XODUS ADVISORY

2018 CPR

Competent Person's Report

UK Oil & Gas Investments PLC

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The Directors

UK Oil & Gas Investments PLC ("UKOG")

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6th June 2018

Dear Sirs,

Reference: Competent Person's Report

UKOG Interests in Assets in South Eastern England

Xodus Group Ltd. ("Xodus") is acting as UK Oil & Gas Investments PLC's ("UKOG" or the "Company") Competent Person as defined by the rules made by the AIM market of the London Stock Exchange ("AIM") in relation to UKOG's interests in the licences in the south east of England. As instructed, Xodus has prepared an independent Competent Person's Report ("CPR") in respect of these interests in connection with the proposed relisting of the Company's shares on the Alternative Investment Market ("AIM") of the London Stock Exchange ("LSE") (the "Proposed Transaction").

In accordance with your instructions, Xodus has reviewed the Reserves and Resources of the following assets: Avington (PEDL70), Baxters Copse (PEDL233), Holmwood (PEDL143), Horndean (PL211), Horse Hill (PEDL 137 and 246), Isle of Wight Onshore (PEDL331) and Markwells Wood (PEDL126). The Horse Hill review focused primarily upon the Upper Portland Sandstone oil discovery. Xodus has also discussed a number of other assets, which are material to UKOG's forward plans.

We were requested to provide an independent evaluation of the Hydrocarbons Initially In Place ("HIIP") and recoverable volumes expected in accordance with Petroleum Resources Management System ("PRMS") (2007 and 2011) 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"). The results of this work have been presented in accordance with the Rules and Guidelines of the AIM[1].

Throughout this report, volumes, unless otherwise stated, are expressed as gross Stock Tank Oil Initially In Place volumes ("STOIIP") or Gas Initially In Place ("GIIP") – these can be considered "discovered petroleum initially in place" and the recoverable volumes are expressed as gross and net Reserves, Contingent Resources or Prospective Resources.

In conducting this review, we have utilised information and interpretations supplied by the Company, including some interpretations from the operators of licences in which UKOG 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

[1] Note for Mining and Oil & Gas companies – June 2009

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 geo-scientific 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.

We confirm that there has been no material change of circumstances or available information since the CPR was compiled and we are not aware of any significant matters arising from our evaluation that are not covered by the CPR which might be of a material nature with respect to the Proposed Transaction. We also confirm that where any information contained in the CPR 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.

The effective date of this report is 1st January 2018.

1 EXECUTIVE SUMMARY

UK Oil & Gas Investments PLC (“UKOG”, “the Client”, or “the Company”) has interests in nine Licences in the south of England, eight of which are located in the Weald Basin and one in the Wessex Basin. There is one currently producing oil field on these licences as well as a number of existing discoveries.

Xodus has previously produced a Competent Person’s Reports or Independent Evaluation on three of the assets which are operated by UKOG (Horse Hill Portland, Markwells Wood and Onshore Isle of Wight). Xodus has confirmed with UKOG that for these assets there has been no update since the writing of the original report. For assets in which UKOG has non-operated interests Xodus has generated independent estimates of recoverable volumes using standard geological and engineering approaches applied to the more limited datasets available.

The Reserves and Resources evaluated in this report focus solely upon UKOG’s conventional oil developments in the Jurassic Great Oolite Limestone, Portland Sandstone and Corallian Sandstone reservoir formations. Due to the early stage of exploration and appraisal of the Company’s recent Kimmeridge Limestone oil discoveries, these assets are not at a stage where any Reserves or Resources can be assigned in accordance with SPE standards. In place volumes have previously been estimated by Nutech and Schlumberger. It is expected that the forthcoming Horse Hill-1 extended well test programme, planned for late spring 2018, will likely provide valuable data necessary to formulate the range of potential Kimmeridge reserve and resource figures at Horse Hill and by analogy, for the wider Kimmeridge play.

The oil and gas potential of the Kimmeridge Limestones in the Weald Basin has received significant recent attention, most notably due to the successful Horse Hill-1 oil discovery (“HH-1”), operated by Horse Hill Developments Ltd (“HHDL”, UKOG 49.9% shareholding interest), and the Broadford Bridge oil discovery operated and 100% owned by Kimmeridge Oil & Gas Limited (“KOGL”), a wholly owned UKOG subsidiary. As the programme of operations planned to appraise both these Kimmeridge discoveries and the wider resource potential of the Kimmeridge form a major component of UKOG’s ongoing activities, Xodus has summarised the results of recent operations.

Drilling and testing operations at KOGL’s Broadford Bridge-1 well (“BB-1”) and sidetrack (“BB-1z”), located within PEDL234 licence, commenced in late May 2017 and concluded in March 2018. The well was designed to test the Kimmeridge Limestone (“KL”) “continuous oil-deposit” geological concept developed after the successful HH-1 Kimmeridge discovery, the Kimmeridge potential within the licence and the regional extent of the play. The subsurface maps supplied by UKOG demonstrate that BB-1 tested a location with no apparent conventional structural closure present at top Kimmeridge level. The well also hoped to confirm the presence and extent of a regional-scale natural fracture network within the Kimmeridge section.

A total of 550 feet of conventional core was cut within the Kimmeridge at BB-1 over the main prospective Kimmeridge Limestone horizons KL2-KL4, including the KL3 and KL4, which were found to be productive at HH-1. Both BB-1 and BB-1z were electric logged to include formation image logging. As reported by UKOG, both core and log interpretations over the Kimmeridge section showed abundant open natural fractures within the Kimmeridge Limestones and sections of interbedded shales and limestones. Live oil was recovered at surface from open fractures in conventional core within the uppermost KL5 reservoir zone. Oil was also recovered from mud retorts throughout 1300 ft of Kimmeridge section together with wet gas shows. In addition to the two Kimmeridge Limestone reservoir units described in the original HH-1 discovery well, four further Kimmeridge Limestone reservoir units were described in BB-1. These six Kimmeridge Limestone reservoir zones, labelled as KL0 to KL5, were tested in BB-1z, recovering light oil to surface from multiple test zones.

Technical Review

UKOG’s licence interests are situated in the Weald and Wessex Basins of southern England. The Weald and Wessex Basins contain proven petroleum systems as demonstrated by 16 commercial producing fields. Oil and gas pools discovered to date lie primarily within Middle Jurassic carbonate and Upper Jurassic sandstone reservoirs.

The Horndean field (PL211) is a typical Weald Basin oil pool and is located on an east-west trending tilted fault block on the south-western flank of the Weald Basin. The field lies along the same east west bounding fault which controls the Markwells Wood oil discovery, possibly an eastern extension of the Horndean field. The field has been on production since November 1987 and a total of seven wells have been drilled into the Great Oolite reservoir. Production peaked at 670 bopd in June 1993, at present the field produces approximately 140 bopd from four production wells, the rate has been steady with very little decline for approximately the last five years. It is presently the only producing asset in which UKOG holds an interest. Xodus estimated future production and Reserves using Decline Curve Analysis ("DCA") of the producing wells. The gross and net Reserves for Horndean, estimated by Xodus, are as per below. These volumes reflect ongoing production from four wells.

Oil Reserves	**W.I.**	**Gross Volumes**			**Net to UKOG**			**Operator**
(MMbbl)		**1P[2]**	**2P**	**3P**	**1P**	**2P**	**3P**	
Horndean	10%	0.39	0.85	1.29	0.039	0.085	0.129	IGas
Total		**0.39**	**0.85**	**1.29**	**0.039**	**0.085**	**0.129**	

Table 1.1 Gross and Net Reserves (in MMbbl)

The Avington field (PEDL70) came on production in 2007 after extensive well testing with initial rates at over 500 bopd. Rates declined quickly with a corresponding increase in water production and the field was shut in for long periods. Until the end of 2017 the field had been on production continuously since 2009, producing at low rates with >90% water cut. The field is now shut in temporarily while pressure builds up in the reservoir and until the field economics are more favourable. Estimates of recoverable volumes for Avington have been made by DCA, volumes for Avington are contingent on production being economic either through Opex reduction or increased oil price.

The Horse Hill discovery (PEDL137 and PEDL246) comprises two main productive intervals, the Upper Portland Sandstone and two Kimmeridge Limestone reservoir units, the KL3 and KL4. The Upper Portland Sandstone pool is considered as Contingent Resources and is included in this evaluation. Xodus have reviewed the interpretations provided by UKOG and have determined estimates of STOIIP and recoverable volumes. Xodus determined a reasonable total well count for an ultimate Portland field recovery. The number of wells on the field was multiplied by the well type profiles to arrive at deterministic "base case", "upside" and "downside" recoverable volume estimates. Recoverable volumes are contingent on an approved Field Development Plan ("FDP").

The Isle of Wight Onshore licence (PEDL331) includes the existing Arreton oil discovery ("Arreton Main") and two undrilled look-alike prospects, Arreton North and South. Two wells have been drilled on the Arreton discovery, namely the Arreton-1 well drilled in 1952 and its twin the Arreton-2 (1974) discovery well. Good oil shows were reported in the Portland Limestone reservoir which demonstrated good total porosity. Electric logs also calculated significant oil saturations within the Portland, Purbeck and Inferior Oolite reservoirs. The Portland reservoir was tested recovering oil-cut mud. However, the test zone coincided with a casing collar and it is now interpreted by UKOG that the original perforations likely did not penetrate into the formation

[2] 1P, 2P and 3P denote the Proved, Proved + Probable and Proved + Probable + Possible Reserves respectively as defined under the PRMS.

through the two overlapping casing strings. UKOG therefore conclude that the Portland pay zone was not tested conclusively and that a missed or bypassed pay opportunity exists.

The Arreton Main discovery lies within a large, elongate, hanging-wall anticlinal structure defined at Portland Limestone level. The Arreton North prospect is located on the northern upthrown footwall side of the major east-west trending Purbeck-Wight disturbance fault zone that defines the northern extent of the Arreton Main structure. Although oil is proven in multiple reservoirs in Arreton Main, only the Portland Limestone prospectivity has been considered for the Arreton North and South prospects. Estimates of recoverable volumes were made for the discovery and the prospects. The Arreton Main volumes are contingent on an approved FDP and the Arreton North and South prospects are Prospective Resources.

Holmwood (PEDL143) is a near geological look-alike prospect to the nearby HH-1 oil discovery which the operator plans to drill in 2018 and for which planning permission has been granted. Holmwood has three prospective reservoir targets – Portland Sandstone, Kimmeridge Limestones and Corallian Sandstone. As stated above, Xodus have only reviewed volumetrics associated with the Portland and Corallian Sandstones for which the geological Chances of Success ("CoS") are 29% and 17% respectively. Xodus has reviewed the interpretations provided by the operator and additional information on reservoir parameters provided by UKOG in order to estimate in place volumes and Prospective Resources.

Markwells Wood (PEDL126) was discovered in 2010 by the Markwells Wood-1 well which remains the only well on the discovery. Oil was encountered in the Middle Jurassic Great Oolite Limestones. MW-1 was tested from December 2011 to May 2012 and produced 3,931 bbl in total during that period. Xodus reviewed the interpretations by UKOG and determined independent estimates for the in place volumes. A reservoir model was built to model to history match the well test and provide a basis for well performance prediction and estimates of recoverable volumes under a number of possible development scenarios. Recoverable volumes are contingent on an approved FDP.

Baxters Copse (PEDL233) is located in the southern part of the Weald Basin. Oil was discovered by the 1983 Baxters Copse-1 well in the Middle Jurassic Great Oolite carbonate. A long-term test was conducted from January to March 1984 on which low stabilised oil rates of ~20 bopd were achieved. After acid stimulation, the rate initially increased to 200 bopd before falling to 30 bopd with an associated increase in water cut from 50 – 70%. Xodus have used existing interpretations and well data to estimate the range of in place on recoverable volumes.

For undeveloped discoveries Xodus has estimated the gross and net recoverable volumes, see Table 1.2 below. They are classified as Contingent Resources. These estimates of recoverable volumes only take into account primary recovery via depletion or gas expansion drives. Where applicable a comment has been provided, to give a range of possible increased recoveries that might result from the implementation of early field life pressure support. Estimates of recoverable volumes have been made using a number of methods: decline curve analysis for the mature Avington field, recovery factors predicted from analogue fields in the basin (Baxters Copse, Onshore Isle of Wight, Horse Hill Portland) and from outline development concepts and modelling for Markwells Wood. To date no FDPs have been submitted to Oil & Gas Authority ("OGA") for any of these discoveries.

For each discovery a Commercial Risk Factor has been estimated which reflects the technical risk and remaining commercial risk for each asset.

The Onshore Isle of Wight and Holmwood licences both include Prospective Resources. Standard geological techniques have been applied in the estimation of in place volumes and recovery factors used, based on analogues fields / reservoirs to estimate the recoverable volumes. The Prospective Resources for the UKOG assets are shown in Table 1.3.

Oil Contingent Resources	W.I.	Gross Volumes			Net to UKOG			Risk Factor [3]	Operator
(MMbbl)		1C[4]	2C	3C	1C	2C	3C	%	
Avington	5%	0.31	0.37	0.41	0.016	0.019	0.021	40%	IGas
Baxters Copse	50%	0.80	2.40	4.80	0.40	1.20	2.40	40%	IGas
Horse Hill - Portland	32%	0.59	1.50	3.63	0.19	0.49	1.18	75%	HHDL
Isle of Wight Onshore	65%	9.9	15.7	24.1	6.44	10.21	15.67	75%	UKOG
Markwells Wood	100%	0.63	1.25	2.71	0.63	1.25	2.71	60%	UKOG (GB)
Total		**12.2**	**21.2**	**35.7**	**7.7**	**13.2**	**22.0**		

Table 1.2: Gross and Net Contingent Resources (in MMbbl)

Oil Prospective Resources	W.I.	Gross Volumes			Net to UKOG			Risk Factor[5]	Operator
(MMbbl)		Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate		
Onshore Isle of Wight	65%	4.0	10.5	21.6	2.6	6.8	14.0	50%	UKOG
Holmwood	40%	1.2	2.3	4.3	0.5	0.9	1.7	17%	Europa O&G
Total		**5.2**	**12.8**	**25.9**	**1.9**	**7.1**	**18.0**		

Table 1.3 Gross and Net Prospective Resources (in MMbbl).

Economics

An economic analysis was carried out on the Reserves of the Horndean field. The results are provided in Table 1.4. The Reserves have a small positive Net Present Value ("NPV").

[3] "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted.
[4] 1C, 2C and 3C denote the low, best and high estimate scenario of Contingent Resources respectively as defined under the PRMS.
[5] "Risk Factor" for Prospective Resources means the estimated chance, or probability, of geological success.

Post Tax NPV (10%)	Gross NPV			Net to UKOG		
(£MM)	1P[2]	2P	3P	1P	2P	3P
Horndean	1.92	4.00	6.01	0.19	0.40	0.60
Total	**1.92**	**4.00**	**6.01**	**0.19**	**0.40**	**0.60**

Table 1.4: Net Present Value of Reserves (in £MM)

Conclusions

Xodus has reviewed the available information on the assets and concludes that the Operators have generally performed a reasonable and robust interpretation of the available data. The estimates of recoverable volume ranges presented in this report reflect the status of current understanding of the fields.

Xodus believes that the figures in this report accurately reflect the potential on the assets, given current knowledge.

Professional Qualifications

Xodus 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 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.

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 22 years of international experience in both International Oil Companies, large Service Companies and Consultancy organisations. Over 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).

Yours faithfully,

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

2 INTRODUCTION

This report was prepared by Xodus Group Ltd ("Xodus") in March 2018 at the request of the Directors of UK Oil & Gas Investments PLC ("UKOG") and their Nominated Advisors. The report covers all the licences in the UKOG portfolio. The UKOG assets include operating and non-operating interests in currently producing fields, undeveloped discoveries and licences with exploration prospects. The licences in which UKOG holds interests are shown in Figure 2.1 and listed in Table 2.1.

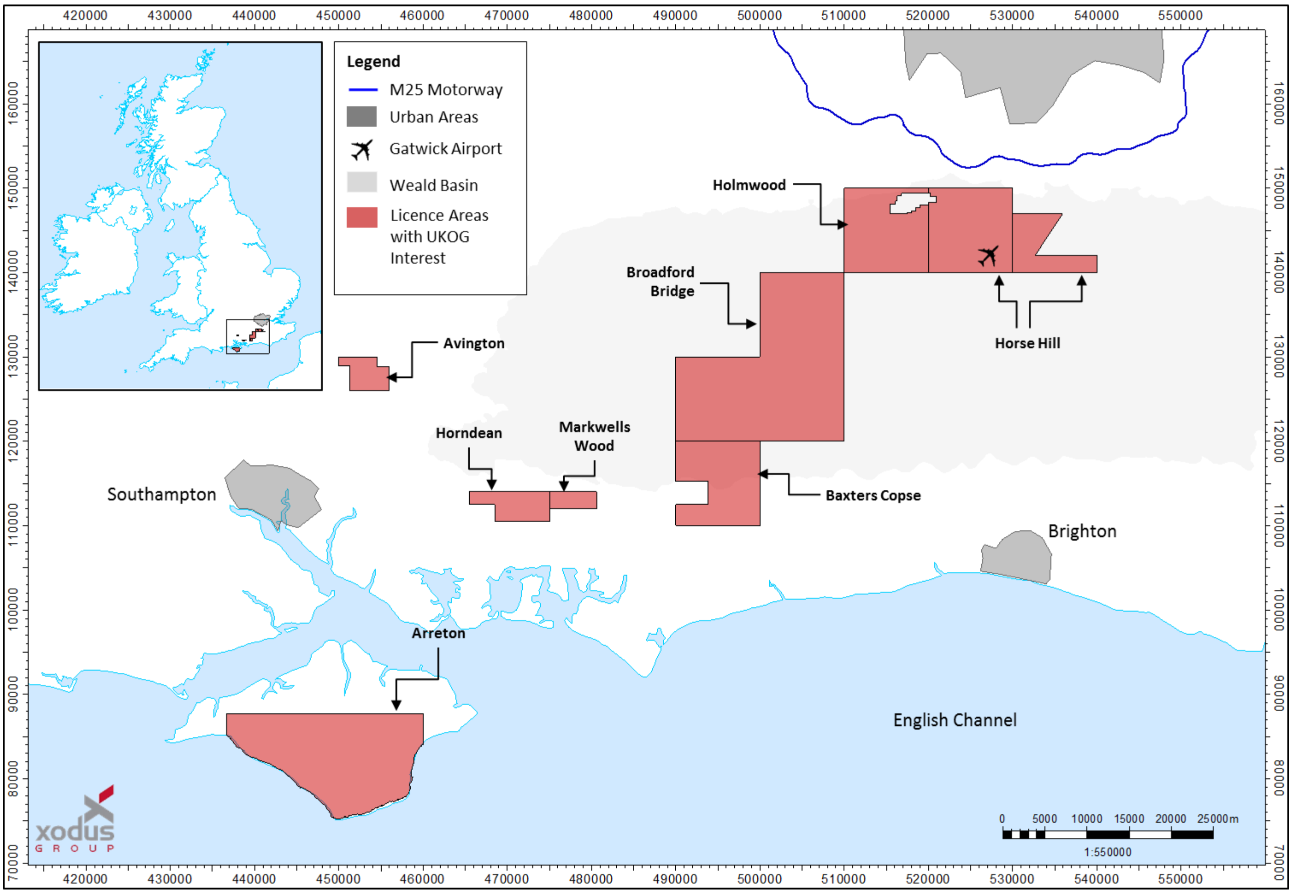


Figure 2.1 Map of UKOG licence interests in the south east England.

2.1 Licence Details

The following table (Table 2.1) summarises the UKOG licence interests.

Asset, Country	Operator	UKOG Interest	Status	Licence Expiry	Licence Area (km^2)	Comment
Avington (PEDL70), UK	IGas Energy Plc	5%	Production	07/09/2031	18.3	Field temporarily shut in
Baxters Copse (PEDL233), UK	IGas Energy Plc	50%	Appraisal / Development	30/06/2039	89.6	Well planned
Broadford Bridge (PEDL234), UK	Kimmeridge Oil & Gas Ltd[6]	100%	Exploration	30/06/2039	300.0	BB-1 & 1z operations completed
Holmwood (PEDL143), UK	Europa Oil & Gas (Holdings) Ltd	40%	Exploration	30/09/2035	91.8	Well planned for 2018
Horndean (PL211)	IGas Energy Plc	10%	Production	04/04/2026	27.3	Field in stable production
Horse Hill (PEDL137), UK	HHDL[7]	32.435%	Exploration	30/09/2035	99.29	Planning permission and EA permit granted for tests and 2 wells
Horse Hill (PEDL246), UK	HHDL[7]	32.435%	Exploration	30/06/2039	43.58	As above
Isle of Wight Onshore (P331), UK	UKOG	65%	Exploration / Appraisal	20/07/2046	200.0	Preparing Arreton-3 planning submission
Markwells Wood (PEDL126), UK	UKOG (GB) Ltd	100%	Appraisal / Development	30/06/2034	11.2	Submitted planning application for appraisal and field development

Table 2.1: UKOG Licence Details

It should be noted that UK oil & gas licences can be extended with OGA's approval.

The Avington (PEDL070) and Horndean (PL211) licences are in the final Production Term. At the end of production there is a standard obligation to plug and abandon the wells and restore the sites.

The Baxters Copse (PEDL233), Holmwood (PEDL143) and Isle of Wight Onshore (PEDL331) licences are all in the Initial Term. The Baxters Copse Initial Term expires on 30th June 2018, there is a licence

[6] UKOG has a 100% interest in Kimmeridge Oil & Gas
[7] UKOG has a direct 49.9% interest in HHDL, which has a 65% interest in PEDL137 and PEDL246

commitment to drill a single well on the licence. The Baxters Copse Joint Venture ("JV") is looking at both extending the licence and avoiding the drilling commitment as the licence is entirely located within the South Downs National Park. The Holmwood Initial Term expires on 30th September 2020 and the Isle of Wight Onshore Initial Term expires on 20th July 2021. The Isle of Wight (PEDL331) licence obligations are the drilling of a single well and the acquisition of 50km of 2D seismic.

The Broadford Bridge (PEDL234), Horse Hill (PEDL137 and PEDL246) and Markwells Wood (PEDL126) licences have all been converted to Retention Areas, over the entirety of the licences. The Broadford Bridge Retention Area expires on 31st December 2023. The Horse Hill Retention Area for PEDL137 expires on 30th September 2021, and the Retention Area for PEDL246 expires on 30th June 2021. The Markwells Wood Retention Area expires on 30th June 2021.

2.2 Director Interests

UKOG have informed Xodus that no UKOG director, Competent Persons or promoter has any direct or indirect interest in any of the company's assets.

2.3 Sources of Information

The content of this report and our estimates of hydrocarbon volumes are based on data provided to us by UKOG. We have accepted, without independent verification, the accuracy and completeness of this data.

The data available for review varied depending on the asset and is noted in the body of the report.

No site visits have been conducted as part of this evaluation.

2.4 Requirements

In accordance with your instructions to us 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 HHDL "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").

2.5 Standards Applied

In compiling this report, we have used the definitions and guidelines set out in the 2007 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).

2.6 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.

2.7 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 UKOG for the correction of erroneous statements or calculations. The use of this material and report is at the user's own discretion and risk.

2.8 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 UKOG on a fee basis. Except with the express written permission from Xodus 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.

3 REGIONAL GEOLOGY

The majority of UKOG licences are all situated in the Weald Basin in South Eastern England, the Arreton discovery, on the Isle of Wight is located in the Wessex Basin. The Weald Basin is situated south of London and extends from Southampton and Winchester in the west to Maidstone and Hastings in the east across the counties of East and West Sussex, Kent and Hampshire. The Wessex Basin includes the counties of Hampshire and Dorset, along with parts of Devon, Somerset and Wiltshire.

3.1 Background

The Weald and Wessex Basins are two of three sedimentary basins within a system of post-Variscan depocentres and intra-basinal highs that developed across central southern England and adjacent offshore areas between the Triassic and Tertiary periods.

The Wessex basin is east of the Weald Basin and to the south west lies the Paris Basin (Figure 3.1). The Weald Basin is bounded to the north by the London-Brabant Massif and is separated from the Wessex-Channel and Paris Basins by a regional arch called the Hampshire-Dieppe High.

Figure 3.1: Geologic map of southeast England and the English Channel region

3.2 Structure & Stratigraphy

The structural history of the Weald and Wessex Basins can be divided into three main phases:

1. A pre-Mesozoic period associated with the culminating in a platform of Palaeozoic rocks;

2. A Mesozoic period of subsidence and sedimentation;

3. A period of Tertiary uplift and Alpine related basin inversion.

3.2.1 Weald Basin

The Weald Basin itself was formed in phase two by rapid subsidence associated with thermal relaxation following early Mesozoic extensional block faulting.

The basin appears initially to have taken the form of an easterly extension of the Wessex Basin but became the major depocentre during the Upper Jurassic and Lower Cretaceous, with associated active faulting.

These movements appear to have ceased prior to Albian times and a full Upper Cretaceous cover is believed to have been deposited in a gentle downwarp which extended far beyond the confines of the Weald and Wessex Basins.

Major inversion of the Weald Basin took place in the Tertiary, with both gentle regional uplift, which in the eastern part of the basin is estimated to have exceeded 5,000 feet (1525 metres) and may have been significantly larger, and intense local uplift along pre-existing zones of weakness, which led to the formation of compressional features such as tight folds and reverse faults. Zones of Tertiary deformation appear to have been strongly influenced by underlying, particularly Hercynian, structural trends.

3.2.2 Wessex Basin

From the Permian to Cretaceous a period of north to south extension resulted in basin formation through rifting and the generation of half grabens. Through the Triassic continental sedimentation in desert environments dominated with fluvial and aeolian facies being deposited. The Jurassic saw a rise in relative sea level and the deposition of marine facies including shales, sandstones and limestones. Sea levels fell towards the end of the Jurassic and into the Cretaceous returning continental deposition to the Wessex basin. Uplift and erosion was also taking place during this time, particularly along major faults to the north of the Purbeck-Isle of White disturbance where much of the Jurassic was removed.

The Late Cretaceous saw the end of extension and a period of thermal subsidence resulting in the widespread deposition of chalk across the basin and the south east of England.

During the Tertiary the extensional movement prevalent in the formation of the basin was reversed as a result of the alpine orogeny. North to south compression resulted in both gentle uplift across much of the basin and more significant basin inversion along pre-existing fault lines, particularly around the Purbeck-Isle of White disturbance. This period has given rise to much of the structuration of the basin and formation of traps for hydrocarbon reservoirs.

3.3 Petroleum Systems

3.3.1 Weald Basin

The Weald Basin is a proven petroleum system (see Figure 3.2) with several commercial producing fields and discoveries, mostly on the flanks of the basin. Since the early 1980s, oil field production has been from Goodworth, Horndean, Humbly Grove, Palmers Wood, Singleton, Stockbridge and Storrington, and gas production from the Albury field.

Jurassic source rocks reached maturity in the early Cretaceous and initial migration occurred at this time, often over long distances, into traps closed by pre-Aptian faults. Tertiary tilting and uplift led to the breaching of many of these pre-existing traps and the formation of large folded closures. A second phase of hydrocarbon migration, particularly of gas, took place at this time, with significant vertical migration along fault zones.

Major reservoirs located to date occur in Middle Jurassic carbonates and Upper Jurassic sandstones, but deep burial in the basin has caused considerable destruction of primary reservoir characteristics; changes in the temperature and pressure regimes and the mobilization of fluids within the basin resulting from the Tertiary uplift caused further diagenetic changes, particularly in the carbonate reservoirs.

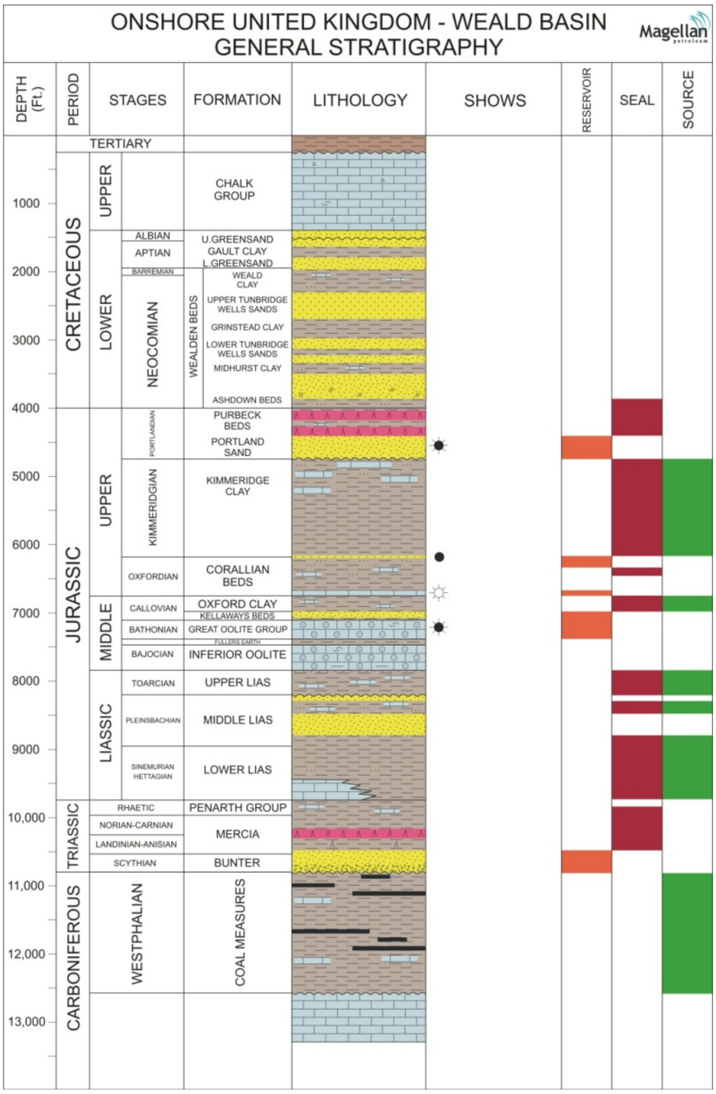


Figure 3.2: Primary Weald Proven Oil Play Details

3.3.2 Wessex Basin

The Wessex Basin is a proven hydrocarbon system with many producing fields, including the giant Wytch Farm oil field.

The primary petroleum system is centred on both vertical and lateral drainage of thermally mature Lower Liassic hot shales from a source kitchen of the Purbeck-South Wight depocentre, which is located primarily offshore to the south of Wytch Farm. Minor to moderate source and charge potential may also be derived from the organic rich Oxford Clay where mature. The Kimmeridge Clay, the primary source for the oil fields of the North Sea is currently considered thermally immature in the Wessex Basin, so hydrocarbon charge from these highly organic rich shales is likely absent or minor over the area. The primary reservoirs are viewed to be those containing significant volumes of hydrocarbons in the basin, namely the Sherwood sandstone and Bridport sandstone.

The uppermost Kimmeridge Clay, Purbeck Anhydrite and Wealden Clays form the regional top seal to the petroleum system. Reservoir seal pairs are present throughout the Jurassic interval by the interbedding of reservoir units with thick shale and hot shale sequences of the Liassic, Oxford Clay and Kimmeridge Clay. The Triassic Sherwood is sealed by a thick sequence of Mercia Mudstone containing shales and evaporites.

Hydrocarbon charge from Liassic hot shales in the Purbeck-South Wight depocentre likely occurred in two distinct phases. The most significant occurred during thermal subsidence during the Cretaceous and early Tertiary encompassing peak oil through to early wet gas and condensate generation and expulsion. Traps available to receive charge consist mostly of Cimmerian age extensional tilted fault blocks and horsts. The second charge phase occurred at the onset of basin inversion during Mid Oligocene and carried on to near recent times.

The second phase of charge was predominantly gas and condensate and is interpreted to be trapped mostly in structures created or modified by later inversion during the Tertiary.

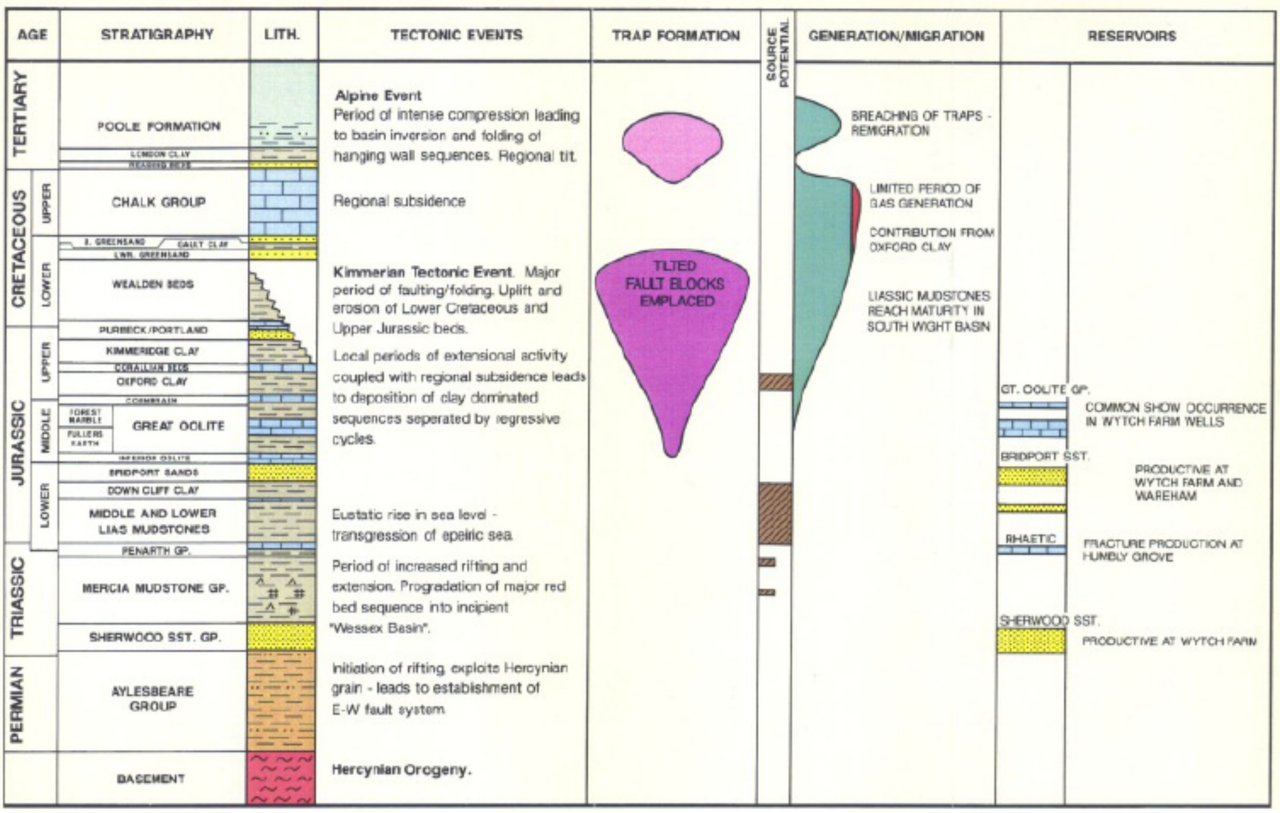


Figure 3.3: Stratigraphy and Petroleum Systems of the Wessex Basin

4 HORNDEAN

The Horndean field, in PL211, is located on an east-west trending tilted fault block on the south-western flank of the Weald Basin, it is on trend with and bounded by the same east-west fault as the adjacent Markwells Wood oil discovery. Horndean is operated by IGas Energy Plc, UKOG have a 10% interest in the licence.

The field has been on production since November 1987 and a total of seven wells, including horizontal sidetracks, have been drilled into the Great Oolite reservoir. The porosity of the reservoir is between 12 and 19% with an average permeability of around 5mD and initial water saturations of around 50%.

Production peaked at 670 bopd in June 1993 after the drilling of well HNC-02 (as a horizontal sidetrack from the HNC-01 well). At present the field produces approximately 140 bopd from four production wells, the rate has been steady for approximately the last five years showing little decline (Figure 4.1).

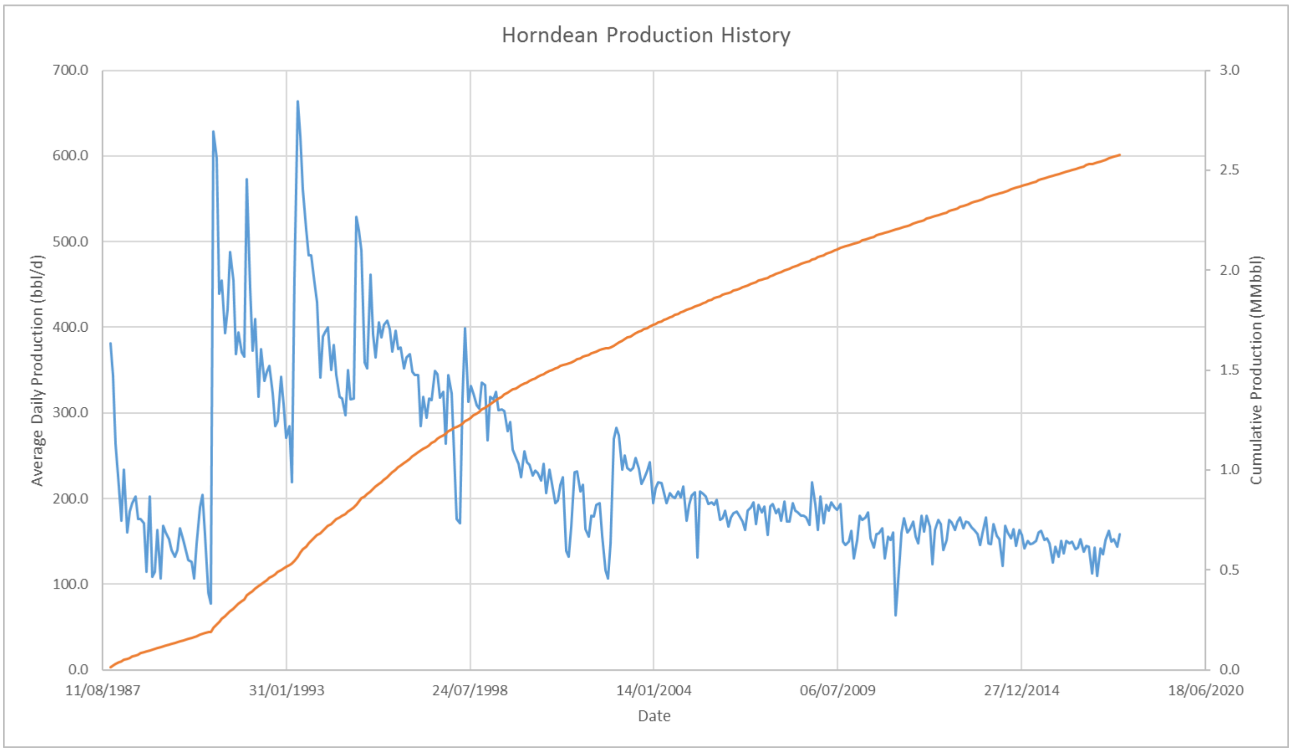


Figure 4.1 Horndean field production

4.1 Estimate of Reserves

Xodus has estimated the Reserves of the Horndean field by decline curve analysis of the recent production from four producing wells. This is the same approach as used in previous CPRs [1]. Decline curves were calculated for each well independently and the forecast production from each summed to give a field wide forecast. 1P, 2P and 3P forecasts have been generated, Figure 4.2 shows the predicted production profiles for the Horndean field. The gross and net Reserves volumes are given in Table 4.1.

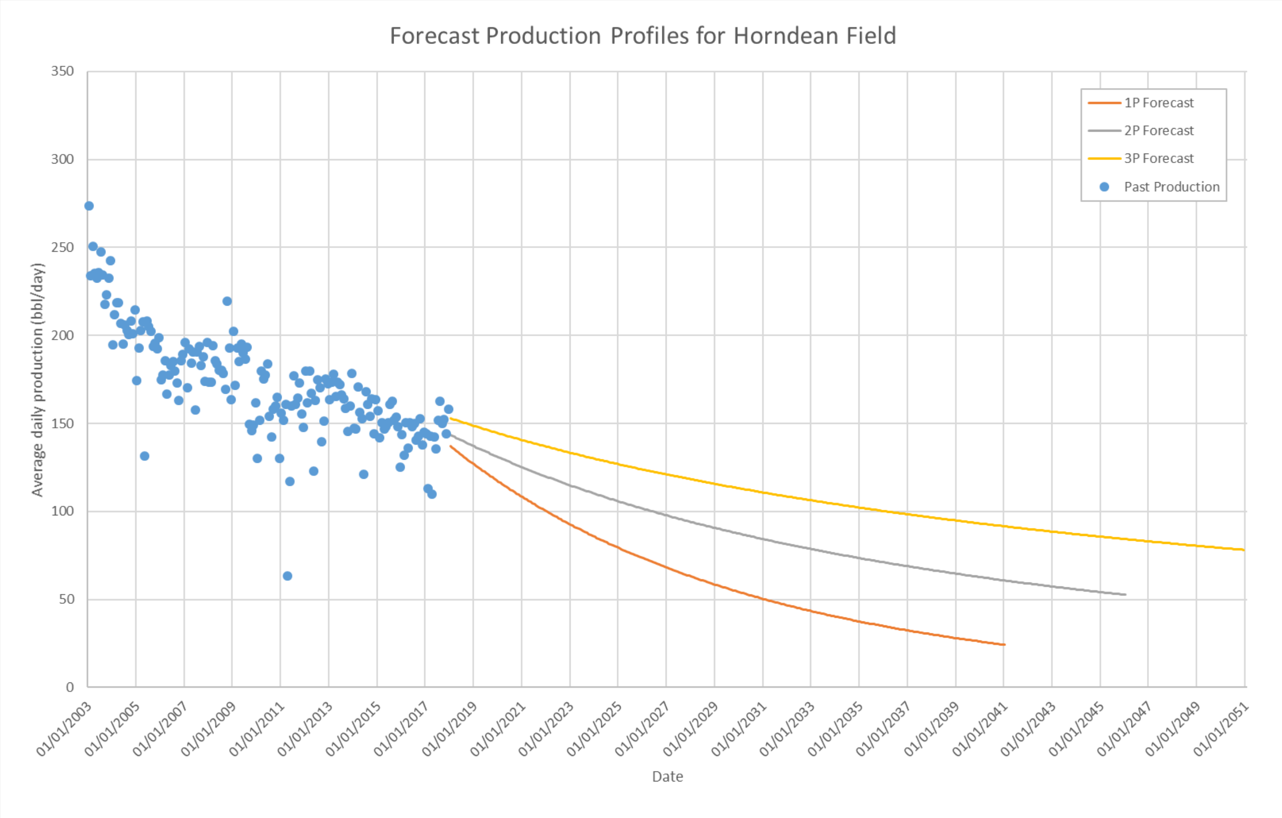


Figure 4.2 Production forecasts for the Horndean field

Oil Reserves	W.I.	Gross Volumes			Net to UKOG		
(MMbbl)		1P[8]	2P	3P	1P	2P	3P
Horndean	10%	0.39	0.85	1.29	0.039	0.085	0.129

Table 4.1 Reserves estimates for Horndean

[8] 1P, 2P and 3P denote the Proved, Proved + Probable and Proved + Probable + Possible Reserves respectively as defined under the PRMS.

4.2 Economics

Based on the IGas Horndean 2017 OCM, the following Capex and Opex figures have been used for economic analysis of the Horndean field:

Capital Expenditure		Gross			Net to UKOG	
(£MM)	**1P[8]**	**2P**	**3P**	**1P**	**2P**	**3P**
2018	0.3	0.3	0.3	0.03	0.03	0.03
2019+	0.0	0.0	0.0	0.00	0.00	0.00

Table 4.2 Horndean capital expenditure

The £300k in 2018 is for boreholes and soakaway works. Trial of a potential performance improvement tool (Enercat) is discussed in the OCMs, however, given the lack definition at present, any associated costs or production improvements are not included (Table 4.2). The information provided lists no planned capital expenditure in 2019.

In addition to the fixed Opex shown in the table below (Table 4.3), a variable Opex of £4.0 / bbl is added to obtain the total Opex. Based on the OCM data provided and the Opex activities listed, Xodus have allocated some of the Opex as fixed and the remainder variable. Costs are inflated at 2% p.a.

Operating Expenditure (Fixed)		Gross			Net to UKOG	
(£MM / yr)	**1P[8]**	**2P**	**3P**	**1P**	**2P**	**3P**
2018	0.75	0.75	0.75	0.08	0.08	0.08
2019+	0.66	0.66	0.66	0.07	0.07	0.07

Table 4.3 Horndean operating expenditure

To calculate the economic limit, the following oil price futures curve has been used up to 2021 (see Table 4.4). The oil price is then inflated at 2% p.a. for 2021 onwards. 4% is deducted from the Brent oil price profile to obtain an estimate of the Horndean price received at the point of sale.

Brent Oil Price (USD / bbl)	
2018	67
2019	63
2020	60
2021	58

Table 4.4 Brent oil price assumptions to 2021, from 2021 onward oil price is inflated at 2% p.a.

The economic limit test (ELT) is then calculated to curtail the technical profiles at the point beyond which cashflow is negative, thereby achieving the reserves volumes. At this point an Abex cost is added in to the cost profiles. Xodus estimate total abandonment costs of approx. £1.5 million for wells and facilities. The ELTs are as follows:

Economic Limit Test	1P[8]	2P	3P*
Horndean	H2 2029	H2 2043	H2 2050

Table 4.5 Economic limits tests

*For the 3P case, the ELT is not reached. A 2050 cut-off has been used as per IGas profiles

NPV(10%) discounted cashflow is calculated. Current (2018) UK onshore fiscal terms are applied to obtain post-tax cashflow figures.

Post Tax NPV (10%)	Gross NPV			Net to UKOG		
(£MM)	1P[8]	2P	3P	1P	2P	3P
Horndean	1.92	4.00	6.01	0.19	0.40	0.60

Table 4.6 Horndean post tax NPV

To investigate the impact of negative economic conditions on the Horndean NPV, cost and oil prices were adjusted. Oil prices until 2021 (Table 4.4) were reduced by 20% and all costs (Table 4.2 and Table 4.3) were increased by 10%, production forecasts were unchanged. The gross post tax NPV (10%) for the 2P volumes, under the adjusted scenario, is £1.1 million and net to UKOG is £110k. The economic limit being reached in H2 2032.

4.3 Conclusions

Horndean production rates are steady at approximately 140 bbl / day. Although producing at modest rates, the decline in production is very low and this is reflected in the length of the production profiles forecast. Post tax NPV(10%) for the 2P case, using the costs data provided, is estimated as £4 million gross and £400k net to UKOG.

5 AVINGTON

The Avington field (PEDL70) is located in the western part of the Weald Basin, it is operated by IGas Energy Plc ("IGas"), UKOG hold a 5% interest in the field.

The Avington field was discovered in 1960 by the Winchester-1 well which encountered oil shows in the Cornbrash and Great Oolite reservoirs. Avington-1 was drilled in 1987, into a separate fault block of the same structure and encountered a 30m oil column. The reservoir porosity is between 14 and 23% and permeability is up to 0.1mD, water saturation is 46 to 57%

The Avington-2 well was drilled in 2003 and a horizontal side track, Avington-2z, was drilled from this pilot hole. Avington-2z initially flowed 38º API oil at rates of up to 700 bopd with no water production. However, on extended well test (EWT) the dry oil zone was lost. The oil rate fell to 25 bopd and very high water production was encountered which remained around 80 to 90% even after stimulation attempts. Avington-3 was drilled in 2006 and encountered high water saturations. A sidetrack from this well, AV-3z was drilled in 2007 and produced 600 bopd on EWT.

Avington has been on production since August 2007. Initial production rates were over 500 bopd, as seen in the EWT wells however, it soon declined with a corresponding increase in water production. The field was initially shut in for a long period (Figure 5.1) but then produced continuously from 2009 with oil rates below 100 bopd and high water cut (>90%) (Figure 5.2).

UKOG have reported to Xodus that the field is now shut in temporarily as the low oil production rate and costs associated with the high water cut have resulted in the field being uneconomic to produce at the present OPEX cost and oil price.

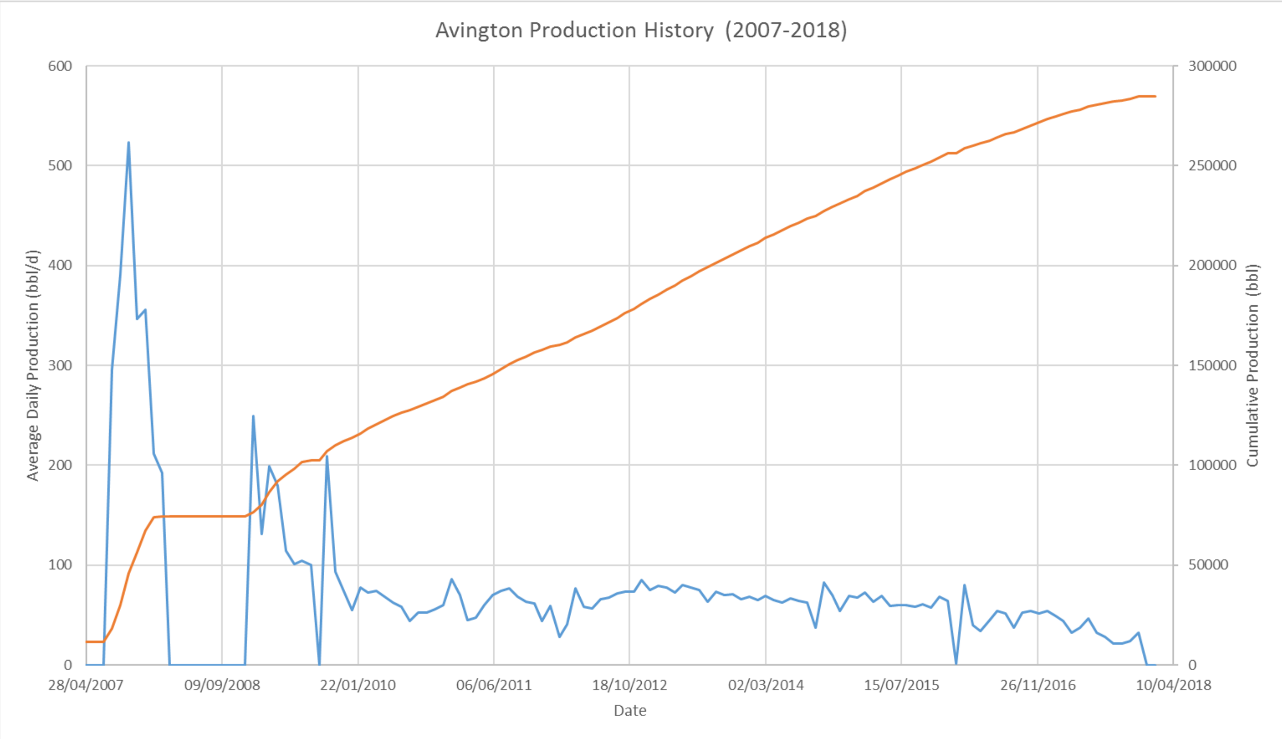


Figure 5.1 Avington Field production history since 2007

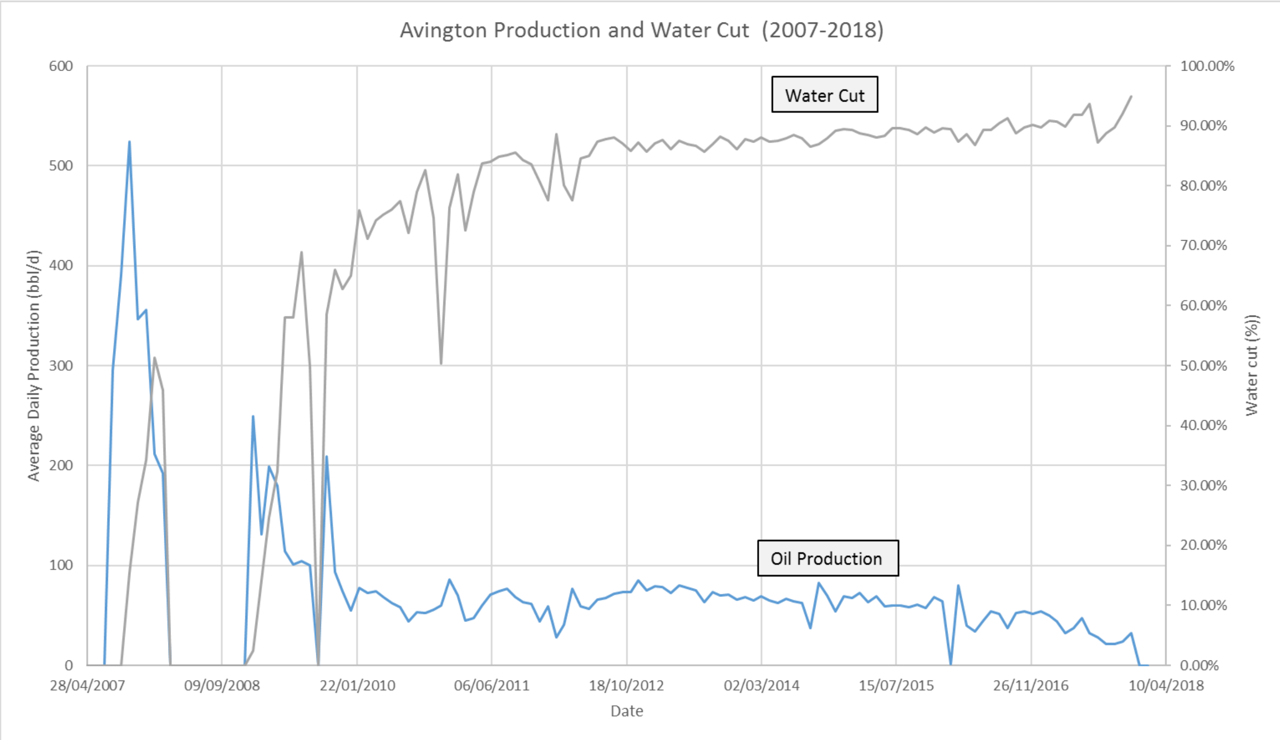


Figure 5.2 Avington field average daily production and water cut since 2007

5.1 Previous Estimates of Recoverable Volumes

IGas' most recent CPR, including Avington, was completed in 2016 by DeGolyer & MacNaughton [1]. DeGolyer & MacNaughton used well performance to predict Proven Reserves, with the Probable and Possible accounted for by modelling better than expected well performance. The Reserves estimates are approximately half the value of the reserves estimation carried out by Senergy [2] for the 2014 CPR on the same assets.

Contingent Resource volumes were also reported by DeGolyer & MacNaughton although the 2C volume of 0.74 MMbbl is significantly less than the 5.8 MMbbl reported by Senergy in the 2014 CPR. Senergy used a previous RPS analysis which was based the development strategy and in place volumetric estimates. DeGolyer & MacNaughton give no commentary on the reasons for the reduction in contingent volumes.

5.2 Recoverable Resources

Xodus has estimated the recoverable volume of the Avington field by decline curve analysis of the recent production from two producing wells. This is the same approach as used in previous CPRs. Decline curves were calculated for each well independently and the forecast production from each summed to give a field wide forecast, 1C, 2C and 3C profiles have been generated. Figure 5.3 shows the predicted production profiles for the Avington field.

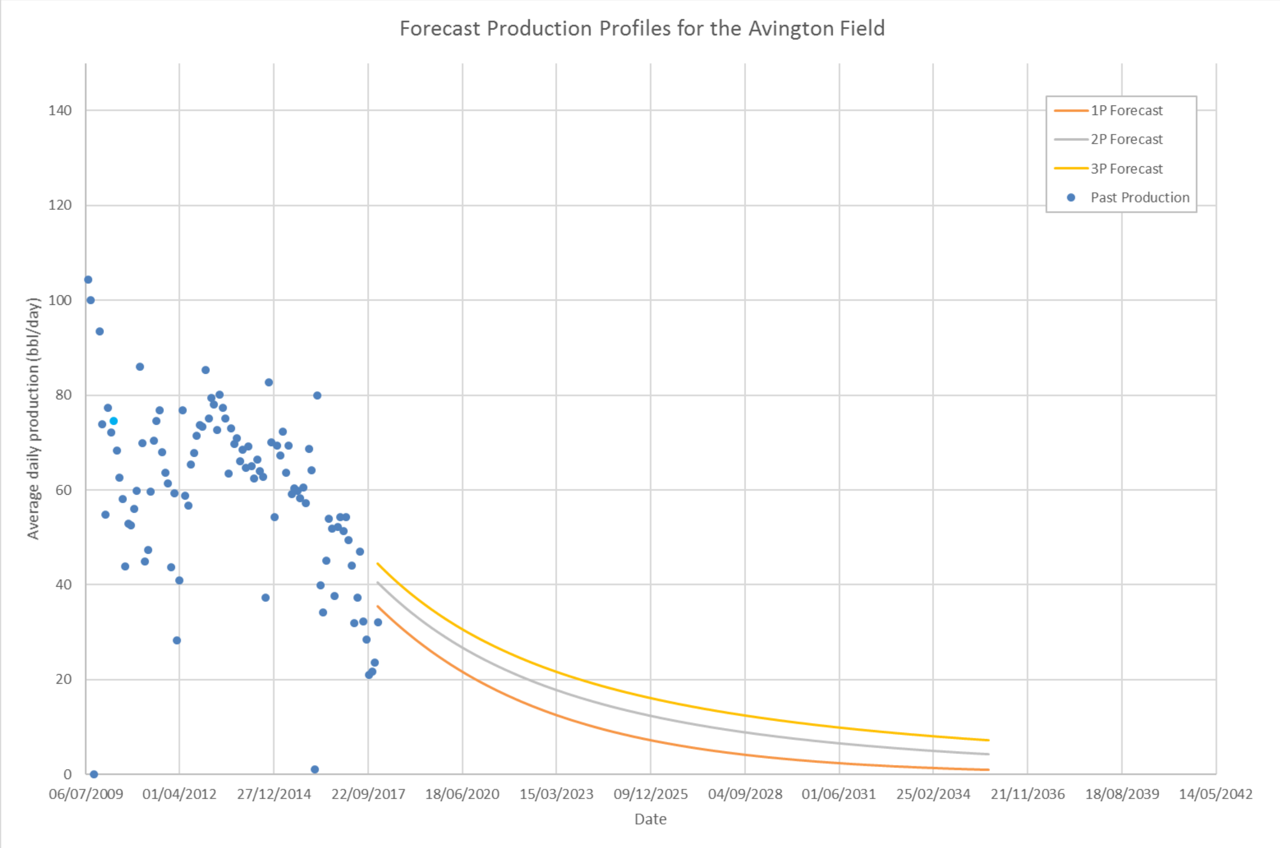


Figure 5.3 Avington forecast production profiles

As the field is temporarily not producing the volumes have been classified as Contingent Resource, the volumes being contingent on achieving economic production. Table 5.1 gives the estimated Contingent Resources for Avington. The reported volumes are larger than the Reserves reported using the same approach in previous CPRs for the operator. This is because a longer production period can be assumed for Contingent Resource as no economic cut off has been considered.

Xodus have estimated the commercial risk factor to be 40%. In November 2017, the operator calculated that the 2017 cost per barrel at Avington was £57, the estimated cost going forward, through 2018, is £80 per barrel. This increase is largely related to reduced production rather than an increase in costs.

Xodus has reviewed the historical cost breakdown for 2017 and estimate for 2018, the principle component of the Avington operating costs are related to the disposal of produced water, water cut is currently 90%. Costs for water disposal at Avington are low compared to other recent cost estimates seen by Xodus, therefore, there would appear to be limited scope for further reductions of the variable costs incurred without reduction in water cut. An increase in oil price to over £90 per barrel would be required to give confidence that economic production could be restarted. Because of these factors Xodus have estimated the commercial risk factor to be 40%.

In previous CPRs Contingent Resource was reported alongside Reserves. These resources were based on a further phase of development, Xodus has seen no information on these plans and given the current status of the field, further development appears unlikely, Xodus has not considered any additional volumes.

Oil Contingent Resources	Contingent Resources Gross			Contingent Resources Net to UKOG			Risk Factor
(MMbbl)	1C	2C	3C	1C	2C	3C	(%)[9]
Avington	0.31	0.37	0.41	0.016	0.019	0.021	40

Table 5.1 Table of Contingent Resources for the Avington field

5.3 Conclusions

The Avington field is currently temporarily shut in due to the low oil production rate and costs associated with the high water cut. Estimates of recoverable volume that were previous classed as Reserves are now Contingent Resource until economic recovery can be sustained. The decline in production is very low and this is reflected in the length of the production profiles forecast; estimates of mid case recoverable volumes are consistent with previous evaluations.

[9] Risk Factor or Commercial Risk Factor for Contingent Resources is the estimated chance, or probability, that the volumes will be commercially extracted.

6 HORSE HILL – PORTLAND SANDSTONE

The Horse Hill discovery is located in licences PEDL137 and PEDL246 and is operated by Horse Hill Developments Ltd ("HHDL"). UKOG hold a 49.9% interest in HHDL, which has a 65% interest in PEDL137 and PEDL246.

The Horse Hill discovery comprises several prospective intervals; however, only the Upper Portland Sandstone is considered as Contingent Resource and is included in this evaluation. Xodus previously evaluated the STOIIP estimates (May 2015) and updated the assessment in January 2017 [3] following flow testing in March 2016, and revised petrophysical interpretation.

The Portland reservoir of the Horse Hill-1 well was tested between 6th and 15th March 2016. The well was acidised to improve production performance and there were several flowing periods and build-ups. The vertical lift performance was improved with a rod pump and with this pump flowed at varying rates over several days. The rates were typically between 150 and 300 bopd (over the ~1.5 days of metered production), although the rate varied as a function of the degree of clean-up from the well. The associated GOR was between 120 and 200 scf / barrel. PVT samples were taken at the separator for recombination and gave a crude API of ~36 degrees and a GOR of 170 scf/stb (although this is an input of the recombined fluid rather than an output).

For this CPR, UKOG have indicated that no changes have been made since the assessment of January 2017. A number of minor changes to parameters in the estimation of STOIIP have been made, recoverable volumes are unchanged

6.1 Structure

The Horse Hill-1 and Collendean Farm-1 wells lie within an overall E-W trending Late Cimmerian age tilted fault block some 6km in length and 3km wide. The Horse Hill Top Portland Sand structure map shows a north-south trending feature formed by a 3-way dip closure in the footwall of a major east-west trending fault system, combined with an extension of this feature in the hanging wall to the north. The hanging wall section appears to show evidence of structural rejuvenation by post-Oligocene Alpine compression. The HH-1 well was drilled close to the crest of the footwall closure, while the older CF-1 well was drilled in the hanging wall. The crestal part of the feature as mapped extends to approximately 4 km east-west by 3 km north-south.

Structural mapping is controlled by 5 or 6 seismic lines of various vintages. The key area of closure is controlled by only 4 lines. Well locations and seismic coverage are shown in Figure 6.1, and a more detailed view of coverage over the crest of the structure, with the key seismic highlighted, in Figure 6.2.

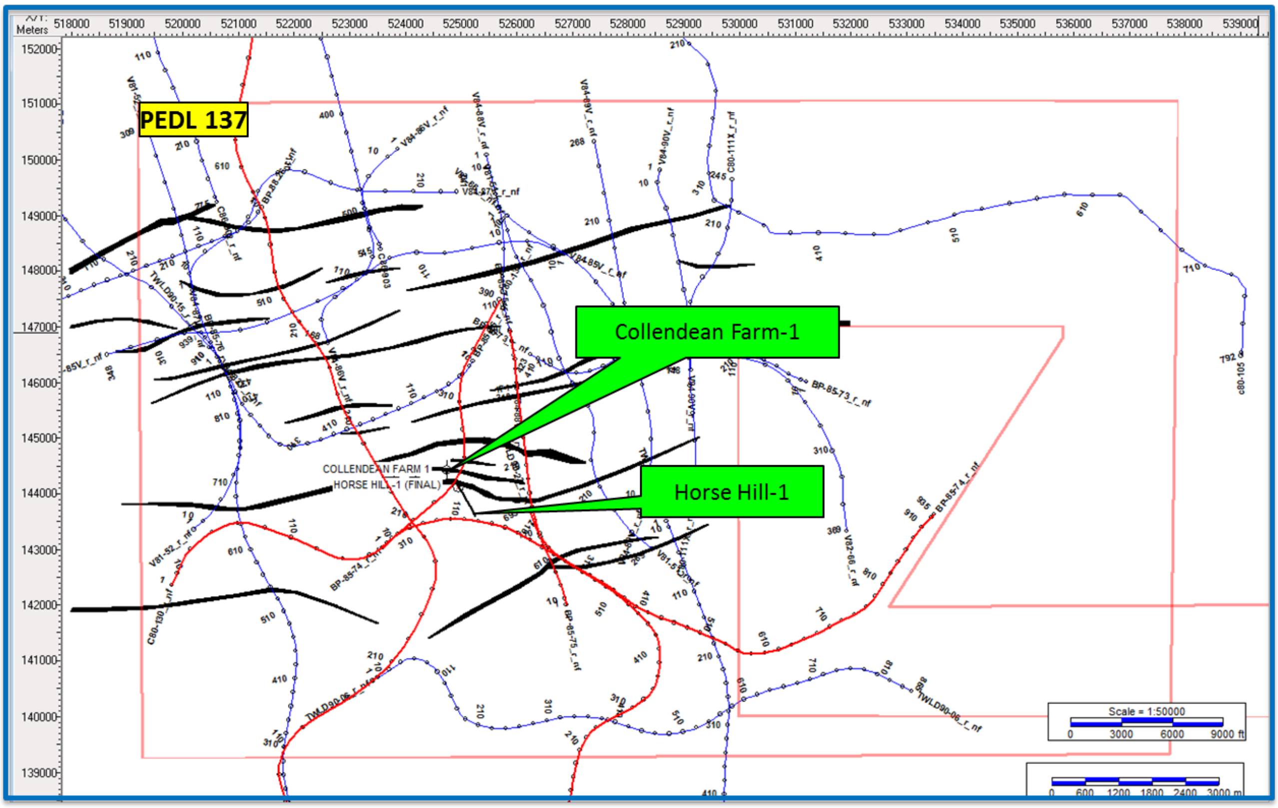


Figure 6.1 Seismic base map, with wells

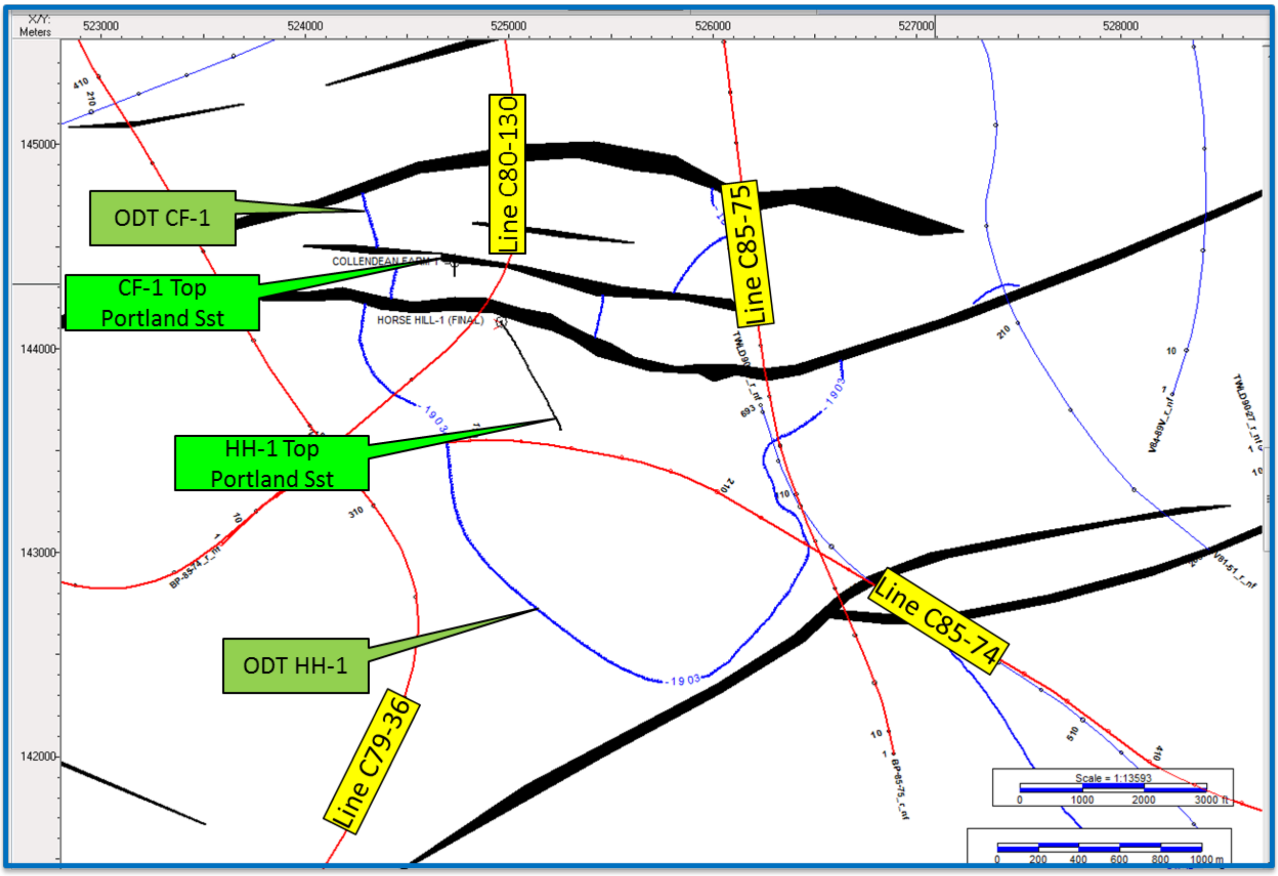


Figure 6.2 Key seismic lines across the Horse Hill discovery

6.1.1 Seismic

The most recent seismic dates from the 1980s, the oldest data were acquired in the 1960s. There is an approximate north-south / east-west grid, but line orientation is very variable, spacing averages around 2-3km. Some lines have been reprocessed since original acquisition, with a substantial improvement in data quality. There is no seismic line in the Kingdom project, which passes directly through either well. Well CF-1 is 250m from the nearest seismic line (C80-130) and well HH-1 lies 85m from the nearest line (C85-74). Despite this, there is sufficient confidence in Vertical Seismic Profile ("VSP") and synthetic character ties to seismic to ensure that the horizon identification is sound. An example of the key seismic lines is shown in Figure 6.3.

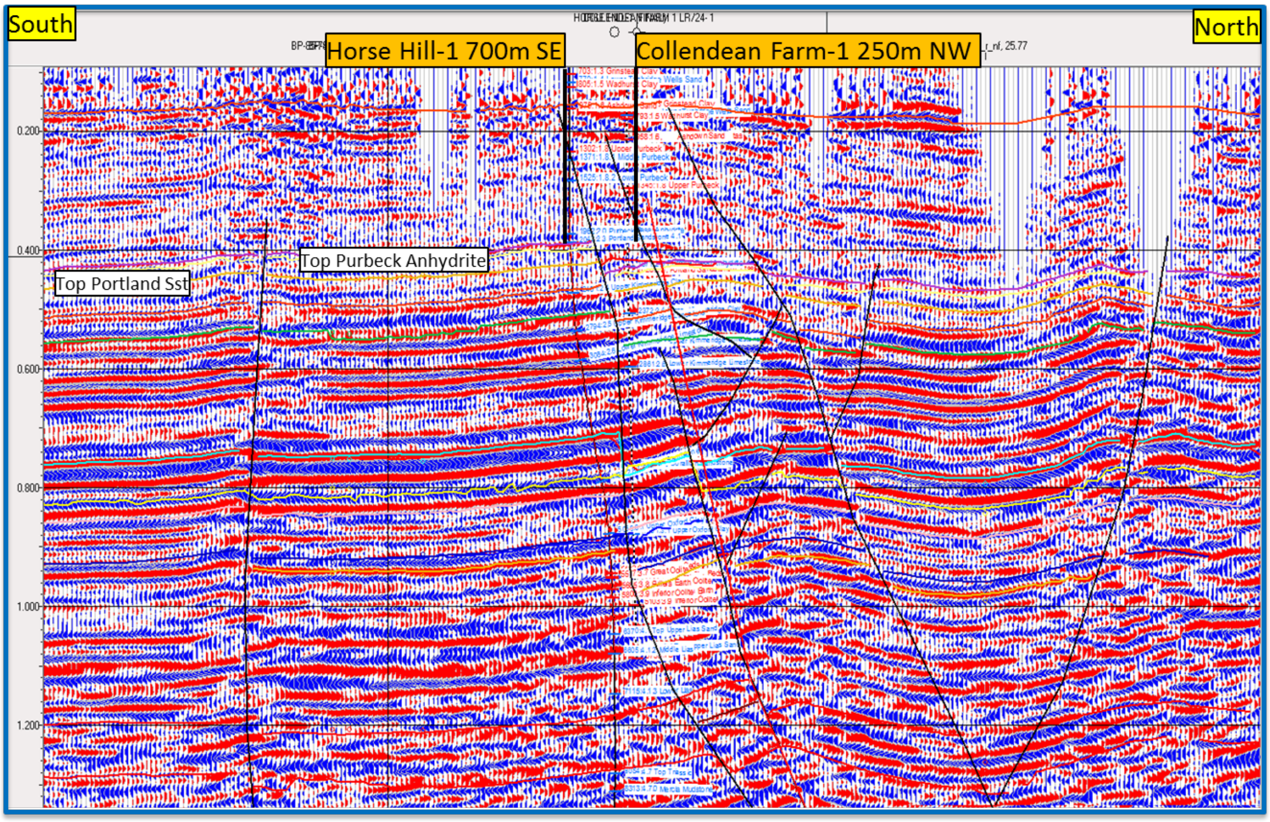


Figure 6.3 Example seismic section - Line C 80-130.

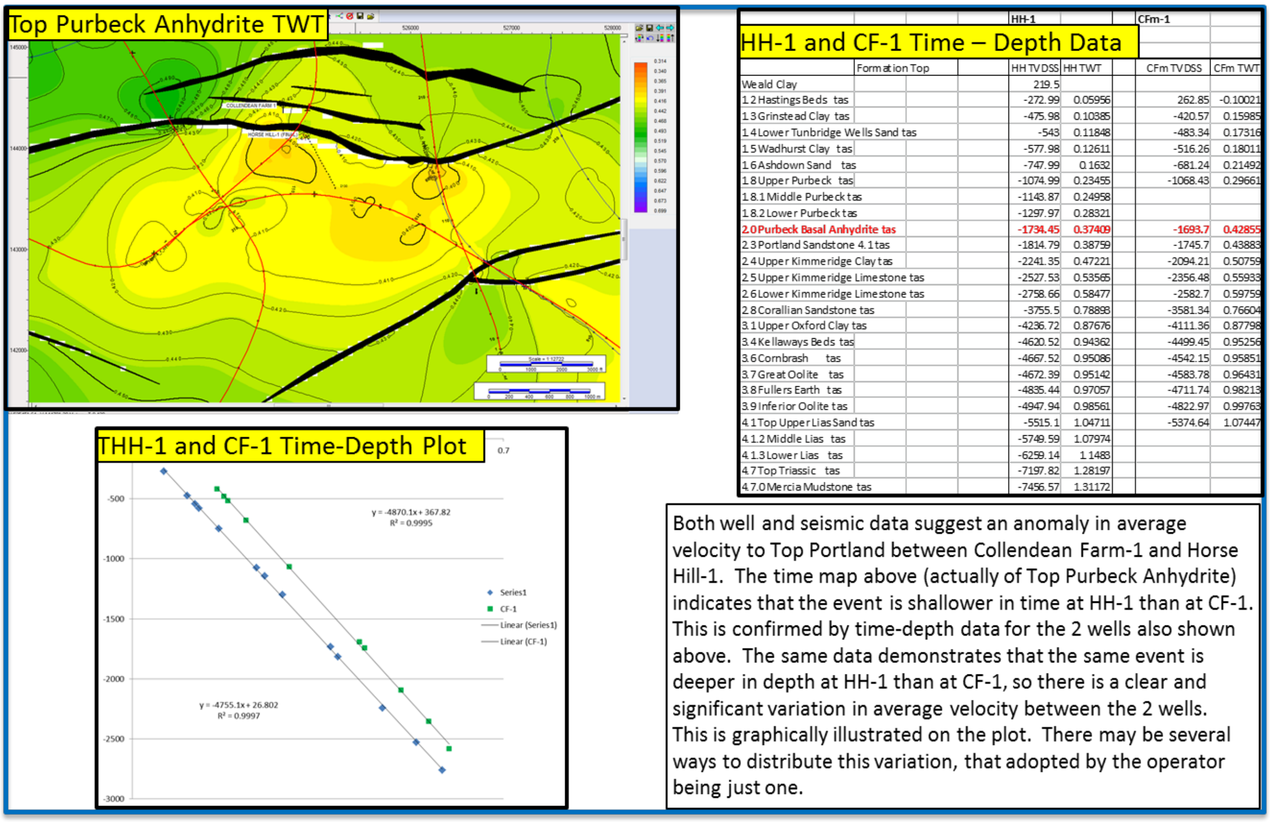
6.1.2 Interpretation and Mapping

VSP data is available from both wells, which allows an accurate correlation of the key well markers to the seismic. Log character in both wells indicates a very close match, suggesting that the Upper and Middle Jurassic sequence is consistent between the two wells. Seismic character is dominated by the very strong, conformable sequence of events lying primarily below the Kimmeridgian. Potential for correlation error exists across the main east west faulting between CF-1 and HH-1, but HHDL have shown detailed correlations to demonstrate that seismic character is very consistent from one side of the fault to the other.

Seismically, the Top Purbeck Anhydrite and the Top Upper Portland Sand form part of the same reflector cycle and are separated by about 10 milliseconds ("msec"). As the Top Anhydrite appears the more continuous event, this has been made the key seismic pick, adjustment to the Top Portland sand depths being made at the end of the depth conversion process. Given the overall conformity of the sequence, and the dataset available, this is quite acceptable.

In general, reflection quality of the Top Purbeck Anhydrite is good, but on some critical lines (e.g. C79-36 and C80-130) continuity of the package sitting above the Kimmeridge is poor, probably due to lower impedance contrasts and reduced fold. This results in lower confidence in the key areas close to the major east-west faulting which divides the structure. Overall conformity of the sequences below helps to support the integrity of the mapping in such areas.

Time mapping and VSP data suggest that there is an average velocity anomaly between the CF-1 well and HH-1. Velocities to the shallow events in CF-1 (including the Portland sandstone) show a significant reduction compared to HH-1. This results in CF-1 Top Portland being deeper in time than HH-1 but shallower in depth. The time map of Top Purbeck Anhydrite and depth map of Top Portland Sands illustrate this. This issue is illustrated in Figure 6.4.



HH-1 and CF-1 Time – Depth Data

Formation Top	HH-1		CFm-1	
	HH TVDSS	HH TWT	CFm TVDSS	CFm TWT
Weald Clay	219.5			
1.2 Hastings Beds tas	-272.99	0.05956	262.85	-0.10021
1.3 Grinstead Clay tas	-475.98	0.10385	-420.57	0.15985
1.4 Lower Tunbridge Wells Sand tas	-543	0.11848	-483.34	0.17316
1.5 Wadhurst Clay tas	-577.98	0.12611	-516.26	0.18011
1.6 Ashdown Sand tas	-747.99	0.1632	-681.24	0.21492
1.8 Upper Purbeck tas	-1074.99	0.23455	-1068.43	0.29661
1.8.1 Middle Purbeck tas	-1143.87	0.24958		
1.8.2 Lower Purbeck tas	-1297.97	0.28321		
2.0 Purbeck Basal Anhydrite tas	**-1734.45**	**0.37409**	**-1693.7**	**0.42855**
2.3 Portland Sandstone 4.1 tas	-1814.79	0.38759	-1745.7	0.43883
2.4 Upper Kimmeridge Clay tas	-2241.35	0.47221	-2094.21	0.50759
2.5 Upper Kimmeridge Limestone tas	-2527.53	0.53565	-2356.48	0.55933
2.6 Lower Kimmeridge Limestone tas	-2758.66	0.58477	-2582.7	0.59759
2.8 Corallian Sandstone tas	-3755.5	0.78898	-3581.34	0.76604
3.1 Upper Oxford Clay tas	-4236.72	0.87676	-4111.36	0.87798
3.4 Kellaways Beds tas	-4620.52	0.94362	-4499.45	0.95256
3.6 Cornbrash tas	-4667.52	0.95086	-4542.15	0.95851
3.7 Great Oolite tas	-4672.39	0.95142	-4583.78	0.96431
3.8 Fullers Earth tas	-4835.44	0.97057	-4711.74	0.98213
3.9 Inferior Oolite tas	-4947.94	0.98561	-4822.97	0.99763
4.1 Top Upper Lias Sand tas	-5515.1	1.04711	-5374.64	1.07447
4.1.2 Middle Lias tas	-5749.59	1.07974		
4.1.3 Lower Lias tas	-6259.14	1.1483		
4.7 Top Triassic tas	-7197.82	1.28197		
4.7.0 Mercia Mudstone tas	-7456.57	1.31172		

Figure 6.4 Velocity anomaly HH-1 to CF-1

UKOG explains this anomaly by the difference in near surface section in the two wells. At CF-1 the Hastings beds are at the surface, while at HH-1 the younger Wealden clay is at the surface, and the Hastings Beds are at 273ft TVDSS. This provides a difference of approximately 480ft in thickness of the lower velocity Hastings sands and silts between the two wells and can explain the difference in average velocity recorded in the shallow part of the sequence. Xodus agrees with HHDL that this is a plausible explanation, but perhaps further analysis of interval velocities in the two wells would help to confirm this.

6.1.3 Depth Conversion

As discussed above, all picking was based on the Top Purbeck Anhydrite reflector, and subsequent derivation of functions and depth conversion was also based on this reflector.

Depth conversion has been based on the VSPs in each of the wells. Because of the anomaly discussed above, it is difficult to define one velocity function which would fit both wells. In practice, separate velocity functions for each well have been derived. This was done by plotting time-depth for the shallow part of each well (down to 3000m) and deriving a straight-line function from the slope. At this depth the time-depth values closely approximate a straight line. This is illustrated in Figure 6.5, which shows the independently derived results by Xodus, confirming the HHDL results.

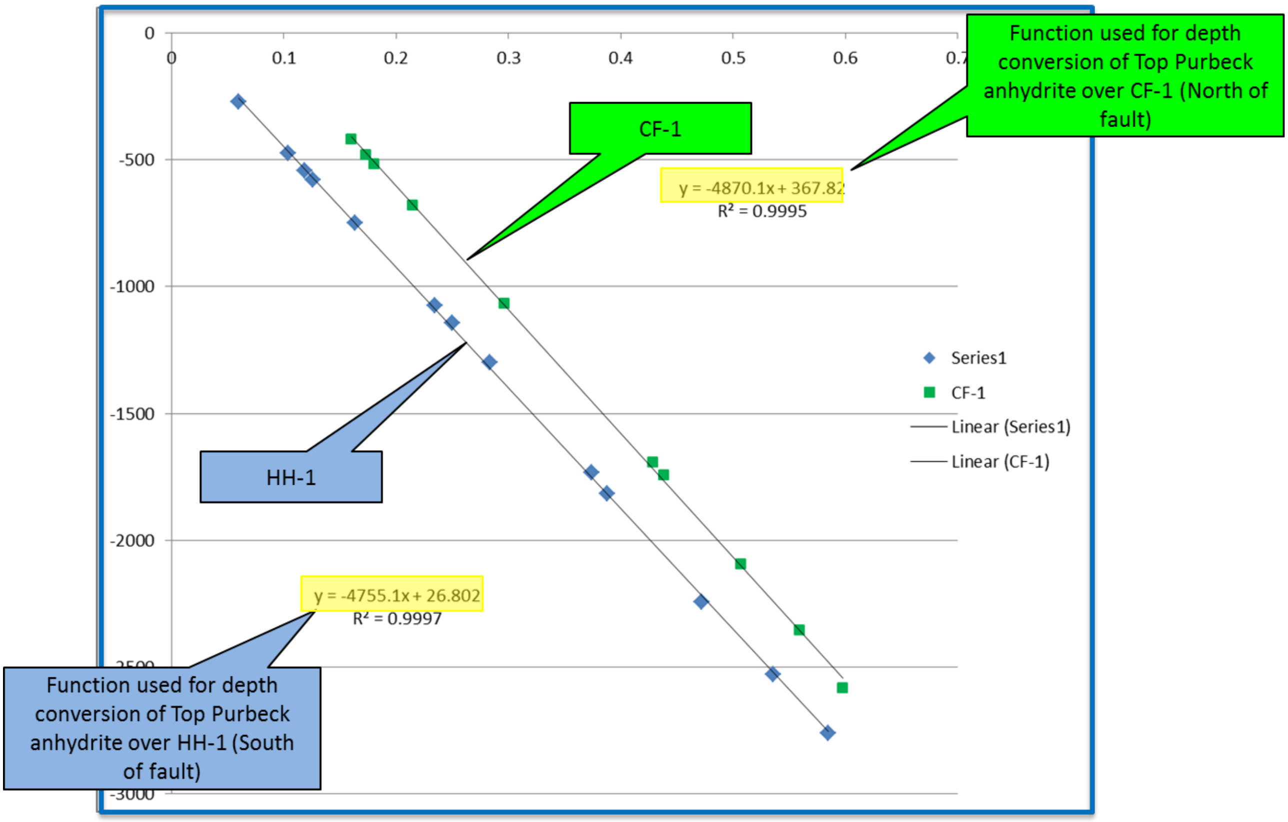


Figure 6.5 HH-1 and CF-1 time depth plot.

These two functions have been used independently to convert the hanging wall part of the structure (CF-1) and the footwall part of the structure (HH-1). The two maps were trimmed in Kingdom and physically joined along the fault. This is a solution, but it does not address the aerial distribution of velocity variation implied by the well data. If the velocity variation is related to gradually varying thickness changes within the upper part of the sequence, then the change should be spread across the area between the two wells. However, with limited well control it is difficult to know how this aspect could be refined and the HHDL interpretation is therefore acceptable.

The final Top Portland Sand map was created by taking the Top Purbeck Anhydrite map and adding an isopach to each part of the feature. An isopach of 52ft (the Top Anhydrite to Top Sand interval in CF-1) was added to the hanging wall part of the structure north of the fault, and an isopach of 80.3ft (the corresponding interval in HH-1) to the footwall part of the structure. Again the method implies that all of the thickness change takes place along the fault, rather than spread over a distance. Equally there is no clear way of improving on this with the data available.

One of the implications of this approach is that the current depth maps do not represent the true throw on the fault. The presented map shows little or no throw at the crest of the structure.

An example of the final depth maps is shown in Figure 6.6, annotated with the Oil Down To ("ODT") levels for the two separate areas. Also shown is a conservative lowest closing contour ("LCC") at 1975ft TVDSS. This is a bit shallower than that proposed by HHDL, but is the deepest level supported by the maps presented. This only applies to the area of closure south of the fault. The apparent lowest closing contour to the north of the fault would be around 1920ft TVDSS. To assume oil to a lower level in the north would imply some additional form of closure – e.g. a fault seal. Such possibility has not been further included in Xodus' volumetric review.

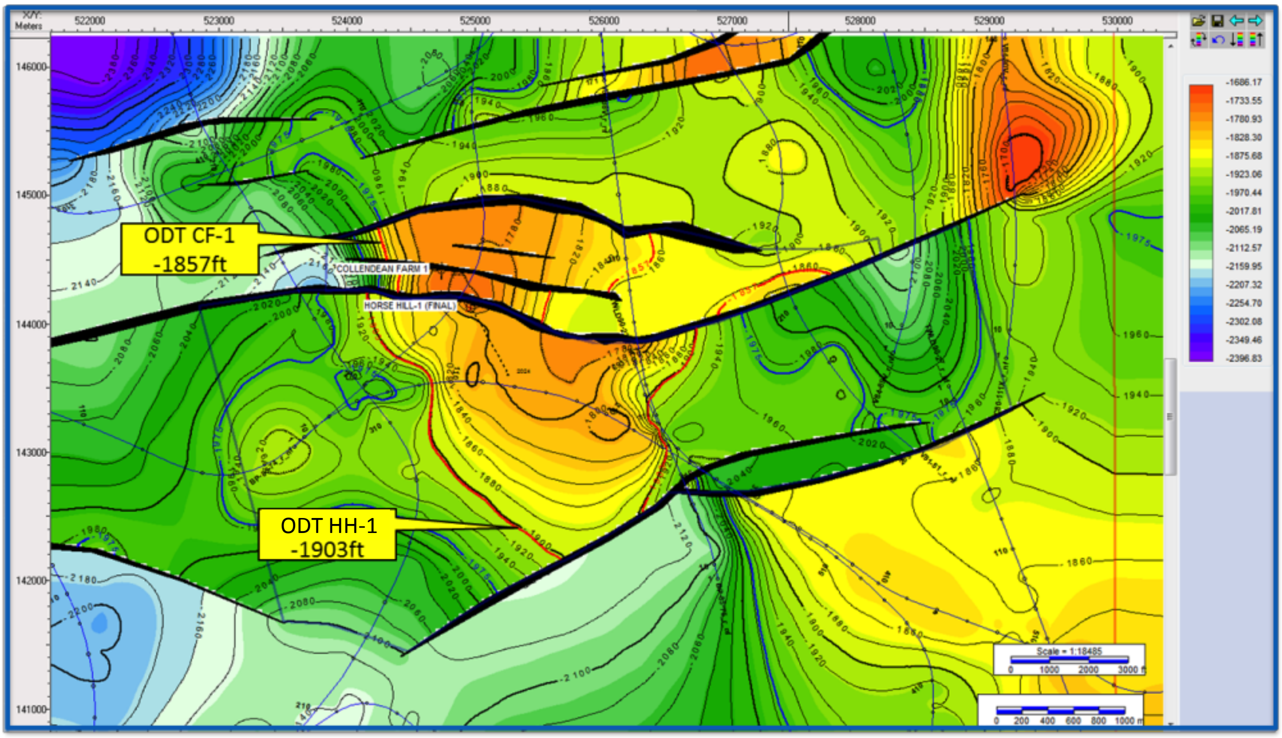


Figure 6.6 Top Portland Sandstone depth map, showing ODTs and LCCs.

Since the CF-1 and HH-1 wells penetrate the same overall tilted fault block feature, show an oil down to base reservoir plus the footwall and hanging wall polygons show a similar maximum mapped spill point, it has been assumed for maximum volumetric purposes that the field is defined by one common spill point. It is possible that the footwall-bounding fault could seal, in which case the areal closure could be greater than the 1920ft TVDSS closure modelled. Xodus have not modelled this scenario. Further refinements to the time to depth conversion are recommended and will permit a more reliable construction of footwall to hanging wall cross fault juxtaposition.

6.2 Reservoir

The Upper Portland Sandstone, as penetrated in the two wells, comprises a number of sand units separated by shale beds, which can be correlated between the two wells (Figure 6.7). The sand units show a coarsening upwards pattern consistent with the interpretation of shallow marine depositional setting. The sands are described in the mudlog as being very fine and well sorted with an argillaceous matrix and traces of glauconite.

The top of the sand is well defined being beneath the Purbeck Anhydrite and is capped by a thin limestone layer. The gross thickness of the sand in the wells is 105ft and 110ft in CF-1 and HH-1 respectively. There are a number of thin sands (less than 4ft) beneath the main sand which are also oil bearing.

Regional data shows the sand thickening to the north into what was probably an active growth fault, the sand correspondingly thins to the south. An isopach map of the Upper Portland, provided by HHDL, shows the discovery to sit in an area of rapidly changing thickness. The thickness of the Upper Portland sandstone in the region of CF-1, as mapped, changes in thickness by 50ft over a distance of approximately 5km. The discovery covers an area of approximately 6 by 4km when considering the spill points of the structure as the limits. The variation and range of thickness observed in the wells may therefore not be truly indicative of the thickness variation in the reservoir across the area. HHDL have applied a narrow thickness range in volumetric estimate, which is justified by the wells but may not capture full range of possible reservoir thickness in this area.

New petrophysical interpretations carried out by Nutech Energy Alliance Corporation ("Nutech") on behalf of UKOG, a 48% shareholder of HHDL, are available for both wells, the new interpretation is based on information gained from the well test carried out on the Portland Sandstone in HH-1 in early 2016. Xodus has undertaken a detailed review of the petrophysical interpretation methodology to confirm the veracity of the new interpretation. The changes to the interpretation and the impact on the volumetric assessment are described below.

6.3 Petrophysical Evaluation

The Nutech interpretation of HH-1 following the results of the test of the Portland resulted in a significant improvement in the net pay. In the previous interpretation the net pay was estimated at approximately 48% of the total reservoir, although it was observed that the entire thickness of the Portland was oil bearing. The 2015 interpretation of net pay was based on the prediction that in zones where water saturation is high, only water would be produced. During the HH-1 well test no water was produced from the Portland suggesting that although the water saturation may be above what is normally considered for an economic pay cut off, that water is immobile and is not produced with the oil. The net pay interval is therefore greater than previously thought.

Xodus has reviewed the Nutech 2016, post well test petrophysical interpretation and found the revisions to be reasonable, except that Nutech did not apply any parameter range cut-offs to determine the net reservoir as it had done in its 2015 analysis. Xodus therefore applied its own cut-off to the porosity (phi) as had been done previously.

Xodus has reviewed the interpretation of well test which Nutech have used as the basis for the interpretation. The well test was conducted over the entire Portland interval of 100ft. In this zone the water saturation is relatively constant between 40 and 60%, depending on rock quality, permeability is predominantly above 0.1mD with an average of about 2mD with some zones (4-10ft) of around 10mD and a high of 20mD.

Xodus agrees given the permeability profile and other available data it is a reasonable assumption that the entire Portland zone has contributed to flow, as in the model suggested by Nutech. However, there is no definitive evidence at this time and other scenarios may explain the lack of water production during the test which cannot be discounted at this time.

As the Nutech porosity interpretation has not changed, using a realistic porosity cut-off to determine net reservoir and net pay results in net to gross estimates that are similar to those reported in 2015. In line with the revision of the bound water model Xodus has not applied a water saturation cut off in determination of net pay. As a result of the porosity cut offs applied Xodus' estimation of net pay is lower than that of Nutech.

Xodus applied a range of cut offs to determine a range of NTG for the probabilistic volumetric estimation. A different range has been applied to reflect the encouraging result of the well test.

The interpretation of porosity has remained unchanged from the previous Nutech interpretation, log porosity varies from 5.9% to 18.7% with an average of 13.3% in the CF-1 well and from 6.7% to 14.2% with an average of 10.2% in the HH-1 well. Net to gross is 58% in Horse Hill-1 assuming a 10% porosity cut off.

Water saturation has improved slightly in the latest interpretation by virtue of a more accurate assessment of Rw, Log data shows that the entire gross thickness of the Upper Portland Sandstone as penetrated in the wells is oil bearing, giving an ODT in both wells. The water saturation was determined for the pay zones giving averages of 56.4% and 46% with an overall range of 39% to 70%. The lowest water saturation corresponds with the highest gas readings on the mud log and is recorded approximately 60ft below the top reservoir in the HH-1 well.

The parameters and results are consistent with previous interpretations and information from other wells in the basin. The interpretations of water saturation and porosity from logs also tie well to the measurements from core available in the CF-1 well.

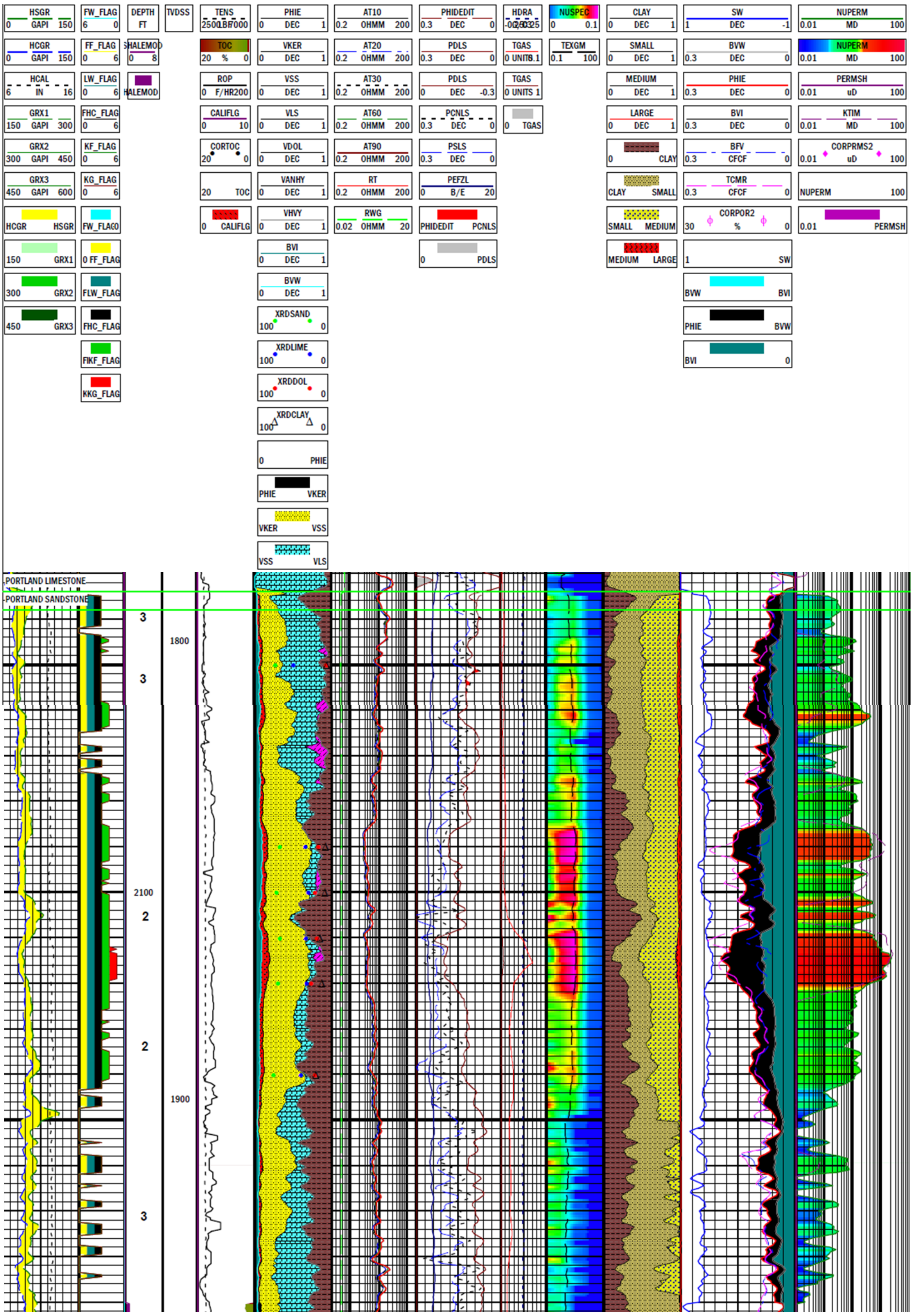


Figure 6.7 Nutech CPI of Portland Sandstone

6.4 Hydrocarbon In Place Estimates

6.4.1 Approach

Xodus' STOIIP values were calculated stochastically using REP5 software from Logicom E&P. The same method has been used as in the previous assessment however the reservoir parameter ranges were updated as described in the previous section.

For the purposes of GRV and STOIIP calculations, the discovery has been divided into two regions along the major east west fault resulting in two blocks defined by the well which has penetrated it (the Collendean Farm Block penetrated by the CF-1 well and the Horse Hill Block, penetrated by the HH-1 well). Figure 6.8 shows the top reservoir map with the polygons used in Petrel for determining GRVs.

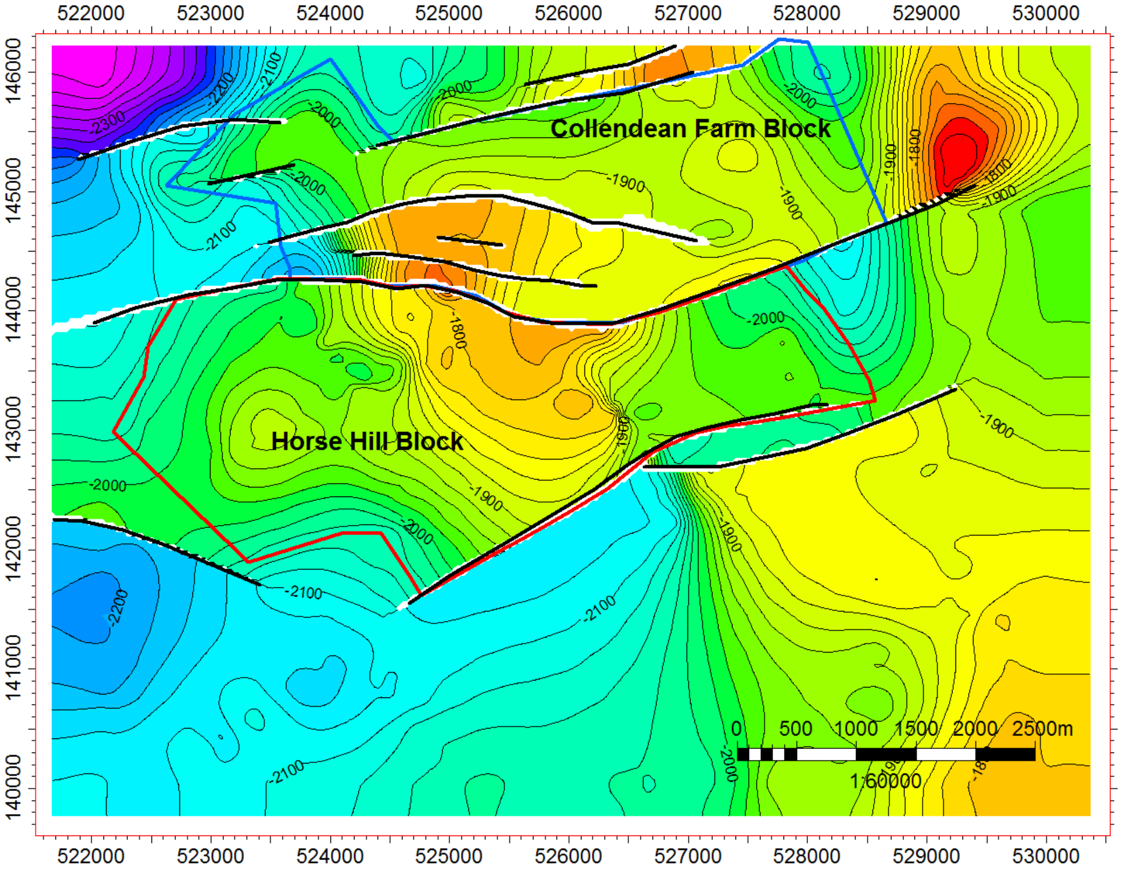


Figure 6.8 Map showing top Portland Sandstone surface and polygons

GRV inputs were derived from the seismic interpretation for the top reservoir surface. A new surface was generated by Xodus, from the existing interpretation, which has been smoothed slightly and for which the match to well tops was improved. Area depth data was calculated using Petrel software, polygons were used to define the northern and southern blocks and to artificially close the structures around the spill point where the seismic mapping could not. HHDL loaded an image of the top reservoir map into REP and manually calibrated and traced the contours to determine the area for each. This method is more reliant on the accuracy of the map and tracing, whereas Petrel software calculates the areas precisely within each depth segment. In both cases the area depth values were exported into REP.

No fluid contacts have been observed in the wells drilled on the discovery and the reservoir sand has been found to be full to the base. The possible range of fluid contact has been defined by the ODTs and spill points for the two fault blocks. In the northern Collendean Farm Block the ODT of 1857ft TVDSS is the minimum depth and the spill point of 2000ft TVDSS is the maximum used to define a normal beta distribution. Correspondingly in the southern Horse Hill Block, the ODT of 1900ft TVDSS and spill point of 2000ft TVDSS are applied in the same way. As described above it is not possible to close the structures at these depths, although this is potentially a result of the sparse seismic coverage and resultant depth conversion uncertainty. For the CF fault block, the ODT/Spill point Beta distribution assigned by UKOG are identical to Xodus'. For the HH fault block, UKOG use a lower P10 spill point input value of 1993ft TVDSS compared to Xodus' 1974ft TVDSS, which results in a more optimistic maximum spill point of 2040ft compared to Xodus' 2000ft TVDSS input.

Reservoir thicknesses were taken from the gross thicknesses observed in the wells, the average thickness (107.5ft) has been used as the P50. To account for some potential variation in reservoir thickness across the reservoir a P90 and P10 of 95ft and 120ft have been selected based on +/- 10ft of the minimum and maximum gross thicknesses observed in the wells.

Net to gross has been ascertained from the new petrophysical interpretations on both HH-1 and CF-1, a beta distribution was defined using a 12% porosity cut off on HH-1 for the minimum case, a P50 at 10% porosity also on HH-1 and a maximum using the 8% porosity cut off on CF-1.

Porosity and water saturation ("Sw") were adjusted slightly to reflect the average net value based on the NTG cut offs described. Ranges for both parameters have improved slightly due to changes in NTG interpretation and improvement in Sw calculation following the well test results.

Formation Volume Factor ("FVF") and Gas Oil Ratio ("GOR") are based on the recombined PVT sample that was taken during the testing of the HH-1 well in 2016.

Table 6.1 and Table 6.2 show the parameters and distributions used in the determination of STOIIP.

	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	78.2	95	108	120	137	108	108
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Beta	1900	1923	1948	1974	2000	1948	1949
Net-to-gross	%	Beta	31	44.2	58.2	72.6	87	58	58.3
Porosity	%	Normal	9.99	12	13.5	15	17	13.5	13.5
Sw	%	Normal	44.6	50	54	58	63.4	54	54
FVF (Bo)	rb/stb	Normal	1.0	1.07	1.1	1.15	1.25	1.1	1.1
GOR	scf/bbl	Normal	53	130	170	210	303	170	170

Table 6.1 Parameters used in the estimation of STOIIP for the Horse Hill fault block

	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	78.2	95	108	120	137	108	108
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Beta	1857	1877	1907	1946	2000	1900	1910
Net-to-gross	%	Beta	31	44.2	58.2	72.6	87	58	58.3
Porosity	%	Normal	9.99	12	13.5	15	17	13.5	13.5
Sw	%	Normal	44.6	50	54	58	63.4	54	54
FVF (Bo)	rb/stb	Normal	1.0	1.07	1.1	1.15	1.25	1.1	1.1
GOR	scf/bbl	Normal	53	130	170	210	303	170	170

Table 6.2 Parameters used in the estimation of STOIIP for the Collendean Farm fault block

Following the estimation of STOIIP in both fault blocks, a stochastic consolidation has been carried out to give a single estimated range for the Upper Portland Sandstone of Horse Hill.

6.4.2 In Place Volumes

Table 6.3 shows Xodus' Gross PEDL137 STOIIP estimates for Upper Portland Sandstone of the Horse Hill discovery.

STOIIP (MMbbl)	Low	Best	High	Mean
Upper Portland	20.0	30.0	44.4	31.4

Table 6.3: Xodus Horse Hill gross PEDL137 STOIIP estimate

6.5 Recoverable Volume Estimates

6.5.1 Approach

Xodus used the March 2016 well test data and PVT report to analyse the various well performance criteria and reservoir extent. The relatively short duration and conditions of the well test do not allow for a more specific assessment and a broad range of possible outcomes remains. Therefore, Xodus has also reviewed analogue wells and fields. From this body of information, three well types were constructed a "base case" well, an "upside performing" well and a "downside performing" well. A crude sector simulation model was also constructed to allow for another check of results.

Rather than applying a recovery factor ("RF") to the STOIIP volumes, Xodus used its engineering judgment to determine a sensible total well count for an ultimate field recovery. The number of wells on the field was multiplied by the well type profiles to arrive at deterministic "base case", "upside" and "downside" recoverable volume estimates. The base case was chosen as the 2C volume, the downside case as the 1C volume and the upside case as the 3C volume. At this stage of development and knowledge of the field it was thought that more advanced methods such as reservoir dynamic simulation modelling, or taking into account well interference would lead to the notion of false precision and hence such methods were not applied for the purposes of this report.

6.5.2 Well Performance

Xodus assumed that each well would be contacted to a STOIIP unit of approximately 10 MMbbl. Initial production rates were derived from the well test results, multiplied by a factor to take into account improved well placement, possible (short) horizontal or slanted well trajectories to increase contact surface, etc. Decline rates were based on analogue wells and on applying compensation factors for the effects caused by:

- connected STOIIP – possibility of sub-seismic faulting / baffling
- potential incremental acid stimulation to improve the well productivity
- water break through – will it be edge or bottom water
- critical gas saturation - as the produced oil (below bubble point) degasses in the reservoir, what is the critical gas saturation, when the gas starts to be produced and the GOR will rapidly increase

Three well types were derived. The production profiles are provided in Table 6.4 below. A cut off rate of 10 bopd was used.

Although no water was produced during the well test, it is foreseen that water will break through at some point and ultimate recovery per well could likely be a function of the amount of produced water. No water production profiles have been determined as part of this report.

Year	Downside Case	Base Case	Upside Case
1	250.0	350.0	500.0
2	175.0	262.5	400.0
3	122.5	196.9	320.0
4	85.8	147.7	256.0
5	60.0	110.7	204.8
6	42.0	83.1	163.8
7	29.4	62.3	131.1
8	20.6	46.7	104.9
9	14.4	35.0	83.9
10	10.1	26.3	67.1
11		19.7	53.7
12		14.8	42.9
13		11.1	34.4
14			27.5
15			22.0
16			17.6
17			15.8
18			14.2

19			12.8
20			11.5
TOTAL (bbl)	**295,777**	**499,202**	**907,311**

Table 6.4 Production Rates (bopd) of HH Portland Well Types

6.5.3 Horse Hill Portland Reservoir Recoverable Resources

Figure 6.9 shows a possible scenario of production wells draining the Horse Hill Portland reservoir. The purple lines denote indicative well locations. Xodus assumed that each well would potentially target a 10MMbbl STOIIP unit. Hence, using the P_{50} STOIIP estimate, we determined that 3 wells could drain the field. This would likely be 1 well targeting the Collendean segment and 2 wells targeting the Horse Hill segment. For a 1C scenario we assumed that only 2 wells would be drilled and for the 3C scenario we assumed that 4 wells would produce on the field. This assumes that no further faults or baffles restrict flow beyond the main faults that have been mapped.

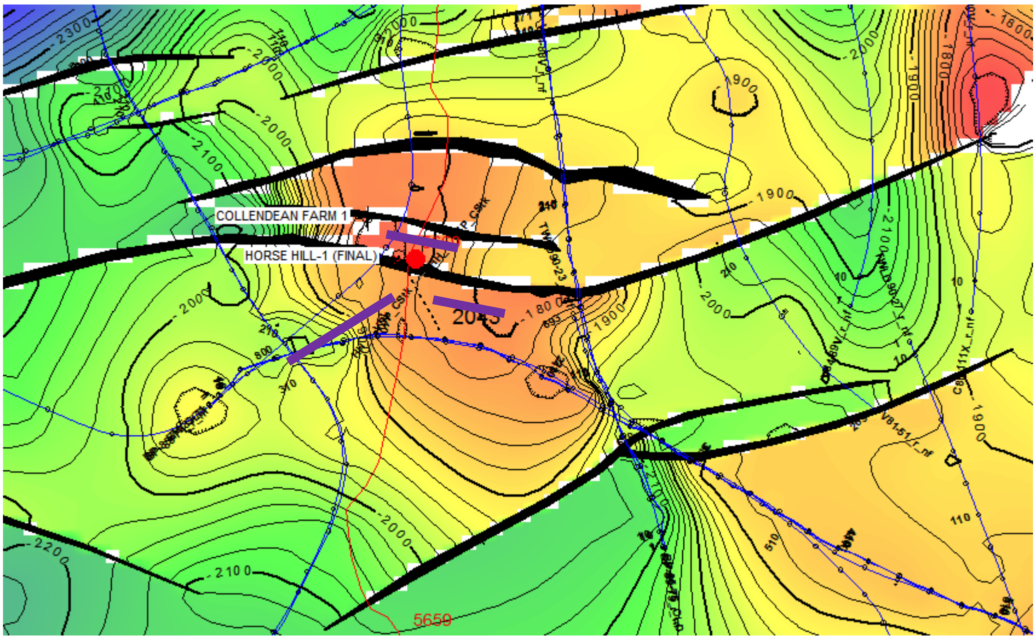


Figure 6.9 Indicative P_{50} Production Well Pattern for Horse Hill Portland

Assuming that all wells would produce independently from each other and that total production from the Horse Hill Portland field would therefore be the sum of production from all wells and furthermore assuming that each well would produce at the rates indicated in the previous section, Xodus has calculated the total recoverable resource volumes for the reservoir. These volumes are provided in Table 6.5 below.

Recoverable Hydrocarbons	Downside Case (1C)	Base Case (2C)	Upside Case (3C)
Upper Portland Oil (MMbbl)	0.592	1.498	3.629

Table 6.5 – PEDL137 Portland Recoverable Volumes

This equates to a RF range of 3% - 5% - 8%, based on the P90, P50 and P10 STOIIP respectively, which Xodus believes is a reasonable first look RF range for primary recovery from this reservoir under a depletion drive mechanism. See note below on the possible incremental increase in recovery that could arise via early implementation of reservoir pressure support.

These volumes are classified as Contingent Resources, being contingent upon the development, submission and approval of a FDP and achieving the necessary approvals and finances to execute against the FDP. A well test of the Horse Hill Portland is planned for 2018 in order to prove the necessary connected volumes for a development. UKOG have indicated that commerciality should be declared following a successful test and a field development plan prepared after this. As a consequence of these intentions Xodus have estimated a commercial risk factor of 75% for the Horse Hill Portland reservoir. Table 6.6 provides the gross Contingent Resources volumes on the field, as well as those volumes that are net attributable to UKOG.

Oil Contingent Resources	Contingent Resources Gross			Contingent Resources Net to UKOG			Risk Factor
(MMbbl)	1C	2C	3C	1C	2C	3C	(%)[9]
Upper Portland	0.592	1.498	3.629	0.19	0.49	1.18	75

Table 6.6 Contingent Resources for PEDL137 Portland Reservoir

For a shallow but permeable reservoir, such as the Portland, should a water re-injection scheme be undertaken to provide pressure support and improve sweep-efficiency in the field's early productive life, it is reasonable to expect a material increment in overall oil recovery. The successful implementation of such a scheme is estimated to lead to the recovery of an additional 8-14% of STOIIP, which based on current estimates of STOIIP, as shown in Table 6.3, could be equivalent to a further 1.7 - 6.6 MMbbl of gross recoverable oil. The Portland itself is a potential source of water for re-injection. Since such a plan would be sanctioned only after further testing of the Portland, Xodus have therefore not included any incremental volumes for water injection in the ultimate recoverable volume estimates at this time.

6.6 Conclusions

Xodus have reviewed the data and interpretation provided by UKOG on the Horse Hill Portland and found it generally to be robust and of good quality. Xodus have used the data provided to calculate STOIIP for the Portland. Recoverable hydrocarbon volumes have been based on primary depletion, with additional resource potential should a water injection scheme be implemented early in field life. The planned long-term test of the Portland is expected to provide valuable information for possible future development.

7 ISLE OF WIGHT

As part of the 14th Licence Round, UKOG was awarded a 65% equity interest in the PEDL331 onshore Isle of Wight licence, which covers a 200 square km area. The licence contains a discovery, Arreton and two prospects. Xodus reviewed the interpretations on PEDL331 for UKOG in 2016 [4], there has been no change to the data available or interpretations made since this evaluation.

Two wells have been drilled on the Arreton structure. The discovery was made by the Arreton-2 well which was a twin of the 1952 well Arreton-1 drilled by BP. Arreton-2 was drilled in 1974 by British Gas and was planned to test the Permo-Triassic potential of the Arreton structure which had been identified from seismic data acquired in 1972. The final well report states that weak oil shows were seen in the Jurassic but in the Portland Limestone good shows were observed and good total porosity. A test was carried out but no hydrocarbons flowed to surface. The report also records that the test was not carried out satisfactorily as a result of drilling concerns.

UKOG's interpretation of the well results is that a section of pay in the Portland has been missed and that the test performed is inconclusive, based on the following data:

> Although washouts present some limitations on the log analysis, UKOG have carried out a new petrophysical interpretation calculating porosity with three different approaches, which yield similar results giving confidence in the interpretation

> Poorly executed well test

> Oil and gas cut mud and other oil shows were observed during drilling.

7.1 Seismic and Structure

The UKOG-licensed onshore acreage, including the whole of the Arreton discovery area, is covered by a grid of 2D seismic lines of varying vintages. UKOG have acquired all of the existing seismic data over the area, in addition to data for most of the nearby onshore and offshore wells to complement the seismic database.

The primary datasets that define the Arreton discovery, are the GCE-86 (assumed 1986 vintage) survey and a further BP dataset of unknown vintage. Combined, these two datasets comprise 39 lines, approximately half of which define the main Arreton discovery (both on and off-structure). Lines are oriented mainly N-S ("dip" direction") and W-E ("strike" direction). Coverage is sparse, with dip lines spaced at approx. 2000m - 5000m, while strike control comes from two lines, which tie at the ends on the crest of the structure.

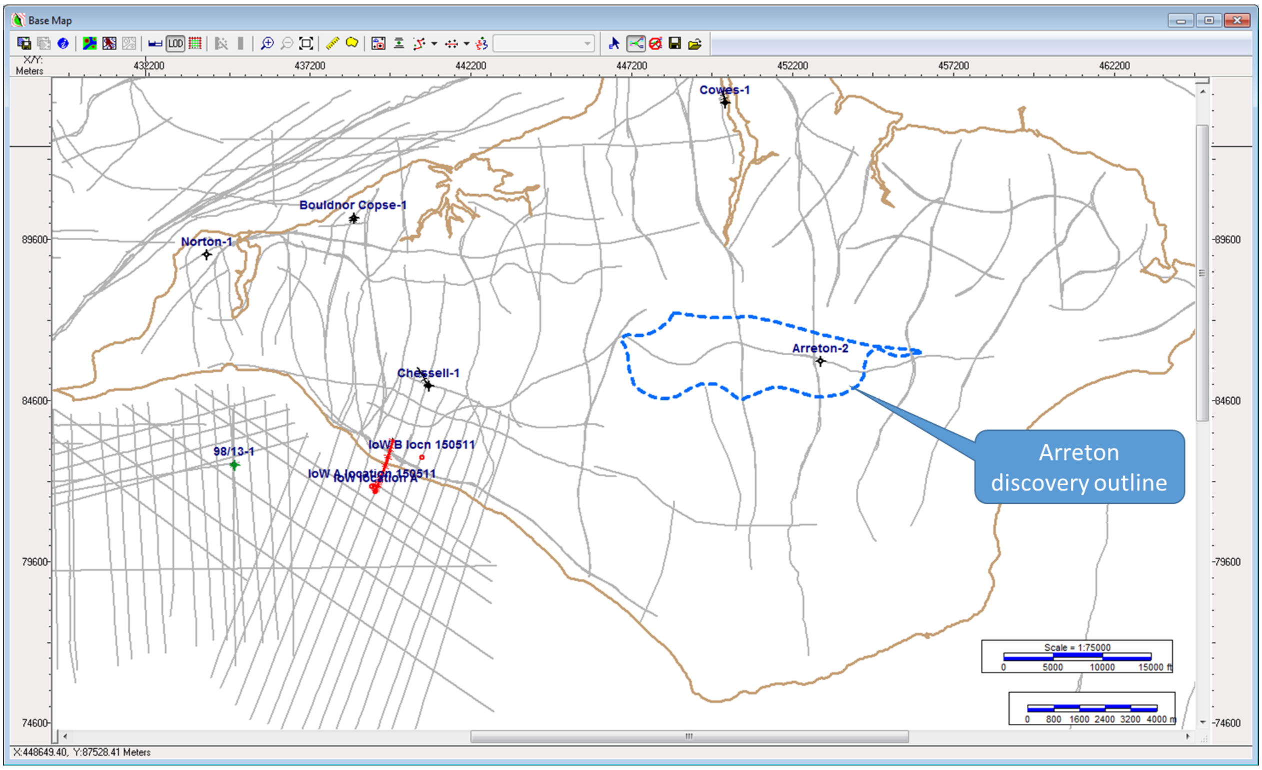


Figure 7.1: Seismic coverage and Arreton discovery outline

Seismic data quality over the Arreton area is deemed, in the main, to be good. There are some minor misties in Two Way Time (**TWT**) between the datasets, particularly with respect to some of the reprocessed "BP" datasets. In general, however, these shifts are minor and have been addressed where possible. Further, some lines display areas of lower fold, likely caused by surface obstructions but are unlikely to affect the overall structure at target level.

7.1.1 Arreton Area Mapping

The main Arreton structure is an elongate, approximately 12 km^2 fault-bounded anticlinal structure at Portland Limestone level apparently formed by inversion on pre-existing faults still in net extension. Figure 7.2 shows a dip line example of the seismic.

Horizon picking in TWT across the structure is unambiguous and of high quality and has recently been improved by UKOG. This new interpretation is now considered to be an accurate interpretation, tying the well tops exactly, and following the zero crossings on the seismic that correlate to Top Portland Limestone and Top Inferior Oolite, rather than simply following the peaks and troughs. Correlation between lines is generally good with no obvious jumps in the interpretation. However, seismic coverage is sparse, thus some ambiguity will exist in the definition of the overall structure.

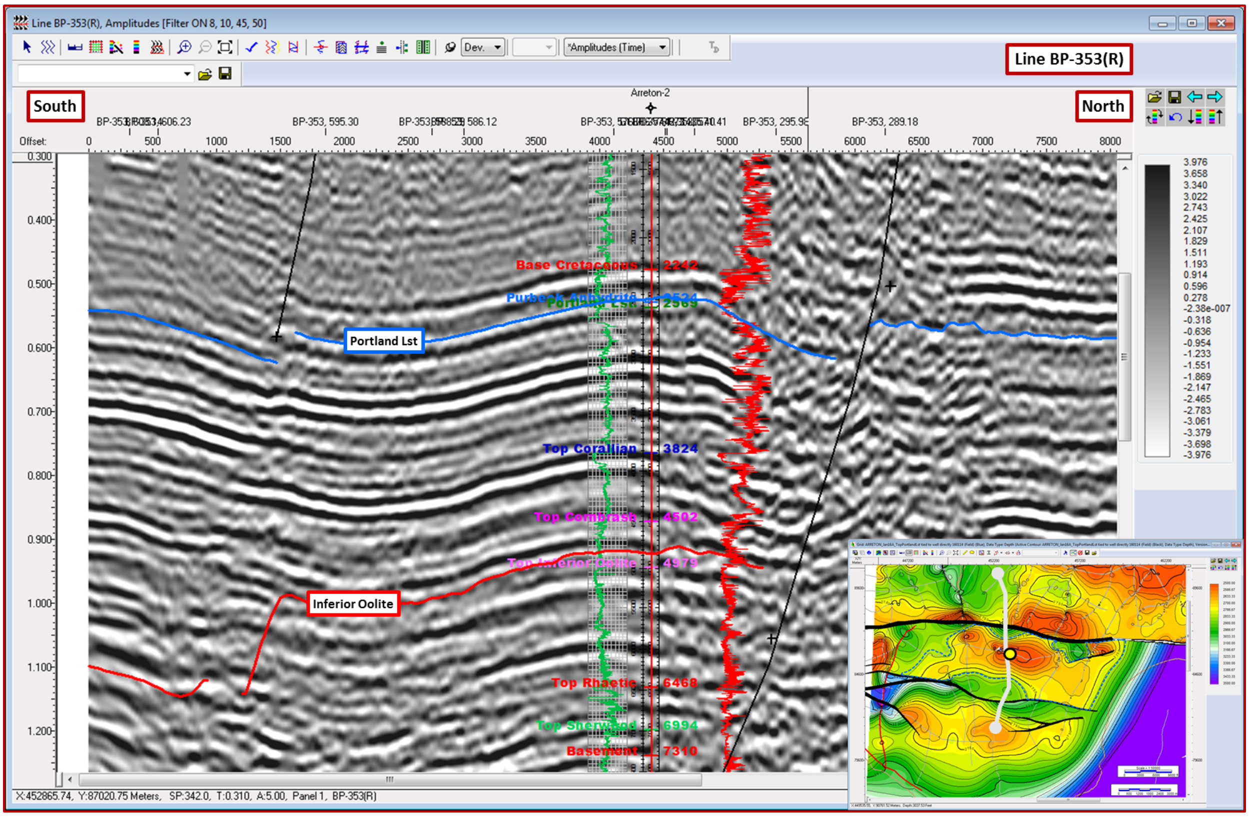


Figure 7.2: "Dip" line

The local Arreton-2 well provides both stratigraphic control for the interpretation, and velocity control for depth conversion purposes. A synthetic seismic tie was provided in the project providing sufficient confidence for stratigraphic control over the interpretation.

Time Maps

Xodus have reviewed the interpretation provided by UKOG, specifically for the Top Portland Limestone and Top Inferior Oolite formations and deem the operator's time mapping to be accurate, reliable and of a high standard. Some minor misties are apparent on the gridded surfaces and these have been determined to be caused by small shifts between seismic lines. These are not deemed to affect the overall structure in any material way.

Figure 7.3 shows the TWT grid for the Top Portland Limestone horizon. The horizon has been mapped on a relatively low-amplitude, negative-to-positive amplitude zero crossing on the seismic as observed on the well to seismic tie. This correlates with the expected response observed on the logs passing from the faster Purbeck Anhydride sequence into the underlying Portland beds.

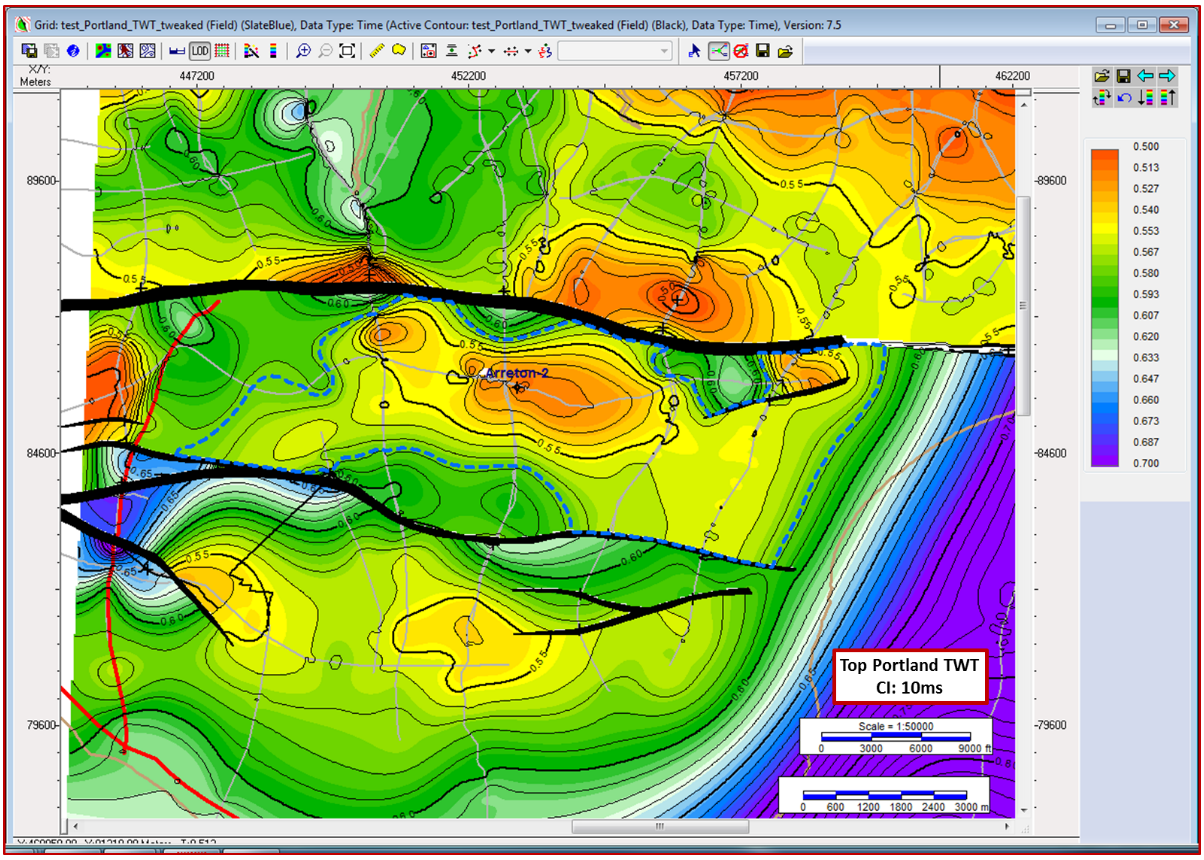


Figure 7.3: Top Portland Limestone TWT structure grid

The deeper Top Inferior Oolite marker has been mapped on a seismic trough, corresponding to the "hard" reflection observed on the Arreton-2 well logs. Whilst the reflection is less continuous in nature than that of the Portland, the interpretation is nonetheless robust (see Figure 7.4).

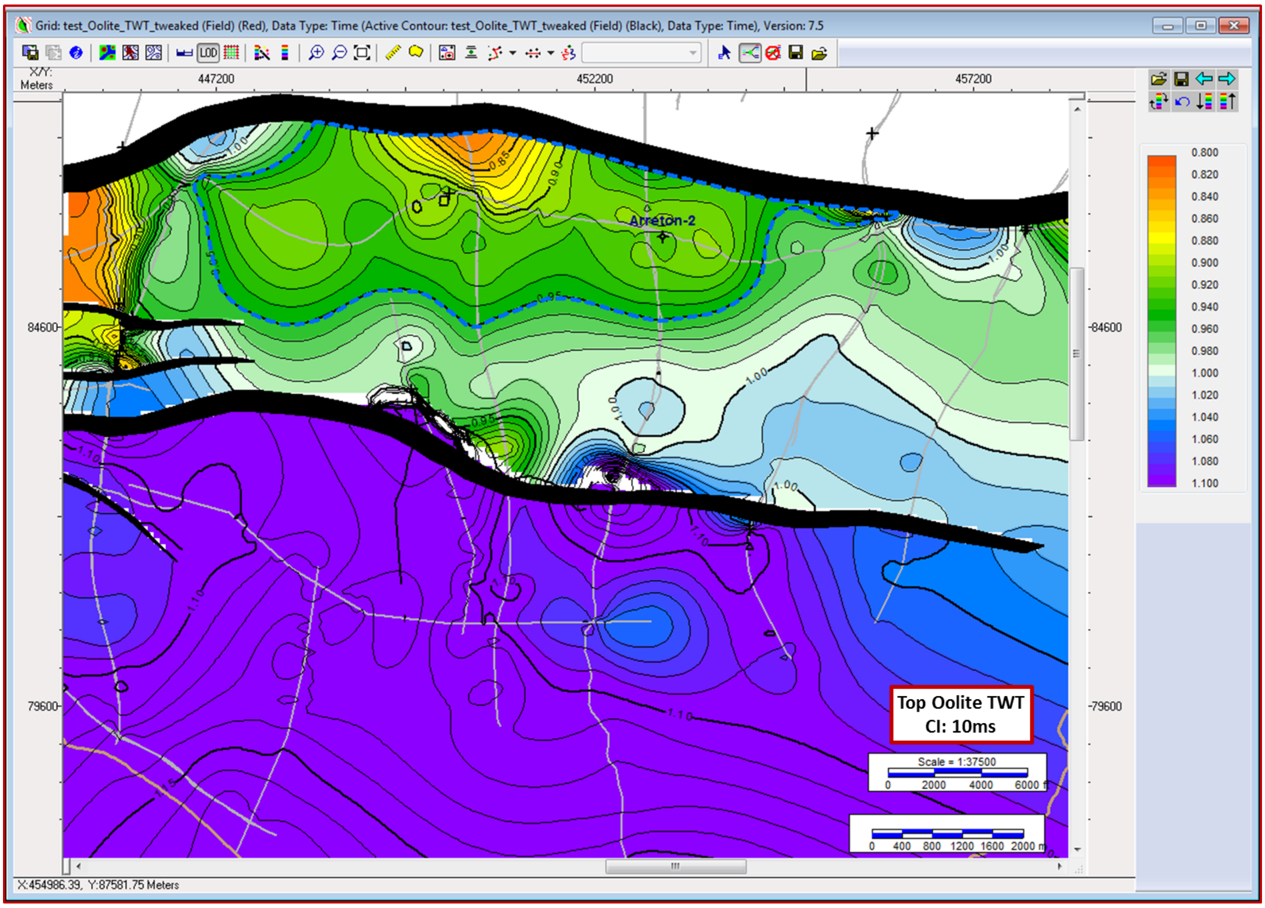


Figure 7.4: Top Inferior Oolite TWT structure grid

The Arreton structure is composed of a West-to-East trending anticline bounded to the north and south by inverted normal faults. The structure was likely generated as a result of compressive forces related to the Alpine / Pyrenean orogeny around 40 million years ago. At Portland Limestone level, the main elongate structure is approximately 10 x 4 km in size, with a similar-sized structure to the south ("Arreton South") and a smaller 3-way structure to the north ("Arreton North"). At Inferior Oolite level, a single material structure is apparent in the main Arreton area (7 x 2.5 km), with only a small culmination at Arreton South.

UKOG have utilised the velocity functions from the Arreton well to produce a velocity profile for depth conversion (Figure 7.5). This average velocity trend will naturally create some mistie to the depths recorded in the well, however UKOG have modified the trend slightly to create an exact tie. This bulk shift methodology could be argued to be simplistic, however, given the lack of well control in the area, it is deemed to be sufficient. But it remains that potentially unaccounted-for velocity variations will likely provide the main uncertainty with respect to Gross Rock Volume calculations.

Using these adjusted velocity functions, depth maps have been created for both levels. These maps closely tie the well tops (Figure 7.6) and are shown in Figure 7.7 and Figure 7.8.

Without cross-fault seal, accumulations are restricted to the 4-way dip closed portions of the structure.

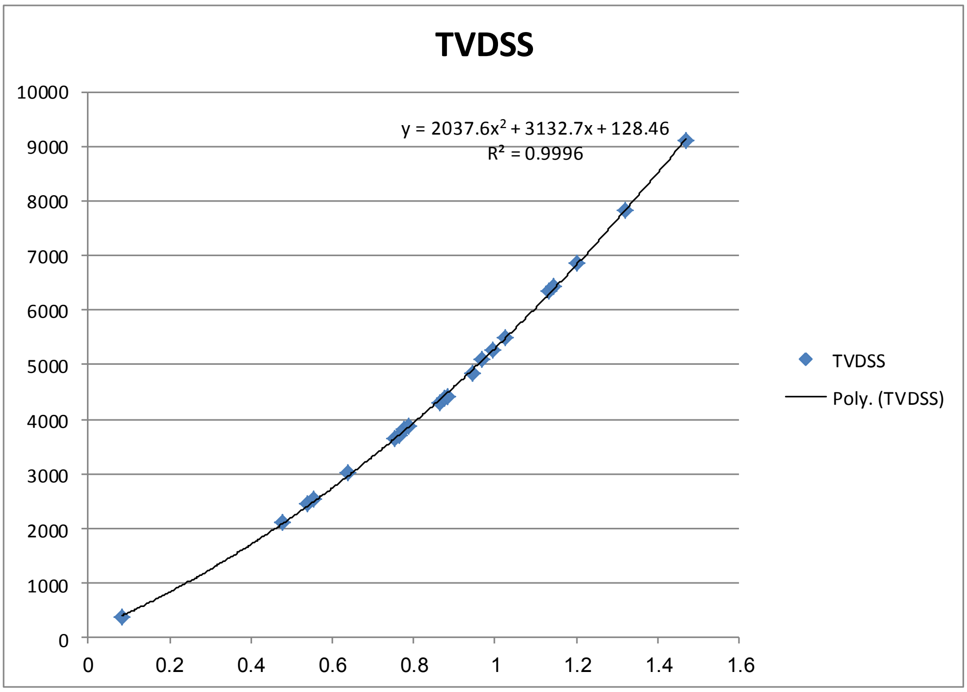


Figure 7.5: Velocity function used for depth conversion.

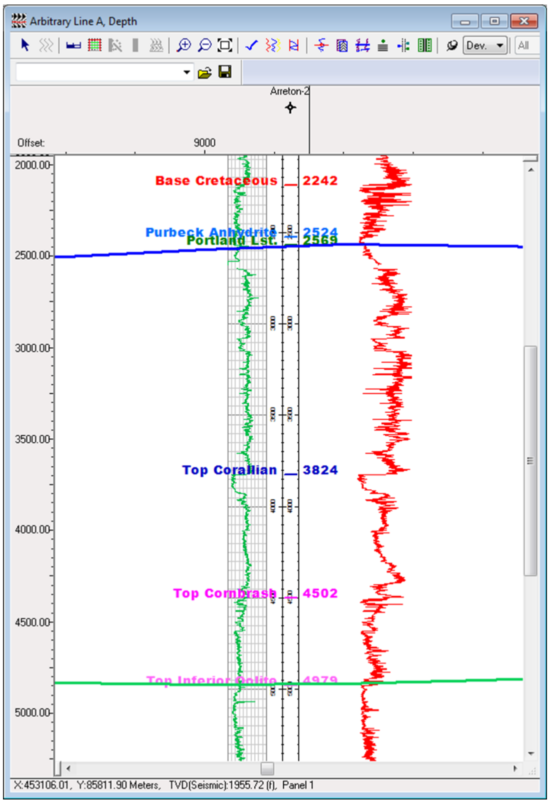


Figure 7.6: Top Portland and Inferior Oolite Depth Grids vs Arreton-2 well

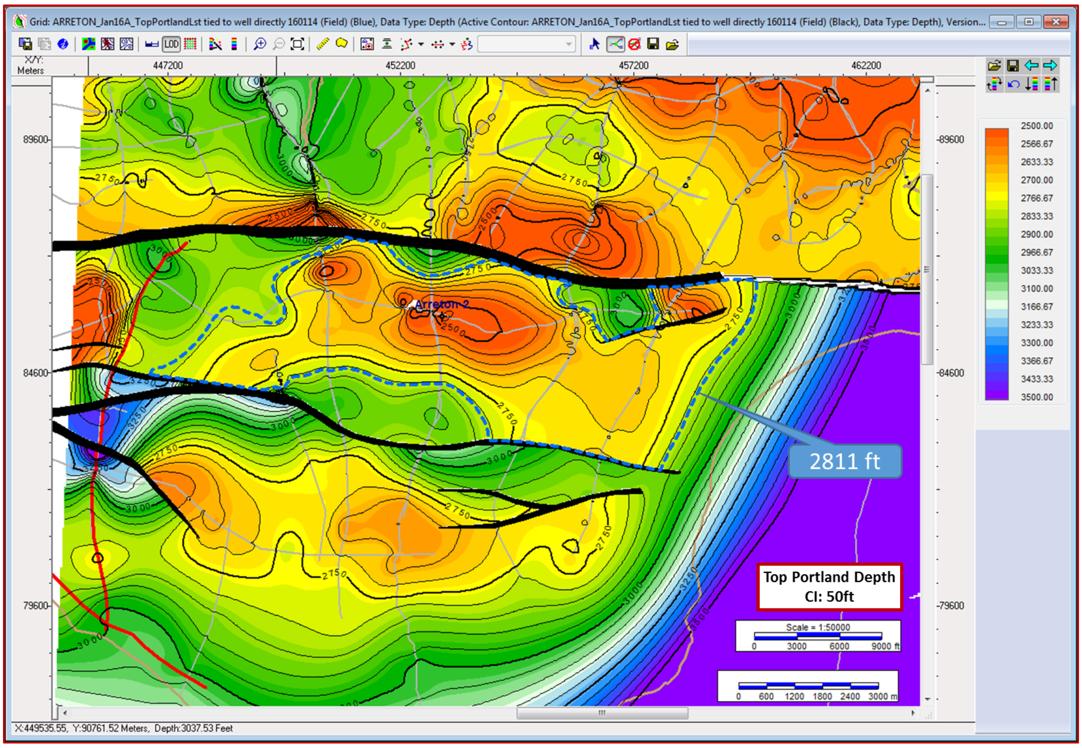


Figure 7.7: Top Portland Limestone Depth Grid

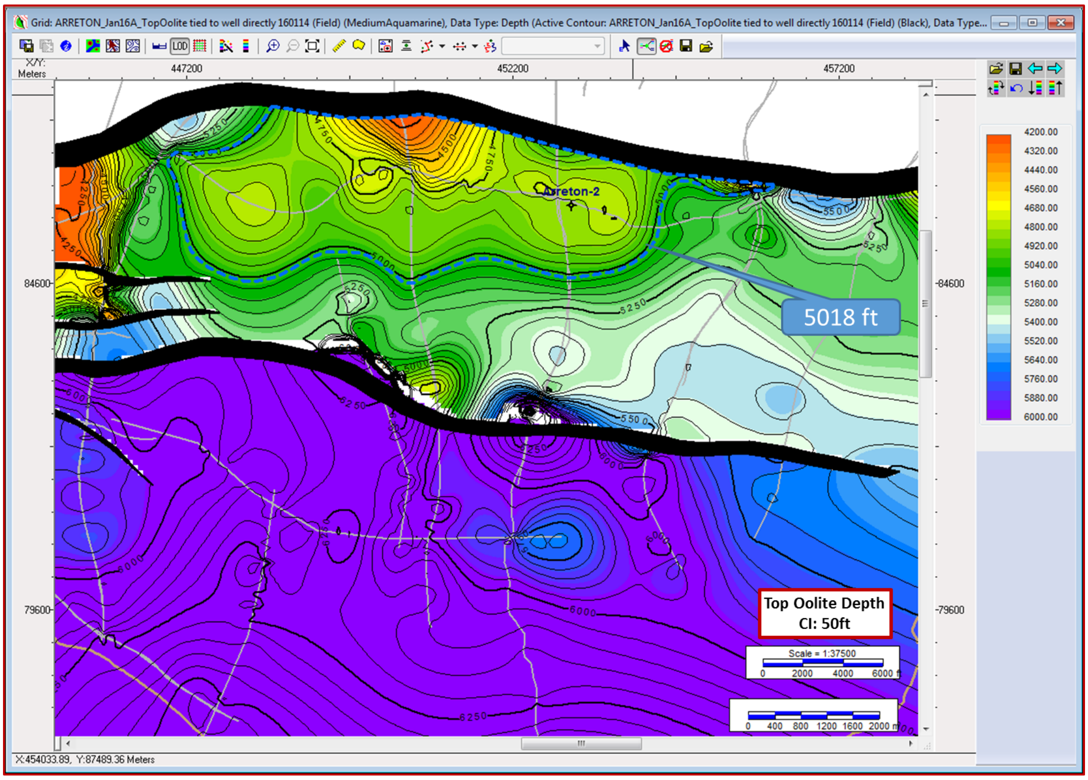


Figure 7.8: Top Inferior Oolite Depth Grid

Based on these depth maps, each closure has been calculated to have the following area of closure:

- Portland Limestone – Arreton Main 31.4 km^2
- Portland Limestone – Arreton North 9.3 km^2
- Portland Limestone – Arreton South 27.9 km^2
- Inferior Oolite – Arreton Main 15.3 km^2

While the work presented by the operator is of a high standard, the following actions would likely improve the quality of the interpretation:

- Additional control on the structure could be achieved through the acquisition of additional seismic lines.
- A global reprocessing of the various seismic vintages together may help to remove any ambiguity re polarity changes and line-to-line misties between surveys. However, the material benefits would likely be small.
- Depth conversion uses the Arreton-2 well only. Incorporating the Chessell-1 well, located on the same structural block to the west, may provide additional information on velocity variation to the west.

7.2 Reservoirs

Three prospective reservoirs have been identified at Arreton: the Portland and Purbeck Limestones and Inferior Oolite. The database available for Xodus to review included a detailed analysis of the Arreton-2 well and other regional wells, in addition there are legacy reports and interpretations from several wells, although the interpretations are limited by the logs acquired and the age of the wells.

7.2.1 Portland Limestone

The Portland Limestone found in Arreton-2 has a gross thickness of 90 ft and can be split into two zones – an upper zone of sandy argillaceous limestone and a lower zone with recrystallized grainstone with higher porosity (Figure 7.9). The petrophysical interpretation by Nutech shows 78 ft of net pay with an average porosity of 10% and water saturation of 35%, and Nutech's report states that this section is "…expected to produce hydrocarbon at a good rate". Oil staining and shows were seen from this interval during drilling.

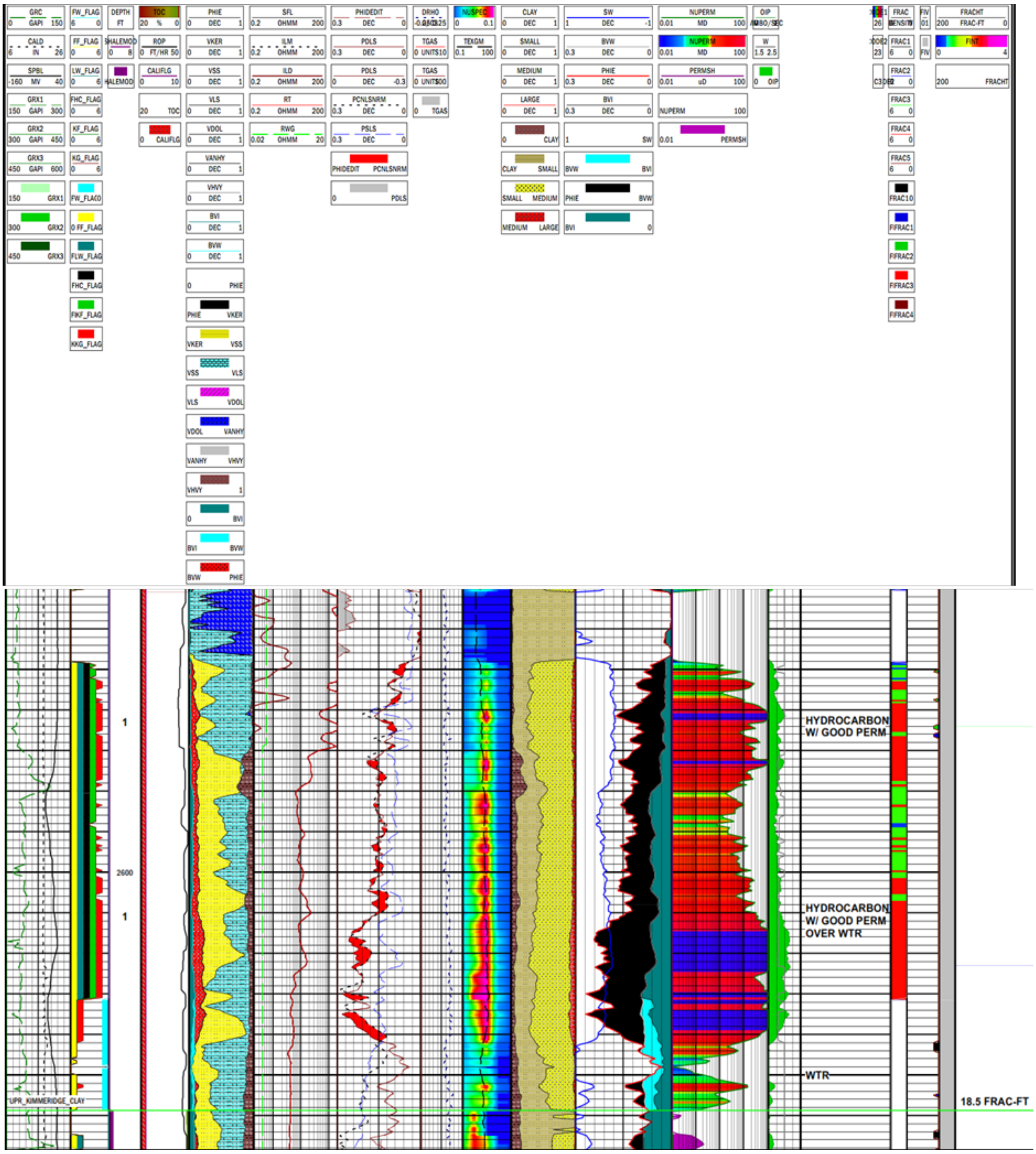


Figure 7.9: Portland Interval of the Arreton-2 well, Nutech interpretation.

7.2.2 Purbeck Limestone

The Purbeck Limestone is a thin carbonate reservoir which sits on top of the Portland Limestone, the two formations forming a single reservoir and a single continuous hydrocarbon column totalling 111 ft. The Arreton-2 well penetrated 20 ft of oil bearing Purbeck Limestone which have an average porosity of 10%, the entire section encountered is considered to be net pay. The Computer Processed Interpretation (CPI) (Figure 7.10) indicates zones of good permeability, over 100mD, and an average of 30mD.

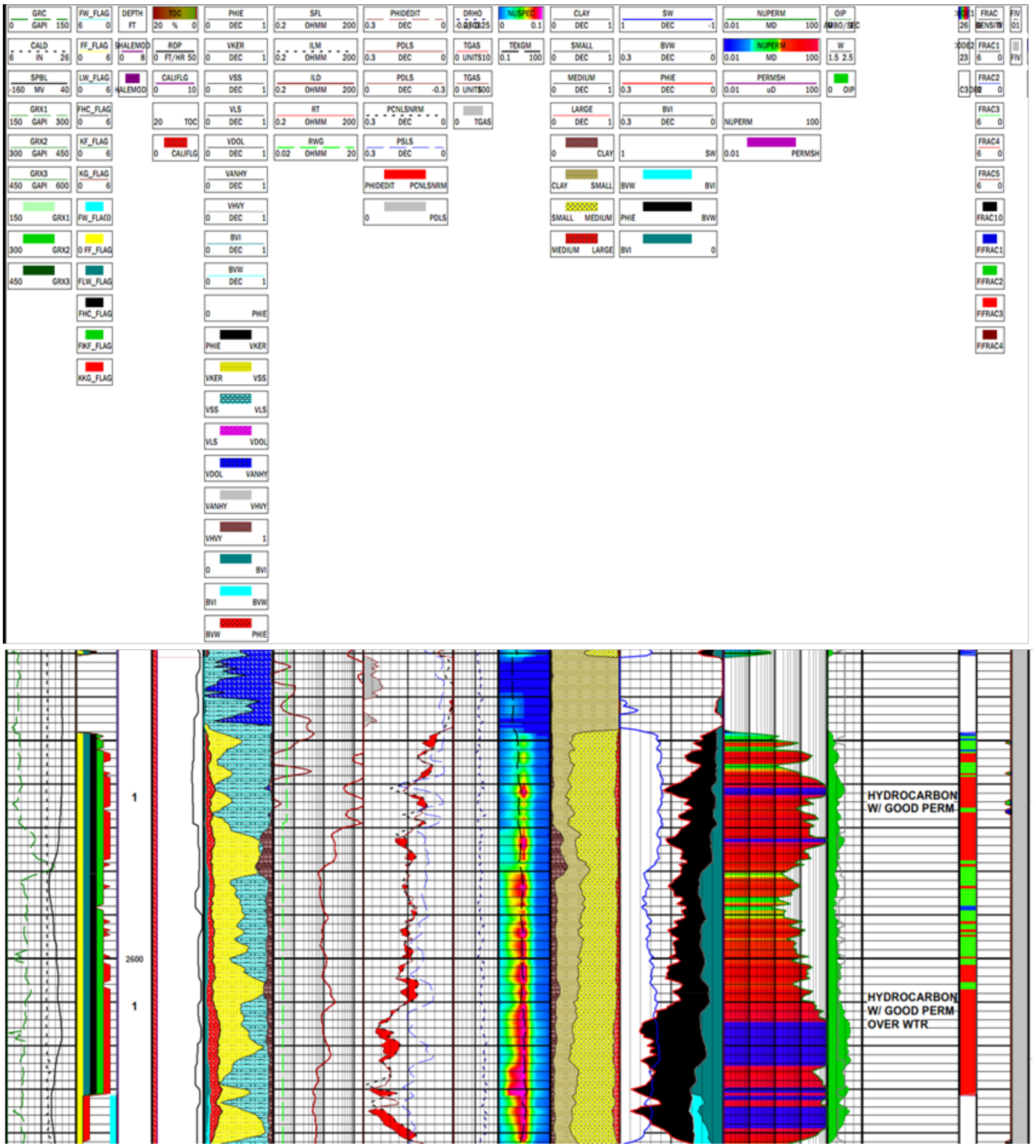


Figure 7.10 Nutech CPI through the Purbeck Limestone.

7.2.3 Inferior Oolite

The Inferior Oolite is a Lower Middle Jurassic reservoir which has flowed oil at other locations in the Wessex Basin. The limestone reservoir is generally argillaceous and in places sandy and has little natural porosity, at Arreton-2 it has an average porosity of 7%. The Arreton-2 well encountered a gross Inferior Oolite section of 191 ft thickness with a net to gross of 66% (Figure 7.11), 127 ft of net pay has been interpreted. Average water saturation is 22% and permeability is interpreted to be 9.2mD. Potential natural fractures resulting from inversion within the Purbeck Isle of Wight Anticline could enhance reservoir deliverability.

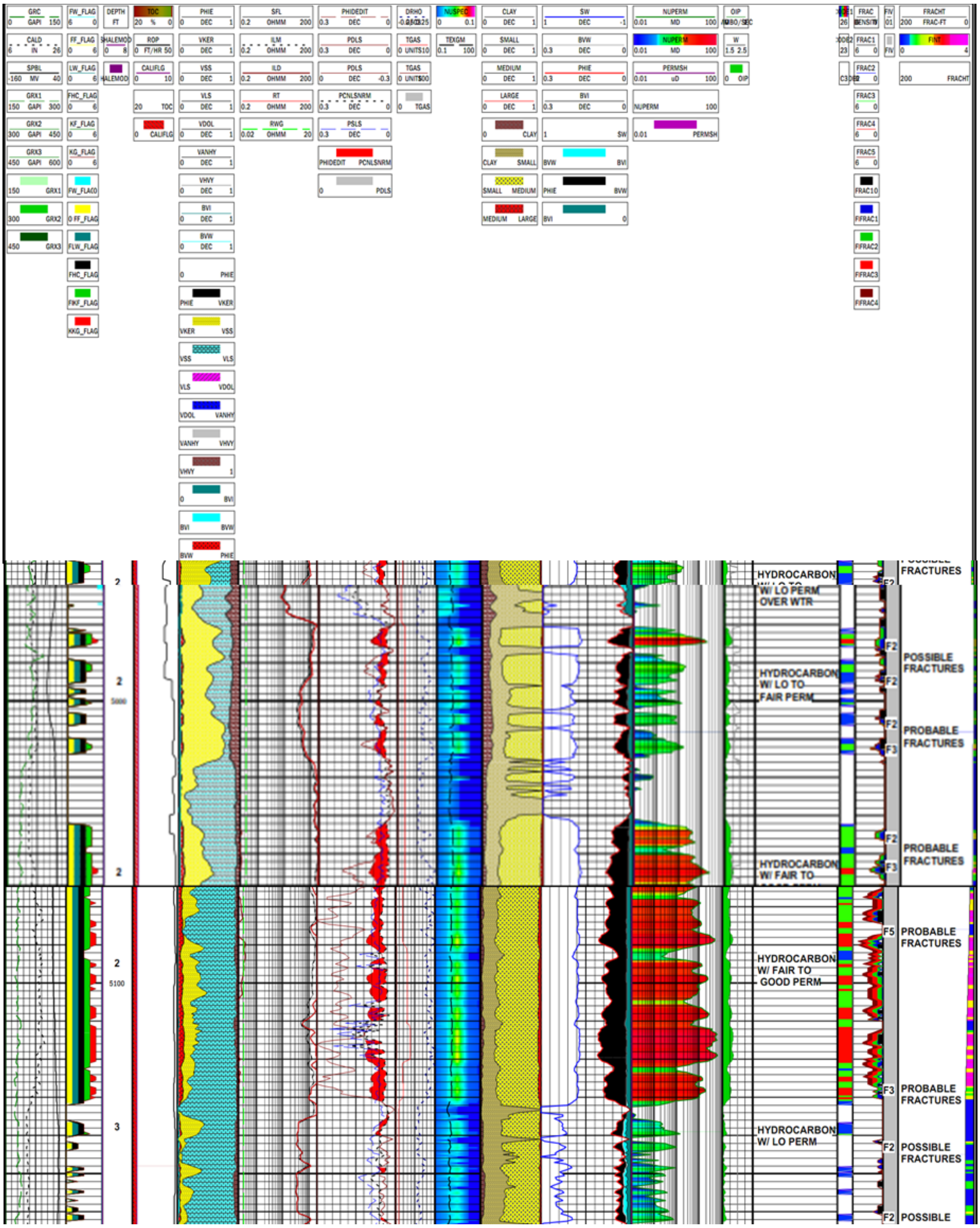


Figure 7.11: Inferior Oolite CPI from Nutech interpretation

A test was carried out on the Portland Limestone of the Arreton-2 well. No hydrocarbons flowed, however UKOG does not view the test as reliable.

7.3 Hydrocarbon In Place Estimates and Recoverable Resources

Hydrocarbons Initially In Place (HIIP) have been estimated stochastically by Xodus using Reserves Evaluation Programme (REP**)** software. Xodus was provided with UKOG's REP input sheets as a basis and has verified the values used to define distributions for each parameter and reservoir.

Area / depth – for each reservoir, a series of area depth data was calculated using the mapped top reservoir interpretations in Petrel software, the same map was used in all cases.

Thickness – reservoir thicknesses were determined from interpretations of Arreton-2 as the mid case with an indication of possible ranges taken from nearby wells.

Fluid Contacts – an indicated Oil Down To (**ODT**) at 2518 ft TVDSS

Net to Gross, Porosity, Sw, FVF and GOR – these petrophysical parameters were determined from analysis of well results and were corroborated against basin analogues with reference to the position of the prospect. Xodus did not undertake a detailed review of the petrophysical interpretations but have checked that the parameter values fall in the range of values expected for relevant reservoir in the Wessex Basin. Only minor changes have been made to the values used by UKOG. The parameter ranges used by Xodus for each reservoir are shown in the tables below.

7.3.1 Arreton Main

Name	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	66.6	80	90	100	113	90	90
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Beta	2503	2518	2559	2626	2760	2534	2567
Net-to-gross	%	Beta	65	76.5	85.8	93.9	100	87	85.5
Porosity	%	Normal	11.3	14	16	18	20.7	16	16
Sw	%	Beta	17.2	28	37	45	51.2	38	36.7
FVF (Bo)	rb/stb	Beta	1	1.05	1.11	1.17	1.25	1.1	1.11
GOR	scf/bbl	Normal	16.5	50	75	100	134	75	75
Oil rec fac	%	Normal	6.65	10	12.5	15	18.4	12.5	12.5

Table 7.1: REP input table for Portland Limestone (Arreton Main)

Name	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	15.3	18	20	22.2	24.7	20	20
Shift top res	ft	Single	-20	-20	-20	-20	-20	-20	-20
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Beta	2503	2518	2559	2626	2760	2534	2567
Net-to-gross	%	Beta	80	84.9	90	95.1	100	90	90
Porosity	%	Normal	5.32	8	10	12	14.7	10	10
Sw	%	Beta	14.1	18	20.3	22	22.8	21	20.2
FVF (Bo)	rb/stb	Beta	1	1.05	1.11	1.17	1.25	1.1	1.11
GOR	scf/bbl	Normal	16.5	50	75	100	134	75	75
Oil rec fac	%	Normal	6.65	10	12.5	15	18.4	12.5	12.5

Table 7.2: REP input table for Purbeck (Arreton Main)

Name	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	184	211	231	251	278	231	231
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Beta	5005	5015	5026	5037	5050	5025	5026
Net-to-gross	%	Normal	40.6	54	64	74	87.4	64	64
Porosity	%	Normal	2.52	5.2	7.2	9.2	11.9	7.2	7.2
Sw	%	Beta	12.7	17	28	45	77.3	22	29.7
FVF (Bo)	rb/stb	Beta	1	1.05	1.11	1.17	1.25	1.1	1.11
GOR	scf/bbl	Normal	16.5	50	75	100	134	75	75
Oil rec fac	%	Normal	6.65	10	12.5	15	18.4	12.5	12.5

Table 7.3: REP input table for Inferior Oolite (Arreton Main)

The resulting STOIIP volumes are shown in Table 7.4 below.

Arreton Main STOIIP (MMbbl)	Low	Best	High	Mean
Portland Limestone	6.8	21.3	61.6	29.3
Purbeck	4.7	9.2	19.6	11.2
Inferior Oolite	52.0	87.5	137.0	91.7
Total STOIIP[10]	**82**	**127**	**189**	**132**

Table 7.4: STOIIP Estimates for Arreton Main

Applying a 10% (P90) to 15% (P10) recovery factor range in REP leads to the recoverable volumes provided in Table 7.5 below. This range of recovery factors is observed in analogue producing fields in the Weald and in Wessex basins.

Oil Contingent Resources	Contingent Resources Gross			Contingent Resources Net to UKOG			Commercial Risk Factor
(MMbbl)	1C	2C	3C	1C	2C	3C	(%)[9]
Portland Limestone	0.8	2.6	7.8	0.5	1.7	5.0	75%
Purbeck	0.6	1.1	2.5	0.4	0.7	1.6	75%
Inferior Oolite	6.2	10.8	17.6	4.0	7.0	11.4	75%
Total Contingent Resources[10]	**9.9**	**15.7**	**24.1**	**6.4**	**10.2**	**15.7**	**75%**

Table 7.5: Contingent Resources Oil Volumes

A commercial success factor of 75% has been assigned to the Arreton Main discovery. UKOG are working towards the drilling of an appraisal well on the Arreton structure which should provide valuable additional data to assess the viability of a future development. A successful test to prove commercial production rates is needed to demonstrate commerciality of the field. A key issue to be addressed for a development is the method used to transport produced oil to the mainland. Possible options include transport by tanker and ferry or by small tanker. Although there is no oil export from the Isle of Wight at present, refined petroleum products are transported to the island using these methods. Ferry timetables and availability of space for tankers (two per ferry) would limit the maximum volume which can be transported and this may act as a control on maximum production rate. The export options will add considerably to the opex costs compared to a similar development in the Weald Basin; however, the 1C volume is sufficient to support a development.

A GOR range of 50 scf/bbl (P90) to 100 scf/bbl (P10) was applied into REP to estimate recoverable gas volumes (Table 7.6).

[10] This is a stochastic summation of the volumes

Gas Contingent Resources	Contingent Resources Gross			Contingent Resources Net to UKOG			Commercial Risk Factor
(bcf)	1C	2C	3C	1C	2C	3C	(%)[9]
Portland Limestone	0.06	0.19	0.59	0.04	0.12	0.39	75%
Purbeck	0.04	0.08	0.19	0.02	0.05	0.13	75%
Inferior Oolite	0.39	0.79	1.42	0.26	0.51	0.92	75%
Total Contingent Resources[10]	**0.68**	**1.16**	**1.90**	**0.44**	**0.75**	**1.24**	**75%**

Table 7.6: Contingent Resources Gas Volumes Arreton Main

The successful implementation of a water re-injection scheme, undertaken to provide pressure support and improve sweep-efficiency in the field's early productive life, could provide an increase in overall oil recovery. This increase would be additional to the resources reported in Table 7.6.

7.3.2 Arreton North

Volumes in the Arreton North Portland reservoir were estimated in the same way as the volumes in the Arreton Main Portland reservoir and similar reservoir parameters and recovery factors were applied.

Name	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	68.3	80	90	101	119	89.2	90.4
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Lognor	2354	2450	2524	2600	2706	2523	2525
Net-to-gross	%	Beta	65	76.5	85.8	93.9	100	87	85.5
Porosity	%	Normal	13.7	15	16	17	18.3	16	16
Sw	%	Beta	17.2	28	37	45	51.2	38	36.7
FVF (Bo)	rb/stb	Beta	1	1.05	1.11	1.17	1.25	1.1	1.11
GOR	scf/bbl	Normal	16.5	50	75	100	134	75	75
Oil rec fac	%	Normal	6.65	10	12.5	15	18.4	12.5	12.5

Table 7.7 REP input table for Arreton North Portland

The resulting STOIIP volumes are shown in Table 7.8 below.

Arreton North STOIIP (MMbbl)	Low	Best	High	Mean
Portland Limestone	3.7	22.0	59.9	27.6

Table 7.8: STOIIP Estimates for Arreton North Portland

In the event of a Portland discovery at Arreton North, that demonstrates similar reservoir parameters to the HH-1 oil discovery, a water re-injection scheme could be implemented to provide pressure support and improve sweep-efficiency in the field's early productive life. It is reasonable to expect a material increment in overall oil recovery. Based on work carried out for HH-1, the successful implementation of such a scheme could lead to the recovery of an additional 8-12% of STOIIP, which based on current estimates of STOIIP, as shown in Table 7.8, could be equivalent to a further 0.3 – 7.2 MMbbl of gross recoverable oil.

As the Arreton North Portland Limestone reservoir is separated from the Arreton Main reservoir by a fault, the recoverable volumes are classified as Prospective Resources. A geological chance of success (**COS**) was determined, using a Rose-style risking and taking into account that the play has been completely de-risked via the discovery made by the Arreton-2 well. Xodus considered that minor risks remain for the undrilled prospects, specifically:

> Source: particularly maturation and volumes generated are not deemed to be a risk, given the high-quality source rock in the area and the proven charge from Arreton-2.

> Timing/Migration: while highly likely, we cannot categorical regard the presence of an effective migration pathway into each prospect.

> Reservoir: while presence is highly likely, we cannot conclude that either it's presence or quality is absolute prior to drilling.

> Closure: a small risk has been placed on the reliability of the mapping, and in particular the depth conversion.

> Containment: risked according to the presence of faults. As the prospects are undrilled, certainty around the effectiveness of lateral seal against the faults and as such preservation from spill cannot be guaranteed.

Based upon these criteria, risks are determined to be small and accordingly a high chance of success for each element has been chosen. Combined, this calculates an overall COS for the Arreton North prospect of 69%.

Prospective Resources	Prospective Resources Gross	Prospective Resources Net to UKOG	Risk Factor

	Low	Best	High	Low	Best	High	COS[11] (%)
Arreton North Portland – Oil (MMbbl)	0.5	2.7	7.6	0.3	1.8	4.9	69%
Arreton North Portland – Gas (bcf)	0.03	0.19	0.58	0.02	0.12	0.38	69%

Table 7.9: Prospective Resources Volumes Arreton North (Oil and Gas)

7.3.3 Arreton South

Volumes in the Arreton South Portland reservoir were estimated in the same way as the volumes in the Arreton North Portland reservoir. The COS was determined in the same way but giving recognition to the fact that Arreton South is closer to the main Jurassic source kitchen.

Name	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	236	321	385	448	533	385	385
Area uncertainty	%	Normal	29.8	70	100	130	170	100	100
OWC	ft	Beta	9800	9986	10235	10523	10878	10200	10246
Net-to-gross	%	Normal	16.6	30	40	50	63.4	40	40
Porosity	%	Normal	4.65	8	10.5	13	16.4	10.5	10.5
Sw	%	Normal	18.2	35	47.5	60	76.8	47.5	47.5
FVF (Bo)	rb/stb	Normal	1.18	1.23	1.26	1.3	1.35	1.26	1.26
GOR	scf/bbl	Normal	286	320	345	370	404	345	345
Oil rec fac	%	Normal	14.9	25	32.5	40	50.1	32.5	32.5

Table 7.10: REP input table for Arreton South Portland

The resulting STOIIP volumes are shown in Table 7.11 and the Prospective Resources in Table 7.12.

Arreton South STOIIP (MMbbl)	Low	Best	High	Mean
Portland Limestone	14.2	55.2	138.0	67.4

Table 7.11: STOIIP Estimates for Arreton South

[11] Risk Factor for Prospective Resources is the geological chance of success (or COS), or the probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. In addition, a prospect has also a Development/Commercial Risk.

Prospective Resources	Prospective Resources Gross			Prospective Resources Net to UKOG			Risk Factor
	Low	Best	High	Low	Best	High	COS[12] (%)
Arreton South Portland – Oil (MMbbl)	1.7	6.8	17.4	1.1	4.4	11.3	73%
Arreton South Portland – Gas (bcf)	0.12	0.49	1.34	0.08	0.32	0.87	73%

Table 7.12: Prospective Resources Volumes Arreton South (Oil and Gas)

In the event of a Portland discovery at Arreton South, that demonstrates similar reservoir parameters to the HH-1 oil discovery, a water re-injection scheme could be implemented to provide pressure support and improve sweep-efficiency in the field's early productive life. It is reasonable to expect a material increment in overall oil recovery. Based on work carried out for Horse Hill, the successful implementation of such a scheme could lead to the recovery of an additional 8-12% of STOIIP, which based on current estimates of STOIIP, as shown in Table 7.8, could be equivalent to a further 1.1 – 11 MMbbl of gross recoverable oil.

7.4 Conclusions

Xodus has reviewed the data and interpretation provided by UKOG on Arreton and found it generally to be robust and of good quality. Xodus has calculated STOIIP and recoverable hydrocarbon volumes and found them to be close to UKOG derived volumes, which is not surprising given that the depth map and reservoir parameters underlying both estimates were the same or very similar.

[12] Risk Factor for Prospective Resources is the geological chance of success (or COS), or the probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. In addition, a prospect has also a Development/Commercial Risk.

8 HOLMWOOD

The Holmwood licence (PEDL143) is located in the northern part of the Weald Basin, to the west of the Horse Hill licence. Holmwood is operated by Europa Oil & Gas Plc ("Europa"). UKOG hold a 40% interest in the licence. One prospect on the Holmwood licence has been considered in this evaluation. Xodus has reviewed maps and interpretations made by the operator over the Holmwood prospect but has not reviewed the original seismic data. There are no wells on the licence, however the closest wells lie on the adjacent Brockham field which lies in a "cut-out" in the northern portion of the PEDL143 licence and at HH-1 immediately to the east of the licence. Xodus has used well and reservoir property interpretations made by UKOG at both HH-1 and Brockham in this evaluation.

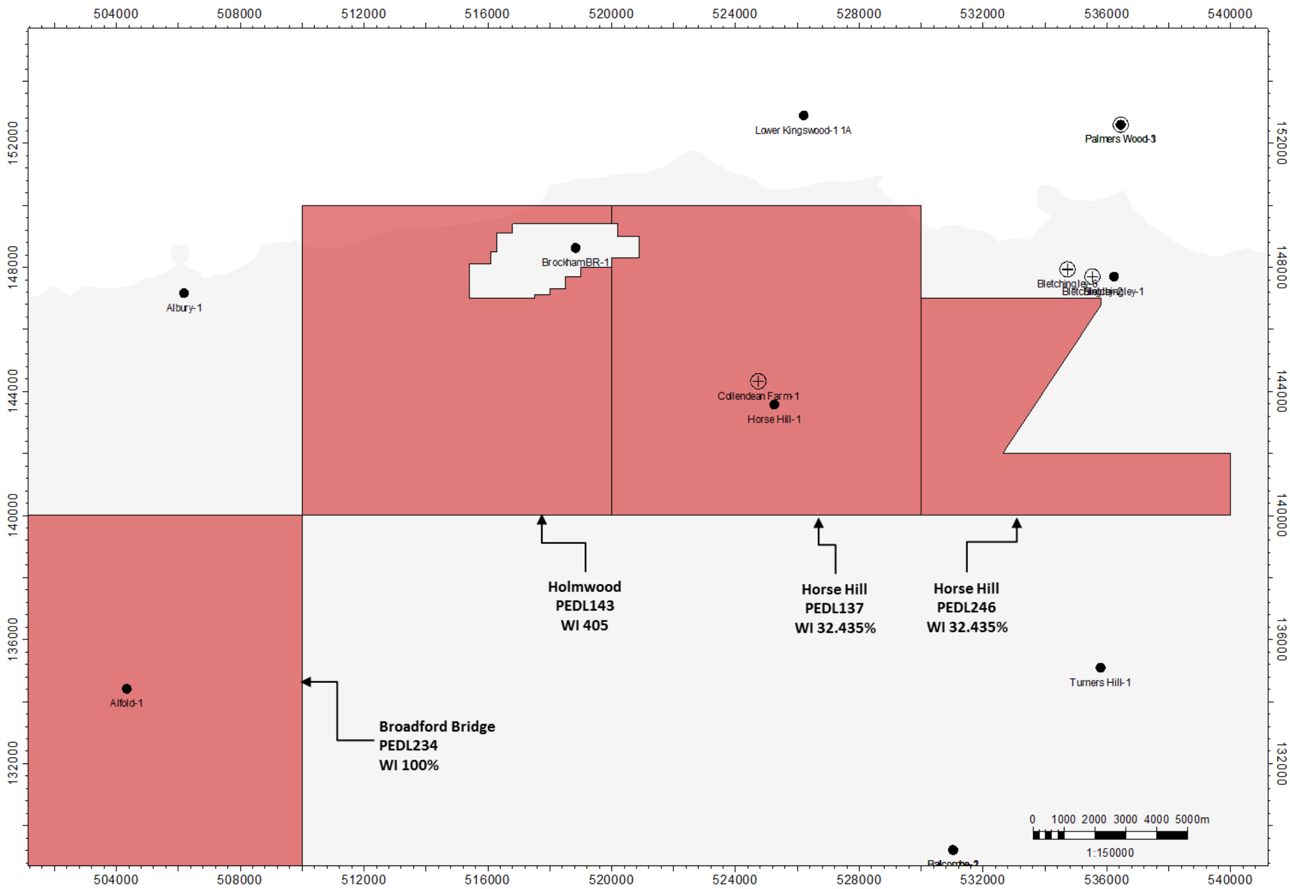


Figure 8.1 Map showing the Holmwood licence and nearby wells

8.1 Structure

The Holmwood prospect is mapped on a relatively sparse 2D seismic dataset, with the closure defined by 7 seismic lines. Seismic sections and maps show that at both potential reservoir levels, the trap is a four way dip closure with a faulted crest. The southern block is positioned higher than the northern block giving greater column height in this block, although the north block is areally larger, extending further to the north and east. The seismic map for the Portland reservoir is based upon using the Purbeck anhydrite seismic event as a proxy for the underlying Portland sequence. Closure polygons have been created on the "near top Purbeck" map which has been interpreted on a strong seismic reflector that ties with the Purbeck anhydrite in the Horse Hill-1 well approximately 10 km to the east. For the deeper Corallian Sandstone interval, a “near top Corallian” map has been provided. This also has been stratigraphically tied to the Horse Hill-1 well.

Whilst Xodus has not been provided with, nor reviewed the seismic interpretation project for Holmwood we consider that the top reservoir maps are consistent with known geological trends and reflect the likely structure. Xodus have reviewed various reports and presentations provided by UKOG and looked in detail at the seismic sections therein. Based upon these lines, it is clear that the interpretation has been carried out with great care and represents a best-estimate of the subsurface structure. Seismic horizons have been extended from nearby well locations for stratigraphic control, and the interpreted closely follows the seismic reflectors (see Figure 8.2 below). It appears that detailed 2D line-to-line mistie analysis has been carried out, with corrections made and little evidence of residual mistie remaining, as evidenced by the lack of “edges” or “jumps” on the TWT grids. The main uncertainty is likely to be the position and trend of the of the faults: given the sparse nature of the seismic data, the jump correlations between lines are inherently interpretative, but these have been created with a clear knowledge of fault trends across the basin and are reasonable. Further, any change in fault placement has no effect on the mapped closure. It is worth noting that a well drilled on the structure will not penetrate both the north and south blocks.

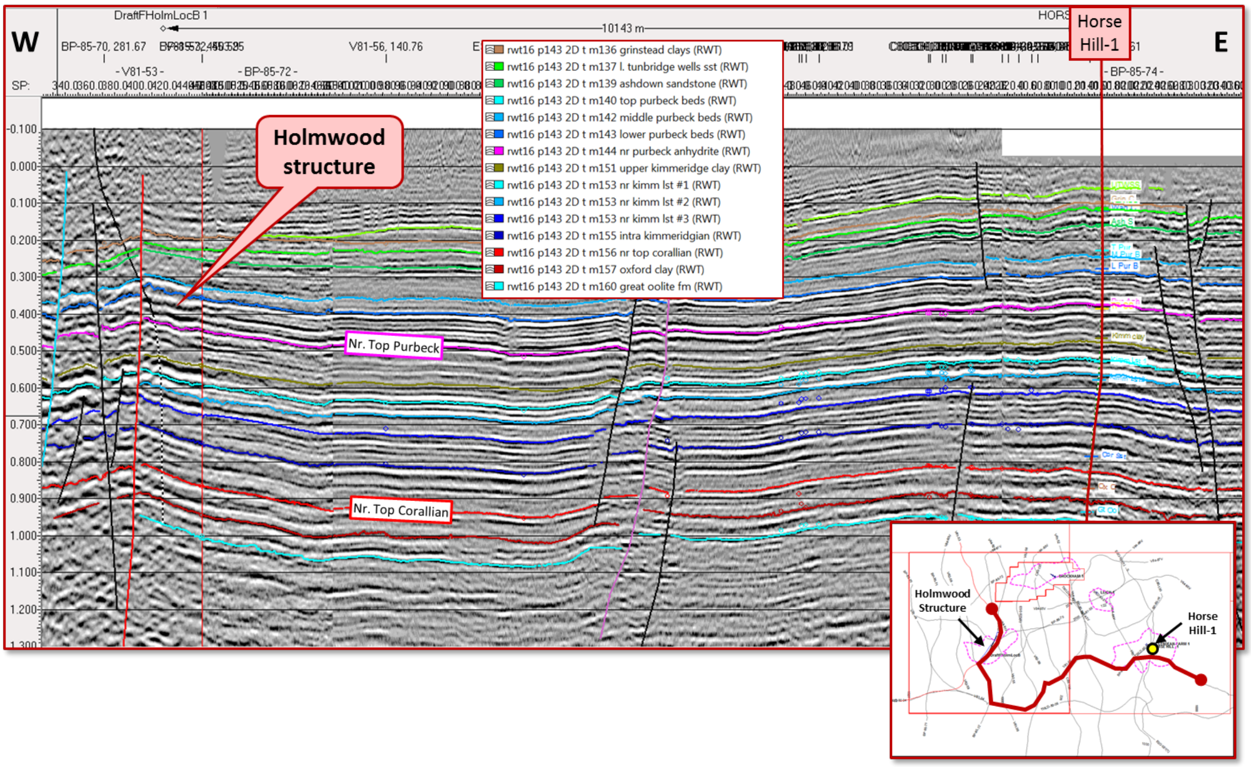


Figure 8.2 Arbitrary seismic traverse line across the Holmwood structure, extending eastwards towards the Horse Hill-1 well

Depth conversion of the two target sequences (Portland and Corallian) has been carried out using a simple Vavg from surface to create the depth structure maps. The Portland closure is based upon using the Purbeck Anhydrite depth grid as a proxy for top Portland and has been depth converted using a Vavg of 2605m/s. The deeper near Top Corallian marker has been depth converted using Vavg = 3010m/s. Both of these Vavg velocities have been derived from local well information, specifically the wells at Albury, Leigh, Brockham and Horse Hill.

8.2 Reservoir

Two reservoirs are considered at the Holmwood Prospect – the Portland and Corallian Sandstones. The Portland reservoir is known to be oil bearing in the Horse Hill discovery in the adjacent block and the Brockham field to the north. Thicknesses and reservoir parameters from the Horse Hill evaluation have been used in the estimation of in-place volumes for the Holmwood Portland reservoir.

Whilst the Corallian Sandstones are also present in both Horse Hill and Brockham, neither are considered as oil bearing reservoirs in these fields. Similar to the Portland, the Corallian is also a shallow marine sandstone, and has been found to be approximately 15m thick (as proven at Horse Hill-1 and Brockham-1). Petrophysical analysis carried out on the Horse Hill-1 well by NUTECH provides figures for net to gross of 61% and average porosity of 13%. Water saturation has been estimated from the ranges seen in reservoirs of similar properties in the basin.

It should be noted that, given the proximity to and geological similarities with the adjacent Horse Hill Kimmeridge oil discovery, the Kimmeridge Limestone reservoirs, are also highly prospective at Holmwood, but they are not considered in this report.

8.3 Hydrocarbon In Place and Resource Estimates

Xodus have estimated STOIIP and recoverable volumes for Holmwood using a stochastic approach. For each reservoir GRV has been determined using area depth data taken from the latest seismic interpretation and thicknesses taken from offset well data. The Top Purbeck (acting as proxy for the Portland sequence) and Near Top Corallian depth grids are shown in Figure 8.3 and Figure 8.4 below (with lowest closing contours and areas shown). As depth surfaces were not available to Xodus, maps were taken from UKOG materials, imported into Kingdom software and rectified in order to make an accurate assessment of closure area.

It is assumed that both the Top Purbeck Anhydrite and the “Near” Top Corallian are isopachs to the prognosed reservoir intervals of the Portland Sandstone and Corallian Sandstone respectively.

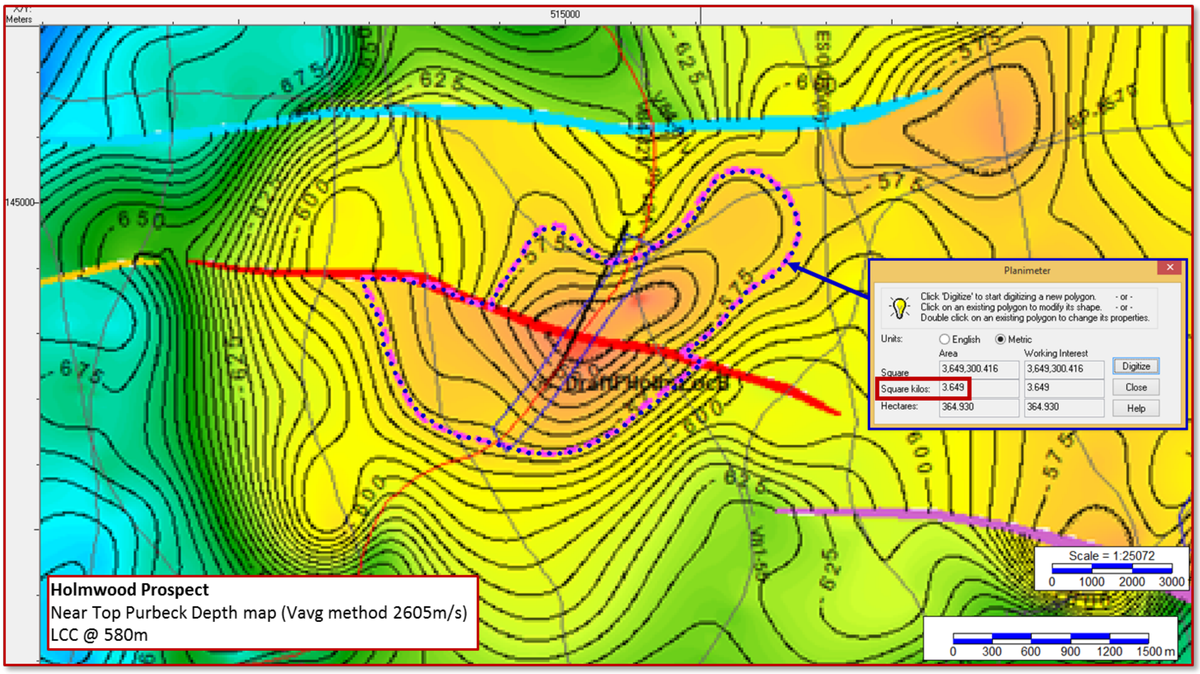


Figure 8.3 Near Top Purbeck (proxy for Top Portland) depth map (Contour Interval = 5m)
Lowest closing contour used for GRV calculation shown in blue. UKOG polygon shown in pink

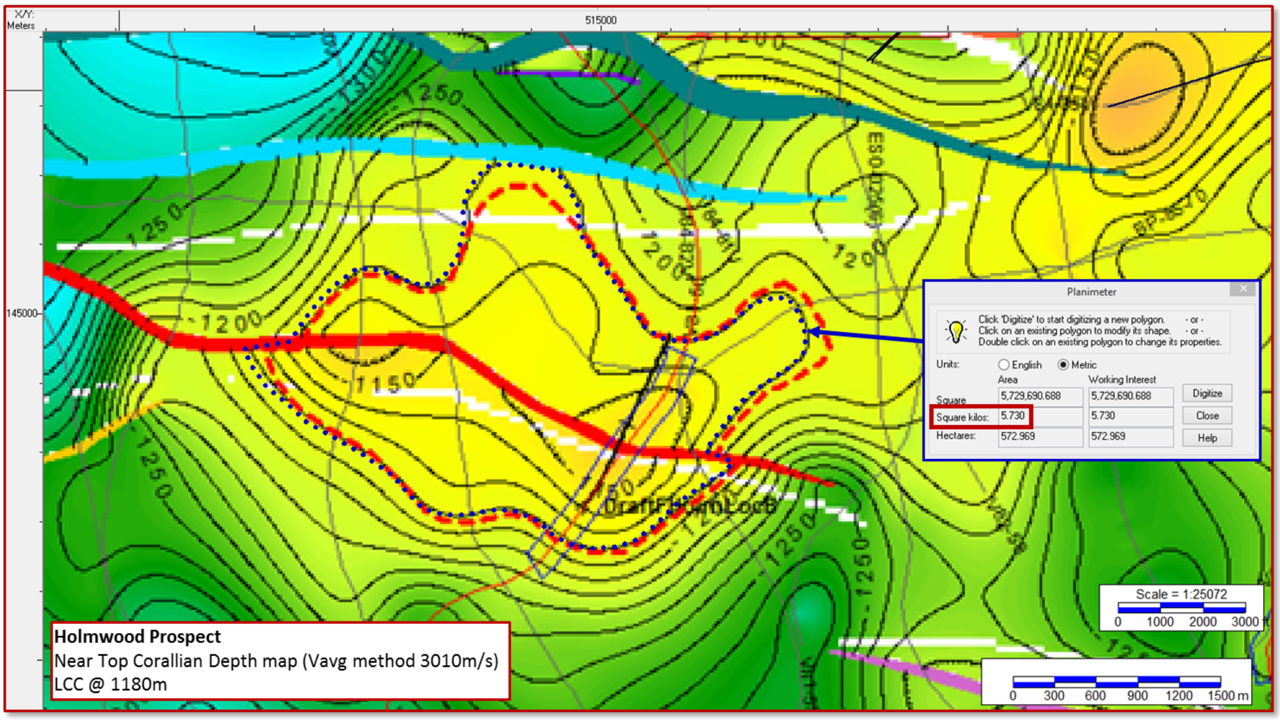


Figure 8.4 Near Top Corallian depth map (Contour Interval = 10m)
Lowest closing contour used for GRV calculation shown in blue. UKOG polygon shown in red

The structure is assumed to be fill to spill in the most likely case, as seen in most Weald Basin discoveries. A "percentage trap fill" has been used to consider both positive and negative uncertainty in the mapping, depth conversion and fill which could result in either shallower or deeper spill points or fluid contacts to occur. The trap is taken as 100% full in the mid case.

Other reservoir parameters have been estimated from nearby wells – Horse Hill-1 and Brockham-1. Table 8.1 and Table 8.2 give the parameters used in the evaluation.

	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	75	95	107	118	139	107	107
% Trap Fill	ft	Beta	53	80	100	125	206		100
Net-to-gross	%	Normal	18.5	44	58.5	73	98.6	58.5	58.5
Porosity	%	Beta	11	12	13.5	16	30		13.5
Sw	%	Normal	23	40	50	60	83	50	50
FVF (Bo)	rb/stb	Normal	1.01	1.03	1.04	1.05	1.07	1.04	1.04
Recovery Factor	%	Normal	1	5	10	15	23.8	10	10

Table 8.1 Portland reservoir parameters

	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	4	33	49	66	95	49	49
% Trap Fill	ft	Beta	53	80	100	125	206		100
Net-to-gross	%	Beta	1	15	35	70	97		37
Porosity	%	Normal	4.7	10	13	16	18.4	16	16
Sw	%	Normal	23	50	62.5	75	99	62.5	62.5
FVF (Bo)	rb/stb	Normal	1	1.09	1.14	1.19	1.28	1.14	1.14
Recovery Factor	%	Normal	1	5	10	15	23.8	10	10

Table 8.2 Corallian reservoir parameters

8.3.1 In Place Volumes

The STOIIP estimates for the Holmwood reservoirs are shown in the table below (Table 8.3).

STOIIP (MMbbl)	**Low**	**Best**	**High**	**Mean**
Portland	6.9	10.1	14.2	10.4
Corallian	4.9	12.5	29.1	15.3
Holmwood Total	**14.4**	**23.1**	**40.1**	**25.7**

Table 8.3 Holmwood prospect STOIIP estimates

8.3.2 Recoverable Resource

Recoverable volumes have been estimated using recovery factor ranges which are shown in Table 8.1 and Table 8.2. Recoverable volumes for Holmwood are designated as Prospective Resources. The estimates of gross Prospective Resource and net to UKOG are shown in Table 8.4.

The risk factor relates to the Geological Chance of Success ("COS"). The COS for the Portland has been estimated as 29% and for the Corallian as 17%. The Holmwood prospect is regarded as a near geological look alike to the Horse Hill discovery which accounts for the reasonably high assigned COS for the Portland. The key risk element for both reservoirs is determined to be reservoir performance, particularly the Corallian which has low NTG and porosity in Brockham. The Corallian is viewed to have a higher risk than the Portland because of the proximity of proven oil bearing Portland reservoirs close to Holmwood at HH-1. Trap definition is also a risk due to sparse seismic data and lack of well control, however, the seismic appears to be robustly interpreted and the closures are not reliant on faults. Depth conversion sensitivity is another aspect of both risk and uncertainty in the size of the overall size of the closure in the higher volume cases.

Prospective Resources	**Prospective Resources Gross**			**Prospective Resources Net to UKOG**			**Risk Factor**
	Low	**Best**	**High**	**Low**	**Best**	**High**	**COS[13] (%)**
Portland	0.45	0.98	1.71	0.18	0.39	0.68	29
Corallian	0.38	1.19	3.12	0.15	0.48	1.25	17
Holmwood Total[14]	1.19	2.29	4.26	0.48	0.92	1.70	

Table 8.4 Estimate of Holmwood Prospective Resource

The estimates for in place and recoverable volumes for the Holmwood reservoirs are different from those reported in the operator's most recent CPR [5]. Some of the inputs in the 2012 assessment are unclear, Xodus has used the maps and reservoir parameters from the closest analogue oil productive wells, HH-1 and Brockham, as described above.

In the event of a Portland discovery at Holmwood that demonstrates similar reservoir parameters to the HH-1 oil discovery, a water re-injection scheme could be implemented to provide pressure support and improve sweep-efficiency in the field's early productive life. It is reasonable to expect a material increment in overall oil recovery. Based on work carried out for Horse Hill, the successful implementation of such a scheme could lead to the recovery of an additional 8-14% of STOIIP, which based on current estimates of STOIIP, as shown in Table 8.3 could be equivalent to a further 0.6 - 2 MMbbl of gross recoverable oil.

8.3.3 Current Status

The operator, Europa Oil & Gas, gave an update to operations at Holmwood on 19th October 2017 stating that they expected to commence drilling operations at Holmwood in the first half of 2018.

[13] Risk Factor for Prospective Resources is the geological chance of success (or COS), or the probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. In addition, a prospect has also a Development / Commercial Risk.
[14] Stochastic sum

8.4 Conclusions

Xodus has reviewed the data available over the two reservoirs for the Holmwood prospect and has determined independent estimates of STOIIP and recoverable volumes.

The interpretation of the top reservoir markers from seismic and resulting maps appear robust, although as with many areas of the Weald basin, the sparse 2D data and depth conversion uncertainty increases the risk and possible range of outcomes. Xodus' methodology for estimating GRV differs from the previous interpretations.

Xodus has used different reservoir parameters from the previously published CPR, being primarily derived from Nutech's petrophysical analyses of the HH-1 and Brockham discovery wells. Xodus believe these volumetric inputs to be more consistent with other nearby fields and wells. The use of these revised parameters and different GRV methodology have resulted in larger volumes of in place in Xodus' estimates compared to the operator's prior 2012 CPR.

Xodus has also utilised its knowledge of nearby analogous fields to determine primary recovery factors for dependent upon a depletion drive mechanism. These numbers are lower than those used in the prior CPR. However, Xodus has noted the possible improvement in recovery efficiency should an early life pressure support scheme be implemented.

9 MARKWELLS WOOD

Markwells Wood is located in PEDL126 in the south west of the Weald Basin area. The Markwells Wood discovery was made in 2010 by the Markwells Wood-1 well (MW-1), which remains the only well on the discovery. Oil was encountered in the Middle Jurassic Great Oolite Limestones.

Xodus previously wrote a CPR on Markwells Wood in 2015 [6]. UKOG have informed Xodus that there has been no change to the interpretations or forward plans since this CPR.

9.1 Structure

9.1.1 Seismic

The Markwells Wood area is covered by a grid of 2D seismic lines of varying vintages, mainly from the early 1980s (Figure 9.1). The seismic database reviewed was provided as a Kingdom SMT project by UKOG. North to south trending dip lines are spaced between 600m-1200m, with strike lines at a similar spacing.

466 line km of the base seismic dataset were reprocessed in 2010-11 by GES and have provided a great improvement on the original dataset, allowing improved confidence in both the horizon and fault interpretation over the structure. Data quality in general is deemed to be acceptable for structural mapping however some small misties between the seismic still exist in the database. This has been accounted for in mapping, and any small jumps between lines are deemed to be inconsequential to the structural mapping.

Eight main lines cover the field area; with the nearest line to the MW-1 well shown in Figure 9.2, with the line through the highest structural closure shown in Figure 9.3. Picking across the structure is of high quality, while fault mapping appears reasonable, intersecting the main structural breaks. Correlation between lines is good with no obvious jumps in the interpretation

A single well has been drilled on the field, MW-1. The surface location of the well lies approximately 75m away from the nearest seismic control (line CV85-369). As the well deviates to the south, the well track and seismic line navigation cross, with the effect that at reservoir level they are just 5m apart. As such, it is possible to get a high quality well-seismic tie adding confidence to the accuracy of event picking on the seismic. The well-seismic tie is shown below in Figure 9.4. A good fit is achieved using a SEG Positive (AI Increase = Peak) synthetic Ormsby wavelet, allowing for some small shifts to tie events

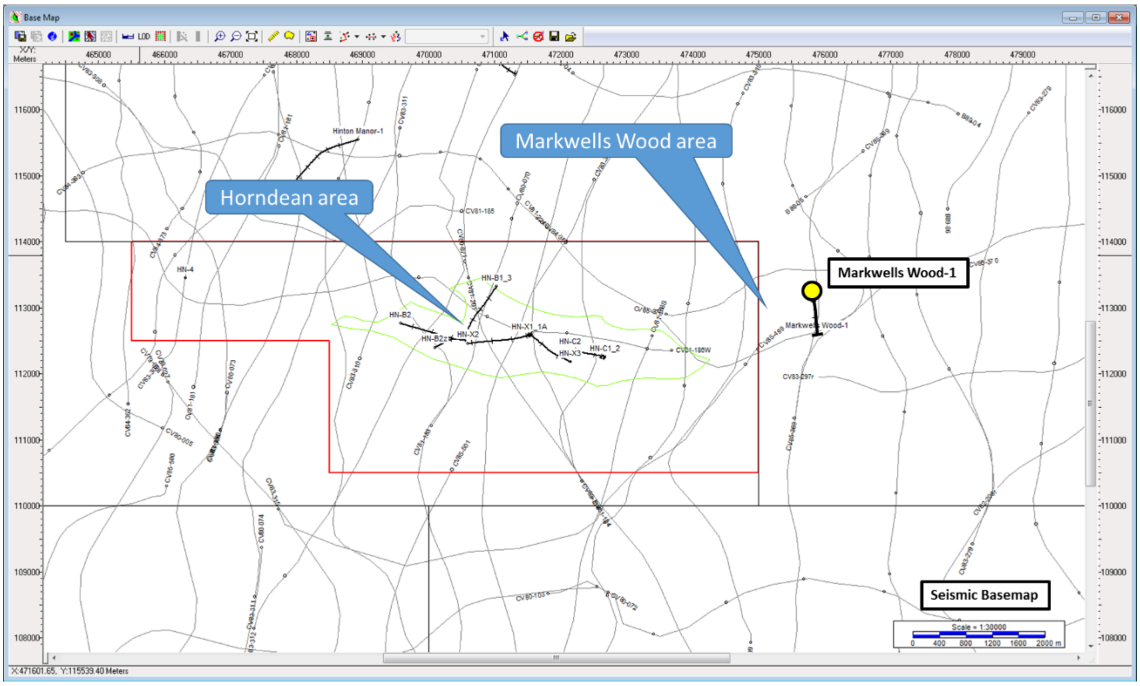


Figure 9.1 Markwells Wood license area seismic coverage

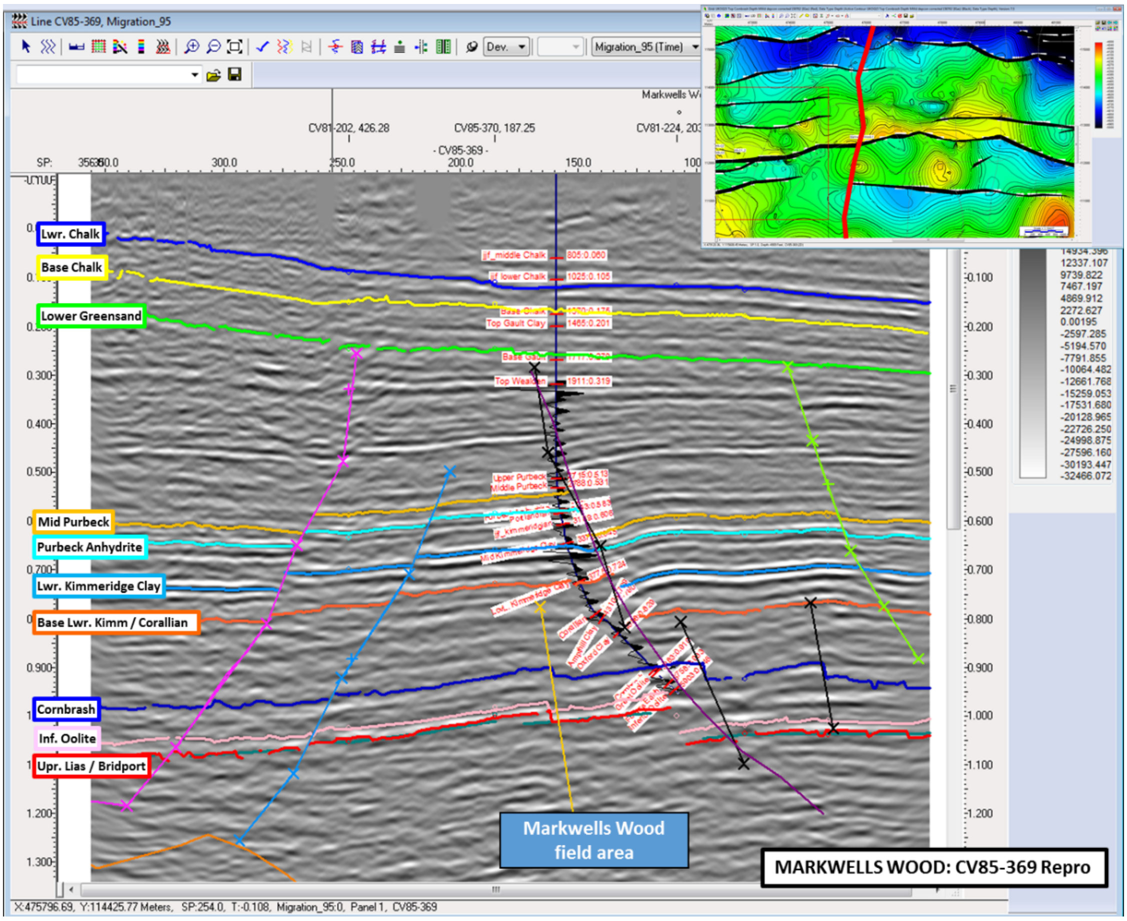


Figure 9.2 Line CV85-369 (Reprocessed)

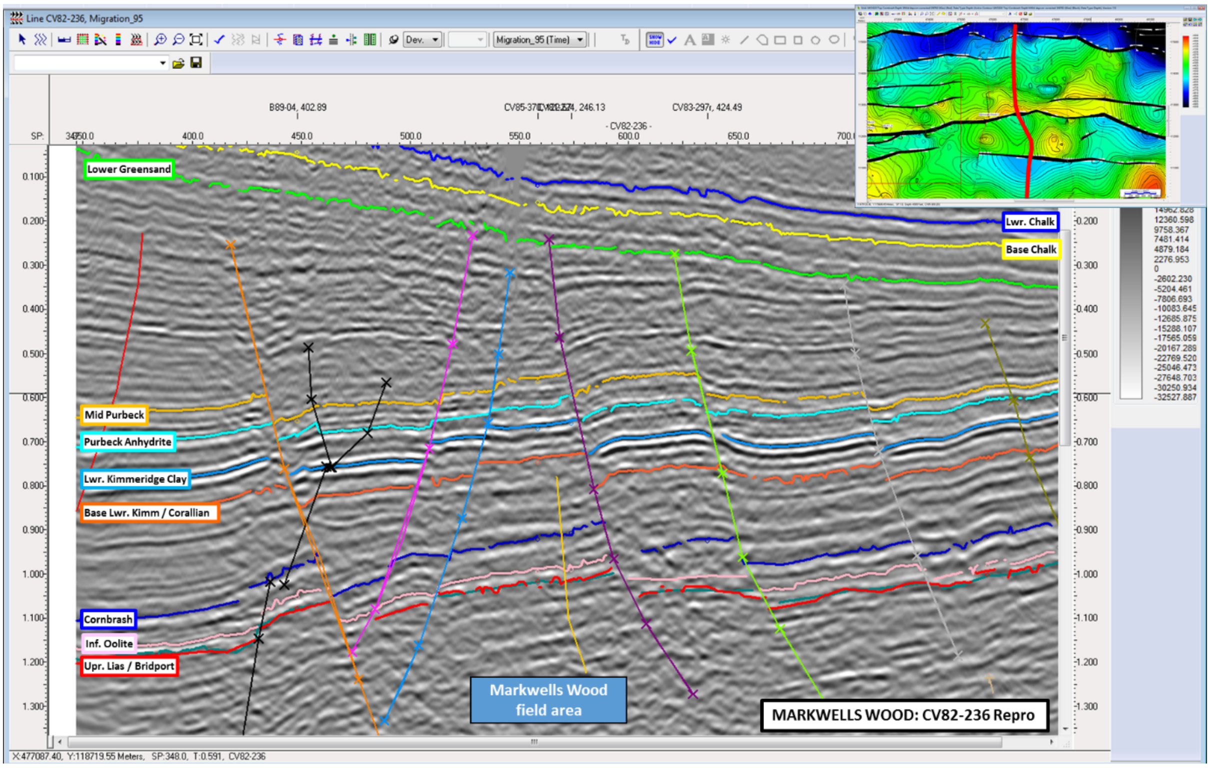


Figure 9.3 Line CV82-236 (Reprocessed)

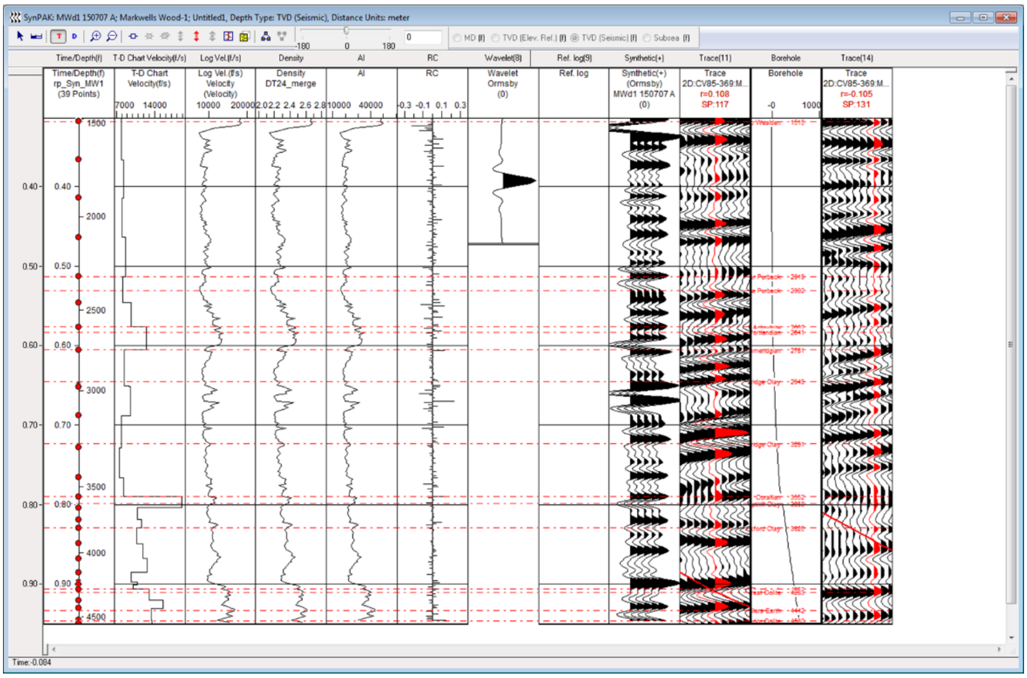


Figure 9.4 Markwells Wood-1 Well-to-seismic tie

9.1.2 Interpretation and Mapping

Whilst Xodus have not carried out any independent seismic interpretation or depth conversion, a thorough review has been undertaken and some simple depth conversion sensitivities have been tested. Based upon this, Xodus believe that the operator's time mapping is mainly reliable and of a high standard, with any small amendments considered to be of minor materiality to the structure. Regional TWT interpretation was provided for 11 horizons over the area. Time picks have been gridded at a single level, Top Cornbrash using a grid cell size of 50m x 50m. This cell size is deemed sufficiently fine to avoid over-simplifying and smoothing the structure by using too wide a spacing. The Top Cornbrash TWT grid was subsequently used for input to the depth conversion. Figure 9.5 below shows the Top Cornbrash gridded TWT map.

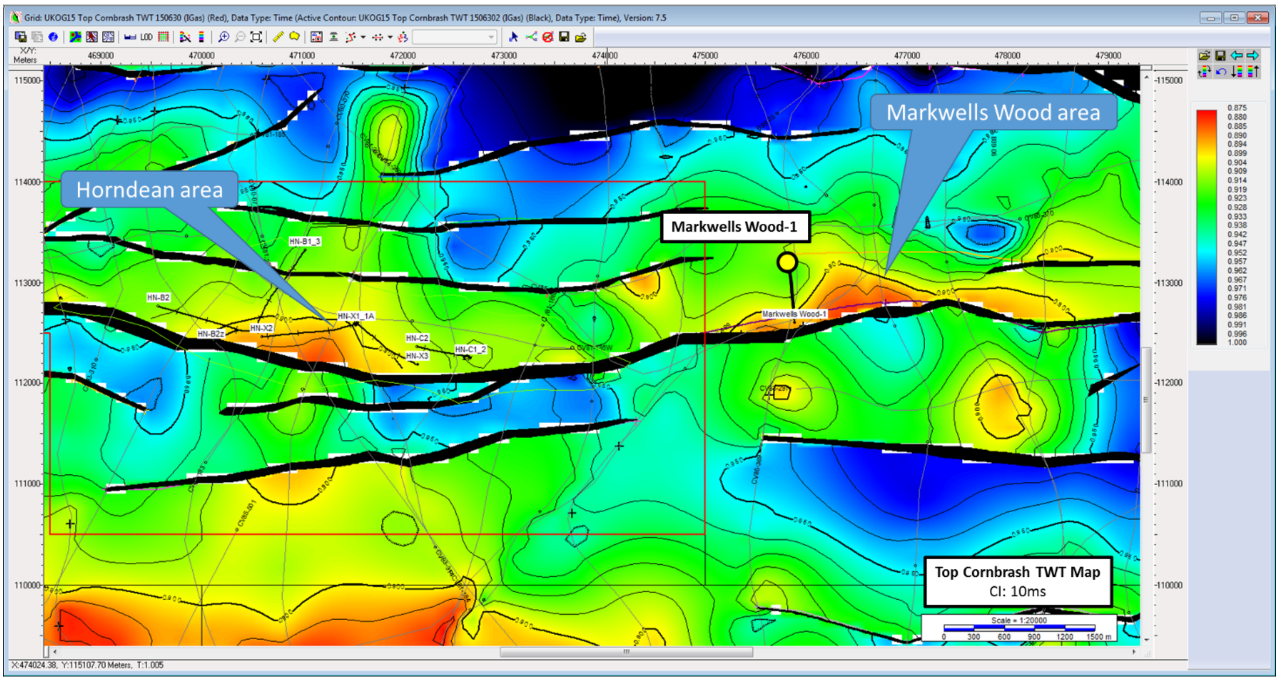


Figure 9.5 Top Cornbrash TWT structure grid (w/faults)

9.1.3 Depth Conversion

The prospect is deemed to be well-defined from seismic time mapping at all horizons over the area. The quality and density of the fault interpretation is deemed sufficient, with the fault polygons providing a good representation of fault heave in the Markwells Wood area.

UKOG have analysed the velocity functions of all nearby wells and found a generally consistent trend in the upper section of all wells to Top Cornbrash. Beneath the Cornbrash, velocity notably increases and as such any deeper surfaces would require a different function. Additionally, the nearby (~3500m to the west) Horndean HNC1-2 well yields a clearly anomalous velocity trend and has been discounted (Figure 9.6).

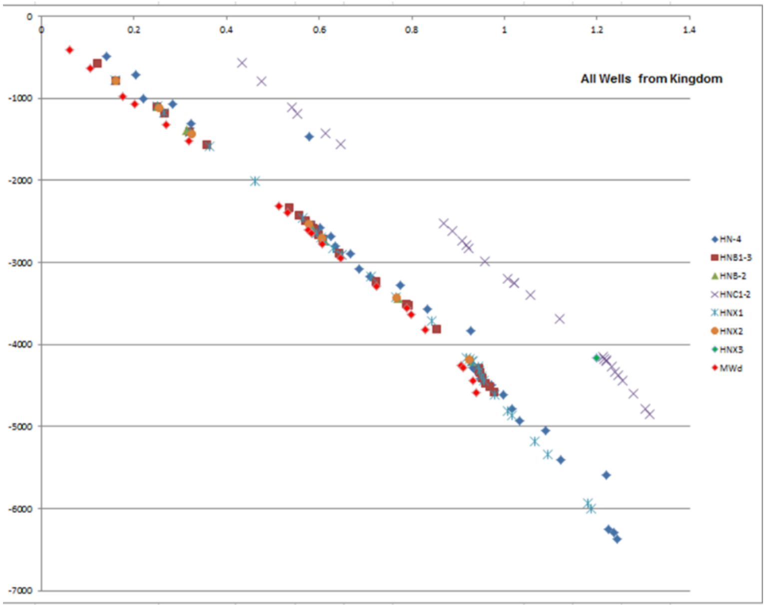


Figure 9.6 Velocity functions from nearby Horndean wells & Markwells Wood-1 (red diamonds). Note HNC1-2 lying anomalously off-trend to the other wells

Based upon consistent velocity function observed (removing the anomalous HNC1-2 well), a depth conversion of the Top Cornbrash marker has been carried out, with residuals to the wells subsequently handled via a correction grid. Residuals from the initial depth conversion were all noted to be consistently deeper than actual depths, and all were noted to be greater than 100ft.

Our review of the depth conversion found that a minor error was made during initial depth conversion, prior to the flexing to fit the wells. The depth function derived from the well information was as follows:

$$Z = -1198.48*TWT^2 – 3337.46*TWT – 295.84$$

However, during the depth conversion the following function was applied:

$$Z = -1198.48*TWT^2 – 3337.46*TWT – 395.84$$

The use of “-395.84” during the depth conversion effectively added a consistent bulk shift on the Top Cornbrash of an additional 100ft, and thus a residual to the well tops 100ft greater than should be the case. This explains the large and consistently >100ft residuals observed from the initial depth conversion. The issue was raised by Xodus during the review and agreed with UKOG geophysicists that this issue be resolved for accuracy and consistency. However, it should be emphasised this error creates **no material difference to the structure** of the field: simply the correction grid created between the depth surface and well tops now requires an additional bulk shift of 100ft included to take account for the shift. (in effect, residuals at Markwells Wood-1 are ~22ft, not ~122ft as noted by UKOG). The top reservoir depth map is shown in Figure 9.7

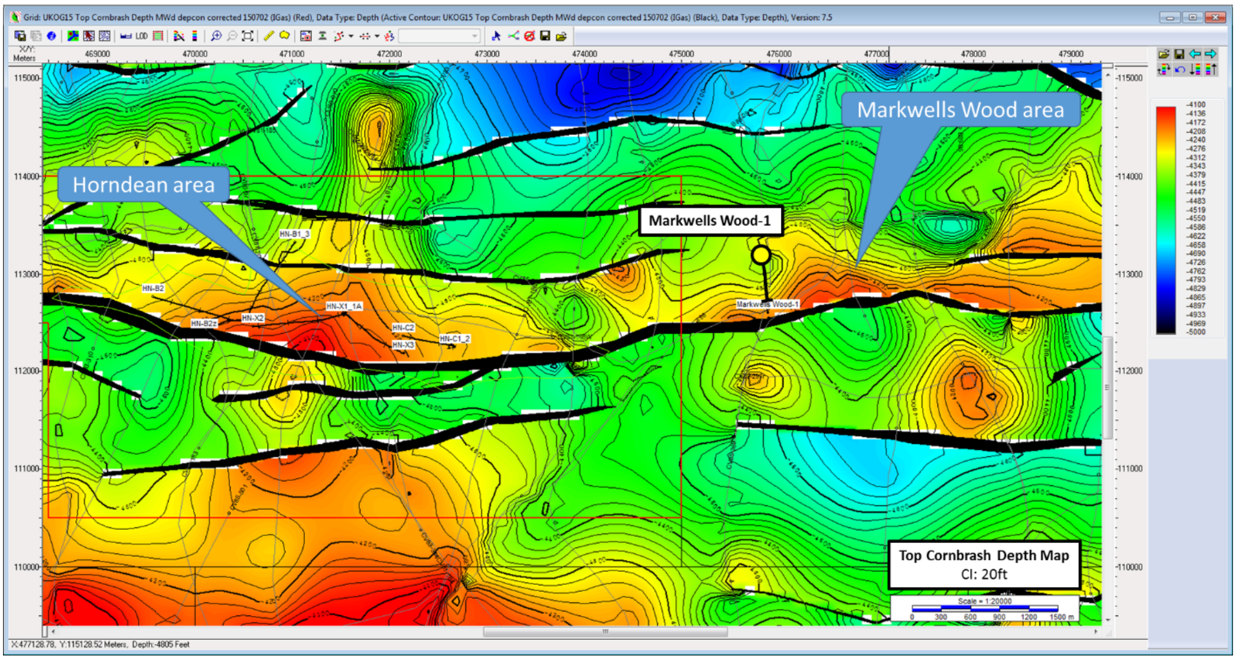


Figure 9.7 Top Cornbrash Depth Grid

The discovery is deemed to be well-defined from seismic time mapping at all horizons over the area. Both horizon and fault mapping appear robust and are good technical representations of the subsurface structure- however it is recognised that some uncertainty will naturally exist in the mapping due to data availability and density of the 2D seismic grid.

Depth conversion, whilst simplistic in the area, is wholly compatible with the field area and control available, without over-complicating the process (deemed unnecessary due to the consistent velocity profile observed in the wells). Sufficient analysis of alternate depthing methods have been investigated. The small error in depth conversion, while of no material difference, is being dealt with by UKOG for consistency and accuracy.

9.2 Reservoir

The reservoir of the Markwells Wood discovery is the Great Oolite Limestone formation which is a common reservoir unit in the Weald basin, the Markwells Wood well encountered 318 ft of the Great Oolite reservoirs from the top of the Cornbrash to the base of the Lower Massive Oolite / top of the Fullers Earth which was logged and cored.

The Great Oolite is a stacked sequence of oolite shoals, which was deposited in the Middle Jurassic on an open marine, carbonate ramp similar to that seen in the Bahamas Bank in the present day. The reservoir rock is generally a clean oolitic limestone with minor argillaceous horizons, the main reservoir facies are oolitic peloidal grainstones and packstones but the best reservoir units are those which were are cross stratified oolitic grainstones. Finer grained intervals composed of less well sorted wackestones and mudstone are generally non-reservoir. The reservoir has also been subject to complex diagenesis which has created both additional moldic porosity and calcite cements resulting in a poorly connected pore spaces and low permeability. The average porosity of the reservoir is about 15% but permeability is commonly less than 1mD. The low permeability leads to high capillary entry pressures and a transition zone above the free water level that extends over approximately 500 feet.

The reservoir is split into 5 zones:

- The Cornbrash – comprises shales and argillaceous limestones which have low porosity and permeability, there is some localised porosity development related to dolomitisation
- Interbedded Oolite – has variable thickness and facies with moderate porosity which is mostly intra particle and poorly connected. Sediments were deposited in small scale oolite bars and washover deposits
- Upper Massive Oolite – this is the best reservoir interval and was deposited as tide dominated oolitic shoals which have formed metre scale bedding, they also have mainly intra-particle porosity but it is enhanced by moldic porosity which improves permeability
- Oncolites – composed of burrowed mudstones the oncolites have low porosity and permeability
- Lower Massive Oolite – good reservoir of well sorted packstones and grainstones deposited on oolitic shoals, intra-particle porosity is developed with some enhancement resulting from dissolution but reduced by cementation. In Markwells Wood these zones are close to the FWL and therefore water saturation is extremely high.

A geological summary of the Great Oolite was available and demonstrates the lateral continuity and thickness variations in the different zones along strike in the analogue fields of Horndean to the west and Chilgrove to the east. An isopach map generated from well data shows Markwells wood to be on the edge of an thick oolite shoal, reservoir quality it observed to decrease to the east, off the shoal, but is locally variable. Reservoir properties are comparable across the analogue wells

A detailed petrophysical study was available for the Markwells Wood well and the nearby wells from analogue fields; Horndean and Chilgrove. Xodus has not carried out a detailed audit of the petrophysical interpretation but has found the methodology applied to be in good practice and the results consistent with the values expected from similar reservoir units in the Weald basin. Figure 9.8 shows the MW-1 CPI.

All formations are seen to be petrophysically similar across the three fields / discoveries, porosities vary from 6-18% and permeability is less than 5mD, Markwells Wood fits into the middle of this range. A deep transition zone of over 500ft is assumed because of the high entry pressure and different oil water contacts depending on the reservoir properties are expected. An ODT is recorded in MW-1 at 4400 ft TVDSS, a number of different methods have been used to calculate water saturation and determine the FWL. Using an Sw height method a FWL of 4590 ft TVDSS has been calculated and this has been used as the basis for assigning OWC depths for volumetrics. Sensitivity studies have been carried out previously but are viewed to be unreliable as there was no data to support its use. The results of the petrophysical study have been used in the determination of HCIIP.

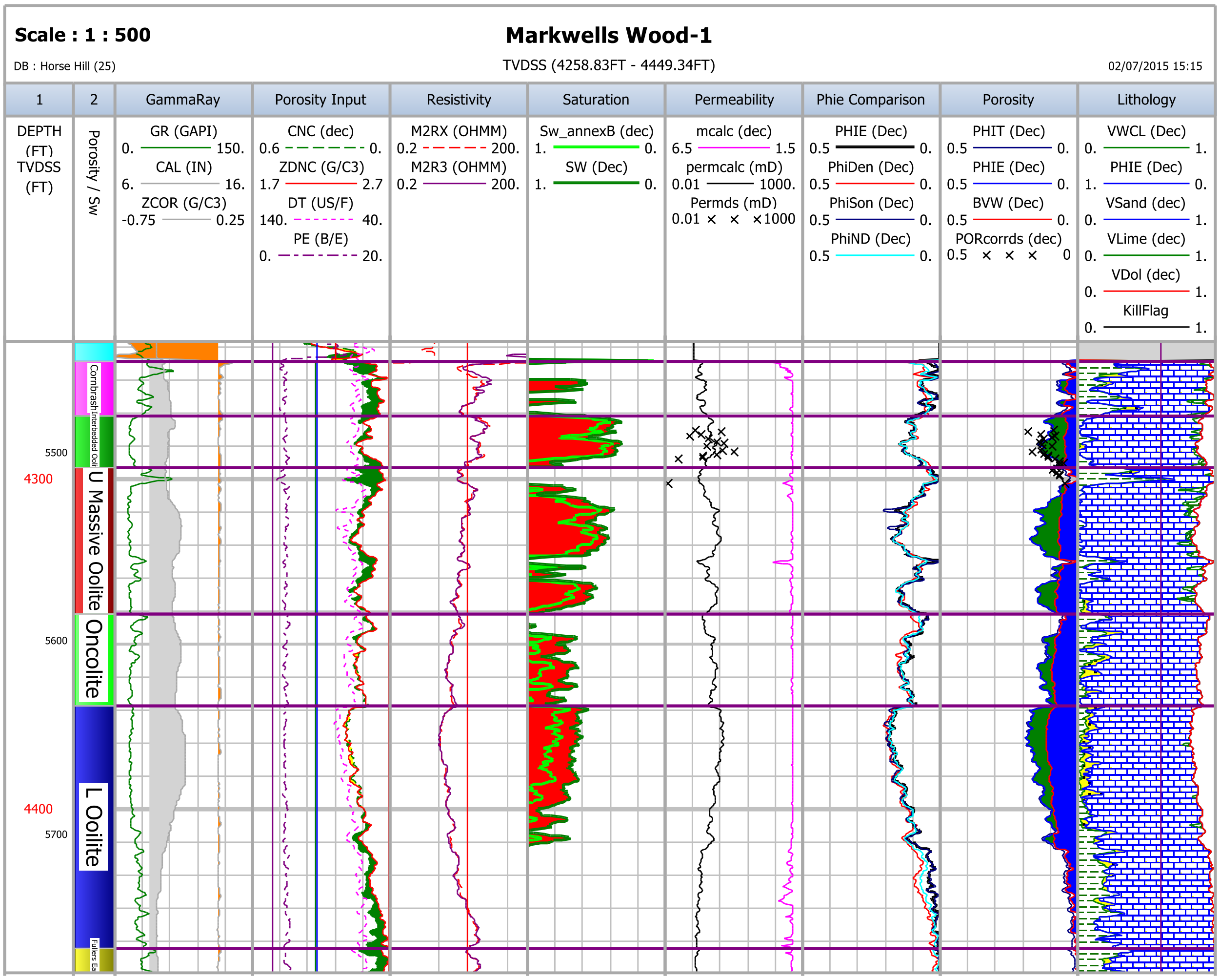


Figure 9.8 Markwells Wood-1 CPI across the Great Oolite formation.

9.3 Hydrocarbon In Place Estimates

9.3.1 Approach

Xodus' STOIIP values were calculated stochastically using REP5 software from Logicom E&P. Xodus has followed the approach applied by UKOG in calculating volumes for each reservoir zone and has found the values and ranges used by UKOG to be generally be fair although some adjustments have been made where deemed appropriate.

For the purposes of GRV and STOIIP calculations, the top reservoir map was loaded into Petrel, Figure 9.9 shows the top reservoir map with the polygons used in Petrel for determining GRVs.

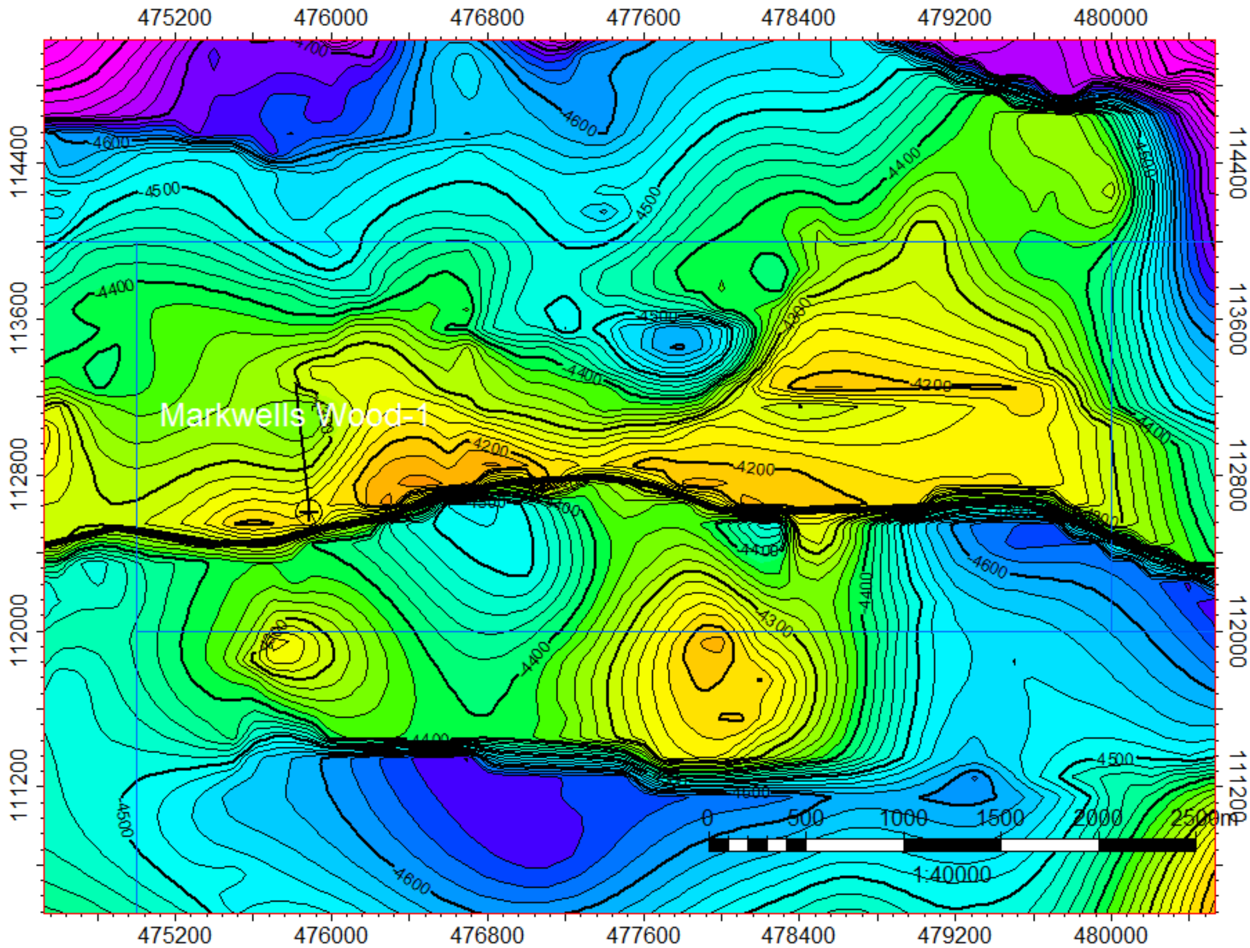


Figure 9.9 Map showing top Cornbrash which was used to generate area depth data for each reservoir.

Area-depth data was calculated using Petrel software for the Cornbrash map within the structural boundaries, polygons were used to define the fault block. For the other reservoir zones a shift was applied to the top input data to account the thickness of the overlying units so that the same map could be used in each case, they cannot be mapped individually from seismic data. The REP files from UKOG contained a shift which was not changed, rather than a single depth shift a range has been applied with a beta distribution. The minimum shift is generally the thickness from the MW-1 well and the mid and high case by the thicknesses from the Chilgrove-1 and Horndean-2 well which are the closest wells to Markwells Wood.

The OWC has been taken from the petrophysical interpretation work. The FWL was calculated as 4590 ft TVDSS and the OWC is thought to be 160ft shallower than this. A deeper contact has been assumed in the higher quality Upper Massive Oolite and shallower contact in the Cornbrash and Oncolite.

Reservoir thicknesses were taken from the gross thicknesses observed in the wells. A normal distribution was generated using the MW-1 well thickness and either the Chilgrove-1 well or the Horndean-2 well depending on which was the most appropriate in relation to the overall well correlation and observed regional thickness changes.

Net to gross, porosity and water saturation (“Sw”) have been taken from the results of the petrophysical interpretation of the same three wells and ranges and distributions generated in a similar method to reservoir thickness, as described above.

Formation volume factor and gas oil ratios have been accepted by Xodus and are unchanged from the UKOG inputs.

Table 9.1 shows the parameters and distributions used in the determination of STOIIP for each reservoir zone

Cornbrash	**Unit**	**Shape**	**Min**	**P90**	**P50**	**P10**	**Max**	**Mode**	**Mean**
Thickness	ft	Normal	4.3	11	16	21	27.7	16	16
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Normal	4283	4350	4400	4450	4517	4400	4400
Net-to-gross	%	Beta	1.5	2.42	5.25	10	20	3.3	5.78
Porosity	%	Normal	7.19	8.4	9.3	10.2	11.4	9.3	9.3
Sw	%	Normal	25.6	42.2	54.6	67	83.6	54.6	54.6
FVF (Bo)	rb/stb	Normal	0.976	1.04	1.09	1.14	1.2	1.09	1.09
GOR	scf/bbl	Lognor	12	25	43.3	75	157	36	47.5

Interbedded Oolite	**Unit**	**Shape**	**Min**	**P90**	**P50**	**P10**	**Max**	**Mode**	**Mean**
Thickness	ft	Normal	0	15.5	27.8	40	56.4	27.8	27.8
Shift Top Reservoir	ft	Beta	7.28	11.2	18	27	40.5	16	18.6
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Normal	4360	4400	4430	4460	4500	4430	4430
Net-to-gross	%	Normal	51.4	64.9	74.9	85	98.5	74.9	74.9
Porosity	%	Normal	7.25	9.4	11	12.6	14.7	11	11
Sw	%	Normal	28.6	39.7	48	56.2	67.3	48	48
FVF (Bo)	rb/stb	Normal	0.976	1.04	1.09	1.14	1.2	1.09	1.09
GOR	scf/bbl	Lognor	12	25	43.3	75	157	36	47.5

U Massive Oolite	**Unit**	**Shape**	**Min**	**P90**	**P50**	**P10**	**Max**	**Mode**	**Mean**
Thickness	ft	Normal	29.6	44.6	55.8	67	82	55.8	55.8
Shift Top Reservoir	ft	Beta	22	31.5	47.1	67	95.9	43	48.3
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Normal	4360	4400	4430	4460	4500	4430	4430
Net-to-gross	%	Normal	57.6	69	77.5	86	97.4	77.5	77.5
Porosity	%	Normal	9.59	11.5	12.9	14.3	16.2	12.9	12.9
Sw	%	Normal	35.9	45.6	52.8	60	69.7	52.8	52.8
FVF (Bo)	rb/stb	Normal	0.976	1.04	1.09	1.14	1.2	1.09	1.09
GOR	scf/bbl	Lognor	12	25	43.3	75	157	36	47.5

Oncolite	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Beta	14	20.7	28.5	36.9	46	28	28.7
Shift Top Reservoir	ft	Beta	65.8	76	95	121	162	88.5	97
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Normal	4372	4383	4391	4399	4410	4391	4391
Net-to-gross	%	Beta	1	30.4	50.7	67	77	55	49.7
Porosity	%	Normal	5.12	7.8	9.8	11.8	14.5	9.8	9.8
Sw	%	Normal	60.7	72.9	82	91.1	103	82	82
FVF (Bo)	rb/stb	Normal	0.976	1.04	1.09	1.14	1.2	1.09	1.09
GOR	scf/bbl	Lognor	12	25	43.3	75	157	36	47.5

L Massive Oolite	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Lognor	40.6	57	73.4	94.5	133	70.6	74.8
Shift Top Reservoir	ft	Beta	93.9	103	123	153	206	114	126
Area uncertainty	%	Normal	41.5	75	100	125	159	100	100
OWC	ft	Beta	4360	4400	4430	4460	4500	4430	4430
Net-to-gross	%	Beta	43	47.9	57.6	71	93	54	58.7
Porosity	%	Normal	5.1	10.2	14	17.8	22.9	14	14
Sw	%	Normal	56	64	70	76	84	70	70
FVF (Bo)	rb/stb	Normal	0.976	1.04	1.09	1.14	1.2	1.09	1.09
GOR	scf/bbl	Lognor	12	25	43.3	75	157	36	47.5

Table 9.1 Parameters used in the estimation of STOIIP

9.3.2 In Place Volumes

Table 9.2 shows Xodus' Gross STOIIP estimates for the Markwells Wood Discovery for the whole structure. The totals are stochastic sums and do not sum together arithmetically.

STOIIP (MMbbl)	Low	Best	High	Mean
Cornbrash	0.15	0.37	0.89	0.46
Interbedded Oolite	6.74	13.4	22.9	14.3
Upper Massive Oolite	13.8	22.4	35.0	23.6
Oncolite	0.36	0.98	2.09	1.13
Lower Massive Oolite	2.66	6.3	12.4	7.07
Markwells Wood Total	**32.7**	**45.6**	**61.8**	**46.6**

Table 9.2: Xodus Markwells Wood gross STOIIP estimate

9.4 Production History and Review of Reservoir Dynamic Behaviour

MW-1 produced during an Extended Well Test (EWT) and the well was then shut in by the previous operator of the licence. The nearby Horndean field has seen some success with horizontal wells and UKOG believes that this success can be reproduced on Markwells Wood. As such, UKOG has modelled well performance for a future horizontal producer (a horizontal well drilled as an up-dip sidetrack of MW-1) on the worst performing horizontal Horndean well (Horndean-X3). Xodus agrees with UKOG that this is a prudent approach, also when taking into account the option to drill longer well trajectories and to apply modern well completion and reservoir stimulation technologies which may further enhance well productivity.

Nevertheless, Xodus took a different approach to determine reservoir productivity and well performance, taking the MW-1 EWT data into account.

A numerical reservoir model has been developed using Eclipse reservoir simulation software. A simple reservoir model was built in Petrel using the latest top reservoir grids and thicknesses of reservoir zones from MW-1. The model was populated with porosity and net to gross based on the petrophysical interpretations provided by UKOG. All reservoir parameters were kept constant within each layer in the model.

The dynamic data provided was reviewed and used for defining other parameters. Where data was not available values from the nearby Horndean field were taken as a good analogue.

9.4.1 MW-1 Extended Well Test (Production History)

MW-1 was tested from December 2011 to May 2012 and produced 3,931 bbl in total during that period. Figure 9.10 shows the results of the test. The EWT has previously been studied by OPC[15] who concluded that a dual porosity model should be used to match the test results.

[15] A Review of the Performance of Markwells Wood 1, Onshore UK, Oilfield Production Consultants (OPC) Ltd, 31 October 2012

It should be noted that there was evidence of wax production during the EWT, which may have restricted production rates. This is evidenced by the recovery in production immediately following the hot oil de-waxing treatments.

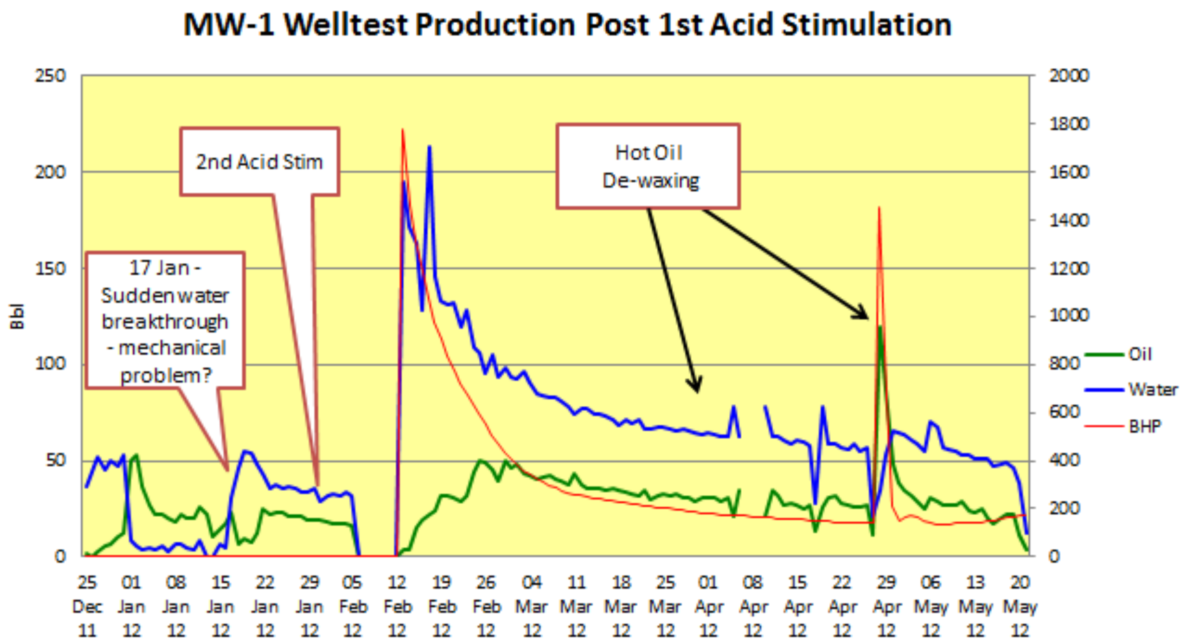


Figure 9.10 MW-1 extended well test

As part of Xodus' review, the OPC interpretation has been revisited to check whether an alternative model can be proposed.

Due to the short durations of the build-ups (BU) in the MW-1 EWT it is not possible to identify any characteristic reservoir flow regimes. Analysis of the drawdown data shows greater uncertainties as it is very much dependent on the accuracy of the rate measurement.

As gauge data were not available, the Bottom Hole Pressure (BHP) was digitised from the OPC report to allow analysis. Rate curves and pressure curves were smoothed for the analysis, see Figure 9.11.

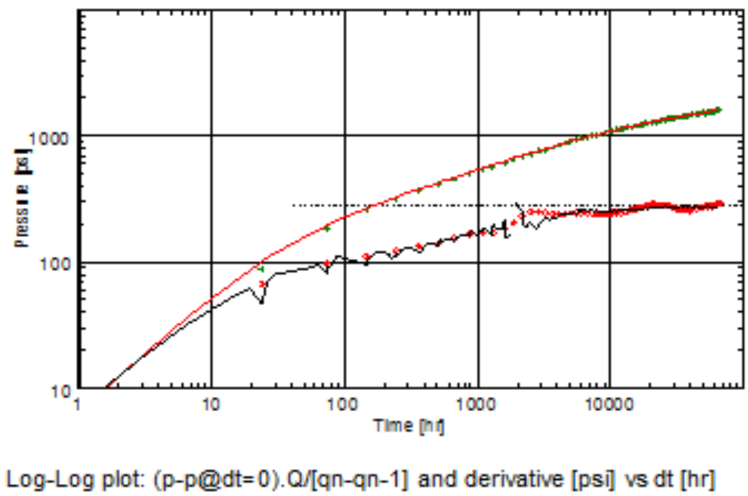


Figure 9.11 Log-log plot of MW-1 drawdown

The derivative of the slope shows the influence of the fracture followed by a period of stabilisation, supporting the OPC interpretation. Xodus' interpretation of the part of the EWT between 12th February 2012 and 28th April 2012 is that the well intersects a fracture of 138 ft half-length and reservoir permeability of 37mD ft. After taking into account the relative permeabilities of the oil and water (the well produced 69% water) a single-phase permeability of 95 mD ft is calculated from the MW-1 well test. Assuming flow from the Upper Massive Oolite only, as this is the highest quality reservoir zone with a thickness of 40 ft, an average permeability of 2.4mD is determined, applying a lognormal distribution gives a distribution which can be used in modelling as shown in the following table.

Permeability	P90	P50	P10
k, mD	1.6	2.4	3.4

Table 9.3 Permeability assumptions used in Xodus modelling

Porosity and Permeability

Air permeability measured on cores varies from 0.1 mD to 10 mD with no reliable correlation between permeability and porosity, even when considering different facies. The porosity-permeability transform from the OPC report was used to generate permeability in the model from the modelled porosity; a permeability multiplier was applied where it is thought the Upper Massive Oolite has the best permeability.

The horizontal permeability is assumed to be isotropic and a ratio of vertical to horizontal permeability (kv/kh) was used as an input for the vertical permeability. This ratio has no impact on the MW-1 history match, but is however important in forecasting the performance of a horizontal well.

PVT

No PVT data is available for Markwells Wood. PVT assumptions are as reported in the Horndean oil field, Field Development Plan, June 1988[16]. The parameters are summarised in the table below.

Reservoir Parameters	
Reservoir Datum	4,374 ft TVDSS
Pressure at Datum	2,026 psia
Temperature at Datum	142 °F
Saturation Pressure (Bubble point pressure	363 psia
Viscosity at initial conditions	1.65 cP
Fluid density at initial conditions	0.783 g/cc
FVF at initial conditions	1.135 res bbl/st bbl
Solution Gas Oil Ratio (Rs)	168 scf/stb

[16] The Horndean oilfield, Field Development and Production Programme, Annex B, submission to the Department of Energy, Carless Exploration Ltd, June 1988

Compressibility above Pbpt:	8.22 x 10^{-6} vol/vol/psi^{-1}
Gravity of residual oil:	35.4 °API
Wax content of residual oil	10.6% w/w

Water Properties

Total solids	99650 mg/l

Based upon Correlations

Compressibility cw	2.5 10^{-6} psi^{-1}
Volume factor: Bw	1.015
Viscosity at datum conditions	0.6 cP

Table 9.4 Summary of PVT parameters from Horndean field

Water Saturation

Initial water saturation and relative permeability curves were taken from the Horndean-2 well as no capillary curves have been measured on MW-1. An irreducible water saturation of 30% and a residual oil saturation of 30% were used. These parameters were not changed for the history match. An OWC at 4400 ft TVDSS was used, with FWL assumed to be 160 ft deeper. Figure 9.12 shows the water saturation in the model.

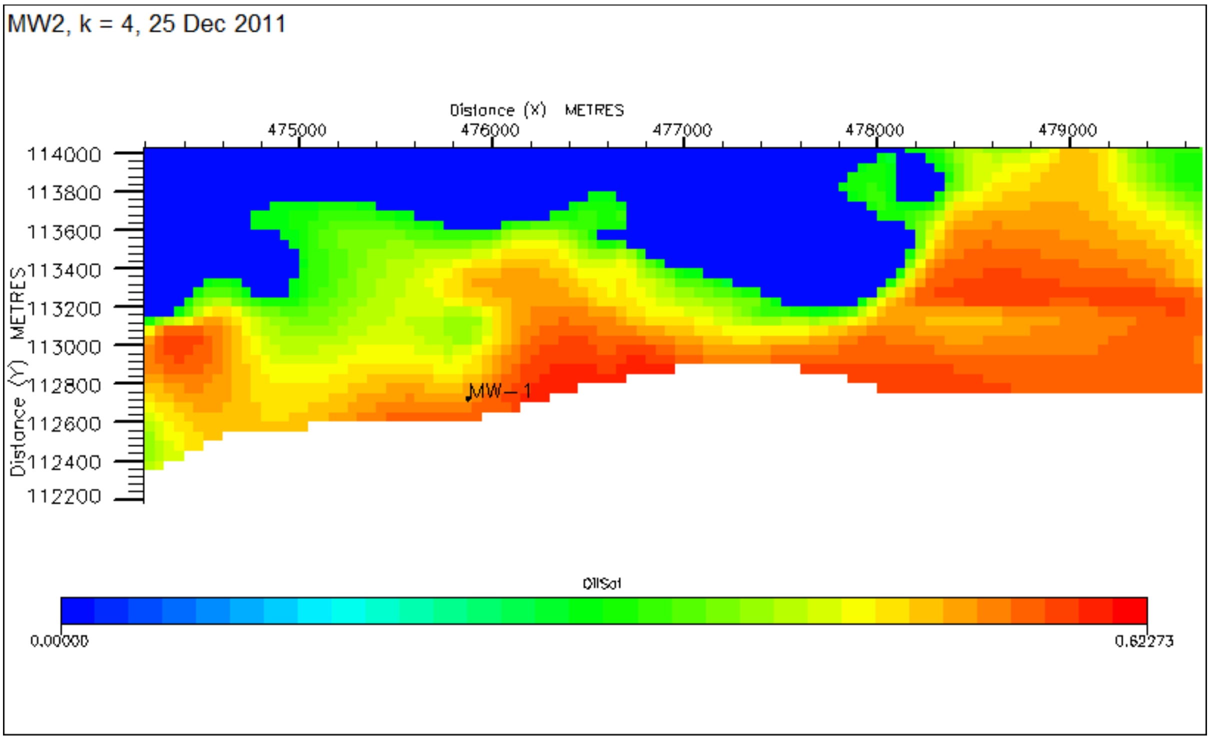


Figure 9.12 Oil saturation in the Markwells Wood model

9.4.2 History Match

The porosity-permeability relationship derived by OPC was used to generate permeability in the model with a permeability multiplier applied to all layers in order to match the well test. The fracture, observed on well test, is not modelled specifically as there are too many uncertainties on the fracture dimensions. A skin was applied to represent the fracture. The history match for MW-1 is shown in Figure 9.13.

During the history match, no attempt was made to match the bottom hole pressure of MW-1. The permeability multiplier was adjusted, within a reasonable range, to match the produced fluids.

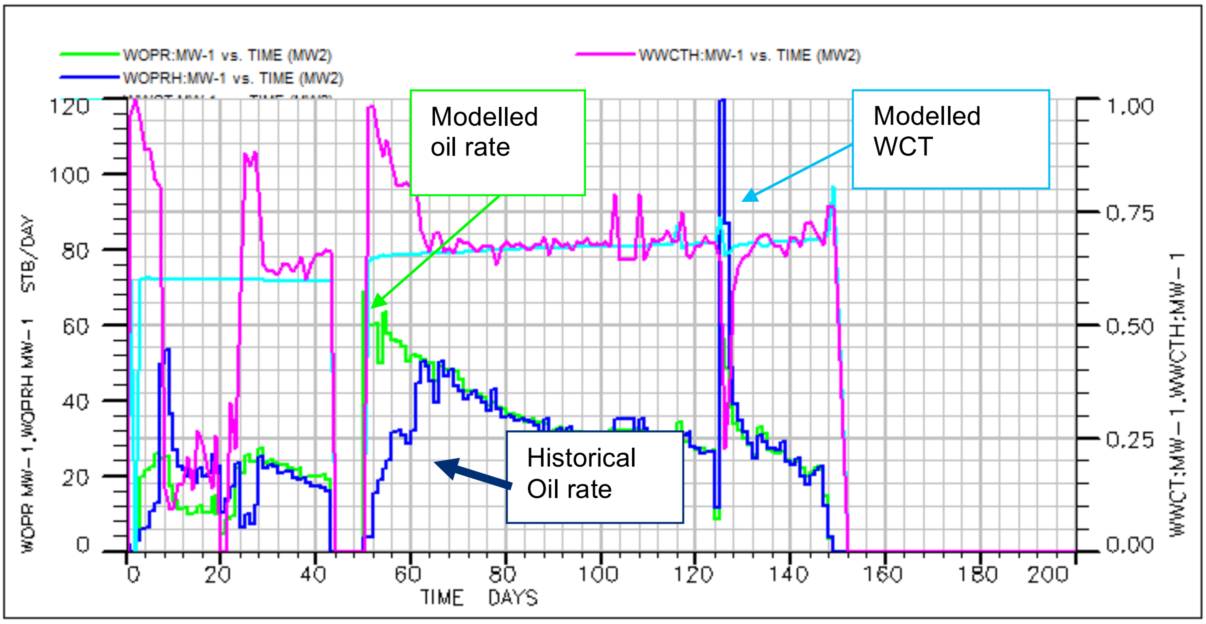


Figure 9.13 History match of MW-1 EWT

9.4.3 Estimated Well Performance

As per UKOG's plan for a horizontal well in the crest of the structure, a production forecast has been generated for a side track to MW-1 with a 1,200 m length horizontal well with an east-west azimuth (denoted MW-1ST in Figure 9.14). The well is positioned high in the structure and targets the layers with the highest permeability in the Upper Massive Oolite zone (Figure 9.15). Further optimisation of well positioning is possible but not undertaken for this report.

UKOG have predicted well performance of the horizontal well based on a conservative analogy to the Horndean-X3 well, which is the poorest performing horizontal well on the Horndean field. A type curve for the well was derived from the Horndean-X3 well to allow modelling of cumulative oil rates at Markwells Wood. The modelling does not account for the well position in the oil column, reservoir quality or lateral length among other factors. Nevertheless, given the direct analogy of Horndean to Markwells Wood and the short distance between the fields, Xodus considers the approach taken by UKOG to be reasonable.

Xodus has predicted future well performance of MW-1ST using the Eclipse model, which has been calibrated to the MW-1 well test results. The simulated oil production rates for the horizontal well MW-1ST are in line with the oil rate production of some horizontal wells in Horndean, a field that produces from the same structure and reservoir less than a kilometre away (see Figure 9.7).

Low, Best and High case production forecasts for the proposed well have been generated using the Best case as a basis for adjustments. A description of the assumptions for each case and the production figures are shown below.

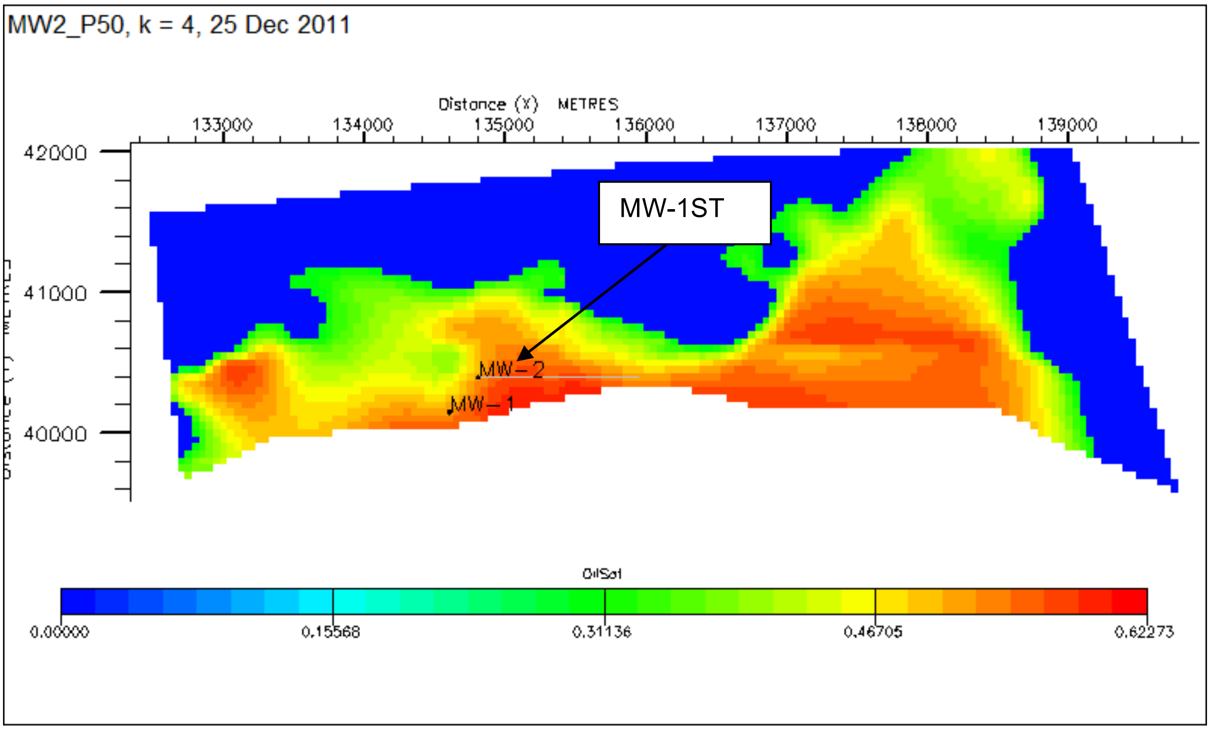


Figure 9.14 Initial oil saturation in the model showing the location of the MW-1ST well

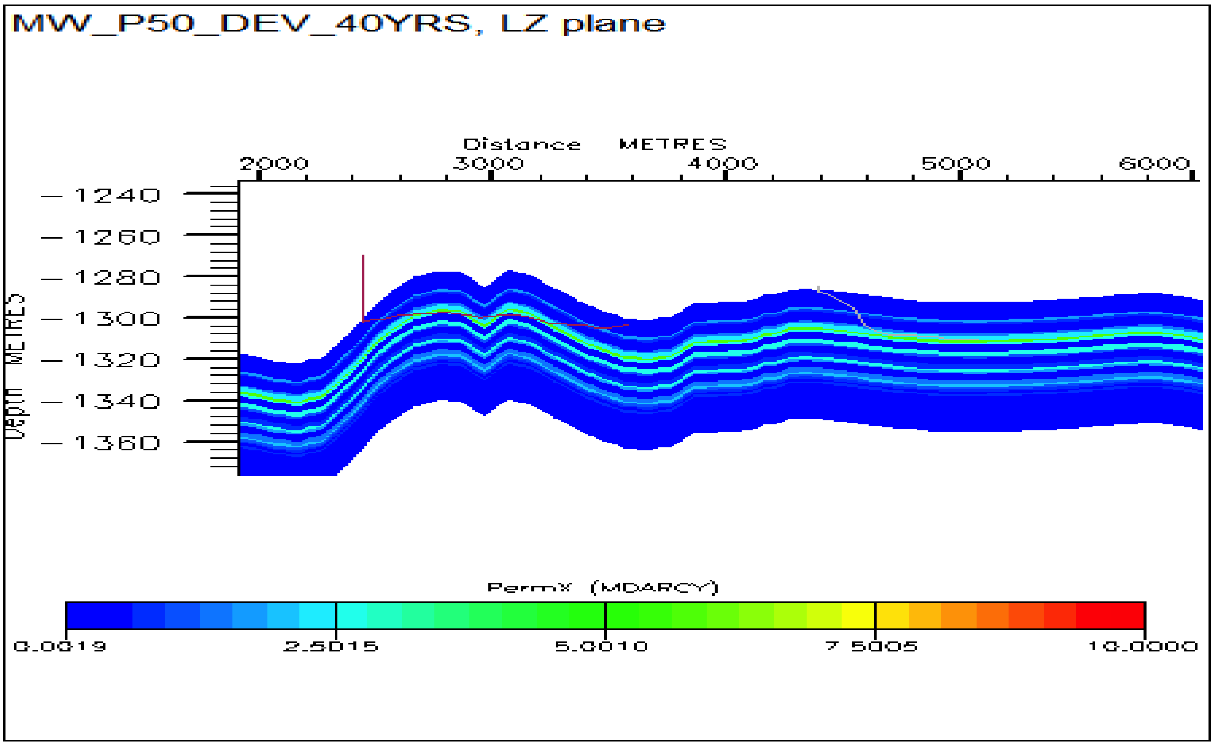


Figure 9.15 MW-1 ST cross section permeability

Best Case

The Best case keeps the history-matched parameters from MW-1. The ratio of vertical permeability to horizontal permeability (kv/kh) was set to 0.05. Table 9.5 gives the annual production figures for the Best case.

Best Case MW-1ST horizontal

Year	Oil Rate (stbpd)	Cum Oil (stb)	Daily Water (bwpd)	Cum Water (stb)	Year	Oil Rate (stbpd)	Cum Oil (stb)	Daily Water (bwpd)	Cum Water (stb)
1	124	45,442	37	13,538	**21**	33	412,867	51	347,243
2	85	76,645	32	25,251	**22**	32	424,609	51	365,915
3	75	104,073	35	37,974	**23**	31	435,998	51	384,594
4	69	129,261	37	51,634	**24**	30	447,052	51	403,269
5	64	152,848	40	66,139	**25**	29	457,815	51	421,980
6	61	175,007	42	81,289	**26**	29	468,246	51	440,615
7	58	195,996	43	97,027	**27**	28	478,386	51	459,215
8	55	215,950	44	113,267	**28**	27	488,250	51	477,772
9	52	235,025	46	129,982	**29**	26	497,874	51	496,332
10	50	253,206	47	147,015	**30**	26	507,219	51	514,784
11	48	270,617	48	164,361	**31**	25	516,321	50	533,176
12	46	287,318	48	181,973	**32**	24	525,191	50	551,501
13	44	303,407	49	199,859	**33**	24	533,861	50	569,803
14	42	318,843	49	217,885	**34**	23	542,293	50	587,978
15	41	333,710	50	236,068	**35**	23	550,518	50	606,071
16	39	348,047	50	254,382	**36**	22	558,546	49	624,078
17	38	361,920	50	272,852	**37**	21	566,404	49	642,046
18	37	375,287	51	291,355	**38**	21	574,058	49	659,873
19	35	388,212	51	309,924	**39**	20	581,534	49	677,605
20	34	400,720	51	328,541	**40**	20	588,839	48	695,241

Table 9.5 Best case production forecast for MW-1ST

Low Case

The Low case has been built from the Best case, reducing the permeability multiplier and reducing the KvKh to 0.01. Other parameters and all the other inputs remained unchanged.

Low Case MW-1ST horizontal

Year	Oil Rate (stbpd)	Cum Oil (stb)	Daily Water (bwpd)	Cum Water (stb)	Year	Oil Rate (stbpd)	Cum Oil (stb)	Daily Water (bwpd)	Cum Water (stb)
1	63	22,915	26	9,591	**21**	22	237,735	29	194,532
2	43	38,653	19	16,529	**22**	22	245,757	30	205,312
3	39	52,979	20	23,695	**23**	22	253,619	30	216,158
4	37	66,417	21	31,219	**24**	21	261,327	30	227,062
5	35	79,228	22	39,110	**25**	21	268,909	30	238,050
6	34	91,469	22	47,298	**26**	20	276,328	30	249,053
7	32	103,257	23	55,780	**27**	20	283,610	30	260,098
8	31	114,646	24	64,529	**28**	20	290,761	30	271,180
9	30	125,705	25	73,547	**29**	19	297,804	30	282,323
10	29	136,406	25	82,763	**30**	19	304,704	31	293,462
11	28	146,805	26	92,185	**31**	19	311,486	31	304,625
12	28	156,921	26	101,796	**32**	18	318,153	31	315,807
13	27	166,800	27	111,605	**33**	18	324,726	31	327,036
14	26	176,403	27	121,544	**34**	18	331,174	31	338,247
15	26	185,772	28	131,626	**35**	17	337,517	31	349,467
16	25	194,920	28	141,837	**36**	17	343,760	31	360,693
17	24	203,880	28	152,195	**37**	17	349,922	31	371,954
18	24	212,616	29	162,633	**38**	17	355,971	31	383,185
19	23	221,161	29	173,169	**39**	16	361,928	31	394,414
20	23	229,524	29	183,795	**40**	16	367,795	31	405,640

Table 9.6 Low case production forecast for MW-1ST

High Case

For the high case the permeability multiplier was increased by a factor 2 and vertical / horizontal permeability ratio (kv/kh) to 0.1. Table 9.7 gives the annual production figures for the high case.

High Case MW-1ST horizontal									
Year	**Oil Rate (stbpd)**	**Cum Oil (stb)**	**Daily Water (bwpd)**	**Cum Water (stb)**	**Year**	**Oil Rate (stbpd)**	**Cum Oil (stb)**	**Daily Water (bwpd)**	**Cum Water (stb)**
1	258	94,498	76	27,951	**21**	37	642,196	84	648,671
2	167	155,325	71	53,727	**22**	35	654,909	83	678,933
3	140	206,537	75	80,939	**23**	33	667,027	82	708,848
4	123	251,443	78	109,566	**24**	32	678,588	81	738,408
5	110	291,640	82	139,463	**25**	30	689,659	80	767,683
6	99	327,846	84	170,192	**26**	29	700,212	79	796,508
7	90	360,812	86	201,596	**27**	28	710,309	78	824,958
8	83	391,037	87	233,492	**28**	26	719,977	77	853,031
9	76	418,978	88	265,807	**29**	25	729,267	76	880,799
10	71	444,781	89	298,236	**30**	24	738,150	75	908,109
11	66	468,773	89	330,760	**31**	23	746,673	74	935,036
12	61	491,161	89	363,298	**32**	22	754,858	73	961,579
13	57	512,175	89	395,872	**33**	22	762,742	72	987,810
14	54	531,846	89	428,245	**34**	21	770,300	71	1,013,585
15	51	550,356	88	460,457	**35**	20	777,569	70	1,038,979
16	48	567,813	88	492,468	**36**	19	784,563	69	1,063,993
17	45	584,351	87	524,330	**37**	18	791,314	67	1,088,695
18	43	599,960	86	555,842	**38**	18	797,798	66	1,112,954
19	41	614,757	86	587,069	**39**	17	804,044	65	1,136,839
20	38	628,804	85	617,990	**40**	16	810,065	64	1,160,354

Table 9.7 High case production forecast for MW-1ST

The plots below show comparisons of the production forecasts for each case (Figure 9.16) and of the oil rate and cumulative production for the first 10,000 days (~28 years) of production, compared to the Horndean wells (Figure 9.17 and Figure 9.18). It can be seen from these plots that the modelled well profiles are in reasonable agreement with the Horndean wells and that the simulated Best Case has slightly better performance than the Horndean-X3 well.

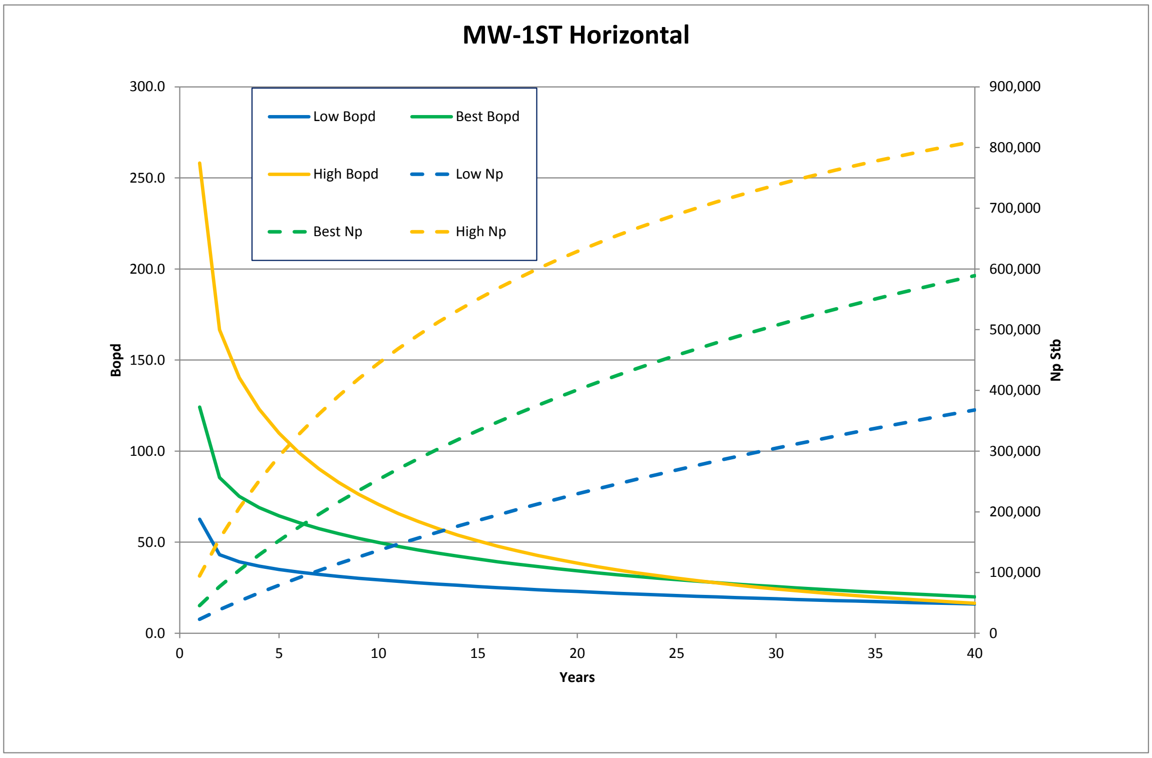


Figure 9.16 Production Forecasts MW-1ST cases

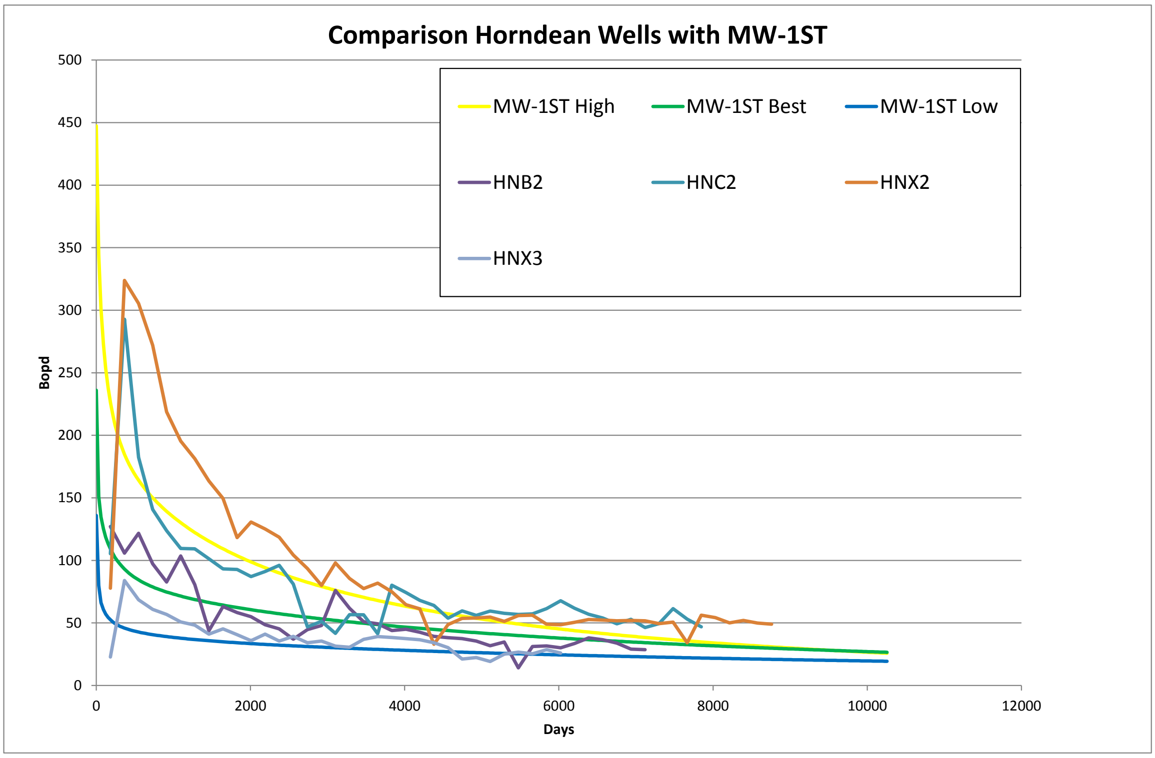


Figure 9.17 Comparison of oil rate for the MW-1ST cases with the Horndean wells

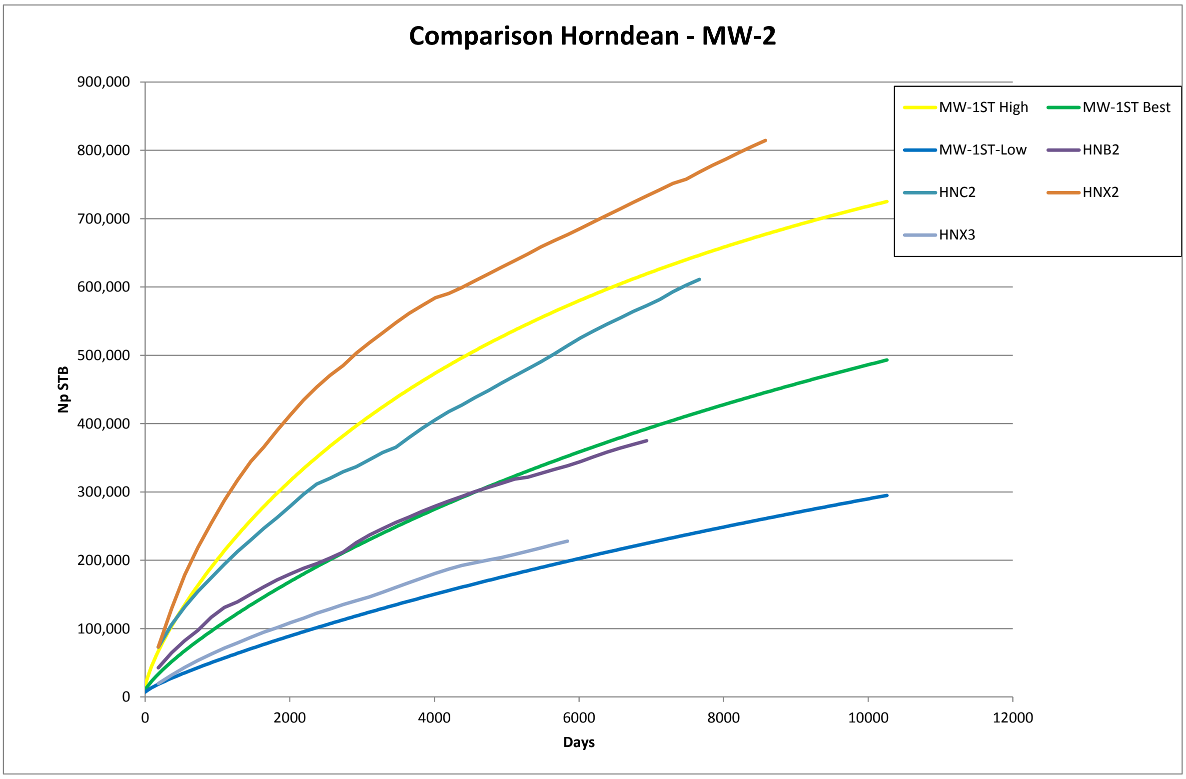


Figure 9.18 Comparison of cumulative production for the MW-1ST cases with the Horndean wells

9.5 Field Development Scenarios

To date no Markwells Wood FDP has been prepared. UKOG has proposed a notional development, which places a number of long horizontal wells in as much vertical relief from the transition zone as possible. UKOG is also investigating novel conventional drilling and completion techniques that may assist optimising the recovery from the wells and from the field overall. A field development with up to four phases is mooted by UKOG.

Although UKOG have prioritised the wells in terms of possible length, position above FWL, reservoir quality and structural control, at present all wells are predicted to have the same performance in all cases as defined by the Horndean-X3 type curve derived by UKOG and are estimated to produce approximately 342,000 barrels each over a 35-year period. UKOG realises that such a development scenario provides an initial estimate only, that further analysis is required to prepare for an initial horizontal well and that new information gained from that well will determine further field development.

To determine the Contingent Resource recoverable volumes Xodus assumed the following notional development scenarios (see also Figure 9.19):

> 1C: 2 horizontal production wells (MW-1ST and MW6) – assuming reservoir quality as per MW-1ST Low Case model

> 2C: 5 horizontal production wells (MW-1ST, MW3, MW4, MW5 and MW6) – assuming reservoir quality as per MW-1ST Best Case model

> 3C: 5 horizontal production wells (MW-1ST, MW3, MW4, MW5 and MW6) – assuming reservoir quality as per MW-1ST High Case model and assuming no interference between wells

Well performance for each of the 1C, 2C and 3C scenarios is simulated in the Eclipse model. The 2C scenario is derived from a model where the parameters such as reservoir permeability and kv/kh (vertical to horizontal permeability ratio) were used to obtain the history match the MW-1 well test. In the 1C scenario the reservoir permeability multiplier and kv/kh were reduced. In the 3C scenario the reservoir permeability multiplier and kv/kh were increased beyond the values used to match the EWT.

Wells have the same or a slightly shorter horizontal section than MW-1ST, depending on locally available space and they are positioned in the Upper Massive Oolite zone with its better permeability. The locations of the wells are shown in Figure 9.19. Wells come onstream in a phased fashion with the last well producing first oil 6 months after the first well.

In Xodus' simulation results the production wells in the development scenarios have poorer performance per well than the simulated MW-1ST, because performance is dependent on the length of penetration of best layers and distance to OWC, which dictates the water cut and because of pressure interference between wells and overall depletion. Xodus recognises that its Eclipse simulation is only a crude model of the Markwells Wood reservoir and that further refinements are needed to better reflect reality[17]. Additionally, well placement can be improved to increase well productivity and contribution from further production wells would increase total field oil recovery. Overall, Xodus believes that its 1C, 2C and 3C ranges provide a balanced, if conservative, reflection of the current state of knowledge of the field and its development.

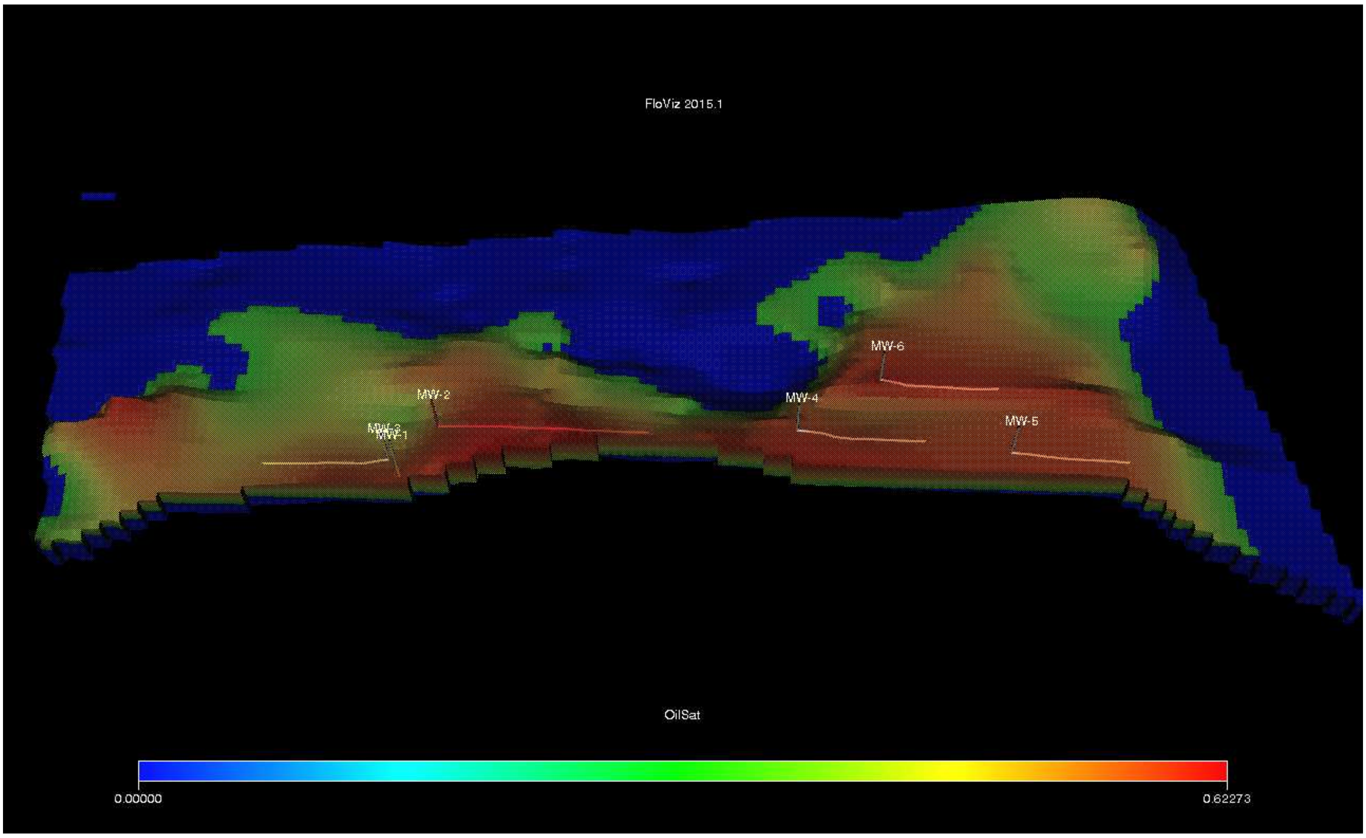


Figure 9.19 Location of Xodus notional development wells

[17] For instance, no interference between wells is reported in nearby fields, including Horndean, although no proof (e.g. pressure measurements) of this is available. The Eclipse model could be adjusted to reduce inter-well connectivity, which UKOG believes to be a more accurate reflection of the actual field.

9.6 Full Field Production Profiles

Running the Eclipse models on the three suggested full field development scenarios, Xodus arrived at the following production profiles. Figure 9.20 shows the total field production forecasts for the three cases.

Total Markwells Wood Field – 1C									
Year	**Oil Rate (stbpd)**	**Cum Oil (stb)**	**Daily Water (bwpd)**	**Cum Water (stb)**	**Year**	**Oil Rate (stbpd)**	**Cum Oil (stb)**	**Daily Water (bwpd)**	**Cum Water (stb)**
1	79	28,884	28	5,135	**21**	39	400,578	39	271,845
2	75	56,196	31	16,613	**22**	39	414,499	38	286,434
3	68	80,991	30	27,603	**23**	38	428,149	37	300,986
4	64	104,253	31	38,993	**24**	37	441,537	37	315,534
5	61	126,425	32	50,830	**25**	36	454,708	36	330,069
6	58	147,601	34	63,111	**26**	36	467,599	35	344,624
7	56	167,979	35	75,721	**27**	35	480,255	35	359,114
8	54	187,657	35	88,650	**28**	34	492,684	34	373,572
9	52	206,760	36	101,855	**29**	34	504,926	33	387,993
10	51	225,241	37	115,335	**30**	33	516,922	33	402,411
11	49	243,199	37	128,984	**31**	33	528,711	32	416,744
12	48	260,674	38	142,812	**32**	32	540,299	32	431,025
13	47	277,744	38	156,791	**33**	31	551,723	31	445,253
14	45	294,345	39	170,938	**34**	31	562,927	31	459,461
15	44	310,549	39	185,155	**35**	30	573,946	30	473,569
16	43	326,378	39	199,460	**36**	30	584,787	30	487,612
17	42	341,892	39	213,838	**37**	29	595,482	29	501,588
18	41	357,024	40	228,314	**38**	29	605,977	29	515,533
19	41	371,833	40	242,795	**39**	29	616,307	28	529,368
20	40	386,334	40	257,308	**40**	28	626,476	28	543,128

Table 9.8 Annual production for 1C case

Total Markwells Wood Field – 2C									
Year	**Oil Rate (stbpd)**	**Cum Oil (stb)**	**Daily Water (bwpd)**	**Cum Water (stb)**	**Year**	**Oil Rate (stbpd)**	**Cum Oil (stb)**	**Daily Water (bwpd)**	**Cum Water (stb)**
1	262	95,966	56	20,384	**21**	63	975,837	99	977,049
2	250	187,373	163	80,059	**22**	59	997,533	96	1,012,185
3	211	264,223	147	133,742	**23**	56	1,018,133	93	1,046,276
4	186	332,193	217	212,789	**24**	54	1,037,700	91	1,079,346
5	169	393,903	144	265,383	**25**	51	1,056,344	88	1,111,500
6	155	450,387	142	317,329	**26**	48	1,074,017	85	1,142,586
7	143	502,678	140	368,588	**27**	46	1,090,823	83	1,172,715
8	133	551,359	138	419,020	**28**	44	1,106,809	80	1,201,908
9	125	596,978	136	468,648	**29**	42	1,122,060	77	1,230,265
10	117	639,620	133	517,126	**30**	40	1,136,535	75	1,257,655
11	110	679,680	130	564,538	**31**	38	1,150,316	73	1,284,178
12	103	717,383	127	610,847	**32**	36	1,163,439	70	1,309,855
13	97	753,013	124	656,155	**33**	34	1,175,971	68	1,334,778
14	92	786,540	121	700,200	**34**	33	1,187,877	66	1,358,832
15	87	818,210	118	743,102	**35**	31	1,199,222	64	1,382,108
16	82	848,154	114	784,861	**36**	30	1,210,035	62	1,404,628
17	78	876,564	111	825,595	**37**	28	1,220,370	60	1,426,471
18	73	903,391	108	865,088	**38**	27	1,230,196	58	1,447,541
19	70	928,812	105	903,469	**39**	26	1,239,566	56	1,467,917
20	66	952,913	102	940,751	**40**	24	1,248,503	54	1,487,621

Table 9.9 Annual production for 2C case

Total Markwells Wood Field – 3C									
Year	**Oil Rate (stbpd)**	**Cum Oil (stb)**	**Daily Water (bwpd)**	**Cum Water (stb)**	**Year**	**Oil Rate (stbpd)**	**Cum Oil (stb)**	**Daily Water (bwpd)**	**Cum Water (stb)**
1	429	157,110	250	45,975	**21**	157	1,826,657	95	1,558,742
2	402	303,751	389	188,232	**22**	153	1,882,684	88	1,591,065
3	343	429,023	342	313,192	**23**	150	1,937,379	82	1,620,905
4	311	542,424	317	429,043	**24**	146	1,990,808	76	1,648,522
5	288	647,738	297	537,464	**25**	143	2,043,173	70	1,674,074
6	270	746,244	279	639,456	**26**	140	2,094,245	65	1,697,772
7	255	839,378	261	734,847	**27**	137	2,144,219	60	1,719,626
8	243	927,944	245	824,210	**28**	134	2,193,143	55	1,739,832
9	232	1,012,765	229	907,821	**29**	131	2,241,188	51	1,758,509
10	222	1,093,837	214	986,156	**30**	129	2,288,132	47	1,775,816
11	213	1,171,759	200	1,059,052	**31**	126	2,334,144	44	1,791,763
12	206	1,246,834	186	1,127,017	**32**	124	2,379,260	40	1,806,497
13	199	1,319,508	173	1,190,293	**33**	121	2,423,631	37	1,820,106
14	192	1,389,599	161	1,249,310	**34**	119	2,467,045	34	1,832,709
15	186	1,457,493	150	1,304,004	**35**	117	2,509,651	32	1,844,313
16	180	1,523,347	139	1,354,804	**36**	115	2,551,477	29	1,855,028
17	175	1,587,472	129	1,401,953	**37**	113	2,592,659	27	1,864,920
18	170	1,649,642	120	1,445,807	**38**	111	2,632,996	25	1,874,075
19	166	1,710,140	111	1,486,354	**39**	109	2,672,625	23	1,882,500
20	161	1,769,065	103	1,523,930	**40**	107	2,711,566	21	1,890,275

Table 9.10 Annual production for 3C case

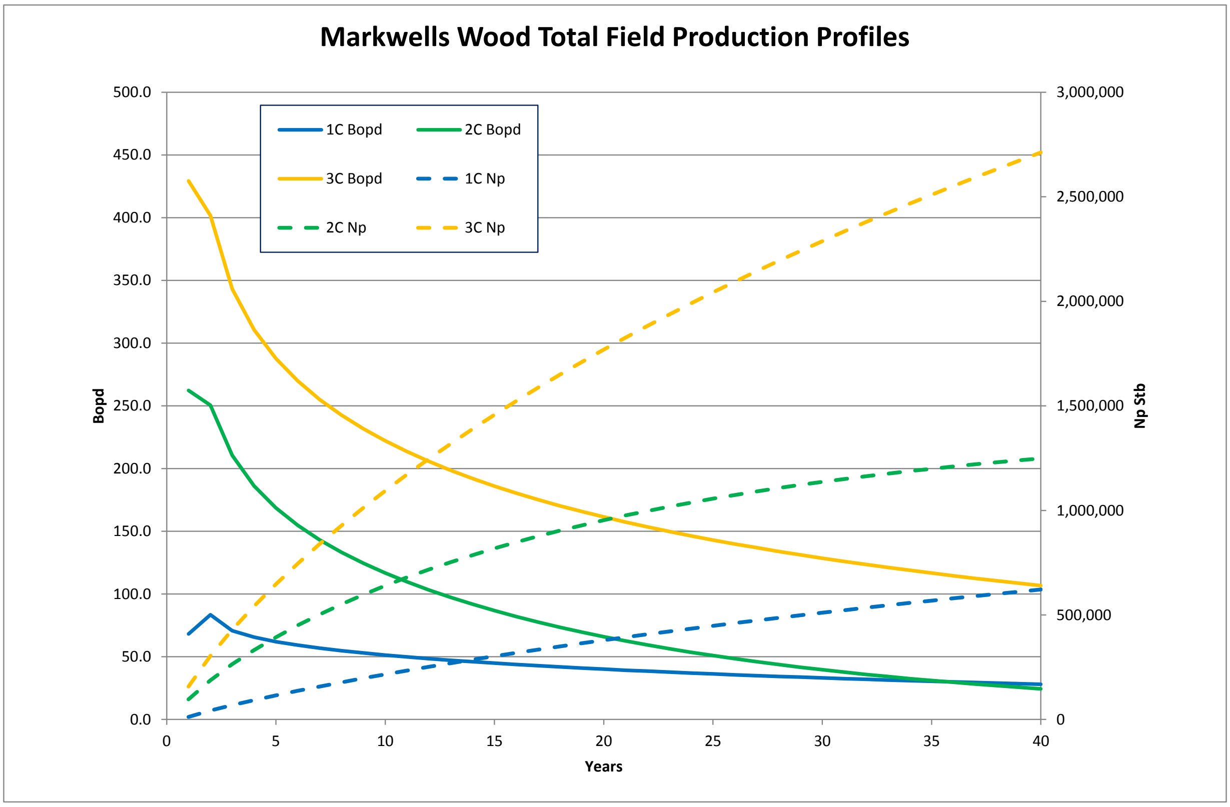


Figure 9.20 Xodus' total field production forecast - rates and cumulative production

9.7 Recoverable Resources

Total recoverable resources are based on the simulated production from the proposed horizontal wells. The base case simulation with 5 horizontal wells was chosen as the 2C, the 1C case has 2 horizontal wells and poorer reservoir permeability, the high case has 5 horizontal production wells and assumes a better reservoir permeability than that used in the 2C scenario. The high case also assumes no interference between wells. The resulting Gross and Net Contingent Resources volumes are provided in Table 9.11.

Oil Contingent Resources	Contingent Resources Gross			Contingent Resources Net to UKOG			Risk Factor
(MMbbl)	1C	2C	3C	1C	2C	3C	(%)[18]
Markwells Wood	0.63	1.25	2.71	0.63	1.25	2.71	60

Table 9.11 Xodus estimation of Markwells Wood Contingent Resources

The recoverable volumes are contingent upon UKOG achieving internal and external authorisation for its Field Development Plan and on the development being commercial and able to secure adequate financing.

[18] Risk Factor or Commercial Risk Factor for Contingent Resources is the estimated chance, or probability, that the volumes will be commercially extracted.

A minimum recoverable volume of 0.5 MMbbl is estimated for a breakeven development. As the 1C volume is above this threshold an economic development could be achieved with a minimal processing facility. UKOG have indicated that their near-term focus is on the Horse Hill and Isle of Wight assets. In addition, the planning application for the Markwells Wood development has been withdrawn to allow for further discussion with the Environment Agency and the gathering of further data. Given these factors Xodus has estimated a 60% chance of commercial success.

Analogous producing fields nearby, including Singleton and Horndean, appear to have Recovery Factors that are in the range of 4.5% - 7% and even higher RF values have been mentioned in other reports[19]. Xodus does not have the data to verify these third party benchmarks. Moreover, these benchmarks are not readily transferable to Markwells Wood as they do not take into account the specific local reservoir properties.

Applying a 5% RF to the Best STOIIP values (but excluding the water saturated Lower Massive Oolite STOIIP) gives a recoverable resource volume of approximately 2 MMbbl. Applying a 7% RF to the High STOIIP values (again excluding the Lower Massive Oolite), gives a recoverable resource volume of approximately 3.5 MMbbl.

Therefore the RF benchmarks indicate that additional recovery above the Xodus 3C estimate is possible. At the time that pressure data from the future Markwells Wood wells will become available, a more accurate reservoir dynamic model can be developed, which may indicate scope for further infill wells above the Xodus 3C scenario.

9.8 Conclusions

Xodus has carried out an independent review of the work undertaken by UKOG in the determination of Contingent Resources for the Markwells Wood discovery.

Xodus has found the work carried out by UKOG to be technically justifiable. The STOIIP calculated by Xodus was very similar to that calculated by UKOG. Although Xodus based its reservoir productivity estimates on a reservoir simulation rather than UKOG's approach of using analogue wells, the resulting single well performance was found to be in reasonable agreement. An initial estimate of total field recoverable resources was based on three deterministic development scenarios.

The next UKOG activities on the discovery are expected to include further analysis of the reservoir, forecasted well performance and production rates and the development of a detailed Field Development Plan. This is likely to include analysis of advanced drilling and completions technologies to further improve the well performance and overall recovery.

[19] See for instance page 17 of "Competent Person's Report Conducted for IGas Energy Plc, Senergy, January 2014.

10 BAXTERS COPSE

The Baxters Copse oil discovery (PEDL233) is located in the southern part of the Weald Basin, it is operated by IGas Energy Plc, UKOG hold a 50% interest in the licence and discovery.

Baxters Copse-1 was drilled in 1983, the primary objective was the Great Oolite with secondary objectives of the Portland Sandstone and Inferior Oolite Limestone. Only the Great Oolite interval tested oil. A long-term test of the field was conducted from January to March 1984. Stabilised oil rates achieved on this test were low at ~20 bopd which, after acid stimulation, declined from an initial rate of 200 to 30 bopd with an associated increase in water cut from 50 – 70%.

For this CPR Xodus have reviewed the operator's interpretations as provided by UKOG.

10.1 Structure

Top reservoir maps for the Great Oolite were provided as part of the dataset. No seismic data or digital map files, other than images, have been reviewed for this evaluation. The seismic interpretation utilises a relatively sparse 2D seismic dataset with eight dip lines and one strike line defining the closure. The overall top reservoir interpretation has remained broadly the same over the different iterations but the fault interpretation has changed significantly with time. In the most recent maps however there is less variation, with a clear fault to the north and south of the structure which is in line with regional fault trends. Xodus has used the most recent map as the basis for the volumetric calculations.

The Baxters Copse structure is an elongate, east west trending anticline which is fault bounded to the north and south. The bounding faults join to the west providing closure, with the structure being dip closed to the east. Fault throw is relatively small (20-40ms) suggesting fault sealing.

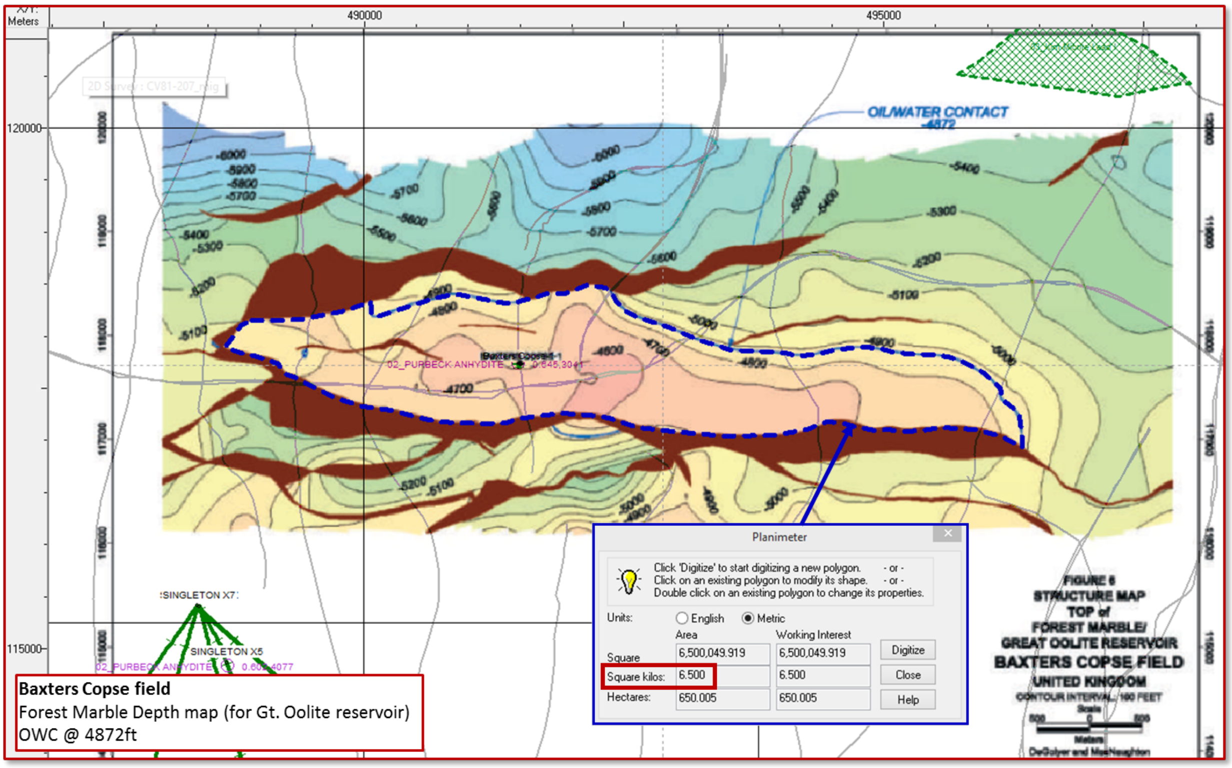


Figure 10.1 Top Forest Marble depth map (used for Great Oolite reservoir), Baxters Copse field. OWC shown at 4872ft

10.2 Reservoir

The main reservoir interval is the Middle Jurassic Great Oolite carbonate which includes the overlying Forest Marble Formation, the overlying Cornbrash Formation is non reservoir in Baxters Copse. The Great Oolite is composed of mainly oolitic, skeletal and oncolitic limestones, detrital clays are also common. The depositional model is that of a high energy shallow water shelf where shoals of oolitic grainstones are deposited.

The Great Oolite reservoir penetrated at Baxters Copse is 217ft (63m) thick, similar in thickness to that observed in the nearby Singleton and Storrington wells. Porosities in Baxters Copse average approximately 10%, lower than found in the nearby Singleton field and other fields in the basin, due to a higher argillaceous content in the reservoir at this location. Average porosities for the Great Oolite elsewhere in the basin range between 15 and 24%. Net to Gross is estimated at 50 to 70% which reflects this reduced porosity range compared with other fields.

An OWC has been interpreted at 4872ft TVDSS, based upon a sharp increase in the water saturation at this depth towards the base of the reservoir. The OWC is shallower than the structural closure of 5100ft TVDSS, thus the structure is underfilled. The depth structure map is shown in Figure 10.1 highlighting the OWC yielding a closure area of approx. 6.5 km^2

Recovery factors have been estimated based on analogue fields. In their 2014 report Senergy identified the nearby fields of Singleton and Storrington as indicating that recovery factors could be between 6 and 12%, DeGolyer & MacNaughton used a 10 to 15% recovery factor.

A Gas Oil Ratio ("GOR") of 600 scf/stb was recorded from the Baxters Copse well test, this has been used as the mid case assumption for volumetric purposes.

10.3 Hydrocarbon In Place Estimates

Xodus have estimated the STOIIP range for Baxters Copse using a stochastic approach. Area-depth data was determined from the latest seismic interpretation of top reservoir and reservoir parameter ranges estimated from the Baxter Copse-1 well and analogue wells where appropriate. Table 10.1 Reservoir parameters used in estimation of Baxters Copse volumetrics.

	Unit	Shape	Min	P90	P50	P10	Max	Mode	Mean
Thickness	ft	Normal	151	187	207	227	262	207	207
Net-to-gross	%	Normal	0.01	20	40	60	95	60	60
Porosity	%	Normal	4.5	8.0	10.0	12.0	13.6	10.0	10.0
Sw	%	Normal	86.1	75.0	62.5	50.0	28.2	62.5	62.5
FVF (Bo)	rb/stb	Normal	1.09	1.16	1.20	1.24	1.31	1.20	1.20
Recovery Factor	%	Normal	1.0	5.0	10.0	15.0	23.8	10.0	10.0
GOR	scf/stb	Normal	517	570	600	630	683	600	600

Table 10.1 Reservoir parameters used in estimation of Baxters Copse volumetrics

10.3.1 In Place Volumes

Table 10.2 Xodus Baxters Copse gross STOIIP estimateshows Xodus' gross STOIIP estimate for the Great Oolite reservoir of Baxters Copse.

STOIIP (MMbbl)	Low	Best	High	Mean
Great Oolite	11.1	25.0	42.6	25.9

Table 10.2 Xodus Baxters Copse gross STOIIP estimate

10.4 Recoverable Resources

Xodus have estimated recoverable volumes using a range of recovery factors based on analogue fields in the basin. Table 10.3 gives the estimated Contingent Resource for Baxters Copse. Baxters Copse is a high GOR oil, as a consequence there is a significant volume of associated gas which would be produced with the oil.

Recoverable volumes are designated as Contingent Resource, volumes are contingent on a firm development plan. In the 2012 CPR Senergy reported that the preliminary development plans were for a single vertical well and three horizontal wells. There is no indication from the operator of development planning that may lead to the field going into production. The high GOR at Baxters Copse means that to produce the oil, gas processing is likely to be required which would increase the minimum recoverable oil volume required for economic development. Production from the EWT had a high water cut which will further add to the costs. Xodus has estimated the minimum recoverable oil volume to be 1.3 MMbbl based on a simple development incorporating a gas to power facility. To reflect that the minimum economic field size is greater than the 1C volume with limited scope for proving a commercial volume and production rate, Xodus has given Baxters Copse a 40% commercial risk factor.

Contingent Resources	Contingent Resources Gross			Contingent Resources Net to UKOG			Commer cial Risk Factor
	1C	2C	3C	1C	2C	3C	(%)[9]
Baxters Copse – Oil (MMbbl)	0.8	2.4	4.8	0.4	1.2	2.4	40%
Baxters Copse – Gas (bcf)	0.5	1.4	2.9	0.25	0.70	1.45	40%
Total (MMboe)	**0.89**	**2.7**	**5.3**	**0.04**	**0.52**	**1.5**	**40%**

Table 10.3 Estimated Contingent Resource for Baxters Copse

10.5 Conclusions

Xodus has reviewed the interpretations made available on the Baxters Copse discovery and found them to be robust and in line with values seen analogue fields from across the basin. To reflect that there has been no apparent progress with field development planning since 2012 and the small recoverable volumes, Xodus has assigned a 40% chance of commercial development.

11 OTHER ASSETS

UKOG also have interests in other licences / discoveries, with significant potential, for which there is presently insufficient available data and understanding to allow for a meaningful quantification of petroleum volumes and chances of success of any development. In this section we provide a brief overview of our understanding of recent events related to the exploration & development of these assets, including unconventional reservoirs, in the Weald.

11.1 Broadford Bridge – Godley Bridge Discovery

The Broadford Bridge licence (PEDL234) is a 300 sq km block in the centre of the Weald Basin between the Holmwood (PEDL143) and Baxters Copse (PEDL233) licences. UKOG holds a 100% interest in Broadford Bridge via its wholly owned subsidiary KOGL. PEDL234 is an exploration licence with a recent oil discovery in the Kimmeridge Limestones. Figure 11.1 is map showing the location of the licence and Godley Bridge discovery.

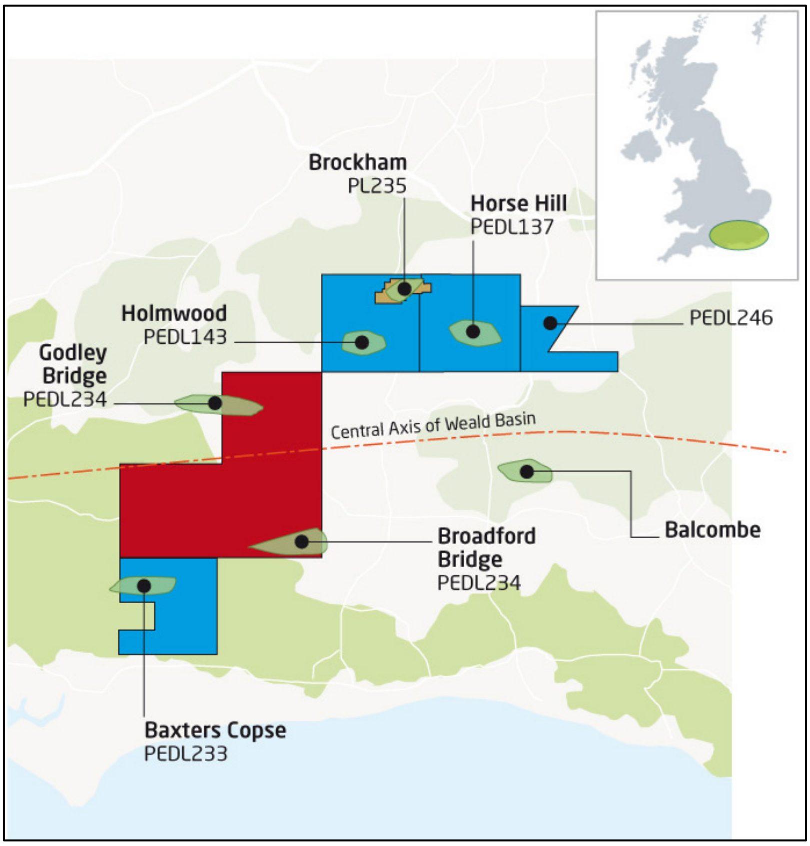


Figure 11.1 Map showing Broadford Bridge and surrounding licences (from UKOG)

Potential has also been identified in the Portland Sandstone which is analogous to one of the zones tested at Horse Hill.

Godley Bridge is a discovery in PEDL235, which is the neighbouring licence to the west of PEDL234. A recent review by Xodus of the interpretation of wells and seismic shows that there is potential that the Godley Bridge discovery extends into PEDL234.

The Godley Bridge gas field was discovered in 1982 by Conoco with the well Godley Bridge-1, which tested gas and a small amount of condensate from Upper Jurassic Portland Sandstones. The trap of the Godley Bridge structure is a broad east-west trending anticline of Tertiary age. There have been two further wells on the structure neither of which encountered hydrocarbon bearing reservoir.

Godley Bridge-2 and 2z were drilled to the west of Godley Bridge-1, both failed to find hydrocarbon bearing sands. The top Portland was encountered deep to prognosis and below the GWC as seen in Godley Bridge-1. The well penetrated 314ft of gross Portland reservoir.

Alfold-1 was drilled in PEDL234 and penetrated a 211 ft gross Portland sand interval with the top of the reservoir 1 ft shallower than Godley Bridge-1. The well reported oil shows in the Upper and Middle Portland zones and weak gas shows. A water wet zone was calculated from electric logs. There is no deviation survey available for Alfold-1 and the location of the well on entering the reservoir is uncertain, however it is apparent that a directional survey was conducted and the final well report lists formation tops with depths. Although the depth of the Portland in the well is known, the XY location is not. The depth and the shape of the structure as mapped from seismic would suggest penetration of the reservoir above the contact however no hydrocarbons were seen, only oil shows.

The structure is covered by only sparse 2D seismic data from which the shape of the discovery is defined but the maps do not close in the north east at the depth of the GWC defined in Godley Bridge-1. Figure 11.2 shows a map of the top Purbeck Anhydrite marker bed showing the structure of the discovery.

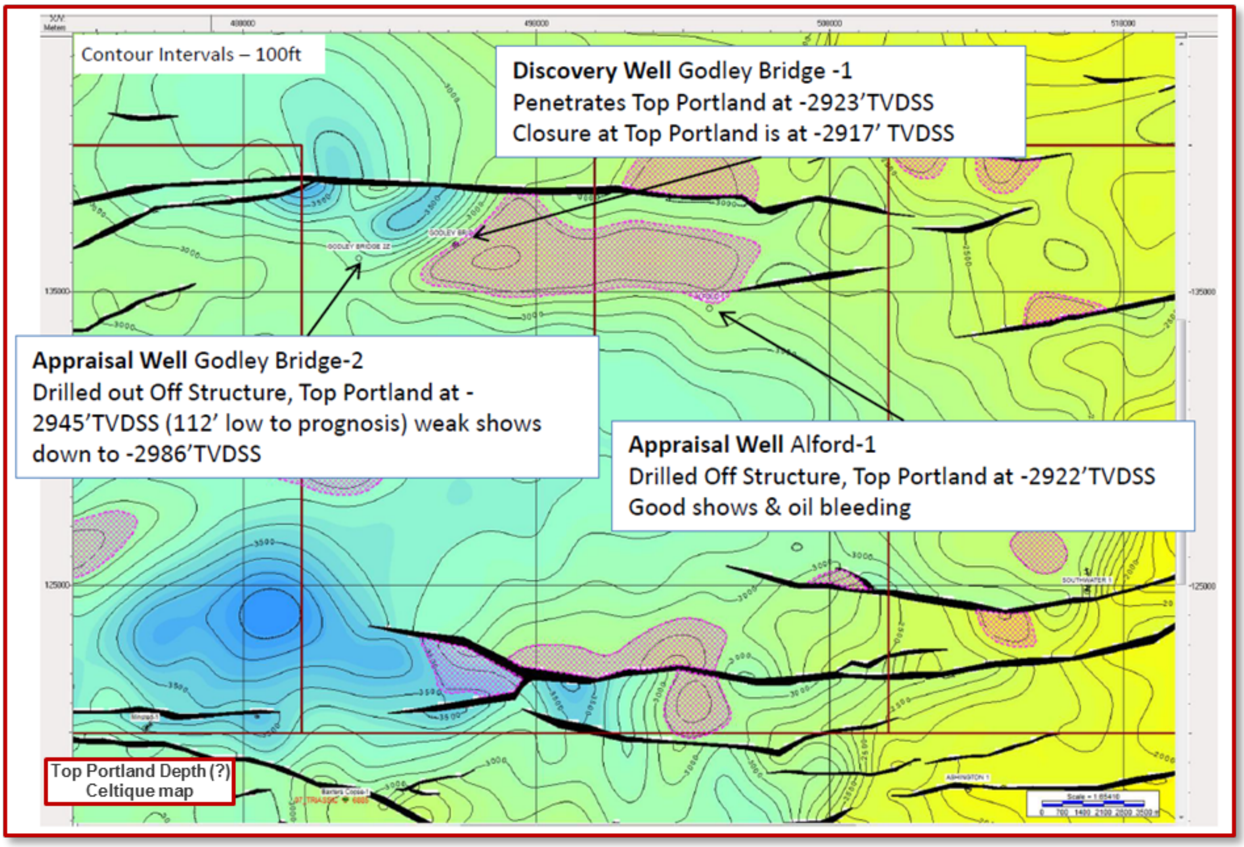


Figure 11.2 Top Purbeck Anhydrite (top seal) map, note the disconnect in the well depths between Godley Bridge-1 and Alfold-1: Godley Bridge-1 is deeper than Alfold (by 1ft) and encountered gas, while the shallower well Alfold-1 was water wet

The dataset available, therefore, gives significant uncertainty in the assessment of in place volumes, the main issues are:

> The Alfold-1 well reportedly penetrates the reservoir at a shallower depth than the discovery well but is calculated to have no gas pay only some likely residual oil shows

> As mapped Alfold-1 is on structure and above the contact

> The precise location of Alfold-1 and its penetration of the Portland is unknown

> The structure does not close at the depth of the contact to the north east

To account for these uncertainties Xodus considered a number of possible scenarios. In all scenarios there was gas bearing reservoir on PEDL234 however, more data is required to properly estimate the in place volumes. Recoverable volumes were not estimated at this time due to the inherent uncertainties. Xodus believes that a further modern appraisal well and extended test is required to narrow the current uncertainties and enable a better estimation of potential recoverable resources to be undertaken.

Previous CPRs for IGas, the operator of PEDL235, have calculated estimates of Contingent Resource of between 5 and 10 bcf net to IGas. There is no comment on the discovery extending into PEDL234 and maps are cut off at the licence boundary.

UKOG has informed Xodus that they have plans to drill a well to appraise and test the Portland gas reservoir and underlying Kimmeridge Limestones in the Godley Bridge structure from a location in the PEDL234 licence. A lease on the site has been finalised, planning permission work is under way and the well is planned for 2019 subject to the necessary grant of regulatory permissions and availability of funds.

11.2 Kimmeridge Potential at Horse Hill and Broadford Bridge

The Horse Hill discovery and Broadford Bridge licence include considerable oil resource potential in the Upper Jurassic Kimmeridge Formation, notably within the Kimmeridge Limestone KL1-KL5 reservoir horizons. The KL3 and KL4 were found to be productive at HH-1, the KL5 at BB-1/1z and the KL4 tested oil at the Balcombe-1 discovery (drilled by Conoco in 1986/7). The Holmwood licence also contains significant Kimmeridge oil potential given its location in relation to Horse Hill and Broadford Bridge, however no wells have been drilled to test the Kimmeridge in the Holmwood licence at this time. The Brockham X-4z well, located within a cut-out in the PEDL143 Holmwood licence, recently drilled through the Kimmeridge, reporting the occurrence of natural fractures and wet gas shows has not yet been tested at the time of writing. Xodus did not carry out a comprehensive detailed study of the Kimmeridge Limestone reservoirs in the Weald.

11.2.1 Horse Hill Kimmeridge

As well as the conventional Portland discovery, oil was flowed from two limestone members of the Upper Jurassic Kimmeridge Clay Formation, the KL3 and KL4. Figure 11.3 shows the top Kimmeridge Limestone depth map at Horse Hill. Horse Hill-1 (“HH-1”) penetrated a total Kimmeridge thickness of 1948 ft, of which, 511 ft has been interpreted as gross pay, which includes 78 ft of limestone across four test zones. Petrophysical analysis by Nutech identifies the Middle Kimmeridge section (KL3 and KL4) as being the most prospective as the limestones are contained within a 593 ft section of high Total Organic Carbon (“TOC”) shale – up to 9.4% TOC. The total Kimmeridge section at Horse Hill has an average TOC of 2.8%. It should be noted that the BB-1z core analysis reports TOCs up to 30% in the equivalent high TOC shale zone.

Fracture analysis from HH-1 logs also demonstrates that the Kimmeridge shows good evidence of natural fracturing. Fractures aid the flow of hydrocarbons from the reservoir rocks into the well and are critical in low permeability / unconventional reservoir units. This analysis is consistent with recent results from BB-1/1z and Brockham-X4z where image log interpretation shows that both the Kimmeridge shale and limestone beds are naturally fractured as at Horse Hill. Conventional core taken at BB-1z also confirms the presence of open natural fractures, with oil recovered to surface from within open natural fractures within the KL5 reservoir section.

The HH-1 KL3 and KL4 reservoirs were flow tested in 2016, the results were reported by UKOG on 21st March 2016 [7]. They summarised that the upper two limestones, KL3 and KL4, flowed at an aggregate stable dry oil flow of 1365 bopd under natural flow with no produced water. Over the 30 to 90 hour flow periods from each of the zones, no clear indication of any reservoir pressure depletion was observed. Interpretation of the tests suggest that there is a dual porosity system which exhibited no depletion. Xodus interpreted that given the low observed matrix porosities and permeabilities calculated permeability of the dual porosity system was likely due to a significant natural fracture component. Pressure transient analysis undertaken by Xodus immediately following the well tests also indicated the possibility that the KL3 and KL4 test could have accessed one single reservoir cell, indicating that the Kimmeridge shales lying between KL3 and KL4 could also contain oil filled open natural fractures.

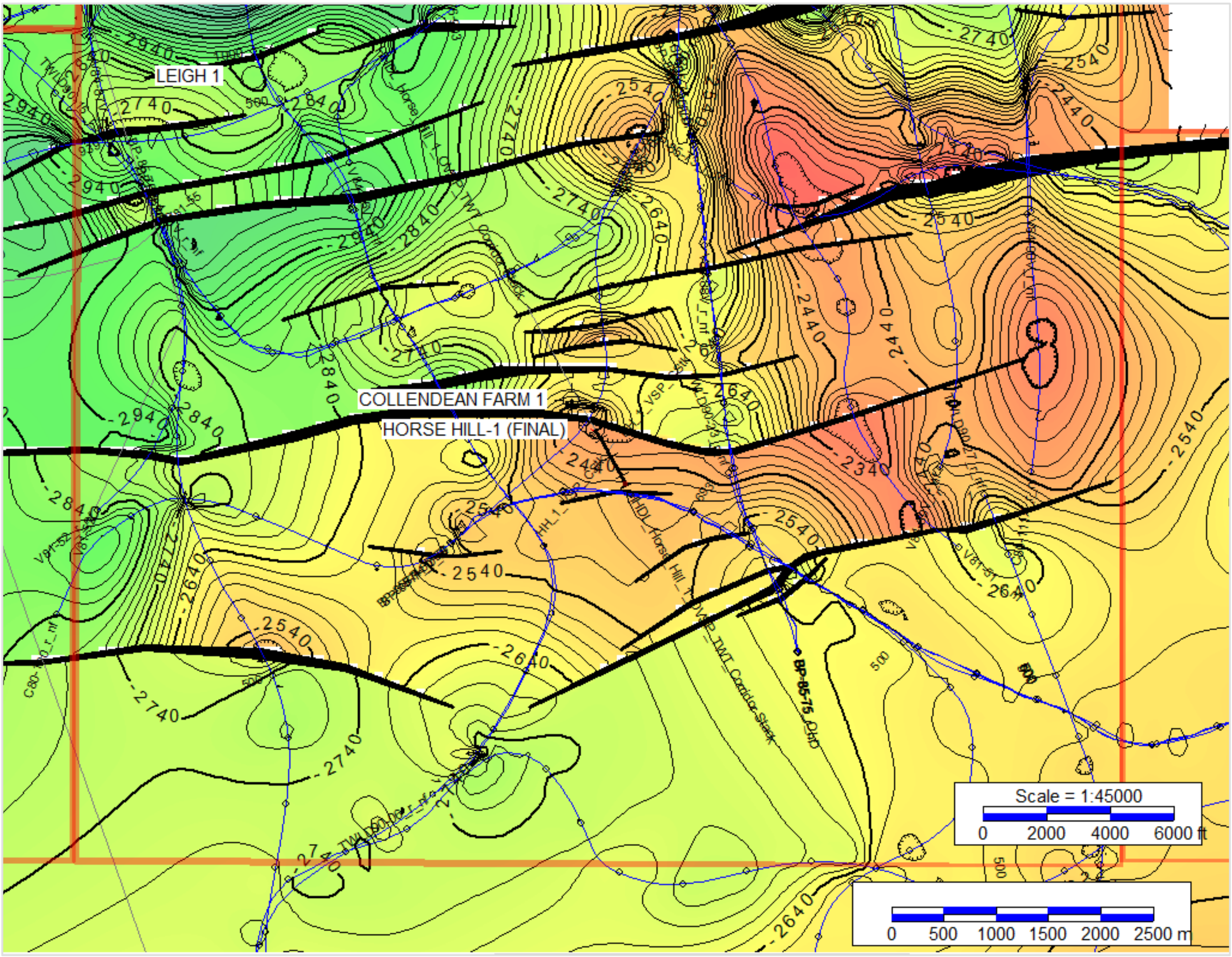


Figure 11.3 Top Kimmeridge Limestone 1 depth map, interpreted by UKOG

Further information on the natural fracture system, the connected volume of oil associated with HH-1 and the vertical connectivity of the overall Kimmeridge oil bearing reservoir section will be gathered by the Company in the forthcoming HH-1 extended well test, which we are advised by the Company is planned to commence in late spring/early summer of 2018.

11.2.2 Broadford Bridge Kimmeridge

Previous analyses of wells and seismic by UKOG within and immediately surrounding the Broadford Bridge licence (PEDL234), suggest that there is similar Kimmeridge Limestone oil potential to that seen at Horse Hill and the Balcombe-1 discovery to the east of PEDL234.

The drilling of BB-1 commenced in May 2017. The primary objective of the well was to test both the southerly extension of the Kimmeridge Limestone oil play across the Weald Basin and its development within the licence. The target reservoirs were the naturally fractured Kimmeridge Limestone reservoir horizons, KL0-KL5, the uppermost two of which, KL3 and KL4, were successfully flow tested at Horse Hill-1 in 2016. The BB-1 well was designed to penetrate the Kimmeridge Limestone units at an inclination and orientation to intersect and test the predicted open natural fracture direction within the Kimmeridge Limestones.

550 ft of core was recovered from the Kimmeridge section, including the limestones of the KL2-KL5 reservoir sections, which is vital for a complete analysis of the prospectivity of the Kimmeridge. Mobile light oil was also recovered from open fractures in the KL5 cores together with oil recovered from mud retorts throughout 1300 ft of Kimmeridge section accompanied by wet gas shows. UKOG have reported that image log interpretations demonstrate that, at the time of logging, natural fractures lying at 90 degrees to the maximum NNW-SSE maximum compressive stress orientation remained open. Previously unrecognised naturally fractured KL potential reservoir zones (KL0 and KL5) have also been identified from cuttings, log and Chemostrat analysis.

BB-1 was sidetracked to Broadford Bridge-1z ("BB-1z") in August 2017 due to bad hole conditions to maximise the Kimmeridge flow test potential.

BB-1z was completed as a potential oil producer with a multizone completion and over 1000ft of perforations. During clean-up operations the well free flowed light oil for short periods and oil was also recovered to surface via pumping. Subsequent analysis showed that the cement bond, between casing and reservoir, was less than optimal over some intervals. The result of which would be that the well bore is not connected to the best open fractures of the reservoir. The decision was made to pull the completion string and work over the well. However subsequent analysis and testing demonstrated that over the main zones of interest the well's cement did not require any remedial treatment.

After workover operations had been completed, including the perforating of additional intervals, testing continued. 38 degree API oil was produced to surface but was not metered, the oil flowed to surface at non-commercial rates. The oil has been typed to the same Upper Jurassic Kimmeridge source as the oil recovered from Horse Hill.

The well results from UKOG operated wells at Horse Hill and Broadford Bridge, which have tested the Kimmeridge Limestone, as well as the reported results of Brockham-X4Z show a consistent picture of Kimmeridge prospectivity across the licences. The Kimmeridge Limestone depth map for the BB-1 well location shows no discernible trap or structural closure. This gives confidence in the concept that the accumulation of oil in the Kimmeridge oil is not reliant on conventional trapping mechanisms.

UKOG's analysis suggests that the Upper Jurassic Kimmeridge potential covers most of PEDL234, north of BB-1. To further prove the potential of the Kimmeridge reservoirs, UKOG are working to acquire two further drilling sites in PEDL234 with planning applications expected to be submitted for the first in 2018.

The Kimmeridge oil potential appears to be regionally extensive with thick sections of high TOC shale with limestone beds, all of which are naturally fractured. Oil has also been flowed from these zones. At present significant additional work is required to determine the development potential of these reservoirs.

11.2.3 Estimates of In Place Volumes

Estimates of OIP for the Kimmeridge Limestones, Kimmeridge Clay Formation and other tight Jurassic reservoirs have been made by Nutech [8], [9] and Schlumberger [10]. These reports have been made public and OIP volumes reported by UKOG in various regulatory press releases, most recently in December 2016 [11]. These estimates have not been updated since the drilling and testing of the BB-1/BB-1z discovery well.

Xodus has not conducted an independent evaluation of the Kimmeridge OIP at this time but have reviewed the static reservoir model, built by Nutech, to estimate OIP for the entire Weald Basin and a short report relating to it. This model was used as the basis for the volumes reported by Nutech in 2015 and UKOG in December 2016. The static model petrophysical inputs upon which the calculations of OIP rely are derived from Nutech's proprietary tight-rock petrophysical analysis techniques and, except for HH-1 and Balcombe-2z are conducted on legacy wells, many of which were drilled over 30 years ago. Whilst the petrophysical parameters derived and utilised by Nutech in the static model appear to fall within a reasonable range, the proprietary algorithms used have not permitted Xodus to comment upon the specific petrophysical analyses undertaken with any degree of absolute confidence.

It should be noted that the current level of knowledge of the Kimmeridge play, the paucity of modern well data and core, together with the dependence on input data from legacy wells means that there is still a significant degree of uncertainty in many of the key factors which control calculations of OIP in the Kimmeridge section. The Nutech model contains three different sets of property models, described as P90, P50 and P10. To build these property models, Nutech have made a number of necessary interpretations and decisions which all have some influence on the OIP estimates. The overall methodology followed by Nutech appears to be reasonable, however, the basis for some of the parameter values used and interpretations made by Nutech is not known to Xodus as it is not described in Nutech's report. Xodus has also not been able to review the input structural grids and petrophysical interpretations which form the basis for the model.

Because of the uncertainty inherent in many aspects of the Kimmeridge Clay Formation reservoir properties there are likely to be many alternative interpretations and scenarios which could be applied which could give different results. The Nutech P90, P50 and P10 property models essentially represent three very similar cases of a single scenario. As a consequence, it is not possible to determine that the P90, P50 and P10 volumes, which come from the Nutech models, represent the full range of possible outcomes for the Kimmeridge Clay Formation OIP. It is possible that the P90 and P50 values could be materially different to those reported if all alternate interpretations and scenarios are considered.

Schlumberger also calculated OIP per square mile volumes based on the results of HH-1 [10]. Similarly to Nutech, Schlumberger used their own proprietary shale / tight rock log analysis techniques developed for the US shale industry. Xodus has not re-run the highly specialist analysis to verify the interpretation. It is noted that the OIP / square mile estimate, calculated by Schlumberger, is of the same order of magnitude as that calculated by Nutech using a similar approach, but they are still substantively different.

Given the large volume of data and analyses collected from BB-1 and the BB-1z sidetrack, the integration of log, core and petrophysical data have not yet been fully completed by UKOG at the time of writing. Consequently, these data have not been integrated into the Nutech Weald Basin reservoir model. The results of the planned HH-1 extended well test will further help to calibrate Nutech's reservoir model and any related basin-wide calculations of Kimmeridge OIP together with providing a more definitive viewpoint of the volumes of OIP that are directly connected to the productive KL3 and KL4 horizons in the well.

12 CONCLUSIONS

Xodus has carried out an independent review of assets in which UKOG hold interests. For the assets which Xodus has previously reviewed, no new data or interpretations have been available but Xodus has updated any comments on future activities and resulting risk factors where appropriate.

Xodus has undertaken new reviews of the assets in which UKOG holds non-operated interests. These evaluations have been completed using information provided by the operator, through UKOG. For Horndean, which is currently on production and Avington, which is currently shut in, Xodus have estimated remaining Reserves and Resources based on past well performance. For Baxters Copse and Holmwood, Xodus have used standard methodologies to estimate STOIIP and recoverable resources.

Xodus has generally found the work carried out by UKOG to be technically justifiable and the estimates of HIIP volumes have been consistent with those calculated by Xodus. A more limited dataset was available for review for the non-operated discoveries and prospects, Xodus' assessments have deviated more from previous evaluations, particularly for Holmwood, this has been due to different approaches in determination of GRV, necessitated by the dataset, and different reservoir parameters, some of which are based on more recent data than previously available. Xodus' evaluation of Reserves at Horndean is consistent with previous evaluations.

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14 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	
Abex	Abandonment expenditure	
AAPG	American Association of Petroleum Geologists	
AIM	Alternative Investment Market of the London Stock Exchange	
API	American Petroleum Institute	api
AVO	Amplitude versus offset or amplitude variation with offset is often used as a direct hydrocarbon indicator	
BB-1	Broadford Bridge-1 well	
Best Estimate	An estimate representing the best technical assessment of projected volumes. Often associated with a central, P_{50} or mean value	
CF-1	Collendean Farm-1 well	
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
GIIP	Gas Initially In Place	
GR	Gamma ray	
GOR	Gas Oil Ratio	
GRV	Gross Rock Volume	
GWC	Gas-water contact	
H	Thickness	ft or m
High Estimate	An estimate representing the high technical assessment of projected volumes. Often associated with a high or P_{10} value	
HIIP	Hydrocarbons Initially in Place	
HH-1	Horse Hill-1 well	
JV	Joint Venture	
K	Permeability	mD
k_a	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 P_{90} 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	
N/G	Net to Gross	
OBM	Oil based mud	
ODT	Oil down to	
OGA	Oil & Gas Authority	
OIP	Oil In Place	
OWC	Oil water contact	
P_{10}	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.	
P_{50}	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.	
P_{90}	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.	
P_{99}	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.	
P_{res}	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 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.
SNS	Southern North Sea
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	

15 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 22 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 O'Connell

Andrew O'Connell is a Senior Geologist with a broad and deep international E&P experience. He is certified Petrel Specialist in Geology and Modelling.

He began his career as a mudlogger and data engineer in the Danish sector of the North Sea, Georgia and Equatorial Guinea before completing his MSc. He subsequently worked on exploration and new ventures projects for Regal Petroleum and Gulf Keystone. In 2008 Andrew joined Senergy and worked as a consultant geologist on projects covering many aspects of E&P but primarily in field development, reservoir modelling and asset evaluation projects. Andrew has a BSc in Applied and Environmental Geology from the University of Birmingham and an MSc in Petroleum Geoscience from Imperial College, London.

David McGurk

David McGurk is a Principal Geophysicist with almost 14 years' experience in structural and quantitative interpretation, reservoir characterisation and prospect generation. He has a broad, varied skill-set with a regional focus on West Africa, in particular the transform margin from Gambia to Cote d'Ivoire.

David has a background in consultancy and operating companies; recently working with Tullow Oil's research group supporting West African and South American assets and New Ventures. He previously worked for Senergy working as a consultant geophysicist on a wide range of projects including being a member of the commercial team working on asset evaluations and reserves audits. He is highly computer literate with experience in using all major packages for interpretation and geophysical analysis. David has a BSc in Geology from Queens University Belfast and an MSc in Tectonics from Royal Holloway.

Fabrice Toussaint

Fabrice is a versatile executive manager and leader with Petroleum Engineering as his core competency. With over 18 years of international and domestic experience in oil and gas operations in on and off-shore, assets evaluation and management Fabrice has gained invaluable experience in the commercialisation of marginal projects. He has worked as a consultant petroleum engineer for six years following senior roles in both small and large oil companies and major service providers.

Edward Spence

Edward Spence is a 7 year experienced Commercial Analyst and Process and Process and Facilities Engineer by background. He has worked in the Advisory team with Jon for the last 2 years and been involved in numerous asset evaluation and field development reviews, in the North Sea and internationally.