Targeting of New Wells Through an Integrated Characterisation of the Basement Reservoir in Zeit Bay Field
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Abstract
The Zeit Bay field consists of sedimentary reservoir units partially overlying a tilted block of fractured basement reservoir. The field has a complex combination drive mechanisms including a secondary scheme of gas re-injection into the original gas cap. One of the major problems was to define the fracture pattern of the reservoir. The main objective of this paper is to present a method of integrating multidisciplinary data to determine and characterise the fracture pattern along the basinement rock. A relationship between the fracture pattern and producing zones identified from the production log interpretation was established. Better definition of the fracture pattern improves the well trajectory in order to intersect more fractures for optimum sweep. An extensive fracture analysis was performed using fracview data from FMS (Formation Micro Scanner) in four wells. The obtained data were insufficient for the fracture characterisation across the field. A relationship between fracview data and conventional log data was derived. This relationship was applied to predict fracture porosity in the 22 remaining wells (without FMS). The prediction of cut off parameters (effective and fracture porosity) was improved by detailed comparative analysis of logs, well tests, and production data. Geological analysis of the basement reservoir were performed and integrated with the analysis of basement surface outcrops at Gebel El Zeit, which exhibited well-defined fracture and joint network to the main Gulf of Suez trend. Maps of reservoir properties were generated and compared to the trends observed on the production data maps. The understanding of the reservoir using this integrated approach successfully helped to target new wells in the basement reservoir.

Introduction
The Zeit Bay Field is a 15 year old reservoir located in the south-western part of the Gulf of Suez, Egypt (Fig. 1). The field was discovered by the well QQ89-1. In the same year an appraisal well QQ89-2 was drilled to the south and down dip. The well proved a gross oil column of about 830 ft-TVT covers the total reservoir (Fig. 2).

The reservoir in Zeit Bay Field is a hydraulically communicated sequence of pre-Cambrian igneous and metamorphic rocks as well as sedimentary reservoirs on the north-east and south-west flanks of the field on lapping onto the basement body. The thick anhydrite of the South Gharib formation serves as a cap rock. Most of the gross rock volume is provided in the centre of the field by basement rock.

The primary recovery mechanisms are solution gas drive supported by gas cap expansion, gravity drainage, aquifer support and gas injection. Pressure maintenance by gas re-injection was implemented in 1987.

Production from Zeit Bay field started in 1984 reaching a cumulative production of 200 MMSTB in April 1998. A significant portion of the early production was from basement wells with individual flow rates up to 10,000 BOPD per well. The field oil production rates have declined from a plateau rate of 80,000 BOPD to 20,000 BOPD with consequent increase in water and gas production. Currently the average producing oil rate is around 700 BOPD per well.

At the beginning, a stepwise approach (single well model, cross sectional model and sector model) was used to identify the key parameters for reservoir description of the fractured basement. The conclusion was that constructing a geological model using an integrated approach is a must.

By late 1995, an integrated characterisation study was conducted using a multidisciplinary approach to review the development plans for the field. The Multi-Disciplinary Team (MDT) incorporated members from geology, geophysics, petrophysics, production and reservoir engineering.

The role of this MDT is to evaluate ideas and concepts which may be misinterpreted by individual views and hence achieve better understanding of the implications of the various models.
Objective
The objective of this paper is to illustrate by example the effectiveness of integrating all the geological, geophysical, petrophysical, production and reservoir engineering data to characterize the basement reservoir and better understanding of the fracture pattern with the target of increasing the rate and reserves through locating new infill wells.

Organization
The idea of the MDT requires that the team members work together on a project, and report to each other under the supervision of a team leader.

Time Frame
The MDT of the Zeit Bay field divided the project into six phases:
1) Data management strategy.
2) 2-D seismic analysis.
3) Petrophysical analysis.
4) Reservoir description.
5) Reservoir Engineering analysis.
6) Reservoir characterisation.
   - Integration of all disciplines
   - Targeting new wells
The MDT study of the Zeit Bay field started in June 1995 and was scheduled to December 1996.

Data Management Strategy
Data collection and management is very important to guarantee any project success. A clear understanding of the purpose and application of the data is needed, i.e. define why the information is needed and how it is used. Justification, priority, quality and quantity should be the guiding factors in data collection and analysis. Required and preferred formats for the data were specified thoroughly.

Part of the MDT objective was to convert all the data to digital format. The data used in this study was a 2-D seismic, geological, petrophysical, fluid properties and production history data. The data base management was designed and created to identify the anticipated and encountered needs with high degree of flexibility and reliability.

2-D Seismic Analysis
The objective of the seismic analysis was to use the seismic amplitude information to constrain the reservoir mapping properly in the inter-well areas. The available seismic data was utilised to update the structural model.

The structural model was successfully updated using the available seismic data. Surface and borehole seismic data were scanned from hard copies and loaded into a workstation for interpretation. Seismic time maps were constructed at six horizons including top basement. Time to depth conversion was not possible down to basement level.

The interpreted fault pattern at basement level shows broad similarities to earlier work but with differences in the orientation of major faults in the eastern flank. A significantly higher degree of minor faulting is noted from the use of both surface and borehole seismic data to image the inter-well area. The use of seismic data to assist reservoir property mapping was studied using seismic inversion, seismic attributes, and amplitude versus offset (AVO) analyses.

The results obtained from this analysis revealed that:
(a) The porosity variations in the basement may be too small to generate an observable seismic response.
(b) The variations in basement overburden lithology (Kareem shale, Kareem carbonate, Kareem, Miocene and Nubian sandstone) cause greater changes in seismic response than variation in basement porosity.
(c) The low seismic signals to noise ratio also reduces the value of the seismic data for porosity mapping

Petrophysical Analysis
The objective of the Petrophysical analysis study was to determine the petrophysical parameters (m, n, Pm, and Rm) and to perform the fracture analysis using fracview data and dipmeter data. The characterization of the fractures would help the geologists and reservoir engineers for better understanding of the fracture network in the field. The fracture analysis comprised interpretation of the fracture porosity, density (intensity), orientation, dip and fracture aperture.

Petrophysical Parameters
The cementation exponent factor "m". The cementation exponent factor “m” is an important parameter in the saturation calculations. Due to the absence of reliable core measurement in the basement reservoir, the Electro Magnetic Propagation Tool (EPT) was used to calculate the factor “m”. Fig. 3 is a frequency plot of the EPT data to choose the proper value of the cementation factor “m”. The mathematical mean of the data indicates an “m” of 1.73.

The saturation exponent “n”. In the absence of special core analysis data (SCAL), a saturation exponent “n” value of 2 was used.

Grain density “ρ g ”. A frequency histogram of the grain density data for the fresh granite samples was prepared. This histogram illustrates that the average value for the granite density data is around 2.62 g/cm³ (Fig.4). This value represents the total matrix density of all the components in the granite.

Formation water resistivity “Rw”. Analysis of the produced water from the exploratory well QQ89-4 indicates that the water resistivity is 0.06 ohm-m at 60°F. At the reservoir temperature of 152°F the water resistivity is 0.025 ohm-m.

Elan Analysis. Based on the above mentioned petrophysical parameters an ELAN analysis was performed for the basement wells in Zeit Bay Field. This analysis was integrated with the other data.

Fracture Analysis
Fracture porosity prediction. Fracture porosity has been estimated with the fracview software. Only four wells in Zeit Bay field have fracview analysis. This limited data set was not considered to be sufficient for mapping of the fracture porosity across the field. Therefore, a relationship was established between the fracview data and conventional log data. This relationship could be used to predict fracview porosity in the non-FMS wells. A software program
identified that the latero log shallow resistivity curve (LLS) have strongest correlation with the fracture porosity. The data from two wells were displayed on a single cross plot of LLS data versus fracview porosity (FVP) in the oil zone as shown in Fig. 5. Two data clouds were observed. Initially it was thought that this difference could be attributed to the hole trajectory intercepting different fracture sets. However, after examining the data in the water zone, a different data distribution was observed as shown in Fig. 6. It was concluded that the different data sets in the oil zone arises from the arbitrary application of a mud resistivity correction during the fracview processing to solve the effect of mud and oil mixture on the FMS tool. A cross plot was produced from well D2B data (Fig. 7) which further illustrated the strong correlation between the shallow resistivity log and fracture porosity.

Fracture porosity prediction equations. Five empirical equations were used to predict the fracture porosity, these are:

For well A6 in the oil zone:
\[ \text{PFVP} = 10^{(-0.9994 \times \text{LLS} + 1.7506)} \]  
(1)

For well D3 in the oil zone:
\[ \text{PFVP} = 10^{(1.1167 \times \text{LLS} - 1.4892)} \]  
(2)

For well D2B in the oil zone:
\[ \text{PFVP} = 10^{(1.0625 \times \text{LLS} - 0.6757)} \]  
(3)

For well D3 and A6 in the water zone:
\[ \text{PFVP} = 10^{(-0.9664 \times \text{LLS} + 1.7204)} \]  
(4)

For those wells without fracview data, FMS equation was used in the oil zone, which was an average of the well A6 and well D3 and the form of this equation, is:
\[ \text{PFVP} = 10^{(-0.9897 \times \text{LLS} + 1.7259)} \]  
(5)

In the water zone equation (4) was used.

Validation of the equations. Overlay log plots were produced from the predicted fracture porosities and original fracview porosities for A6 and D3. This step was considered as a validation of individual well equation and displayed in Figs. 8 and 9.

For those wells having an induction log tool rather than the usual latero log tool, the predicted equations have used the medium induction device (ILD).

Fracture density. Fracture density or intensity is defined by Cheung and Heliot (1990) as the number of fractures per unit length inside an interval of defined height. The High Resolution Dipmeter Tool (HDT) and Stratigraphic High Resolution Dipmeter Tool (SHDT) underestimate the fracture density when compared with FMS data from the same well. This underestimation was due to the orientation bias created by changes in the angle of the fracture planes, the borehole axis and to the differences in vertical resolution between HDT/SHDT and FMS. This counted fractures densities by HDT/SHDT required to be corrected by multiplying by a factor of 2-3 to match the fracview results.

Fracture orientation. In the early 1980's, a fracture orientation was determined using a software FIL (Fracture Identification Log). The majority of the Basement wells in the field were interpreted by this type of software and hence revealed that the dominant fracture orientation was the Northwest (260°-180°) and the Northwest-Southeast (300°-120°). There are also spread of fracture orientation in the field with no clearly defined sets.

Currently, the methodology to determine the fracture orientation was updated by using the data from FMS tool. The advantages of this tool were the high sampling rate and excellent vertical resolution. However, there is a good correspondences between the FIL orientation data and that derived from FMS, but the FMS orientation data are more enhanced. Fig. 10 illustrates the well plot map within the fracture sets of Zeit Bay field that included FIL and FMS data.

Fracture dip. The dip of the fractures were determined using the FMS. In the highly fracture granite about 75% of the fractures were dipping 50-60° (Fig. 11) while in low fracture granite about 76% of the fractures were dipping 70-90° as shown in Fig. 12.

Fracture aperture. Only four wells (A6, A7, D2B and D3) have fracture aperture data derived from fracview analysis of FMS. Like fracture porosity, a resemble correlation was observed between the LLS and the fracture aperture. Fracture aperture and fracture porosity is positively correlated. This means that the reservoir with good fracture porosity can be interpreted to represent areas with wide fracture aperture and then production.

Cut-off Parameters
Due to the lack of core analysis data which makes the prediction of cut-off parameters very difficult, a detailed comparative analysis of the log and production data was performed to optimise the cut-off limits.

Core permeability / porosity cross plot. A cross plot was prepared for the permeability and porosity data from Zeit Bay field (Fig. 13) in order to assist in the determination of a porosity cut-off. However, this approach was not pursued as no correlation was observed between the two measurements.

Well test permeability versus flow rate. In order to determine which well test permeability would permit reasonable flow rates, a cross plot was made for well test permeability versus flow rate as shown in Fig. 14. From this cross plot it can be seen that any reservoir interval which has permeability of at least between 0.6 and 1.0 millidarcies will permit flow of 100 reservoir barrels per day.

Correlation between well test permeability and fracture porosity. The computed well test permeabilities and fractured porosities for the tested intervals were compared as illustrated in Fig. 15. This cross plot suggests that any reservoir interval with a fracture porosity greater than 0.09% should permit flow:

**Correlation between well test permeabilities and log porosity.** A cross plot of the well test permeabilities and open hole porosity was made as shown in Fig. 16. This plot shows any reservoir interval with total porosity greater than 2.3% should permit flow. It appears that net reservoir cut-off values are as shown in Table 1.

### TABLE 1 – CUT OFF POROSITY VALUES

<table>
<thead>
<tr>
<th>Type of porosity</th>
<th>Cut off values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Effective porosity</td>
<td>Greater than 2.3%</td>
</tr>
<tr>
<td>Fracture porosity</td>
<td>Greater than 0.09%</td>
</tr>
</tbody>
</table>

Reservoir Description
The objectives of the reservoir description phase were to:
(a) Describe the basement reservoir in terms of lithology, porosity and permeability with the integration with other disciplines.

(b) Investigate well-to-well correlation of properties.

(c) Propose a geological base of reservoir zonation and microzonation.

(d) Distribute reservoir properties by mapping.

(e) Estimate the volume of the hydrocarbon originally in place.

This work involved a field trip to Gebel El Zeit area on the West Coast of the Gulf of Suez (15Km to the Southeast Zeit Bay Field), core analysis, and core thin sections and log correlations.

Geological Field Trip:

Structural lithology and stratigraphy. The basement outcrop at Gebel El Zeit represents the uplifted footwall of a related tilted fault block that is bounded to the north east by a major planar extensional fault. Vertical displacement in the hanging wall of this fault is in the order of hundred of meters. The fault block is tilted to the SW and formed the basement complex under the Gemaas Basin to the Southwest.

A complete stratigraphy from Palaeozoic Nubian sandstone through Miocene evaporites (Belayim – South Gharib) is present in the north of the study area (Wadi Kabrit). Regional seismic together with well data have confirmed that the Zeit Bay field block does not lie on the same fault line. The Zeit Bay field block lies on a separate major extensional fault system offset to the Southwest.

Fractures, faults and dykes. From the outcrop data it can be seen that a relationship exists between the two dominant fracture sets (N-W and NW-SE), especially at north Gebel El Zeit. A high density or intensity (5-15 fracture per foot) was observed. The principal fracture strike is in the same direction (NW-SE) but dips on opposite direction. This has produced a distinctive conjugate pattern of fracturing.

These fractures have been superimposed on another fracture pattern, particularly at north Gebel EL Zeit. From this analysis it is clear that the principal trend of fractures is consistent with the NW-SE dyamic trend of the Gebel EL Zeit boundary fault.

North Gebel EL Zeit is characterised by the presence of mafic dykes. These dykes are typically vertical or subvertical trend WSW-ENE and vary in width from 1 m to 10-20 m. The dykes appear to be genetically related to 060-090 / 070-090 fracture pattern and are therefore perpendicular to the principal NW-SE fault pattern. The contacts between the dykes and the granite were noticeably sharp with brecciated contacts.

The majority of the observed fractures were open, with little or no evidence of mineralogical infills. However some veins consisting of quartz and occasionally calcite were seen.

Core and thin section. Cores were reviewed to examine the types of basement lithology and fracture characterisation of the Zeit Bay field. Total basement penetration in about 37 wells in Zeit Bay field is 15500 ft, of which 584 ft was cut from 15 wells during coring operations. A total of 377 ft was recovered, which represents a recovery factor of 64%. The dominant lithology is granite, which is fractured, weathered or clean. Some of the cores contain mafic dykes material and the others contain complex lithology. Two types of granite were classified weathered and fractured, the weathered granite is characterised by distinct vuggy porosity due to dissolution of feldspar and the fracture granite is characterised by fracture porosity. Visible matrix porosity was observed in fresh granite and is generally less than 1-2%.

The recovery of core seems to be entirely dependent on the fracture density, i.e. the higher the fracture density the lower the recovery. In cores of higher recovery, the fractures present are closed or only partially opened. Occasionally fractures up to 3-5 mm are filled with clay matrix. The core coverage and preservation is generally poor, and is considered to be unrepresentative data for the quantitative distribution of reservoir parameters. However, it provides a guide to the different types of porosity and fracture types.

 Petrological similarities do exist between the granites and associated dykes seen in the cores and that in the outcrop at north Gebel El Zeit. Fracture dip and orientation were not measured as the wells are deviated and the cores were not oriented.

Geological Analysis

Reservoir zonation. The most important issue pertaining to the reservoir description is the analysis of data and the consequent distribution of reservoir properties for volumetric assessment and simulation. The reservoir layering scheme was considered in the past (Askary 1988) and divided the basement into four zones based on alternatively porous and non-porous intervals. The limitation of such a scheme was encountered where there is no geological basis.

Geological zonation scheme was believed (not layering), based on log analyses and well data. The basement reservoir was divided into two basement zones the weathered zone and unweathered zone. The weathered zone referred to the upper most portion of the reservoir and the unweathered zone was the majority of the basement which lies below the weathered zone.

A differentiation were performed by the presence of clays and other weathering products in the upper weathered zone and in the absence of their minerals in the lower unweathered zone. Table 2 illustrates another sets of logging parameters which were used to differentiate between the two zones (weathered and unweathered).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Weathered</th>
<th>Unweathered</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density (g/cc)</td>
<td>2.3 - 2.5</td>
<td>2.5 - 2.7</td>
</tr>
<tr>
<td>Gamma Ray (API)</td>
<td>50 - 80</td>
<td>80 - 150</td>
</tr>
<tr>
<td>Invasion Profile</td>
<td>Shallow</td>
<td>Little or No</td>
</tr>
<tr>
<td>Sonic (msec/ft)</td>
<td>100 - 150</td>
<td>Indifferent</td>
</tr>
<tr>
<td>FFVP (%)</td>
<td>0.3 - 2.8</td>
<td>0.2 - 1.0</td>
</tr>
<tr>
<td>Core Recovery</td>
<td>Poor</td>
<td>Fair to Poor</td>
</tr>
<tr>
<td>Rate of Penetration</td>
<td>15 - 30</td>
<td>Better</td>
</tr>
</tbody>
</table>

Initial fluid contact. The initial gas oil contact (GOC) is inferred at 4020 ft-TVDs with a corresponding pressure of 2095 psia, which should be the saturation pressure. The initial oil water contact (OWC) was taken at 4850 ft-TVDs. The figures of these contacts were determined by conventional
logging from the wells drilled prior to any production from the field. These figures confirmed by the RFT (Repeat Formation Tester) and well test data. Fig.17 shows the initial pressure profile and fluid level contacts.

**Volumetrics.** Deterministic calculations of STOIP and FGIP were carried out for the upper weathered portion and the lowered Fracture portion of the reservoir.

 Petrophysical sums and averages for the two-macro zones were calculated for each 50-fi micro zone, from which averages for the two-macro zones were derived. Thickness, water saturation and porosity were prepared and summed accordingly. The PFVP values were used in the calculations taking into consideration the parameter with and without cut off.

**Reservoir Engineering**

**Fluid Properties.** The fluid properties have been produced from the limited number of samples. These PVT analysis revealed that the hydrocarbon in all formations come from a common source and there is a vertical communication between sedimentary and igneous horizons. In addition, the faults across the main field are likely to be none sealing.

**Well Test Analysis.** A total of 25 basement tests were interpreted taking into account knowledge of the fluid properties and reservoir performance.

The chosen model to analyse the transient pressure data is dual porosity, deviated well with partial completion, multiphase flow, gas cap support. In addition, the effect of wellbore phase re-distribution was considered. Fig. 18 shows an example of well test analysis for a basement well.

The main parameters that result from the dual porosity analysis in naturally fractured wells are the omega and lambda. The omega is the storativity ratio and essentially gives a quantitative indication of the volumes of the fractures compared to the total reservoir (matrix + fractures) pore volume. The lambda is the inter- porosity flow co-efficient and gives an indication of the degree of the homogeneity of the reservoir (i.e. relatively large approach to 1 tends to be homogeneous). The formation is assumed to have uniform thickness h, and the top and bottom boundaries can be either no-flow or constant pressure type. If the gas cap does not intersect the tested formation at the well, both boundaries are set to no-flow and the thickness h, is set to the entire formation thickness. If the gas cap is present at the well, the top boundary is set to be a constant pressure and the thickness h, is measured from the bottom of the formation to the gas cap. Permeability is defined in the horizontal, Kx, Ky, and vertical Kz directions.

Wellbore phase re-distribution is simulated using a changing wellbore storage model suggested by Fair (1979). The model is particularly suited to simulate what is commonly called “gas humping” where the gas redistribution in the wellbore creates an over pressure at the surface for a short time after surface shut in of the well.

**PLT and TDT Data.** The PLT data was used in well Test analysis and integrated with the other disciplines. The TDT data (Current fluid level contacts, gas and water swept zones) were used in the calculations of the remaining reserves and the current reservoir production performance.

**Basement Production Performance.** Thirteen wells have produced hydrocarbons from the basement in the Zeit Bay field. Lately out of the thirteen, eight were still producing in May 1998. Most of the wells are suffering from high gas oil ratio (GOR) and water cut.

**Reservoir Characterization**

The objective of this section is to integrate the results previously determined from each discipline and to define the most reliable reservoir model to be used in future reservoir management. This will lead ultimately to recommendation for future oiltake well location in the basement in order to extend the economic life of the Zeit Bay Field.

The integration process involves comparative analysis between the main findings of the reservoir description disciplines (geology, geophysics, petrophysics & fracture analysis) with the support of the historical production data. For this purpose a number of illustrative reservoir property contour maps were constructed (Figs. 19, 20, 21, and 22) and compared to the trends observed on the production data maps.

**Integration of All Disciplines**

**Basement faulting & fractures.** The updated revised fault map using seismic exhibits broad similarities to earlier work. However, differences in fault orientation and density were observed. The majority of faults trend NE-SW in line with the main Gulf of Suez trend and in addition a number of perpendicular and cross faults were identified. The density of internal faulting was observed to be greater than previously estimated. This revised fault map was taken forward and compared to fracture, petrophysical, and production data. This indicated that the major block bounding faults are to the north east. These faults have caused considerable internal deformation of the granitic mass. A direct relationship between these faults and the high fracture porosity and subsequently high fluid production was observed.

**Basement porosity types & saturation.** Three types of pore system are observed:

- **Primary:** This type of pores are described as very low permeability, probably entirely water filled, and having negligible contribution to production.
- **Secondary:** This type of pores are described as low permeability, possible low water saturation ($S_w$). They are potentially important for oil storage and have a large impact on production if linked by fracture network.
- **Tertiary:** This type of pores are described as high permeability and very low water saturation ($S_w$). This pores represents the principle production path which feed fluids to the wells from secondary porosity and the overlying sediments.

The selection of a dual porosity model for well test analysis proved that two porosity systems contribute to production in the basement, especially in crystal part of the basement high. Geological investigation of the available core in hand specimen and in thin section proved that it is the case. The matrix porosity is able to contribute to the reservoir hydrodynamic behaviour only where the micro-fractures pass through the vugs to enable connectivity.
Fracture dip and production data. A plot of borehole dip versus productivity index (PI), cumulative oil and cumulative water production is slightly instructive. Fig.23 shows a correlation of well deviation angle with production performance. This histogram shows a trend of decreasing cumulative oil with increasing dip angle in the basement.

Water production is greater in the east and is therefore not related to dip angle. PI tends to be higher for those wells with borehole dips in the range of 30-40°. The plot indicates dip angles higher than 40° have low cumulative oil and low PI (except for A6).

Production map. Contour maps of PI, KH, Omega, Lambda, cumulative oil production and water cut were produced as shown in Figs. 19, 20, 21, 22, 24 and 25 to assist in identification of "good" fracture zone and potentially upswept areas which may be targets for infill drilling. These maps confirm the results of the reservoir mapping, namely that the 'good' fracture zones are in the north east of the field.

However, the water cut map shows high values in the C platform area, which is well swept. In the highly fractured D platform area the water cut is much lower (0.2) and the PI is moderate.

Approach for Targeting New Infill Wells
Due to the absence of simulation model in Zeit Bay field, a conventional approach was used for targeting new wells. The output data from the integrated reservoir characterization study using MDT approach has helped in increased production and reserves. This conventional approach is described in the following paragraphs.

Drainage pattern map. A drainage pattern map in the south part of the Zeit Bay field was constructed based on the current well performance of the offset wells for the basement reservoir using decline curve analysis and volumetric calculations. This map revealed a scope for an additional drainage point within the basement reservoir between wells B3, B5 and D2B. Fig.26 illustrate a schematic representation of unswept areas i.e. remaining reserves which can not be efficiently drained by the existing wells.

Oil leg map. Based on TDT log measurements and well performance, fluid level maps have been updated, and from these the oil leg at the well location was estimated to be approximately 150-175 ft-TVT.

Well path. The well path is designed to be in a direction perpendicular to the fracture strike in order to maximize the fracture density along the well path. The dip of the fractures at this location is approximately 35° (conjugate set). A selected inclination for the well path of 60° will encounter an equal density of fractures per unit length. The 60° inclination however, is practical to drill the well and encounter 70% more fractures than 30° due to the longer producing interval for a given vertical thickness.

Reservoir quality. The proposed area is characterised by granite that has been affected by meteoric and/or hydrothermal alteration together with fracturing by tectonism. This has given rise to good matrix and fracture porosity. A series of maps have been constructed based on the characterisation of basement and showed that the zone of interest is from the depth 4250-4450 ft-TVDss within the oil leg. The depth has been divided into two 50-ft intervals and both intervals showed a good reservoir quality. Table 3 shows the expected reservoir parameters for each interval.

<table>
<thead>
<tr>
<th>TABLE 3 – RESERVOIR PARAMETERS FOR THE CHOSEN INTERVALS</th>
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<tbody>
<tr>
<td>Interval Depth</td>
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<tr>
<td>(ft-TVDss)</td>
</tr>
<tr>
<td>φr (%)</td>
</tr>
<tr>
<td>φfr (%)</td>
</tr>
<tr>
<td>Fracture density (#/ft)</td>
</tr>
<tr>
<td>Fracture Dip (°)</td>
</tr>
<tr>
<td>Fracture Orientation</td>
</tr>
</tbody>
</table>

Oil-in-place (OIP). Based on the current contacts combined with the correspondence formation tops and the estimated OIP/acre-ft for each formation, the estimated OIP for this drainage area is approximately 5.0 MMSTB assuming a closed area around the proposed well.

Reserves and production profile. Based on the estimated OIP of 5.0 MMSTB, the estimated recoverable oil from the proposed well was 1.2 MMSTB using a conservative recovery factor of 23%. The expected initial rate from this well was 1000 BOPD but a 4000 BOPD start rate was achieved.

CONCLUSIONS
1. Zeit Bay field is a mature field that has a complex highly faulted reservoir, complex drive mechanisms and considered one of the few fields in the world which has productive reservoir in fractured granite basement.
2. Planning new wells in a mature field demands a multidisciplinary approach to ensure optimum bottom hole location at minimum cost.
3. Multidisciplinary team in Zeit Bay field study:
   ♦ Consists of engineers, geologists, petrophysicists, and geophysiists.
   ♦ Aimed to characterise the heterogeneous reservoir in order to improve oil recovery and optimize reservoir management.
   ♦ Improve organization over the previous traditional views aligned along technical disciplines with the objective to save time, money and better solution for the problems.
   ♦ Improve the database.
   ♦ Identify in fill well locations
4. Basement reservoir description was developed by integration between local surface analogue and subsurface geological data.
5. Comparison of the fault pattern at the top basement derived from 2D seismic data and well data shows a good agreement.
6. Determination of the different types of porosity in a fractured reservoir is essential for the complete evaluation.
7. Prediction of the fracture porosity for the whole field was shown to be possible by developing a relationship between the FMS analysis and the conventional logs and fracview processing.
8. Permeability from well tests correlated with fracture porosity to define net cut off in fragmented reservoirs.

9. In a complex fracture field like Zeit Bay, an integrated approach using the output from the MDT study was used for targeting new wells in unswept areas which possesses high fracture porosity and high permeability with a good storage capacity in the fracture reservoir.

Recommendations

1. 3D seismic should be run in Zeit Bay field to get accurate models with fine vertical resolution of well data and correcting predicted structural aspects than the available 2D seismic.

2. An integrated study using the planned 3D seismic with the other disciplines to construct:
   - Three-dimensional geological modeling using the updated software including fracture porosity, fracture density and fracture permeability models.
   - Numerical simulation model.

3. Team must have clear goals or purpose which must be understood by the team and management.

4. Team training for all members is important so that they understand their role within the team.

Nomenclature

API = American Petroleum Institute
BOPD = Barrel Oil Per Day
BSCF = Billion standard cubic feet
°F = Degree fahrenheit
ft. = Feet
ft/hr. = Feet per hour
gm/cc. = Gram per cubic centimeter
GOC = Gas Oil Contact
i.e. = id est (in other words)
Kxy = Areal oil phase permeability
Kz = Vertical oil phase permeability
mm. = Millimeters
MMSTB = Million stock tank barrels
msec/ft. = Microseconds per foot
N-W = North west
Ohm.m = Ohm meter
OWC = Oil Water contact
PFVP = Predicted Final Viscosity porosity
Psia = Pounds per square inch absolute
PVT = Pressure Volume Temperature
RFT = Repeat Formation Tester
Rw = Formation water resistivity
S-E = South east
STOIP = Stock Tank Oil Initially In Place
Sw = Water saturation
TVDss = True Vertical Depth sub sea
TVP = True Vertical Thickness
WSW-ENE = West south west- east north east

References


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Fig. 1- Location Map For Zeit Bay Field.

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