Impact of Proposal Changes to Libyan Oil Taxation System on Developing the 137 B Offshore Field

¹Saad Balhasan, ²Biltayib Misbah, ²Mohamed Omar, ³Ibrahim Musbah and ⁴Belkasim Khameiss
¹Department of Chemical and Petroleum Engineering, American University of Ras Al Khaimah,
Ras Al Khaimah, United Arab Emirates
²Department of Petroleum Engineering, Australian College of Kuwait, Kuwait City, Kuwait
³Department of Petroleum Engineering, Sirt University, Sirt, Libya
⁴Department of Geological Sciences, Ball State University, Muncie, USA

Abstract: The Libyan economy is generating revenue through exploration and production oil agreements (EPSA). The contemporary taxation system when implemented on the project 137B offshore under the original EPSA 1, the project appraisal exposed that is was economically less attractive to the second party (TOTAL). To avoid that conflict of interest, it was suggested that EPSA 1 must be accordingly amended. This study is an attempt to document those proposed amendment to EPSA 1 and EPSA 3 to avoid the conflict of interest between Libyan National Oil Corporation (First Party, FP) and Total (Second Party, SP) and consequently to develop the 137 B, an economical offshore oil field. Based on estimates, two different decision-making models were coded in a spread-sheet program to estimate profitability indicators for the 137 B offshore field. The proposed amendments of EPSA 1 are as following: the production sharing 81% to first party and 19% to second party in addition, the Operating Expenditure (OPEX) sharing also 81% to first party and 19% to second party. Moreover, the Capital Expenditure (CAPEX) was sharing 50% to first party and 50% to second party. Furthermore, 100% exploration costs to be paid by the first party. It is proposed that the project profitability indicators Net Present Value (NPV) and Internal Rate of Return (IRR) of the second party were improved from $15 million to $165 million and 7-23%, respectively. The proposed amendments of EPSA 3 are as following: the total production to be shared equally by both parties in addition, the OPEX also to be shared equally by both parties. Moreover, the CAPEX was sharing 50% to first party and 50% to second party. Furthermore, the exploration costs 100% paid by the first party. The project profitability indicators NPV and IRR of the second party were improved from-$15-$319 million and 7-44%, respectively.

Key words: Oil agreements, national oil company, international oil company, amendment, profitability indicators, economic model

INTRODUCTION

Statement of the problem and research objectives: The present fiscal regime in Libya is Exploration and Production Shearing Agreement (EPSA). The libyan government is focusing on accumulating higher revenue over time. Currently the libyan fiscal regime under EPSA is aiming to maximize the Libya's profit share, however, they are ignoring the effect on volume of the recoverable reserves and this behavior can be considered as responsible for low recovery in most of the libyan oil reservoirs. As a result, EPSA can have serious effects on field development strategies and the volume of recoverable reserves calculations.

The prime purpose of this study is to modify the the original contract, EPSA 1, relating to block 137 offshore that was signed on Oct. 13, 1974, between the NOC, Elf Libya and Aquitaine Libya with obvious aim to optimize the recoverable reserves of the field that apply to it.

In reaching above mentioned goal, the following objectives will be achieved: First, propose new amendments in the EPSA 1 Model to optimize the production of recoverable reserves. Second, develop a model that incorporates the most relevant decision variables of oil production, oil price, costs, cost oil, production share and profit indicators explicitly.

Third, modified form of EPSA 1 will be applied on the 137-B field and a critical comparison will be made of the results to the original and modified model of EPSA 1.

Corresponding Author: Saad Balhasan, Department of Chemical and Petroleum Engineering,
American University of Ras Al Khaimah, Ras Al Khaimah, United Arab Emirates

Historical background: By 1969, the year of the Libyan revolution, Libya had become the world's fourth largest oil exporter, however, unfortunately the government was receiving probably the lowest per-barrel price in the world. This explicit and remarkable variation in per-barrel price eventually resulted to the nationalization of some foreign companies and the conclusion of participation agreement. In 1970, the government with explicit order replaced the Libyan General Petroleum Corporation with the National Oil Corporation (NOC). Under the new setup, the company was given more powers including the control over the nationwide production of the oil. This was aimed at slowing the rapid depletion of Libyan reservoirs during the 1960's (Anonymous, 1989).

Oil reserves: Libya's proven oil reserves are officially estimated at 41.6 billion barrels as at January 2015 with (R/P ratio 67 years), however, some of the field experts postulate that the reserve could amount to considerably higher than that potential of both onshore and offshore sedimentary basins as they projected that the country's six large sedimentary basins Sirte, Murzuk, Ghadames, Cyrenaica, Kufra and offshore could contain oil in place of as much as 220 billion barrels (Anonymous, 1989).

National Oil Corporation (NOC): The NOC was officially established on 12. 11. 1970. The prime responsibilities of the corporation were to assert the feasibility of petroleum related developmental plans and supervision of operation and investment activities through its affiliates or in association with others (Anonymous, 1989).

The role of national oil corporation in exploration and production (E and P): The Libyan national oil corporation is currently controlling all exploration, production and marketing activities related to oil and gas sector both inside and outside of the country by the subsidiaries (National companies) or by contracts with International Companies (Anonymous, 1989).

Strategy: The Libyan NOC continuously develops plans for expansion country oil production. NOC has highlighted its plans for exploration and production in the following points:

- To be directed towards unexplored areas such as Kufra, Cyrenaica, remote areas and basin margins
- The exploration of deep targets within the Sirte basin
- The application of modern, state-of-the-art technology in exploration

- The opening of new areas within Sirte, Ghadames and Murzuq
- The introduction of new flexible terms in EPSA models

Implement Improve Oil Recovery (IOR) and Enhanced Oil Recovery (EOR) (Anonymous, 1989).

Petroleum legislation: The petroleum law was set up on 21.4.1955. Tax collection was set as the prime role for the ministry of petroleum. Concession-holders had complete freedom in the conduct of their activities. The Libyan general petroleum corporation has been established in 1970 and was completely replaced by the NOC in the same year and followed by adjustment of the Petroleum Law:

- Adjustment (22) 04-26-1971 (Fine and amends) in case of infraction of the roles related to conservation oil resource
- Adjustment (82) 11-18-1973, the price of crude oil will determined by NOC
- Adjustment (2) 1-1-1975, rising the tax up to 65%

Duration of Exploration is usually initial 4-6 years and production sharing contracts have total duration of between 20-35 years (Anonymous, 1989).

MATERIALS AND METHODS

Libyan's taxation system: Libya has no corporate income taxes. The only applicable fiscal package in Libya is EPSA. The main policies of the NOC are concentrated on the control over the level of oil production in the country and maximization of its revenue. This is aimed at slowing the rapid depletion of Libyan reservoirs. During the last four decades, Libya has applied four major types of exploration and production sharing agreements, the EPSA 1, the EPSA 2, the EPSA 3 and the EPSA 4. The significance advantage of the EPSA type of agreements as highlighted by the experts is that it gives more freedom to both parties to negotiate over the applied terms (Balhasan, 2002).

Exploration and Production Sharing Agreement 1 (EPSA 1): In 1974, NOC has converted its oil contracts to EPSA 1. The agreement forces the SP to take all responsibility for the total exploration costs. The Libyan NOC, FP, pays its full share of operating costs which is equal to its agreement share at 85% (onshore field) and 81% (offshore field). The FP pays only 50% of development costs. Once the production starts, SP fixes their percentage of share by 15% (onshore field) and 19%

Table 1: Assumed values of B factor and R factor

Production index (B)	Revenue/Cost index (R)		
Oil production10E3 bbl/day	B factor	R ratio	A factor
0-10	0.95	<1.5	1.0
10-25	0.80	1.5-3.4	0.8
25-50	0.50	3.4-4.0	0.6
50-75	0.20	>4.0	0.4

(offshore field) of the production to allow return of their share of expenditure for the exploration and the development. This percentage is technically termed as "Cost oil" (Balhasan, 2002).

The economic model of EPSA 1: The First Party Net Cash Flow (FPNCF) and the Second Party Net Cash Flow (SPNCF) is determined through the following method (Balhasan, 2002):

- SP is responsible for 100% of exploration expenditures
- CAPEX are shared equally 50/50%
- The production share split as:
- 85-15% (Onshore)
- 81-19% (Offshore)
- OPEX are shared according to the production share
- No production index (B) and Revenue/Cost index I
- No royalty, No Tax paid by the second party
- SPNCF = [SPS%*(production*price)-(50%*CAPEX)-(SPS%*OPEX)]
- FPNCF = [FPS%*(production*price)-(50%*CAPEX)-(fps%*OPEX)]

Where:
- FPS is the first party share
- SPS is the second party share

Exploration and production sharing agreement 3 (EPSA 3): Similar to EPSA 1, the EPSA 3 agreement force the SP to take all responsibility for all exploration costs. The FP takes 50% working interest upon commercial discovery along with paying its full share of operating costs and only 50% of development costs. No royalties and no bonuses are applied. Costs may be recovered as soon as possible from the contractor's share of production. Production remaining after FP participation and SP cost recovery is shared between the FP and the SP based on sliding scale linked to average daily production and R factor, Table 1. The SP is subject to customs duties according to petroleum law (Balhasan, 2002).

The economic model of EPSA 3: The First Party Net Cash Flow (FPNCF) and the Second Party Net Cash Flow (SPNCF) are determined through the following method (Balhasan, 2002).

- SP is responsible for 100% of exploration expenditures
- CAPEX are shared equally 50/50%
- OPEX are shared according to the respective production share
- SPS% Production allocated for SP cost recovery
- Excess Profit (Profit oil) share:
  Excess Profit = [(SPS%*production*price)-unrecovered ependitures]
- SPNCF = [(SPS%*production)+((A*base factor)* Excess Profit) * Price]
- FPNCF =[(FPS% * production)+((1-A*base factor) * excess profit)*price]
- A factor is a step function of the R ratio (Tble 1).
- R ratio is calculated by the following equation:

$$R = \frac{\sum\limits^{j-1} \text{Cumulative revenue of second party}}{\sum\limits^{j-1} \text{Cumulative expenditure of second party}}$$

- Base factor is a step function of the field oil production (Table 1)
  Base factor = [((B factor 1*oil production1)+(B factor 2*oil production 2)+(B factor 3*oil production 3))/ total oil production]
- (Both A and B factors are negotiable parameters between the two parties)
- No royalty, no tax paid by SP

RESULTS AND DISCUSSION

Second party's economic criteria: To have a successful business, every decision requires a certain minimum criteria for measuring the value of proposed investments and financial opportunities. Each company has its own economic criteria with required minimum values to fit its strategy to make business profitable. In most of the case the company economic criteria work as a prime factor behind the acceptance and rejection of individual proposal. For economic evaluation of the current project (oil field development) four profitability indicators of NPV, IRR, POT and ROI are taken into consideration (Stermole and Stermole, 1974).

Net Present Value (NPV): NPV measures the capital created over and above the company's discount rate or simply NPV is the difference between the present value of the cash outflow generated by the investment and the present value of the cash inflow generated by the project. When the cash flow of the operation is discounted at the given percentage rate, a positive or negative value is computed. The larger the positive NPV of a project the more profitable it is consequently among different alternatives company will select the project with highest positive NPV (Stermole and Stermole, 1974):

$$NPV = \sum_{t=0}^{t=n} \frac{NCF(t)}{(1+i)^t}$$

- I is the minimum acceptable rate of return required by the second party
- NCF (t) is the net cash flow at time t

Acceptable minimum Rate of Return (IRR): The internal rate of return is defined as the discount rate at which the sum of the present value of all future discounted cash flow is equal to zero. Some companies in specific regions add some percentages of the technology transfer and technical risks to the bank interest. In the case of Libyan economy, it will be significantly fair if an IRR of 13-17% is guaranteed to the SP (Urayet, 2002). The ranged value of 13-17% is the sum of 7% as the highest interest rate currently in the European banks, plus 2-3% for technology transfer and another 2-3% for investing outside of SP's countries, along with 2-4% for the technical risk. However, political financial and environmental risks would also need to be taken into consideration by the decision makers in Libya to determine what would be considered as a fair IRR. Internal Rate of Return becomes a more important profit indicator for any party when the value of IRR is <20%. For field development projects in Libya, the IRR is considered relatively more important for the second party than it is to the first party for which the IRR is higher than 50%. The only concern that should be considered in the EOR and offshore development projects where the IRR has a high importance to the first and second parties. Therefore, in the present study for economically recoverable resources, the minimum IRR of 25% is considered as economic criteria. This criterion is often required by the oil and gas companies, especially in international investments (Stermole and Stermole, 1974).

Pay Out Time (POT): It is defined as the expected number of years that is required for recovering the original initial cash outflow. The payback period is estimated from the cumulative net cash flow by accumulating the negative net cash flow each year until turns positive (from time zero) (Stermole and Stermole, 1974).

Return On Investment (ROI): Technically ROI is the ratio of project cumulative net cash flow to the total investment required for the project (Stermole and Stermole, 1974):

$$ROI = CNCF/Investment$$

Project evaluation; License: C 137 block is located in the western part of Libya offshore zone, extending up to about 100 km from the cost, Fig. 1. In 1968, the Aquitaine Libya was properly awarded the licence. It is ruled under the amended EPSA 1 which was authorised by the Libyan government in April 1997 and is valid until April 2022 (Anonymous, 2000).
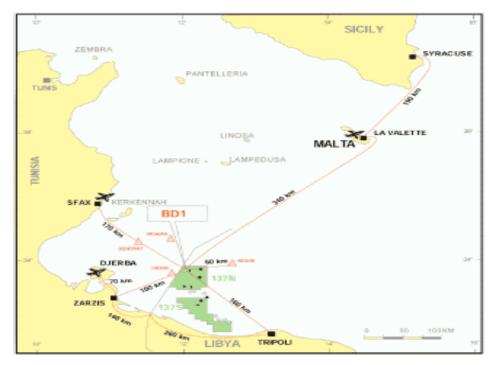

Fig. 1: Location of the C137-B field

Participating interest: For the exploration and appraisal phase, the project was financed by the group of Aquitaine Libya/ Elf Libya/ Wintershall with a participation share of 37.5, 37.5 and 25%, respectively (Anonymous, 2002). After the final investment decision in 1997, the participating interest was:

- National Oil Corporation 50.0%
- Total Libya 37.5%
- Wintershall 12.5%

Operator: For the exploration and appraisal phase, the operator ship is ensured by Aquitaine Libya. Where's, for the developmental phase the operator ship is insured by the Totalfinaelf assets in Libya (Anonymous, 2002).

Discovery and appraisal: The "B structural" discovery well (B1a-137) has been drilled in 1975 and was oil and gas bearing in lower Eocene. A first appraisal well (B2-137) has been drilled in 1983 but was water bearing. 3D seismic acquisition carried out in 1997, a second appraisal well (B3-137) has been drilled in 1998 and was able to determine the water oil contact. Aquitaine Libya has notified the parties on April 26th 1999 that the discovery could be considered as commercial discovery (Anonymous, 2002).

Original Oil in Place (OOIP) and estimated reserves: As the volumes initially in place, the minimum and median OOIP have been calculated with commercial software. Maximum OOIP have been estimated by applying an incremental 30% coefficient to median OOIP this to take into consideration uncertainties such as structural size. OOIP values are given in Table 2 (Anonymous, 2000).

As the volumes initially in place, the reserves proved (1P) and Proved+Probable (2P) results directly of simulations for natural depletion and gas and water injection. Reserve values are provided in Table 3 quitaine Anonymous, 2000).

Table 2: Estimated OOIP in MMSTB of B 137 field

Reservoir	Minimum	Median (most likely)	Maximum
El Gueria	569	727	945
Chouabine	85	109	141
Total	654	836	1086

Table 3: Estimated reserves of 137 B field

Recovery strategy	Natural depletion (2P)	Gas and water inj. (2P)	Gas and water inj. (3P)
Reserves, (MM STB)	170	205	260
Recovery factor (%)	20.3	24.5	31.1

Development strategy of 137 B offshore field: It has been planned that secondary recovery strategy will come into place to for the significant economic improvement field reserves with reinjection of produced gas in order to take into consideration environmental constraints. For this purpose, minimum two gas injector wells for cycling the produced gas will be drilled in the gas cap and four peripheral water injection wells for pressure maintenance and improvement of the sweeping and recovery factor. The cumulative production is projected to reach about 205 MM bbl. At the end of year 2022 estimated recovery factor is 24.5%. The facilities consist of a well head-drilling platform (BD1) and injection platform (BD2) and flare boom and storage facilities (FPOS) (Anonymous, 2000). The developmental cost is distributed as:

- CAPEX 569.18 $MM
- OPEX 464.5 $MM
- Other costs 91.35
- Total costs 1125.03 $MM

Applying the libyan taxation system on 137 B offshore field EPSA 1 (Offshore Model): EPSA agreement is sharing of the produced crude oil. Sharing% depends on agreements between two parties (Balhasan, 2002):

- All associated risk to be accepted by the SP along with taking all of financial burden of exploration
- FP and SP share development costs, operating costs and production accordingly
- Production to be shared among parties as 81% (FP) and % (SP)

Results of forecasting the cash flow under EPSA 1: The economic feasibility analysis of 137 B field under the original EPSA I is provided in Table 4. The production shares and costs distribution for the two parties in typical EPSA 1 agreement are as follows:

- Production sharing 81% (FP) and 19% (SP)
- Similarly, OPEX sharing also 81% (FP) and 19% (SP)
- CAPEX sharing 50% (first party) and 50% (second party)
- Exploration costs 100% paid by (second party)

The proposed amended EPSA 1: The best amended that gave the best economic results for the second party to avoid conflict of the interest under EPSA I is obtained when the first party paid the exploration costs.

Table 4: Economic evaluation of 137 B offshore field under EPSA 1

Variables	NPV $MM	IRR (%)	POT	ROI
FP	1395	81	3	4.2
SP	-15	7	-	-

Table 5: Economic evaluation of 137 B offshore field under amended EPSA 1

Variable	NPV $MM	IRR (%)	POT	ROI
FP	1215	30	4	3.2
SP	165	23	8	1.3

Table 6: Economic Evaluation of 137 B offshore field under EPSA 3

Variable	NPV $MM	IRR (%)	POT	ROI
FP	1392	40	3	4.1
SP	-12	6	-	-

Table 7: Economic Evaluation of 137 B offshore field under amended EPSA 3

Variable	NPV $MM	IRR %	POT	ROI
FP	1060	27	5	3.6
SP	319	44	4	1.3

The economic feasibility analysis of 137 B field under the amended EPSA 1 is showed in Table 5. The production shares and costs distribution for the two parties in typical EPSA 1 agreement are as follows:

- Production sharing 81% (FP) and 19% (SP)
- OPEX sharing also 81% (FP) and 19% (SP)
- CAPEX sharing 50% (FP) and 50% (SP)
- Exploration costs 100% paid by (FP)

Result of forecasting the cash flow under EPSA 3: The economic feasibility analysis of 137 B field under the original EPSA 3 is showed in Table 6. The production share and costs distribution for the two parties in typical EPSA 1 agreement are as follows:

- Production sharing 75% (FP) and 25% (SP)
- OPEX sharing also 75% (FP) and 25% (SP)
- CAPEX sharing 50% (FP) and 50% (SP)
- Exploration costs sharing 50% (FP) and 50% (SP)

The proposed amended EPSA 3: The best amended that gave the best economic results for the second party to avoid conflict of the interest is obtained when the first party paid the exploration costs and production shared 50% (FP) and 50% (SP).

The amended EPSA 3: The economic feasibility analysis of 137 B field under the amended EPSA 3 is showed in Table 7. The production share and costs distribution for the two parties in typical EPSA 3 agreement are as follows:

- Production sharing 50% (FP) and 50% (SP)
- OPEX sharing also 50% (FP) and 50% (SP)
- CAPEX sharing 50% (FP) and 50% (SP)
- Exploration costs 100% paid by (FP)

CONCLUSION

The overall above analysis of the phenomenon under consideration leads us to the following conclusions. The present fiscal regime in Libya is exploration and production shearing agreement. EPSA can simultaneously have serious effects on field development strategies and the volume of recoverable reserves calculations. The project (137B Offshore) under the original EPSA 1 was not economically attractive to the second party. To avoid the conflict of interest, EPSA 1 must be amended. The Amended EPSA 1 will be as following:

- Production sharing 81% (FP) and 19% (SP)
- OPEX sharing also 81% (FP) and 19% (SP)
- CAPEX sharing 50% (FP) and 50% (SP)
- Exploration costs 100% paid by (FP)

The economic feasibility of the amended EPSA 1 showed that the first party's NPV, IRR, POT and ROI are estimated at 1215 $MM, 30%, 4 and 3.2, respectively. Similarly, the second Party's NPV, IRR, POT and ROI are estimated at 165 $MM, 23%, 8 and 1.3, respectively. The amended EPSA 3 will be:

- Production sharing 50% (FP) and 50% (SP)
- OPEX sharing also 50% (FP) and 50% (SP)
- CAPEX sharing 50% (FP) and 50% (SP)
- Total 100% exploration costs to be borne by the FP

The economic feasibility of the amended EPSA III exposed that the First Party's NPV, IRR, POT and ROI are estimated at 1060 $mm, 27%, 5 and 3.6, respectively. But, the second party's NPV, IRR, POT and ROI are estimated at 319 $MM, 44%, 4 and 1.3, respectively.

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