Competent Person's Report

IF discovery Block 7,

Etinde Permit, Cameroon

for Bowleven plc

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May 2009

This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry. Estimates of hydrocarbon reserves/resources should be regarded only as estimates that may change as further information become available. Not only are reserves estimates based on the information currently available, but are also subject to uncertainties inherent in the application of judgemental factors in interpreting such information. TRACS International Consultancy Ltd. shall have no liability arising out of or related to the use of the report.

No Political or Country Risk have been accounted for in this evaluation.

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Signed	
Report status	FINAL

Qualification

TRACS International was founded in 1992, and currently has over 75 petroleum engineers, geoscientists and petroleum economists working from three office locations. TRACS has extensive reserves and asset valuation experience and are recognised as industry reserve, risk and valuation experts.

The Etinde Block 7 IF discovery evaluation was performed by senior TRACS staff as detailed in Appendix 1 with a combined 60 years in the oil and gas industry. The report author is TRACS staff with 22 years experience in the industry. The team members all hold at least a bachelor's degree in geoscience, petroleum engineering or related discipline, and have extensive reserves evaluation experience.

No TRACS personnel have any substantive financial interest (past or present) in the Etinde Permit or in Bowleven plc.

This assessment has been conducted within the context of the TRACS understanding of the effects of petroleum legislation, taxation, and other regulations that currently apply to the Etinde Permit. However, TRACS is not in a position to attest to property title, financial interest relationships or encumbrances thereon for any part of the appraised properties.

It should be understood that any determination of reserve volumes and corresponding NPVs, particularly involving petroleum developments, may be subject to significant variations over short periods of time as new information becomes available and perceptions change. This is particularly relevant to exploration activities which by their nature involve a high degree of uncertainty.

Yours Sincerely,

TRACS International Consultancy Limited

Sven Tiefenthal

Reserves Co-ordinator

Contents

Qualification ii

1. Introduction 4

2. Overview of Region and Licence Area 5

3. Technical evaluation 6
   3.1. Introduction 6
   3.2. Geological setting and play concept 6
   3.3. Wells 7
   3.4. Petrophysical evaluation 8
   3.5. Seismic interpretation 10
      3.5.1. Seismic data 10
      3.5.2. Top structure 10
   3.6. Mapping and volumetric calculations 12
   3.7. Fluid data 13
   3.8. Production test 15
   3.9. Recovery factors 15
   3.10. Field development plan 16

4. Reserves and Resources assessment 18
   4.1. Uncertainty 18
   4.2. STOIIP 18
   4.3. Recoverable volumes 20

5. Valuation of Resources 22
   5.1. Overview of PSC terms for oil developments 22
   5.2. Economic input (costs and production profiles) 23
   5.3. Results 24

Appendix 1 Personnel 25

Appendix 2 Glossary 26

Appendix 3 Petroleum Reserves Definitions 28

Appendix 4 Reservoir Engineering data 37

Appendix 5 PSC Fiscal Terms for Oil Developments 39

Figures

Figure 0-1 Probability Density Function 2
Figure 2-1 Location map for Etinde Permit 5
Figure 3-1 Stratigraphic column 6
Figure 3-2 Slope collapse and development of lateral ramp 7
Figure 3-3 CPI plot of IF-1r 9
Figure 3-4 Seismic data 10
Figure 3-5 Seismic line through IF-1r 11
Figure 3-6 Depth map of top Sand 1 in m TVD (Contour Interval = 10m) 12
Figure 3-7 Cross section through mid case model 13
Figure 3-8 Results of MDT from IF-1r 14
Figure 3-9 Oil production profiles for low, mid and high resource volumes 17
Figure 4-1 Recoverable resource expectation curve 20

Tables

Table 4-1 LOW Input parameters for STOIIP calculations 19
Table 4-2 MID Input parameters for STOIIP calculations 19
Table 4-3 HIGH Input parameters for STOIIP calculations 19
Table 4-4 Range of gross Contingent Resources 20
Table 5-1 Oil price deck 22
Table 5-2 Development Capex for IF 23
Table 5-3 IF contingent resource post-tax Net Present Value Summary 24

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Competent Person's Report for Bowleven plc

Etinde Block 7 IF discovery

Executive Summary

Bowleven plc has oil and gas interests both onshore and offshore in Gabon and Cameroon. This Competent Person's Report reports the IF Oil Discovery within the Etinde Block 7 area only.

EurOil Limited ("EurOil"), a wholly owned subsidiary of Bowleven plc, acquired the original interest in the Etinde exploration permit in 1998. The permit is currently constituted by a production sharing contract (PSC) dated 22 December 2008 between The Republic of Cameroon and EurOil.

The Etinde permit is separated into three blocks (MLHP-5, 6, 7) within which several gas, gas condensate and oil discoveries are present. The IF discovery is planned for appraisal drilling in 2009/10, after which a declaration of commerciality may be submitted and EurOil may seek the award of an exploitation authorisation from the Cameroon authorities. Under the PSC the state oil company of Cameroon, Societe Nationale des Hydrocarbures (SNH) has the right to elect to take a 20% participating interest in the development with effect from the grant of the relevant exploitation authorization.

Property Interests Evaluated

Asset	*Operator*	*Interest*	*Status*	*PSC Award Date*	*Phase Expiry Date*	*Licence Area*	*Comments*
Etinde Permit (including MLHP-7)	Bowleven	100%	Exploration Permit	22 December 2008	Exploration: 22 December 2011 *[2]	2,316 km^2	Will be converted to exploitation phase with award of exploitation authorisation
Etinde Permit (including MLHP-7)	Bowleven	80%*[1]	Exploitation Permit	22 December 2008	From date of exploitation authorisation*[3]: 15 years for oil 20 years for gas	To be determined	

Notes:

*[1] Assuming SNH back-in

*[2] Further 12 month extension possible

*[3] 10 years renewal option for oil and gas

The Etinde Block 7 Area is located some 25km offshore Cameroon in water depths around 200'. To date 14 wells have been drilled in the block and two wells have been drilled on the IF structure. These were the last wells drilled in the Etinde block.

The original IF well was drilled in 2007 following from the gas condensate discoveries at IE. The primary target was the Upper Isongo Sandstone, but a gas and oil kick was experienced above the prognosed reservoir and the well was plugged and abandoned.

Well IF-1r (Redrill) was spudded in 2008 by Euroil, again targeting the Isongo Sandstone. The well successfully reached TD in the Upper Isongo Sandstone Formation and discovered a thinly-bedded Isongo sandstone sequence with a 100 ft proven oil column. The underlying main interval of the Isongo Sandstone was found to be water-bearing.

Two tests were carried out in the thinly bedded sands. The tests flowed 33-35°API oil at a maximum rate of 4184 bopd.

IF is an oil discovery, but the proven area of the field is insufficient in size to justify development and further appraisal is required. The planned appraisal well will penetrate an area where seismic image quality is poor. The structure, sand presence and connectivity to the discovery are being appraised by this well. The chance of firming up sufficient volumes to justify a development , i.e. the commercial risk factor, has been estimated at 65%.

The resource volumes and economics quoted in the report are post-appraisal resources (low-mid-high) in the event of a successful appraisal programme and declaration of commerciality (Figure 0-1), and should therefore be risked at 65%.

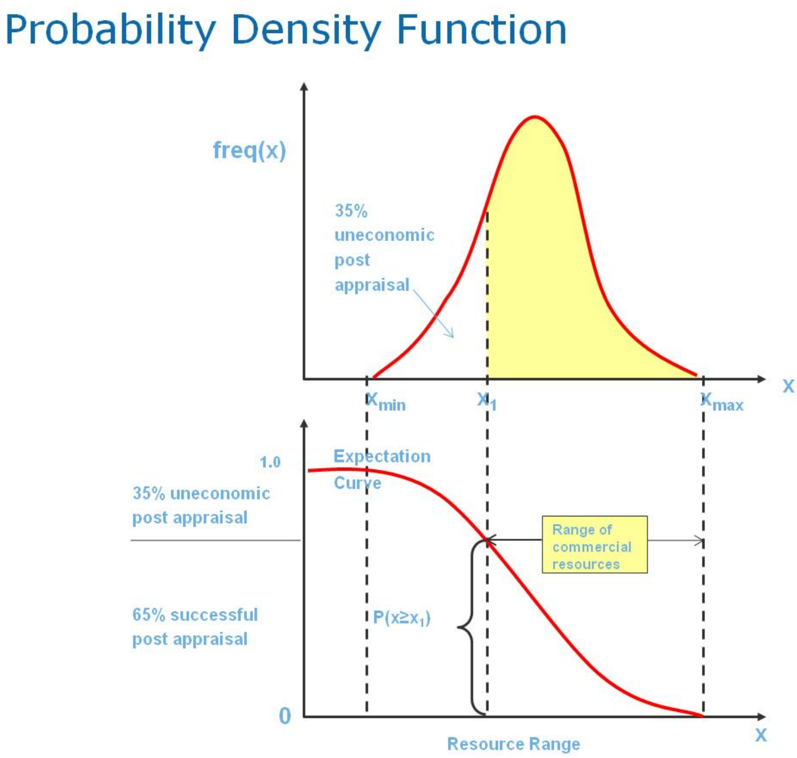

Figure 0-1 Probability Density Function

No reserves are defined for the IF discovery as appraisal drilling is required.

The Resources are Contingent on appraisal success, with probability of success defined at 65%.

Contingent Resources Summary

Net Contingent Resources Bowleven 100%*	1C MMbbls	2C MMbbls	3C MMbbls	Probability of Success
Etinde MLHP-7	23.9	53.1	94.3	65%

*Note that if SNH back-in to the development then they will be assigned 20% of the resources (proportional to shareholding) and Bowleven resources will become 80% of the volumes shown in the table above.

The work programme presented to TRACS calls for the two well appraisal programme to be completed in 2009/10 followed up with a Front End Engineering Design (FEED) study and the investment decision planned for Q3 2010. The development would commence in 2011 and first production is planned for the end of 2012.

Development is planned using a well head platform (WHP) with multiphase export to new processing facilities to be built onshore. The development wells will be drilled by a mobile jack-up rig located over the WHP, with 4 production wells (two of which will be completed appraisal wells) and 3 injectors planned.

The 1C, 2C and 3C forecasts are economically evaluated using the same development. However, data from the appraisal wells should reduce the range of uncertainty and a more optimal development may be identified based on the new range of resources (e.g. if low case is identified then fewer wells and lower facility capacities will result in lower costs).

Contingent Resources Valuation

Net Contingent Resources Bowleven 80%*	1C million $	2C million $	3C Million $	Probability of Success
Etinde MLHP-7	10.6	556.4	1038.4	65%

*Assuming SNH back-in

This gives an estimated monetary value (EMV) at 10% discount rate at 1st July 2009 of 339 million US$, assuming only one appraisal well is required to identify the failure case.

1. Introduction

TRACS International Consultancy Ltd. ("TRACS") was commissioned by Bowleven Plc ("Bowleven") to complete a Competent Person's Report assessing the resource potential of the IF oil discovery in Block 7 of the Etinde Permit, offshore Cameroon. The other Etinde prospects and discoveries are not considered in this report.

Property Interests Evaluated

Asset	*Operator*	*Interest*	*Status*	*PSC Award Date*	*Phase Expiry Date*	*Licence Area*	*Comments*
Etinde Permit (including MLHP-7)	Bowleven	100%	Exploration Permit	22 December 2008	Exploration: 22 December 2011 *[2]	2,316 km²	Will be converted to exploitation phase with award of exploitation authorisation
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The IF evaluation by TRACS was based on data sets provided by Bowleven during the first quarter of 2009. This included the 3D seismic data set over the Block, the results of a detailed seismic interpretation conducted in-house by Bowleven, the well data from the wells of interest in the block, and supporting internal Bowleven reports about hydrocarbon geochemistry and seismic studies.

All volumetric calculations are based on mapping done using the above data as input, and were conducted independently by TRACS. The reservoir property input to the volumetric calculations and the associated volume uncertainty ranges are based on TRACS experience in deep water clastic reservoir evaluations such as Etinde, and the statement on risking represents the independent view of TRACS.

The evaluation was performed by senior TRACS staff as detailed in Appendix 1.

The resource estimates presented in this report have been prepared in accordance with reserves definitions presented in the SPE's Petroleum Resources Management System ("SPE-PRMS" Appendix 3), and the risking of contingent resources has been done in accordance with the LSE/AIM Guidance note for Mining, Oil and Gas Companies ("LSE/AIM Guidelines").

Estimates of petroleum reserves and contingent and prospective resources should be regarded only as estimates that may change as additional information becomes available. Not only are such reserve and resource estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgement factors in interpreting such information.

No site visit was considered necessary as there are no active well or production facilities currently in the licence.

2. Overview of Region and Licence Area

The Etinde Permit covers an area of 2,316 km² offshore Cameroon, and is divided into Blocks 5, 6 and 7.

The permit is constituted by a production sharing contract dated 22 December 2008, the exploration phase of which is valid until 22 December 2011, with a possible extension of up to 12 months beyond that. Under the PSC, the process for moving to the exploitation phase involves the application for an exploitation authorization from the Cameroon authorities, following declaration of a commercial discovery. Following the granting of an exploitation authorization in respect of a discovery, the PSC provides for exploitation periods of 15 years for oil developments and 20 years for gas developments, with the option in each case to seek a further 10 year extension to the exploitation phase where the possibility of continuing commercial production can be demonstrated. The PSC is held 100% by Bowleven's wholly owned Cameroon subsidiary EurOil.

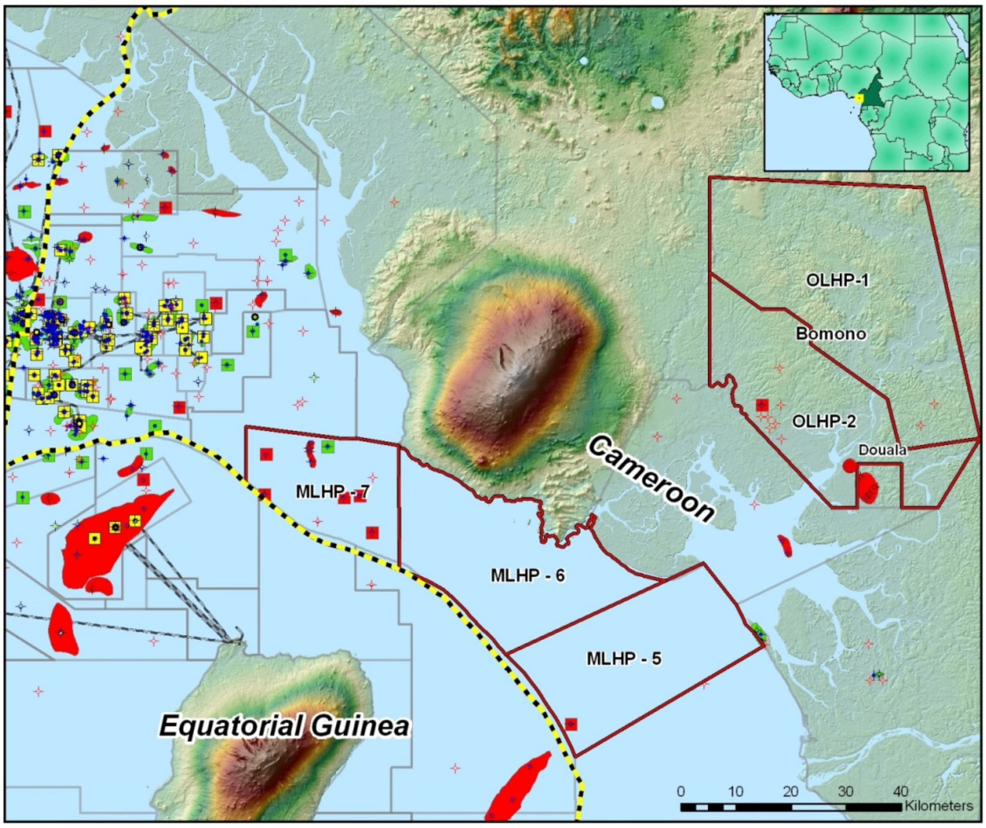


Figure 2-1 Location map for Etinde Permit

This CPR concerns only the IF oil discovery in Block 7 of the Etinde Permit, and excludes all other discoveries and prospects in the Etinde Permit.

3. Technical evaluation

3.1. Introduction

The IF discovery is located approximately 15 km offshore Cameroon in Block 7 ("MLHP-7") of the Etinde Permit. The discovery is located on the continental shelf in around 200 ft water depth. Well IF-1r discovered a 100ft oil column within a thinly bedded section of the Miocene-aged Isongo Sandstone Formation. The well lies about 10 km to the SE of IE-1 and IE-2z which discovered and tested gas condensate in a separate field in amalgamated sands of the Isongo Sandstone Formation.

3.2. Geological setting and play concept

The Block 7 portion of the Etinde Permit lies in the Rio Del Rey Basin, which formed during rifting of the Atlantic in the Early Cretaceous. To the south the basin is limited by a volcanically-active crustal-scale fracture system, the Cameroon Volcanic Line ("CVL"). To the southeast of the CVL lies the Douala Basin. The Rio Del Ray Basin is dominated by major slope collapse structures, related to activity of the CVL, mechanical failure and re-activation of fracture zones. To date salt tectonism has not been observed in the Etinde area.

Sedimentation in the basin is dominated by the Niger River Delta with Block 7 lying in its outer zone of influence. The prospective reservoir sections are deep water turbidite units - sandstones and siltstones - deposited in a mid to outer slope environment during the Middle Miocene (Isongo Formation). The Isongo sands typically have abrupt bases followed by amalgamated, box-car sands overlain by more thinly bedded sandstones which fine upwards. The deep marine section is superseded by shallower-water deltaic sediments of Late Miocene, Pliocene and Pleistocene age.

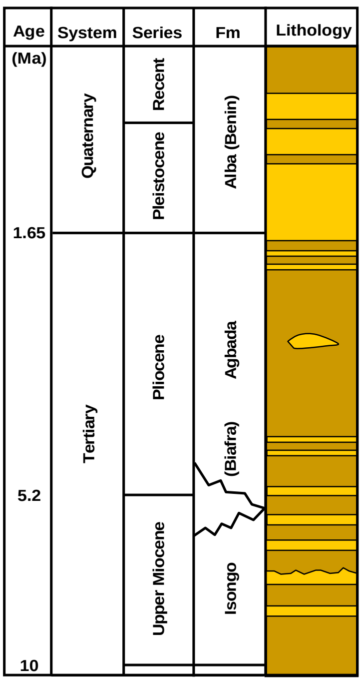


Figure 3-1 Stratigraphic column

The Mid to Late Miocene basin configuration was substantially modified by a major mid-slope collapse which set up the majority of structural and structural-stratigraphic traps in the eastern part of the block, many of which have been partially reactivated during ongoing extension related to further slope instability.

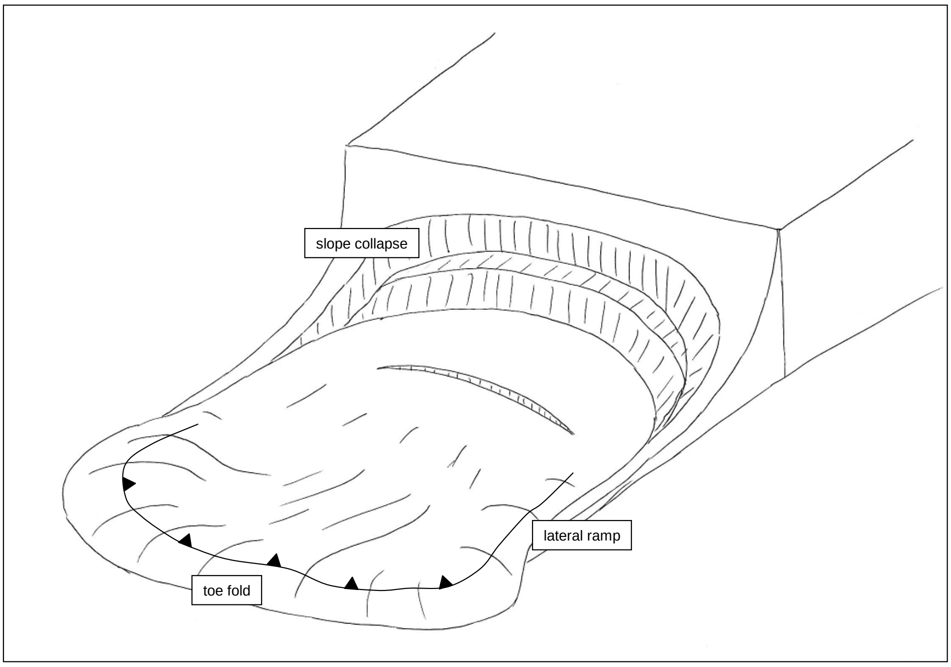


Figure 3-2 Slope collapse and development of lateral ramp

Thick intervals of marine and lacustrine shales of Cretaceous and Early Tertiary age provide laterally extensive source rocks and seal.

Geochemical analysis has shown that hydrocarbons in Block 7 are derived from two active petroleum systems, a mature Cretaceous source rock system and a less mature Tertiary source. Gas, condensate and oil have all been encountered in the block.

Hydrocarbon migration appears to post-date trap formation but some structures carry more risk than others depending on later phases of extensional reactivation and the top seal configuration of the pre and post-collapse section.

3.3. Wells

There are 14 wells in Block 7. The IF structure was first drilled in 2007 by Euroil and followed on from the success at IE. The primary target was the Isongo Sandstone. The well took a gas and oil kick at 6355ft MD, above the prognosed reservoir depth. The well was plugged and abandoned.

Well IF-1r (Redrill) was spudded in 2008 by Euroil, again targeting the Isongo Sandstone; the well reached TD at 7750 ft MD. The main porous interval of the Isongo Sandstone was found to be water-bearing. The overlying thinly-bedded sandstones were oil-bearing with an OWC at 6547 ft MD proving a 100 ft gross oil column.

Two tests were carried out in the thinly bedded sands. The first test ("DST-1B") flowed 33-35°API oil at a maximum rate of 4184 bopd. The second test ("DST-2") was carried out shallower in the well and produced oil and water. The water is believed to originate from the underlying water-bearing sands flowing up behind the casing due to a very poor cement bond. The absence of any cement signature on the cement bond logs is confirmed, supporting this interpretation.

Approximately 450 ft of core was recovered from the Upper Isongo Sandstone (below the oil water contact). A full wireline logging suite was run, and the interpretation confirmed the presence of a 100 ft oil column in thinly bedded sands. Log and pressure data confirm the presence of an OWC at 6455 ft TVD.

3.4. Petrophysical evaluation

A full suite of good quality open hole and LWD logs are available in IF-1r, which include a Magnetic Resonance Log ("CMR") and Oil Based Mud Imaging tool ("OBMI"). Four cores were cut within the water-bearing Thin Beds and the Isongo Sand with 95-100% recovery. The interval of Thin Beds overlying the thicker sand packages (Sands 1, 2 and 3) has a gross thickness of 279 ft. The volume of net sand within this interval is defined as a key influence on the STOIIP determination.

Net to gross was independently evaluated using all of the available information. A wide range of values was calculated from each data source as a result of differences in measurement type and resolution of the data recorded. A range of 15% to 35% was applied reflecting the uncertainty range.

Sand 1 is an amalgamated sand and has a net-to-gross ratio ("N:G") ranging from 58% for the whole interval to 81% for the upper thick sand. Values of 58%, 70% and 78% were applied in the low, mid and high cases.

Sand 2 has log-derived N:G values of 82%; the N:G of Sand 3 is 54%. These were not varied in the three cases.

Porosity was derived from the density log. A value of 2.67 g/cc was used for the matrix density (supported by core grain density) and 1 g/cc for fluid density as is appropriate for a salinity of 20,000 ppm. Porosity from a neutron-density crossplot was also calculated but was generally around 2 p.u. lower than the density porosity. This is suspected to be attributable to the greater than expected (anomalous) Neutron Log ("TNPH") cross-over in the water-bearing sands.

The average log derived porosities for the Thin Beds, Sand 1, Sand 2 and Sand 3 are 21%, 21%, 21% and 23%, respectively. Porosity derived from the CMR in the Thin Beds is lower at 14% due to tool vertical resolution limitations.

The oil down to (ODT) from logs is interpreted at 6454.3 ft TVDSS and water up to at 6456.8 ft TVDSS.

The oil column in IF-1r is restricted to the Thin Beds. The lack of resolution of the induction tool would lead to an underestimation of the hydrocarbon saturation if honoured. No capillary data are available from core at this time so saturations have been derived from the nearest field – IE. Hydrocarbon saturations reached an average in the best sands of 80% through the thicker sands and a saturation of 75% has been applied here. The Free Water Level is at 6547 ft MD (6455 ft TVDSS).

Permeability from core is very good in the amalgamated sands measuring 100's of mD. This does deteriorate to <1mD in places even where porosity is over 20%. The mechanism for the permeability reduction is not fully understood, and the low permeability zones have not been included in the net sand thickness estimates.

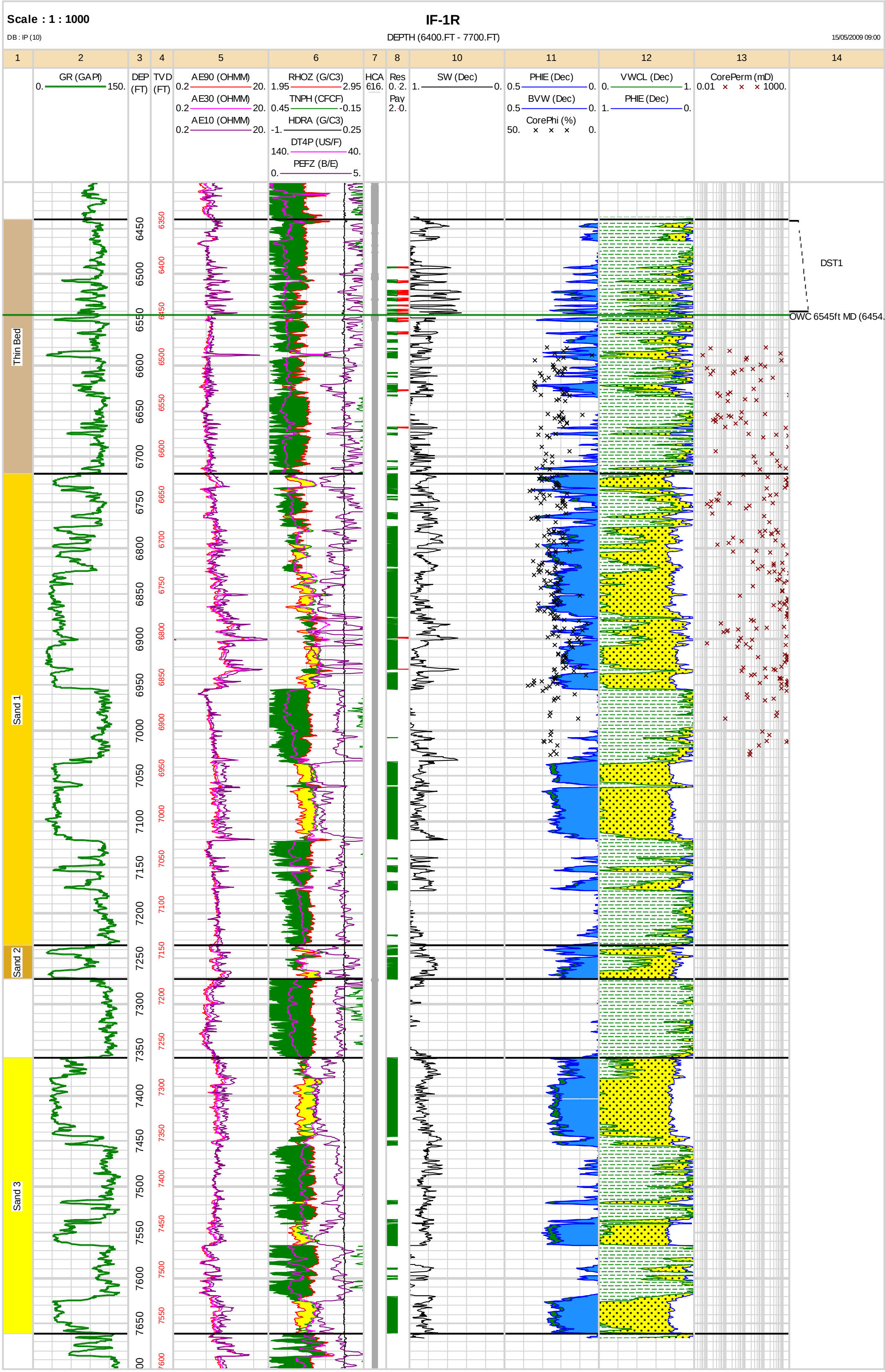


Figure 3-3 CPI plot of IF-1r

3.5. Seismic interpretation

3.5.1. Seismic data

The volumetric review presented in this report is based on time mapping from 3D seismic data acquired in 2005. In early 2009 Bowleven undertook a block-wide seismic re-interpretation project. The current Bowleven maps are based on a re-sampled seismic data set and incorporate an improved understanding of the structural framework of the area.

The Bowleven interpretation is based on a block-wide sequence stratigraphic approach. Picked events are:

- top Isongo unconformity: base of volcaniclastic layer
- intra-thin bed marker (trough)
- intra Isongo marker (trough): top of good shale in IF-1r

Seismic data quality is generally good over the interval Late Miocene to Recent. Below the volcaniclastic layer, seismic data quality is reduced. Also, in the east of the survey, there is an area of IF-1r where seismic imaging is very poor and seismic interpretation at reservoir level is challenging.

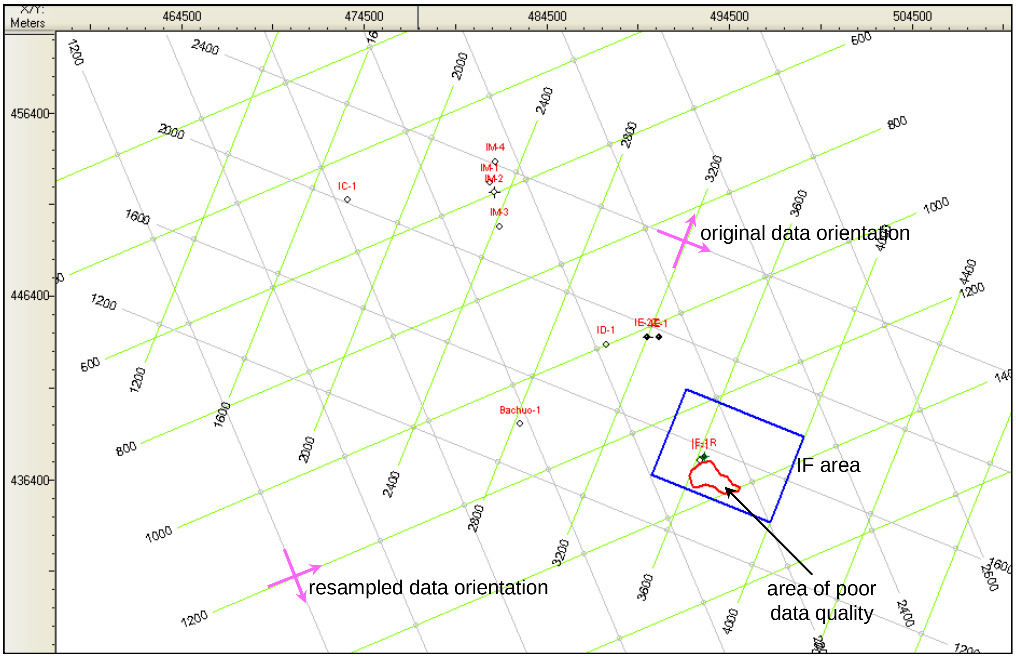


Figure 3-4 Seismic data

Various explanations have been put forward for the poor quality data area. The most common is that of a gas cloud above the crest of the structure. An alternative explanation is that a shale diapir has deformed or pierced the overlying layers.

3.5.2. Top structure

TRACS has carried out an independent, well-centric interpretation of the IF area.

TRACS follows a seismic peak which corresponds to top Sand 1 in well IF-1r, based on the generated synthetic seismogram. Where data quality is poor, the top Isongo unconformity, which has a clear seismic signature, is used as a guide. Deeper shale markers display a similar topography to the top sand seismic horizon. The top of the Thin Beds cannot be reliably mapped away from the well.

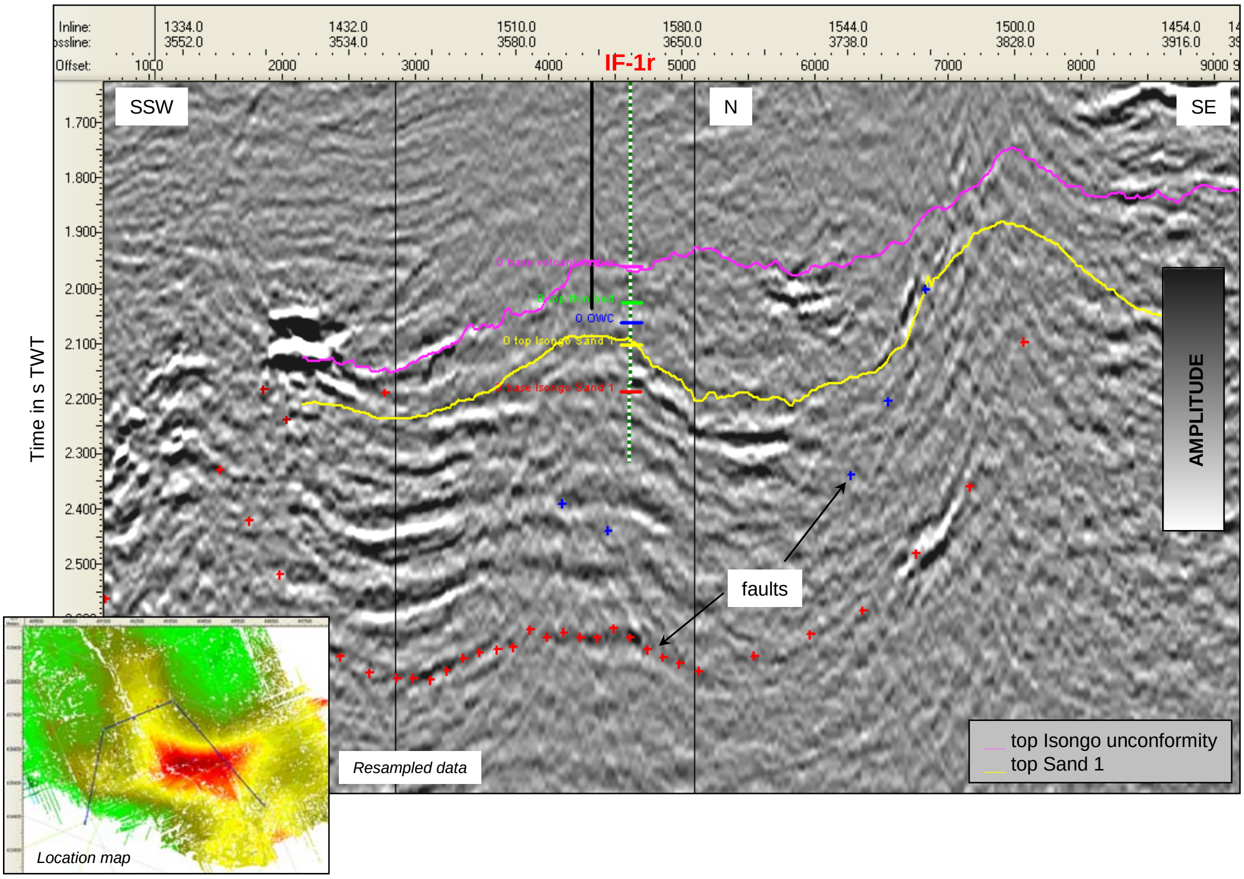


Figure 3-5 Seismic line through IF-1r

Mapping over the western and northern parts of the IF structure is relatively straightforward but there is considerable uncertainty to the south and east, i.e. in the poor quality area. The IF structure is interpreted as a toe fold developing to the east into a lateral ramp within a large-scale slope collapse feature. The fold is faulted at the crest and may have additional faulting to the south. The trap is described as combined structural with dip closure to the west and north and a combination of dip and fault closure to the south and east.

The depth conversion uses the Bowleven V0-k function derived for the IF-1r well. Velocities over the IE structure are sufficiently different to warrant using a local method for the best technical evaluation. The surface was then tied to the well using a local well tie algorithm.

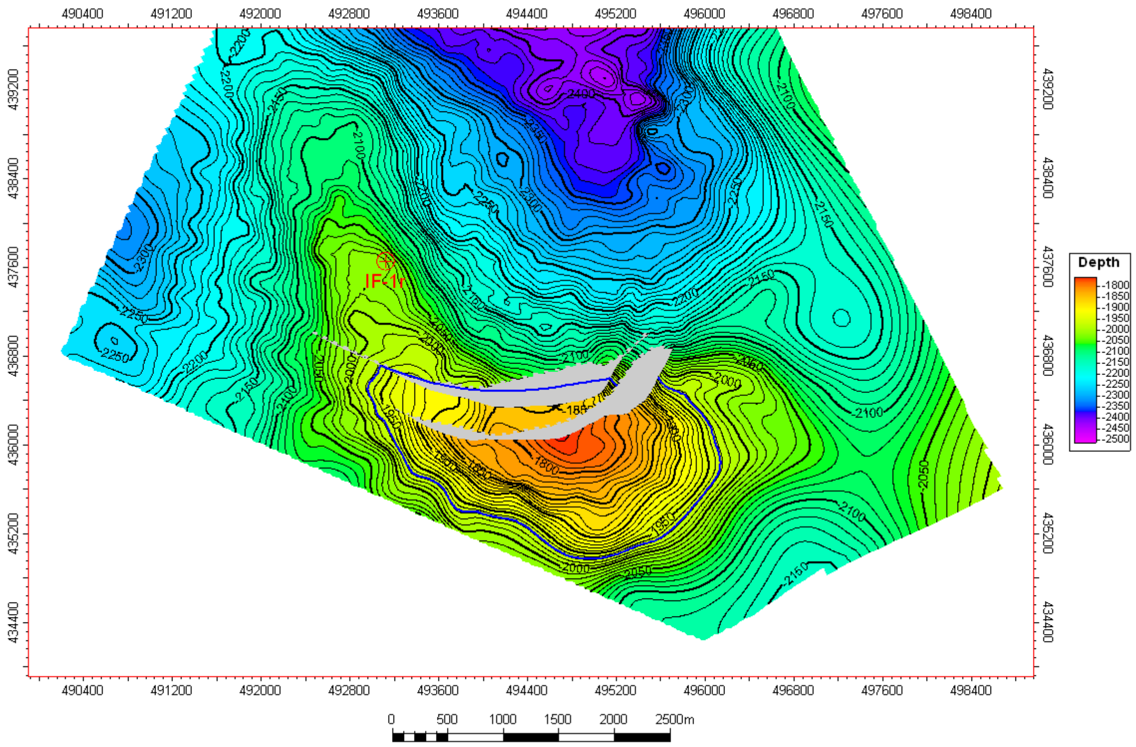


Figure 3-6 Depth map of top Sand 1 in m TVD (Contour Interval = 10m)

Amplitude maps were generated over various windowed horizons at reservoir level but no conformance to structure was detected and no meaningful patterns were apparent. There is no evidence of direct hydrocarbon indicators ("DHIs") in this area. Previous analysis by Bowleven of Amplitude Variations with Offset ("AVO") did not highlight any AVO anomalies.

3.6. Mapping and volumetric calculations

The depth-converted top Sand 1 horizon was imported into the 3D modelling software ("Petrel") and a structural model with a simplified fault network was constructed. The Gross Rock Volume ("GRV") for each zone was calculated in Petrel. Deterministic realisations for the mid case and high case were generated.

The mid case realisation is based on the TRACS top Sand 1 map. The zones were assumed as constant thickness units, derived from IF-1r. It is recognised that thickness variations are likely to occur although there is insufficient information to predict. These uncertainties are captured in the volumetric range and in the estimated probability of appraisal success.

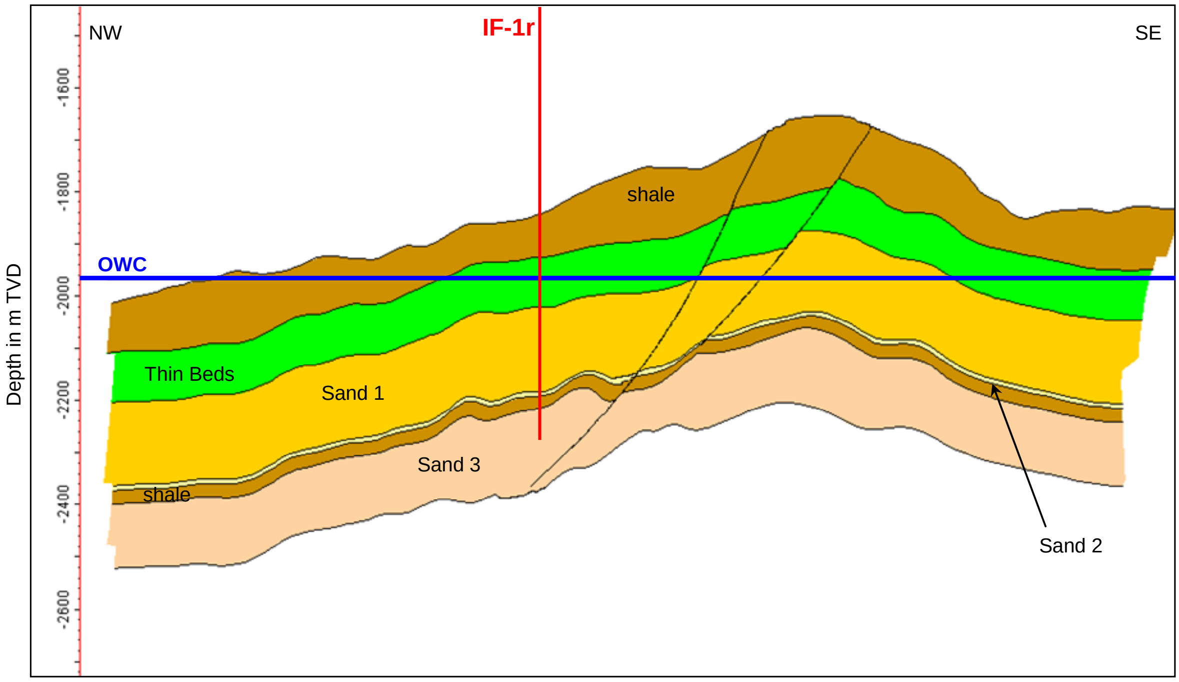


Figure 3-7 Cross section through mid case model

Based on a block-wide mapping study, Bowleven has identified potential upside in the crestal area of the structure; this has been taken as the high case realisation. In this realisation, the Thin Beds interval is thinned onto the crest as they are truncated by the top Isongo unconformity.

The low case is designed to account for uncertainties in the depth conversion, especially over the poor data area where differences are observed throughout the overburden, and the uncertainty in the seismic pick over the poor data area. Differences in the velocity from using the IF-1r time-depth conversion versus the regional time-depth conversion could give up to 250 ft differences at top reservoir. The depth of the crest of the structure is therefore considered uncertain and it has been depressed to result in a uniform GRV range for Sand 1 (high-mid=mid-low). Depressing the structure does not substantially reduce the volume of the Thin Beds which lie above the oil water contact, therefore, the low case GRV for the Thin Beds is similar in the mid and low cases (high is truncated at Isongo unconformity).

The low case represents an instance where the amplitude of the structure is smaller than anticipated as a result of seismic pick and depth conversion uncertainty.

No deterministic low case maps/models were generated

The GRV inputs to the STOIIP and Contingent Resource estimation are presented in Section 4.

3.7. Fluid data

A Modular Dynamic Tester ("MDT") was run in well IF-1r which recorded pressures through the Isongo reservoir sequence. Fluid samples were also taken at two levels, from an oil-bearing interval and from a water-bearing interval.

The MDT pressures plotted against depth are presented in Figure 4-1. There is a clear oil gradient (0.26 psi/ft) in the Isongo Thin Beds sands and a common water gradient (0.435 psi/ft) through reservoir units in the Thin beds pay and Isongo 1 and 2 sands. Although there is some scatter in the pressure data of the oil leg the Free Water Level (considered as coincident with the OWC) from the pressure data is consistent with the log interpretation.

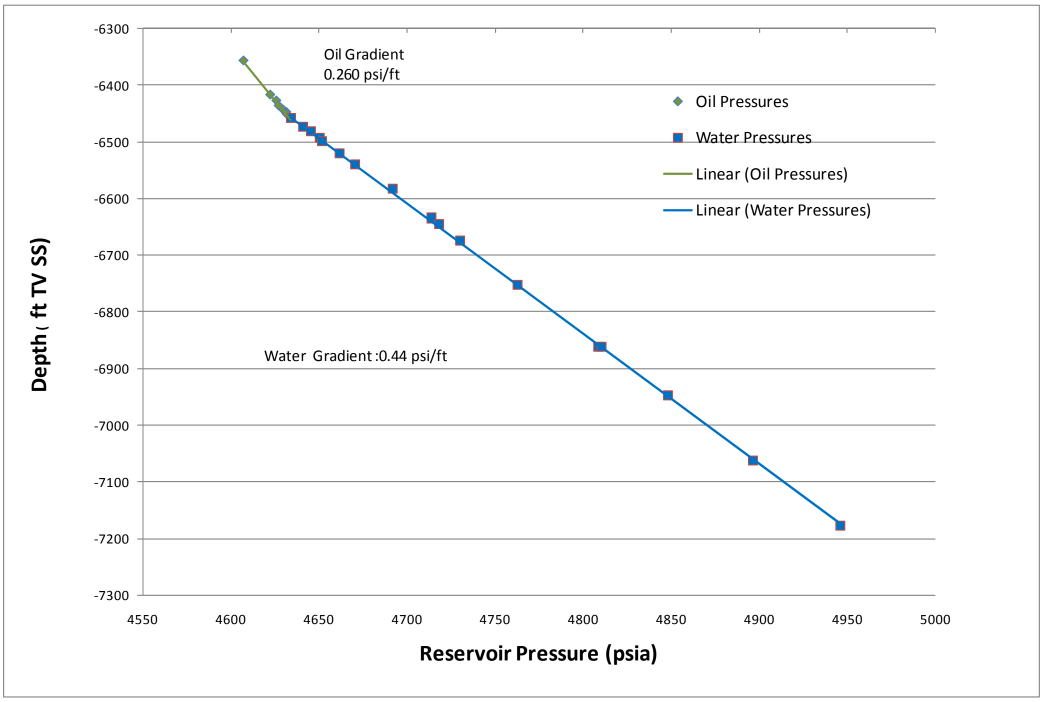


Figure 3-8 Results of MDT from IF-1r

The initial pressure in the oil column is estimated at 4618.4 psia at 6400 ft TVD. This represents an over-pressured regime compared to hydrostatic (0.72 psi/ft to surface). It should also be noted that this pressure regime is lower than that seen in the Isongo Sand units of other fields in Block 7, i.e. ID, IE etc. This indicates that there are issues with block-wide lateral connectivity in the Isongo sands. The estimated reservoir temperature is 235 deg F and is obtained from the production test.

Oil samples were taken with the MDT at a depth of 6449 ft TVD ("MDT samples"). Two oil samples were analysed on site using the PVT Express unit. Both MDT samples had between 8% and 10% oil base mud contamination in the stock tank liquid, which is on the border of what is acceptable as being reliable for (corrected) PVT measurements. Consequently the results from the sample analysis need to be treated with caution. Both MDT samples were evaluated as being undersaturated fluids with corrected initial gas oil ratios ("GORs") of 1254 scf/stb and 1294 scf/stb. The GORs correspond to estimated bubble point pressures of 4148 psia and 4206 psia, respectively. These values were derived using the Lasater correlation which was found to be the most suitable correlation for this oil type.

Two further downhole oil samples were taken during the production testing programme ("DST samples"). The DST samples were also analysed on site using the PVT Express unit. Both samples were shown to be undersaturated oil (34-35 API) with measured GORs of 1338 and 1393 scf/stb, corresponding to measured bubble points of 4255 and 4344psia, respectively. The key uncertainty around the validity of the DST samples as being representative of the reservoir fluid is that the samples were taken at a well flowing pressure (at sample depth) of 4193 psia. This would indicate that if the measured bubble points were correct, then the samples were taken in the two phase region (i.e. flowing below bubble point). The consequence of this would be that the sampled GOR is lower than the true GOR, and consequently, that the estimated bubble point pressure is lower than the true bubble point pressure.

It should be noted that the producing GOR measured at surface during the sampling was 1531 scf/stb. If this is a representative GOR of the reservoir fluid then correlations indicate that the fluid will be saturated, i.e. bubble point equal to reservoir pressure.

The sample data is not internally consistent and it cannot be ruled out that the fluids are saturated at the sampling depth. The consequence is that there remains the risk of a gas cap updip of the discovery. If the gas cap is sizeable (a column length in the order of 500 ft or more but dependent on structure) this will have a significant impact on the profitability of the development since gas would be present in the better quality Sand 1 where the best recovery is expected. The chance of such a gas cap being present has been taken into account when assessing the probability of appraisal success.

The formation volume factor ("FVF") used for volumetric calculations is based on the measured properties from the DST samples and taking into account the corrected values for the MDT samples. The FVF is estimated at 1.74rb/stb. This would correspond to a bubble point of approximately 4285psia and an initial GOR of 1300 scf/stb. The estimated in situ viscosity of the oil is 0.4 cp.

The water sample obtained with the MDT was analysed and showed to be consistent with the water gradient obtained in the pressure survey, i.e. a relatively fresh water of 20,000 ppm.

3.8. Production test

Two production tests were carried out on IF. The first attempt to production test (DST-1A) failed due to faulty perforation guns. The second attempt (DST-1B) was successful and perforated an interval in the Isongo Thin Beds reservoir between 6442 and 6454 ft MD.

On a 32/64" choke the well flowed at a peak oil rate of 4184bopd and an average rate of 3371 bopd. During all flow periods high water cuts were present with peak water rates reaching 3000 bpd. The water is believed to have been produced from the lower Isongo sands due to the very poor cement job resulting in limited or no isolation of lower water zones (a poor cement bond is interpreted from the CBL and, in addition, there were no returns during the cement job). The significant water production compromised the test quality and in particular the final build-up which shows unusual trends, possibly due to phase segregation. Based on the flow rates an estimate has been made of kh between 2500 and 5500 md ft. This corresponds to average permeabilities of around 100 to 225 md.

A second DST (DST-2) was attempted on the interval 6244 to 6366 ft MD. The test was aborted after quickly experiencing high water rates believed again to have come from behind casing.

3.9. Recovery factors

Pressure data has shown (see Figure A4-1 in Appendix 4) that the Isongo sands are generally not connected across the fields in Block 7 (different pressure regimes). This brings into question the lateral continuity of the aquifer connected to the IF field. The Isongo sands in the IF-1r well have a common water gradient through them and do seem to be in communication. However, the extent of the vertical communication during production lifetime remains an uncertainty.

PVT data has shown that in the most likely case the oil is an undersaturated fluid. Combining this with the aquifer uncertainty indicates that the IF system will have limited natural energy. This type of setting should benefit significantly from a water injection development.

The low viscosity of the reservoir fluid (0.4 cp) is expected to give a favourable mobility ratio for waterflood. However, the key uncertainty for the water injection development is the lateral continuity and connectivity of the sands. This is particularly the case for the Thin Beds, where the heterogeneity of the sand units is also likely to impact on the sweep efficiency of the waterflood.

To assess the recovery factors of a water injection development in the IF field the sweep efficiency has been divided into three areas: microscopic sweep, vertical sweep and areal sweep. Each of the three areas of sweep has been assessed for the Thin Beds and Isongo sands independently; a low (P90), mid (P50) and high (P10) has been estimated for the three factors. The range is given in Table A4.1 in Appendix 4.

Note that the vertical and areal sweep efficiencies need to be assessed together to provide a range of macroscopic sweep efficiencies. In this assessment the vertical range has been assessed first and the areal range assessed based on the vertical sweep efficiency.

The sweep efficiencies have been probabilistically combined on an independent basis for both the Thin Beds and Sands 1 and 2 to obtain a range of recovery factors. These are given in Table A4.2 in Appendix 4.

3.10. Field development plan

The development plan for the IF Field is based on a water injection scheme. An offshore platform centred on IF, will host the water injection facilities, including seawater de-aeration and filtration, and will accommodate a mobile jack-up rig for the drilling the development wells. The produced fluids will be sent onshore (approximately 25km), in multi-phase mode (without prior separation) where they will be processed at a new oil and gas processing plant. The processed oil will be transported to new storage facilities and exported through existing facilities. Part of the produced gas will be utilised for own use fuel gas and the remaining evacuated to an existing power station located nearby the new processing facilities or will be flared. All produced water will be treated and disposed of in the sea or nearby river. A subsea power cable is required to export the required power to the offshore platform.

Four producing wells and three injector wells are envisaged. The two appraisal wells planned for 2009/2010 will, if successful, be converted to producers as part of the plan. All wells will be able to be drilled from the platform location with the exception of one injector well, which is planned to be a subsea well tied back to the platform via a 2km pipeline. The producing wells will be required to each produce approximately 10,000 bpd of liquid and the injectors will be required to inject approximately 15,000 bpd of water each. These rates are considered to be achievable given the evidence of core permeabilities, logs and production test, and also that the better quality Isongo 1 sand will be a key contributor.

The processing facilities will cater for 30,000 bpd oil, 45000 bpd liquid, a water injection capacity of 60,000 bwpd and a gas capacity of 36 MMscfd.

The development schedule provided by Bowleven is as follows:

- Project sanction for drilling appraisal wells in August 2009
- Mobilise rig and spud first appraisal well in Q4 2009
- Update reservoir models and generate FDP in Q2 2010
- Start FEED Q2 2010
- Acquire (Q1 2010) and interpret new 3D seismic data to optimise development wells. Completed Q3 2010
- Obtain Exploitation Authorisation and final project sanction in Q3 2010

- Finalise detailed design in Q1 2011
- Start of development drilling in Q2 2011
- Facilities in place Q2 2012
- Facilities commissioned and first production end 2012

It should be noted that the schedule outlined above is considered to be aggressive.

The oil production profiles associated with this development for the low, mid and high resources are presented in the figure below. An uptime factor of 90% has been applied to the production forecasts to obtain an average daily rate. In the low case the full capacity of the facilities has not been utilised. In this scenario it is assumed that although initially the field may be produced at 30,000 bpd, this high offtake (45% of recoverable volumes per annum) would result in declining rates with the water injection not keeping up with production due to transient effects in the reservoir. Therefore an average offtake of 20,000 bpd is assumed.

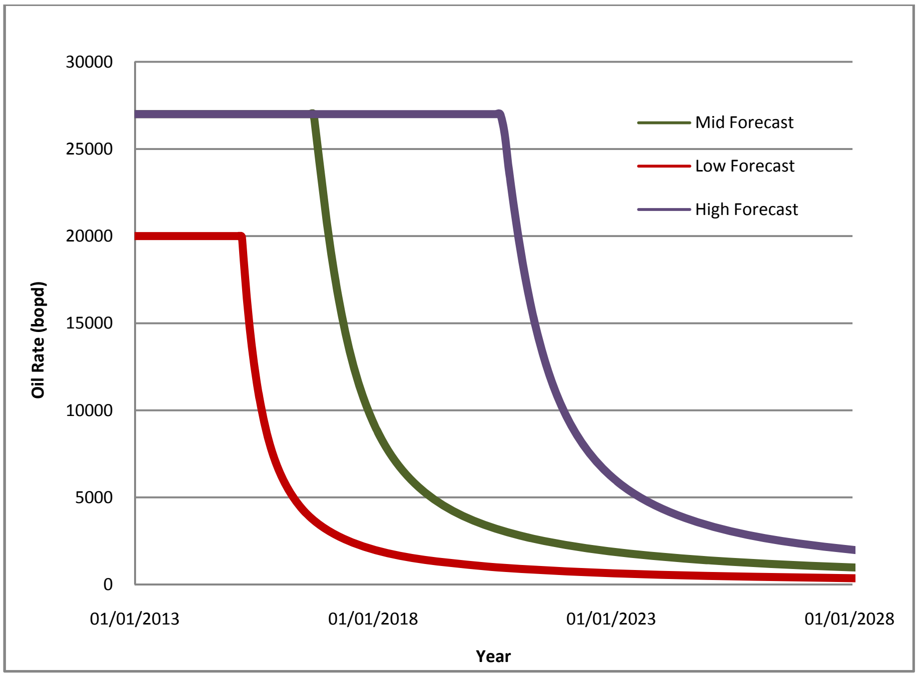


Figure 3-9 Oil production profiles for low, mid and high resource volumes

It should be further noted that all development cases are defined after appraisal. Data from the appraisal wells should reduce the range of uncertainty and a more optimal development should be identified (e.g. if low case is identified then fewer wells and lower facility capacities will result in lower costs).

4. Reserves and Resources assessment

4.1. Uncertainty

IF is an oil discovery. The proven area of the field, however, is insufficient in size to justify development and an appraisal programme is required. The first appraisal well will penetrate the area where the seismic definition is poor in order to better determine the structure, sand presence, fluid fill and connectivity to the discovery. The development of the field is contingent on the success of the appraisal wells. The risk of achieving this success has been evaluated.

The uncertainties that would contribute to project failure are listed below:

1. Presence of significant gas cap defined as >500 ft column.
2. Absence of Sand 1 and 2 in the crestal area as a result of a shale diapir piercing the overlying layers – oil rim only.
3. No structure: The seismic data are totally contaminated by artefacts and the structure interpreted under the gas chimney is not present.
4. No closure: The extent of closure is limited by faults not imaged on seismic data.

The total probability of commercial success is evaluated at 65% (35% failure possibility).

Given these risks, the recoverable volumes associated with this planned development have been classified as Contingent Resources in line with the definitions in the SPE-PRMS.

The volumes quoted in the sections below are post-appraisal Contingent Resources (low-mid-high) in the event of a commercial success.

4.2. STOIIP

The stock tank oil initially in place ("STOIIP") for each zone were calculated by combining low-mid-high gross rock volumes ("GRVs") with the log-derived petrophysical parameters for each zone.

Computed GRVs were input as Min, Most Likely and Max and P90-P50-P10 GRVs were then estimated assuming a triangular distribution.

A range of N:G values was input as P10-P50-P90. The remaining reservoir and fluid parameters were kept constant. A summary of the input parameters for the low, mid and high cases is given in the tables below.

Zone	GRV	N:G	Phi	Sh	Shrinkage	STOIIP
	MM m3	fr	fr	fr	rb/stb	MM bbls
Thin Beds	450	0.15	0.21	0.75	1.74	38.4
Sand 1	190	0.58	0.21	0.75	1.74	62.7
Sand 2	0	0.82	0.21	0.75	1.74	0
Sand 3	0	0.54	0.23	0.75	1.74	0
					Total Thin Beds	38.4
					Total Sands 1,2 and 3	62.7
					Total	101.2

Table 4-1 LOW Input parameters for STOIIP calculations

Zone	GRV	N:G	Phi	Sh	Shrinkage	STOIIP
	MM m3	fr	fr	fr	rb/stb	MM bbls
Thin Beds	525	0.25	0.21	0.75	1.74	74.7
Sand 1	290	0.70	0.21	0.75	1.74	115.6
Sand 2	6	0.82	0.21	0.75	1.74	2.8
Sand 3	4	0.54	0.23	0.75	1.74	1.3
					Total Thin Beds	74.7
					Total Sands 1,2 and 3	119.7
					Total	194.5

Table 4-2 MID Input parameters for STOIIP calculations

Zone	GRV	N:G	Phi	Sh	Shrinkage	STOIIP
	MM m3	fr	fr	fr	rb/stb	MM bbls
Thin Beds	365	0.35	0.21	0.75	1.74	72.7
Sand 1	390	0.78	0.21	0.75	1.74	173.2
Sand 2	13.5	0.82	0.21	0.75	1.74	6.3
Sand 3	65	0.54	0.23	0.75	1.74	21.9
					Total Thin Beds	72.7
					Total Sands 1,2 and 3	201.4
					Total	274.1

Table 4-3 HIGH Input parameters for STOIIP calculations

4.3. Recoverable volumes

An expectation curve for the recoverable volumes has been generated by combining the range of recovery factors presented in Table A4.2 in Appendix 4 with the STOIIP values presented in Table 4-1 to Table 4-3.

The recovery factors are assumed to be independent of the STOIIP value, i.e. each recovery factor can be applied to the low, mid and high STOIIP numbers. The recovery factors of the Thin Beds are also assumed to be independent of the recovery factors of the Isongo Sands 1 and 2, i.e. they can have any combination of the recovery factors in Table A4.2.

This approach generates 27 realisations which can be combined into an expectation curve, presented in Figure 4-1.

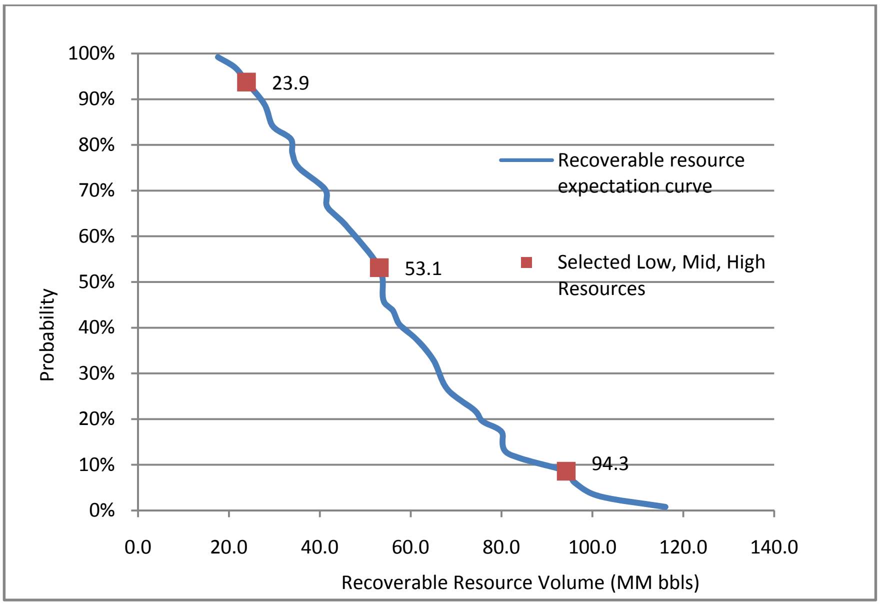


Figure 4-1 Recoverable resource expectation curve

Three discrete realisations are selected off the curve to represent the P90 (low), P50 (mid) and P10 (high) recoverable volumes. The resulting total Contingent Resources, together with the average recovery factor for the combined Thin Beds and Sand 1, are presented in Table 4-4.

	1C	2C	3C
Total STOIIP (MM stb)	101.2	194.5	274.1
Oil Contingent Resources (MM stb)	23.9	53.1	94.3
Average Recovery Factor	23.6%	27.3%	34.4%

Table 4-4 Range of gross Contingent Resources

Note that if SNH back-in to the development then they will be assigned 20% of the resources (proportional to shareholding) and Bowleven resources will become 80% of the volumes shown in Table 4-4. The Bowleven resources based on an 80% shareholding are presented in Table 4-5.

	1C	2C	3C
Oil Contingent Resources (MM stb)	19.1	42.5	75.4

Table 4-5 Range of net Contingent Resources for Bowleven if SNH back-in to IF

No Resource is documented for the associated gas, which will be used for fuel and the remainder flared or sold locally.

5. Valuation of Resources

The IF resources have been valued using a detailed economic model representing the PSC terms. The economic model has been constructed by Bowleven and has previously been reviewed (when used on different assets) by an external party to confirm validity. For this evaluation the model has been quickly reviewed but largely accepted as being valid.

The model incorporates all PSC fiscal terms (section 5.1) together with costs for exploration, appraisal and development facilities, pipelines, wells, abandonment and operating costs.

The Nymex crude oil (light) forward curve from May 13th 2009 was used for oil through to 2017 (see Table 5.1) and an inflation rate of 1.8% per year applied thereafter. This inflation honours the forward curve trend.

2010	2011	2012	2013	2014	2015	2016	2017
$67.1	$71.3	$73.3	$74.8	$76.3	$77.7	$79.2	$80.6

Table 5-1 Oil price deck

The associated gas is assumed to carry no value in the economics as there is no definitive market.

5.1. Overview of PSC terms for oil developments

The Etinde PSC was signed on December 22nd 2008 and covers Blocks 5, 6 and 7. EurOil holds a 100% participating interest in the PSC, which is currently in the exploration phase. The exploration phase runs until 22 December 2011, with the possibility of a further extension of up to 12 months.. The exploitation period for oil is 15 years and for gas 20 years, with a possible extension of 10 years for each if demonstrated to be commercial. The exploitation period begins on award of the relevant exploitation authorisation. Under the PSC the state oil company of Cameroon, Societe Nationale des Hydrocarbures (SNH) has the right to elect to take a 20% participating interest in a development with effect from the grant of the relevant exploitation authorisation. Following such back-in, and assuming no other contractor parties, EurOil would accordingly retain an 80% participating interest in the relevant development. The valuations in this report assume SNH back-in to the IF oil development.

A detailed listing of the fiscal terms associated with oil developments under the PSC is given in Appendix 5. A summary of the terms is given below:

- Company tax rate for oil is 40%.
- Cost recovery is limited to a maximum 70% of gross revenue per year for oil.
- The share of profit oil is governed by an R-factor (net cumulative revenue/contractor gross revenues). The Contractor share of profit oil varies from 95% to 65% for oil.
- Tax losses can be carried forward 4 years for oil from start of production.
- Production bonuses of between 2 and 5 US$ million are payable at discrete steps between 25 and 150 MM boe of production.

Note: no value has been attributed to the gas in this evaluation and consequently the PSC fiscal terms for gas are not presented in this document.

5.2. Economic input (costs and production profiles)

The production profiles used for the economic input are presented in Section 3.10.

A cost estimate has been generated for the development concept presented in Section 3.10. The cost estimate was generated by the independent oil and gas engineering consultancy Genesis, on behalf of Bowleven. For this evaluation the costs have been taken as valid. An overview of the cost estimates for the development plan is presented in Table 5-2. All cost estimates are US$ million RT 2009.

Cost Item	Cost (MM US$ RT 2009)
Topsides	67.8
Platform substructure	73.8
Offshore pipelines	68.9
Subsea equipment	6.8
Onshore processing plant	297.5
Appraisal wells	70
Development drilling	190
Total	**774.9**

Table 5-2 Development Capex for IF

An investment tax (SIT) of 15% is added to all Capex estimates presented in Table 5-2 The annual inflation factor on costs is 3% pa.

In addition to the aforementioned Capex estimates, the historical exploration costs for the permit (Blocks 5, 6 and 7) are included in the economics for cost recovery. These costs total 235 MMUS$. It should be noted that including these costs assumes that there is no other development in the permit, i.e. IF is the sole development to offset the exploration costs. It should also be noted that the historic exploration costs have been approved at technical committee meetings (attended by SNH representatives) but have not been subject to final audit.

Operating costs are estimated at 15 MMUS$ per annum (RT 2009). An additional 10 MMUS$ (RT 2009) is included every other year to accommodate workovers of wells as rig access will require a mobile jack-up.

Abandonment costs are estimated as 7% of total development Capex and an abandonment fund is assumed in the economics.

5.3. Results

The estimated post-tax Net Present Value at 10% discount rate of the IF project is presented in Table 5-3. The table details the net value attributable to Bowleven for the low, mid and high resource cases. All values are referenced to July 1st 2009.

	1C	2C	3C	POS
Oil Contingent Resources (MM bbl)	23.9	53.1	94.3	65%
Post-tax NPV (10%) MMUS$	10.6	556.3	1038.3	

Table 5-3 IF contingent resource post-tax Net Present Value Summary

Since 1C, 2C and 3C resources are estimated as P90, P50 and P10 values, respectively probabilities of 25%, 50% and 25%, respectively, have been attributed to the categories. Assuming a successful appraisal of IF, this gives an estimated monetary value (EMV) at 10% discount rate of 540 MMUS$. The EMV (10%) as of today is 339 MMUS$, assuming only one appraisal well is required to identify the failure case.

Appendix 1 Personnel

Senior Petroleum Engineer

Harry Crighton has 22 years oil industry experience; 3 with BP; 8 with Shell; and the last 11 with TRACS International. Since joining TRACS, Harry has undertaken consultancy projects in a Senior Petrophysical and Petroleum Engineering Manager role for a significant number of companies, both on individual studies and while working as part of integrated Petroleum Engineering studies team. Harry is a senior partner in TRACS and generally acts in a project team coordinator role for a TRACS integrated team. He is also an experienced asset valuator and reserves auditor.

Geophysicist

Liz Chellingsworth has 8 years of oil industry experience; 5 with specialist geophysical consultancies and 3 with TRACS International. Liz has worked on geophysical and geological aspects of deep water clastic reservoir evaluations during exploration and appraisal and has developed expertise in the seismic interpretation and 3D mapping of such systems on the Atlantic margin in the UK and West Africa.

Reservoir Engineer

Mike Wynne has 22 years of petroleum/reservoir engineering experience, predominately with Shell operating units. He is a highly competent reservoir engineer with experience in simulation, PVT and well test analysis and has a proven track record as a subsurface/field development project co-ordinator He is a specialist in technical and economic screening of greenfield and brownfield development concepts and has extensive experience in reserves estimation and production forecasting and well test design and analysis (including wireline formation testing)

Petrophysicist

Jackie Mullinor worked in the Oil and Gas industry for 8 years before taking time out as an at-home mother. She began working with wireline data at a service company in 1992 and went on to interpret petrophysical data with them. She joined an operator in 1997 and stayed with them until 2000. She was the log analyst in the exploration department and carried out petrophysical duties there and for the reservoir department. She was also responsible for supplying QC'd raw well data to a service company for depth matching and merging, loading all well data; interpreting logs for current and old wells; provided and downloaded data from CDA. She represented the company at the CDA user group and was eventually on the CDA board.

Appendix 2 Glossary

List of key abbreviations used in this report.

AIM	Alternative Investment Market
B	Billion (10^9)
bbl	Barrels
stb	Stock tank barrels
bopd	Barrels oil per day
Bscf	Billion standard cubic feet
BS&W	Bottom sediment and water
CGR	Condensate Gas Ratio
CPR	Competent Person's Report
Ft	feet
ft3	Cubic feet
GDT	Gas Down To
GIIP	Gas initially in place
GWC	Gas Water Contact
km	Kilometres
km2	Square kilometres
m	Metres
m3	Cubic metres
mD	Permeability in millidarcies
M	Thousand (10^3)
MM	Million (10^6)
MD	Measured Depth
PI	Productivity Index
psi	Pounds per square inch
psig	Pounds per square inch gauge
RF	Recovery Factor
scf	Standard Cubic Feet
scfd	Standard Cubic Feet per day
SPE	Society of Petroleum Engineers
SS	Subsea
SW	Water Saturation
Tcf	Trillion cubic feet of gas

TVDSS	True Vertical Depth Subsea
WPC	World Petroleum Congresses
2D	Two dimensional
3D	Three dimensional
%	Percentage

Appendix 3 Petroleum Reserves Definitions

SOCIETY OF PETROLEUM ENGINEERS (SPE)

AND

WORLD PETROLEUM CONGRESSES (WPC)

DEFINITIONS

Reserves are those quantities of petroleum1 which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

The intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of reserves classified as unproved. Public disclosure of the quantities classified as unproved reserves is left to the discretion of the countries or companies involved.

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

Reserves estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

1. PETROLEUM: For the purpose of these definitions, the term petroleum refers to naturally occurring liquids and gases which are predominately comprised of hydrocarbon compounds. Petroleum may also contain non-hydrocarbon compounds in which sulphur, oxygen, and/or nitrogen atoms are combined with carbon and hydrogen. Common examples of non-hydrocarbons found in petroleum are nitrogen, carbon dioxide and hydrogen sulphide.

PROVED RESERVES

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves.

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. In this context, the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir. In certain cases, proved reserves may be assigned on the basis of well logs and/or core analysis that indicate the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

The area of the reservoir considered as proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data.

Reserves may be classified as proved if facilities to process and transport those reserves to market are operational at the time of the estimate or there is a reasonable expectation that such facilities will be installed. Reserves in undeveloped locations may be classified as proved undeveloped provided (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain such locations are within the known proved productive limits of the objective formation, (3) the locations conform to existing well spacing regulations where applicable, and (4) it is reasonably certain the locations will be developed. Reserves from other locations are categorized as proved undeveloped only where interpretations of geological and engineering data from wells indicate with reasonable certainty that the objective formation is laterally continuous and contains commercially recoverable petroleum at locations beyond direct offsets.

Reserves which are to be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favourable response of an installed program in the same or an analogous reservoir with similar rock and fluid properties provides support for the analysis on which the project was based, and, (2) it is reasonably certain that the project will proceed. Reserves to be recovered by improved recovery methods that have yet to be established through commercially successful applications are included in the proved classification only (1) after a favourable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program where the response provides support for the analysis on which the project is based and (2) it is reasonably certain the project will proceed.

UNPROVED RESERVES

Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

Unproved reserves may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. The effect of possible future improvements in economic conditions and technological developments can be expressed by allocating appropriate quantities of reserves to the probable and possible classifications.

PROBABLE RESERVES

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when

(a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favourable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behaviour in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

POSSIBLE RESERVES

Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

In general, possible reserves may include (1) reserves which, based on geological interpretations, could possibly exist beyond areas classified as probable, (2) reserves in formations that appear to be petroleum bearing based on log and core analysis but may not be productive at commercial rates, (3) incremental reserves attributed to infill drilling that are subject to technical uncertainty, (4) reserves attributed to improved recovery methods when (a) a project or pilot is planned but not in operation and (b) rock, fluid and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and geological interpretation indicates the subject area is structurally lower than the proved area.

RESERVE STATUS CATEGORIES

Reserve status categories define the development and producing status of wells and reservoirs.

Developed: Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be sub-categorized as producing or non-producing.

Producing: Reserves subcategorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Non-producing: Reserves subcategorized as non-producing include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells, which will required additional completion work or future recompletion prior to the start of production.

Undeveloped Reserves: Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Approved by the Board of Directors, Society of Petroleum Engineers (SPE), Inc., and the Executive Board, World Petroleum Congresses (WPC), March 1997.

PETROLEUM RESOURCES CLASSIFICATION AND DEFINITIONS

SOCIETY OF PETROLEUM ENGINEERS (SPE)

WORLD PETROLEUM CONGRESSES (WPC)

AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)

In March 1997, the Society of Petroleum Engineers (SPE) and the World Petroleum Congresses (WPC) approved a set of petroleum * reserves definitions which represented a major step forward in their mutual desire to improve the level of consistency in reserves estimation and reporting on a worldwide basis. As a further development, the SPE and WPC recognized the potential benefits to be obtained by supplementing those definitions to cover the entire resource base, including those quantities of Petroleum contained in accumulations that are currently sub-commercial or that have yet to be discovered. These other resources represent potential future additions to reserves and are therefore important to both countries and companies for planning and portfolio management purposes. In addition, the American Association of Petroleum Geologists (AAPG) participated in the development of these definitions and joined SPE and WPC as a sponsoring organization.

In 1987, the WPC published its report "Classification and Nomenclature Systems for Petroleum and Petroleum Reserves", which included definitions for all categories of resources. The WPC report, together with definitions by other industry organizations and recognition of current industry practice, provided the basis for the system outlined here.

Nothing in the following resource definitions should be construed as modifying the existing definitions for petroleum reserves as approved by the SPE/WPC in March 1997.

As with unproved (i.e. probable and possible) reserves, the intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of quantities classified as resources. Such disclosure is left to the discretion of the countries or companies involved.

Estimates derived under these definitions rely on the integrity, skill, and judgement of the evaluator and are affected by the geological complexity, stage of exploration or development, degree of depletion of the reservoirs, and amount of available data. Use of the definitions should sharpen the distinction between various classifications and provide more consistent resources reporting.

DEFINITIONS

The resource classification system is summarized in Figure 1 and the relevant definitions are given below. Elsewhere, resources have been defined as including all quantities of petroleum which are estimated to be initially-in-place; however, some users consider only the estimated recoverable portion to constitute a resource. In these definitions, the quantities estimated to be initially-in-place are defined as Total Petroleum-initially-in-place, Discovered Petroleum-initially-in-place and Undiscovered Petroleum-initially-in-place, and the recoverable portions are defined separately as Reserves, Contingent Resources and Prospective Resources. In any event, it should be understood that reserves constitute a subset of resources, being those quantities that are discovered (i.e. in known accumulations), recoverable, commercial and remaining.

TOTAL PETROLEUM-INITIALLY-IN-PLACE

Total Petroleum-initially-in-place is that quantity of petroleum which is estimated to exist originally in naturally occurring accumulations. Total Petroleum-initially-in-place is, therefore, that quantity of petroleum which is estimated, on a given date, to be contained in known accumulations, plus those quantities already produced therefrom, plus those estimated quantities in accumulations yet to be discovered. Total Petroleum-initially-in-place may be subdivided into Discovered Petroleum-initially-in-place and Undiscovered Petroleum-initially-in-place, with Discovered Petroleum-initially-in-place being limited to known accumulations.

It is recognized that all Petroleum-initially-in-place quantities may constitute potentially recoverable resources since the estimation of the proportion which may be recoverable can be subject to significant uncertainty and will change with variations in commercial circumstances, technological developments and data availability. A portion of those quantities classified as Unrecoverable may become recoverable resources in the future as commercial circumstances change, technological developments occur, or additional data are acquired.

For the purpose of these definitions, the term "petroleum" refers to naturally occurring liquids and gases that are predominantly comprised of hydrocarbon compounds. Petroleum may also contain non-hydrocarbon compounds in which sulphur, oxygen, and/or nitrogen atoms are combined with carbon and hydrogen. Common examples of non-hydrocarbons found in petroleum are nitrogen, carbon dioxide, and hydrogen sulphide.

DISCOVERED PETROLEUM-INITIALLY-IN-PLACE

Discovered Petroleum-initially-in-place is that quantity of petroleum which is estimated, on a given date, to be contained in known accumulations, plus those quantities already produced therefrom. Discovered Petroleum-initially-in-place may be subdivided into Commercial and Sub-commercial categories, with the estimated potentially recoverable portion being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES

Reserves are defined as those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. Reference should be made to the full SPE/WPC Petroleum Reserves Definitions for the complete definitions and guidelines.

Estimated recoverable quantities from known accumulations which do not fulfil the requirement of commerciality should be classified as Contingent Resources, as defined below. The definition of commerciality for an accumulation will vary according to local conditions and circumstances and is left to the discretion of the country or company concerned. However, reserves must still be categorized according to the specific criteria of the SPE/WPC definitions and therefore proved reserves will be limited to those quantities that are commercial under current economic conditions, while probable and possible reserves may be based on future economic conditions. In general, quantities should not be classified as reserves unless there is an expectation that the accumulation will be developed and placed on production within a reasonable timeframe.

In certain circumstances, reserves may be assigned even though development may not occur for some time. An example of this would be where fields are dedicated to a long-term supply contract and will only be developed as and when they are required to satisfy that contract.

CONTINGENT RESOURCES

Contingent Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.

It is recognized that some ambiguity may exist between the definitions of contingent resources and unproved reserves. This is a reflection of variations in current industry practice. It is recommended that if the degree of commitment is not such that the accumulation is expected to be developed and placed on production within a reasonable timeframe, the estimated recoverable volumes for the accumulation be classified as contingent resources.

Contingent Resources may include, for example, accumulations for which there is currently no viable market, or where commercial recovery is dependent on the development of new technology, or where evaluation of the accumulation is still at an early stage.

UNDISCOVERED PETROLEUM-INITIALLY-IN-PLACE

Undiscovered Petroleum-initially-in-place is that quantity of petroleum which is estimated, on a given date, to be contained in accumulations yet to be discovered. The estimated potentially recoverable portion of Undiscovered Petroleum-initially-in-place is classified as Prospective Resources, as defined below.

PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.

ESTIMATED ULTIMATE RECOVERY

Estimated Ultimate Recovery (EUR) is not a resource category as such, but a term which may be applied to an individual accumulation of any status/maturity (discovered or undiscovered). Estimated Ultimate Recovery is defined as those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

AGGREGATION

Petroleum quantities classified as Reserves, Contingent Resources or Prospective Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations containing Contingent Resources or Prospective Resources will not achieve commercial production.

RANGE OF UNCERTAINTY

The Range of Uncertainty, as shown in Figure 1, reflects a reasonable range of estimated potentially recoverable volumes for an individual accumulation. Any estimation of resource quantities for an accumulation is subject to both technical and commercial uncertainties, and should, in general, be quoted as a range. In the case of reserves, and where appropriate, this range of uncertainty can be reflected in estimates for Proved Reserves (1P), Proved plus Probable Reserves (2P) and Proved plus Probable plus Possible Reserves (3P) scenarios. For other resource categories, the terms Low Estimate, Best Estimate and High Estimate are recommended.

The term "Best Estimate" is used here as a generic expression for the estimate considered to be the closest to the quantity that will actually be recovered from the accumulation between the date of the estimate and the time of abandonment. If probabilistic methods are used, this term would generally be a measure of central tendency of the uncertainty distribution (most likely/mode, median/P50 or mean). The terms "Low Estimate" and "High Estimate" should provide a reasonable assessment of the range of uncertainty in the Best Estimate.

For undiscovered accumulations (Prospective Resources) the range will, in general, be substantially greater than the ranges for discovered accumulations. In all cases, however, the actual range will be dependent on the amount and quality of data (both technical and commercial) which is available for that accumulation. As more data become available for a specific accumulation (e.g. additional wells, reservoir performance data) the range of uncertainty in EUR for that accumulation should be reduced.

RESOURCES CLASSIFICATION SYSTEM

Graphical Representation

Figure 1 is a graphical representation of the definitions. The horizontal axis represents the range of uncertainty in the estimated potentially recoverable volume for an accumulation, whereas the vertical axis represents the level of status/maturity of the accumulation. Many organizations choose to further sub-divide each resource category using the vertical axis to classify accumulations on the basis of the commercial decisions required to move an accumulation towards production.

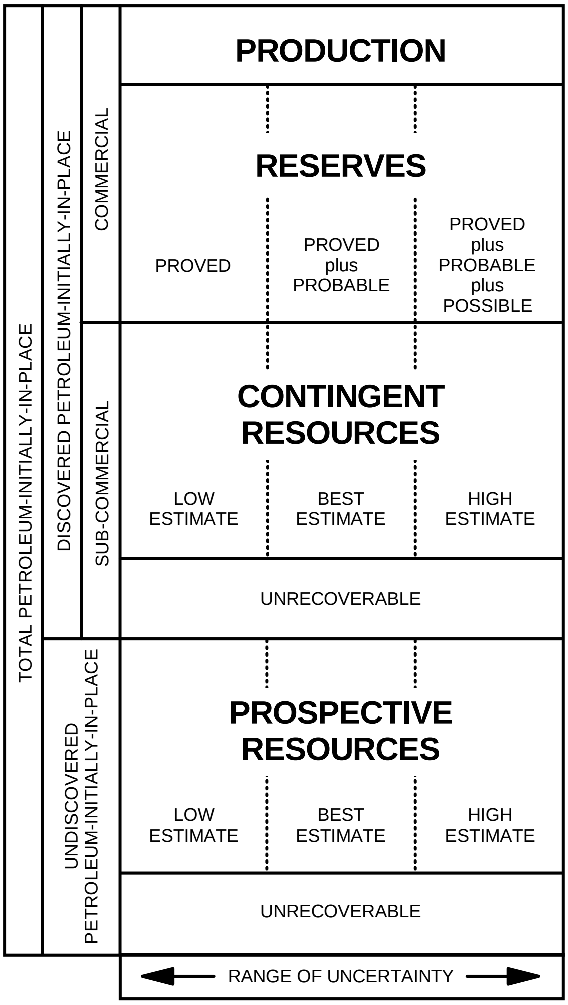
As indicated in Figure 1, the Low, Best and High Estimates of potentially recoverable volumes should reflect some comparability with the reserves categories of Proved, Proved plus Probable and Proved plus Probable plus Possible, respectively. While there may be a significant risk that sub-commercial or undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable volumes independently of such a risk.

If probabilistic methods are used, these estimated quantities should be based on methodologies analogous to those applicable to the definitions of reserves; therefore, in general, there should be at least a 90% probability that, assuming the accumulation is developed, the quantities actually recovered will equal or exceed the Low Estimate. In addition, an equivalent probability value of 10% should, in general, be used for the High Estimate. Where deterministic methods are used, a similar analogy to the reserves definitions should be followed.

As one possible example, consider an accumulation that is currently not commercial due solely to the lack of a market. The estimated recoverable volumes are classified as Contingent Resources, with Low, Best and High estimates. Where a market is subsequently developed, and in the absence of any new technical data, the accumulation moves up into the Reserves category and the Proved Reserves estimate would be expected to approximate the previous Low Estimate.

Approved by the Board of Directors, Society of Petroleum Engineers (SPE), Inc., the Executive Board, World Petroleum Congresses (WPC), and the Executive Committee, American Association of Petroleum Geologists (AAPG), February, 2000.

FIGURE 1 - RESOURCES CLASSIFICATION SYSTEM



Not to scale

Appendix 4 Reservoir Engineering data

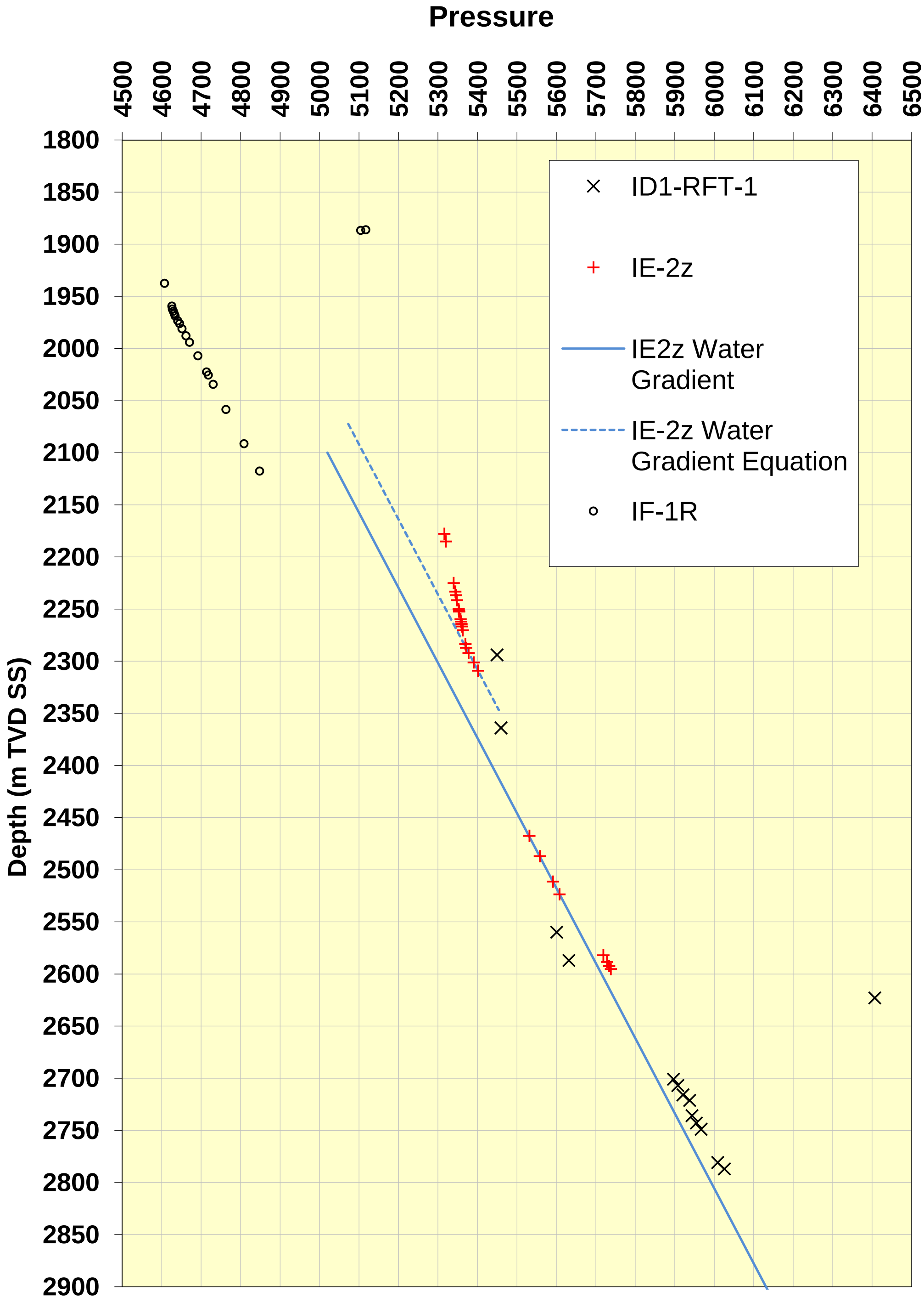


Figure A4-1: Pressure surveys showing different regimes for Isongo Sands in ID, IE and IF

Sweep Parameter	Thin Beds			Sands 1 and 2		
	Low	Mid	High	Low	Mid	High
Microscopic	59%	66%	75%	59%	66%	75%
Vertical	10%	30%	75%	50%	65%	80%
Areal	40%	60%	80%	60%	75%	90%

Table A4.1 Range of sweep efficiency factors for IF

	Range of Recovery Factors		
Thin Beds	5%	15%	35%
Sands 1+2	25%	35%	45%

Table A4.2: Range of recovery factors for IF

Appendix 5 PSC Fiscal Terms for Oil Developments

Fiscal Terms Summary		Notes
Company Tax Rate	40.0%	
Tax Losses cfwd	4 years	
Cost Recovery Limit	70.0%	
State Participation	20.0%	
Signature Bonus	US$3 million	
Production Bonuses	**US$ million**	Not cost recoverable Payable by Companies (not NOC)
After 25 mmboe	2	
After 50 mmboe	2	
After 75 mmboe	3	
After 100 mmboe	4	
After 150 mmboe	5	
	US$	
Training Budget per annum	150,000	

Oil R Factors			Notes
Values of "R"	**State Share**	**Contractor Share**	R Factor = ratio of Net Cumulative Revenue over Cumulative Investments calculated at end of previous year. Net Cumulative Revenue = Contractor Gross Revenues (cost recovery + profit oil) less Opex less Tax. Cumulative Investments = Exploration + Development Costs.
R <= 1.0	5.0%	95.0%	
1.0 < R <= 1.5	6.25%	93.75%	
1.5 < R <= 2.0	7.5%	92.5%	
2.0 < R <= 2.5	10.0%	90.0%	
2.5 < R <=3.0	17.5%	82.5%	
3.0 < R <= 3.5	25.0%	75.0%	
R >3.5	35.0%	65.0%	