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Modelling Development Strategies for a Green Marginal Gas Condensate Reservoir in the Niger Delta

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ABSTRACT

The increasing global demand for gas necessitates the consideration of fields that were previously ignored due to their marginal hydrocarbon reserves. The development of these marginal gas condensate reservoirs is challenging due to their complex phase behavior. In this study, the MBAL and PROSPER tools from the Integrated Petroleum Modelling suite were used to model development alternatives for a marginal gas condensate reservoir in the Niger Delta. Several scenarios were evaluated, including volumetric reservoir depletion (the base case), gas production under aquifer influence and reservoir production via gas cycling. In these different cases, production rates used were determined by the production tubing sizes considered. Gas recovery from Orbit reservoir under natural depletion could result in recovery factors of 55% and 22% for gas and condensate respectively. Gas recovery from gas recycling increased by 4% and condensate recovery increased by 8% with increasing cycled gas from 20% to 40%. The presence of a partially active aquifer would severely impact negatively of hydrocarbon recovery resulting in reservoir abandonment at relatively high pressures. Optimal development of this marginal gas condensate reservoir requires utilizing existing wells completed with a minimum of 5.5-inch tubing tied-in to nearby facilities with a single gas producer with or without recycled gas.

Keywords: Condensate gas reservoirs; Marginal fields; Green field development; Gas recycling, Gas recovery factor; Integrated production modelling; Niger Delta

Introduction

Natural gas has grown in popularity during the last 30 years, accounting for 24% of global energy consumption. It is now the fastest-growing fossil fuel, increasing by 0.9% from 2020 to 2035. It is also the only fossil fuel anticipated to grow after 2030, possibly peaking in 2037[1]. Domestic gas demand in Nigeria increased thrice between 2001 and 2014, from roughly 4.1 billion cubic meters to 12 billion cubic meters per year[2]. Furthermore, Commission Chief Executive of the Nigerian Upstream Petroleum Regulatory Commission asserted that Nigeria's gas demand is expected to outpace supply at a compound annual growth rate of 16.6% by 2030 reaching 22.5 billion cubic feet per day by 2030 with the shortfall in supply of a 3.1 billion cubic feet per day[3]. This projected growth is especially noteworthy given the importance of gas as a transition fuel in Nigeria's net-zero strategy. It is a staggering 300 percent increase over the 4.9 billion cubic feet per day achieved in 2020. There is, therefore, a critical need for gas maturation studies that foster and explore optimal development procedures and operational efficiencies with due consideration to long-term economic implications.

Attaining this growth would require developing marginal gas reservoirs which have been overlooked because of potential subsurface concerns, inadequate project financing options, hydrocarbon products price volatility and uncertain economic feasibility. Any field that has been discovered and has been neglected for ten years or more after the date of first discovery is considered a marginal field, according to the 2020 Guidelines for the Award and Operations of Marginal Fields in Nigeria, which were released by the now-defunct Department of Petroleum Resources. Broadly speaking, marginal fields have been classified by any of the following five traits: low initial hydrocarbons in place which would result in low recoverable reserves, fields too far from the current production facilities making them not feasible financially to develop, fields with marginal economics due to the current state of the economy and financial system, fields technically challenging that cannot be developed with traditional techniques and low-volume producing fields where the difference between production revenue and operating costs has rendered the field unprofitable[4]. The Petroleum Industry Act (PIA) 2021, Nigeria's most recent legal framework for the oil and gas industry in Nigeria, has definitions for marginal fields. A field or discovery is considered a marginal field under the PIA if it satisfies one of the following two requirements: it was classified as a "marginal field" before January 1, 2021 or no action has been taken for seven years after discovery.

The overarching aim of this study is to devise a sustainable, development strategy for a marginal gas condensate reservoir in the Niger Delta for meeting the increasing gas demand for both domestic and international markets.

Literature Review

A gas condensate reservoir is a single-phase hydrocarbon fluid system at initial reservoir pressure and temperature, primarily composed of methane and other short-chain hydrocarbons, but also long-chain hydrocarbons. Fluid production under certain temperature and pressure conditions results in fluid separation into two phases, gas and the liquid phase also known as retrograde condensate[5]. The phase envelope shown in **(Figure 1)** portrays retrograde condensation using the black vertical line. The reservoir is initially single-phase gas. The initial reservoir pressure decreases as gas is produced at constant reservoir temperature until the dew point line is crossed at which point the first liquid drop occurs. The percentage of liquid saturation rises as pressure drops and eventually reaches a maximum within the two-phase region. The liquid volume subsequently decreases with further pressure decline.

Gas condensate resources are important commodities during times of high gas prices. Likewise, they are also very helpful when gas prices are low since they can supply valuable liquids. The development of gas condensate reservoirs and dry gas reservoirs is similar. However, two notable differences exist which are condensate flow in the reservoir's wellbore area and significant liquid production over the reservoir's lifetime[6]. The condensation of liquids in the pore spaces as reservoir pressure declines below the reservoir fluid's dewpoint pressure, results in a problem known as "condensate banking," particularly in the wellbore region where the pressure reduction is greatest[7]. Gas mobility is lowered and both reservoir performance and recovery rates are lowered, owing to the reduced relative permeability to gas. Gas condensate reservoirs are often at risk of formation damage due to the buildup of condensate. The liquid dropout can lead to blockages, reducing both gas relative permeability and mobility near the wellbore which reduces well productivity[8].

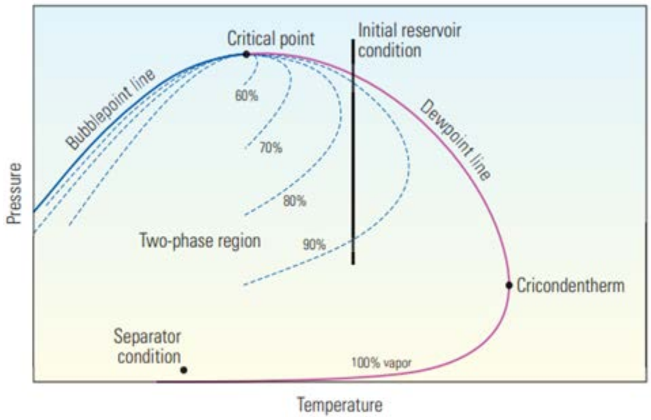

Figure 1: The phase diagram of a generic gas condensate system (Fan, 2005).

To minimize condensate buildup, it is important to maintain the flowing bottom-hole pressure as close to the dew point pressure as possible. Several studies have recommended development techniques for optimally producing gas condensate reservoirs[9]. A numerical model was used to analyze how horizontal wells could reduce gas condensate banking in a large reservoir in Northeast China as horizontal wells experience lower drawdown pressure as compared to vertical wells[10]. Increased production was observed even after the dew point for horizontal wells. This inference was corroborated by study in which a 3D reservoir simulation model of a reservoir in the Niger Delta that horizontal wells outperformed vertical wells in terms of productivity and experienced a slower decline in pressure. Horizontal wells help lessen the water coning in oil and gas reservoirs, offer a larger well and reservoir contact area, which enhances well productivity and increases the possibility of accessing several potentially isolated fault compartment drawdowns[6]. Two production techniques were compared, natural depletion and gas cycling, in a reservoir simulation study for the development of a gas condensate reservoir in the Niger Delta[11]. It was inferred that gas cycling maintains the reservoir pressure which in turn, maintains the gas production rate. Four production schemes were evaluated, natural pressure support, pressure maintenance via gas injection, water injection and water alternating gas (WAG) injection via a reservoir simulation study. It was found that nitrogen gas injection and WAG injection far outperformed primary recovery[12]. Reservoir modelling and simulation has been used to show that the injection of carbon dioxide minimizing condensate banking around the wellbore and can outperform water flooding, improving productivity by 1.39 times[13,14].

Several field cases have been reported in literature on optimal development of gas condensate reservoirs. Based on field performance, it was inferred that gas cycling was the most efficient method in developing condensate gas fields in Tura and Tarim basins, China[15]. The production performance of Sand20, a large-scale gas-condensate sandstone situated in the Nam Con Son basin offshore Vietnam, was examined. The rate of gas production did not significantly impact gas recovery, but a minimum rate was required to maximize oil recovery, minimize water production and prolong field life over a 20-year field life[16]. Improved gas recovery was reported by the use of extended reach drilling and horizontal completions for developing a gas condensate field near Sakhalin Island[17]. Similarly, horizontal wells were found to be more effective than vertical wells for developing gas condensate reservoirs in Uzbekistan fields, taking into account the facies distribution, fault patterns and reservoir structure[18]. The overarching aim of this study is to devise an effective development strategy for a marginal gas condensate reservoir in the Niger Delta.

Methodology

Study workflow

The workflow used for conducting this study is shown in **(Figure 2)**. The reservoir and well models were built using the Integrated Production Modelling suite modules, MBAL and PROSPER respectively.

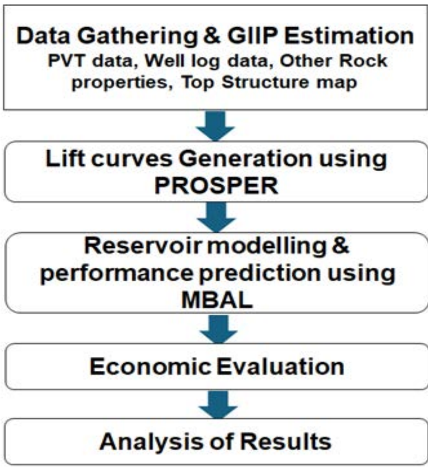

Figure 2: Study workflow used.

Data used: The data to be used for this study is for the Orbit reservoir which is a minor NAG (Non-Associated Gas) reservoir located in the Bravo field in the Niger Delta. The Orbit reservoir accounts for 20% of the hydrocarbon in Bravo field. The Orbit reservoir is an approximately 67ft thick package of both channel sands and stacked shoreface sands with thin shale layers. Orbit is a Marginal Reservoir as it is a relatively smaller accumulation compared to other reservoirs in the field with their respective gas initially in place volumes exceeding 250 Bscf. The PVT data is shown in Tables 1 to 5. The top structure map and well log correlation panel for Orbit reservoir are shown in Figures 1 and 2 respectively. The Top Structure map (Figure 2) shows that the reservoir has a dip-assisted fault closure, is crestally faulted and the faults are oriented in NE-SW vs Almost E-W direction. It can be inferred from the correlation panel (Figure 3) that the well BRV-01 traversed mostly channel sands whose quality deteriorates towards the BRV-02 well. Lift curves were generated with the PROSPER tool with the following sensitivities in Table 3 for 3.5 inches, 4.5 inches and 5.5 inches production tubing **(Tables 1,2 and 3), (Figures 3 and 4)**.

Modelling production under volumetric reservoir conditions

In this case, the production performance of Orbit reservoir was predicted for three different tubing sizes using an integrated reservoir-well model in predictive MBAL mode under natural pressure depletion as the drive mechanism. The abandonment pressure was about 1612 psia. The recoverable volumes are relatively the same across various tubing sizes, indicating that the gas and condensate recovery is insensitive to tubing size in this case. Producing with the 5.5-inch tubing is the most viable option for a volumetric reservoir, as more than half of the in-place volumes are recovered in less than 3 years. The recovery factor (RF) for gas and condensate is shown in **(Table 5)**. This scenario is taken as the base case because no gas-water contact was logged in the three wells drilled within the Orbit reservoir structure. The shallowest depth at which water was found was 262 feet from the top of the sand in well BRV-002, which is situated away from the main gas accumulation. It is anticipated that pressure depletion will align with typical volumetric gas reservoir behavior.

Table 1: Reservoir Fluid Properties.

Parameters	Value
Initial Reservoir Pressure (psia)	5943
Reservoir Temperature (°F)	200
Gas Specific Gravity	0.71
Initial Gas Formation Volume Factor (cu. ft/scf)	0.00396
Initial Condensate Gas Ratio (Stb/MMScf)	46.64
Condensate Specific Gravity	0.808
Separator Pressure (psia)	298
Water Salinity	10000
Gas Viscosity	0.03696
Z-Factor	1.072
Condensate API Gravity	43.6

Table 2: Orbit Reservoir Rock Properties.

Parameters	Value
Porosity	0.24
Connate Water Saturation	0.08
Net to Gross	0.4
Gross Reservoir thickness (ft)	67
Gross Rock Volume (acre ft)	89,486
Gas Initially in Place (Bscf)	69.6
Rock Compressibility	8.00E-6
Top of sand (ftss)	9025
Base of sand (ftss)	9093

Table 3: Sensitivities used in Lift Curves generation.

Variables	Min	Max	Base Case
Manifold Pressure (psia)	14.7	6000	Manifold Pressure =1200 Separator Pres=298
WGR (STB/MMscf)	0	1000	Initial WGR=0
CGR (STB/MMscf)	30	50	Initial CGR=46

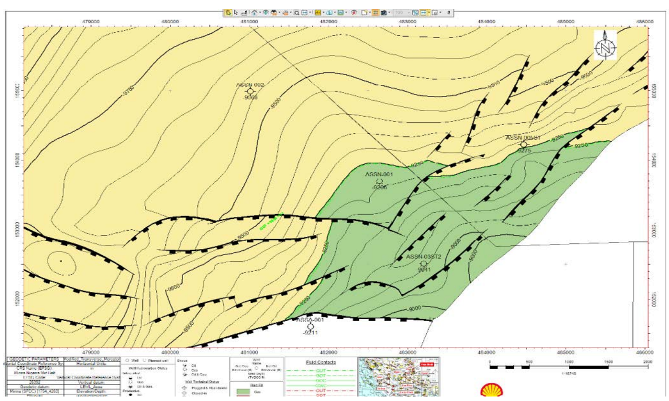

Figure 3: Top Structure Map for Orbit Reservoir.

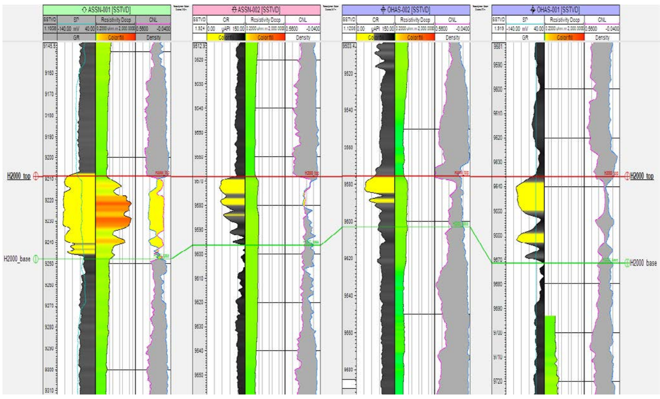

Figure 4: Correlation Panel for Orbit Reservoir.

Results and Discussion

Results from reservoir and well modelling of the Orbit reservoir are presented and discussed in this section. Three different development scenarios were considered – production under volumetric reservoir conditions, production with aquifer presence and gas cycling under volumetric reservoir conditions. Projected cumulative gas production (gas recovery), well life and development economics are the criteria for comparison used in this study.

Tubing size selection

The inflow performance relationship (IPR) plot was generated based on the reservoir data in PROSPER while the vertical lift performance (VLP) plots were generated for three production tubing, 3.5 in, 4.5 in and 5.5 in as shown in Figure 4. Matching the IPR and VLP determines the operating point in terms of pressure and production rate. It can be inferred that the tubing sizes 3.5 in and 4.5 in are too small. The reservoir is capable of high deliverability but is constrained by the tubing size **(Table 4)**. Therefore, the 5.5-inch tubing is most preferred for producing gas from the Orbit reservoir. The obtainable rates for each tubing size are given in Table 4. The production forecast for the use of 5.5-in production tubing is shown in **(Figures 5 and 6)**.

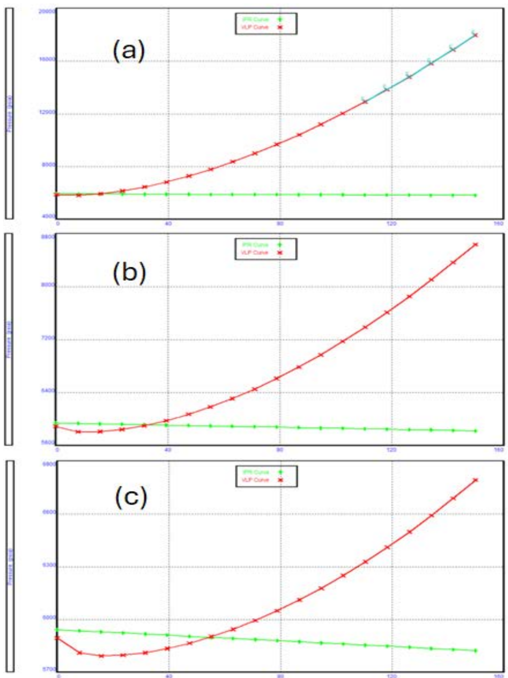

Figure 5: VLP/IPR Plot for (a) 3.5-in tubing (b) 4.5-in tubing (c) 5.5-in tubing.

Table 4: Gas Production Rates per production tubing size.

Production Tubing Size (in.)	Gas Production Rate (MMscf/d)
3.5	14.6
4.5	33.1
5.5	54.7

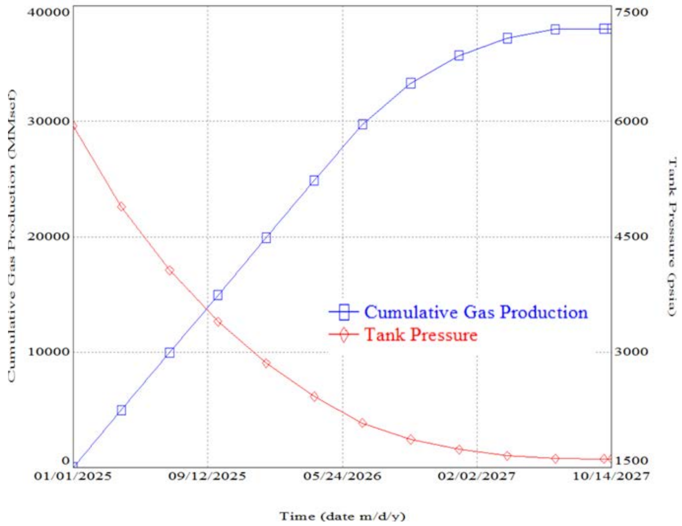

Figure 6: Production forecast using 5.5-in tubing

Table 5: Gas recovery from a volumetric gas reservoir.

Tubing Size (in)	Gas RF (%)	Condensate RF (%)	Well Life
3.5	54.7	22.1	12 years
4.5	54.6	22.1	5 years
5.5	54.6	22.2	3 years

Modelling natural depletion under aquifer influence

Varying aquifer strength was sensitized to assess their influence on the recoverable volumes. The gas recovery results are shown in Table 6. The highest gas recovery was observed in the weak aquifer case with a gas recovery factor and a condensate recovery factor of 47.5% and 23.7% respectively. The Orbit reservoir has an abandonment pressure of 2029 psi in this case. In this study, gas recovery does not decline with increasing aquifer strength. The partially weak aquifer case has the lowest gas recovery, closely followed by gas recovery in strong aquifer case with about 26% and 30% respectively. Abandonment pressure for the weak aquifer and strong aquifer cases are 4817 psi and 5291 psi respectively **(Table 6)**. The reduction in gas recovery for the weak aquifer case as compared to the natural depletion from a volumetric reservoir (47% versus 54%). This can be attributed to the reservoir thickness (67 ft) which could potentially encourage early water breakthrough during production in cases with aquifer presence.

Table 6: Gas recovery under varying aquifer strength.

Aquifer Strength	Gas RF (%)	Condensate RF (%)	Well life
Weak Aquifer	47.5	23.7	3.5 years
Partially Active Aquifer	25.8	25.1	5.33 years
Strong Aquifer	29.6	29.6	8 years

Modelling production under gas cycling

In this case, three different percentages of recycled gas were modelled to predict gas recovery and how the reservoir life cycle is affected. The abandonment pressure is 1596 psi, 1585 psi and 1571 psia for 20%, 30% and 40% recycled gas respectively. The gas recovery factor increases with an increasing percentage of the gas cycled back as shown in **(Table 7)**. Cycling a percentage of the gas back into the reservoir is viable if the demand from Orbit reservoir is secondary. The recovery factors and production life cycle increased with higher recycling percentages, ranging between 2.6 and 6.6% increase in gas recovery and 4.1% and 11.4% increase in condensate recovery. This is similar to results obtained in a study done which showed a 7.26% increase in condensate recovery when the gas cycling method was implemented[19]. also conducted a similar study aimed at improving the performance of a gas condensate reservoir through gas cycling showed an increase of 6.53% compared to the base scenario which was natural depletion[20].

Table 7: Gas recovery: gas cycling scenario.

Gas Cycling (%)	Gas RF (%)	Condensate RF (%)	Life Cycle
20	57.3	26.8	5 years
30	59	29	6 years
40	61.2	33.5	9 years

Economic Evaluation

The basis for economic evaluation is given in Table 7. Existing wells would require workover or recompletion. No new wells are required. It is noteworthy that in this study the produced gas is converted to barrels of oil equivalent. The fiscal system is the typical Tax-Royalty system prior to the Petroleum Industry Act, 2021. The net present value (NPV) of the different cases considered is shown in **(Tables 8 and 9)**. Considering total hydrocarbon recovery and project NPV, gas cycling is a viable alternative to natural depletion.

Table 8: Basis for Economic Evaluation.

Item	Value
Capital Expenses including well workover costs	$18.1 million
Crude oil price	$85.77
1 barrel of oil equivalent	5,800 scf
Petroleum Profit Tax	85%
Discount rate	10%

Table 9: Net Present Value for two cases.

Case	NPV ($million)
Natural depletion from a volumetric reservoir	$74.7
40% Gas Recycling	$77.5

Limitations to the study

The Orbit reservoir has not been modelling with geological detailed in this study. This is partly due to our inference that a single well is sufficient to develop this reservoir. However, should a second well be considered to improve the gas and condensate recovery factors, detailed reservoir modelling and simulation would be required, Secondly, an integrated production system model incorporating surface facilities would better capture uncertainties related to the optimal development of a marginal green gas condensate reservoir such as the Orbit field.

Conclusion

Based on the reservoir and well modeling of the green, marginal gas condensate reservoir (Orbit), the following conclusions can be reached:

- Orbit reservoir can be economically produced for a limited time to a nearby production facility, via a 5.5-inch tubing.
- A single well is sufficient to recover gas as high as 54% under volumetric expansion and 62% under gas cycling.
- Gas cycling is a viable option to natural depletion especially if Orbit is treated as a backup gas and condensate producer. Condensate recovery is improved significantly under gas cycling.
- Aquifer influence would limit hydrocarbon recovery leading to abandonment at relatively high reservoir pressures.

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