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Quantifying the Uncertainty in the Development of 'OWA' Marginal Field, Onshore Niger Delta, Nigeria

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ABSTRACT

The development of the field was considered by running the cashflow analysis and establishing the economic indications. The one-well scenario was only able to produce 50% of EUR (2.8MMbbl) while the two-well scenario gave up to 80% EUR (4.7MMbbl) before abandonment rate for a field life of about 15 years. The cashflow analysis showed an attractive marginal project with positive Net Present Value (NPV) for the \$50/bbl base oil price scenario and the contractor's take was estimated to be about 22% of the total share. The greatest effect on the NPV was seen from the Petroleum Profit Tax (PPT) and the oil price in the sensitivity analysis which is negative and positive respectively. OWA marginal field reflects a typical low reserve development category and with effective cost management even at extreme low crude oil prices, a marginal profit can be ascertained and eventually fostering the Nigeria economy.

1. Introduction

A review on the development of marginal oil fields in Nigeria has now become an important strategic issue if she must remain amongst the top producers in the global market, and these fields are vast available all over the Niger Delta. The aim of any investor is to make profit. He ranks and screens his investment based on several profitability and financial criteria such as Net Present Value (NPV), Internal Rate of Return (IRR), Profit to Investment Ratio (PIR) etc. The aim of any government in all oil and gas producing countries is to maximize its share in the economic rent generated from exploration activities and at the same time guaranteeing a reasonable return to the oil and gas companies carrying out such explorations [1][2][3].

2. Methodology

Hypothetical figures were assumed due to unavailability of some data including; production data, well test and other relevant cost. These were used to estimate various scenarios and a pseudo field production profile was generated for the field life. Two scenarios (well 1 and well 2) were compared for the possible outcomes regarding production profile and cost effectiveness.

Table 1. Production Forecast Assumptions.

Initial prod rate (bbl/d)	700
Peak prod rate (bbl/d)	875
Period of incline (years)	1
Duration of plateau (years	4
Initial decline rate (%)	5%
Duration of initial decline (yr)	1
Duration of second decline (%)	8%
Duration of second decline (yr)	2
Decline before 60% of EUR	10%
Final decline rate	20%
Abandonment prod. rate (bbl/d)	100
Estimated days per year	300
EUR	5700000

NCFt = Investor's after tax net cash flow in year t,

GRt = Gross revenues in year t,

ROYt = Total royalties paid in year t,

CAPEXt = Total capital expenditures in year t,

OPEXt = Total operating expenditures in year t,

BONUSt = Total Bonus paid in year t,

TAXt = Total taxes paid in year t

VATt = Value added tax paid in year t.

OTHERt = Other costs paid which are NDDC charge

The discounted net cashflow analysis was generated on excel through cost forecast and tax deduction using the concessionary fiscal policy. The Net Present Value (NPV) thus generated was simulated using the Monte Carlo techniques to quantify the uncertainty and sensitivity around the cashflow with the crystal ball software. The net cash flow of a marginal field investment is the cash received less the cash spent during a year over the life of the field development project. The investor after tax net cash flow of the marginal field in year t is given as

$$NCF^{I}t = GRt - ROYt - CAPEXt - OPEXt - BONUSt - TAXt - VATt - OTHERt \quad \text{...EQN (I)}$$

The government net cash flow is given as

$$NCF^{G}t = ROY^{G}t + TAXt + BONUSt + NDDCt + VATt \quad \text{...EQN (II)}$$

The farmour net cash flow is given as

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$$NCF^{F}t = ROY^{F}t \quad \text{……EQN (III)}$$

After computing the respective Net Cash Flows for investor or contractor, government and farmour, their respective takes can then be computed in percentage as:

INVESTOR'S TAKE=

$$\frac{NCF^{I}t}{NCF^{I}t + NCF^{G}t + NCF^{F}t} \quad \text{……EQN (IV)}$$

GOVERNMENT'S TAKE =

$$\frac{NCF^{G}t}{NCF^{I}t + NCF^{G}t + NCF^{F}t} \quad \text{……EQN (V)}$$

FARMOUR'S TAKE =

$$\frac{NCF^{F}t}{NCF^{I}t + NCF^{G}t + NCF^{F}t} \quad \text{……EQN (VI)}$$

3. RESULTS AND DISCUSSIONS

The EUR estimated from this marginal field was about 4.7MMbbls [4]. Looking at cost management particularly with marginal field, production forecast options were compared for one-well and two-well drilling. The one-well scenario was only able to produce 50% of EUR (2,842,369) before the abandonment rate while the two-well scenario gave up to 80% EUR (4,699,390) for a field life of about 15 years (Fig. 1). The two-well plan was accepted as recovery was at its peak (Fig. 2). Economic limit of a field refers to the point at which further production will result in loss and the field becomes a financial liability.

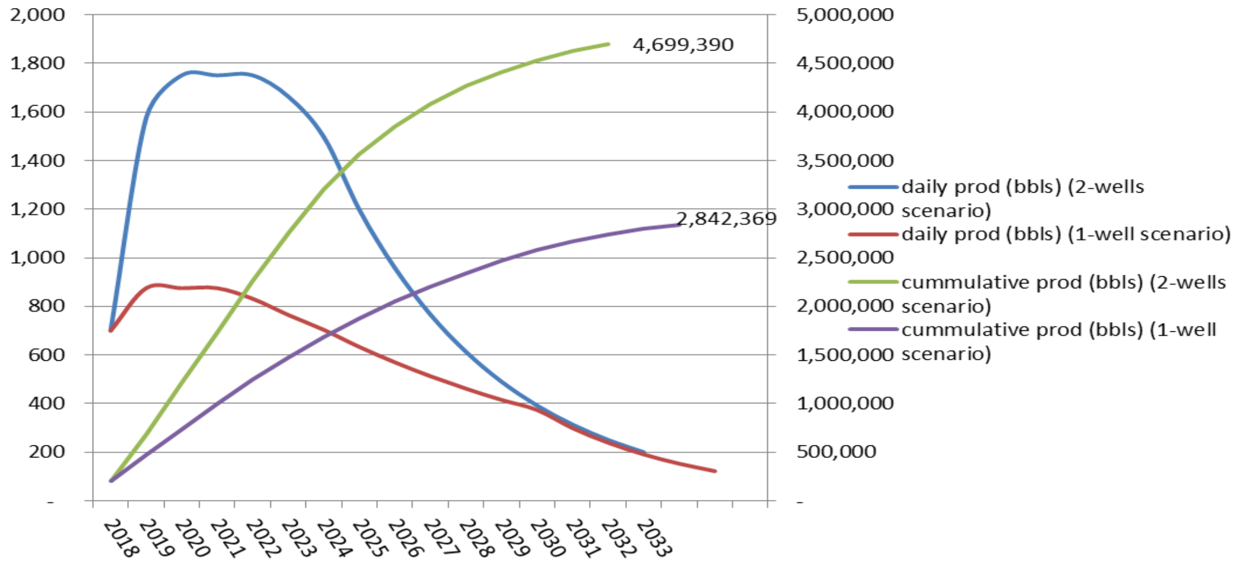

Fig. 1. Production Profile for the Field.

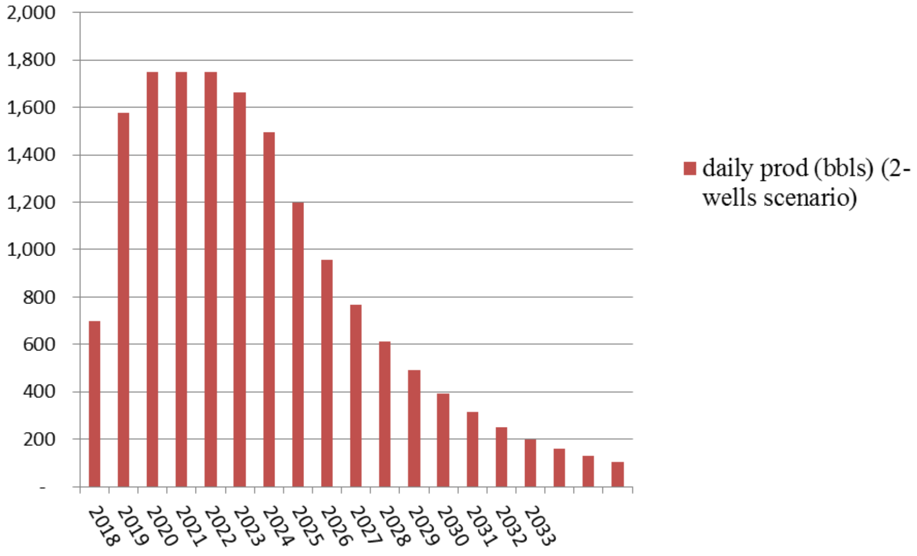

Fig. 2. Production Profile (two wells); peak production is <1.8MMBOPD.

Cost Forecast

The cashflow analysis for OWA marginal field were based on the following assumptions

Table 2. Technical Input.

Drilling (MM$)	Flowlines (MM$)	Manifold & Bulkline (MM$)	Total CAPEX (MM$)	OFFTAKE-2 wells (BOPD)	EUR (MMstb)
20.0	1.5	2.0	23.5	1750	4.7

- 2 wells at $10million each
- Flowlines @ $750k per well
- Manifold & bulklines for evacuation to a nearby flowstation @ $2million

Parameters	Details
Oil Price	$50/bbl flat, $60/bbl flat, $65/bbl flat, $70/bbl flat
OPEX	General & Admin :$1.5m p.a Flowstation/well services : $3.0/bbl Crude Handling & Evacuation : $4.0/bbl
Taxes	Govt. Royalty :2.5% (i.e 0 to 5Mbopd) Overriding Royalty :2.5% Petroleum Profit Tax (PPT) :65%, 85% Education Tax : 2% Niger Delta Development Commission (NDDC) : 3% Nigerian Export Supervision Scheme (NESS) :0.12%

Table 3. cashflow summary.

Price Scenerio ($/bbl)	NPV_{10} (MM$)	PIR_{10} (FRAC)	IRR (%)	PAYBACK (YRS)	UDC ($/BBL)	UTC ($/BBL)
50	16.03	0.4	39	<4	5	12.52
60	22.31	0.95	49	3		
65	25.45	1.08	53	<3		
70	28.59	1.22	57	<3		

The development cost was about $24million for the marginal offtake of 1750bopd and ultimate recovery of c.4.7MMstb. The contractor's NPV after due taxes was estimated to be c. $16million amounting to 22% of the total share while the government's NPV from all the taxes and royalty was estimated as c.$55million which amounted to the largest share of 74% and the overriding royalty belonging to the farmour was estimated to be c. $3million NPV and that only was 4% of the total take. Several profitability and financial indicators such as NPV, IRR (Internal Rate of Return), PIR, and payback etc, are used by the investors to accept or reject a project. Table 3 shows the cashflow summary with the NPV all positive and the payback period (period for which investment fund can be recovered and reinvested) less than four (4) years. The greater the positive NPV is, the more economical the project and this is being depicted with the greater oil price scenarios.

The Monte Carlo simulation randomly selects available data within the range of distributions to forecast values [5]. P90 denotes the highest level of confidence i.e. at least 90% of the range of volume that will be gotten will not be lower than the P90 value while P10 is the lowest level of confidence i.e. at least 10% of the range of volume that will be gotten will not be lower than the P10 value. The percentiles reveal that at least c.$29million (P90) can be ascertained (Fig. 3).

Fig. 4 and 5 show the effect of the input variables on the base scenario of the financial model built in this study. Fig. 4 shows the spider chart which further depicts the effect of each parameter on NPV with the steepness of the slope. Curves with steep slopes either positive or negative, indicate that those variables have a large effect on the forecast, while curves that are almost horizontal have little or no effect on the forecast. The slopes of the lines also indicate whether a positive change in the variable has a positive or negative effect on the forecast (NPV). The spider diagram shows that PPT, OPEX, decline rate, and CAPEX have negative relationship with the field's NPV, which means as each of these parameters increases, the firm's NPV decreases. On the other hand, oil price per barrel and recoverable reserves have positive relationship with the field's NPV. That is, as global oil price and total field production increase, the field's NPV also increases.

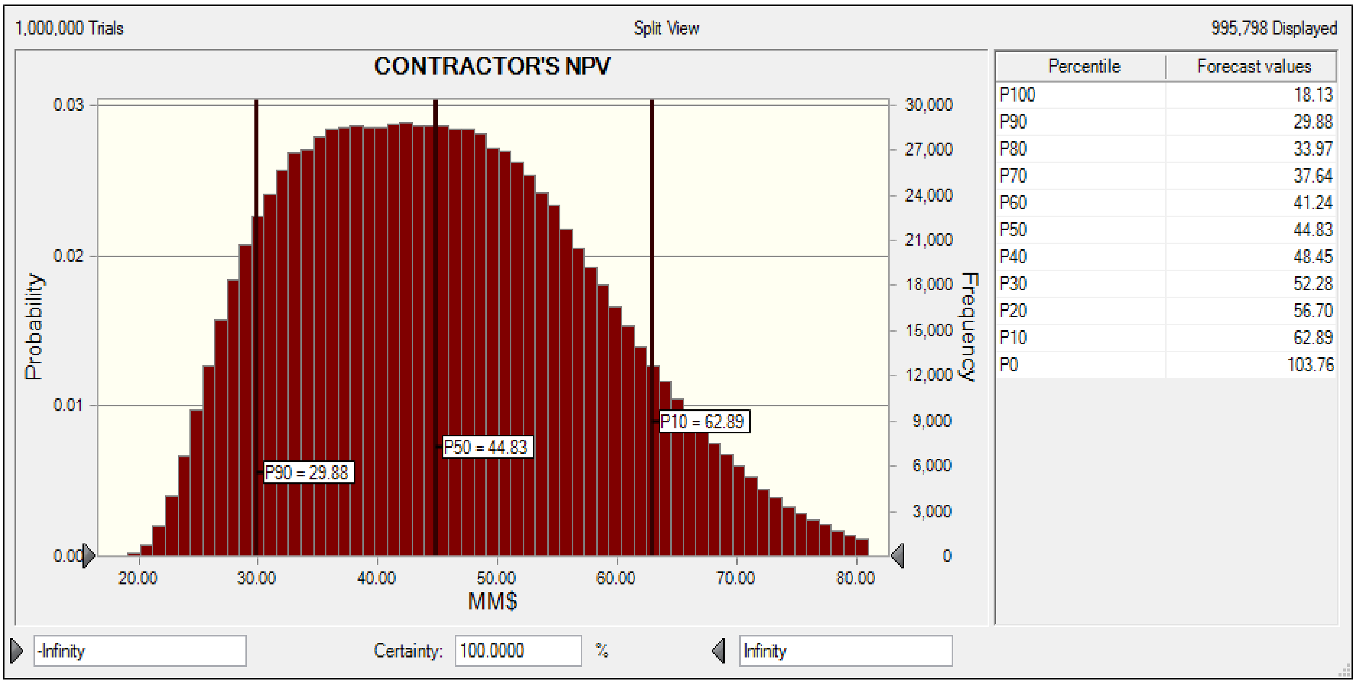

Fig. 3. NPV simulation.

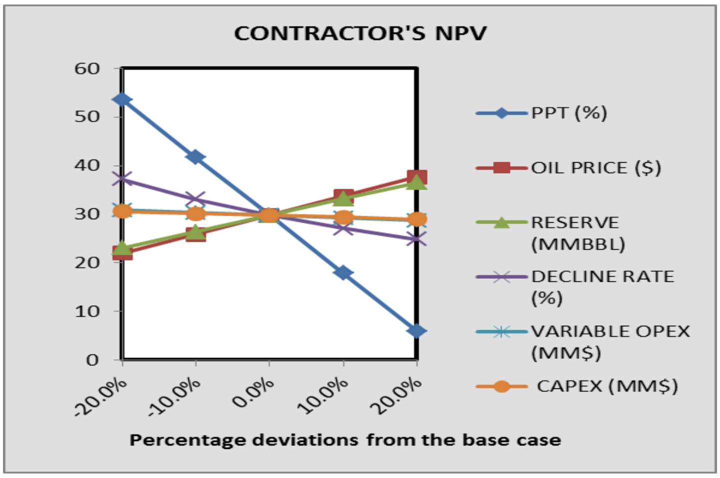

Fig. 4. Spider chart for effect of parameters on NPV.

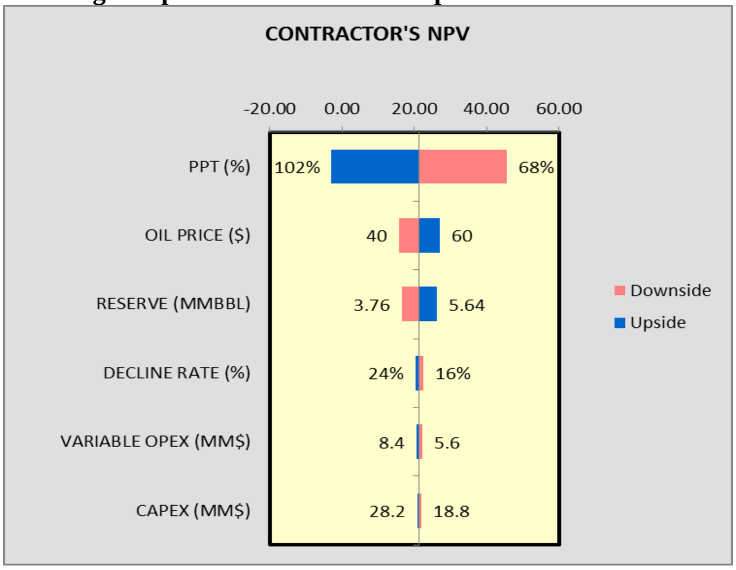

Fig. 5. Tornado chart for effects of parameters on NPV.

4. CONCLUSIONS AND RECOMMENDATIONS

OWA marginal field was considered as a typical low reserve development category and the two-well plan scenario gave more than 80% of the expected ultimate recovery and a field life of 15years.

The cashflow analysis showed an attractive project with positive NPV for the $50/ bbl base oil price scenario and the contractor’s take was estimated to be about 22% of the total share. Other profitability criteria were reasonably appropriate for the marginal field development.

To keep the project even economical at extreme lower prices, development cost should be significantly lowered and the offtake improved, which is crucial for a marginal field development.

Strategies for reducing risk and uncertainty include collecting additional information before making a decision [6][7][8] or deferring decisions until additional information becomes available. Hence, to further advance the economics and also the potential of this field, more data should be provided.

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