fluid saturations

Table 1 Oil rim properties

Properties	Value	Properties	Value
Oil Sand Porosity (%)	0.26	Oil Rim Thickness (ft)	38
Gas sand Porosity (%)	0.24	Swc	0.14
Sh Oil	0.9	Oil Viscosity (cP)	0.43
Sh Gas	0.77	Oil Gravity (°API)	32
NTG	0.8	Boi (bbl/stb)	1.48
Permeability (mD)	400 – 1500	Rsi (scf/stb)	1035
Sand Thickness (ft)	71	Ti (°F)	179
Pi (psi)	4394	Np (MMstb)	10.73
Pb (psi)	4394	Free Gas In Place (bcf)	128.5
STOIIP (MMbbls)	35.9	$\Delta P/P_i @ N_p/N$	7% @ 26%
No. of Drainage Points	5		

2.2. WELL EVENTS SCHEDULE

The observed production history data for oil, gas and water from E5 “reservoir were made into a Schedule production data format and imported into Schedule Module. In addition, well events data such as perforation intervals, bottom-hole pressure measurements, well tests, stimulations, plugs and sidetracks, squeezes and re-working were specified on Schedule interface interactively. Well geometries, positions and connections with the grid were equally specified. Finally, the simulation options and tuning were configured and the interface submitted for the simulator to generate an output schedule file used for the history matching. This section is the core of simulation study. All the 5 wells in question were at some point shut in due to excessive GOR (gas oil ratio) and high water cuts leading to low ultimate oil recoveries.

2.3. History Matching

The history matching was done in two phases: first the wells were set to produce the correct reservoir fluid volume rate for each time step. This was done by setting the control mode to calculate the reservoir fluid volume rate from the observed phase flow rates in the keyword WCONHIST. The resulting pressures that are calculated by ECLIPSE* were compared to the observed BHP field measurements. The volume of reservoir fluids was tuned for the model to produce pressure results similar to those measured; this was not perfectly matched due to very sparse BHP pressure data available. In the second phase of the history matching, wells were set to produce the correct oil rates. Again, this was controlled to calculate oil rates from the observed oil rates in the keyword WCONHIST. Subsequently, vertical permeability was varied and gas relative permeability modified to tune the model until the produced water and gas matches the historical rates. The oil initially in place must first be matched with the simulated data before the cumulative oil production is matched. The simulated and field gas oil ratio and water cut are matched as shown in (figure 3). The table 2 shows the summary of the initial fluid in place data after history matching. The simulator gave an increase of 0.88% in original oil in place while the gas in place also increased by 2%. While table 3 shows total well productions before and after history matching.

Table 2 Simulated original oil and gas in place before production

	Oil (stb)	Water (stb)	Gas (Mscf)
Currently in place	36,216,568	797,816,825	131,098,739
Outflow through wells	0	0	0
Analytical aquifer	0	0	0
Well material balance	0	0	0
Originally in place	36,216,568	797,816,825	131,098,739

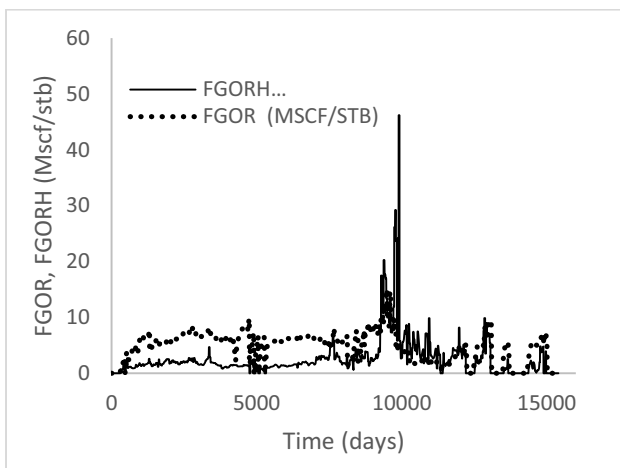
Table 3 Total well production

WELLS	OIL (STB)		GAS (MSCF)	
	Before history match	After history match	Before history match	After history match
Well 4L	164,367.23	4,692,793	922,498.81	9,494,806
Well 6L	237,827.52	2,628,576.3	613,888.4	4,903,431
Well 9L	325,913.44	3,416,676.5	911,229.5	9,172,350
Well 10L	37,369.77	344,142.5	361,014.22	358,795
Well 13L	8560.623	397,169.94	115,643.89	819,233.62
TOTAL	634,559.25	11,479,358.	2,924,274.8	24,748,616

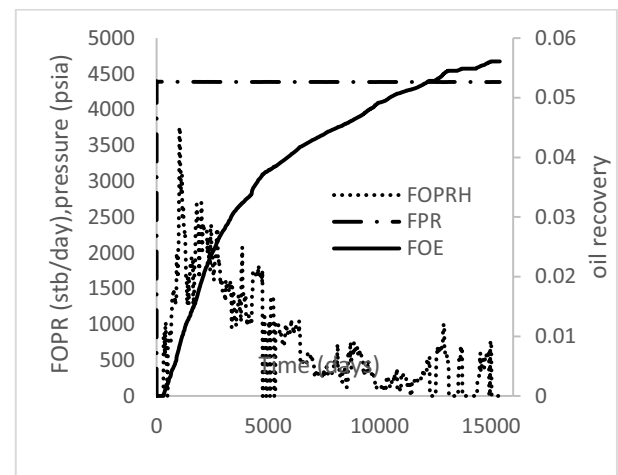
Figure 3 shows that the production rate for oil is very low indicating a higher water and gas influx while figure 4 shows the history matched production rates. A high gas production suggests an initial gas cap or has high quantity of initial solution gas. The field historical production rate also follows similar trend. Figure 3 shows the field production total with 11,522,593 barrels of oil and 25 MM scf of gas produced during 44 years of production. Water production was very high which indicates the existence of a large aquifer accompanied with a large gas cap. Figure 3 shows the history matched cumulative production which closely corresponds to the oil produced given in table 1.

The static pressure decline in the aquifer from 0 to 10000 days (approximately for up to 24 years of production) is about 22% of initial reservoir pressure. A finite acting (fetkovich) aquifer was modeled was modelled in accordance to the grid dimensions, pressure, compressibility and reservoir fluid contacts to match observed pressure level in the field. Adding an aquifer to the reservoir though helped to maintain or balance the reservoir pressure.

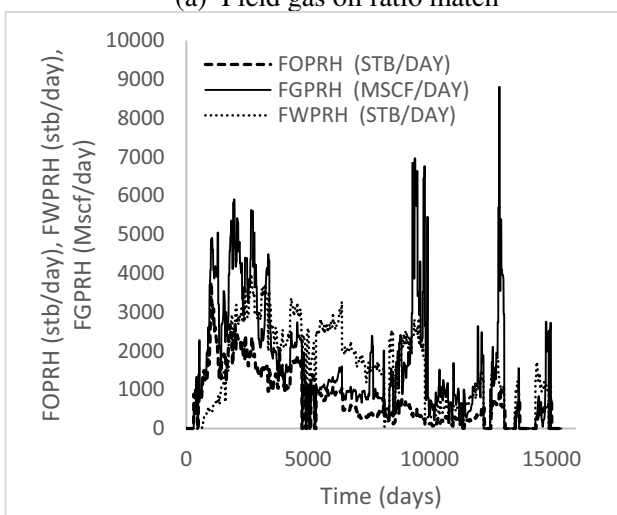
Figure 3 also shows the history matched profiles for water cut and gas oil ratios respectively. This is a major step in reservoir simulation before the commencement of prediction.



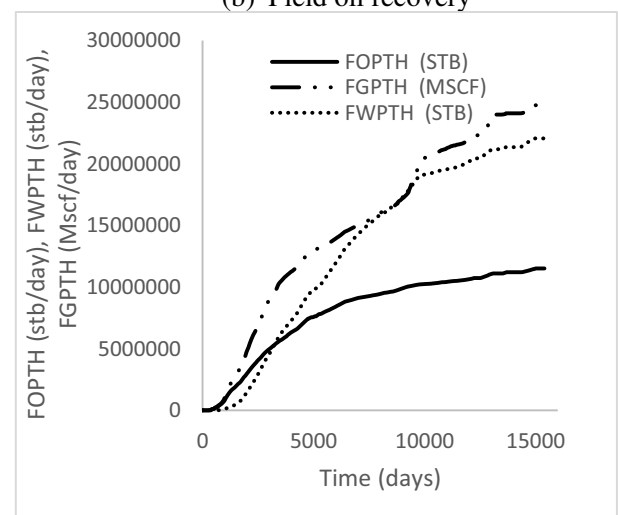
(a) Field gas oil ratio match



(b) Field oil recovery



(c) Field production rate history



(d) Field production total history

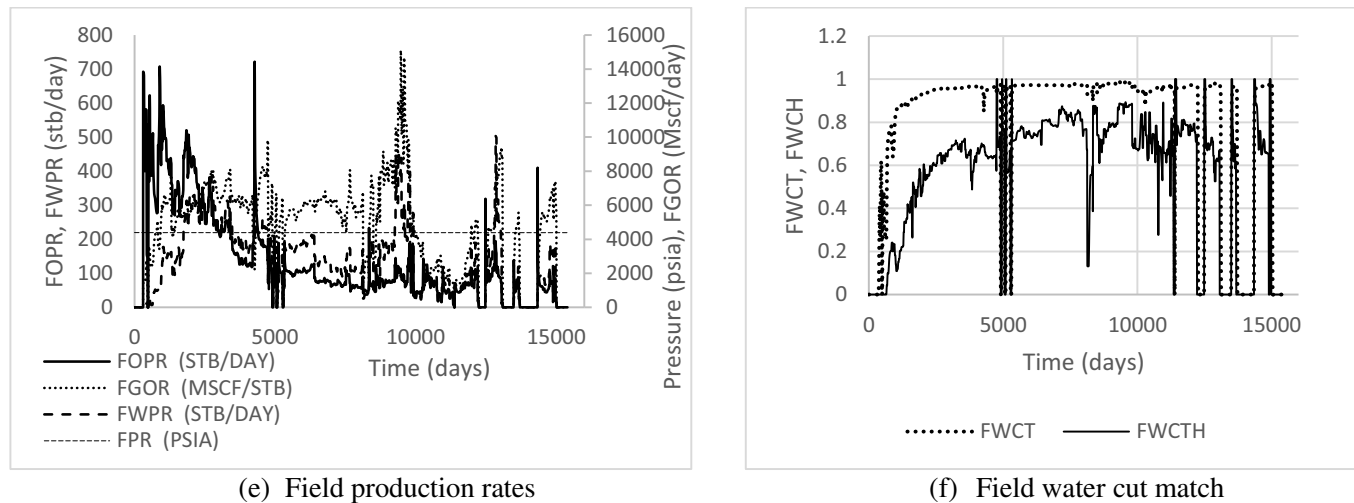


Fig. 3 E2 production history and profiles

2.4. Prediction.

Having history- matched the simulated model to the observed data and concluded on having a near perfect simulation run with an average of 2% increase, a number of prediction runs were made on the history matched model. 3 sensitivity runs were made for the following case scenarios that were investigated:

1. The type of completion (vertical or horizontal) we try to figure out which completion gives best oil recovery.
2. Expected rate recoveries from sequential production i.e. produce oil first then gas.
3. Effect of concurrent production on overall field performance (i.e. recovery of both oil and gas)

The base case scenario is the history matched model. The sequential production scenario was run as a benchmark for comparing the performance of concurrent production and also to estimate the expected performance of such scenarios.

The concurrent production cases were selected to investigate typical oil rim reservoir development scenario in which the reservoirs serve as an important source of gas supply for an available market. This will economically improve the overall field development from sales of gas. In concurrent production unlike sequential production the gas production is not differed till after recovery as the gas is needed to meet demands.

2.5. Description of the Cases

1. Base case: this describes the current situation of the reservoir after history matching (table 3).
2. Case 1: studies the effect of type of well i.e. (vertical or horizontal) used in the field right from production inception. The historical wells in the field were modelled to be 5 vertical wells. In this case however the field was put on 5 horizontal wells. The well location and trajectory were identified with respect to initial oil saturation distribution in the field before the start of production. This case was developed to investigate the draining field with horizontal wells from inception of production and if it would deliver a better result than vertical.
3. Case 2: oil recovery from concurrent oil and gas production. All existing 5 wells were converted to horizontal wells.

4. Case 3: oil recovery from sequential production (producing the oil rim first and then producing the gas subsequently after the oil wells reach abandonment). Apart from the first case scenario, all other subsequent cases were run with 3 multiple oil rate sensitivities. A total number of 19 prediction runs asides history match were made.

A total number of 19 prediction runs asides history match were made.

2.6. Analysis of Prediction

The predictions simulations were made on the history matched models after normal production for a period of 15 years thus making overall field life 57 years. (i.e. normal production commenced 1968 and ended 2010, prediction started 2010 and ended 2025). Some of the economic limit used for the field and these wells are maximum water cut of 100%, the minimum allowable oil rate for the wells was 100bopd while that for the field too was 500bopd multiplied by the number of wells in the prediction model. The simulator was programmed to shut in wells that violated stipulated well penalties and stop simulation run once any of the field penalties was violated. Oil rates of (2000, 1500, 1000 and 500 stb/day were used on different case scenario)

For the gas wells producing from the gas cap, the minimum gas rate was set to be 10 Mscf/d. The bottom hole target for all wells was assumed to be 2000 psia and put under a minimum field constraint of 1200 psia.

The figure 9 shows the location of new or predicted wells (pred1, pred2, pred3, pred4, and pred5) and location of the 5 history matched wells) with respect to oil saturation grid function.

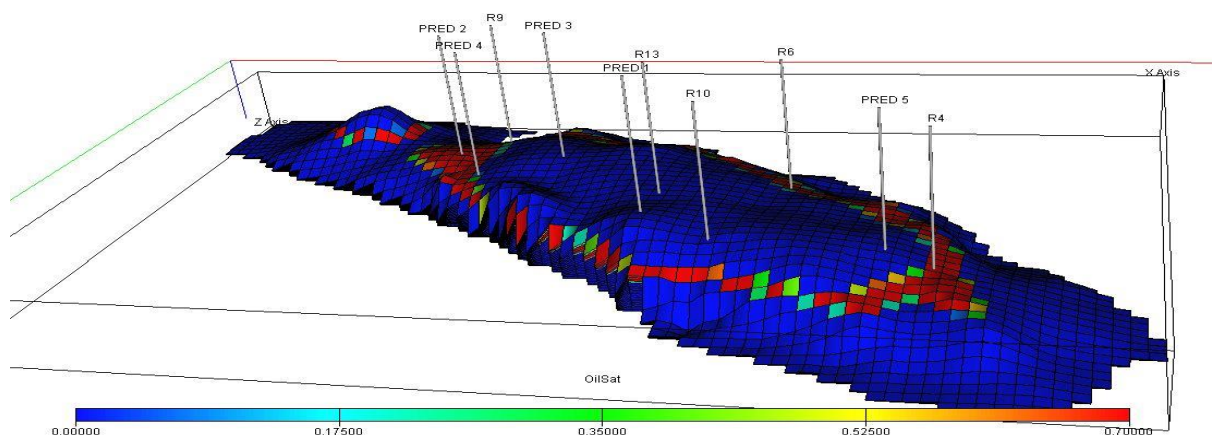


Fig. 4 Location of history match and prediction wells

3. Results

Here the analysis of the results according to their case specifications are highlighted and discussed below:

3.1. Base Case: this case is the do-nothing case. It models the case where the current historical wells for the reservoir in question are reopened for production without any stimulation, production enhancement or intervention or advanced recovery runs made. This case records a low 0.4% increase in oil recovery over the historical production. Most of the wells in this case scenario didn't produce much as the wells were not properly located within region of high reserves.

Firstly, a change of well production trajectory from vertical to horizontal or deviated showed a significant increment in oil and gas production and it was also noticed that this increments occurred for lower oil production rates. To also further prove these two vertical and horizontal wells were added and simulated

at different occasions and the simulated result from the horizontal wells had higher deliverability. Horizontal wells also proved higher productivity for both sequential and concurrent production as compared to vertical wells with horizontal concurrent production having higher performance.

3.2. Case 1: Converting All Previous Vertical Wells to Horizontal Wells.

This case scenario considers converting all the initial history matched wells from vertical completions to horizontal completions. 2 rate sensitivities were still used in this case scenario just as in case scenario 1. The 1500 stb/day gave the highest oil recovery of about 33.04% an equivalent of an additional of 351,521 barrels of oil produced. Actual field total oil production was 11,861,144 barrels of oil was produced as compared to 11,779,557 barrels of oil for vertical wells. Comparison of the results from this case study suggests that vertical completion of wells in this reservoir were not or shouldn't have been the best completion to be used in the initial field development. Horizontal completions should have been initiated.

Also, a recovery factor of 79.51% was recorded for gas. The simulation ran for an average of 35 years for all the horizontally completed wells and stopped due to low predicted well pressure.

3.3. Case 2: Concurrent Production of Gas and Oil After History (5 Horizontal Wells).

This last case on concurrent production of oil and gas via considers 5 horizontal wells. The rate sensitivities used are same as in case 1 above namely (2000, 1500 and 1000 stb/day). The 1000 stb/day produced or performed best. A total of 1,343,576 barrels was produced over an average period of 43 years. Rate sensitivities of 2000 and 1500 stb/day produced 12,425,652 barrels and 12,464,984 barrels respectively. Oil recoveries for oil rates 2000 stb/day, 1500 stb/day and 1000 stb/day were 34.30%, 34.42% and 37.1% respectively. The gas recoveries for the same rates were 44.2%, 44% and 35.32% respectively.

This case clearly shows the dynamic effect of the displacement efficiency of the two dominant drive mechanisms in the reservoir (i.e. water influx and gas cap expansion). Analysis of field performance with respect to oil recovery shows that gas cap expansion is the predominant drive actively followed by water drive. However even though gas cap expansion is the predominant drive, the displacement of oil by gas is relatively less efficient as compared to the displacement of oil by water because of relatively less mobility ratio. Since the aquifer water is generally more viscous than reservoir gas, the mobility ratio for the water oil displacement process (i.e. water influx).

At 1000 stb/day per well oil rate water influx had relatively larger effect on oil displacement. at oil recovery of 37.1% a cumulative of 909 MMSTB of water was produced with a gas recovery factor of 35.32%. At a higher oil rate 2000 stb/day the gas recovery was 44.2% which indicates that the gas cap expanded more rapidly to occupy the voidage caused by increased underground withdrawal since it had more energy than the aquifer.

It is also worth knowing that with respect to oil recovery, this case performed better than the case of sequential production of oil and gas which shall be proved in a later case scenario. In sequential production, the gas cap is not produced until the oil has been produced to economic rates. This implies gas cap expansion been the dominant reservoir drive throughout field oil production life. This makes oil displacement process for sequential production case less as compared to concurrent production due to the fact that in the latter case the production is also supported by an aquifer support in conjunction with the gas cap expansion. Also the simultaneous production of gas cap with oil rim reduces the effect of gas cap energy and thereby resulting to a relative corresponding increase in effect of aquifer energy on reservoir drive.

An analogy of increasing the aquifer size (aquifer support) was also carried out on this concurrent scenario. After running the simulation, an average of 39% oil recovery and 46.6% gas recovery was

derived from all the respective oil rates i.e. (500, 1000, 1500 and 2000 stb/day). This signifies that a larger aquifer support helps in additional oil recovery.

On a further note, it is worthy to note that at a lower rate i.e. 500 stb per day for this case scenario an oil recovery factor of 38% was recorded but at a lower gas recovery factor.

3.4. Case 3: Sequential Production (5 Horizontal Wells).

This case scenario considers sequentially producing the oil rim first and then the gas cap using 5 horizontal wells. This case was also developed to test the relative productivity of concurrent production of the gas and oil so that gas sales supply will meet demands without delay. Analysis of concurrent production case vis-a-vis the sequential production case would proffer to what extent concurrent production would adversely affect oil recovery. Two oil sensitivity rates were used for this case scenario (1000 stb/day and 2000 stb/day) were run for all the 5 horizontal wells in this case. An oil recovery of 34.3% was recorded for 1000 stb/day as compared to 38% of concurrent production while a recovery of 34% was recorded for 2000 stb/day. The simulation run for these horizontal wells ran for an average of 15 years and stopped due to low field pressure. As earlier explained, sequential production is not as effective as concurrent production in terms of oil recovery for the E2 reservoir. This shows that concurrently producing the field does not have adverse effect on oil recovery. Indeed results of the study shows that concurrent production is a desirable development option for field oil and gas reserves.

Below is tabulated summary of the result analysis of each case scenario.

Table 4: Result for case 2

OIL RATE (STB/DAY)	CUM OIL (STB)	CUM GAS (MSCF)	CUM WATE R (BBL)	OIL RF(%)	GA S RF (%)	Incremental oil RF (%)	Incremental gas RF (%)	NFA
500	13,773,703	43,909,304	5.11E+08	38.364	65.82	6.30	0.64	2025
1000	13,435,767	41,792,712	8.87E+08	37.425	67.48	5.37	2.30	2025
1500	11,779,557	43,362,576	1.68E+08	34.721	66.25	2.66	1.07	2025
2000	11,781,926	43,165,032	1.77E+08	34.611	66.41	2.55	1.23	2025
(extended aquifer size)	14,073,079	38,626,416	2.11E+09	39.2	69.94	7.14	4.76	2025

Table 5: Result for case 3

OIL RATE (STB/DAY)	CUM OIL (STB)	CUM GAS (MSCF)	CUM WATER (BBL)	OIL RECO VERY (%)	GAS RECO VERY (%)	CHANGE IN OIL RF WRT HISTORY MATCH	CHANGE IN GAS RF WRT HISTORY MATCH	SIMULA TION END YEAR
1000	12410337	34272896	1.42E+08	34.578	73.33	2.64	8.15	2025
1500	12357815	31643808	1.10E+08	34.428	75.37	2.36	10.19	2025

4 Conclusions

From the three cases considered, a production rate of 1000 stb/day is considered suitable in developing oil rim reservoirs under concurrent oil and gas production.

Horizontal completions generally performed better than the vertical completions for oil recovery for E2 reservoir both for cases that considered different scenarios at initial development of the field i.e. without history and for cases that considered re-development of the field after history.

This is consistent with what has been reported in literature, but the applicability of horizontal wells has to be considered for each oil rim reservoir. The economic importance and analysis of horizontal completions also have to be run to know the viability of such completions for the field and optimal number required for adequate field drainage. Other crucial factors that may affect feasibility of horizontal completions are the average net oil column thickness and formation anisotropy.

The results also show that the concurrent oil and gas production is the best strategy to be considered in developing oil rim. Sequential production is not necessarily a bad development option, it was not a better option for this particular field. It may be applicable where gas cap expansion is the only active source of reservoir energy, or has overriding effect on the other sources of reservoir energy.

Nomenclature

GOR: gas oil ration

Stb: stock tank barrel

Scf: standard cubic feet

References

- [1] Masoudi, R. How to get the most out of your Oil Rim Reservoirs? Reservoir management and hydrocarbon recovery enhancement initiatives. *SPE*. (2012)
- [2] Ibukun, S. “*Evaluation of Oil Rim Reservoirs Development – A Case Study*”. ibadan: Master of Science Thesis of the University of Ibadan, Department of Petroleum Engineering. (2011)
- [3] Wanye, M.. *Nun river mode: Gas Recovery Mechanism and oil rim development strategy*. Rijswijk: shell. (2005)
- [4] Iyare, U., Marcelle-De silva, J., & UWI.. effect of gas cap and aquifer strenght on the opyimal well location for thin oil rim reservoirs. *SPETT 2012 Energy Conference and Exhibition* . port of spain, trinidad: SPE. (2012)
- [5] Sascha, v., & marc, N.. concurrent oil and gas development wells: a smart well solution to thin oil. *international petroleum technology conference* . kuala lumpur: IPTC. (2008)