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First Development Plan for a Small Offshore Field

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ABSTRACT

This work describes the proposed development program for the accumulations in the virtual Beta field located in Libya offshore. In 2018, the contractor informed the Management Committee about the Commercial discovery of Beta-field. This development plan has been prepared for submission to the Management for its consideration. After collecting all the available data; including geological data, reservoir data, drilling data, production data, economical data, and environmental data. The suitable assumption has been made. All the modules were built with suitable sensitivities. The important results were laid out with some recommendations in each section. Due consideration is paid to the environmental impact and all the possible use is made of the existing infrastructure.

KEYWORDS: *Field, Development Plan; Discovery, Oil, Reservoir Management, Depletion*

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INTRODUCTION

Beta-field is located offshore Libya in a water depth of 150 m. The structure is defined as Horst and Graben fault system predominantly orienting in the East-West direction. The crest of this anticlinal structure is 2550 m TVD SS with an oil water contact at 3160.5 m TVD SS. The stratigraphy consists of an old red sandstone reservoir from the Devonian period and sealing shale at the top from the Lower Cretaceous period. Between these two periods lies an unconformity due to continual erosion. This reservoir is highly fractured with low porosity and low matrix permeability. It is composed of fluvial sediments deposited from braided river with multi channels.

The Petrophysical analysis of the various logs from Beta-field, show a massive column of shaly-sandstone reservoir with low N/G, high initial water saturations and low matrix porosities. The reservoir properties of the field sands are poor, with porosity ranging of 10-13% and permeability in ranges from 0.06 mD to 12 mD. The core based wettability analyses indicate that the reservoir sands are mixed to oil-wet.

Beta-field contains about 605 MMSTB of oil and 216.6 BSCF of associated gas in place within the massive old red shaly-sandstone reservoir. The oil and gas that can be economically recovered are estimated to be 157 MMSTB and 63 BSCF, respectively. Due to its geological complexity and associated uncertainties, it has been planned to develop Beta-field in three phases.

A. Problem Statement

This study is to check the profitability of Beta field after the information had been received from the contactor about its commercial recovery.

B. Study Objectives

This study was conducted on Beta field in order to achieve the following objectives:

- Decide whether it is profitable development or not, what are reserves and the associated uncertainty.

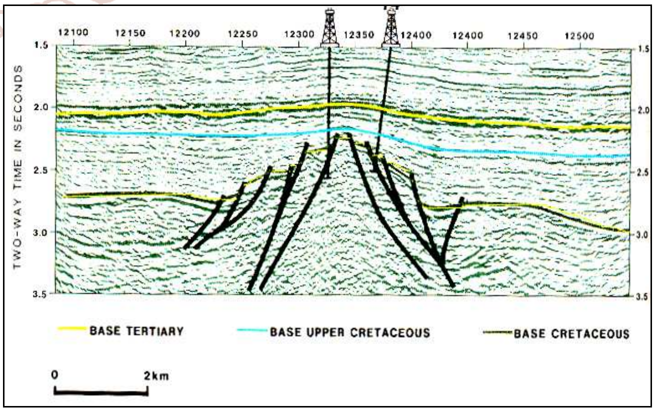

Figure 1 - Seismic Cross Section.

- The kind of development plan should be adopted.
- The way the uncertainty in the data should be handled.

Field Description

A. Structural Configuration

Beta-field was formed as a result of several geological changes. Originally, there was an anticline, then a normal faults system was generated, over time these started to subside generating a Horst and Graben fault system which created the structural trap. Subsequently on the top of the reservoir, a stratigraphic trap was created by sealing shale (approximate 430 ft at the thickest point). The shale was deposited during the Low Cretaceous (140 MM years ago) and reservoir sandstone was deposited during the Devonian (416 - 359 MM years ago) which shows an unconformity due to the missing geological time between the two rocks. The top structure map shows 21 normal faults, see figure 1.

B. Fracture Analysis

- **Origin:** The fractures were generated due to stress during the folding of the anticline followed by the normal faults system creating a Horst and Graben sequence, see Figure 2.
- **Fracture** Network: Open fractures create secondary

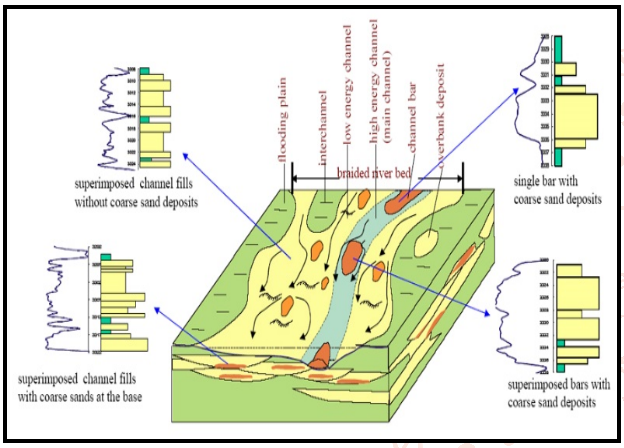

Figure 2 - 3D Braided River with sedimentary logs. Ref W. Beta-9

- porosity due to increase of void space, but are strongly dependent on the scale size they are examined. In certain areas, on a small scale secondary porosity can increase total porosity up to a factor of 100%. However, on the reservoir scale it only increases around 1 % of the total porosity.
- **Storage Capacity**: Studying the matrix and permeability relationship, the matrix has the storage capacity and the communicating fractures aid the permeability. This phenomenon has been clearly demonstrated by calculating the ratio between the permeability obtained from the well test (K wt) and the permeability measured in the core (K cl).

C. Reservoir Description

- **Geology**The braided river system consisted of a network of small channels separated by sandy or braid bars. As there had been had a tropical desert climate and the weather was more arid with occasional heavy rains causing dramatically variations in channel depths, channel velocity and sediment loads. This climate cycle was repeated during 150 million years resulting in new channels with low or high energy. Figure 3 shows a 3D braided river with different sedimentary logs.
- **Petro physics and Reservoir Fluids** The available data for estimating the petro physical properties for include core data and wireline logs. Table 2, lists the specific logs used for the analysis of the petro physical properties. All the exploration wells were drilled vertically except well Beta-6. Wire line log data was available for all six Exploration/Appraisal wells while the core data was available from wells Beta-2, Beta-3 and Beta-5. The cores were depth matched to the logs to ensure proper well interpretation.
- **Fluid contacts** The oil-water contact (OWC) was determined from the logs by observing an average decrease of 4 ohms in resistivity within wells Beta-1, Beta-2 and Beta-3. From the log interpretation of these wells the OWC was clearly established at 10450 ft, 10490 ft and 10510ft MDBRT. The variation in the OWC has been interpreted as a result of porosity anisotropy and varying transition zones between the oil and water leg and not due to compartmentalization of the reservoir. By selecting the shallowest OWC of 10450 ft TVD BRT, a worst-case scenario was considered. The free water level (FWL) could not be established from the logs due to the uncertainty in the transition zones. However, for the STOIIP calculations this uncertainty has been managed by creating three scenarios that account for the possible FWL's. The worst case scenario would be if the FWL was

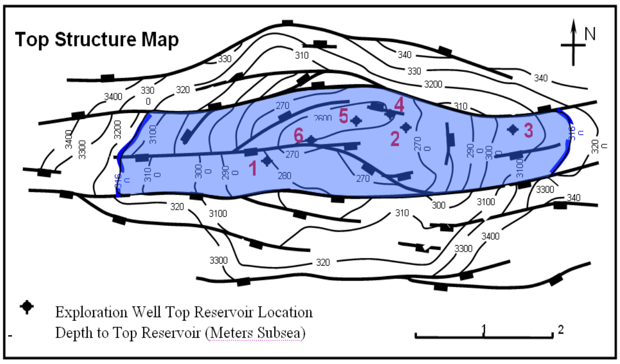

Figure 3 – Top Structure Map with Highlighted "Known Area"

- right below the deepest known oil at 10360 ft TVD BRT, the most likely case would have been the OWC at 10450 ft TVD BRT and finally the best case scenario would have been if the FWL was at the highest known water at 10652 ft TVD BRT.
- **Porosity** It was obtained by comparing porosities from the different porosity models available in Terrastation software package. After comparing these models, the 'Porter model' was selected as the most representative for porosity across the whole reservoir section. The porosity determined from the gamma ray and sonic logs using Porter model was compared to the manually calculated values from the logs and the stress corrected core porosity data, which showed good agreement between them.
- **Water saturation** was also determined using Terrastation software package. Again, various models were compared to determine the most representative model. The 'Laminar model' which uses the porosity, resistivity and V-shale from logs was then chosen as the most representative.
- **Volume of shale** was determined using Terrastation software package. The various models available were compared to determine the most representative model.

The 'Density-Sonic model' which uses the Sonic and the Bulk Density logs was then chosen as the most representative for the V-Shale calculations in all the wells.

- **Cut off sensitivity analysis** was performed on the cut offs used for the water saturation, V-shale and porosity in Terrastation to determine its varying effect on the net pay thickness and select the optimum value for each well. The optimum cut off selected was the one which had the least effect on the net pay thickness. The Cut offs were varied by 20%, 35% and 50% of the maximum value and from these an optimum cut off value for V-shale, water saturation and porosity were selected for each well.
- **Porosity - Permeability Cross** Plot was created for Well-Beta-5, which had the most data available.
- **Reservoir Fluids**The initial drilling and testing programmes showed that Beta-field oil is compositionally homogeneous with similar API gravity.
- **PVT Study** Both surface and sub-surface fluid samples were collected in wells Beta-1, Beta-2, Beta-3 and Beta-5 for testing purposes. Wellhead samples and the recombined samples were collected at surface. Thirteen Down hole/surface recombined samples have been collected and analyzed for basic black oil PVT properties. The single-phase PCT sample from Beta-2 DST-7 and the wellhead sample from Beta-2 DST-8 are considered the most representative of the full field reservoir fluid properties. As might be expected from the discussions above, the PVT data also show homogeneity within the reservoir. Ignoring these unrepresentative samples, oil samples that are clearly representative of the main oil column show bubble point pressures ranging from 1340-1342 psi, bubble point GOR's of 346-359 scf/stb, bubble point formation volume factors of 1.299 – 1.322 rb/stb, API gravities of 31.1-32.2º, and bubble point oil viscosities ranging from 0.83-0.86 cp.
- **Wettability and Relative Permeability** Limited number of special core analyses has been conducted due the limited time to determine capillary pressures, wettability, oil/water relative permeability, and residual oil saturation. After reaching the residual oil saturation by forced displacement, the cores were tested for spontaneous imbibition of oil followed by measurement of additional oil recovery by forced displacement. The ratio of spontaneously uptake of oil to the total displaced oil gives a wettability index to oil, OWI. The Amott-Harvey Wettability index was calculated using the two ratios as: WI = WWI-OWI. All the cores taken at different depths in Well Beta-5 show a mixed oil-wet reservoir.

Initial water saturations from these cores range 8% to 23%. Residual oil saturations from these cores range from 22% to 41%. (Figure 4).

However, there are some measurement issues with this low permeability plug, particularly in the measurement of oil permeabilities. Note that the end-point Oil relative permeability is unrealistically high (kro (Swi) >1); which is physically impossible. Hence the end point rel. perms were modified to represent correct data for simulation studies. The modified rel. perm is as shown in Figure 5. Further SCAL studies would be performed on the recovered cored intervals during Phase-I that is considered a valuable input before drawing any further conclusions.

Hydrocarbons in Place

A. Deterministic STOIIP Estimates

The following scenarios have been created to try to quantify the impact of the uncertainty with the top structure map and the contours. Case 1 – this has been done by considering the known area highlighted in blue in figure 6, as the most likely P50 scenario.

In this area; the contours were then condensed by about 100 m to give P90 scenario, and extended by the same range to create P10 scenario. Case 2 – the same three P90, P50 and P10 GRV's that were calculated for the known area have been considered in this case but with the GRV of both the North and South Flanks added on to each value.

The STOIIP estimates are highlighted in Table 4 below.

B. Uncertainty in STOIIP Estimates

The following is a list of the key uncertainties in the estimation of STOIIP, and the work already planned which will help to reduce these uncertainties.

- **Uncertainty in GRV Estimation** - are due to the uncertainty in seismic time picking of the Top and Base horizons, position of the main bounding fault, depth conversion of the time surfaces and Depth of the OWC.
- **N/G Uncertainty -** The reservoir distribution in a fluvial dominated setting is always difficult to establish. However the well control within the field has helped in building a reservoir distribution model, which was confirmed by the results from additional exploration wells drilled in this area.

Hydrocarbon Saturation - The uncertainties in the saturation estimates are mainly due to the mixed-oil wet nature of the reservoir.

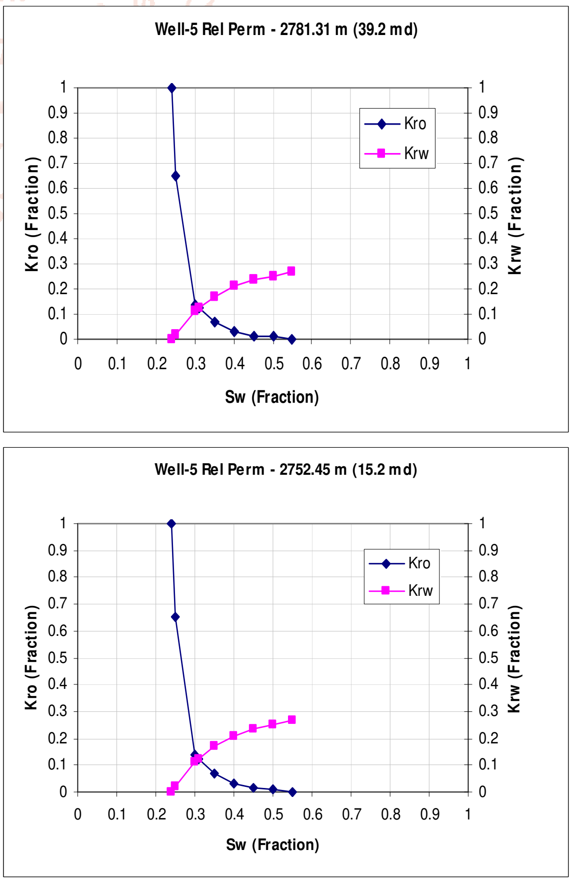

Figure 4 – Rel Perm Curves from SCAL experiments in Well Beta-5

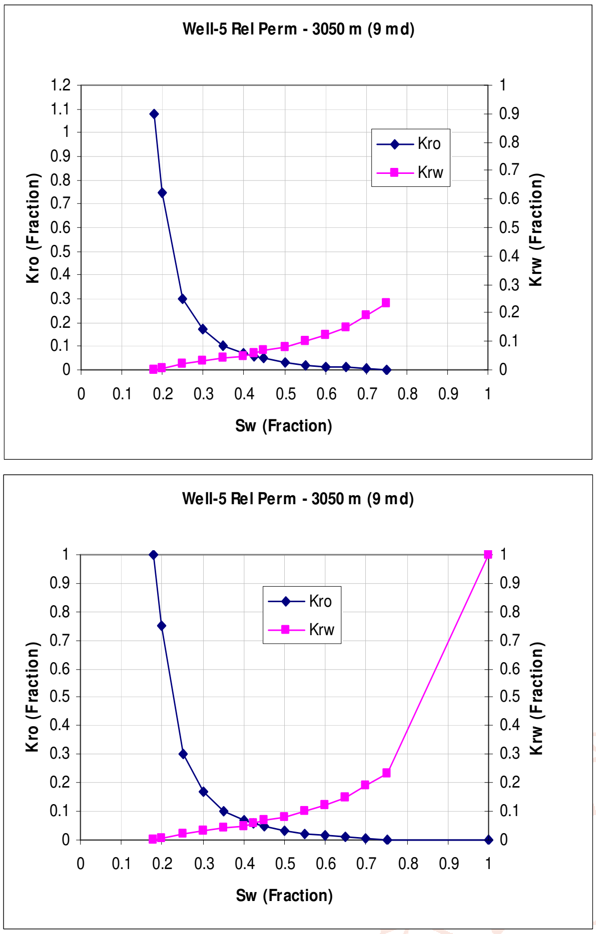

Figure 5 – Rel Perm & Modified Rel Perm Curves for the most Representative Sample.

Well Performance

A. Production Test Analysis

A total of 14 drill stem tests were performed in Beta-field. In well Beta-1 DST-3 had a mechanical failure as well DST-2 & 3 in well Beta-2. The maximum oil production rate of 7492 BOPD was observed in well Beta-2 (DST-5); interval 9794-9884 ft MDBRT & 9906-9942 ft MDBRT. The well Beta-5 (DST-1); interval 9462-9823 ft MDBRT also flowed at an average rate of 7032 BOPD. All other wells flowed at a significantly lower rate.

The production tests performed in three wells Beta-1, Beta-2 and Beta-3, along various intervals were aimed to collect most representative well test data. However due to extreme heterogeneity along the reservoir, quality well test data could not be acquired. Most of the production tests show an increase in FBHP during drawdown indicating changing skin due to well clean up. To cope up with this uncertainty all the well tests were screened and the most representative have been analysed.

B. Corrosion

The corrosion level in Beta-field is intermediate, see Table 5.Hence, the use of normal materials like C80, N80 and Cr13 would be quite justifiable.

C. Wax and Asphaltenes

Currently no specific data is available on the wax appearance temperature and the asphaltenes concentration of Beta-field crude oil. A detailed analysis would be performed in Phase –I to highlight any possible issues arising due to presence of wax and asphaltenes.

The Reservoir Model

A. The Geological Model

The geological modelling was performed modelling different types of wells and various properties and faults. The orthonormal system was used for selecting the origin and the Northing and Easting of the model. The top structure map shows a lateral extent in the X direction (Easting) of 9800 m and in Y direction (Northing) of about 7275 m. The model was then digitized from the top structure map to include the different contours, faults and boundaries.

Reservoir Structure -The current model is based on 21 faults present in the top structure map which were modelled using zigzag faults. These faults were constructed using vertical pillars, which were incorporated by joining the mid points of the fault polygons in order to minimize errors associated with verticalization.

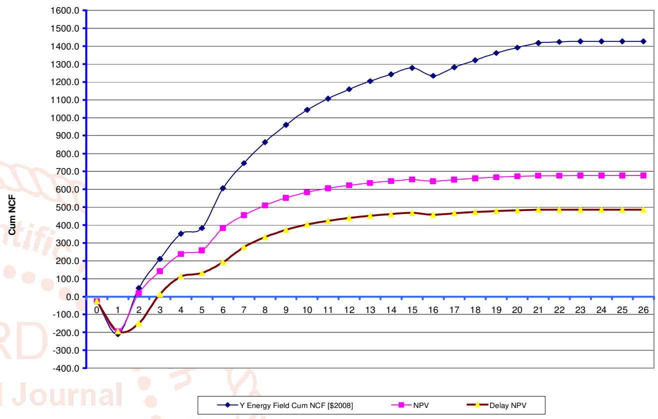

Figure 6 – Illustrate NCF, NPV and they effect of delay on NPV

B. Property Modelling

Reservoir properties have been modelled from the data available from Terrastation as an input to Petrel. The up scaled log data and original well log data have shown good correlation for the basic property parameters. A mean value of 9% for porosity, 7md for permeability and 35% for average water saturation was obtained from both up scaled and well logs. The well tops were identified and the OWC was determined at 3160.5 m TVDSS.

C. Simulation Models

The static geological model was exported to ECLIPSE for initiation of dynamic simulation. The logs show a very low matrix permeability and porosity across the reservoir which is in good agreement with the core studies. The main objective for this full field model was to study the effects of fracture-matrix constraints, run sensitivities and optimize well positioning. A total of 4 producers and 2 injectors were considered for the development of Beta field while taking into account the various uncertainties. In all the wells modelled a mechanical skin factor of 5 was assumed as the best case scenario.

D. Initialization

The model has been initialised with an OWC of 10370 ft. TVDSS. A datum pressure of 7534.7 psia at a datum depth of 9677.6 ft has been considered for hydrostatic equilibration of liquids. The reference pressure of 7881 psia at OWC has been used for initialization of rock and water properties.

E. Model Sensitivities

- **Natural Depletion Model -** A base case with no water leg was considered to see the effect of compaction without an aquifer support on the recovery factor. Initially two cases were run, with two producers followed by two additional producers. These wells were placed on the crestal and central location for ease of quality data gathering and adequate stand-off from early water encroachments which proved to be optimum for the drainage of the reservoir.
- **Aquifer Modelling -** The existence of aquifer has already been determined from well test analysis but the extent of the aquifer is an uncertainty. To deal with this uncertainty and its effect on recovery a finite numerical aquifer was attached to the bottom of the reservoir. The aquifer extents considered for this model were 153*50 m in the X direction and 67*50 m in Y direction, extending to thrice the size of the reservoir.

F. Main Sensitivities and Results –

Before concluding many factors had to be assessed. Out of these a few important ones have been short listed and play an elementary role in determining the reserves and URF of the reservoir. The sensitivities here have been classified into two main categories:

1. Factors affecting STOIIP:

- **NTG:** An increase in NTG increases the STOIIP while a decrease automatically decreases the same. Considering a NTG of 0.67 as our base case for matrix, two more values has been used to run sensitivities which were obtained from the petro physical data, see Table 6
- **Connate water saturation:** From the analysis of log data & SCAL data no fixed connate water saturation could be identified for Beta field. As a result a sensitivity has been carried out for analysing the effect of connate water saturation on the reserves, see Table 7

2. Factors affecting RF and Water cut:

- **Fracture Permeability:** This is one of the prime and important factors affecting the recovery and water cut of a reservoir. Beta-field reservoir is very heterogeneous and has channel sands showing permeability anisotropy. Also, the well test data indicate different effective permeability values at different tested intervals. The available literature depicts that fracture porosity and permeability are a function of the effective permeability. In order to see the effects of fracture permeability on the reservoir different sensitivities were done, see Table 8.
- **Relative Permeability:** Yet another important sensitivity is the relative permeability tables governing the relative oil and water permeabilities at different water saturations. From the SCAL data 5 sets of relative permeability tables were obtained. From this data, the most representative table was chosen for the base case while the rest were incorporated for sensitivity study. For the results see Table 9
- **Faults:** The top structure map and the seismic interpretation show the presence of many faults in the reservoir. It would be of prime importance to see the fluid flow across these faults that would help to know the nature of faults and transportation path of fluids. This would help in the later development stage of the field and would help in justifying well placements. As a result sensitivities were carried out using different values for fault multipliers in order to see the effect on the RF & water cut keeping 0.5 as the base case, see Table 10.

G. Recovery Mechanism

Different recovery mechanisms have been carried out using the full field simulation model of the Beta field. Natural depletion with and without aquifer drive has been investigated using this model. The initial reservoir pressure is 7881 psig at OWC which is higher than the average bubble point pressure of 1340 psig. Hence, when producing above the bubble point pressure, natural depletion to delineate aquifer drive would be the most attractive and optimum option in the first couple of years. Simulation runs indicate that aquifer strength is a very important parameter for deciding the further development stages, if needed.

H. Alternative Development Plans Considered

Limited data has been acquired until date from the exploration and the appraisal wells drilled in Beta-field to decide on a development strategy for this complex field. Further quality data needs to be acquired in this field to reduce the current uncertainties. Hence completing the 6 exploration/appraisal wells and acquiring the necessary data was considered the first option to develop Beta-field.

Management Plan

A. Economic Considerations

The Economic Environment Overview Beta-field location is in the Mid Libyan Coast in Sirt Basin. This region is generally considered to be likely a gas area and therefore infrastructure development has modelled this assumption. For the purpose of this economic consideration, the economic environment and economical strategies of Libya will be the basis for economic assumptions and economic feasibility analysis.

B. Cash Flow Modelling

To determine the long-term feasibility and profitability of this project, there is a need to model the cash flow of the project with a view of determining the base profitability values of the project. The following base assumptions have been made and the outcome of these assumptions forms the input parameters of base case cash flow model.

Base Case Input Parameters

- **Inflation -** The base price inflation for the cash flow model is 2.5%. This is based on the forecasted Libyan inflation rate 2.5%.
- **Oil and Gas Price -** The base assumption for oil and gas price are shown below:

OIL PRICE	Oil price assumption in nominal terms is us \$88.25/barrel in 2018, \$72.13/barrel in 2019, \$68.29/barrel in 2020, \$64.61/barrel in 2011 escalating at 2.5% per annum from the beginning of 2022 onwards.
GAS PRICE	Gas prices are linked to oil prices with a lag of three months. the average annualised gas price in nominal terms is \$10.42/mcf in 2018, \$9.45/mcf in 2019, \$8.63/mcf in 2020, \$8.19/mcf in 2021, escalating at 2.5% per annum from the beginning of 2022 onwards

A discount of 10% has been assumed based on the fact that the API of Beta Field (32^0).

- **Production Profile -** The base case production profile for this economic model is the result of the full field simulation model run on eclipse. However to determine the economic life of the field, a plot of the revenue and operating cost / expense with time was done and it was determined that the operating cost (2018 real terms) will become higher than the revenue (2018 real terms) in the 23rd year.
- **Opex and Tariff -** The components of the Operating Cost include; Annual lease cost for FPSO, Gas pipeline usage tariff and CO_2 and NO_x tax. The base assumption for the lease cost is based on the average of the FPSO lease cost for field with similar production rates and recoverable reserves. The tariff for the transport system used in the base case cash flow model is (NKr 2.0 – 2.2 per Mcf). The CO_2 and NO_x tax is also considered as an operating cost in this base case model.
- **Capex -** The Capex of a development project is dependent on the following factors: Location peculiarities (remoteness, water depth and availability of infrastructure), Reservoir geology and complexity, fluid properties (viscosity, number of phases, impurities). The following development approaches were considered:
    1. Lease FPSO, lay 30 km gas pipeline to the existing transport system for gas transport, Rent drilling rig for drilling operations and oil sales Free on Board (FOB).
    2. Build FPSO, lay 30 km gas pipeline to the existing transport system for gas transport, Rent drilling rig for drilling operations and oil sales Free on Board (FOB).
    3. rig for drilling operations and oil sales Free on Board (FOB).
    4. Build Semi Sub for production processing, FSU for storage and lay 30 km pipeline to the existing transport system for gas transport, Rent drilling rig for drilling operations and oil sales Free on Board (FOB).
- **Tax -** The base case considered for taxation is same as described in the economic environment analysis section.
- **Discount Rate -** The discount rate employed for the base case is based on the most likely case discount rate (10%).

Base Case Cash Flow Model

- **Maximum Capital Outlay (MCO)** – In this case, the MCO for the base case model is USD210.3 million. MCO is the minimum point on the cumulative cash flow and it indicates the maximum amount of money to be sourced external to the project if the project is to survive the investment phase. It should also be noted that it is not same as the maximum Capex.
- **Capex** – For this project will be USD 518 million. Capex is also a measure of investment size and gives an indication of the cost of creating a productive unit. In this case it does not end before production as investment continues even after production has started.
- **Pay Back** – the Payback for Beta-field base case is 2.5 years. The payback is a measure of how long before investments are recouped.
- **Terminal Cash Surplus (TCS)** – For the base case is USD1428 million. It is an indication of the profit to be made by the project before taking into account the cost of capital and the risk elements of the investment (discount rate).
- **Profit to Investment Ratio (PIR)** – For the base case is 6.7.
- **Internal Rate of Return (IRR)** – For the base case is 86.5%.
- **NPV** – The NPV for the base case is USD 705Million. The NPV calculated for the base case is based on 10% discount rate.
- **NPVI** - The NPVI for the base case is 3.5 and the MCO Index is 6.8.

Development Plan

Beta-field oil has no unusual or troublesome properties, especially for water flooding. Beta-field's high initial reservoir pressure 7881 psig at OWC, low GOR 358 SCF/STB and low bubble point pressure 1340 psig, means that pressure maintenance by water flood might not be very critical at initial stages for reasonable recovery levels. There is sufficient evidence for these fractures being cemented, close to the OWC and within the water leg as discussed in the sections above. Beta-field would be developed in different phases. The three Phases of development would be as follows:

A. Phase-I: Natural depletion with 2 producers for initial 4 years.
B. Phase-II: Natural depletion and/or Water-Flooding with 3 additional producers and 3 injectors depending of success of Phase-I.
C. Phase-III: Use of gas lift for increasing ultimate recovery and economic water cut.

Well Optimization

From the production profiles and the simulation studies done, an estimate of well optimization was established. Differences in recovery factors along with increase of wells and increase in water cut were plotted in order to optimize the number of wells to be used for the development.

A. Base Case Development Plan

- **Initially in Phase I, a natural** depletion mechanism was adopted. Two deviated wells acting as producers were placed on the crest and drilled into the northern and the southern flanks. The reason for the same was the presence of vertical and high angular fractures in the reservoir which constitute the main fluid flow pathway s. Two sensitivities, with and without aquifer were modelled to see the effect on RF.

Case 1 : 2 producers with NTG = 0.67, Fault transmissibility = 0.5, Skin = 5, BHP = 1500 psia (well control), without aquifer and runtime of 25 years. See Table 12.

Case 2 : 2 producers with NTG = 0.67, Fault transmissibility = 0.5, Skin = 5, BHP = 1500 psia (well control), with aquifer and runtime of 25 years. See Table 13.

Wells Drilling and Work over

For Beta-Field development; it is recommended to use a second generation Semi-submersible so cost will be lower. It's is capable of drilling in water depths of 1000 ft and can drill up to 25000 ft which is well within the expected drilling targets. The phased drilling programme is planned through a drill centre with six slots on the seabed having a spacing of 15m between them. The FPSO will be located in such a position to accommodate any unplanned work overs without interrupting the production.

A. Pore & Fracture Pressure Prediction
It is assumed the formation above the reservoir is normally pressured with a pressure gradient of 0.453 psi/ft. An oil gradient of 0.35 psi/ft is expected within the reservoir which is over pressured by 2300 psi. For the normally pressured zone; an overbalance of 150 psi will be maintained while for the reservoir section it has been decided to maintain an overbalance of 100 psi to minimize formation damage (figure 7).

B. Deviation Design
It has been planned to follow a deviated well path with an angle of 55° to intersect the maximum number of high angled / vertical fractures and the inter-bedding layers within the reservoir, while keeping the angle within the range of wire line services. See figure 8.

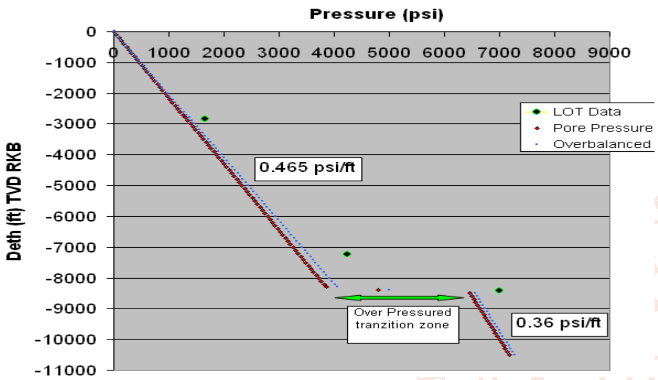

Figure 7 - Pore Pressure Profile

A Positive Displacement Motor on the 17-1/2" PDC steerable motor assembly will be used to kick off at 6250 ft with a build up rate of 1.5° / 100 ft to have a 10° angle at the 13-3/8th casing setting depth (6490 ft) with an azimuth of 180°. The initial 10° angle is to reduce the severity of the build angle in the subsequent hole section. At the kick off point the formation is consolidated sandstone which is not expected to be a troublesome formation. Most essentially, the 10° inclination would facilitate the 12-1/4" rotary steerable system in finding the high side of the hole.

The 12-1/4" RSS will be used to build up to 55° at BUR of 2° / 100 ft drilled with an azimuth of 180° to a TD of around 9320 ft. The TD for the 12-1/4" section would depend on the rate of pressure increase in the transition zone (shale section), which would be monitored using the MWD to indicate the over pressured zone.

C. Litho logy
The compositional logs were analysed carefully and the expected litho logy description was used in choosing the casing setting depths.

D. Drilling Schedule
Drilling objectives of Phase I:
- Establish the reservoir potential of Beta-field by entering the Southern & Northern Flanks.
- Core reservoir section
- Complete suite of open hole logs

E. Drill bit Selection
- **Spud Drilling (9890 ft MD BRT)** – While drilling thissection a one-trip approach will be implemented using a 17 ½" / 36" hole-opener. Once the TD for this section is reached the boulder intervals would be wiped clean to check for ledges and ensure that the conductor is run within <1° inclination.
- **26" Drilling (2663 ft MD BRT) -** This interval will be drilled with a 26" Roller Cone drill bit studded with tungsten carbide insert cutters. This is considered based on the length of this hole section (1673 ft), the cost of this type of bit (lower) and no hole size constraints. The drill string is designed to accommodate a small offset angle as to facilitate scrapping action and increase the drilling rate in the softer formations
- **17-1/2" Drilling (6595 ft MD BRT) -** This interval will be drilled with a 17-1/2" PDC steerable motor assembly (SMA). The PDC has been selected due to its extended drilling life (no moving components) and it is suitable for drilling in hard, non –sticky formations without bit balling. The SMA will be in a rotary mode until it drills vertically up to 6100ft. It will then be switched to its sliding mode with continuous mud circulation through a PDM driving the drillbit.

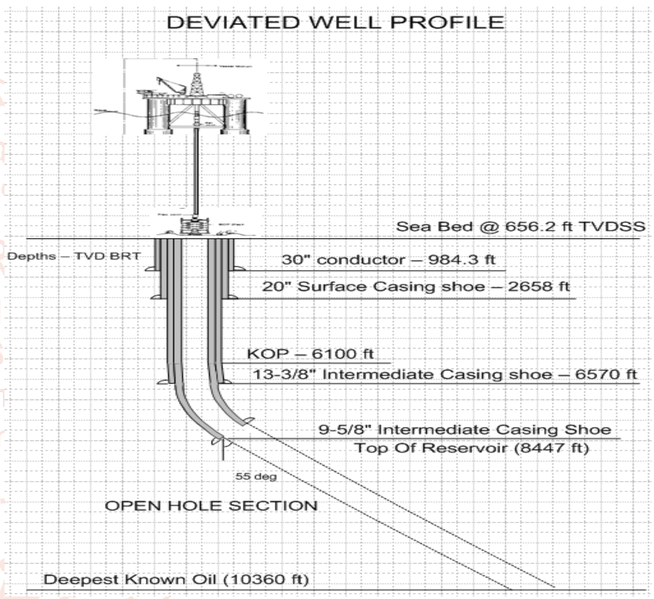

Figure 8 – Deviated Well Profile

- **12-1/4" Drilling (8853 ft MD BRT) -** This interval will be drilled with a PDC Rotary Steerable System. The PDC bit is selected to achieve longer drilled intervals, lowering the amount of trip time and reducing the chances of failure due to no moving components. It also gives proper hole cleaning benefits allowing rotation of the string while building up at 2°/100ft up towards 55°.
- **8-1/2" Drilling (12186 ft MD BRT) -** This interval will again be drilled with a PDC Rotary Steerable System for the same reasons as discussed in the previous section. However, the most important selection criteria for RSS for this hole section was to allow flexibility in maintaining correct path and deviation to reach the target zone in the Southern Flank.

F. Casing Design
The current calculation for the burst and collapse loads are based on the fluid properties that are present in the reservoir (discussed in reservoir engineering) and the future possibility of gas lifting, see table 14. However if phase three is delayed then a possible work over and a re-evaluation of the casing integrity would be expected.

- **Run and Cement 30" Casing (984 ft MD BRT) -** This procedure could have problems getting conductor to bottom due to bottom fill and/or boulders falling / protruding into the hole. The drill pipe stringer would help on reducing the pumping time with lower displacement volumes and no chance of packers becoming stuck. However, "bridging off" in the annulus space might be an issue as large compressive loads may cause the conductor to collapse. The Top of Cement (TOC) will be to the seabed between the temporary guide base (TGB) and permanent guide base (PGB). An excess of 100% of the gauge hole annular volume is planned to ensure good returns to seabed since this is a major load bearing element in the wellhead system.
- **Run and Cement 20" Casing (2658 ft MD BRT)-** The 20" surface casing will be cemented using single stage method as low pump pressures are expected at this shallow depth. The TOC will be till seabed between the TGB and PGB since this casing cement bond will also be a major load bearing element in the wellhead system. The casing setting depth has been chosen to have the casing shoe within the limestone section and ensure a good L.O.T for the 17 1/2" section.
- **Run and Cement 13-3/8" Casing (6590 ft MD BRT) -** The 13-3/8" intermediate casing will again be cemented using a single staged cementing operation. The available data shows no lost circulation within this section. The TOC is planned 500 ft above the 13-3/8 casing shoe at 6068 ft. The TOC will be changed to isolate the zones that contain gas lost circulation zones. The amount of cement required for a particular job would be only dependent on the drilling problems encountered while drilling the section.
- **Run and Cement 9-5/8" Casing (8848 ft MD BRT) -** The casing setting depth for this 9-5/8" production casing is in the shale region just before the over pressured reservoir is encountered. This would facilitate change over to higher mud weights before entering the over pressured reservoir. From analysis of the mud logs a lost circulation zone is likely to be encountered in the limestone region around 7300 ft would also be sealed off behind the casing. The top of cement for this casing interval will be placed 500ft above the expected lost circulation zone using a two staged cementing method.

G. Well Control

The BOP stack will be installed after cementing the 20" surface casing. The further hole sections would be drilled with a 10 000 psi BOP in place. The rating of the BOP stack is chosen on the basis of a worst case scenario of gas filling the casing all the way to surface. This scenario gives the expected surface pressure of 6150 psi which even with a safety factor of 20% is covered by the BOP rating. Once the 10, 000psi BOP is latched on it will be pressure tested to its working pressure limit before drilling later hole sections.

The 26" hole will be drilled without a riser to around 2658 ft TVD BRT. From the available data the risk of encountering shallow gas has been deemed to be 'low'. However, shallow seismic data, tidal current data with respect to tidal position and possible gas cone degree size will have to be collected before this decision is finalised.

If loses are seen while drilling the mud weight should first be cut back to stop losing excessive mud in the fractured formation. If heavy losses continue, which is expected due to fractures or faults being "re-activated" and/or opening in the formation then heavy duty LCM pills should be added.

H. Drilling Mud Design

It has been intended to use seawater planned until placing the riser and BOP to minimise environmental impact. Then moving to a water based mud with KCl / polymer to drill down to the setting depth of the 9-5/8" casing, to avoid any instability problems. Losses are expected when drilling the 8-1/2" hole section within the fractured. From the past data in well Betta-2 a maximum mud loss of 49 bbl/hr had been documented. Even though the high loss rates were not encountered while drilling the previous wells in Beta-field, safety measures should be in place to deal with these situations.

Casing and Completion Design

1. Completion design

An openhole Subsea completion is planned for the new wells in Phase-I and II, as the reservoir is naturally fractured, well consolidated with a very low matrix porosity and permeability. The Subsea completion is designed to include all the necessary completion jewellery like TRSSSV, gas lift mandrels, telescopic joint, SSD, Hydraulic set permanent packer with seal receptacle, top and bottom no-go nipples and a wireline entry guide. The 4-1/2" completion string would be RIH as an integrated assembly to set the Hydraulic packer as deep as possible and to have the WEG just below the 9-5/8" casing shoe depth. This would leave a complete 8-1/2" openhole section across the reservoir. This is planned to have the highest Kh and the maximum inflow area available for flow. Though the formation is quite consolidated, the tendency for sand production in the later life of this field after water breakthrough cannot be neglected. Due to lack of sieve analysis data, a detailed sand control design could not be achieved at this stage.

The various Completion equipment are:

- **Tubular:** The tubing sizes considered for different sensitivities were 2-7/8"OD, 3-1/2" OD, 4" OD, 4-1/2" OD, 5" OD and 5-1/2" OD. The criterion used to select the optimum tubing size was based on the technical and economic considerations. A reservoir pressure of 5500psi with a FTHP of 1000 psi and a maximum expected skin of 15 with a variation in water cut from 0-90% was considered the worst case scenario for this analysis.
- It can be seen from this analysis that increment in oil flow rate by increasing the tubing size from 4-1/2" to 5" is small as compared to the increment from 4" to 4-1/2" tubing.
- **Down hole Safety Valve:** A Tubing Retrievable Sub-Surface Safety control Valve (TRSSSV) which provides more advantages compared to the Wire line Retrievable Safety Valve will be used. A TRSSV is more reliable as this leaves less chance of control system leaks, permits a full bore passage and reduces wire line interventions. A flapper-type valve will also be required for a temporary lock-out.
- **Production packer:** A 9-5/8" hydraulic set permanent packer with seal receptacles will be used. This packer will be run on the completion tubing.
- **Gas lift Mandrels:** 3 x4-1/2" gas lift mandrels would be run along with the planned completion for future possible gas lifting operations.

- **SSD:** A sliding side door is included in the completion for well killing operations for any possible workovers.
- **Telescopic Joint:** This equipment is required as a part of the tubing to accommodate any expansion that will take place during production.
- **Wire line entry guide:** is used for smooth wire line interventions without any hung-up.
- **Swell packer:** This is a special type of packer which is used as an open hole plug to reduce the water cut. This will be required to plug off the watered out open hole sections in future.
- **Tubing Hanger:** The type of tubing hanger used is the hydraulic type which provided the facilities for tubing hanger setting and simultaneous wire line access to the bore.
- **Subsea Xmas Tree:** The production from the well required a Xmas Tree with a 4-inch nominal bore. The main valve assembly comprises of lower manual master valve, upper master valve, hydraulic wing valve and swab valve. These valves are fixed on the downstream side then connected to the flow loop. The pressure rate of the wellhead equipment is 10000 psi.

Production Facilities

The potential production facilities available for the development include:

A. Floating Production, Storage Facility

From the economic and technical benefits, a FPSO unit would be leased for this development. This unit which has a mono hull construction type will be considered because it will host all the necessary facilities including the production, processing, storage and export. The FPSO will be placed between the glory holes and will receive production via flow lines through the turret located near the bow of the vessel.

B. Surface Facilities for Production and Storage

- **Vessel -** The FPSO will have a design life of 25 years with a storage capacity of roughly 500000 barrels representing about 7 to 9 days of production. The peak liquid production to be handled by this FPSO will be 45000 barrels of oil per day and 13000 barrels of water per day.
- **Test Separator -** will be used for carrying out periodic well test to collect reservoir data.
- **Multi-Stage Separator -** The first stage separator (HP separator) will provide the initial stage of the crude oil separation. The incoming production fluids will be heated and allowed to settle in the HP separator. Crude from the first separator will be further separated in the LP separator and then in the electrostatic treater. Here remaining gas and water will be removed from the oil. The sales quality oil thus produced will then flow to the cargo tanks for storage until offloading. Water that has been separated from the oil will be processed to remove dissolved gasses.
- **Gas Compressors -** Separated gas from the HP separator will be compressed to high pressure to allow it to be injected at the subsea wellhead so as to facilitate the flow of the incoming production fluids (gas lift) later in the life of the field.
- **Water Treatment -** The produced water will then be treated to meet a maximum concentration of 30mg/l of oil-in-water specification before it can be disposed overboard.
- **Utility Systems –** Three main utility services will be needed – heating, cooling and electricity. The heating and cooling will be provided by the a medium, which contains circulating hot fresh water for process heating and cold fresh water for process and compressor cooling. The heating for the hot water system will be achieved using steam from the vessel's boilers, and cooling for the cold water system will be achieved by using seawater.
- **Seawater lift and injection system -** During Phase-II, sea water will be required for injection into the reservoir for pressure maintenance. Thus, three lift pumps and coarse filters will be required to treat the seawater to the reservoir filtration requirements. De-aeration of the seawater will also be carried out prior to injection to prevent corrosion in the injection well.
- **Gas Generators -** Three Gas generators will provide electric power for the FPSO. Under normal conditions, two of the three topsides High Voltage (HV) generators will be on line. These will supply all topsides and vessel consumers.
- **Flare and Vent System -** There will be no continuous flaring except during emergency conditions. Measures will be evaluated to reduce atmospheric emission wherever possible.
- **Safety Equipment -** The vessel will be provided with a minimum of 150 percent capacity in persons on board in lifeboats and 200 percent capacity in life rafts. Lifeboats and life rafts will be located close to the temporary refuge and on both sides of the vessel. Additional lifeboat(s) and life rafts will be provided at other suitable locations on the vessel. All safety equipment will meet international marine requirements.
- **Accommodation -** The FPSO will provide accommodation for about 50 to 60 people located furthest away from the skids containing oil and gas.
- **Crude Oil Metering -** The crude oil product will be metered to custody transfer standards before offloading to the off-take tankers. Quantity and quality measurement of the liquid will be required to satisfy the DTI legal requirements for accounting and reporting purposes
- **Export Gas Metering -** Prior to being exported to the transportation system, dry associated gas will be metered by an orifice plate meter to the fiscal standard. Also, the quality of the gas will be compatible with the dense phase flowing criteria.
- **Injection -** Venturi flow meters will be installed on the Xmas tree to monitor the injection volumes.

C. Subsea Production and Associated Facilities

- **Subsea trees and controls -** Subsea Christmas trees employed shall either be of vertical or horizontal Christmas tree and these will be using the manufacturers' specifications. It will have the capability for production with gas lift and water injection.
- **Subsea manifolds modules -** Manifold modules will be required to handle flow from the producing wells and direct them into the production flow line headers, pigging loops, flow meters and control systems. Subsea manifolds will also be required for Phase-II of this development plan. This will provide for the functions of water injection and control.
- **Subsea control systems and umbilicals -** The Subsea control system is expected to be an open loop system that is powered electro -hydraulically. The FPSO located control equipment will be connected to the subsea

equipment (e.g. manifold) via electro-hydraulic control umbilicals. Dynamic umbilicals will be used for control from a FPSO. The control system will be designed to supply sufficient hydraulic fluid high pressure (HP) and low pressure (LP) to control the remotely operated valves on the manifolds and Christmas trees at all drill centers. Consideration will also be given to possible future expansion requirements.

- **Subsea flow lines and risers -** The flow lines and risers for Beta-field will be designed to the API standards. They will provide an unobstructed flow conduit between the subsea facilities and the FPSO and will be fully compatible with the intended service for the entire design life. Valves will be installed to control flows for both normal and emergency situations. Design wise, it is expected that no maintenance will be required during the design life, except for external inspection using an ROV and damage repair and operational pigging.

D. Production Export Systems

- **Offloading facilities -** The FPSO will be designed such that the offloading facilities will be located at the stern of the vessel. A fiscal metering system will be incorporated as an integrated package.
- **Oil export -** Crude oil will be exported directly from the FPSO to the shuttle tanker. The shuttle tanker will be expected to be in the size range of 80,000 DWT. The cargo storage capacity is expected to be around 480,000 bbls to meet peak production storage period of upto 8-10 days.
- **Gas Export -**Process gas export will be achieved via a nominal 6" diameter pipeline from the FPSO to the 42" Transport pipeline. This pipeline will be expected to be about 30km in length and will be trenched. The Transport pipeline will run some 730km to the landfall site at Karsto.

Environmental Impact

A. Existing Environment

The measured sensitivities of the area are described below.

1. Any of this area has not been designated as a Special Areas of Conservation (SAC) or a Special Protection Area (SPC). The bottom sediment within this area is mainly mud and sand.
2. Seabirds are present throughout the year in this area except in April, September and December.
3. The fishing effort is classified as relatively low in this part of Libyan water.

B. Risks and modification plans

Modification plans have been developed for some activities which may cause environment impacts. The measured environmental impacts are described below:

1. High or low frequency sound emit into the marine environment during anchoring the drilling rig and while drilling.
2. The emissions raised from the drilling and production operations mainly from burning of well oil and gas during the short term of drill stream test and diesel combustion for power generation.
3. Oil spills and leaks may occur during various stages of the field development activities.
4. The seabed would directly be disturbed from the placement and the subsequent dragging of rig anchors. But, the physical presence of anchors is expected to create minor environmental impact on the benthos, which should recover quickly once operations are completed.
5. The cuttings contaminated from oil will be contained and shipped to shore for reprocessing at a licensed site.

Abandonment

A. General

The current economic production from Beta-field is expected to last 25 years. However, this might extend depending on the success of Phase-II and Phase-III. Decommissioning of the wells and facilities will be in accordance with the legal requirements on the disposal of disused offshore installation.

B. Subsea facilities

It is planned that even though the sizes of all sub-sea pipelines are less than 10", all those lines in trenching and burial will be flushed, plugged and decommissioned in-place.

C. Wells

To achieve effective isolation of the reservoir; all wells will be plugged and abandoned with two permanent barriers from the seabed and casing string will be recovered.

D. FPSO

The leased FPSO of Beta-field will be disconnected from the risers and collected by the leasing company. Any residual hazardous waste arising from this will be taken to shore and treated at appropriate approved waste treatment facilities.

Costs

A. General

The cost implications for this development plan have been divided into 2 broad aspects.

1. Capital Expenditure (Capex)
2. Operating Expenditure

A breakdown of the revenue and the project costs including Opex, Capex and taxes is illustrated in figure 9.

B. Exploration, Appraisal and Development Costs

The key components of the Capex include the drilling, sub sea completion and the 30km pipeline from the FPSO to the transport system. There is no exploration and appraisal cost covered in this report as these cost have been considered as sunk cost. Due to the marginal nature of this field and the significant level of data uncertainty, the Capital expenditure will be phased into the three distinct phases.

A pie chart that shows the phases and the magnitude of expense is shown below.

C. Operating Expenditure (Opex)

The Opex for this project can be considered high as this includes the cost of leasing the FPSO facility. Other components of the Opex include well maintenance, insurance logistics and consumables. Pipeline usage tariff is also included in the Opex.

D. Abandonment Cost

- The abandonment cost for this project would cost $53.9 million in 2018 terms. This value comprises the cost of plugging the 4 producers and the 2 injectors. It will also include the cost of abandoning the pipelines. The FPSO lease contract will be terminated. The leasor will be responsible for its abandonment.

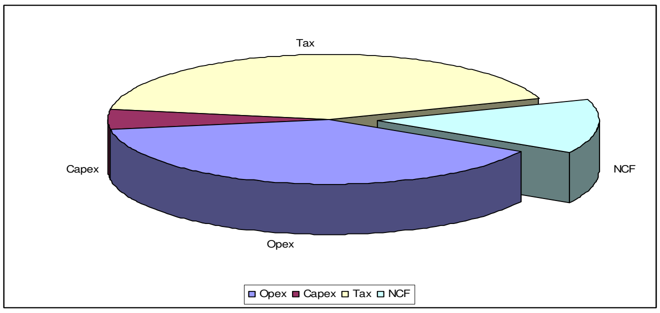

Figure 9 – NCF as a proportion of the revenue.

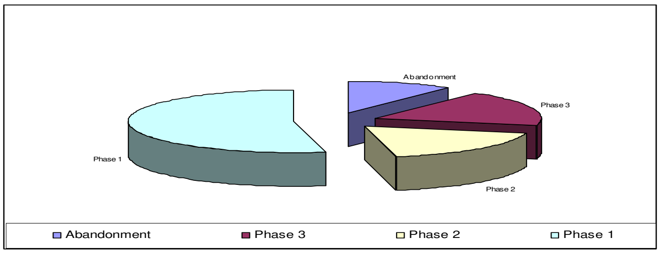

Figure 10 - Distribution of the Capex over the life of the project

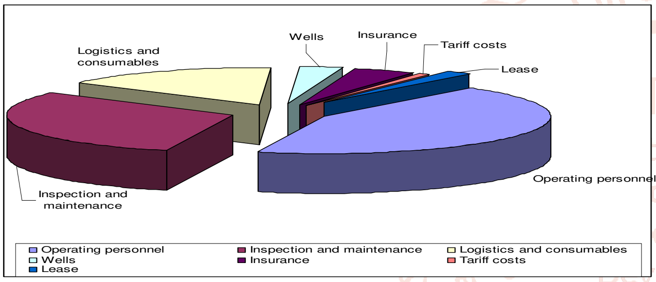

Figure 11 – Showing the distribution of the Opex over the life of the project

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