



# Comparative assessment of proposed fiscal models for offshore deep water petroleum exploration in Nigeria

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## ABSTRACT

Two appropriate post-tax petroleum exploration models were constructed and tested for three hypothetical field profiles (i.e low, medium and high volume fields) from a development economics perspective and the proposed tax regimes tested for both oil price and development cost (\$/bbl). 40% government participation through the international oil company was considered in both cases. The resulted government takes for the first proposal are 76.89%, 83.07%, and 86.94% for low, medium and high volume fields respectively. Respective percentages for the second proposal are 76.20%, 80.03% and 85.43%. These values are above the average global take of 64% but within the range of 40% to 87% for most world oil producers. Analysis of the models indicates an increase in government take as the development costs (\$/bbl) increases but a decrease when the oil price (\$/bb) increases, which shows regressivity. However, the second regime shows more neutrality, efficiency and focused stability, though still maintaining high government take. This contributes to more attraction for investment from both government and investors perspective. Thus, the second fiscal proposal is recommended to the Nigerian government, considering its incentives.

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## Introduction

The objectives of a host government should be to design a stable, flexible and neutral fiscal system that favours investment and allow government's mutual interests by providing an equitable arrangement for both less and highly profitable discoveries (Sansing, 1993; Nutavoot, 2004). Thus, there is an absolute need to design a fiscal system that encourages macroeconomic stability by providing predictable and stable tax revenue flows, allow capturing larger share of the revenues during periods of high profit, avoid the introduction of distortion elements through the fiscal instruments, maximises the present value of revenue receipts and is neutral and encourages economic efficiency (Tordo, 2007). This definitely requires that two or more fiscal models are proposed, effective models constructed and an assessment of relative performance of the models by changing a selected number of fiscal and system parameters carried out (Blake and Roberts, 2006). Post-tax models are usually employed because a clear indication of the effects of government takes, oil price, and development expenditure on the investor's cash flow and NPV can be generated (Blake and Robert, 2006; Luo and Na, 2010). This paper provides an assessment of the two proposed fiscal models for Nigerian deep waters. Post-tax financial models were constructed and their solutions tested for low, medium and high volume fields. Performance of the models was also investigated for both oil price and development cost (\$/bbl). This is required to be certain of the most appropriate Production Sharing Agreement (PSA), considering inflation and economic variations. The models were proposed based on the instigation that, the previously ignored deepwater fields are currently

gaining attention due to foreseeable depletion of the onshore and shallow water reserves.

## Nigerian Petroleum Fiscal System

**The Licence System:** Nigerian licence system composed of oil exploration licences, oil prospecting licences and oil mining leases and licences, which are treated according to Petroleum (drilling and production) Regulations of 1969, 1973 and other amendments (Akhigbe, 2007). The regulations also provides obligation for recruitment and training of Nigerians, exploration and drilling, fields development, accounts and records, fees, rents and royalties. The Oil Exploration Licences (OEL) is a non-exclusive licence of limited period, which allow a regulation size of 5,000 sq miles. Oil Prospecting Licence (OPL) on the other hand confers exclusive rights of surface and subsurface exploration of petroleum in area not more than 2,950 sq Km for initial period of 3 years before a maximum renewal of 2 years. It give an operator a right to petroleum won during prospecting activities, under the Petroleum Profit Act 1959 (Nwete, 2005). The Oil Mining Lease (OML) grants the rights to explore, win, produce, transport and carry petroleum away from leased area in accordance with the Petroleum Act 1969 and any special condition imposed. A stipulated size of 1295 sq Km is allowed for duration of 20 years (almost similar to United Kingdom). Operators with OPL can apply for OML, subject to satisfactory conditions.

**The Tax System:** The fiscal regimes consist of Joint Ventures (JV), Production Sharing Agreements (PSA) and service contracts, Memorandum Of Understanding (MOU) and are derived from Petroleum Tax Act 1959, its several amendments (i.e. 1967, 1970, 1973, 1977, 1979, and 1990), and

contracts between Nigerian National Petroleum Corporation (NNPC) and operating companies (Akhigbe, 2007).. The subsequent production sharing contract (PSC) composed of royalty, bonuses, rentals, and petroleum profit tax (PPT), with the application of ring fence and cost recovery, in addition to investment allowances and obligations imposed on operators (John, 1994; John, 2001). Some other contrasting and consolidated taxes include 2% education tax levied on assessable profit, 5% contribution of employee wages to Nigeria Social Insurance Trust Fund (NSITF) and payment of 1% of the company payroll to the Industrial Training Fund (ITF).

Bonuses are main pre-production payments, and are a feature of the production sharing and service contracts. The amounts are steadily increasing. In the early 1990's the PSCs contractors paid \$1 million each and \$20 million in 1999. The signature bonuses for post-2000 were up to \$30 million. A value of US \$123 was paid in respect of Block 1 of Nigeria-Sao Tome Principe Joint Development Zone, 2003 (Gomes, 2005; Omorogbe, 2005). Since before now, royalties are in the Nigerian context, paid based on volume of production and decrease with increase in water depth for offshore fields. Payment can range from 20% to 0% depending on whether the field is onshore or offshore. The NNPC owns an average of 57% of Joint Ventures, the profits from which are shared in the same ratio (Odianosen, 2006). The MOU is a contract between the government and Joint Venture companies, which first came in 1961 before previous and current changes. This is to guarantee certain level of profits to the oil company irrespective of fluctuating market prices. Under the 1986 MOU profit margin was \$2.0 per barrel (after tax and royalty), \$2.30 to \$2.50 per barrel under 1999 MOU and currently about \$4.0 per barrel. The MOU was believed not to be in line with the present trends towards good governance, transparency, and accountability (Omorogbe, 2005).

It can be seen that the PSC retains the payment of large royalty, indicating a non-neutral tax system. This distorts a project revenue profile by creating a delay in the project's pay-back. However, uplift allowance and accelerated depreciation can delay taxation, and consequently generating positive impact on the investor's cash flow.

### The Models

An understanding of how the various components of a post-tax financial models influence decision making and out comes forms the basis for the modelling. It is very useful to accept the fact that good fiscal modelling without complementary institutional structures may still deviates from the desired objectives for both the investors and the host government. Therefore the modelling needs to be within the administrative and audit capacity of the parties involved. In essence, for the Nigerian provinces under consideration a simple model would be more viable than the current theoretically ideal but complex to manage model. In modelling the various field economics under the proposed fiscal options, a number of simplifying assumptions were made. In particular, no any distinction was made between tangible and intangible costs (Tordo, 2007); a ten year straight line depreciation was used for all the models, a deterministic approach was applied to calculate the total production levels, and costs for all the three field categories. 10% discount rate was used in both models and the participation of national oil company (40%) was considered and its share of expenses was carried by the investor's group without any interest rate. Five percent inflation rate was considered and in

testing the the performance, efficiency, neutrality and sensitivity to price volatility oil prices were varied (i.e. \$30, \$45, \$60, and \$75). The development expenditure was also varied from \$2/bbl to \$5/bbl at \$60/bbl oil price, in line with the common practice in the oil industry. The Nigerian fiscal system involved a royalty of 20% for certain field category. This is generally reduced to 12.5% to allow adequate risk sharing between government and investors. The general assumptions used are given below while the models parameters are presented in Tables 1 and 2.

### General assumption data:

The following parameters were generally assumed in line with real situations.

Inflation: 5%

Oil price: \$45 for the models and later varied.

Government participation: 40%.

Depreciation rate: 10 years straight line.

Discount rate: 10% throughout the modelling and performance assessment.

Field life: 26 years for all fields.

Royalty: 12.5%.

Corporation tax: 35%.

### Results

The results of the various analyses are illustrated in figures 1 to 18. The effects of change in government take with various parameters such as oil price and field development cost are illustrated in Figures 1 to 12. The remaining figures (i.e. 13 to 18) show the effects of oil price on the investor's post-participation return.

### Government take variation with oil price

#### A: Low volume field

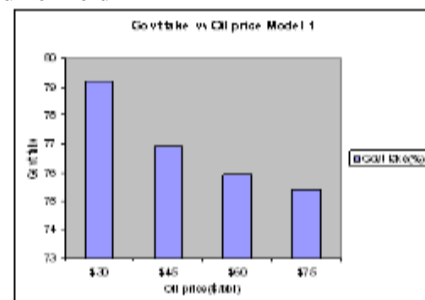


Figure 1: Government take vs oil price, model 1

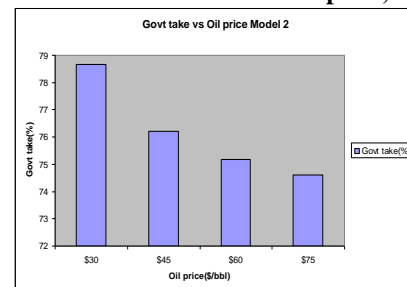


Figure 2: Government take vs oil price, model 2

#### B: Medium volume field

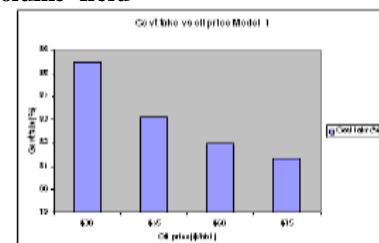


Figure 3 Government take vs oil price, model 1

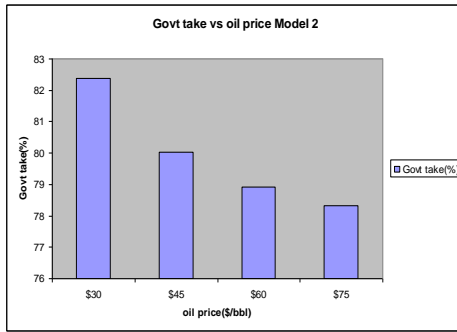


Figure 4: Government take vs oil price, model 2

C: Large volume field

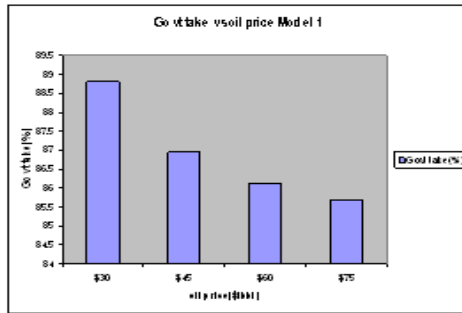


Figure 5: Government take vs oil price, model 1

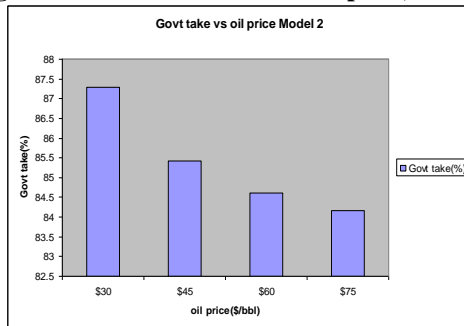


Figure 6: Government take vs oil price, model 2

Government take variation with development cost (\$/bbl)

E: Low volume field

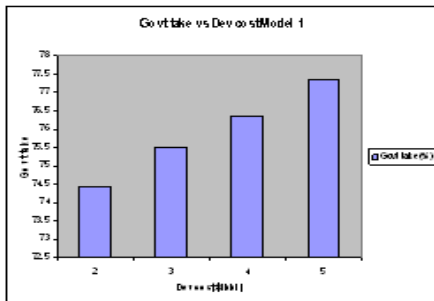


Figure 7: Government take vs oil price, model 1

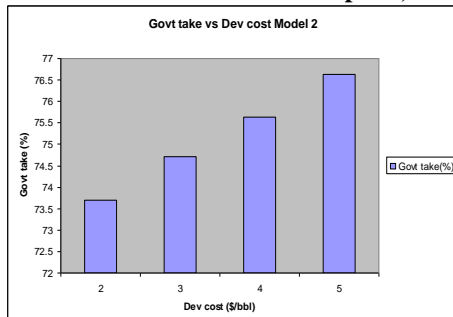


Figure 8: Government take vs oil price, model 2

F: Medium volume field

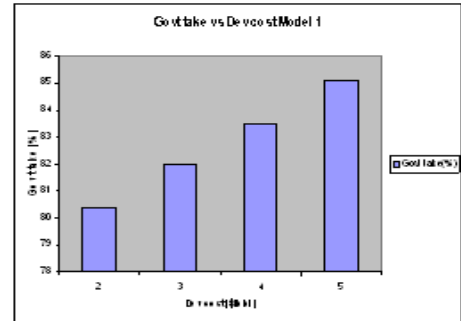


Figure 9: Government take vs oil price, model 1



Figure 10: Government take vs oil price, model 2

G: Large volume field

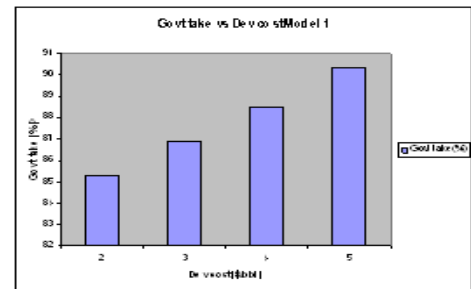
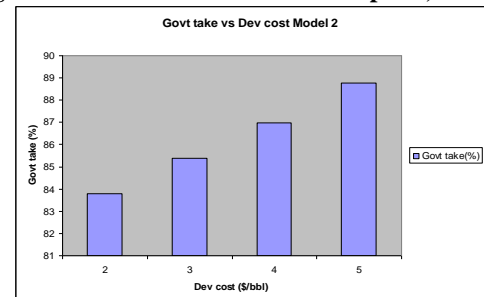


Figure 11: Government take vs oil price, model 1

Figure 12: Government take vs oil price, model 2  
Variation of oil price (\$/bbl) with investor's post-participation return

H: Low volume field

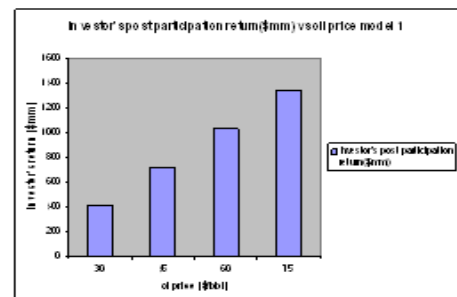


Figure 13: Oil price vs investor's return, model 1

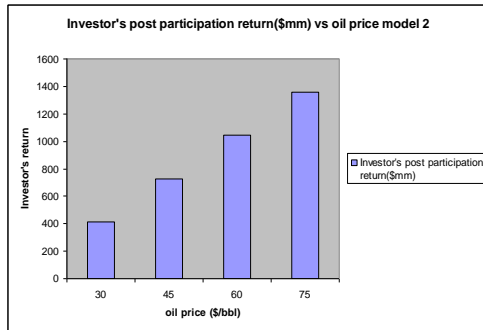


Figure 14: Oil price vs investor's return, model 2.  
I: Medium volume field

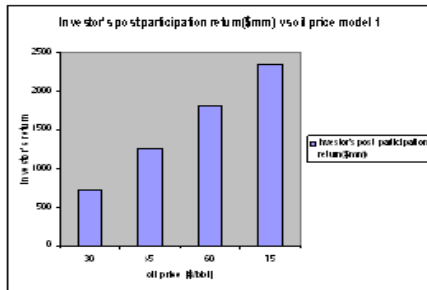


Figure 15: Oil price vs investor's return, model 1

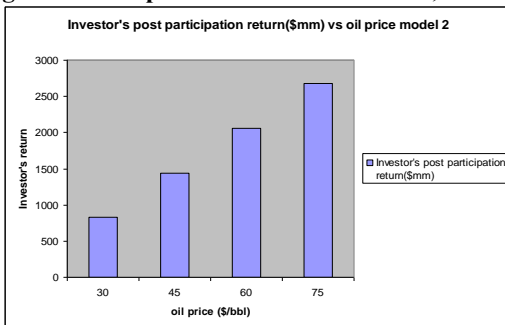


Figure 16: Oil price vs investor's return, model 2.  
J: Large volume field

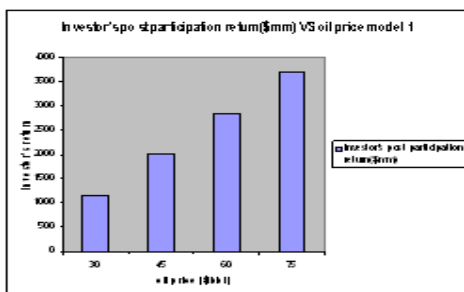


Figure 17: Oil price vs investor's return, model 1

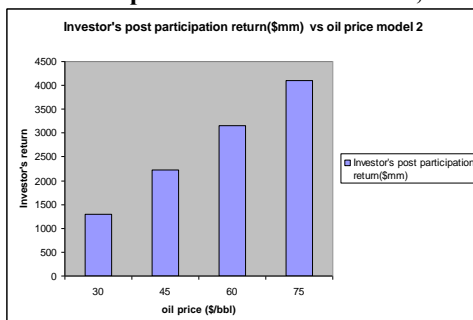


Figure 18: Oil price vs investor's return, model 2

From figures 1 to 6, the government take for the fiscal package of model 1 is higher than the take for fiscal proposal 2, which indicates high share for the government and in return low take for the investor. To encourage attractive investment the

fiscal package 2 should be used since the province is a new field. Similar trend exists also for the large volume field. It is generally clear from figures 7-12 that government get higher take as the development cost increases for all the field types, and in both models. However fiscal package 2 allows lower take in comparison and is therefore attractive to investors for a new province. Figures 13 to 18 show that an increase in oil price increases the investor's post- participation return. More return can be realised from the model package 2 and therefore becoming more attractive for investment. This in consideration to variation of government take with oil price allows both high government rents and attractive investment.

#### Discussion/Interpretation

Although the oil company and the host government may share the same production sharing objectives. i.e. the desire for the exploration activities to produce high level of revenues, there are some discrepancies (Deming, 1999; Jiuliang and Fenglan, 2001; Yuhua and Dongkun, 2009). Investors always aim to ensure that the return on investment is consistent with the level of risks and uncertainties associated petroleum exploration and with the company's objectives. On the other hand, the government aims are to obtain maximum possible wealth from the reserves and upgrade its socioeconomic status through local infrastructure development, creation of job opportunities and transfer of modern science and technology. The use of neutral, flexible, stable and risk-sharing fiscal model provides the most suitable reconciliation mechanism for these conflicting objectives. The two models are therefore solely compared on this scale.

Investors always require an overall fiscal policy environment that is predictable, transparent, stable and based on rule of law, which allow reasonably confidence decision making (Phina, 2004). The inclusion of flat rate gross well head production royalty produces regressive tax system and consequently affects the investor's return on investment. This is because royalty affects the net present value (NPV) of the company (Phina, 2004) and causes a delay in the project payback period. The two proposed regimes modelled are regressive because of the inclusion of gross well head production royalty (12.5%), which result to high government take when the profit is low and a low government when the profit is high. Although the figure is below the upper royalty band of 20% currently imposed it is attractive to the government as early revenues are obtained (Kheilil, 1995).

One of the most important elements of the profitability and regressivity of a project is the oil price level. In the past a barrel of oil costs below \$30 but with rapid industrialisation, changes in economic strategies and political reasons the price raises up to \$140/bbl or more. Therefore the price range of \$30- \$75 employed is basically in line with the real situation. The variability and volatility of oil prices provide for the possibility that even projects with normal profits can experience periods where excess profits are generated. In this case the government take tend to reduce, though by little percentage in some cases, as the price of oil increases (Figures 1 to 6). This is directly or indirectly associated with the effect of the flat rate royalty.

However, from the world Bank definition of (1995) of progressive and regressive tax system for different field categories similar to those analysed , both models showed progressive regimes since the government take is larger percentage of the cash flow for large and profitable fields than for the low volume (marginal) and less profitable field (Tables 3

and 4). Both fiscal models thus encouraged high take by the government as the field size increases (Figures 1 to 6 and Tables 3 and 4). Fiscal model number 1 shows significantly larger government takes for all the three field types analysed. With this many investors will prefer the second model for investment in a new province.

Development expenditure is another important parameter for assessing and testing a proposed fiscal model because such values are associated with risk, uncertainty and certainly affect return on investment. Contrary to the progressive and neutral fiscal systems, which allow lower taxes as the development costs increase, the two proposed regimes contribute to high government take as the development costs (\$/bbl) increases (Figures 7 to 12). The first fiscal model contributes more to these effects as can be seen in the earlier stated figures.

New investors are always concerned about the level of return from their investment both post-tax and post-participation where a national company is carried (Adam and Browne, 2006). Post-participation return on investment is the most appropriate decision making tool, because it provides investors with information on the maximum profitability or loss associated with the project, when the host government's share of the revenue streams (i.e. government take) is removed. It is widely believed that the level of the government take is inversely proportional to the quality and availability of investment opportunities (Khelil, 1995). Both models allow positive post participation return on investment (Tables 3 and 4). However, higher returns are obtained from regime 2 (Figures 13 to 18), still maintaining high government take, and thus becoming more attractive to investors.

It is most times useful to compare fiscal model for a new province with the world fiscal system for oil and gas producers. Both the two regimes are above the world average government of 64%, but are within the range of 40% to 87% for most global oil producers (Khelil, 1995). They are similarly within the current fiscal range for Nigerian fields but with lower level of gross well head royalty. For these reasons both government and investors should be comfortable with the models.

Stability of a tax system is also an important indicator of its fairness and effectiveness because it indicates the extent of changes applied and whether or not the changes are predictable (Kheli, 1995). A stable and progressive regime can lead to a limit for renegotiation in the future production of life of fields. As seen from all figures the model 2 shows more limited and easily predictable change in government take when viewed from oil price variation point and therefore is more likely to yield stability.

#### **Conclusion and recommendations:**

Oil and gas fiscal systems are associated with conflicting objectives between the host government and the investors. Host government aim is always to obtain the maximum value for their countries over time in terms of net receipts for treasury. The goal is to maximise the wealth from their natural resources, and at the same time, attract foreign investment. Oil companies on the other hand aim to ensure the return on capital is consistent with the risk associated with the project and with the strategic objectives of the corporation. These goals can both be reached by effective fiscal regime design and modelling. Assessment of the two proposed fiscal system indicates regressivity due to the inclusion of flat rate royalty causing government take to increase with increase in development costs and decrease with increase in oil price. However, the fiscal packages are within the world

range of 40% to 87% for most oil producers (Nigeria and Norway for example). This contributes to their suitability for investment. The second fiscal proposal is recommended to the Nigerian government considering its incentives that include the following.

- Though high, it allows lower government take compared to regime 1 for all the field types and therefore encouraged more investments from foreign companies.
- It also allows higher return on investor's post-participation income
- The regime can lead to more stability, neutrality, reduce the need for subsequent future negotiations and will allow shorter pay back compared to the first proposal.

Being a new offshore province, the government should also initiate safeguard for marginal fields and ring fence, contribute to risk sharing and avoid high licensing fees as they can eclipse a delay in the investor's pay back.

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**Table 1: Production sharing terms and recovery limit for model 1**

**Recovery limit: 65%**

| Government share (%) | Threshold level (000's) |
|----------------------|-------------------------|
| 15                   | 10                      |
| 25                   | 25                      |
| 50                   | 35                      |
| 60                   | 45                      |
| 75                   | 60                      |

**Table 2: Production sharing terms and recovery limit for model 2**

**Recovery limit: 75%**

| Government share (%) | Threshold level (000's) |
|----------------------|-------------------------|
| 25                   | 40                      |
| 45                   | 50                      |
| 65                   | 70                      |
| 75                   | 90                      |
| 85                   | 100                     |

**Table 3: Economic parameters for model 1**

|  | Low volume field | Medium volume field | High volume field |
|--|------------------|---------------------|-------------------|
| Govt take (%)                              | 76.89            | 83.07               | 86.94             |
| Post-participation investor's return(\$mm) | 716.16           | 1251.23             | 2003.5            |
| Investor's IRR(%)                          | 47.49            | 37.60               | 39.22             |
| Total oil production (MMBBL)               | 99.65            | 249.60              | 503.7             |
| Oil price (\$/bbl)                         | 45               | 45                  | 45                |
| Dev. Expenditure(\$mm)                     | 350              | 750                 | 1250              |

**Table 4: Economic parameters for model 2**

|  | Low volume field | Medium volume field | High volume field |
|--|------------------|---------------------|-------------------|
| Govt take (%)                              | 76.20            | 80.03               | 85.43             |
| Post-participation investor's return(\$mm) | 728.03           | 1438.21             | 2218.00           |
| Investor's IRR(%)                          | 47.49            | 37.60               | 39.22             |
| Total oil production (MMBBL)               | 99.65            | 249.60              | 503.7             |
| Oil price (\$/bbl)                         | 45               | 45                  | 45                |
| Dev. Expenditure(\$mm)                     | 350              | 750                 | 1250              |