ADM Energy

Barracuda CPR Phase 2

Barracuda CPR

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REV	DATE	DESCRIPTION	ISSUED	CHECKED	APPROVED	CLIENT
01	29/03/2022	Final report	JS/SG/KG/CM	AS	AS	
00	25/02/2022	Report issued for comments	JS/SG/KG/CM	AS	AS	

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The Directors
60 Gracechurch Street
London
EC3V OHR
ADM Energy PLC ("ADME")
30th March 2022

Dear Sirs,

Reference: Competent Person's Report on the Barracuda area of OML 141, Nigeria

Xodus Group Limited ("Xodus") has provided an independent evaluation of the Hydrocarbons Initially In Place ("HIIP") and recoverable volumes expected in accordance with the Petroleum Resources Management System ("PRMS") (2018) prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers ("SPE") and reviewed and jointly sponsored by the World Petroleum Council ("WPC"), the American Association of Petroleum Geologists ("AAPG") and the Society of Petroleum Evaluation Engineers ("SPEE").

Throughout this report, volumes, unless otherwise stated, are expressed as gross Stock Tank Oil Initially In Place ("STOIIP") or Gas Initially In Place ("GIIP") volumes. These can be considered "discovered petroleum initially in place". Recoverable volumes are expressed as gross Prospective Resources.

In conducting this review, we have utilised information and interpretations supplied by ADM Energy PLC, including some interpretations from the operators of licences in which ADM Energy PLC hold interests as well as information in public domain. The information supplied comprised operator information, geological, geophysical, petrophysical, well logs and other data along with various technical reports. We have reviewed the information provided and modified assumptions where we considered this to be appropriate. No site visit has been undertaken.

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating the volumes. These techniques rely on geoscientific interpretation and judgement; hence the Resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognised that such estimates of in place and recoverable volumes may increase or decrease in future if more data becomes available and/or there are changes to the technical interpretation. As far as Xodus is aware there are no special factors that would affect the operation of the assets and which would require additional information for their proper appraisal.

Xodus is not aware of any significant matters arising from this evaluation that are not covered by the report which might be of a material nature with respect to the assessment. Xodus also confirms that where any information contained in the report has been sourced from a third party (other than the Company or the Operator), such information has been accurately reproduced and, so far as we are aware and are able to ascertain from the information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

Yours faithfully,

Jonathan Fuller
Director, Global Head Advisory - Xodus Group Ltd, London
For and on behalf of Xodus Group Ltd.

EXECUTIVE SUMMARY

Overview

ADM Energy PLC ("ADME" or "the Company") requested Xodus Group Limited ("Xodus") to provide a Competent Person's Report on the exploration and development plans for the Barracuda Risk Sharing Agreement ("RSA") area, located in the northwest of OML 141 in the swamp of the Niger Delta in Nigeria.

ADM Energy PLC ("ADME") has acquired a 51% stake in K.O.N.H (UK) Limited ("KONH") and through that a controlling interest in the RSA, for which KONH holds a 70% interest. The Company, together with a consortium of parties with an interest in the RSA, intends to provide or procure funding for all capital expenditure ("Capex") subject to the joint interest executive committee ("JIEC") approval to develop any discovered hydrocarbons, in return for 235% of approved Capex to be recovered plus a 15% Net Profit Interest ("NPI"). After return of the invested capital to the RSA Consortium, the RSA Consortium remains entitled to the NPI throughout the life of the field. The equity owners are of OML 141 are Emerald Energy Resources (54%), Amni International Petroleum Development Company Limited (44 per cent.) and Supernova Energy B.V. (2 per cent.).

Xodus has calculated gross, unrisked Prospective Resources for the RSA using standard geological and engineering approaches applied to the data made available by ADME.

Technical Review

Interpreted well and 3D seismic data covering the full extent of the Barracuda RSA area were provided to Xodus by ADME. Xodus analysed these data and interpretations using standard geoscience techniques to calculate a range of oil in-place volumes for each potential reservoir identified by ADME.

STOIIP (UNRISKED)	GROSS VOLUMES			CHANCE OF SUCCESS
Reservoir	P90 (mmbbl)	P50 (mmbbl)	P10 (mmbbl)	
C3	106	193	343	15%
D1A	15	25	43	30%
D1B	70	103	149	18%
Deep Prospect	20	51	131	25%
Combined	275	397	574	

Unrisked STOIIP

A key issue in the assessment of the Barracuda RSA is whether the resources should be classified as Prospective or Contingent. If there is there an existing, potentially commercial oil discovery, proven by one of the previous wells drilled in the area, then according to SPE PRMS guidelines, the resource classification would be Contingent and if there is no discovered resource, then the resource classification is Prospective.

There are four exploration wells within the current Barracuda area of development, with the most recent being Barracuda-4 (BX-1), drilled in 2007 by Emerald Energy Resources and partners. This well provides the most relevant data for classifying the resources. Post-well petrophysical analysis had been carried out by Hunt Wallace, and fluid analysis by CoreLab in 2007. The Barracuda RSA was the subject of a CPR undertaken by Ryder Scott in 2016, which concluded that the resources should be classified as Prospective.

Xodus has reviewed the available relevant Barracuda data and has not identified convincing evidence as to the presence of light, producible hydrocarbons. There are however, numerous indications as to the presence of heavy, residual hydrocarbons from past migration. Based upon this review, Xodus has concluded that any resources in the Barracuda area would need to be categorised as Prospective.

The limit of the provided seismic volume does not extend far beyond the eastern boundary of OML 141. Therefore, Xodus could not verify an up-dip trapping mechanism to the north-east of the block and a fault, structural or stratigraphic closure has to be assumed in the neighbouring block to create a trap. This has an impact on the geological chance of success for a new well in the east of the Barracuda area.

Xodus based its estimates of reservoir and production parameters on data provided by ADME supplemented with data from nearby analogue fields. Xodus used the same drilling and development schedule as described in the economic model provided by ADME to calculate Prospective Resource ranges. These represent resources for a first phase development plan which ADME designed to exploit any future discovery in the D1A/B reservoirs. Discovery of larger volumes would require additional phases of development to recover the hydrocarbons.

PROSPECTIVE RESOURCES (RISKED)	GROSS VOLUMES			OPERATOR
	1U[1] (mmbbl)	2U (mmbbl)	3U (mmbbl)	
Barracuda RSA OML 141	20.7	24.0	27.8	Emerald Energy Resources, Amni International Petroleum Development Company Limited, Supernova Energy B.V.

OML 141 Barracuda RSA Gross Prospective Resources (Risked)

Conclusions

The economic model supplied by ADME has been reviewed against the RSA scope and provisions to confirm that the economic model represents the RSA accurately. Xodus has used this model with its independent production profiles, and CAPEX and OPEX adjustments to assess the economics of the RSA. For the 2U (P50) case the NPV10 is +$99mm with an IRR of 45% and therefore the prospect is considered to be robust for development, assuming at least 70mmbbl STOIIP is discovered..

[1] *1U, 2U and 3U represent low, best and high case estimates of Prospective Resources respectively as defined in PRMS*

Professional Qualifications

Xodus Group Limited is an independent, international energy consultancy. Established in 2005, the company has 300+ subsurface and surface focused personnel spread across offices in Aberdeen, Anglesey, Cairo, Dubai, Edinburgh, Glasgow, London, Orkney, Oslo, Perth and Southampton.
The Advisory division specialises in petroleum reservoir engineering, geology and geophysics and petroleum economics. All of these services are supplied under an accredited ISO9001 quality assurance system.
Except for the provision of professional services on a fee basis, Xodus has no commercial arrangement with any person or company involved in the interest that is the subject of this report.
Jonathan (Jon) Fuller is the Global Head of Advisory for Xodus and was responsible for supervising this evaluation. A Reservoir Engineer, with a strong commercial experience he has 28 years of international experience in both International Oil Companies, large Service Companies and Consultancy organisations. Over the last 15 years he has been the technical and project management lead on reserve / resource evaluations in M&A, competent person reports, and expert opinion linked bank and institutional investment (both debt and equity). He is a recognised competent person as per the London Stock Exchange Guidance note for Mining, Oil and Gas Companies of June 2009.
Jon has an M.Eng (Hons) in Engineering Science from Oxford University, a Master's Degree in Petroleum Engineering from Heriot-Watt, and an MBA from INSEAD. He is a member of the Society of Petroleum Engineers (SPE), and the Association of International Petroleum Negotiators (AIPN).

Yours faithfully,

Jonathan Fuller
Director, Global Head Advisory - Xodus Group Ltd, London
For and on behalf of Xodus Group Ltd.

1 INTRODUCTION

1.1 ADME Interest

ADM Energy PLC ("ADME") has acquired a 51% stake in Karra Oil Noble Hill UK Limited ("KONH") and through that a controlling interest in a Risk Sharing Agreement ("RSA") entered into for the development of the Barracuda area, of which KONH holds a 70% interest. The RSA Consortium intends to provide or procure funding for all capital expenditure ("Capex") subject to the JIEC approval to develop the any discovered hydrocarbons, in return for 235% of approved Capex to be recovered plus a 15% Net Profit Interest ("NPI"). After return of the invested capital to the RSA Consortium, the RSA Consortium remains entitled to the NPI throughout the life of the field. The equity owners of OML 141 are Nigerian indigenous companies Emerald Energy Resources (54%), Amni Oil and Gas (44%) and Bluewater Oil and Gas Investments (2%) with Emerald Energy Resources as operator.

1.2 Sources of Information

The content of this report and its estimates of hydrocarbon volumes are based on data provided to Xodus Group Limited ("Xodus") by ADME and regional analogue data available to Xodus. Xodus has accepted, without independent verification, the accuracy and completeness of the data provided by ADME. The data available for review are noted in the body of the report. No site visits have been conducted as part of this evaluation

1.3 Requirements

In accordance with ADME's instructions to Xodus, we confirm that:

> we are professionally qualified and a member in good standing of a self-regulatory organisation of engineers and/or geoscientists;

> Jonathan Fuller is a Director of Xodus Advisory, London and was responsible for supervising this evaluation;

> we have at least five years relevant experience in the estimation, assessment and evaluation of oil and gas assets;

> we are independent of ADM Energy PLC "the Company", its directors, senior management and advisers;

> we will be remunerated by way of a time-based fee and not by way of a fee that is linked to the value of the Company;

> we are not a sole practitioner;

> we have the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets, being all assets, licences, joint ventures or other arrangements owned by the Company or proposed to be exploited or utilised by it ("Assets") and liabilities, being all liabilities, royalty payments, contractual agreements and minimum funding requirements relating to the Company's work programme and Assets ("Liabilities").

1.4 Standards Applied

In compiling this report, we have used the definitions and guidelines set out in the 2018 update of the Petroleum Resources Management System prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE).

1.5 No Material Change

We confirm that to our knowledge there has been no material change of circumstances or available information since the effective date of this report and we are not aware of any significant matters, arising from our evaluation, that are not covered within this report which might be of a material nature with respect to the Company valuation.

1.6 Liability

All interpretations and conclusions presented herein are opinions based on inferences from geological, geophysical, or other data. The report represents Xodus' best professional judgment and should not be considered a guarantee of results. Our liability is limited solely to ADME for the correction of erroneous statements or calculations. The use of this material and report is at the user's own discretion and risk.

1.7 Consent

We hereby consent, and have not revoked such consent, to:

- the inclusion of this report, and a summary of portions of this report, in documents prepared by the Company and its advisers;
- the filing of this report with any stock exchange and other regulatory authority;
- the electronic publication of this report on websites accessible by the public, including a website of the Company; and the inclusion of our name in documents prepared in connection to commercial or financial activities.
- The report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. The report must therefore, be read in its entirety. This report was provided for the sole use of ADME on a fee basis. Except with the express written permission from Xodus, or for purposes noted above, this report may not be reproduced or redistributed, in whole or in part, to any other person or published, in whole or in part, for any other purpose.

2 BACKGROUND

The Barracuda area is located in the northwest of OML 141 in the swamp of the Niger Delta in Nigeria. There are four exploration wells within the current Barracuda area of development as shown in Figure 2-1

> Barracuda 1: Igbabelle 1, 1967; TD 3,627 m RKB; Operator: Tenneco

> Barracuda 2: Egwema North-1; 1967; TD 3,658 m RKB; Operator: Tenneco

> Barracuda 3: Clarendon Island, 1967; TD 3,661 m RKB; Operator: Tenneco

> Barracuda 4: BX-1, 2007; TD 2,717 m RKB; Operator: Emerald (CNOOC)

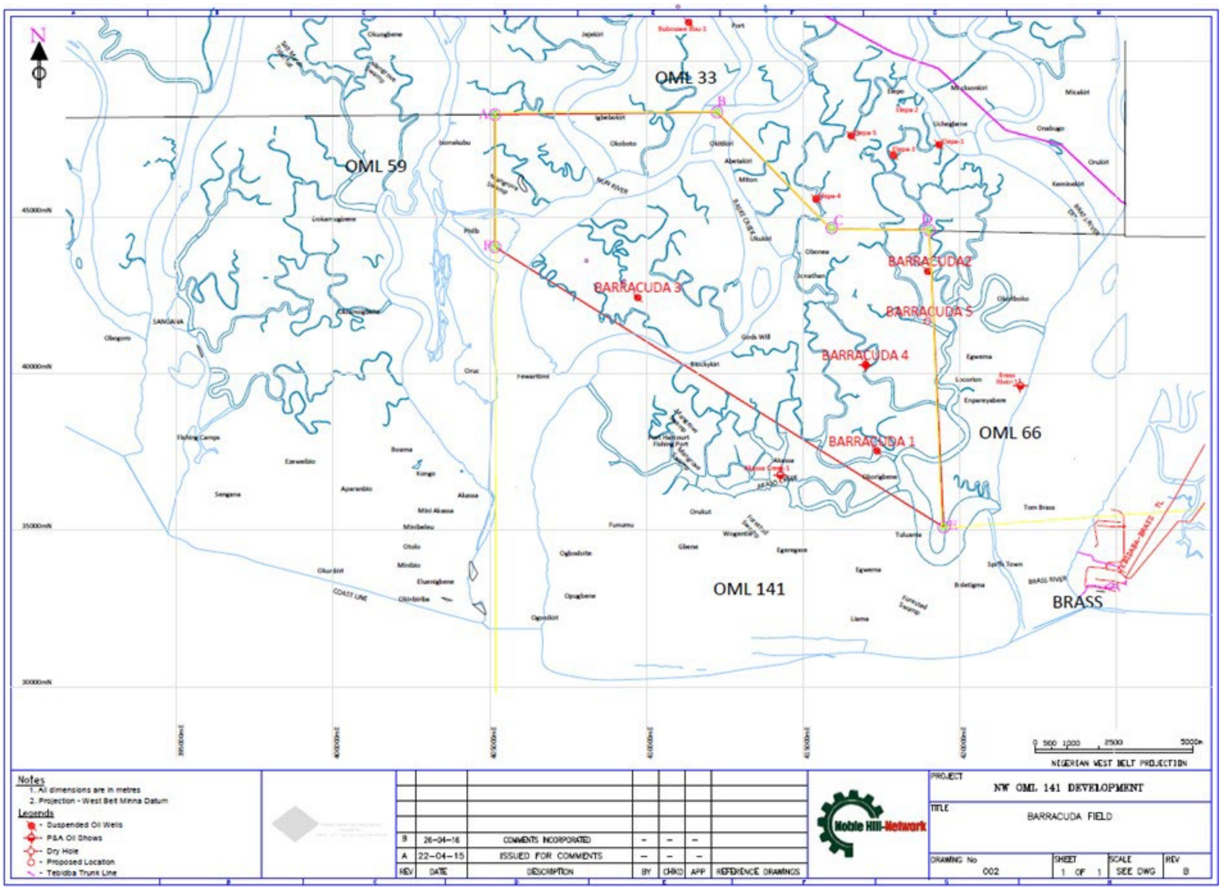

Figure 2-1 - Map of Barracuda area showing wells

Exploration of the area started in 1959 with Shell's Akassa Creek-1, an exploration well on the southern flank of the Elepa Mega Structure. It encountered dead oil shows within the Agbada C reservoirs from 3,900 to 4,490 feet RKB. In 1960 Shell drilled Elepa-1 on the crest of the Elepa structure in OML 33, immediately to the north of OML 141, and encountered stacked oil and gas reservoirs from 10,713 feet RKB to 12,195 feet RKB.

The original three Barracuda wells drilled in 1967 were not tested or completed because of the ongoing Biafra Unrest and all were left fallow after the crisis ended. Barracuda 4 was drilled by the current operator in 2007 with primary objectives of the lower D, E, F and G reservoirs encountered in the Elepa Field. However due to ongoing unrest and cost overruns the Service Provider (CNOOC) terminated the well prior to reaching these objectives.

3 REGIONAL OVERVIEW

The Niger Delta Basin is one of the most prolific oil and gas provinces in the world, covering an area of ~2,000 km^2 within the Gulf of Guinea in equatorial West Africa. The first commercial discovery was made in 1956, with initial exploration focusing on rollover anticlines and listric fault traps onshore and in shallow water. Over time, exploration has expanded into the deep-water frontier, where turbidites and submarine fans form combination traps with shale diapirs and thrust anticlines

3.1 Regional Stratigraphy

The Niger Delta ranges in age from Middle Eocene to Present and is divided into three principle lithostratigraphic units, the Benin Fm., Agbada Fm. and Akata Formations, all of which are diachronous. The Agbada Formation represents the largely pro-gradational deltaic facies which represent multiple prospective intervals. The Akata Formation both underlies and is laterally equivalent to the entire Niger Delta and is comprised of thick marine shale deposits. Marine shales were also deposited across the delta during intermittent phases of marine transgression and/or deltaic subsidence. The depositional complex also incorporates sub-aerially exposed, alluvial to coastal plain deposits of the Benin Formation around the northern margins of the delta. This. is generally non-prospective due to lack of seals.

3.2 Regional Structural Setting

The Niger Delta began to develop during the Eocene as the River Niger captured a significant hinterland drainage area creating a depocenter within the structural low of the Benue-Abakaliki trough. Five depo-belts ranging in age from Eocene to Holocene are recognised within the Niger Delta and reflect interplay between subsidence and sediment supply with seaward pro-gradation of sediments over the shelf.

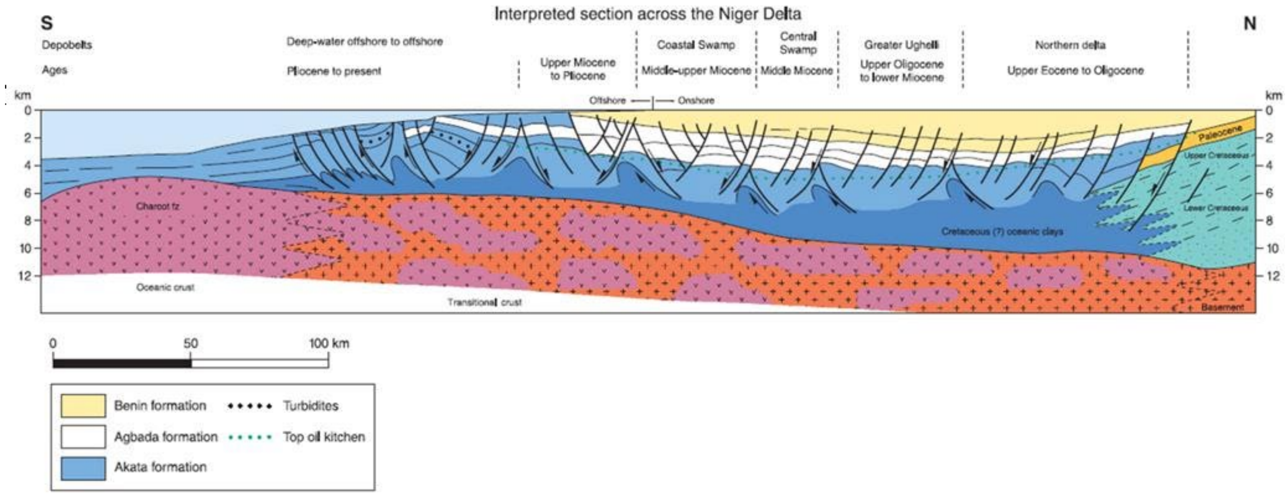

Figure 3-1 - Nigel Delta: Regional Cross Section

The primary lithostratigraphic units are characterised by syn-sedimentary listric faulting and at the delta toe, the development of a belt of thrust anticlines. This change in structural style is evident in Figure 3-1 which shows a map of the main structural elements with reverse faulting mostly restricted to the deeper water areas of the basin.

OML 141 lies predominately within the coastal swamp depo-belt with some extensions into shallow offshore upper Miocene to Pliocene depo-belt.

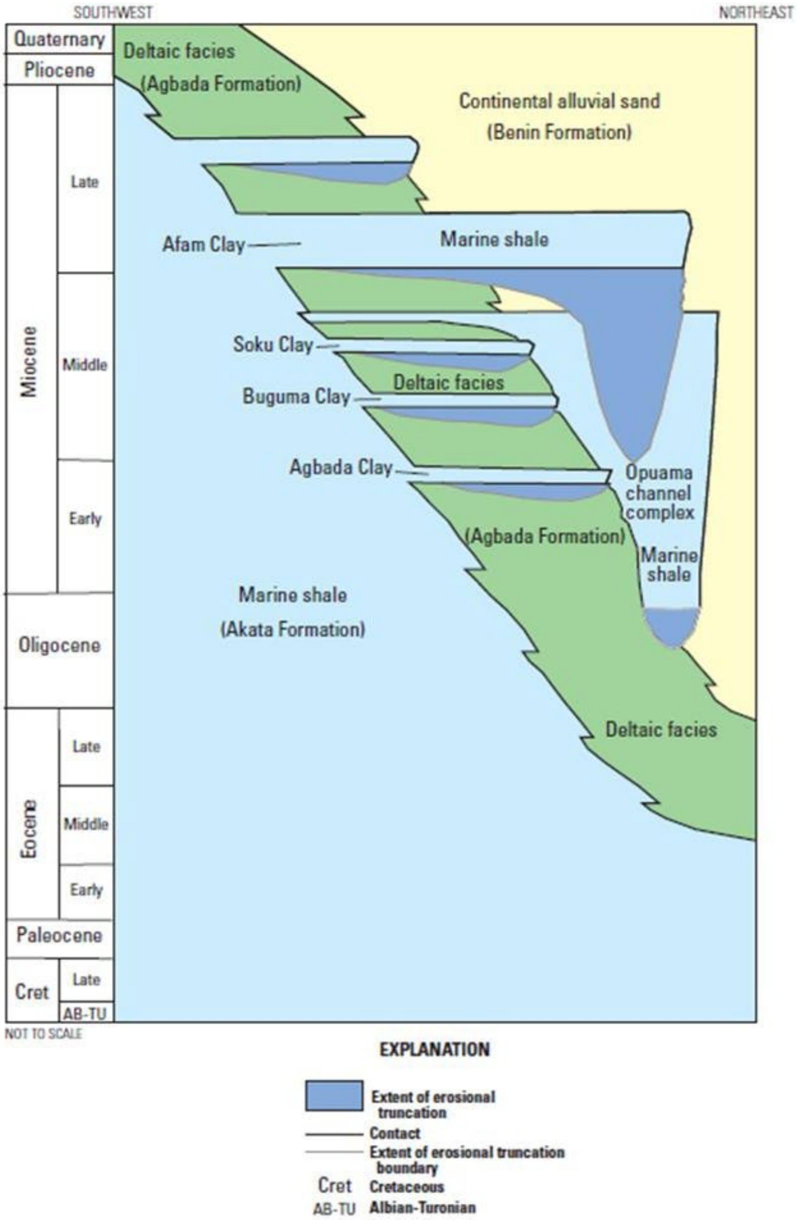

Figure 3-2 - Generalised Chronostratigraphy of the Niger Delta

3.3 Petroleum Systems

Hydrocarbon generation began in the Palaeocene and continues into the present day. The oil window in the Southeast of the Niger Delta, sits ~1,200 m below the Upper Akata Fm. and Lower Agbada Fm. oil window in the North West. Generation, migration and accumulation processes occur simultaneously across the Niger Delta with the Critical Moment occurring from the Eocene through the Pliocene, see Figure 3.3. Due to this overlap, migration pathways have been evidenced as short and primarily occurring across and up faults.

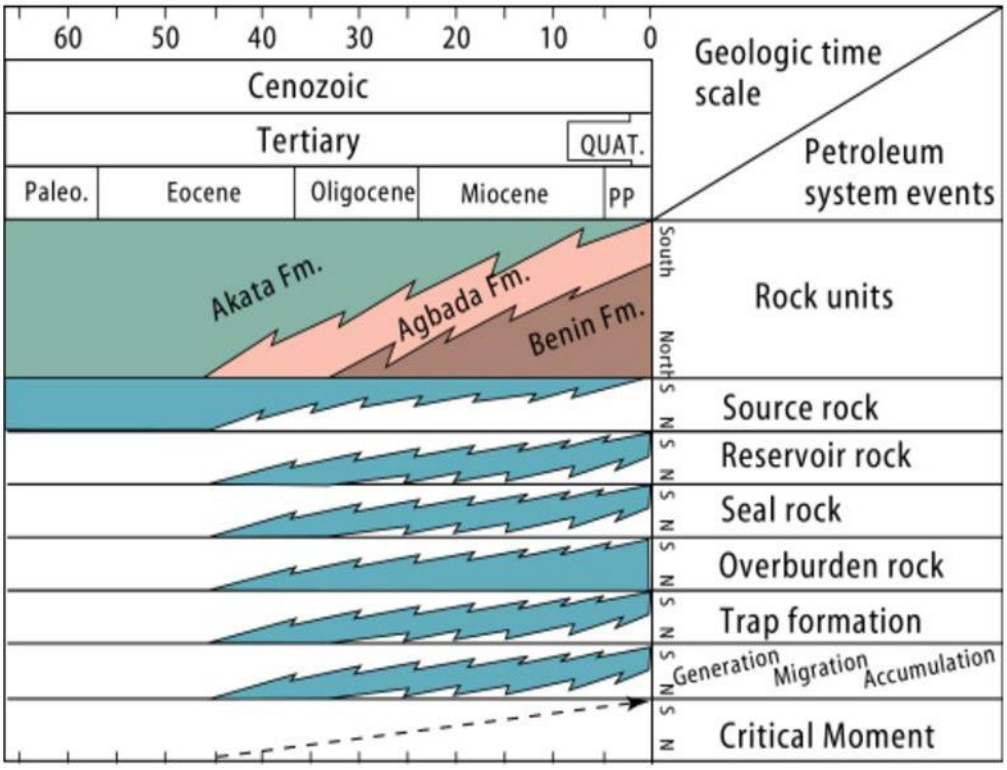

Figure 3-3 - Generalised Petroleum Systems Events Chart for the Niger Delta

4 CLASSIFICATION OF RESOURCES

A key issue in the assessment of the Barracuda area is whether the resources should be classified as Prospective or Contingent. If there is there an existing, potentially commercial oil discovery, proven by one of the previous wells drilled in the area, then according to SPE PRMS guidelines, the resource classification would be contingent and if there is no discovered resource, then the resource classification is prospective. Based upon this review, Xodus has concluded that any resources in the Barracuda area would need to be categorised as Prospective, as there is no proven oil discovery.

4.1 Background

The most important data are those from the Barracuda-4/Barracuda X-1 (BX-1 ST1 & ST2) well drilled in 2007 by Emerald and CNOOC. Post-well petrophysical analysis had been carried out by Hunt Wallace, and fluid analysis by CoreLab in 2007. The area was later the subject of a CPR undertaken by Ryder Scott in 2016. AGR Petroleum Services, Angus Technical Services, and Noble Hill also contributed independent reviews /comments. In addition to well BX-1, there were three wells drilled in the area by Tenneco in 1967 before the advent of modern downhole logging. Two of these wells have oil shows reported on the mud log. Four more wells were also referenced /quoted in the files & documents shared with Xodus, namely nearby well Akassa Creek-1/Akassa South-1 drilled by Shell in 1959 down to 12,385 ft MD (short of the planned TD 14,000 ft MD) , and wells Sakiri-1, Kula-1, and Kula-2 located much farther away to the east of OML-141, however no actual data were shared for these wells. There is also the possibility that additional wells may have been drilled &/or additional data have been lost, in relation to the Biafra crisis /civil war. Akassa Creek-1 reportedly only encountered dead oil shows.

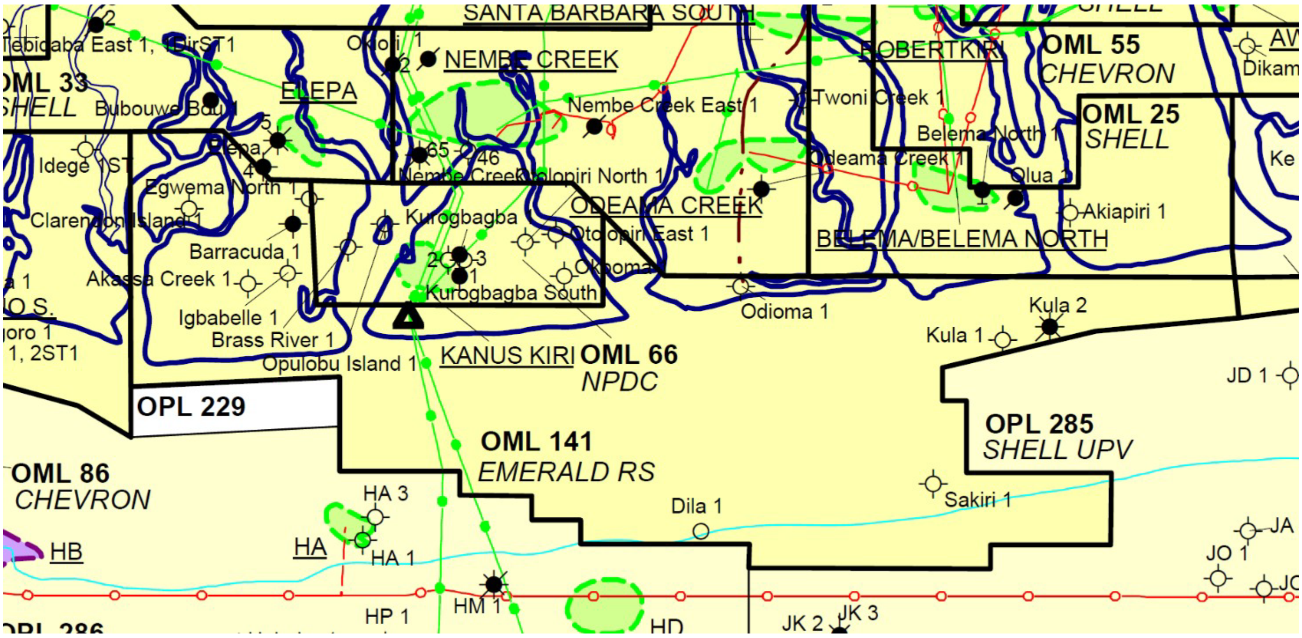

Figure 4-1 - OML-141 overview

Xodus performed an independent review of the BX-1 logs and pressure data available, as well as reviewing previous CPRs and other reports. The CoreLab report describes the analysis of three fluid samples taken from three reservoir zones which were potentially oil bearing based on petrophysics. The analysis shows that the samples are largely fresh water with some C1 and C3 gas. The CoreLab conclusion is not clear and states: "The analysis indicates that the three waters are fairly fresh in nature but quite different to each other. There are no significant concentrations of any ions which indicate the samples to be formation water or drilling fluid. "

The 2007 report by Hunt Wallace describes its petrophysical analysis performed on the BX-1 well data. Hunt Wallace was aware of the CoreLab work but decided to ignore the results, which it believed to be unreliable, and used the indirect method of Pickett plots to calculate water salinity. This choice was key in determining the results of the subsequent petrophysical analysis, which indicated hydrocarbon saturations in the C and D sands, albeit with a long transition zone in the C sand, and low hydrocarbon saturation in the D sands. Hunt Wallace stated that drill stem tests (DSTs) would be needed to confirm the hydrocarbon accumulations.

The Ryder Scott CPR of 2016 (and the AGR Petroleum Services review) discussed the challenges and uncertainties of any potential petrophysical analysis, particularly with respect to the impact of water salinity on saturation calculations where the formation water is fairly fresh. Ryder Scott did not mention the fluid analysis by CoreLab.

Both Hunt Wallace and Ryder Scott discussed the RDT pressure measurements taken in BX-1, which show a water gradient throughout. Both described how this could alternatively be indicative of heavy, residual oil. More recently there has been discussion amongst the parties with an interest in Barracuda as to the possibility of oil bearing reservoirs showing a water gradient, citing drilling mud invasion as a possible cause, and providing data from analogue fields purporting to show the same effect. Xodus does not find the arguments for drilling mud invasion convincing and believes the analogue field pressure gradients can be explained by there being a single pressure measurement for each reservoir in the data provided, in contrast to BX-1 which has multiple pressure measurements in each reservoir forming a water gradient.

Xodus' conclusion is similar to Ryder Scott's, which is that there is a strong case for residual (heavy) oil that would not flow to surface, and that the reservoir sands penetrated by the well contain predominantly moveable fresh water. The case for light, moveable hydrocarbons is not directly supported by the data.

4.2 Barracuda-4/BX-1 Log Data

The log data available from well BX-1 in the 12"1/4 TD section are the most complete to date in the Barracuda area, and consist of Schlumberger logging-while-drilling (LWD) data, and Halliburton wireline (WL) standard triple-combo, formation percussion sidewall cores, formation pressure testing data and formation fluid samples.

The full formation pre-test pressure profiles versus time were not available for review by Xodus, and nor were the RDT in-situ fluid analysis data during pump-out and sampling. However, the measured formation mobilities were high, and the mud hydrostatic pressures were consistent with the reported mud density, thereby lending credibility to the formation pressures.

4.3 Data Analysis

The section below, details some of the information made available to Xodus that are relevant to the analysis and worthy of comment.

Synthetic oil-based mud (sOBM) with low Hydrogen Index (HI)
Synthetic OBM are known to have low HI, which can cause thermal-neutron porosity logs to read anomalously low. This is because thermal-neutron porosity environmental correction algorithms only correct for some limited conventional water-based mud (WBM) and oil-based mud, (OBM). It is not straightforward to correct for this effect with synthetic-based mud and requires care. The LWD thermal-neutron porosity histograms and cumulative distribution function (CDF) provided to Xodus clearly indicate that this effect has not been properly accounted for and is evident when comparing the LWD & WL thermal-neutron data in shale (i.e. the highest readings), where no invasion effects are expected.

A proper correction would comprise shifting the LWD thermal-neutron porosity data by a constant value, to match the WL data in shale. The presented LWD thermal-neutron porosity data, appear to show a light hydrocarbon was present inside the formation while drilling (i.e. at LWD time), prior to being flushed by mud filtrate by the time the WL data were acquired. In fact, properly corrected LWD thermal-neutron porosity data would indicate a decrease in thermal-neutron porosity between LWD and WL, consistent with sOBM filtrate displacing moveable formation water.

Gamma-ray (GR) data tool-to-tool variation
LWD vs. WL GR differences are not associated with mud invasion in oil reservoirs. The proposed cause-effect relationship between mud-filtrate invasion and LWD versus WL gamma-ray data differences, is not valid. This looks like a GR calibration issue, because the high GR readings in shale should not change. It is not uncommon to observe as much as a factor of two mismatch between LWD & WL tools GR readings because of different attenuations. The difference in measured GR between LWD and WL has been used to suggest the presence of light hydrocarbons in the formation. This is not justified.

Pressure gradients that do not represent the actual fluid present inside the formation
With limited exceptions, it is highly unlikely for a mathematically correct pressure gradient (i.e. measurement errors aside) to indicate a fluid density different from that of the continuous fluid phase inside a reservoir. The exceptions are due to capillary effects (long transition zones) in some tight reservoirs, and typically result in shifting the actual fluid contact. Pressure readings from different reservoirs (sand bodies) should not be mixed together for interpretation purposes. For fluid-typing purposes, only closely spaced pressure stations from within the same sand body should be used. In the BX-1 well, multiple pressure stations within individual sand bodies show a water gradient.

Documents shared with Xodus attempted to show that the "observed water gradient" was not inconsistent with hydrocarbons present in the reservoirs, based on a comparison with analogue fields. Some of the fields near to Barracuda were presented as exhibiting a similar "non-representative water gradient" whilst being oil bearing and producing. However, the data presented to Xodus appears to show pressure stations in the analogue fields which are from separate sand bodies. Therefore, one can expect them to show a water gradient even if the individual sand bodies contain hydrocarbons. The water gradient across multiple, separate sand bodies, merely points to a common aquifer.

No significant deviation from the water gradient (i.e. excess pressure) was observed in BX-1 data. The water pressure gradients from closely-spaced pressure stations in BX-1 within the same sand body, indicate instead that water is the continuous fluid phase inside the individual sand bodies.

Percussion sidewall core samples are taken from the invaded zone, barely 2" from the wellbore face
Any oil shows from highly-permeable sandstone formation samples, in a well drilled with sOBM, are likely to be from the sOBM filtrate itself, and residual heavy hydrocarbons if present. Significant mud losses were reported, which would lead to deeper mud-filtrate invasion and more thorough flushing of the near-wellbore formation fluids. The case for light hydrocarbons being present in the core samples is not clear. It is more likely than not, that the reported "shows" are residual heavy hydrocarbons, that have not been flushed away by the sOBM filtrate.

Fresh water present in the formation fluid samples
In wells drilled with sOBM, highly-permeable, light-hydrocarbon bearing sandstones cannot contribute any water during formation fluid-sampling operations, whether from the invaded zone (because of insufficient pump-out time), or from the virgin zone. Furthermore, if it were possible to retrieve any amount of water from such formation, then the sampled water would have been accompanied by a significant amount of light hydrocarbons.

It has been proposed to Xodus that the water samples were invalid and that the collected water samples do not represent formation water. However, there is no alternative to explain where the fresh water would have come from in the three samples collected from parts of the reservoirs identified as oil bearing in the Hunt Wallace petrophysical analysis. If light, moveable hydrocarbons were present inside the sampled sandstone formations, then it would be expected that the samples would contain at least some oil. It is more plausible that the continuous phase is water, and that there are residual heavy hydrocarbons not flowing into the fluid sample bottles, not observed on the pressure gradient, and not suppressing the large mobilities measured.

An additional proposed explanation is that that "an emulsion developed due to the miscibility of the two fluids (Oil and the sOBM) creating an impermeable fluid which impacted both the pressure and the PVT samples". This isn't supported by the high formation mobilities measured at the pressure stations.

Temperature profile
For interpretation purposes, one should only use well static temperature data. Enough time should have passed between the last mud circulation and the time of temperature data acquisition. The temperature sensor should be located outside the tool, and not an internal sensor used to monitor the tool electronics operating conditions. The exception being internal pressure gauges placed inside formation testing tools and used to measure flowline pressure & temperature. But even so, the temperature measured would be that of the body of the formation testing tool, and not directly the temperature of the formation.

Furthermore, it is usually recommended to acquire the data on a WL down-log, prior to any mud remixing while running-in-hole (RiH), and to acquire multiple passes, to assess how the borehole is warming-up. A temperature profile was included with the data Xodus reviewed. However, it consisted of temperature measurements at discrete pressure stations, with a time stamp at the exact time the stations were acquired. As the borehole was most likely still warming-up to static temperature, and pressure stations were not equally spaced in time or space, this can show-up as artificial changes in the measured temperature gradient. A static temperature profile would be free from such effects.

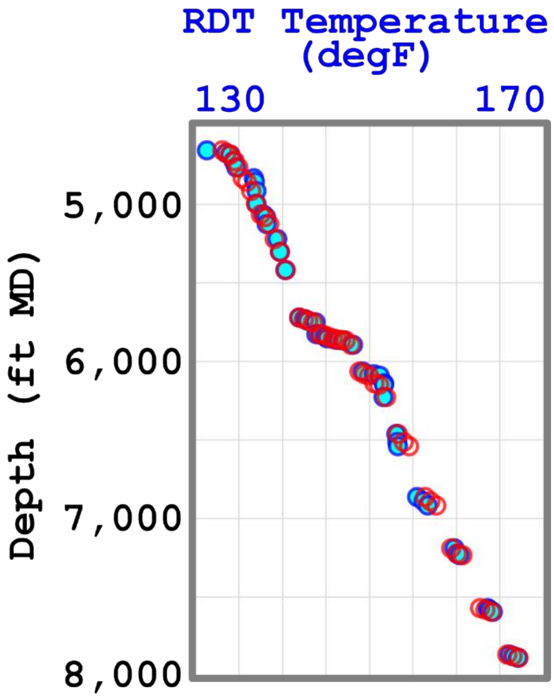

Figure 4-2 - Modelled (red) versus actual (blue) discrete Temperature profile at pressure stations

In fact, as pressure stations are typically acquired from the top down (to avoid hysteresis effects) the artificially-highest temperature gradients, would be observed where the density of pressure stations is also highest. For the BX-1 temperature data this is what is observed. The highest temperature gradient reported is at around 6,000 ft TVD which corresponds to where the pressure stations are more closely spaced. This was validated using a simple model which reproduced the "anomalous" temperature profile, assuming ~10 mins average stationary time during pressure stations, moving between stations at ~734 ft/hr average speed, and the borehole warming up with roughly a time constant ~1.5 days (see Figure 4-2), and ignoring any time spent on depth correlations or perhaps other operational issues. Therefore the BX-1 temperature profile should not be used for any geological interpretations.

4.4 Summary

The petrophysical interpretation and reservoir evaluation of fresh-water environments, so-called high-resistivity low-contrast formations (HRLC), always represent a challenge. Xodus has reviewed the available relevant Barracuda data and has not identified convincing evidence as to the presence of light, producible hydrocarbons. There are however, numerous indications as to the presence of heavy, residual hydrocarbons from past migration, and these are:

> Resistivity increasing and HI/neutron porosity and bulk density both decreasing with time and increased sOBM filtrate invasion.
> The petrophysical interpretation implying a long transition zone in a highly-permeability sandstone.
> Closely-spaced pressure stations from within the same sandstone body consistent with a water gradient.
> Fresh water and no oil present in the collected formation fluid samples.
> Residual hydrocarbons present in the collected sidewall core samples.

5 EVALUATION OF RESOURCES

5.1 Geophysical Evaluation

5.1.1 Seismic Data

3D seismic covering the full extent of the Barracuda area in OML 141 was provided to Xodus by ADME in a Petrel project including time and depth interpretation of the key reservoir horizons, summarised in Table 5-1, along with fault segment and associated fault polygons. The seismic appears as a single 3D survey split into, and loaded as, three separate volumes, named 'seismic1', '..2' and '..3'. The C and D1A/B reservoirs are mapped over the entire survey whilst interpretation of the 'Deep Prospect' is confined to the main B4 (and planned B5) fault block only. The depth maps and associated fault polygons by ADME have been utilised directly by Xodus for volume definition (see Section 5.3).

RESERVOIR LEVEL	WELL PICK	TWT PICK	DEPTH MAP	REMARKS
Top C	✓	✓	✓	Mapped over entirety of OML 141.
Base C	✓	✓	✗	
Top D1A	✓	✓	✓	
Base D1A	✓	✓	✓	
Top D1B	✓	✓	✓	
Base D1B	✓	✓	✓	
Deep Prospect	✗	✓	✓	Penetrated in B1, B2 and B3, planned for B5. Mapped in B4/B5 fault block only and not assigned to a specific sand. Xodus interpreted well picks.

Table 5-1 - Key Reservoir Horizons provided by ADME

5.1.2 Seismic Interpretation and Mapping

The seismic data is reflectivity and the horizons are picked on zero crossings, suggesting the seismic wavelet might be non-symmetrical or the volume transformed to band limited impedance. No verification of this was found in the data but the structural picking of the seismic horizons is not impacted either way. The seismic data quality is generally very good in terms of reflector clarity and continuity, but interpretation uncertainty is present from event truncations, stratigraphic thinning and correlation across faults.

The limit of the provided seismic volume does not extend far beyond the eastern boundary of OML 141. This affects all reservoir levels evaluated in that no convincing up dip trapping mechanism is observed on the data. This drives the trap risk described in Section 5.3.7. A fault, structural or stratigraphic closure has to be assumed further to the north and north-east to create a trap at any of the reservoir levels and this situation is illustrated by Figure 5.1 below.

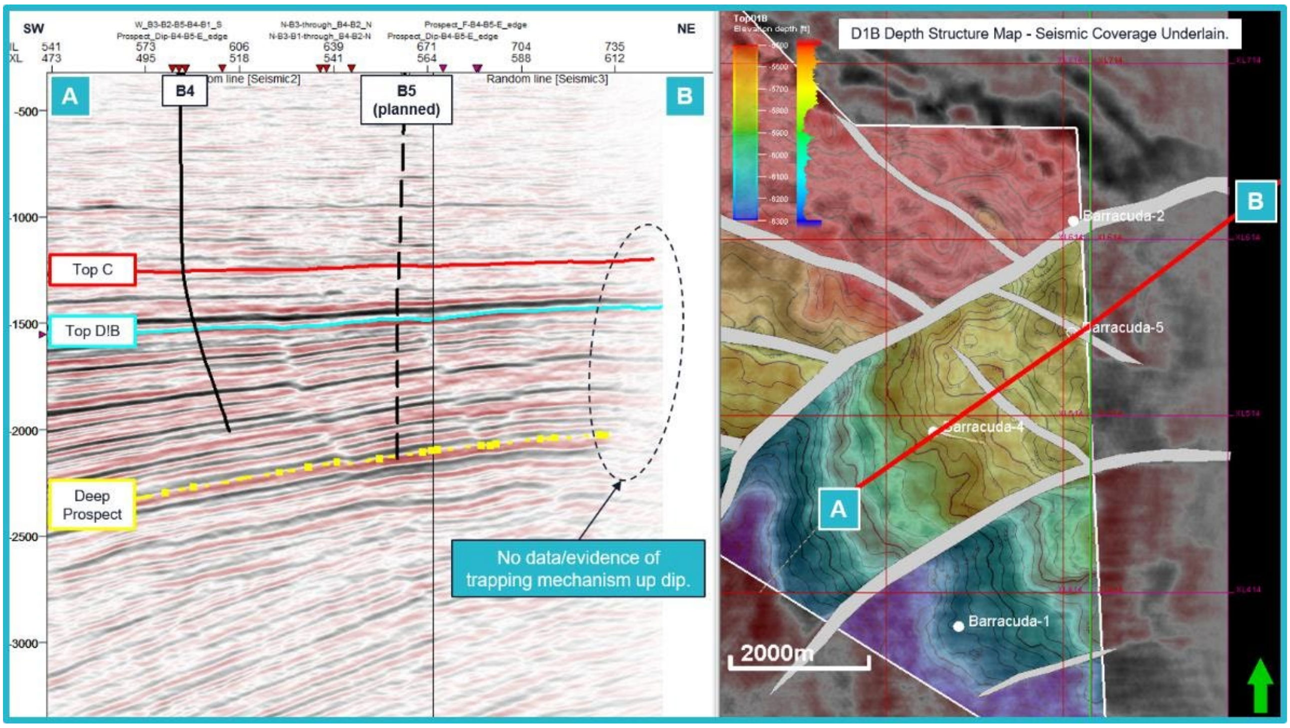

Figure 5-1 - Trap: No data or evidence of the trapping mechanism up dip

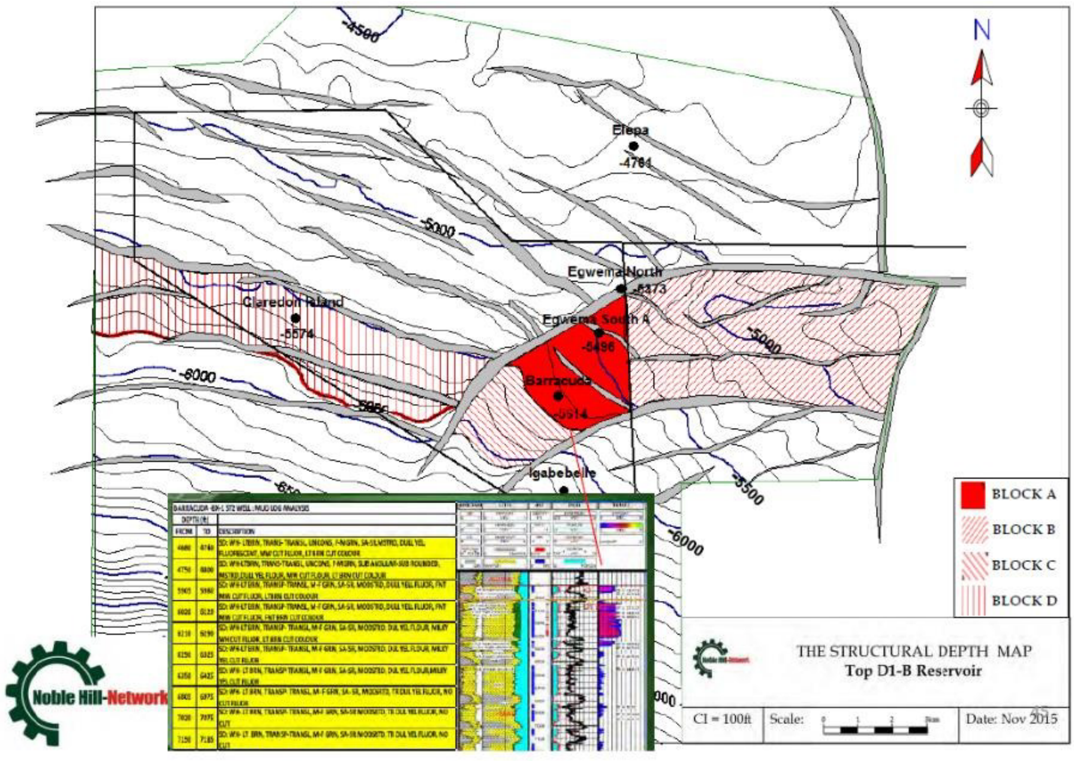

Figure 5-2 – Noble Hill D1-B depth map showing possible trapping mechanism to the north and east of BX-1 in neighbouring block

Structure maps by Noble Hill Network (Figure 5-2) and Ryder Scott (in its 2016 CPR) show a trapping mechanism to the east in OML 66, but this could not be independently verified using digital data by Xodus.

The NW/SE fault to the NE of well B4 (Figure 5-1) has a visible seismic offset in the D reservoirs but can be assumed to be non-sealing or B4 would have been a hydrocarbon discovery. The fault to the NE of the proposed B5 location has a similar character and is therefore unlikely to form a trap. A fault closure NE of the available data coverage would therefore need to have a larger offset than these. Furthermore, seismic amplitude mapping shows that the observed NW/SE faults are not spatially persistent enough to provide closure, separated by relay ramps (see Section 5.3.5) and with throw direction switching between NE and SW.

It is noted ADME proposes a regional stratigraphic seal by thinning/truncation against the Lower C-3 erosional unconformity (MFS) to the north. In addition, higher order stratigraphic pinch-outs are eminently possible locally. Whilst such thinning is clear in a northerly direction based on ADME's top and base reservoir interpretation (Figure 5-3), it is not so apparent in a more easterly direction (Figure 5-4). ADME also provided an amplitude map at the top D1-B reservoir (Figure 5-5) which shows an apparent change in amplitudes to the north east of B4 (BX-1). This dimming of amplitudes is proposed by ADME as evidence of hydrocarbon presence.

Time to depth velocity information was reviewed and the functions presented in Petrel found to be the same (Figure 5-6). These include the B4 (BX-1) well, considered to be the most reliable calibration point because it is a modern well (2007) compared to the other Barracuda wells that were drilled in the 1950s and 1960s. In the absence of any other data, this suggests depth conversion is a vertical stretch from the single function and Xodus assumes the depth maps were generated by this method.

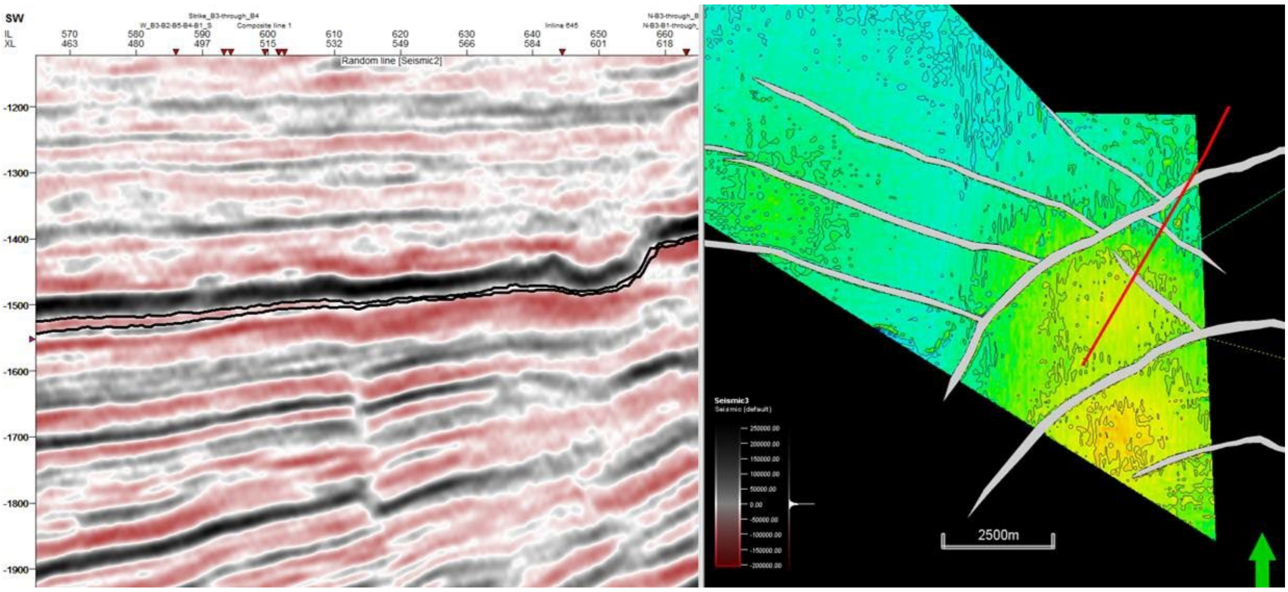

Figure 5-3 – Thinning of D1 sands in northerly direction

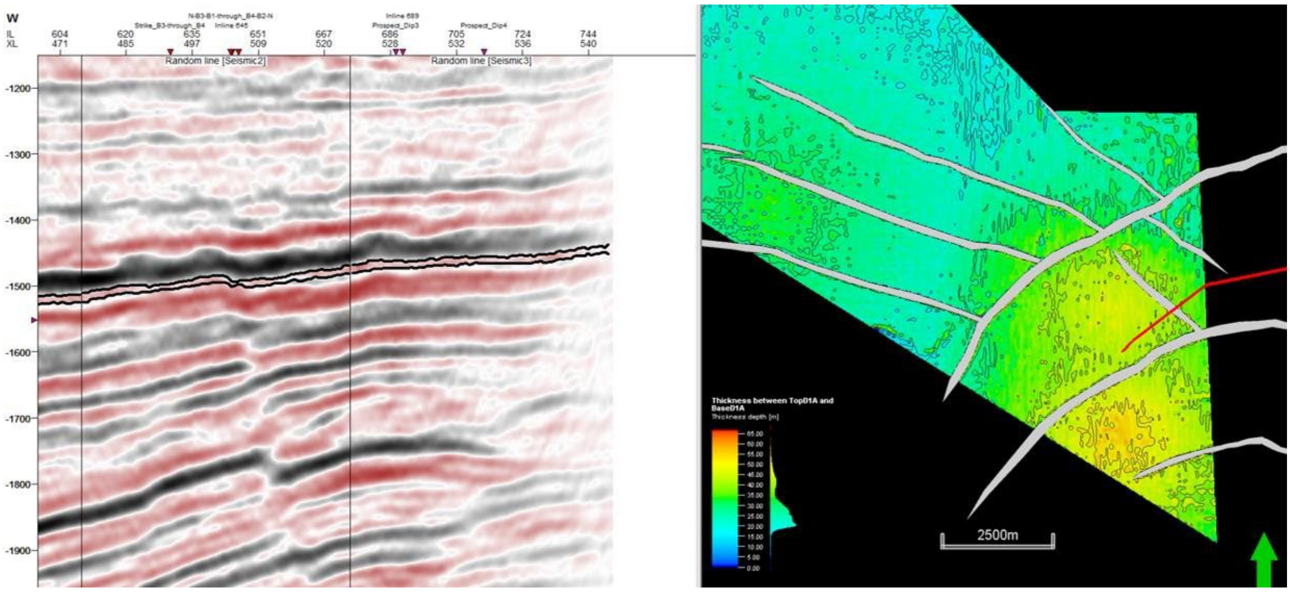

Figure 5-4 – Thinning of D1 sands in easterly direction

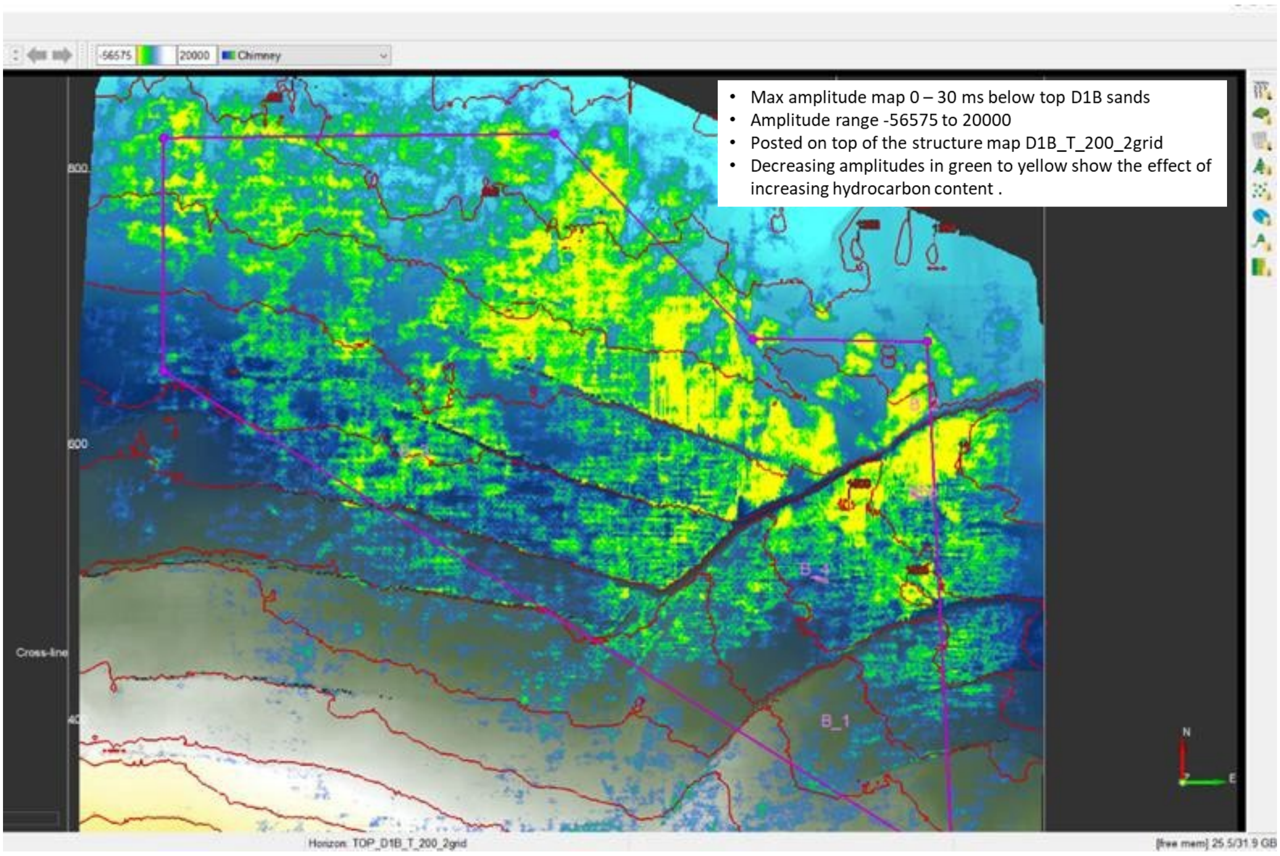

Figure 5-5 - ADME amplitude map at top D1B reservoir

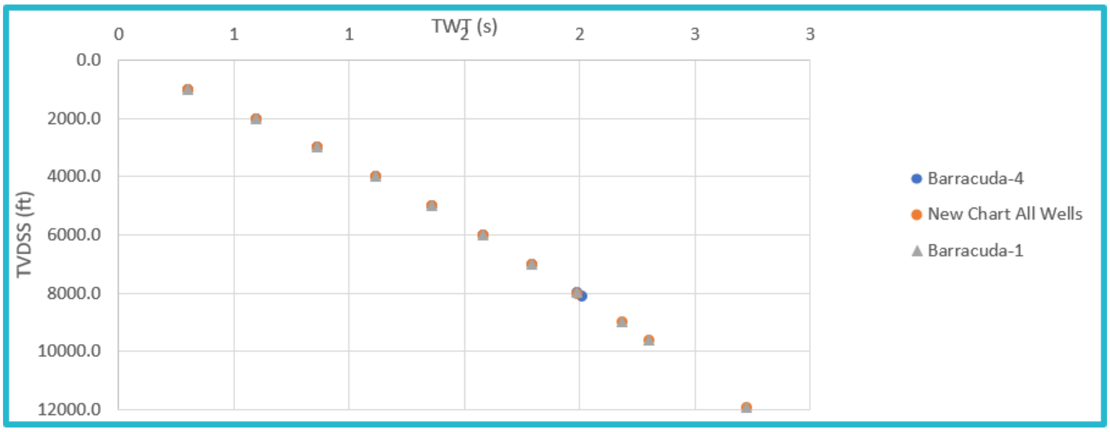

Figure 5-6 - Depth conversion and QC of Petrel project T-D functions

5.1.3 Deep Prospect

The deep prospect is only interpreted over the B4-B5 fault block and no well picks exist for this horizon in the B4 well as it is below the TD of the well. To evaluate it, Xodus made a first pass seismic interpretation around well B2, extending the existing interpretation across the major fault near planned well B5, followed by single arbitrary lines into wells B1 and B3 to tie these (Figure 5-7).

Wells B3 and B1 initially appeared not to penetrate the 'Deep Prospect' level but the total depths for these wells in Petrel were found to be incorrect. Xodus corrected these to the well log reported total depths. This demonstrated that the 'Deep Prospect' level was encountered by wells B3 and B1 also. Xodus made approximate well picks for this horizon using the aforementioned time/depth function. Well B5 is planned to evaluate this prospect further.

5.2 Petrophysical Evaluation

5.2.1 Database

The reservoir data supplied to Xodus included logs and petrophysical interpretations for the four Barracuda wells, including 3 wells of 1967 vintage and derived data from Elepa-1, -2, -3, -4 and -5; Nembe-1, -2, and -3 and Kanus Kiri wells. Note that the limited data from the three Barracuda wells drilled before 1970 have intrinsically large error bars around them because they were drilled before the advent of modern logging tools, mud design and engineering, well construction best practices, and well directional control and trajectory surveying techniques.

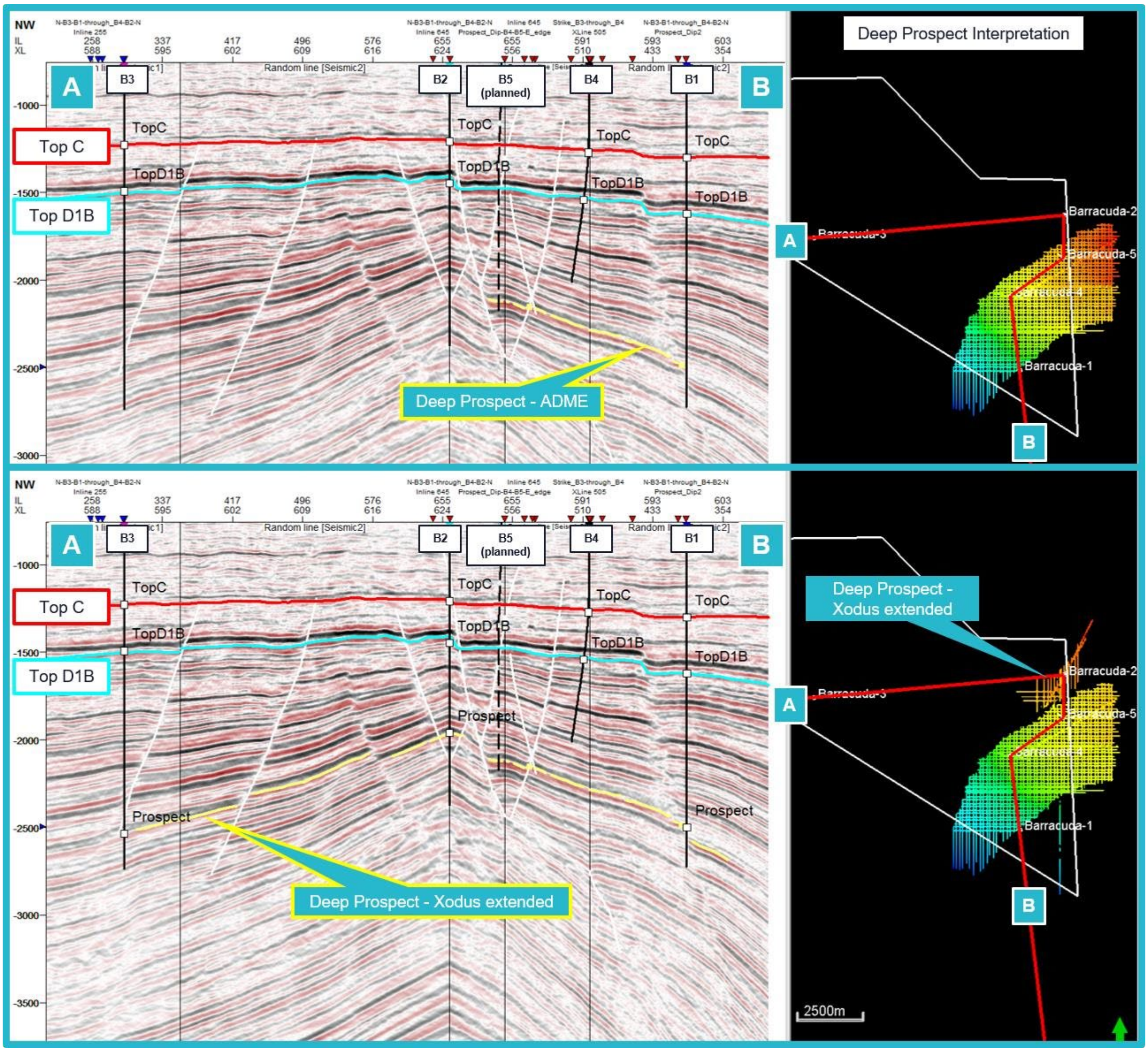

Figure 5-7 - Seismic interpretation of 'Deep Prospect'

5.2.2 Data Processing and Interpretation

Data processing and interpretation may introduce further uncertainty, arising from the use of modelled estimates for various mineral and fluid volumes and the subjective cut-offs used for N:G. There are several challenges with the Barracuda data:

- Different reservoir cut-offs have been used, either Vsh<40% & Phi>12%, or Vsh<50% & Phi>15%, although resulting differences in reservoir properties are practically insignificant because they relate to well-delineated sand bodies.
- N:G ratios have been expressed differently in each of the datasets with some examples incorrectly recording ratios within defined clean sand bodies rather than gross reservoir intervals.

- Water saturation data consists of a mix of original Sw, present-day Sw, and wet-reservoir Sw (including reservoirs at residual oil saturation from past migration), but no irreducible Sw (SWirr) which would be required for oil-bearing reservoirs.
- The presence of 'hot sands' cannot be identified reliably on the basis of total natural gamma-ray counts alone.
- There are not enough data available to account for formation resistivity & permeability anisotropy, (i.e. thin/laminated sand analysis), which are highly likely to be present in these depositional environments;
- The water salinity in the Barracuda sandstone reservoirs can vary significantly between reservoir zones, especially where they are within- the fresh water to saline transition.
- The reservoirs reportedly contain a high percentage of heavy minerals including, pyrite, glauconite, and biotite, resulting in a high grain density which may potentially suppress the resistivity.
- The potential oil density is unknown.

Therefore, Xodus has made use of a simple model using established data transforms to augment the actual well data and fill in the gaps where needed.

5.2.3 Correlations and Synthetic Data Transforms

1. This transform defines porosity as a function of depth due to burial and compaction:

$$PHI(\text{pu}) \approx 44 \exp\left(-\frac{TVD(\text{ft})}{18{,}219}\right)$$

Chiamogu, G.A. et al, 2010 state that "There is an overall decrease of porosity with increasing burial depth at a rate of 2 pu every 1,000 ft TVD at the shallower level, lowering to 1•1.5 pu at greater depths (>12,000 ft) . . . a porosity of about 44 pu is hypothesized in this study as the initial porosity of the reservoir sands."

2. This transform derived from Figure 5-8 defines permeability as a function of porosity over the ranges anticipated in this study:

$$K(\text{mD}) \approx 10^{0.2\,PHI(\text{pu})-3}$$

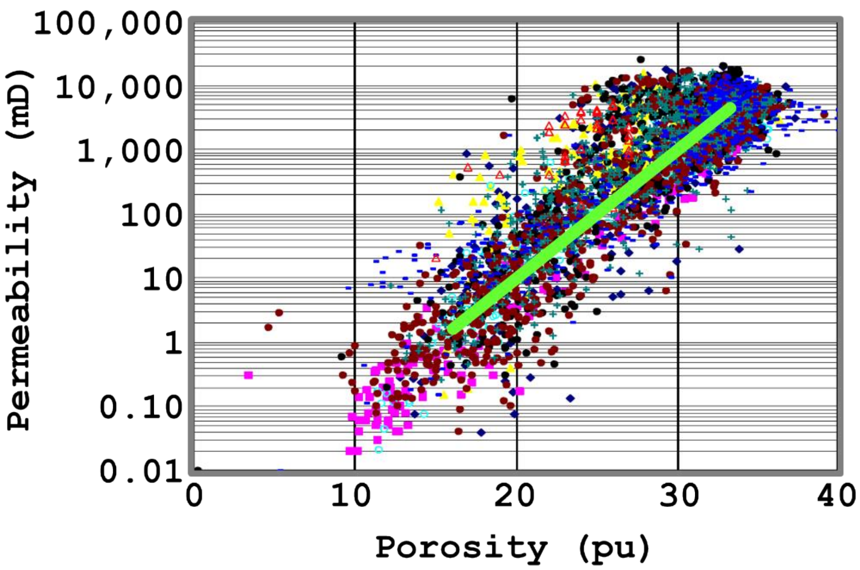

Figure 5-8 - Permeability versus Porosity for typical Niger Delta reservoirs provided by ADME

3. This transform defines irreducible water saturation (SWirr) as a function of porosity:

$$S_{Wirr}(\%) \approx 2.5\ 10^{-2}\ \frac{PHI(\mathrm{pu})^3}{10^{0.1\ PHI(\mathrm{pu})-1.5}}$$

It is derived from the combination of the permeability transform above with the permeability equation quoted in a study on Nembe Creek, (Alaminiokuma, G & Ofuyah, W, 2017. in order to extract S_Wirr:

$$K(\mathrm{mD}) \approx \left(\frac{2.5\ 10^{-2}\ PHI(\mathrm{pu})^3}{S_{Wirr}(\%)}\right)^2$$

5.2.4 Reservoir Parameters used in this Study

Xodus calculated petrophysical averages and ranges from the data provided by ADME and appropriate data from analogue fields, together with the transforms described above. The data from Barracuda-4 (BX-1) for the C and D reservoirs were the best quality data available. As there are no clear hydrocarbon saturations in the Barracuda wells, the water saturation (SWirr) data were calculated from porosity, using the third transform (i.e. Niger Delta correlation) described above, together with data from analogue fields.

5.3 Hydrocarbon In-Place Estimates

5.3.1 Approach

STOIIP for the Agbada Sandstone reservoirs, C3, D1B, D1A and 'Deep prospect' were calculated probabilistically using Crystal Ball software. The Prospective Resource has been assessed separately for each individual reservoir unit and collectively for the combined reservoirs. This approach aligns with that of previous evaluations. In all cases, Xodus used a slab model (a range of constant thicknesses over the fixed areas of reservoir extent) and the parameters are tabulated below in this section.

5.3.2 Barracuda C3 Reservoir

GRV estimates for the C3 reservoir are based upon the 'Top C' depth grid supplied by ADME and independently corroborated by Xodus. Polygons were constructed on the top reservoir map representing P1 and P50 percentiles for reservoir extent. The P1 representing the deepest possible contact at the Barracuda-4 well pick where the C3 reservoir unit contains residual oil. The P50 represents approximately 50% of the P1 area (Figure 5-9)

A range of N:G ratios, (P90 - 0.59, P50 – 0.83 and P10 – 0.91) for the C3 reservoir has been defined from the range of average petrophysical N:G ratios observed in the available wells. The range of average Phi, (P90 - 0.24, P50 – 0.28 and P10 – 0.32) is derived from the same wells. Both N:G and Phi ranges have been defined by P90 and P10 cases in Normal distributions. The So and Bo ranges are derived from Niger Delta analogue data. Input parameters for volumetric calculations are shown in Table 5-2 Parameters used in the estimation of STOIIP in Agbada C3 Reservoir

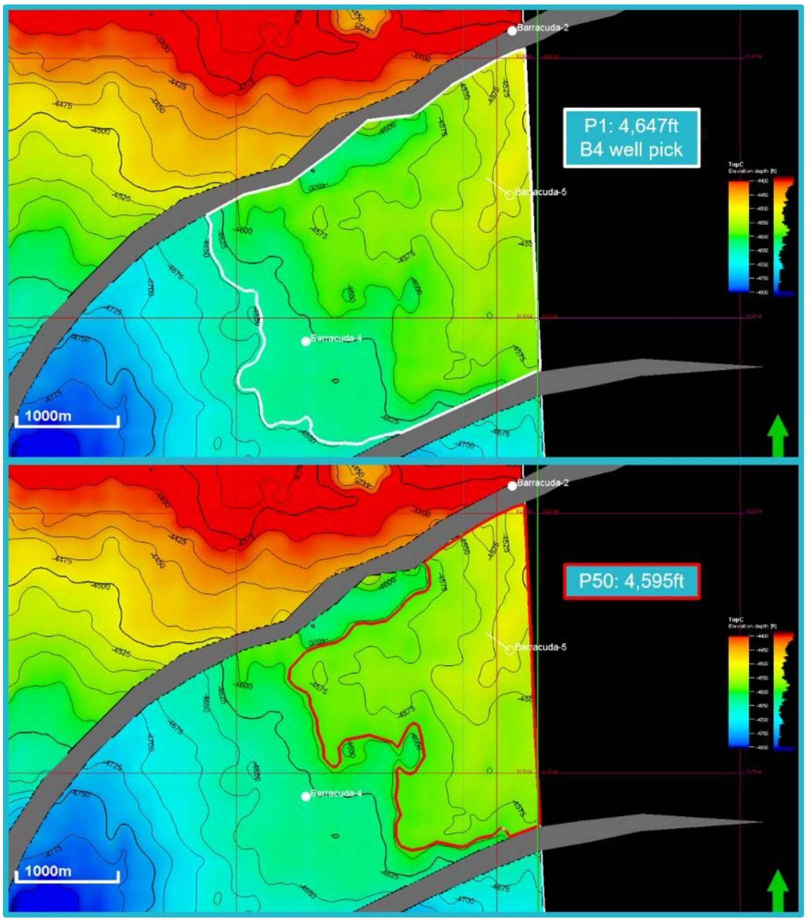

Figure 5-9 - Top C Depth Map showing P1 and P50 C3 Reservoir Polygons

1 Parameter	Unit	Shape		P50	P99
Area	Km²	Log-normal		4.51	8.00
Thickness	m	Log-normal		67	127
Parameter	**Unit**	**Shape**	**P90**	**P50**	**P10**
GRV	(10^6m³)	Log-normal	192.26	306.13	481.72
Contact	ft TVDSS	Constant	4647	4647	4647
Net-to-gross	decimal	Normal	0.59	0.83	0.91
Porosity	decimal	Normal	0.24	0.28	0.32
So	decimal	Normal	0.64	0.755	0.87
FVF (1/Bo)	decimal	Normal	0.52	0.63	0.80
STOIIP (MMbbls)			**106**	**193**	**343**

Table 5-2 - Parameters used in the estimation of STOIIP in Agbada C3 Reservoir

5.3.3 Barracuda D1A Reservoir

GRV estimates for the D1A reservoir are based upon the 'TopD1A' depth grid supplied by ADME and independently corroborated by Xodus. Polygons were constructed on the top reservoir map representing P1 and P50 percentiles for reservoir extent, P1 being the deepest possible contact at the Barracuda-4 well pick where the D1A reservoir unit contains residual oil. The P50 polygon represents an up dip high, consistent with the 5,630ft contour representing a spill point around the crest adjacent to the block boundary (Figure 5-10).

A range of N:G, (P90 - 0.40, P50 – 0.50 and P10 – 0.60) for the D1A reservoir has been defined from the range of average petrophysical N:G ratios observed in the supplied offset wells and from Niger Delta, Agbada D reservoirs in analogue datasets. A similar approach has been used in estimating the range of porosities. The NTG and porosity ranges have been defined by P90 and P10 cases in Normal distributions. The So and Bo ranges are derived from the same Niger Delta analogue data. Input parameters for volumetric calculations are shown in Table 5.3.

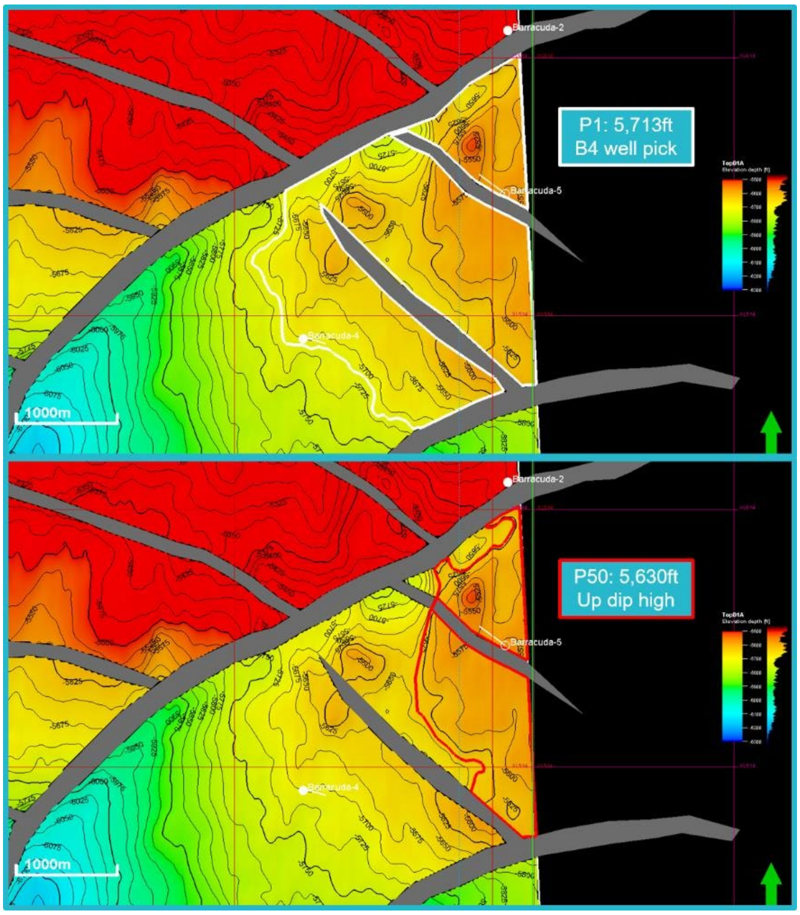

Figure 5-10 - Top D1A Depth Map Showing P1 and P50 Reservoir Polygons

Parameter	Unit	Shape	P1	P50	P99
Area	Km²	Log-normal		2.16	5.58
			P10	**P50**	**P90**
Thickness	m	Log-normal	21		35
Parameter	**Unit**	**Shape**	**P10**	**P50**	**P90**
GRV	(10^6m³)	Log-normal	38.96	59.56	100.01
Contact	ft TVDSS	Constant	5713	5713	5713
Net-to-gross	decimal	Normal	0.40	0.50	0.60
Porosity	decimal	Normal	0.23	0.27	0.30
So	decimal	Normal	0.76	0.785	0.81
FVF (1/Bo)	decimal	Normal	0.56	0.62	0.69
STOIIP (MMbbls)			**14.68**	**25.24**	**43.39**

Table 5-3 - Parameters used in the estimation of STOIIP in Agbada D1A Reservoir

5.3.4 Barracuda D1B Reservoir

GRV estimates for the D1B reservoir are based upon the 'TopD1B' depth grid supplied by ADME and independently corroborated by Xodus. Polygons were constructed on the top reservoir map representing P1 and P50 percentiles for reservoir extent, P1 representing the deepest possible contact at the Barracuda-4 well pick where the D1B reservoir unit contains residual oil. The P50 polygon represents an up dip high, consistent with the 5,715ft contour (Figure 5.6). ADME notes a strengthening of amplitudes up dip and use this in defining the prospect (Figure 5-5, although no rock physics calibration is presented.

The same range of N:G ratios used in the D1A reservoir has been applied in the D1B reservoir although the porosity range is reduced based upon porosity depth trends. A similar approach has been used in estimating the range of porosities. The N:G and porosity ranges have been defined by P90 and P10 cases in Normal distributions. The So range is a Normal distribution derived from the same Niger Delta analogue data. Input parameters for volumetric calculations are shown in Table 5-4.

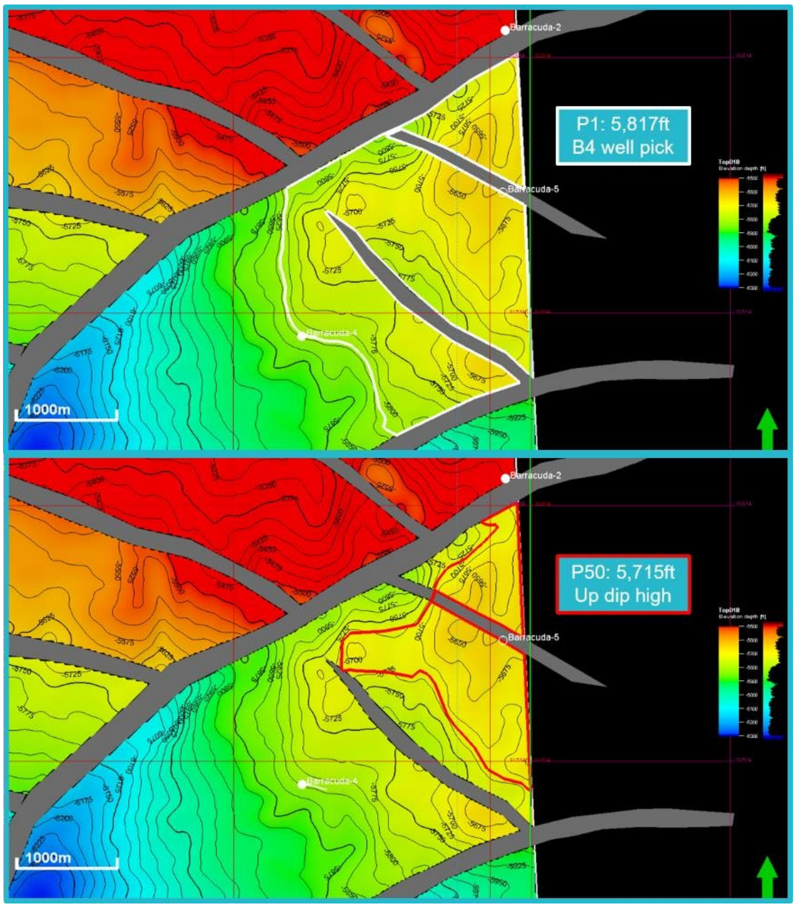

Figure 5-11 - Top D1B Depth Map Showing P1 and P50 Reservoir Polygons

Parameter	Unit	Shape		P50	P99
Area	Km²	Log-normal		2.1	5.48
Thickness	m	Log-normal		100	152
Parameter	**Unit**	**Shape**	**P10**	**P50**	**P90**
GRV	(10^6m³)	Log-normal	140.74	212.01	354.85
Contact	ft TVDSS	Constant	5817	5817	5817
Net-to-gross	decimal	Normal	0.50	0.60	0.70
Porosity	decimal	Normal	0.23	0.27	0.30
So	decimal	Normal	0.76	0.785	0.81
FVF (1/Bo)	decimal	Normal	0.56	0.62	0.69
STOIIP (MMbbls)			**70.41**	**102.9**	**148.88**

Table 5-4 - Parameters used in the estimation of STOIIP in Agbada D1B Reservoir

5.3.5 Barracuda 'Deep Prospect' Reservoir

The 'Deep prospect' reservoir level has been encountered in wells B1, B2 and B3 and mapped on seismic data by ADME over the B4-B5 main fault block. Xodus has extended this mapping with a first pass seismic interpretation (Section 5.1.3), suggesting the reservoir level is at approximately 10,700ft and 10,900ft MD in wells B1 and B3 respectively, rising up dip in the NE to 7,855ft MD in well B2. GRV estimates for the 'Deep Prospect' reservoir are based upon independent mapping by Xodus. Xodus has investigated the amplitudes (Figure 5-12) and used this map to derive the P90 case. The P50 is defined to be a reasonable column height for the prospect. Figure 5-12 shows the P50 and P90 polygons in red and yellow respectively.

Parameter	**Unit**	**Shape**	**P90**	**P50**	
Area	Km²	Log-normal	0.88	4.48	
Thickness	m	Log-normal	55	67	
Parameter	**Unit**	**Shape**	**P10**	**P50**	**P90**
GRV	(10^6m³)	Log-normal	48.4	163.48	300.16
Contact	ft TVDSS	Constant	9400	9400	9400
Net-to-gross	decimal	Normal	0.50	0.60	0.70
Porosity	decimal	Normal	0.24	0.27	0.29
So	decimal	Normal	0.70	0.8	0.90
FVF (1/Bo)	decimal	Normal	0.51	0.54	0.57
STOIIP (MMbbls)			**20.12**	**51.08**	**131.17**

Table 5-5 - Parameters used in the estimation of STOIIP in Agbada 'Deep Prospect' Reservoir

A range of N:G, (P90 - 0.50, P50 – 0.60 and P10 – 0.70) has been defined from the range of average petrophysical N:G ratios observed in the offset wells and from E and F reservoirs in nearby analogue datasets. A range of porosities of P90 - 0.24, P50 – 0.27 and P10 – 0.29 has been used, based upon the same datasets. N:G, porosity and So ranges have all been defined by P90 and P10 cases in Normal distributions. Input parameters for volumetric calculations are shown in Table 5.5.

5.3.6 Barracuda STOIIP: Combined Agbada Reservoirs

The estimate of STOIIP pertaining to the combined reservoirs, C3, D1A, D1B and 'Deep' is shown in Table 5.6 below.

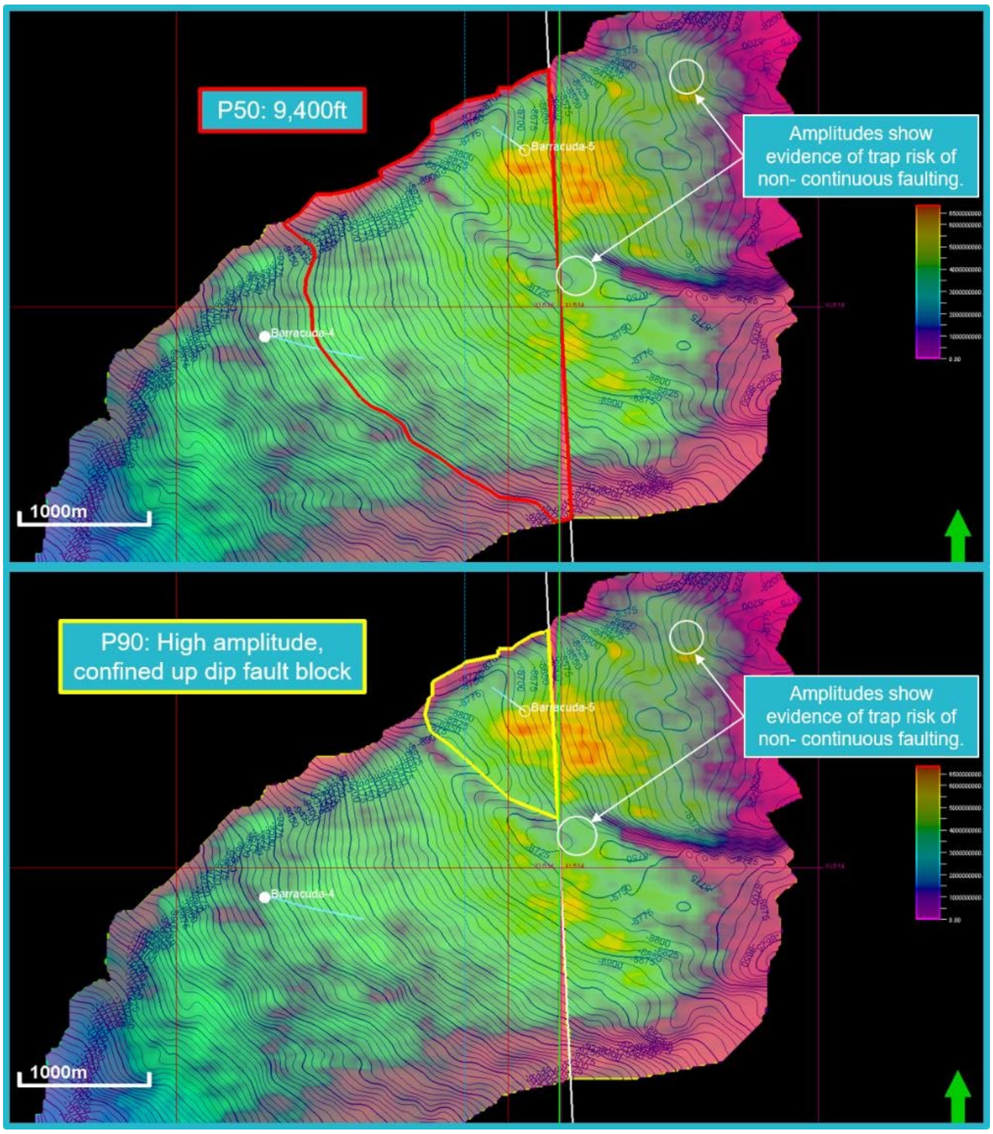

Figure 5-12 - Deep Prospect Amplitude Map Showing P90 and P50 Reservoir Polygons

5.3.7 Chance of Geological Success

The key geological risk is containment or trap, which Xodus has risked at 25% to 33%. There is no clear evidence on the Barracuda seismic data of a trap to the northeast, although maps produced by Noble Hill Network show potential fault seals to the east of Barracuda in OML 66. A fault seal will be difficult for the C and D1B reservoirs within or near the Barracuda area because sand-sand connections across the up-dip faults are likely and there is evidence of relays i.e. the faults may not be continuous (see Section 5.3.5 and Figure 5-12). Other risks associated with source, migration/timing and reservoir presence/quality are minimal and have less bearing on the overall geological chances of success.

STOIIP (UNRISKED)	GROSS VOLUMES			CHANCE OF SUCCESS
Reservoir	P90 (mmbbl)	P50 (mmbbl)	P10 (mmbbl)	
C3	106	193	343	15%
D1A	15	25	43	30%
D1B	70	103	149	18%
Deep Prospect	20	51	131	25%
Combined	275	397	574	

Table 5-6 - Summary of STOIIP, Risk and Chance of Success

If the D1A and "Deep Prospect" reservoirs are regarded as independent then the CoS for discovering hydrocarbons in at least one of the reservoirs is 47%. ADME risks the reservoirs individually at 30% to 70% in the B5 prospect area.

5.4 Recoverable Volume Estimates

5.4.1 Approach

Xodus based its estimates of EUR/Well, initial rates and plateau duration on production data from analogue fields. The combination of those factors determines the decline rates. Xodus used the same drilling and development schedule as provided in the economic model by ADME, meaning a total of six wells in all cases. If more than approximately 70 mmbbl STOIIP is discovered then it is likely that additional production wells would be needed.

GOR was assumed to be 1,000 scf/bbl.

5.4.2 Recoverable Resource and Production Forecast

		Low	Mid	High
Barracuda	Well Count	6	6	6
	Initial Well Rate (Kbopd)	2.0	2.4	3.2
	Rec/well (MMbbl)	3.45	4.00	4.60

Table 5-7 - Xodus field development parameters range for Barracuda

		1U	2U	3U
Barracuda	Oil Recovered (MMbbls)	20.7	24.0	27.8
	Associated Gas (Bscf)	20.7	24.0	27.8

Table 5-8 - Xodus Gross Prospective Resources for Barracuda

Barracuda Development – 1U					
Year	Oil Rate (Kbopd)	Cum. Oil (MMbbls)	Ass. Gas Rate (MMscfd)	Cum. Gas (Bscf)	Well Count
1	1.94	0.71	1.94	0.71	1
2	4.00	2.17	4.00	2.17	2
3	4.00	3.63	4.00	3.63	3
4	6.56	6.02	6.56	6.02	5
5	11.78	10.32	11.78	10.32	6
6	9.97	13.96	9.97	13.96	6
7	6.56	16.35	6.56	16.35	6
8	4.31	17.93	4.31	17.93	6
9	2.83	18.96	2.83	18.96	6
10	1.86	19.64	1.86	19.64	6
11	1.22	20.09	1.22	20.09	6
12	0.80	20.38	0.80	20.38	6
13	0.53	20.57	0.53	20.57	6
14	0.35	20.7	0.35	20.7	6

Table 5-9 - Xodus Gross 1U Production Forecast for Barracuda

Barracuda Development – 2U					
Year	Oil Rate (Kbopd)	Cum. Oil (MMbbls)	Ass. Gas Rate (MMscfd)	Cum. Gas (Bscf)	Well Count
1	2.33	0.85	2.33	0.85	1

Barracuda Development – 2U					
2	4.8	2.6	4.8	2.6	2
3	4.8	4.35	4.8	4.35	3
4	7.87	7.23	7.87	7.23	5
5	14.13	12.39	14.13	12.39	6
6	11.15	16.46	11.15	16.46	6
7	6.63	18.88	6.63	18.88	6
8	4.31	20.45	4.31	20.45	6
9	2.97	21.53	2.97	21.53	6
10	2.15	22.32	2.15	22.32	6
11	1.61	22.9	1.61	22.9	6
12	1.24	23.36	1.24	23.36	6
13	0.98	23.71	0.98	23.71	6
14	0.79	24.00	0.79	24.00	6

Table 5-10 - Xodus Gross 2U Production Forecast for Barracuda

Barracuda Development – 3U					
Year	Oil Rate (Kbopd)	Cum. Oil (MMbbls)	Ass. Gas Rate (MMscfd)	Cum. Gas (Bscf)	Well Count (producers only)
1	3.11	1.13	3.11	1.13	1
2	6.4	3.47	6.4	3.47	2
3	6.4	5.81	6.4	5.81	3
4	10.5	9.64	10.5	9.64	5
5	18.52	16.4	18.52	16.4	6
6	11.45	20.57	11.45	20.57	6
7	6.34	22.89	6.34	22.89	6
8	4.03	24.36	4.03	24.36	6
9	2.78	25.37	2.78	25.37	6

Barracuda Development – 3U					
10	2.04	26.12	2.04	26.12	6
11	1.56	26.69	1.56	26.69	6
12	1.23	27.14	1.23	27.14	6
13	1.00	27.5	1.00	27.5	6
14	0.82	27.8	0.82	27.8	6

Table 5-11 - Xodus Gross 3C Production Forecast for Barracuda

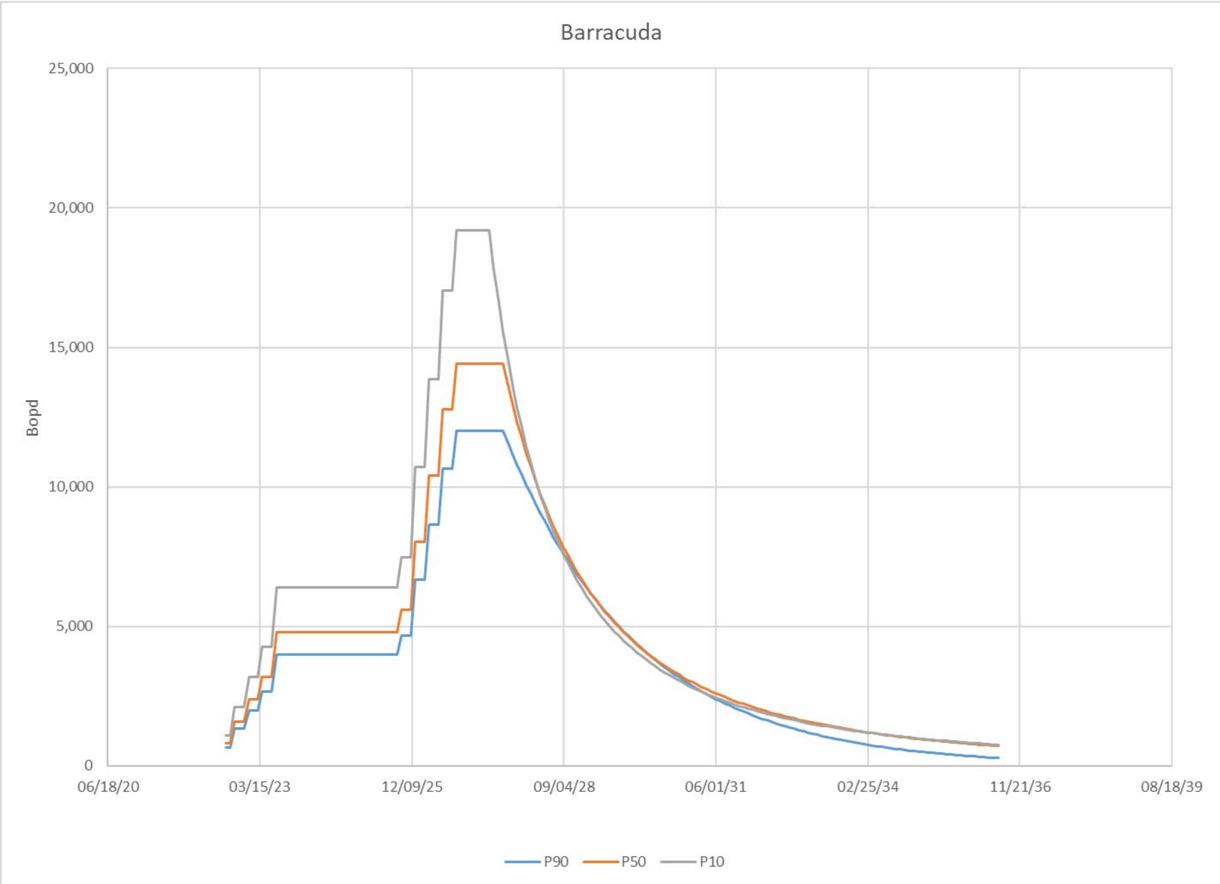

Figure 5-13 - Xodus production profiles

5.5 Development Concept and Costs

The development concept provided by ADME includes an early production phase using a leased production facility with oil export via barge to Brass Terminal. The early production facility will be used for production from the first two wells. The concept is to then develop a full field production facility, sized for production from six wells (with a peak rate of 18,000 bopd in the mid case profiles). During full field production oil export could either continue to be via barge to Brass Terminal, or via a new 13.5km export pipeline to Brass Terminal installed as part of the development. Development costs presented by ADME include the following assumptions:

- Early production phase processing costs of $6 / bbl for the rented production barge.
- Early production phase oil export by barge costs of $4 / bbl.
- CAPEX for full field development phase of $16.8M
  - Full field production facility CAPEX financed by the production system vendor using profit from early production phase.
  - Installation of a 13.5km oil export pipeline to Brass Terminal.
- Pipeline OPEX in full field phase of $3 / bbl.
- Well costs of $18M per well plus $4.25M flowline costs per well.

The Presented Case information assumes that a vendor supplies the facilities for the Early Production Phase (EPS) and the subsequent full field development phase. The full field development equipment/facilities can be optimised following the EPS for the Barracuda specific requirements. It is assumed that the full field development equipment/facilities Engineering, Procurement and Construction (EPC) and installation will be provided by the vendor. It will be possible to specify a design basis for the full field development facilities based on EPS results, such that production rate, water processing, gas handling facilities are provided as necessary. The assumption is that the vendor will invest a portion of their revenues into the field development facilities project, which will allow funding of Capex for engineering and construction of the permanent facilities, with the option for ADME to own the permanent facility once costs have been recovered. For this Build–Operate–Transfer business model, it is reasonable to assume that the vendor will target a rental cost / bbl that allows recovery of costs plus profit. It is also reasonable to assume that the more complex the processing needs (additional modules for water processing or gas handling for example), that this rental cost will need to be higher.

The concept presented does not include any gas reinjection or gas export facilities, therefore it is assumed that the intent is to flare produced gas that is not used for fuel. Given initiatives such as the World Bank's Zero Routine Flaring by 2030 and Nigeria's inclusion of zero routine flaring by 2030 as a required mitigation to achieve its Nationally Determined Contribution as submitted to the UN under article 4.2 of the Paris Agreement, the lack of a gas export or disposal route could result in either issues with financing the project or with regulatory approvals. Gas injection facilities have not been included in the development facilities assessed in the economics. If required, it is expected that addition CAPEX of at least $20M would be required to provide these facilities. If funded through OPEX this would be expected to add $1/bbl to the lease costs.

To assess the robustness of the development economics, Xodus has adjusted costs as follows:

- Early production phase processing cost increased to $8 / bbl for the rented production barge.

    - The indicative $6 / bbl includes oil processing only, therefore additional processing modules would be needed for water treatment for example
    - $6 / bbl combined with Xodus' production profiles would mean there is no profit for a vendor financed processing facility. For this concept to be viable it is assumed that the vendor needs to recover their costs with some profit. $8 / bbl is the minimum fee that allows a positive NPV (8%) for the vendor.
- Early production phase oil export by barge costs of $4 / bbl.
    - No change
- Independent CAPEX estimate for 13.5 km oil export pipeline. CAPEX estimated as $20.6 M used for all cases.
- Pipeline OPEX in full field phase of $3 / bbl.
    - No change
- Well costs of $18M per well plus $4.25M flowline costs per well.
    - No change

6 ECONOMICS

6.1 Development Economics - Basis

Economics have been tested for a full field development funded through OPEX (vendor financed). Two oil price profiles have been used:

> Flat $85/bbl nominal
> Flat $60/bbl nominal

Economics have been run using the Xodus P10, P50 and P90 production profiles.

6.2 RSA Economics – Results

The economic model supplied by ADME has been reviewed against the Risk Service Agreement scope and provisions to confirm that the economic model represents the RSA accurately. Xodus has used this model with its independent production profiles, and CAPEX and OPEX adjustments described in section 5.5 to assess the economics of the RSA. Xodus used the same development concept assumptions, and drilling and development schedule as provided in the economic model by ADME, as these are reasonable at this stage.

Results show that the RSA is repaid before the end of field life (this is the point at which the maximum 235% of qualifying expenditure is recovered) except in the $60/bbl oil price P90 profile case. For the $60/bbl P90 profile case, the maximum 235% is not recovered. Figure 6-1 shows the RSA balance for each of the cases. It can be seen that for the P90 $60 case, the RSA has a small residual balance of $11.3M at end of field life.

P90 Profile Flat $50 / bbl nominal		P50 Profile $60 / bbl nominal	P50 Profile $85 / bbl nominal	P90 Profile $60 / bbl nominal	P90 Profile $85 / bbl nominal	P10 Profile $60 / bbl nominal	P10 Profile $85 / bbl nominal
RSA undiscounted cash (un-levered)	US$M	213.7	227.4	200.3	221.8	219.0	235.7
Maximum equity exposure	US$M	(44.1)	(34.7)	(57.6)	(36.6)	(36.4)	(31.0)
RSA NPV 10.0	US$M	99.0	126.5	86.1	115.8	113.4	143.9
RSA IRR	%	45%	74%	38%	60%	60%	111%
RSA repaid	Date	Jul-33	Apr-30	Not repaid	Oct-30	Oct-31	Jan-29
RSA undiscounted cash (levered)	US$M	211.5	226.3	197.5	220.3	217.6	235.2
Maximum equity exposure	US$M	(38.8)	(34.7)	(40.0)	(36.6)	(36.4)	(31.0)
RSA NPV 10.0	US$M	98.9	126.5	86.0	115.8	113.4	143.9
RSA IRR	%	46%	76%	39%	61%	61%	113%
Debt provider to RSA repaid	Date	Apr-27	Oct-26	Jul-27	Jan-27	Jan-27	Oct-26

Table 6-1 - RSA Results – Xodus Profiles & Cost Assumptions

Figure 6-1 – RSA Balance

6.3 Project Economics

Xodus has also assessed the economics at a project level and the results are presented in the tables below. The results show that:

> All cases are NPV positive

> NPV10 for the P50 case is in the range $70-140M

> The prospect is therefore considered to be robust for development, assuming at least 70mmbbl STOIIP is discovered.

$60/bbl nominal Xodus Profiles	P90 $M	P50 $M	P10 $M
Net Profit	93	120	160
NPV10	60.5	76.9	104.6

Table 6-2 - Flat $60/bbl

$85/bbl nominal Xodus Profiles	P90 $M	P50 $M	P10 $M
Net Profit	181	224	286
NPV10	113.4	139.5	182.4

Table 6-3 - Flat $85/bbl

7 NOMENCLATURE

TERM	MEANING	UNITS OF MEASUREMENT
2D	Two dimensional seismic data covering length and depth of a given geological surface	
3D	Three dimensional seismic data covering length, breadth and depth of a given geological surface	
AAPG	American Association of Petroleum Geologists	
API	American Petroleum Institute	api
AVO	Amplitude versus offset or amplitude variation with offset is often used as a direct hydrocarbon indicator	
Best Estimate	An estimate representing the best technical assessment of projected volumes. Often associated with a central, P50 or mean value	
CIIP	Condensate Initially In Place	mmboe
Contingent Resources	Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.	
COS	Exploration or geological chance of success. The probability, typically expressed as a percentage that a given outcome will occur.	
CPI	Computer-processed interpretation	
D	Day	
ft	Foot/feet	ft
° F / ° C	Degrees Fahrenheit / Centigrade	
FDP	Field Development Programme	
FVF	Formation Volume Factor	
FWL	Free water level	
GDT	Gas Down To	ft or m

TERM	MEANING	UNITS OF MEASUREMENT
STOIIP	Gas Initially In Place	bcf
GR	Gamma ray	
GOR	Gas Oil Ratio	
GWC	Gas-water contact	
H **HDT**	Thickness Hydrocarbon down to	ft or m
High Estimate	An estimate representing the high technical assessment of projected volumes. Often associated with a high or P10 value	
JV	Joint Venture	
K	Permeability	mD
ka	Air permeability	mD
Kh	Permeability-thickness	mDft
km	Kilometres	km
Kw	Water Permeability	mD
LCC	Lowest closing contour	
Lead	A feature identified on seismic data that has the potential to become a prospect. Usually a Lead is associated with poorer quality or limited 2D seismic data.	
LKG	Lowest Known Gas	ft or m
Low Estimate	An estimate representing the low technical assessment of projected volumes. Often associated with a low or P90 value.	
M	Metres	
MD	Measured depth	ft or m
mD	Millidarcies	
MDRKB	Measured Depth Rotary Kelly Bushing	ft or m
MDBRT	Measured depth Below Rotary Table	ft or m
Mean	The arithmetic average of a set of values	
msec	Millisecond	
MM	Million	
MMbo	Millions of barrels of oil	
MMboe	Millions of barrels of oil equivalent	
MMstb	Millions of barrels of stock tank oil	
NTG	Net to Gross	

TERM	MEANING	UNITS OF MEASUREMENT
OBM	Oil based mud	
ODT	Oil down to	
OGA	Oil & Gas Authority	
OIP	Oil In Place	
OWC	Oil water contact	
P10	The probability of that a stated volume will be equalled or exceeded. In this example a 10% chance that the actual volume will be greater than or equal to that stated.	
P50	The probability of that a stated volume will be equalled or exceeded. In this example a 50% chance that the actual volume will be greater than or equal to that stated.	
P90	The probability of that a stated volume will be equalled or exceeded. In this example a 90% chance that the actual volume will be greater than or equal to that stated.	
P99	The probability of that a stated volume will be equalled or exceeded. In this example a 99% chance that the actual volume will be greater than or equal to that stated.	
Pres	Reservoir pressure	psi
Ppg	pounds per gallon	
Producing	Related to development projects (e.g. wells and platforms): Active facilities, currently involved in the extraction (production) of hydrocarbons from discovered reservoirs.	
Prospective Resources	Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.	
PVT	Pressure Volume Temperature: Measurement of the variation in petroleum properties as the stated parameters are varied.	
REP	Reserves Evaluation Programme - REP5 software from Logicom E&P	
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development	

TERM	MEANING	UNITS OF MEASUREMENT
	projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status.	
Rw	Water resistivity	
Seismic	Use of sound waves generated by controlled explosions to ascertain the nature of the subsurface geological structures. 2D records a cross section through the subsurface while 3Dprovides a three dimensional image of the subsurface.	
So	Oil saturation	
STOIIP	Stock tank oil initially in place	
SPE	Society of Petroleum Engineers	
SPEE	Society of Petroleum Evaluation Engineers	
Sqmi	Square mile	
Sw	Water saturation	ratio
TD	Total depth	ft or m
TVDBRT	True vertical depth below rotary table	ft or m
TVDSS	True vertical depth sub sea	ft or m
VoK	Average velocity function for depth conversion of time based seismic data, where Vo is the initial velocity and k provides information on the increase or decrease in velocity with depth. V0+k therefore provides a method of depth conversion using a linear velocity field, increasing or decreasing with depth for each geological zone.	
VSP	Vertical Seismic Profile	
WGR	Water gas ratio	
WHP	Wellhead pressure	psi
WPC	World Petroleum Council	
WUT	Water up to	

8 XODUS & AUTHOR CREDENTIALS

Xodus is an independent, international energy consultancy. Established in 2005, the company has 300+ subsurface and surface focused personnel spread across thirteen offices in Aberdeen, Anglesey, Dubai, Edinburgh, Glasgow, The Hague, Houston, London, Orkney, Oslo, Perth and Southampton.

The wells and subsurface division specialise in petroleum reservoir engineering, geology and geophysics and petroleum economics. All of these services are supplied under an accredited ISO9001 quality assurance system.

Jonathan Fuller
Jonathan (Jon) Fuller is the Global Head of Advisory for Xodus and was responsible for supervising this evaluation. A Reservoir Engineer, with a strong commercial experience he has 28 years of international experience in both International Oil Companies, large Service Companies and Consultancy organisations. The last 10 years he has been the technical and project management lead on reserve / resource evaluations in M&A, competent person reports and expert opinion linked bank and institutional investment (both debt and equity).

Jon has an M.Eng (Hons) in Engineering Science from Oxford University, a Master's Degree in Petroleum Engineering from Heriot-Watt, and an MBA from INSEAD. He is a member of the Society of Petroleum Engineers (SPE), and the Association of International Petroleum Negotiators (AIPN).

Andrew Sewell
Andrew is the Director of Subsurface for Xodus. Andy has 30 years' experience in the oil and gas industry, the first 17 of which were with Schlumberger as a geophysicist, operations manager and global discipline manager. Subsequently Andy has been a geophysicist and subsurface manager in consultancy, including working either as a project manager or acting as a technical resource in a wide variety of technical and commercial projects. Andy has managed several large integrated projects in exploration, development and new ventures.

Andy has an MA in Physics from Cambridge University. He is a member of the PESGB, SEG and EAGE.

Sam Girling
Sam Girling is a dedicated Senior Geophysicist and seasoned subsurface E&P professional with experience from a variety of basins worldwide. Strong grounding in exploration and development in Sea and Atlantic margin plays. Broad experience of different geological settings from exploration internationally, including expat postings to Norway and Indonesia. Adept at working in different organisation types having held roles in large corporates to small independents, often with a high degree of responsibility. Creative and pragmatic in approach, applies commercial judgement.

Jeff Standring
Jeff Standring is a Petroleum Geologist with diverse experience in stratigraphy, sub-regional and basin scale exploration projects, prospect evaluation and commercial work gained with leading service companies and secondments with operators. He has over 30 years' experience in UK and international including West Africa, (Nigeria, Senegal-Bove Basin, Gulf of Guinea), Pakistan, India, and Central America, Eastern Europe and the Middle East. He has worked for Robertson Research, Senergy, Baker Hughes and Xodus.

Kais Gzara

A subject matter expert in logging operations and open/cased hole log interpretations, with a particular specialty in Wireline and LWD operations. 22 years of experience in the Middle East and North Africa, 6 years of experience in West Africa and a combined 3 years of experience in the USA and Europe. Open and cased hole field operations, onshore and offshore fields, issuing invitations-to-tender, evaluating tenders and managing contracts, tender submissions, engineering, research and development, petrophysics and well placement experience. Numerous publications and patents related to drilling and logging technology and interpretation.

Caragh McWhirr

Caragh McWhirr has 20 years' experience in the oil and gas sector. She has a broad and multidisciplinary technical base covering electrical, mechanical, process and safety engineering. Caragh joined Xodus in 2005, in her time here Caragh has developed specialities in process engineering and in appraise and select conceptual engineering studies. Caragh has carried out many lead engineer and study management roles. She has been an inherent part of client project teams, working as the project technical lead, technical representative in JV partner meetings and gate reviews and providing technical support to commercial discussions.