THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt as to the contents of this Document or the action you should take, you should immediately seek your own personal financial advice from your stockbroker, bank manager, solicitor, accountant or other independent professional adviser authorised pursuant to the Financial Services and Markets Act 2000, as amended if you are resident in the United Kingdom or, if not, another appropriately authorised independent financial adviser.

The Company and the Directors whose names appear on page 4 of this Document accept individual and collective responsibility for the information contained in this Document including individual and collective responsibility for compliance with the AIM Rules. To the best of the knowledge and belief of the Company and the Directors (who have taken all reasonable care to ensure that such is the case) the information contained in this Document is in accordance with the facts and does not omit anything likely to affect the import of such information.

Application has been made for all of the Existing Ordinary Shares to be admitted to trading on the London Stock Exchange's AIM market. It is expected that trading in the Ordinary Shares will commence on AIM on 1 August 2018. **AIM is a market designed primarily for emerging or smaller companies to which a higher investment risk tends to be attached than to larger or more established companies. AIM securities are not admitted to the Official List of the United Kingdom Listing Authority. A prospective investor should be aware of the risks of investing in such companies and should make the decision to invest only after careful consideration and, if appropriate, consultation with an independent financial adviser. Each AIM company is required pursuant to the AIM Rules to have a Nominated Adviser. The Nominated Adviser is required to make a declaration to the London Stock Exchange on Admission in the form set out in Schedule Two to the AIM Rules for Nominated Advisers. The London Stock Exchange has not itself examined or approved the contents of this Document.**

A copy of this Document, which comprises an Admission Document drawn up in accordance with the AIM Rules has been issued in connection with the application for Admission to trading of all of the Existing Ordinary Shares of the Company in issue. This Document does not comprise a prospectus for the purpose of the FSMA and the Prospectus Rules of the FCA and has not been pre-approved by the FCA pursuant to section 85 of FSMA. This Document does not constitute a financial promotion and has not been approved for issue as such in the United Kingdom for the purposes for Section 21 of FSMA.

The whole of this Document should be read. Your attention is particularly drawn to the Risk Factors set out in Part II of this Document. All statements regarding the Company's business, financial position and prospects should be viewed in light of these Risk Factors.

UK Oil & Gas Investments PLC

(Incorporated in England and Wales with registered number 05299925)

(to be renamed UK Oil & Gas Plc with effect from Admission)

Re-Admission to AIM of existing share capital as an Operating Company

and Notice of General Meeting

Nominated Adviser and Broker

Ordinary Share Capital on Admission

	Issued and fully paid	
	Number	*Aggregate Nominal Value*
Ordinary Shares of £0.0001 each	5,207,240,526	£0.0001

WH Ireland Limited, which is authorised and regulated in the United Kingdom by the FCA, is acting as Nominated Adviser and Broker to the Company. Its responsibilities as the Company's Nominated Adviser and Broker under the AIM Rules are owed solely to the London Stock Exchange and are not owed to the Company or to any Director or to any other person. No representation or warranty, expressed or implied, is made by WH Ireland Limited as to any of the contents of this Document. WH Ireland Limited will not be offering advice and will not otherwise be responsible for providing customer protections to recipients of this Document or for advising them on the contents of this Document or any other matter.

The distribution of this Document outside the UK may be restricted by law and therefore any persons outside the UK into whose possession this Document comes should inform themselves about and observe any such restrictions as to the Ordinary Shares and the distribution of this Document. Any failure to comply with such restrictions may constitute a violation of the securities laws of any jurisdiction outside of the UK. This Document does not constitute an offer to sell or the solicitation of an offer to buy shares in any jurisdiction in which such offer is unlawful. In particular, this Document is not for distribution, directly, or indirectly, in or into Canada, Australia, Japan, the Republic of South Africa or the United States or to any national, resident or citizen of Canada, Australia, Japan, the Republic of South Africa or the United States.

The Ordinary Shares have not been and will not be registered under the securities legislation of any province or territory of Canada, Australia, Japan, or the Republic of South Africa. Accordingly, the Ordinary Shares may not, subject to certain exceptions, be offered or sold directly or indirectly, in or into the United States, Canada, Australia, Japan, the Republic of South Africa or to any national, citizen or resident of the United States, Canada, Australia, Japan or the Republic of South Africa.

Copies of this Document will be available for collection, free of charge, from WH Ireland Limited, 24 Martin Lane, London EC4R 0DR for 1 month from the date of this Document. No person has been authorised to give any information or to make any representation about the Company and about the matters that are the subject of this Document, other than those contained in this Document. If any such information or representation is given or made then it must not be relied upon as having been so authorised. The delivery of this Document shall not imply that no change has occurred in the Company's affairs since the date of issue of this Document or that the information in this Document is correct as at any time after the date of this Document, save as shall be required to be updated by law or regulation.

Notice of a Meeting of Shareholders to be held at 10.00 a.m. BST at Hill Dickinson LLP, The Broadgate Tower, 8th Floor, 20 Primrose Street, London EC2A 2EW on 31 July 2018 is set out at the end of this Document. A Form of Proxy for holders of Ordinary Shares for use in connection with the General Meeting accompanies this Document and, to be valid, must be completed and lodged with Share Registrars Limited at The Courtyard, 17 West Street, Farnham, Surrey GU9 7DR or sent by email to voting@shareregistrars.uk.com as soon as possible but in any event to be received not later than 10.00 a.m. BST on 27 July 2018 or 48 hours before any adjourned meeting. Completion of a Form of Proxy will not preclude a Shareholder from attending and voting at the General Meeting in person save that in each case the Shareholder should contact Share Registrars Limited in advance to confirm what identity documents they should bring with them and to complete a form of representation (available on request from Share Registrars Limited) if necessary.

IMPORTANT INFORMATION

The information below is for general guidance only and it is the responsibility of any person or persons in possession of this Document to inform themselves of, and to observe, all applicable laws and regulations of any relevant jurisdiction. No person has been authorised by the Company to issue any advertisement or to give any information or to make any representation in connection with the contents of this Document and, if issued, given or made, such advertisement, information or representation must not be relied upon as having been authorised by the Company.

Prospective investors should inform themselves as to: (a) the legal requirements of their own countries for the purchase, holding, transfer or other disposal of the Ordinary Shares; (b) any foreign exchange restrictions applicable to the purchase, holding, transfer or other disposal of the Ordinary Shares which they might encounter; and (c) the income and other tax consequences which may apply in their own countries as a result of the purchase, holding, transfer or other disposal of the Ordinary Shares. Prospective investors must rely upon their own representatives, including their own legal advisers and accountants, as to legal, tax, investment or any other related matters concerning the Company and an investment therein. Statements made in this Document are based on the law and practice currently in force in the UK and are subject to change. This Document should be read in its entirety. All holders of Ordinary Shares are entitled to the benefit of, and are bound by and are deemed to have notice of, the provisions of the Articles of Association of the Company.

FORWARD LOOKING STATEMENTS

All statements other than statements of historical fact, contained in this Document constitute "forward looking statements". In some cases forward looking statements can be identified by terms such as "may", "intend", "might", "will", "should", "could", "would", "believe", "forecast", "anticipate", "expect", "estimate", "predict", "project", "potential", or the negative of these terms, and similar expressions. Such forward looking statements are based on assumptions and estimates and involve risks, uncertainties and other factors which may cause the actual results, financial condition, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward looking statements. Except as required by the AIM Rules the Company expressly disclaims any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements contained in this Document to reflect any change in the Group's expectations with regard thereto or any change in events, conditions or circumstances on which any such statement is based. New factors may emerge from time to time that could cause the Company's business not to develop as it expects, and it is not possible for the Company to predict all such factors. Given these uncertainties, prospective investors are cautioned not to place any undue reliance on such forward-looking statements except as required by law.

CONTENTS

DIRECTORS, SECRETARY AND ADVISERS

Directors	Allen Dee Howard II (*Non-Executive Chairman*) Stephen Paul Sanderson (*CEO and, until Admission, Executive Chairman)*) Kiran Caldas Morzaria (*Finance Director*) Nicholas John Mardon-Taylor (*Proposed Non-Executive Director*) *all of the Company's registered office*
Registered office	The Broadgate Tower 8th Floor 20 Primrose Street London EC2A 2EW United Kingdom
Website	www.ukogplc.com
Nominated Adviser and Broker	WH Ireland Limited 24 Martin Lane London EC4R 0DR United Kingdom
Reporting Accountants	Chapman Davis LLP 2 Chapel Court London SE1 1HH United Kingdom
Solicitors to the Company	Hill Dickinson LLP The Broadgate Tower 8th Floor 20 Primrose Street London EC2A 2EW United Kingdom
Solicitors to the Nominated Adviser and Broker	Bird & Bird LLP 12 New Fetter Lane London EC4A 1JP United Kingdom
Competent Person	Xodus Group Cheapside House 138 Cheapside London EC2V 6BJ
Registrar	Share Registrars Limited The Courtyard 17 West Street Farnham Surrey GU9 7DR United Kingdom
Joint Broker	Cenkos Securities plc 6 7 8 Tokenhouse Yard London EC2R 7AS United Kingdom

SHARE ADMISSION STATISTICS AND DATES

Number of Existing Ordinary Shares	5,207,240,526
Number of Ordinary Shares in issue immediately following Admission	5,207,240,526
Number of Warrants in issue at the date of this Document	30,555,555
Number of Warrants in issue immediately following Admission	30,555,555
Number of Options in issue at the date of this Document	220,500,000
Number of Options in issue immediately following Admission	220,500,000
ISIN	GB00B9MRZ543
SEDOL	B9MRZ54
AIM symbol/TIDM	UKOG
LEI	213800IZP9HKGVLHQ907

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Publication of this Document	13 July 2018
Last time and date for receipt of Forms of Proxy	27 July 2018, 10am
General Meeting	31 July 2018
Expected date of Admission and commencement of dealings in the Ordinary Shares on AIM	1 August 2018

Save for the date of publication of this Document, each of the date and times above is subject to change. Any such change will be notified to Shareholders by an announcement on a Regulatory Information Service.

If the Meeting of Shareholders is adjourned, the latest time and date for receipt of Forms of Proxy for the adjourned meeting will be notified to Shareholders by announcement through the RNS.

DEFINITIONS

In this Document, where the context permits, the expressions set out below shall bear the following meanings:

"**Admission**"	admission of the Existing Ordinary Shares to trading on AIM and such admission becoming effective in accordance with Rule 6 of the AIM Rules
"**Board**" or "**Directors**"	the directors, and if the context requires, the Proposed Director of the Company, whose names appear on page 4 of this Document
"**UKOG**" or "**Company**"	UK Oil & Gas Investments PLC a company incorporated in England and Wales with registered number 05299925
"**AIM**"	the market of that name operated by the London Stock Exchange
"**AIM Rules**"	the AIM Rules for Companies published by the London Stock Exchange, as amended from time to time
"**AIM Rules for Nominated Advisers**"	the AIM Rules for Nominated Advisers published by the London Stock Exchange, as amended from time to time
"**Articles**"	the Articles of Association of the Company
"**BB**"	Billion barrels
"**Companies Act**"	the Companies Act 2006
"**Competent Person**"	Xodus Group Ltd, registered in Scotland with company number SC286421
"**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 subclassified based on project maturity and/or characterised by their economic status
"**CREST**"	the electronic systems for the holding and transfer of shares in dematerialised form operated by Euroclear
"**Deferred Shareholder**"	a holder of Deferred Shares
"**Deferred Shares**"	deferred shares of £0.00001 each in the capital of the Company, having the rights and being subject to the restrictions set out in the Articles
"**Director**"	a director of the Company
"**Document**"	this Document, comprising an Admission Document under the AIM Rules
"**Euroclear**"	Euroclear UK & Ireland Limited

“**European Union**” or “**EU**”	has the meaning given to it in Article 299(1) of the Establishing the European Economic Community Treaty as amended by, among others, the Treaty on European Unity (the Maastrict Treaty), the Treaty of Amsterdam and the Treaty of Lisbon
“**Existing Ordinary Shares**” or “**Existing Share Capital**”	the existing Ordinary Shares in issue at the date of this document
“**FCA**”	the Financial Conduct Authority of the United Kingdom
“**Form of Proxy**”	the form of proxy for use by Shareholders in connection with the General Meeting
“**FSMA**”	the Financial Services and Markets Act 2000 (as amended) of the UK
“**General Meeting**”	the meeting of Shareholders to be held at 10.00 a.m. on 31 July 2018 at Hill Dickinson LLP, The Broadgate Tower, 8th Floor, 20 Primrose Street, London EC2A 2EW, notice of which is set out at the end of this Document, or any adjournment thereof
“**Group**”	the Company and its Subsidiaries
“**HHDL**” or “**Horse Hill Developments Ltd**”	Horse Hill Developments Ltd, a company registered in England and Wales with company number 08808553
“**HHDL Investment Agreement**”	the investment agreement entered into by the Company with Horse Hill Developments Ltd and a number of investors on 15 September 2014 in respect of Horse Hill Developments Ltd
“**HHDL Investors**”	means the investors in HHDL from time to time who were an original party to, or have agreed to adhere to, the HHDL Investment Agreement
“**HMRC**”	Her Majesty’s Revenue & Customs
“**Horse Hill Licences**”	PEDL137 and PEDL246
“**IFRS**”	International Financial Reporting Standards as adopted by the European Union
“**Investing Company**”	as defined by the AIM Rules, any AIM company which has as its primary business or objective, the investing of its funds in securities, businesses or assets of any description
“**KL**”	Kimmeridge Limestone
“**Last Practicable Date**”	means the date falling immediately before the publication of this Document
“**London Stock Exchange**”	London Stock Exchange PLC
“**MAR**”	The Market Abuse Regulation (No. 596/2014)
“**Magellan**”	Magellan Petroleum (UK) Limited, a company incorporated in England and Wales with company number 06807023
“**Magellan Agreement**”	the farmout agreement entered into between HHDL and Magellan on 20 December 2013
“**NPetroleum SPA**”	the sale and purchase agreement entered into by the Company and Northern Petroleum PLC on 23 July 2014 pursuant to which the Company agreed to purchase the entire issued share capital of UKOG (GB) Limited
“**Official List**”	the official list of the UKLA
“**OIP**”	oil in place
“**Ordinary Shares**”	ordinary shares of £0.0001 each in the capital of the Company

"**Operating Company**"	an AIM company, other than an Investing Company, with an operating business and with a material trading activity
"**Options**"	the existing options to subscribe for new Ordinary Shares, further details of which are set out in paragraph 13 of Part 1 of this Document
"**OGA**"	the UK Oil and Gas Authority
"**PEDL**"	a production exploration and development licence
"**PEDL143 JOA**"	the joint operating agreement entered into by Europa Oil & Gas Limited, Egdon Resources PLC, Warwick Energy Exploration and Production Limited and Altwood Petroleum Limited on 1 March 2006 in respect of PEDL143
"**PEDL331 JOA**"	the joint operating agreement entered into by the Company and Solo Oil PLC and Doriemus PLC on 28 November 2017 in respect of PEDL331
"**Proposal**"	the proposed change of status of the Company from an Investing Company under the AIM Rules to an Operating Company
"**Proposed Director**"	Nicholas Mardon-Taylor
"**Prospectus Rules**"	the Prospectus Rules made by the FCA pursuant to sections 73(A)(1) and (4) of FSMA
"**QCA Code**"	the Corporate Governance Code for Small and Mid-size Quoted Companies 2018, published in April 2018 by the Quoted Companies Alliance
"**Register**"	the register of members of the Company
"**Regulatory Information Service**" or "**RIS**"	one of the regulatory information services authorised by the London Stock Exchange to receive, process and disseminate regulatory information in respect of AIM quoted companies
"**Resolutions**"	the resolutions set out in the notice of the General Meeting, which is set out at the end of this Document
"**Shareholder**" or "**Ordinary Shareholder**"	a holder of Ordinary Shares
"**Share Dealing Policy**"	the policy on share dealings adopted by the Company as more particularly described in paragraph 10 of Part I
"**Subsidiaries**"	the subsidiaries of the Company, details of which are set out in paragraph 3 of Part V of this Document
"**Takeover Code**" or "**City Code**"	the City Code on Takeovers and Mergers (as published by the Panel)
"**Takeover Panel**" or "**Panel**"	the UK Panel on Takeovers and Mergers
"**United Kingdom**" or "**UK**"	the United Kingdom of Great Britain and Northern Ireland
"**UKLA**"	the United Kingdom Listing Authority, being the FCA acting in its capacity as the competent authority for the purposes of FSMA
"**Warrants**"	warrants to subscribe for new Ordinary Shares, further details of which are set out in Part V of this Document
"**Weald SPA**"	the sale and purchase agreement entered into by the Company and NP Oil & Gas Holdings Limited on 23 July 2014 pursuant to which the Company agreed to purchase the entire issued share capital of UKOG Weald Limited

"**WH Ireland**"	WH Ireland Limited, Nominated Adviser and Broker to the Company
"**£**" and "**p**"	United Kingdom pounds and pence sterling, respectively

All references to times in this Document are to London time unless otherwise stated. References to the singular shall include references to the plural, where applicable, and vice versa.

Technical Glossary

For a further glossary of technical terms used throughout this Document, please see the 'Nomenclature' section of the CPR within Part III of this Document.

PART I

LETTER FROM CHAIRMAN AND INFORMATION ON THE GROUP

UK Oil & Gas Investments PLC

(Incorporated in England and Wales with registered number 05299925)
(to be renamed UK Oil & Gas Plc with effect from Admission)

Directors	**Registered Address**
Allen Dee Howard II (Non-Executive Chairman)	The Broadgate Tower
Stephen Paul Sanderson (CEO and, until Admission Executive Chairman)	8th Floor
Kiran Caldas Morzaria (Finance Director)	20 Primrose Street
Nicholas John Mardon-Taylor (Proposed Non-Executive Director)	London, EC2A 2EW
	United Kingdom

To the holders of Existing Ordinary Shares and, for information only, to holders of Options and Warrants.

Dear Shareholder,

RE-ADMISSION TO AIM OF EXISTING SHARE CAPITAL AS AN OPERATING COMPANY

AND NOTICE OF GENERAL MEETING

1. INTRODUCTION

The Board of UK Oil & Gas Investments PLC ("UKOG") announced earlier today that, subject to Shareholder approval, the Board has decided to implement fully a number of changes to the way that UKOG is managed which will have the effect of changing the status of the Company from an Investing Company under the AIM Rules to an Operating Company with a material trading activity.

The change to an Operating Company is classified as a fundamental change of the business of the Company under the AIM Rules and therefore is conditional, *inter alia*, upon the approval of Shareholders at the General Meeting. Accordingly, set out at the end of this Document, is a notice convening the General Meeting to be held at Hill Dickinson LLP, The Broadgate Tower, 8th Floor, 20 Primrose Street, London EC2A 2EW at 10.00 a.m. BST on 31 July 2018, at which Shareholders will be asked to approve the Proposal for the purposes of the AIM Rules.

Provided that the Resolution is duly passed at the General Meeting, trading in the Existing Ordinary Shares will be cancelled at 4.30 p.m. on 31 July 2018 and it is expected that the Shares will be readmitted to trading on AIM the following day at 8.00 a.m. on 1 August 2018.

It is also proposed that the Company will change its name to UK Oil & Gas Plc with effect from Admission.

The purpose of this Document, which comprises an Admission Document prepared under the AIM Rules, is to provide you with information on the Admission and to explain why the Directors consider the Proposal is in the best interests of the Company and its Shareholders as a whole, and why they unanimously recommend that Shareholders vote in favour of the Resolutions.

2. BACKGROUND

UKOG is a British oil and gas investment company, seeking to support the drive for increased energy security for this country, while ensuring its assets preserve the natural beauty of the Weald and Wessex region. The Company specialises in investing in new geological ideas, concepts and methodologies to find and produce oil from previously under-explored rock formations within established oil-producing basins.

The Company is admitted to trading on AIM and currently has a portfolio of direct and indirect investments in 8 UK onshore exploration, appraisal, development and production assets. UKOG is the largest acreage holder in the South of England, and the fourth largest in the overall UK onshore, with assets covering 791.5 gross km^2. The Company's portfolio includes 4 non-KL oil discoveries and the Directors believe that this area has the potential for significant growth in the future. UKOG is focussed on the KL geological section and its licences cover 591.51 gross km^2 of KL reservoir targets. The Directors advise that the Company's Kimmeridge 'sweet spot' licences were independently calculated by Nutech to contain a significant proportion of the play's total OIP which was 9.831BB. Subsequent to this, PEDL233 has expired and as such the Company has calculated the remaining oil as 8.651BB.

The Company is generating cash from its interests in the Horndean oil field, as well as developing the Horse Hill project. UKOG is also working to advance its Markwells Wood, Holmwood and the Arreton (onshore Isle of Wight) licences, which are set out in further detail in this Document.

By making use of some of the world's latest oil and gas technologies, UKOG is endeavouring to turn its discoveries into commercially viable producing assets.

UKOG is currently categorised as an Investing Company under the AIM Rules and is therefore subject to the requirements of the AIM Note for Investing Companies. The Company substantially implemented its current investing policy on 19 September 2014. The Company is seeking to re-admit its shares to trading on AIM as an Operating Company subject to approval by Shareholders. Following this change in status, the Company will no longer have an investing policy.

In the course of its investment strategy, UKOG has taken indirect and direct non-controlling stakes in oil and gas asset in the Weald Basin. It is now seeking to become more active in the development of these investments and in other assets it may identify. Following approval for and the change of status to an Operating Company, UKOG's investing policy will cease and UKOG will be able to take direct controlling interests in oil and gas assets without restriction and under the AIM Rules become the operator of such assets.

3. OUTLINE OF INTERESTS

An overview of UKOG's wholly-owned assets and assets in which UKOG owns an interest are outlined in the below table (Figure 1) and their geographic spread is presented in Figure 3.

Asset	**Licence**	**UKOG Interest**	**Licence Holder**	**Operator**	**Area (km^2)**	**Status**
Avington[1]	PEDL070	5%	UKOG (GB) Limited	IGas Energy Plc	18.3	Field currently shut in
Broadford Bridge[3]	PEDL234	100%	Kimmeridge Oil & Gas Limited	Kimmeridge Oil & Gas Limited	300.0	BB-1 & 1z completed, preparing two further planning applications
Holmwood[3]	PEDL143	40%	UKOG	Europa Oil & Gas (Holdings) plc	91.8	Holmwood-1 exploration well planned in 2018
Horndean[1]	PL211	10%	UKOG (GB) Limited	IGas Energy Plc	27.3	Field in stable production
Horse Hill[5]	PEDL137	32.435%	Horse Hill Developments Ltd[6]	Horse Hill Developments Ltd[6]	99.3	Production tests and further appraisal well(s) scheduled for 2018
Horse Hill	PEDL246	32.435%	Horse Hill Developments Ltd[6]	Horse Hill Developments Ltd	43.6	As above
Isle of Wight (Onshore)[2,3]	PEDL331	65%	UKOG	UKOG	200.0	Preparing Arreton-3 oil discovery appraisal well planning submission
Markwells Wood[2]	PEDL126	100%	UKOG (GB) Limited	UKOG (GB) Limited	11.2	Revised planning application underway

Notes:
1. Oil field currently in production.
2. Oil discovery pending development and/or appraisal drilling.
3. Exploration asset with drillable prospects and leads. PEDL234 contains the Broadford Bridge-1 and 1z discovery well, the extension of the Godley Bridge Portland gas discovery plus further exploration prospects.
4. UKOG has a 100% interest in Kimmeridge Oil & Gas Limited, which has a 100% interest in PEDL234.
5. Oil discovery with successful flow test in 3 zones, further long-term testing scheduled in 2018
6. UKOG has a direct 49.9% interest in HHDL, which has a 65% interest in PEDL137 and PEDL246.

Figure 1, UKOG, Table of Interest in Assets

UKOG CORPORATE STRUCTURE

The below (Figure 2) outlines the corporate structure of UKOG, its assets and economic interests in each.

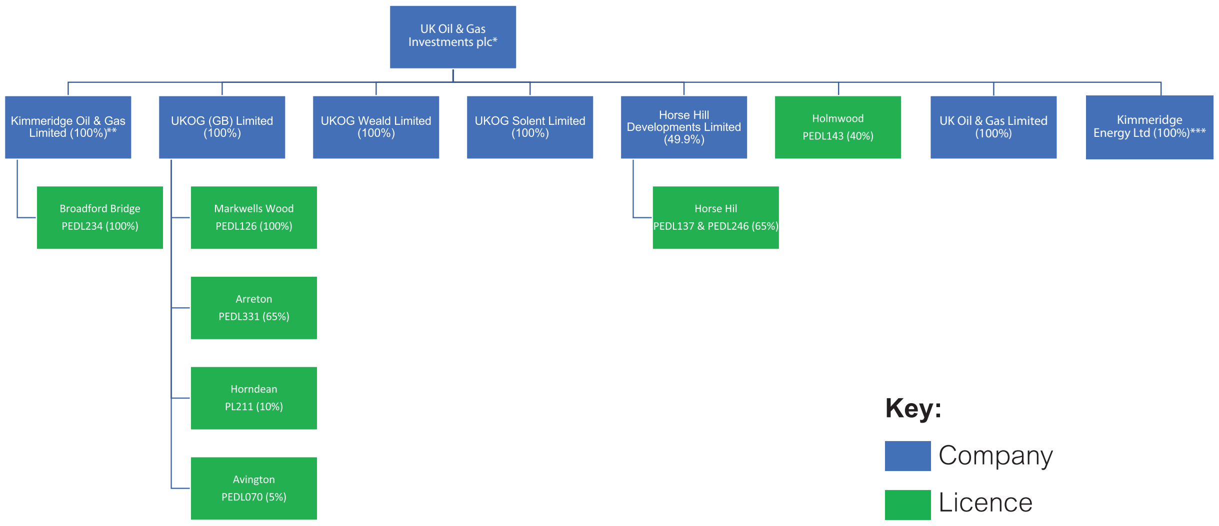

Figure 2 UKOG, Corporate Structure.

* To be renamed UK Oil & Gas PLC with effect from Admission

** To be renamed UKOG 234

*** Kimmeridge Energy Ltd to be renamed UKOG (KOGL) Ltd

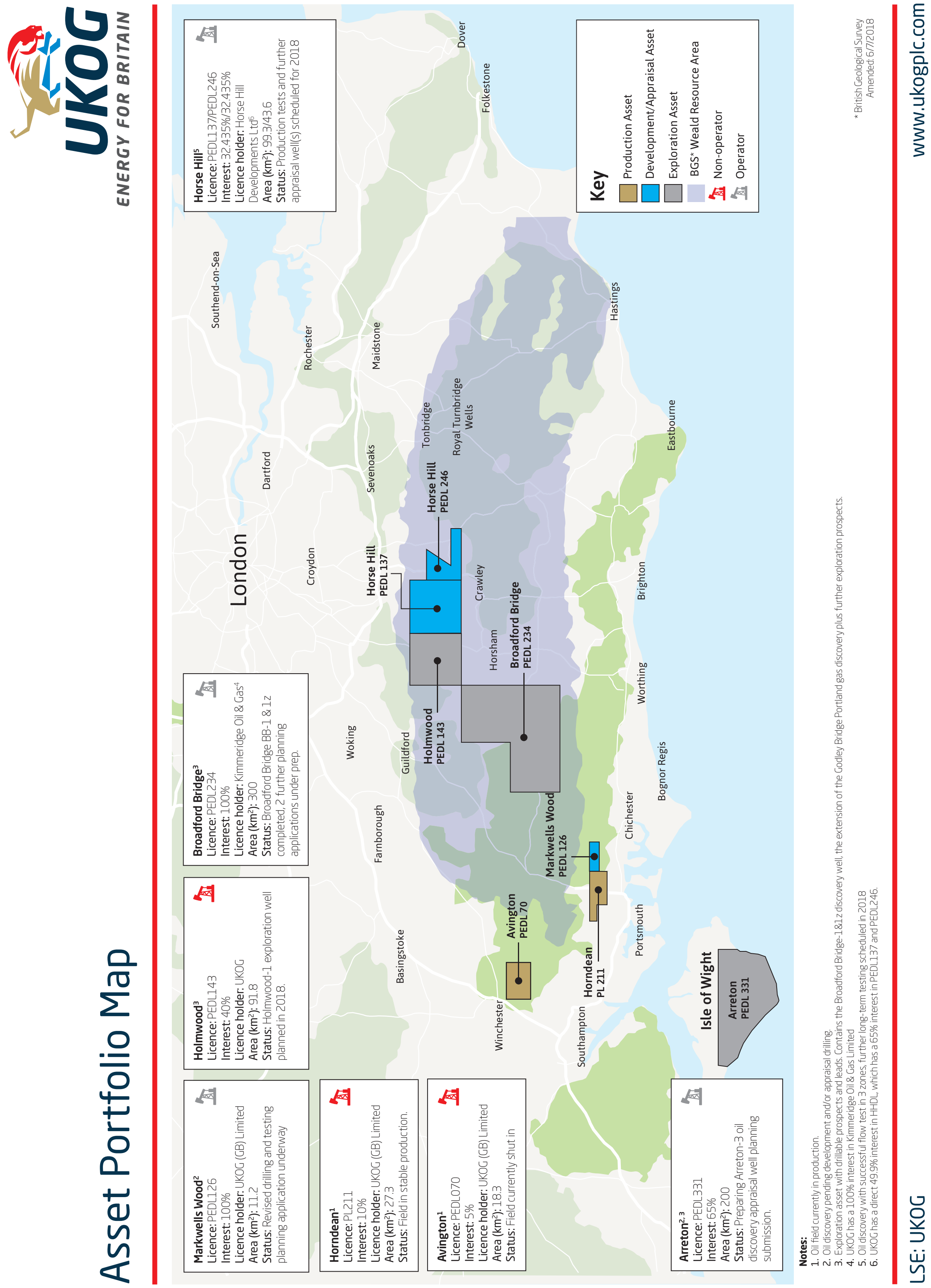

Figure 3, UKOG, Asset Portfolio Map.

4. SUMMARY OF THE ASSETS

Xodus Group have completed a Competent Persons Report as commissioned by UKOG. The report has covered UKOG's 8 licences in the south of England, 7 of which are located in the Weald Basin and 1 in the Wessex Basin. One of those licences contains a currently producing oil field, another contains a shut-in oil field that is not economically viable and a number of others contain existing discoveries. The following is a summary of UKOG's assets. Further details can be found within the CPR section in Part III of this Document.

OIP projections for the KL, Kimmeridge Clay Formation and other tight Jurassic reservoirs have been made by Nutech. These reports have been made public and OIP volumes reported by UKOG in its regulatory press releases, most recently in December 2016 where Nutech calculated a P50 estimate of the Company's net interest over its licence interests in the Weald Basin of 9.831 BB of OIP in the Kimmeridge clay formation. These estimates have not been updated since the drilling and testing of the BB-1/BB-1z discovery well. Subsequent to this PEDL233 expired and as such the OIP reduced by 1.180 BB to 8.651 BB OIP.

It should be noted that to date insufficient data exists in regards to the KL and other Jurassic continuous oil deposits to make an assessment of any resources or reserves under SPE standards. Accordingly these OIP numbers should not be construed as either resources or reserves and for the avoidance of doubt the Competent Person has not audited these OIP estimates of Nutech.

The Company will update the market in the event of any material change or change in status of the following assets.

Broadford Bridge

UKOG acquired exploration licence PEDL234 (interest 100%) in 2016, significantly increasing its acreage holding within the KL's prime prospective area. The licence is operated by Kimmeridge Oil & Gas Limited ("KOGL"), a wholly-owned subsidiary of UKOG. The onshore licence, PEDL234, covers 300 km². The licence acquisition included the existing Broadford Bridge well pad, along with planning permission and Environmental Agency ("EA") consent to drill the exploratory well ("BB-1").

Kimmeridge Potential – Broadford Bridge

UKOG, as disclosed within the analysis in section 10.2.2 of the CPR, has previously conducted analysis of PEDL234 and suggests that KL oil potential is also prevalent in a similar way to that at Horse Hill. BB-1 drilling commenced in May 2017 and was designed to penetrate the KL units at an inclination and orientation to test the open natural fractures within the KLs. Mobile light oil was recovered from open fractures in the KL5 cores within the Kimmeridge section. BB-1 was sidetracked to Broadford Bridge-1z ("BB-1z") in August 2017 due to difficult hole conditions to seek 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 The well was tested over multiple zones within the KL0-KL5 sections with the well free flowing light oil for short periods during the clean-up operations. Oil was also recovered to surface via pumping from multiple zones. The oil flowed to the surface during this testing programme, although at likely sub commercial rates. This has led the company to explore new completion methods that might achieve higher sustainable flow rates.

The BB-1z oil discovery within PEDL234 licence area is reported in section 10.2.2 of the CPR with no resource associated with it. The CPR details that Godley Bridge, a discovery, which is combined with PEDL235 and adjoins PEDL234, may extend into PEDL234, in which UKOG has a 100% interest. At Godley Bridge, wells GB-2/2Z and Alfold-1 failed to find hydrocarbons unlike Godley Bridge-1. See section 10.1 of the CPR, page 106 for further information. The report also notes that the previous competent persons reports for IGas, the operator of PEDL235, have calculated estimated of Contingent Resource of between 5 and 10 bcf.

The CPR states that after workover operations had been completed, testing continued and recovered 38 degree API oil. 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 is working to acquire 2 further drilling sites in PEDL234. If this is successful, planning applications are expected to be submitted for the first site (which neighbours Godley Bridge) later this year.

The well results from the UKOG operated wells at Horse Hill and Broadford Bridge, which have tested the KL, as well as the reported results of Brockham-X4Z, show a consistent picture of Kimmeridge prospectivity across these licence areas. The Kimmeridge oil potential appears to be regionally extensive with thick sections of high total organic carbon ("TOC") shale with limestone beds; all of which are naturally fractured. To date, oil has also flowed from all three exploration wells that has tested the KL. At present, significant additional work is required to determine the development potential of these reservoirs.

Horse Hill

UKOG has an indirect 32.435% interest in each of its 2 Horse Hill area licences operated by Horse Hill Developments Ltd (HHDL): PEDL137 and PEDL246. UKOG holds a 49.9% interest in HHDL which, in turn, has a 65% interest in PEDL137 and PEDL246.

The Horse Hill discovery comprises several prospective intervals; with only the Upper Portland Sandstone being considered as Contingent Resource. HHDL flow tested the Portland Sandstone and KL intervals of the Horse Hill-1 (HH-1) oil discovery well in 2016. The Company notes that the three reservoirs tested in 2016 demonstrated an initial aggregate stabilised natural flow rate of 1,688 barrels of oil per day.

Horse Hill is the first in a series of planned near-continuous appraisal drilling and testing operations designed to convert the company's recoverable resources into permanent production and reserves. The Directors believe that if the current Horse Hill testing programme is successful then it could deliver stable oil production in 2019, subject to obtaining the necessary regulatory consents and capital financing. The anticipation is that, should the Horse Hill testing programme produce oil in sufficient quantities and of the right quality it will be sold to offset the costs of the well test.

The extended well test is specifically designed to determine the presence of a commercial value of OIP. Consequently, the Company expects that HHDL will be able to determine the commerciality for the Kimmeridge and Portland following these test results. This is further explained in paragraph 5 of this Part I which outlines the future plans in respect of Horse Hill.

As reported on 27 June 2018, EWT operations at the Horse Hill site have commenced. As of the date of this Document operations to date have included equipment set-up and the necessary well clean-up process in preparation for the first sequence of the planned Portland flow test programme.

Horse Hill – Kimmeridge Potential

Within section 10.2.1 of the CPR, it is noted that the Kimmeridge shows good evidence of natural fracturing and that this is consistent with recent results from Brockham-X4z well where image log interpretation shows that both the Kimmeridge shale and the limestone beds are naturally fractured as at Horse Hill.The HH-1 KL3 and KL4 reservoirs were flow tested in 2016. The upper 2 limestones were tested and flowed an aggregate stable dry oil flow of 1,365 bopd under natural flow with no water produced. Interpretation of the tests suggest that there is a dual porosity system which exhibited no observed depletion.

Figure 4 outlines the report's estimate for Contingent Resources of PEDL137, Portland Reservoir.

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

Figure 4. CPR, Contingent Resources for PEDL137 Portland Reservoir.

Avington

The Avington oil field (onshore licence PEDL070) in which UKOG holds a 5% interest is located in Hampshire, close to the Stockbridge oil field, and is operated by IGas Energy PLC. It was discovered in 1960 and commenced production in 2007. UKOG acquired its indirect 5% interest from Northern Petroleum plc in 2014.

As outlined in section 5 of the CPR, Avington is a conventional field producing from the Jurassic Great Oolite limestone reservoir. Average Avington production in 2017 was approximately 35 bopd. Due to high operating costs and issues with one of the production wells, Avington production was temporarily shut down in early 2018. Three wells were drilled at Avington between 1987 and 2006 and the site has been in production since August 2007, with initial production rates over 500 bopd. The field has produced continuously from 2009 with low oil rates and high water cut (>90%).

The field is temporarily shut as the low oil production rate and costs linked to the high water cut have resulted in the field being uneconomic at the current cost and oil price.

Historically there has been Contingent Resource reported alongside Reserves. These resources were based on a further phase of development, However, given the current status of the field, further development appears unlikely.

Baxters Copse

UKOG held a 50% interest in the Baxters Copse (onshore licence PEDL233) oil discovery located in Hampshire, close to the Singleton oil field and which was operated by IGas Energy PLC. The initial term of the licence expired on 30 June 2018 and, due to the operator not having carried out the relevant exploration work commitment, the OGA served notice of determination of the licence on 5 July 2018.

IGas Energy Plc (as licence operator) must formalise an expiry of the licence by providing a relinquishment report to the OGA. This is due within 3 months of notification of the expiry of the licence. The Company expects to be responsible for 50% of the operator's costs associated in preparing the relinquishment report, but does not expect there to be any material costs associated with the relinquishment of the licence as no substantive works have been carried out to date.

Holmwood Well

Onshore licence PEDL143 in which UKOG holds a 40% interest and is operated by Europa Oil & Gas Limited contains the Holmwood prospect. It is located to the west of the Horse Hill licence, in the northern part of the Weald Basin. Planning permission is in place to drill the Holmwood-1 well to test the Portland and the Kimmeridge in 2018. This is further explained in paragraph 5 of this Part I which outlines future plans.

Two reservoirs are considered, in section 8.2 of the CPR, at the Holmwood Prospect – the Portland and Corllian 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. However, despite the presence or Corrilian Sandstones at both, neither are considered as oil bearing reservoirs in these fields. There are no wells on the licence, with the closest well on the adjacent Brockham field which lies in a "cut-out" in the northern portion of the PEDL143 licence. The CPR further notes that given the proximity to Horse Hill, the KLs are also highly prospective at Holmwood, but they are not included within the report.

Xodus have calculated the following STOIIP estimates for the Holmwood Well.

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
Homwood Total[14]	**1.19**	**2.29**	**4.26**	**0.48**	**0.92**	**1.70**	

Figure 5, CPR, Estimate of Holmwood Prospective Resource.

Horndean

Onshore licence PL211, in which UKOG holds a 10% interest is located in Hampshire, UK and is operated by IGas Energy PLC. Section 4 of the CPR states that 7 wells including horizontal sidetracks have been drilled into the Great Oolite Reservoir. Currently, the Directors believe that production is very stable at a rate of approximately 150 bbl/d (15 bbl/d net to UKOG). Historically, Horndean oil production has been above forecast due to improved well performance and this has been reflected in increases in Reserves estimates in the past, including from 2014 to 2016.

Oil Reserves (MMbbl)	W.I.	Gross Volumes 1P2	2P	3P	Net to UKOG 1P	2P	3P	Operator
Horndean	10%	0.39	0.85	1.29	0.039	0.085	0.129	IGas
Total (MMboe)		**0.39**	**0.85**	**1.29**	**0.039**	**0.085**	**0.129**	

Figure 6, CPR, Reserves Estimates for Horndean.

Isle of Wight

The onshore licence PEDL331, in which UKOG holds a 65% interest, contains the Arreton oil discovery and two geologically similar prospects. The Directors see this as an important element of the Company's portfolio with a focus upon the Portland fracture-enhanced conventional reservoirs in Arreton and look-alike exploration prospects which other operators have missed. Recoverable gross 2C Contingent Resources were calculated as 15.7 MMbbl, with 10.2 MMbbl net to UKOG according to the CPR. Arreton site selection and regulatory permitting activities are now underway to permit a planned appraisal drilling campaign targeted for 2019.

The PEDL331 licence was formally granted to UKOG by the OGA in September 2016. Angus Energy Holdings UK Limited assigned its 5% licence interest to Doriemus Plc and UKOG was formally appointed by the OGA as the licence operator. The PEDL331 JOA was entered into by the Company with Doriemus plc and 30% partner Solo Oil Plc. UKOG is finalising the selection of the well site and preparing a planning application to drill the Arreton-3 appraisal well, with a view to achieving oil production in the event of success, as detailed in section 5 of the CPR.

Two wells have previously been drilled on the Arreton structure. The discovery was made by the Arreton-2 well which was a twin of the 1952 Arreton-1 drilled by BP as noted within section 7 of the CPR. This further outlines that as the Arreton North Portland Limestone reservoir is separated from the Arreton Main reservoir by a fault, the recoverable volumes in the prospect are classified as Prospective Resources. The estimated STOIIP volumes from the Xodus report are shown in Figures 7, 8 and 9, below.

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

Figure 7, CPR, STOIIP Estimates for Arreton North Portland

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

Figure 8, CPR, STOIIP Estimates for Arreton South

Arreton South 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]	**82.0**	**127.0**	**189.0**	**132.0**

Figure 9, STOIIP Estimates for Arreton Main

Markwells Wood

The onshore licence PEDL126, in which UKOG holds a 100% interest through its subsidiary UKOG (GB) Limited, contains the Markwells Wood-1 oil discovery. In September 2016, UKOG submitted a planning application to the South Downs National Park Authority ("SDNPA") to further appraise and develop the Markwells Wood-1 oil discovery. The planned 2-phase programme would see 4 horizontal wells drilled within the conventional Great Oolite limestone reservoir.

Section 9 of the CPR states that currently, a single well has been drilled on the field, Markwells Wood-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. The reservoir of the Markwells Wood discovery is of Great Oolite Limestone formation which is a common reservoir unit in the Weald Basin. This 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. There are 5 zones in this reservoir named as follows and more detail on each can be found in the CPR contained within Part III of this Document:

- The Cornbrash
- Interbedded Oolite
- Upper Massive Oolite
- Oncolites
- Lower Massive Oolite

A geological summary of the Great Oolite was available to Xodus 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. Markwells Wood-1 well tests were conducted from December 2011 to May 2012 and produced 3931 bbl in total during that period. The CPR further notes, in section 9, that UKOG plans for a horizontal well in the crest of the structure a production forecast has been generated for a side track to Markswell Wood-1 1,200m length horizontal well with an east-west azimuth. The well is positioned high in the structure and targets the layers with the highest permeability.

Figure 10 below shows the STOIIP estimates calculated by Xodus in their report broken down into each of the reservoir's 5 zones, extracted from section 9 of the CPR. Likewise, Figure 12 outlines the CPR estimation of Markwells Wood Gross and Net Contingent Resources in '000 bbl, below.

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**

Figure 10, CPR, STOIIP Estimates for Markwells Wood.

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

Figure 11, CPR, Xodus estimation of Markwells Wood Contingent Resources.

Summary of Resources

The Competent person has estimated gross and net recoverable volumes for undeveloped discoveries and are classified as Contingent Resources. A commercial risk factor has been estimated for each discovery and shown in the following Figure 12.

Oil Contingent Resources	W.I.	Gross Volumes			Net to UKOG			Risk Factor[1]	Operator
(MMbbl)		**1C[2]**	**2C**	**3C**	**1C**	**2C**	**3C**	**%**	
Avington	5%	0.31	0.37	0.41	0.016	0.019	0.021	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		**11.5**	**18.8**	**30.9**	**7.3**	**12.0**	**19.6**		

Figure 12, Gross and Net Contingent Resources (in MMbl).

1 "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted.

2 1C, 2C and 3C denote the low, best and high estimate scenario of Contingent Resources respectively as defined under the PRMS.

The Onshore Isle of Wight and Holmwood licences both include Prospective Resources. The Prospective Resources for UKOG's assets are shown in the following figure 13. "Risk Factor" for Prospective Resources means the estimated chance, or probability, of geological success.

Oil Prospective Resources (MMbbl)	**W.I.**	**Gross Volumes**			**Net to UKOG**			**RF**	**Operator**
		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**		

Figure 13, Gross and Net Prospective Resources (in MMbl).

5. PROPOSED UKOG WORK PROGRAMME

In relation to Horse Hill, the OGA has granted its consent for the HH-1 Extended Well Test ("EWT") programme. All other necessary regulatory consents from Surrey County Council ("SCC"), the Environment Agency ("EA") and the Health and Safety Executive are in place. The Company has previously announced that it has funded its full share of operational EWT costs. The EWT will comprise a series of three separate test sequences commencing in the Portland followed by the KL4 and finally, the deeper KL3. If time permits a test combining the KL4 and KL3 (a commingled test) may be undertaken. Each test will utilise existing perforated zones as per the 2016 test programme. The expected duration of the full flow programme is around 150 days. The 2018 long-term testing programme's goal is to determine commerciality by confirming that HH-1's reservoirs are each connected to a commercially viable oil volume. It is expected that, should the minimum commercial volume threshold be met or exceeded, a declaration of commerciality for each horizon could be made in a timely manner after the completion of each testing sequence.

The Directors are targeting an assessment of Portland commerciality in Q3 2018 subject to a successful outcome of tests. In a similar manner to the 2016 test, which flowed oil from the Portland at a stable metered rate of 323 bopd over an 8.5 hour period, a linear rod-pump will be utilised to flow Portland oil from around 35 metres of existing perforations located at around 615 metres below surface. As the 2016 test rates were constrained by the pump's capacity, the new test will use a larger pump with a capacity of around 475 bopd.

Subject to a successful testing outcome in the Kimmeridge and Portland, the HH-2 appraisal well is planned to immediately follow the EWT in late 2018 / early 2019. The well will be drilled as a future Portland production well. Drilling plans include optionality to deepen HH-2 into the Kimmeridge to gather core and image log data, together with a possible northwards deviation to access the adjacent oil bearing Collendean Farm fault block's significant Portland oil resources.

Similarly, contingent upon EWT success, an HH-1z Kimmeridge sidetrack spud is planned in 2019 following integration of HH-1 Kimmeridge production data into a reservoir model and data from any future HH-2 Kimmeridge core. Necessary Planning and EA permits for HH-2 and HH-1z are in place. To achieve its goal of stable, long-term Horse Hill oil production during 2019, HHDL now plans to submit a further production planning application to SCC in Q3 2018. This application will seek consent to produce oil initially from HH-1 & 1z, and HH-2, together with further production wells in a second contingent drilling phase.

UKOG was awarded an extension of the licence term at its 100% owned PEDL234 from 30 June 2018 until 31 December 2023. The Licence has been converted into the 14th Licence Round Master Clauses Agreement which permits a Retention Area ("RA") covering the entirety of the 300km^2 licence area to be created.

UKOG intends to progress leases and regulatory approvals for two further well sites and exploration wells in the north of PEDL234 and potentially for a BB-1y sidetrack. An application was made recently to the West Sussex County Council to extend the existing planning consent on the BB-1 site for a further 18 months to the end of 2019.

On PEDL331: UKOG intends to secure a site lease and regulatory steps necessary to drill an appraisal well on the Arreton Main oil discovery and look-alike Arreton South prospect in PEDL331. PEDL331 currently has an estimate of 10.2 million barrels UKOG Net P50 Contingent (recoverable) Resources.

UKOG intends to participate in the share of the planned Portland and Kimmeridge Holmwood exploration well which currently has an estimated 0.92 million barrels UKOG Net P50 Prospective Resources. Europa plans to drill the Holmwood-1 exploration well.

On Markwells Wood: UKOG intends to submit a revised planning application for further flow testing to include the Kimmeridge section of the well. UKOG will seek necessary consents from EA to test this area.

UKOG plans to continue to consolidate and expand its licence position in the UK onshore, particularly in its core Weald Basin Kimmeridge oil play, with additional exploration, development and production.

6. OIL & GAS REGULATORY BACKGROUND

This paragraph is intended as background information in relation to the oil and gas regulatory framework in place in the UK. As such, it is only a summary of the more pertinent provisions of the Petroleum Act 1998 ("Petroleum Act"). The Petroleum Act is the principal legislation regulating the grant of rights to bore for and obtain petroleum in the United Kingdom. The Petroleum Act was enacted on 11 June 1998 and repealed the Petroleum Production Act 1934.

The Petroleum Act provides that petroleum deposits (which includes shale gas) below land in Great Britain are the property of the Crown but permits the OGA to grant licences to search and bore for and get petroleum to such persons as he thinks fit. The Petroleum Act is supplemented by various environmental and health and safety legislative provisions. All regulatory powers for the oil and gas industry, apart from those concerned with the environment, have been transferred from the Secretary of State to the OGA.

A PEDL (Production Exploration and Development Licence) is an onshore production licence which allows a company to pursue a range of oil and gas exploration activities, subject to necessary drilling/development consents and planning permission. All PEDLs run for the following 3 successive terms:

- The initial term is associated with an exploration work programme that the licensee will have agreed with the OGA during the competitive application process. The licence will expire at the end of its initial term unless the licensee has completed the work programme and surrendered a fixed amount of acreage (usually 50%). While the initial term is associated with a work programme of exploration work that must be completed if the licence is to continue into a second term, the licensee has the right to start production during the initial term, if the licensee can move quickly enough, subject to normal regulatory controls.
- The second term is associated with appraisal and development. There is no agreed work programme; instead the licence will expire at the end of its second term unless the OGA has approved a development plan.
- The third term is intended for production (production period). The OGA has the discretion to extend the term if production is continuing, but reserves the right to reconsider the provisions of the licence before doing so, especially the acreage and rentals. While the initial term is associated with a work programme of exploration work that must be completed if the licence is to continue into a second term, the licensee has the right to start production during the initial term, if the licensee can move quickly enough, subject to normal regulatory controls.

The length of each of the terms of a PEDL is agreed between the OGA and the licensees prior to the licence being issued, but may be subject to any subsequent amendments being agreed in the manner set out in this paragraph 6.

A PL (Production Licence) is an older form of onshore production licence issued by the UK government which grants exclusive rights to explore, drill and produce petroleum within a specified area for a specified time. An operator is approved for each petroleum licence and is responsible for managing all activities that take place in relation to that licence.

As from 1 October 2016, the Energy Act 2016, and Regulations made under it, transferred certain functions from the Secretary of State for Energy and Climate Change (now the Secretary of State for Business, Energy and Industrial Strategy) to the OGA. These include the licensing function conferred by the Petroleum Act 1998 insofar as it affects existing licences. Consequently, any legal agreement that would previously have named the Secretary of State for Energy and Climate Change as a party must correspondingly name the OGA instead (and all pre-existing agreements are deemed to refer to the OGA as necessary).

All petroleum exploration and production licences that are granted incorporate the model clauses (the "Model Clauses") which are contained in statutory instruments at the time of grant of each respective licence. Alternatively the OGA may agree bespoke clauses that may apply to the exclusion of the Model Clauses.

Part 1 Article 5 of the Petroleum Act determines that all licences granted prior to the enactment of the Petroleum Act will incorporate the current Model Clauses in substitution of any previous model clauses. The current Model Clauses applicable to onshore licenses are contained in the Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014 (SI 2014/1686).

Clause 5 of the Model Clauses contains an option in favour of a licensee to continue a licence beyond the initial term of that licence. Notice to exercise this option must be given to the OGA no later than 1 month prior to the expiry of the initial term of the licence and will be subject to and conditional on: (i) all sums outstanding under the licence having been paid; and (ii) performance by the licensee of the work programme specified in the licence having been performed.

Clause 7 of the Model Clauses determines that a licensee may give notice to the OGA that it wishes for a licence to continue beyond a second term into the production period, provided that such notice may be given at any time not later than 3 months before the expiry of the second term of a licence, subject to all due payments having been made and the terms and conditions contained in the Model Clauses having been performed. In order for a licence to continue beyond a second term, the OGA must have either: (i) approved a programme submitted to him it and such programme must be in force upon expiry of the second term; (ii) served a programme on the licensee and such programme must be in force upon expiry of the second term; or (iii) the OGA has with a view to securing the maximum economic recovery of petroleum so directed in writing (subject to any conditions specified by the OGA).

The Model Clauses provide that each of the 3 terms of a PEDL may be amended as follows:

- The initial term and or the second term of a licence may be extended by the OGA, on application being made to him it in writing not later than 1 month prior to the expiry of the relevant period, subject to all due payments having been made and the terms and conditions contained in the Model Clauses having been performed. Any extension of the initial term or second term shall be given by the OGA and which shall be for such period, and subject to such conditions, as the OGA may determine. There is no limitation on the number of extensions that may be made to the initial term or second term contained in the Model Clauses.
- The production period of a licence may be extended for such further period as may be agreed by the OGA and a licensee in order to secure the maximum economic recovery of petroleum from the licensed area. Any such extension shall be subject to such modification of the terms and conditions of the licence as may be agreed by the OGA and a licensee. Any application to extend the production period must be made to the OGA no later than 1 month prior to the expiry of the production period. There is no limitation on the number of extensions that may be made to the production period contained in the Model Clauses.

The consideration payable in terms of respect of each licence shall be determined by the provisions contained in each such licence or shall be determined by the Model Clauses, as the case may be. In the past, a royalty regime applied whereby the UK government would receive a royalty (usually linked to petroleum produced, or profits made pursuant to licences), but this was abolished from 1 January 2003.

The Model Clauses contain restrictions prohibiting the (i) assignment of licences (or any interest therein) or (ii) the entry into agreements to share in the proceeds of sale from petroleum extracted from an area subject to a licence already granted by the OGA which has not, but may be, won and saved, unless the prior consent of the OGA has been obtained.

Fiscal and regulatory regime

There are currently two main elements of government tax to which oil and gas companies are subject. These are Ring Fence Corporation tax ("RFCT") and Supplementary Charge ("SC"). A third, Petroleum Revenue Tax (PRT), still exists but has been set at zero per cent with effect from 1 January 2016.

RFCT

Corporate profits generated in the upstream oil and gas industry are liable for RFCT which is assessed against the upstream profits of the company. The RFCT tax rate is currently 30% and is assessed on an annual basis. First year allowances are given as a relief at a rate of 100% for virtually all capital expenditure.

The RFCT rules are designed to prevent companies reducing their upstream ring fence profits with reliefs and allowances from other activities. The main restrictions are that losses and expenses from other activities, either within the company or accruing to an affiliate, cannot be deducted against ring fence profits. The deductibility of financing costs is also limited such that, broadly, interest deductions are only available in respect of monies borrowed which have been used in the ring fence business, and where the terms do not exceed those applicable at arm's length. Ring Fence Expenditure Supplement allow companies to claim a 10% supplement on their ring fence trading losses carried forward for 10 (previously six), not necessarily consecutive, periods.

SC

SC was introduced in 2002 and applies to all profits obtained from oil and gas production, and transportation and processing from 17 April 2002 onwards. SC is charged at a rate of 10% (with no deduction for finance costs) and is calculated in a very similar way to RFCT. SC can be reduced by the investment allowance, cluster area allowance or onshore allowance once the relevant allowance has been activated.

Investment Allowance

Investment Allowance is calculated as a percentage of the amount of qualifying ring fence expenditure, which was only capital expenditure when the Investment Allowance was originally introduced, with effect from 1 April 2015. However, the scope of the qualifying expenditure has been extended to include certain operating and leasing expenditure incurred on or after 8 October 2015. Once activated by production income from the relevant field the allowance reduces the company's profits subject to supplementary charge

Cluster Allowance

Cluster Allowance is similar to Investment Allowance in the way it is calculated; however qualifying costs for the purposes of Cluster Allowance are those in respect of qualifying expenditure incurred in relation to a cluster area on or after 3 December 2014. The definition of qualifying expenditure is the same as for Investment Allowance. Once an area has been determined as a cluster area all subsequent qualifying capital expenditure will qualify for the allowance. The benefit of cluster allowance over investment allowance is that income from any of the interests included in the cluster will activate the allowance, not just income from the licence in question.

Onshore Allowance

Onshore Allowance is designed to support the early development of onshore oil and gas projects including shale gas developments. The allowance is available in respect of capital expenditure incurred on and after 5 December 2013 in relation to an onshore oil and gas related activity, and is calculated as a percentage of a qualifying capital expenditure spend, reducing adjusted ring fence profits subject to supplementary charge once activated. The extension of qualifying costs to include certain operating and leasing costs does not apply to the onshore allowance. If the allowance cannot be activated (due to a lack of production income from the site) it can be transferred to another site three years after the expenditure was incurred.

Environmental Regime

The regulatory framework for the hydrocarbon extraction industry is administered by a number of regulatory authorities. The framework involves a number of review processes and permissions/consents to be obtained before any operation can commence. These requirements are in addition to the consenting process under the Town and Country Planning Act 1990. A brief summary of the key regulatory requirements is set out below.

The Oil and Gas Authority

The Petroleum Act 1998 vests all rights to petroleum in the Crown, including the rights to search for, bore for and get petroleum. It empowers the OGA to grant licences to search for and bore for and get petroleum to such persons as they see fit.

The OGA has regulatory control for petroleum licencing under the Petroleum Act 1998 (as amended by the Infrastructure Act 2015). Under the Petroleum Act, the Secretary of State (SoS) issues landward production licences (Petroleum Exploration and Development Licences (PEDL)).

Under the terms of a PEDL, a licensee is obligated to seek consent from the OGA to undertake well operations including but not limited to the drilling of a well, extended well test and production as well as consent to flaring or venting.

Standard provisions in PEDLs include obligations on the licensee to avoid harmful methods of working, powers for the SoS to execute works in the event of breach of the PEDL by the licensee and powers to revoke the PEDL.

The Environment Agency

Onshore oil and gas production is regulated by the Environment Agency (EA) by an environmental permitting regime granted by the EA pursuant to the Environmental Permitting (England and Wales) Regulations 2016 (EPR 2016).

One of the principal aims of the permitting regime is to protect the environment. Under the EPR 2016, the EA controls the treatment and disposal of mining waste and naturally occurring radioactive material (NORM) should this be encountered, any emissions to air and water as a result of the permitted operations through to restoration and aftercare. Other permits/licences may also be required from the EA depending on the site location and geological and hydrogeological characteristics of the site.

In addition to the EPR 2016, the EA controls water resources, water quality and water pollution under the Water Resources Act 1991. Part of its requirements relate specifically to drilling, by ensuring the protection of any groundwater sources.

Health and Safety Executive

The Health and Safety Executive (HSE) regulates the safety aspects of all phases of extraction. It ensures that safe working practices are adopted by onshore operators as required under the Health and Safety at Work etc Act 1974, and regulations made under the Act.

HSE works closely with the EA and the Department for Business, Energy and Industrial Strategy to share relevant information on such activities and to ensure that there are no material gaps between the safety, environmental protection and planning authorisation considerations, and that all material concerns are addressed.

Minerals Planning Authority

Minerals Planning Authorities (as part of local councils) grant planning permission for the location of any wells and well pads, and impose conditions to ensure that the impact on the use of the land is acceptable. Where planning permission is granted for petroleum exploration and development, the development will be subject to restoration and aftercare provisions, which will be enforced by way of planning condition.

The planning system controls the development and use of land in the public interest. The focus of the planning system is on whether the application is an acceptable use of the land, and the impacts of those uses. This includes ensuring that any new development is appropriate for its location. This takes into account the effects (including cumulative effects) of potential pollution on health, the natural environment or general amenity. Certain types of planning application are required to undertake an environmental impact assessment before they are determined.

The planning regime and other regulatory regimes are separate but do complement each other. Any control processes, health and safety issues or emissions themselves are then subject to the approval of the other regulators mentioned above.

Abandonment Framework

The Model Clauses prohibit operators from abandoning any well without the consent of the OGA. The operator must submit an application for consent to abandon a well and provide detailed information regarding the results of the well. The OGA's consent to well abandonment must be given before this operational activity is undertaken and the operator must adhere to any conditions imposed by the OGA. After well abandonment consent is given, the operator must notify the OGA upon completion of the work and a well engineering diagram must be submitted at this time.

7. REASONS FOR ADMISSION

The Company is seeking readmission to trading on AIM as an Operating Company (instead of its current status as an Investing Company) under the AIM Rules. Following approval for and the change of status to an Operating Company, UKOG's investing policy will cease and the Company will be able to take direct controlling interests in oil and gas assets without restriction and under the AIM Rules become the operator of such assets.

8. DIRECTORS, EMPLOYEES AND KEY PERSONNEL

Directors

At Admission, the Board will comprise Stephen Sanderson, Kiran Morzaria, Allen Howard and Nicholas Mardon-Taylor.

Brief biographical details of the Directors are set out below:

Allen Dee Howard, Non-Executive Chairman – aged 40

Mr Howard has extensive experience in the oil sector. He was previously a Senior Vice President of Houston-based Premier Oilfield Laboratories, and Chief Commercial Officer of well analysis experts Nutech. Mr Howard also held senior positions with Schlumberger. He holds a degree in Chemical Engineering from Texas Tech University and an MBA from Mays Business School in Texas.

Stephen Paul Sanderson, CEO – aged 61

Stephen Sanderson joined UKOG in September 2014 and was appointed Executive Chairman and Chief Executive in July 2015. A highly-experienced petroleum geologist, oil industry veteran and upstream energy business leader, with over 30 years operating experience, Stephen is a proven oil finder and has been instrumental in the discovery of more than 10 commercial conventional fields, including the giant Norwegian Smorbuk-Midgaard field complex. Stephen held a variety of senior management roles for ARCO (which was acquired by BP in 2000), Wintershall AG (a subsidiary of German chemical giant BASF) and 3 junior start-ups. He created and ran successful new exploration businesses in Africa, Europe and South America. He has significant technical and commercial expertise in the petroleum systems of Africa, the North Sea, Norway, onshore UK and Europe, South America, the South Atlantic, Middle East, Asia, India, Australia and the USA. He is a graduate and Associate of the Royal School of Mines, Imperial College, London, a Fellow of the Geological Society of London and a member of the American Association of Petroleum Geologists. He served for 4 years in the British Army and TAVR as a platoon commander, serving in the UK and Berlin.

Kiran Caldas Morzaria, Finance Director – aged 44

Mr Morzaria holds a Bachelor of Engineering (Industrial Geology) from the Camborne School of Mines and an MBA (Finance) from CASS Business School. He has extensive experience in the mineral resource industry working in both operational and management roles. Mr Morzaria spent the first 4 years of his career in exploration, mining and civil engineering. He then obtained his MBA and became the Finance Director of Vatukoula Gold Mines Plc. He has served as a director of a number of public companies in both an executive and non-executive capacity and is currently the Chief Executive Officer for Cadence Minerals plc, and a non-executive director of European Metals Holdings Ltd.

Nicholas John Mardon-Taylor, Proposed Non-Executive Director – aged 73

Mr. Mardon-Taylor served as the Chief Financial Officer of Hurricane Energy PLC from May 2012 until January 2016. He has worked in the oil industry for over 35 years, his first involvement in the North Sea being in the early licensing rounds. He was with Hurricane from 2005 to January 2016 when he was the Group's first CFO and was subsequently responsible for the Group's Environmental Management System.

Key personnel

Matt Cartwright, Chief Operating Officer – aged 56

Mr Cartwright is a part of key management of UKOG and joined the Company as a Business Adviser in July 2014 to help close and manage the Company's successful Northern Petroleum acquisition. He has provided services as Chief Operating Officer since September 2015. Matt has worked for 35 years in the international oil & gas industry for super-majors and start-ups. He started his career with BP and ARCO in the UK before spending 13 years with Total where he made a significant contribution to Total's growth in the Canadian heavy oil sands, the UK Elgin/Franklin development and in several ultra-deep-water West Africa projects. Matt is highly experienced in the areas of executive management, business development, development planning, strategic planning, economic evaluation, asset acquisitions and deployment of new engineering technology. His international experience encompasses Canada, Norway, France, Africa and the Middle East. Matt has a first class engineering degree from the University of Cambridge.

Employees

As at the date of this Document, the Group has 6 full time employees.

9. CORPORATE GOVERNANCE

From Admission, the Company is required under the AIM Rules to comply with a recognised corporate governance code to be chosen by the Board. The Board recognises the importance of sound corporate governance and intends that the Company will comply with the provisions of the QCA Code. The Company shall disclose on its website how it complies with the QCA Code and, where it departs from the QCA Code, will explain the reasons for doing so.

Following Admission, the Board will comprise 2 executive directors and 2 non-executive directors (one of whom is considered by the Board to be independent) in line with QCA guidelines.

The Board is responsible for formulating, reviewing and approving the Group's strategy, budgets and corporate actions.

The Group has established properly constituted audit and remuneration committees of the Board with formally delegated duties and responsibilities.

Audit Committee

The Audit Committee has primary responsibility for monitoring the quality of internal controls, ensuring that the financial performance of the Group is properly measured and reported on. It will receive and review reports from the Group's management and auditors relating to the interim and annual accounts and the accounting and internal control systems in use throughout the Group. The Audit Committee will meet no less than 3 times each year and will have unrestricted access to the Group's auditors. The Audit Committee comprises a minimum of 2 directors including, at least, 1 independent Non-Executive Director and 1 member with recent and relevant financial experience. At Admission, the members of the Audit Committee shall be Allen Howard and Nicholas Mardon-Taylor.

Remuneration Committee

The Remuneration Committee reviews the performance of executive directors and makes recommendations to the Board on matters relating to their remuneration and terms of employment. The committee also makes recommendations to the Board on proposals for the granting of share options and other equity incentives pursuant to any share option scheme or equity incentive scheme in operation from time to time. The Remuneration will meet at least twice each year. The Remuneration Committee comprises a minimum of 2 directors all of whom shall be independent Non-Executive Directors. At Admission, the members of the Remuneration Committee shall be Allen Howard and Nicholas Mardon-Taylor.

AIM Rules Compliance Code

The Company has also adopted an AIM rules compliance code to ensure that they have in place sufficient procedures for ensuring compliance with the AIM Rules.

10. SHARE DEALING POLICY

The Board has adopted the Share Dealing Policy in order to comply with Rule 21 of the AIM Rules relating to directors' and applicable employees' (as defined in the AIM Rules) and key personnel dealings in Shares. It also complies with the requirements of MAR.

The Share Dealing Policy applies to the Directors, other relevant employees and key personnel of the Group. The Share Dealing Policy provides that there are certain periods during which dealing in Ordinary Shares cannot be made. Such periods include the periods leading up to the publication of the Company's financial results, including interim results, and any periods in which the Directors and other relevant employees and key personnel may be in possession of unpublished price sensitive information.

In addition, a clearance procedure must be followed before any dealings by persons subject to the Share Dealing Policy can take place (including dealings by their families and other associates).

11. ANTI-BRIBERY AND CORRUPTION POLICY

The Company has implemented an anti-bribery and corruption policy and also implemented appropriate procedures to ensure that, *inter alia*, the Board, employees, key personnel, agency staff and consultants comply with the Bribery Act 2010.

12. SOCIAL MEDIA POLICY

The Company has implemented a Social Media Policy which details the ways in which all employees, officers, consultants, contractors, volunteers, interns, casual workers and agency workers interact with social media in relation to UKOG. This policy deals with the use of all forms of social media, including Facebook, LinkedIn, Twitter, Google+, Wikipedia, Whisper, Instagram, Vine, Tumblr, ADVFN bulletin board, London South East bulletin board, iii bulletin board and all other social networking sites, internet postings, bulletin boards and blogs. It applies to use of social media for business purposes as well as personal use that may affect the business in any way. It is designed to ensure that there is no unauthorised release of potentially price sensitive information regarding the Company so that all such information is released in the first instance through the correct authorised regulatory news services and that no misleading information is contained in unauthorised media channels. The Policy is also designed to mitigate the risk of use of terminology in the media being inconsistent with the Company's authorised regulatory announcements. The Policy has been implemented following events in 2015 when UKOG was forced to provide clarifications on its earlier RNS statements following media reports of the Company's announcements and associated interviews with the Company's management. Risks associated with Social Media details can also be found within Part II of this Document.

13. SHARE OPTIONS, INCENTIVES AND WARRANTS

The Directors believe it is important for the success and growth of the Company to employ highly motivated personnel and that equity incentives are available to attract, retain and reward staff. On Admission, the following directors and key personnel/employees have the following shares and options:

Name	Number of shares	Number of options	Current shareholding excluding unexercised options
Stephen Sanderson	–	85,000,000	–
Kiran Morzaria	4,508,178	20,000,000	0.1%
Allen Howard	–	10,000,000	–
Matt Cartwright	–	40,000,000	–

As at the date of this Document, Warrants and Options for a total of 251,055,555 Ordinary Shares are outstanding. Further details on the outstanding Warrants are set out in Part V of this Document. The Company does not intend to apply for the Warrants to be admitted to trading on AIM.

14. FINANCIAL REPORTING

The Company operates a September year end. It is anticipated that the preliminary statement of results for each year will be announced by the end of March and that an interim statement of the results for the first half-year will be announced in June each year. It is intended to hold the Company's Annual General Meeting during April of each year.

In accordance with Rule 28 of the AIM Rules, this Document does not contain historical financial information on the Company, which would otherwise be required under Section 20 of Annex I of the Prospectus Rules. The Group's published financial information can be located on the Company's website under AIM Rule 26 at the following link: http://www.ukogplc.com/page.php?pID=82

The most recently published Annual Report and Accounts for the Year Ended 30 September 2017 and most recent interim results for the period ended 31 March 2018 are contained within the Appendix to this Document.

15. DIVIDEND POLICY

The Directors do not intend to declare a dividend at the current time.

16. ADMISSION AND DEALINGS IN SHARES

Application has been made to the London Stock Exchange for the Existing Ordinary Shares to be admitted to trading on AIM. It is expected that Admission will be effective and that dealings on AIM will commence at 8.00 a.m. on 1 August 2018.

17. TAXATION

Your attention is drawn to the further information regarding taxation set out in Part V of this Document. These details are, however, intended only as a general guide to the current tax position for UK resident Shareholders under UK taxation law and you should seek independent advice if you are in any doubt as to your tax position and/or if you are subject to tax in a jurisdiction other than in the UK.

18. THE TAKEOVER CODE

The Company is incorporated in England and its Ordinary Shares are admitted to trading on AIM. Accordingly, the Takeover Code applies to the Company.

19. GENERAL MEETING

As described above, the change of status of the Company from an Investing Company to an Operating Company is classified as a fundamental change of the Company under the AIM Rules and therefore is conditional upon the approval of Shareholders at the General Meeting. Accordingly, set out at the end of this Document, is a notice convening the General Meeting at which the following resolutions will be proposed:

- Resolution 1 seeks to approve the change of the status of the Company from an Investing Company to an Operating Company with a material trading activity for the purposes of the AIM Rules and to approve the Admission;
- Resolution 2 seeks to authorise the Directors to issue up to £170,000 in nominal value of Ordinary Shares following Admission; and
- Resolution 3 seeks to disapply pre-emption rights in connection with the issue of up to £170,000 in nominal value of Ordinary Shares following Admission.

The attention of Shareholders is also drawn to the voting intentions of the Directors set out in paragraph 23 below.

20. COMPETENT PERSON'S REPORT

A technical report prepared in accordance with the 2011 Petroleum Resources Management System (as defined by the Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and the Society of Petroleum Evaluation Engineers), and the "AIM Note for Mining and Oil & Gas Companies" as published in June 2009 by the London Stock Exchange that is effective 1 July 2018 (the "Competent Person's Report") prepared by Xodus Group is available in this document, and on the Company's website.

A competent person's report had been published by the Company on 6 June 2018 which has not been used in this Document. The reason for this is that PEDL233 has expired since this competent person's report had been prepared and accordingly that report no longer complies with the AIM Note for Oil & Gas Companies as it does not accurately detail the oil and gas interests of the Company as at the date of this Document. The Competent Person's Report used is an updated version of the 6 June 2018 report and reaches the same conclusions included therein save for any changes required as a result of the expiry of PEDL233.

21. FURTHER INFORMATION

Your attention is drawn to the further information set out in Parts III and V of this Document, and the "Risk Factors" set out in Part II. You are advised to read the whole of this Document rather than relying on the summary information set out in Part I of this Document before making any decision to invest in the Company.

22. ACTION TO BE TAKEN

Shareholders will find enclosed with this Document a Form of Proxy for use at the General Meeting. Whether or not you intend to be present at the General Meeting, you are requested to complete, sign and return your Form of Proxy to Share Registrars Limited at The Courtyard, 17 West Street, Farnham, Surrey GU9 7DR or sent by email to voting@shareregistrars.uk.com, as soon as possible but, in any event, so as to arrive no later than 10.00 a.m. BST on 27 July 2018.

Completion of a Form of Proxy will not preclude a Shareholder from attending and voting at the General Meeting in person save that in each case the Shareholder should contact Share Registrars Limited in advance to confirm what identity documents they should bring with them and to complete a form of representation (available on request from Share Registrars Limited) if necessary.

23. RECOMMENDATION

The Board believes that the Proposal is in the best interest of the Company and its Shareholders and therefore recommends that Shareholders vote in favour of resolutions to be proposed at the General Meeting as they intend to do so in respect of their own beneficial holding of Ordinary Shares which in aggregate amounts to 4,508,178 Ordinary Shares representing 0.1% of the Existing Share Capital.

Yours faithfully,

Stephen Sanderson
Executive Chairman and CEO

PART II

RISK FACTORS

Any investment in the Company and the Ordinary Shares carries a significant degree of risk, including risks in relation to the Company's business strategy, potential conflicts of interest, risks relating to taxation and risks relating to the Ordinary Shares.

The risks referred to below are those risks the Company and the Directors consider to be the material risks relating to the Company. However, there may be additional risks that the Company and the Directors do not currently consider to be material or of which the Company and the Directors are not currently aware that may adversely affect the Company's business, financial condition, results of operations or prospects. Investors should review this Document carefully and in its entirety and consult with their professional advisers before acquiring any Ordinary Shares. If any of the risks referred to in this Document were to occur, the results of operations, financial condition and prospects of the Company could be materially adversely affected. If that were to be the case, the trading price of the Ordinary Shares and/or the level of dividends or distributions (if any) received from the Ordinary Shares could decline significantly. Further, investors could lose all or part of their investment.

This summary of risk factors is not intended to be exhaustive, nor is it an explanation of all the risk factors involved in investing in the Company and nor are the risks set out in any order of priority. It should be noted that the risks described below are not the only risks faced by the Company and there may be additional risks that the Directors currently consider not to be material or of which they are currently not aware.

RISKS RELATING TO THE COMPANY AND ITS BUSINESS STRATEGY

Internal systems and controls

The Company faces risks frequently encountered by developing companies such as under-capitalisation, cash shortages and limited resources. In particular, its future growth and prospects will depend on its ability to manage growth and to continue to maintain, expand and improve operational, financial and management information systems on a timely basis, whilst at the same time maintaining effective cost controls. Any damage to, failure of or inability to maintain, expand and upgrade effective operational, financial and management information systems and internal controls in line with the Company's growth could have a material adverse effect on the Company's business, financial condition and results of operations.

Attraction and retention of key employees and personnel

The Company's success will depend on its current and future executive management team. If any key person resigns, there is a risk that no suitable replacement with the requisite skills, contacts and experience will be found to replace such person. The senior executive personnel currently have equity or share option interests in the Company. Notwithstanding this, if key personnel were to leave the Company, it could have a material adverse effect on the Company's business, financial condition and operating results.

Retention of key business relationships

The Company will rely significantly on strategic relationships with other entities on good relationships with regulatory and governmental departments and upon third parties to provide essential contracting services. There can be no assurance that its existing relationships will continue to be maintained or that new ones will be successfully formed and the Company could be adversely affected by changes to such relationships or difficulties in forming new ones. Any circumstance which causes the early termination or non-renewal of one or more of these key business alliances or contracts or the failure successfully to form new ones, could adversely impact the Company, its business, operating results and prospects.

Political conditions and government regulations

Although political conditions in the UK are generally stable, changes may occur in its political, fiscal and legal systems, which might adversely affect the ownership or operation of the Company's interests including, *inter alia*, changes in exchange rates, exchange control regulations, expropriation of oil and gas rights, changes in government and in legislative, fiscal and regulatory regimes. The Company's strategy has been formulated in the light of the current regulatory environment and likely future changes.

Although the Directors believe that the Company's activities are currently carried out in accordance with all applicable rules and regulations, no assurance can be given that new rules, laws and regulations will not be enacted or that existing or future rules and regulations will not be applied in a manner which could serve to limit or curtail exploration production or development of the Company's business or have an otherwise negative impact on its activities. Amendments to existing rules, laws and regulations governing the Company's operations and activities, or increases in or more stringent enforcement, implementation or interpretation thereof, could have a material adverse impact on the Company's business, results of operations and financial condition and its industry in general in terms of additional compliance costs.

Project development risks

There can be no assurance that the Company will be able to manage effectively the expansion of its operations or that the Company's current personnel, systems, procedures and controls will be adequate to support the Company's operations. This includes among other things, the Company managing the acquisition of required land tenure, infrastructure development and other related issues. Any failure of the Board to manage effectively the Company's growth and development could have a material adverse effect on the Company's business, financial condition and results of operations. There is no certainty that all, or indeed, any of the elements of the Company's current strategy will develop as anticipated and that the Company will be profitable.

Environmental, health and safety and other regulatory standards

The projects in which the Company invests and its existing and potential production and exploration activities are subject to various laws and regulations relating to the protection of the environment (including regular environmental impact assessments and the obtaining of appropriate permits or approvals by relevant environmental authorities) and are also required to comply with applicable health and safety and other regulatory standards. Environmental legislation in particular can comprise numerous regulations which might conflict with one another and which cannot be consistently interpreted. Such regulations typically cover a wide variety of matters including without limitation prevention of waste pollution and protection of the environment, labour regulations and worker safety. The Company may also be subject under such regulations to clean-up costs and liability for toxic or hazardous substances which may exist on or under any of its properties or which may be produced as a result of its operations. As a result, although the Company intends to operate in accordance with the highest standards of environmental practice and comply in all material respects, full compliance with applicable environmental laws and regulations may not always be ensured.

The current and anticipated operations of the Company, including further exploration, appraisal, development, production and ultimately decommissioning activities require permits from various national and local governmental authorities. Such operations are subject to a substantial body of laws and regulations governing land use, the protection of the environment, production, taxes, labour standards, occupational health, waste disposal, toxic substances, mine safety and other matters.

Any changes to, and increases in, current regulation or legal requirements, with the enforcement thereof, may have a material adverse effect upon the Company in terms of additional compliance costs. Unfavourable amendments to current laws, regulations and permits governing operations and activities of development and/or production companies, or more stringent implementation thereof, could have a materially adverse impact on the Company and cause increases in capital expenditures which could result in a cessation of operations by the Company.

Any failure to comply with relevant environmental, health and safety and other regulatory standards may subject the Company to extensive liability, fines and/or penalties and have an adverse effect on the business and operations financial results or financial position of the Company. Furthermore, the future introduction or enactment of new laws, guidelines and regulations could serve to limit or curtail the growth and development of the Company's business or have an otherwise negative impact on its operations. Failure to comply with applicable laws, regulations and permitting requirements may result in enforcement actions thereunder, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed, and may include corrective measures requiring capital expenditures, installation or additional equipment or remedial actions.

Currency risks

The Company receives revenue from the sale of oil from its Projects; oil is priced in US dollars whilst the bulk of the Company's costs are in GBP and therefore the Company's financial position and performance will be affected by fluctuations in the US dollar, sterling exchange rate along with fluctuations in the oil price.

In addition the Company may make investments in currencies other than Sterling and the Company does not currently intend to hedge against exchange rate fluctuations. Accordingly, the value of such investments may be adversely affected by changes in currency exchange rates notwithstanding the performance of the investments themselves, which may have a material adverse effect on the business, financial condition, results of operations and prospects of the Company.

Insurance coverage and uninsured risks

The Company insures its operations in accordance with industry practice and plans to insure the risks it considers appropriate for the Company's needs and circumstances. However, the Company may elect not to have insurance for certain risks, due to the high premium costs associated with insuring those risks or for various other reasons, including an assessment that the risks are remote.

No assurance can be given that the Company will be able to obtain insurance coverage at reasonable rates (or at all), or that any coverage it obtains will be adequate and available to cover any claims arising. The Company may become subject to liability for pollution or other hazards against which it has not insured or cannot insure, including those in respect of past activities for which it was not responsible. In the event that insurance coverage is not available or the Company's insurance is insufficient to fully cover any losses, claims and/or liabilities incurred, the Company's business and operations, financial results or financial position may be disrupted and adversely affected.

The payment by the Company's insurers of any insurance claims may result in increases in the premiums payable by the Company for its insurance cover and adversely affect the Company's financial performance. In the future, some or all of the Company's insurance coverage may become unavailable or prohibitively expensive.

Fluctuations of revenues, expenses and operating results

Future revenues, expenses and operating results of the Company could vary significantly from period to period as a result of a variety of factors, some of which are outside its control. These factors include general economic conditions, adverse movements in interest rates, conditions specific to the oil and gas market, seasonal trends in revenues, capital expenditure and other costs and the introduction of new products or services to the market. In response to a changing competitive environment, the Company may elect from time to time to make certain pricing, service or marketing decisions or investments that could have a material adverse effect on the Company's revenues, results of operations and financial conditions and prospects.

Third-Party Credit Risk

The Company is and may in the future be exposed to third-party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and production and other parties. Significant changes in the oil and natural gas industry, including fluctuations in commodity prices and economic conditions, environmental regulations, government policy and other geopolitical factors, could adversely affect the Company's ability to realise the full value of its accounts receivable.

Typically, oil and gas operations are funded pro rata to the participants' interests in the licences or concessions, accordingly to budgets and work programmes drawn up by the operator and approved by the requisite majority of the participants, subject to variations as agreed between the participants. Any failure of a participant to pay its share of operational costs in whole or in part may increase the costs for the other participants and/or lead to delays or changes to proposed operations, which may have a material and adverse effect on the Company's business, financial condition, results of operations or prospects.

Decommissioning and abandonment

As a party to certain Licences, the Company (together with the other participants) has undertaken obligations to restore production areas to standards acceptable to the OGA and the environmental regulator at the end of the production fields' commercial lives. The Company will be liable for its share of any decommission work. Any obligation to decommission a production facility may involve a substantial expenditure. These decommissioning costs are necessarily incurred at a time when the related production facilities are no longer generating revenue and no provisioning has been made in the Company's accounts for such future decommissioning costs. It is intended that the decommissioning costs, when they arise, will be borne by the Company out of production revenue. There can, however, be no assurance that the production revenue will be sufficient to meet these decommissioning costs as and when they arise, and if the Company has to apply other or additional financial resources to meet these costs instead, it could have a material adverse effect on the Company's business, financial condition, cash flows, results of operations and prospects.

Upon cessation of any operations on a licence area, the Company is likely to be responsible for costs associated with abandoning infrastructure and restoring the operational sites by taking reasonable and necessary steps in accordance with generally accepted environmental practices in the international petroleum industry. The Company's environmental permits may specify commitments to the relevant government authority for specific rehabilitation activities on a site.

Licensing, planning permission and other consents

The development of the Company's current and future assets may be dependent on the receipt of planning permission from the appropriate local authorities as well as other necessary consents such as environmental permits, leases and regulatory consents. Obtaining the necessary consents and approvals may be costly, and they may not be granted or may be withdrawn or made subject to limitations. The failure to gain such permissions, or gain such permissions on terms or at a cost acceptable to the Company, may limit the Company in its ability to develop and extract value from its assets and could have a material adverse effect on the Company's business, results of operations, financial conditions and prospects. Onshore oil and gas operations in the UK have recently been subject to extensive planning and environmental approval procedures, the outcome of which has been uncertain. Unforeseen circumstances or circumstances beyond the control of the Company may lead to commitments given to licencing authorities not being discharged on time.

In particular, the Company's activities are dependent upon the grant and maintenance of appropriate permissions from, amongst others, the OGA. As operator of certain of the Licences, the Company is responsible for adhering to the work programme in the form approved by the OGA. Failure to do so may result in the rescinding of permission by the OGA, which could result in the Company suffering significant damage through loss of the opportunity to identify and extract hydrocarbons.

The expiry dates of the Licences in which the Company is interested are set out in Part V of this Document. The Licences are not automatically renewed. Although the Company believes that the Licences will be renewed or extended following expiry, provided oil and gas operations are continuing at the licence areas and operations have complied with all applicable regulatory requirements, there can be no assurance that such Licences will be renewed or extended.

Production

The delivery of the Company's plans depends on the successful continuation of existing field production operations and the development of key projects. Both of these involve risks normally incidental to such activities including blowouts, oil spills, explosions, fires, equipment damage or failure, natural disasters, geological uncertainties, unusual or unexpected rock formations, abnormal pressures, seismic events, availability of technology and engineering capacity, availability of skilled resources, maintaining project schedules and managing costs, as well as technical, fiscal, regulatory, political and other conditions. Such potential obstacles may impair the Company's continuation of existing field production and delivery of key projects and, in turn, the Company's operational performance and financial position (including the financial impact from failure to fulfil contractual commitments related to project delivery). The Company may face interruptions or delays in the availability of infrastructure, including pipelines and storage tanks, on which exploration and production activities are dependent. The production performance of the reservoirs and wells may also be different to that forecast due to normal geological or mechanical uncertainties. Such interruptions, delays or performance differences could result in disruptions or changes to the

Company's existing production and projects, lower production and increased costs, and may have an adverse effect on the Company's profitability.

Social Media

The Company is aware that it has a large following of stakeholders and is often covered and mentioned in the media, including social media. It is important to note that UKOG has no direct influence on articles published by third parties however such publications hold the potential to effect its share price. This was evident during June 2015, when UKOG was forced to provide clarifications on its earlier RNS statements following media reports of the Company's announcements and associated interviews with the Company's management. Consequently, the Board has implemented a Social Media Policy across its operations which applies to all employees, officers, consultants, contractors, interns, casual workers and agency workers. Although this policy will ensure that the Company does not publish any un-authorised media itself, it is important to note that other media providers and individuals may publish their own information without consultation with the company and such articles may therefore may have an unqualified effect on UKOG's share price and should not be relied upon.

Undated documents

The Group does not have in its possession certain dated contractual documents relating to the acquisition and disposal of interests in, and the operations of, its oil and gas assets (including the Licences), the terms of which are referred to in Part V of this document. The descriptions of the contracts contained in this document accurately reflect the documentation held by the Company and which the Company believes represents the final form of the definitive executed agreements between the respective counterparties. The operations of the Group's assets and dealings with the counterparties to the respective agreements have been conducted in accordance with the terms of such documentation held by the Group, which follow standard industry terms and provide for usual pro rata costs of and entitlements in the Licences for the participants therein, and terms of appointment of the operator. The interests of the Group in the Licences referred to in this document, as shown on the OGA's website, are also in accordance with the contractual documentation held by the Group.

Therefore, whilst the Directors are confident that the position and terms of the interests in its oil and gas are as described in Part V of this document and that there would be a very small chance of legal challenge, should any counterparty dispute the terms of the agreements and assert that different terms and conditions had been agreed with the Group, the Group may require legal process to be followed to establish that the documentation it holds is definitive in governing the contractual relationship. Any finding that terms are materially different from the terms of the material contracts as described in this document may have a material adverse effect on the Group's business, financial condition, results of operations and prospects.

RISKS ASSOCIATED WITH THE OIL AND GAS INDUSTRY

Payment obligations

Under the Licences and certain other contractual agreements to which the Company is or may in the future become a party, the Company is or may become subject to payment and other obligations. In particular, the Licence holders are required to expend the funds necessary to meet the minimum work commitments attaching to permits and licences. Failure to meet these work commitments will render the Licence liable to be cancelled. Further, if any contractual obligations are not complied with when due, in addition to any other remedies which may be available to other parties, this could result in dilution or forfeiture of interests held by the Company.

Litigation

The operating hazards inherent in the Company's business expose the Company to litigation, including personal injury litigation, environmental litigation, contractual litigation with clients, intellectual property litigation, tax or other litigation.

As the date of this Document the Company is involved in legal proceedings, further details of which are set out in paragraph 17 of Part V. There is no assurance that the outcome of these proceedings will be favourable to the Company. The Company cannot predict with certainty the outcome or effect of these proceedings or any other litigation matter that it may be involved in the future. The current proceedings and any future litigation may have an adverse effect on the Company's business, financial position, results of operations and the Company's ability to pay dividends, because of potential negative outcomes, the costs associated with prosecuting or defending such lawsuits, and the diversion of management's attention to these matters.

The petroleum industry, as with all industries, may be subject to legal claims including personal injury claims, both with and without merit, from time to time. The Directors cannot preclude that such litigation may be brought against the Company in the future. Defence and settlement costs can be substantial, even with respect to claims that have no merit. Due to the inherent uncertainty of the litigation process, there can be no assurance that the resolution of any particular legal proceeding will not have a material adverse effect on the Company's financial position, results or operations. The Company's business may be materially adversely affected if the Company and/or its employees or agents are found not to have met the appropriate standard of care or not exercised their discretion or authority in a prudent or appropriate manner in accordance with accepted standards.

Ability to exploit successful discoveries

It may not always be possible for the Company to participate in the exploitation of all successful discoveries made in areas in which the Company has an interest. Such exploitation may involve the need to obtain licences or consents from the relevant authorities, which may require conditions to be satisfied and/or the exercise of discretion by such authorities. It may, or may not, be possible for such conditions to be satisfied. Furthermore, the decision to proceed to further exploitation may require the participation of other companies whose interest and objectives may not be the same as those of the Company. Such further work may also require the Company to meet, or commit to, financing obligations, which it may not have anticipated or may not be able to commit to, due to lack of funds, or inability to raise funds.

Market risk

The continued marketing of the oil that the Company produces will be dependent on market fluctuations and the availability of processing and refining facilities and transportation infrastructure, including access to roads, train lines and any other relevant options at economic tariff rates, over which the Company may have limited or no control. Transport links (including roads and pipelines) may be inadequately maintained and subject to capacity constraints and economic tariff rates may be increased with little or no notice and without taking into account producer concerns.

Producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance.

The marketability and prices of oil that may be discovered or acquired by the Company will be affected by numerous factors beyond its control.

Technological developments

The Company may not be able to keep pace with technological developments in its industry. The oil industry is characterised by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, the Company may be placed at a competitive disadvantage, and competitive pressures may force the Company to implement those new technologies at substantial cost. In addition, other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Company can. The Company may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies the Company uses now or in the future were to become obsolete or if the Company is unable to use the most advanced commercially available technology, the Company's business, financial condition and results of operations could be materially and adversely affected.

Competition

The Company operates in a very challenging business environment and competition for access to explorations acreage, oil services and rigs, technology and processes, and human resources is intense. Competitors include companies with, in many cases, greater financial resources, local contacts, staff and facilities than those of the Company for exploration and production licences as well as other regional investment or acquisition opportunities may increase in the future. This may lead to increased costs in the carrying on the Company's activities and reduced available growth opportunities. Any failure by the Company to compete effectively could adversely affect the Company's operating results and financial condition.

Increase in drilling and production costs and the availability of drilling equipment

The oil industry historically has experienced periods of rapid cost increases. Increases in the cost of exploration, production and development would affect the Company's ability to invest in prospects and to purchase or hire equipment, supplies and services. In addition, the availability of drilling rigs and other equipment and services is affected by the level and location of drilling activity around the world. The reduced availability of equipment and services may delay its ability to exploit reserves and adversely affect the Company's operations and profitability. Such pressures are likely to increase the actual cost of services, extend the time to secure such services and add costs for damages due to any accidents sustained from the overuse of equipment and inexperienced personnel. Delays in drilling and other exploration activities, the possibility of poor services coupled with potential damage to downhole reservoirs and personnel injuries may also result in increased costs.

Other factors affecting the production and sale of oil and natural gas that could result in decreases in profitability or otherwise adversely affect the Company's operations include: (i) expiration or termination of leases, concession right, consents, permits or licences, or sales price redeterminations or suspension of deliveries; (ii) future litigation; (iii) the timing and amount of insurance recoveries; (iv) work stoppages or other labour difficulties; (v) worker vacation schedules and related maintenance activities; and (vi) limitations on access to transport capacity. There can be no assurance that these or similar issues may not cause disruptions to the Company's ability to produce or sell oil in the future.

Delays in production and transportation

Various production, marketing and transportation conditions may cause delays in oil production and adversely affect the Company's business. The inability to complete wells in a timely manner would result in production delays and could have a material adverse effect on the Company's financial position and future results of operations.

Restrictions on the Company's ability to access necessary infrastructure services may adversely affect the Company's operations

Inadequate supply of the critical infrastructure elements for drilling activity could result in reduced production or sales volumes, which could have a negative effect on the Company's financial performance. Disruptions in the supply of essential utility services, such as water and electricity, can halt the Company's production for the duration of the disruption and, when unexpected, may cause loss of life or damage to its drilling equipment or facilities, which may in turn affect its ability to recommence operations on a timely basis. The Company may be dependent on third party providers of utility and transportation services. As such, third party provision of services, maintenance of networks and expansion and contingency plans will be outside of the Company's control.

Volatility of prices for oil and gas

The demand for, and price of, oil and gas is highly dependent on a variety of factors beyond the Company's control, including international supply and demand, weather conditions, the price and availability of alternative fuels, actions taken by governments and international cartels, supply and demand of capital, employment trends, international economic trends, currency exchange rate fluctuations, the level of interest rates and the rate of inflation, the cost of freight, global or regional political events and international events, as well as a range of other market forces. The aggregate effect of these factors is impossible to predict. International oil and gas prices have fluctuated widely in recent years and may continue to fluctuate significantly in the future. Sustained downward movements in oil and gas prices could render less economic, or wholly uneconomic, some or all of the exploration and the existing, and potential future, oil production related activities to be undertaken by the Company. Any material decline in oil and gas prices could result in a reduction of the Company's net production revenue and overall value.

The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's net production revenue causing a reduction in its acquisition and development activities. A substantial material decline in prices from historical average prices could reduce the Company's ability to borrow funds.

The Company's operations and development projects could be adversely affected by shortages of, as well as lead times to deliver, certain key inputs

The inability to obtain, in a timely manner, strategic consumables, raw materials, drilling and processing equipment could have an adverse impact on any results of operations and financial condition. Periods of high demand for such supplies can result in periods when availability of supplies are limited and cause costs to increase above normal inflation rates. Any interruption to supplies or increase in costs could adversely affect the operating results and cash flows of the Company.

Over-run of drilling programme and costs over-run

It may not be possible for the Company, as the operator of certain Licences, to adhere to agreed drilling schedules. This may impact all participants in the Licences, and their future plans. The project partners' final determination of whether to drill any scheduled or budgeted wells will depend on a number of factors including:

- results of the exploration efforts and the acquisition, review and analysis of seismic data, if any;
- availability of sufficient capital resources and any other participants for the drilling of the prospects;
- approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated process for oil and natural gas and the availability and prices of drilling rigs and crews; and
- availability of leases, licence options, farm-outs, other rights to explore and permits on reasonable terms for the prospects

Although the Company, as the operator of certain Licences, will at the time identify or budget for drilling prospects, it will require the approval of all or a requisite majority of the participants of those Licences. It may not be possible to drill those prospects within the expected timeframe, or at all, and the drilling schedule, once agreed, may vary from its expectations because of future uncertainties and rig availability and access to drilling locations. In addition, there is a risk that no commercially productive oil or gas reservoirs will be discovered.

Dependence on third party services

The Company may rely on products and services provided by independent third parties, such as undertaking due diligence and technical reviews, carrying out drilling activities and delivering oil products, and providing general financial and strategic advice. If there is any interruption to the products or services provided, or failure to perform those services with due care and skill, by such third parties, the Company's business could be adversely affected and the Company may be unable to find adequate replacement services on a timely basis, if at all, and/or on acceptable commercial terms. This may have a material adverse effect on the business, financial conditions, results of operations and prospects of the Company.

Exploration, development and production activities are capital intensive and inherently uncertain in their outcome. As a result, the Company may not generate a return on its investments or recover its costs and it may not be able to generate cash flows or secure adequate financing for its discretionary capital expenditure plans

Exploration, development and production activities are capital intensive and inherently uncertain in their outcome. The Company's projects may involve unprofitable efforts, either from dry wells or from wells that are productive but do not produce sufficient net revenues to return a profit after development, operating and other costs. Furthermore, completion of a well does not guarantee a profit on the investment or recovery of the costs associated with that well. In addition, drilling hazards or environmental damage could significantly affect operating costs, and production from successful wells may be adversely affected by conditions including delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or adverse geological conditions. Production delays and declines, whether or not as a result of the foregoing conditions, may result in lower revenue or cash flows from operating activities until such time, if at all, that the delay or decline is cured or arrested. In the event that such cash flows are reduced in the future, the Company may be forced to scale back or delay discretionary capital expenditure resulting in delays to, or the postponement of, the Company's planned production and development activities which could have a material adverse effect on its business, results of operations, financial condition or prospects.

Operational risks

Drilling, appraisal, exploration, construction, development and production activities may involve significant risks and operational hazards and environmental, technical and logistical difficulties, as usually associated with oil and gas operations. These include, *inter alia*, the possibility of uncontrolled hydrocarbon emissions, fires, earthquake activity, extreme weather conditions, coastal erosion, explosions, blowouts, cratering, over-pressurised formations, unusual or unexpected geological conditions, unpredictable drilling-related problems, equipment failure, labour disputes and the absence of economically viable reserves. These hazards may result in delays or interruption to production, cost over-runs, the failure to produce oil in commercial quantities, substantial losses and/or exposure to substantial environmental and other liabilities, including potential litigation and clean-up or other remedial costs. Damages claimed in connection with any consequent litigation and the costs to the Company in defending itself against such litigation are difficult to predict and may be material. In addition, the Company could experience adverse publicity as a result of any such litigation. Any loss of production or adverse legal consequences stemming from production hazards could have a material adverse effect on the Company's business, results of operations, financial condition or prospects.

Non achievement of anticipated timetables

Drilling rigs or other equipment may not be available at the time envisaged (due to, for example, delays in making appropriate modifications, adverse weather conditions, insolvency of the owners or total loss) or may fail to perform in accordance with the Directors' expectations in regard to the timetable. There is no guarantee that replacement equipment will be available on reasonable commercial terms or at all.

Failure to meet the expected timetables may result in the Company being unable to generate cash from those assets. This would have a material adverse effect on the Company's business, prospects, financial condition and operations.

The Company's anticipated timetables for all of its current and expected operations are estimates of the Directors based on a number of variables not all of which are under the Company's direct control. If the timetable estimates prove to be wrong or the operators or any of the participants in the Licences do not take the actions in relation to maintaining or developing the assets then it may lead to delays or further problems which may have a material adverse effect on the Company's business, prospects, financial conditions and operations.

Existing and proposed legislation and regulation affecting greenhouse gas emissions may adversely affect certain of the Company's operations

Many participants in the oil and gas sector are subject to current and planned legislation in relation to the emission of carbon dioxide, methane, nitrous oxide and other so called 'greenhouse gases'.

Failure to comply with existing legislation or any future legislation could adversely affect the Company's profitability. Future legislative initiatives designed to reduce the consumption of hydrocarbons could also have an impact on the ability of the Company to market its commodities and/or the prices which it is able to obtain. These factors could have a material adverse effect on the Company's business, results of operations, financial condition or prospects.

Failure to discover new reserves, enhance existing reserves or adequately develop new projects could adversely affect the Company's business

Exploration and development are costly, speculative and often unproductive, but are necessary for the Company's business. This is particularly the case in the oil and gas industry, where there may be many reasons why the Company may not be able to find oil reserves or develop them for commercially viable production. For instance, factors such as adverse weather conditions, natural disasters, equipment or services shortages, procurement delays or difficulties arising from the environmental and other conditions in the areas where the reserves are located or through which production is transported may increase costs and make it uneconomical to develop potential reserves. Failure to discover new reserves, to enhance existing reserves or to extract resources from such reserves in sufficient amounts and in a timely manner could materially and adversely affect the Company's results of operations, cash flows, financial condition and prospects. In addition, the Company may not be able to recover the funds used in any exploration programme to identify new opportunities.

Increasingly stringent requirements relating to regulatory, environmental and social approvals can result in significant delays in construction of additional facilities and may adversely affect new drilling projects, the expansion of existing operations and, consequently, the Company's results of operations, cash flows and financial condition, and such effects could be material.

Reserve and resource estimates

No assurance can be given that hydrocarbon reserves and resources reported by the Company in the future are present as estimated, will be recovered at the rates estimated or that they can be brought into profitable production. Hydrocarbon reserve and resource estimates may require revisions and/or changes (either up or down) based on actual production experience and in light of the prevailing market price of oil and gas. A decline in the market price for oil and gas could render reserves uneconomic to recover and may ultimately result in a reclassification of reserves as resources.

Unless stated otherwise, the hydrocarbon resources data contained in this Document are taken from the Competent Person's Report. The reserves and resources data contained in this Document have been certified by Xodus unless stated otherwise. There are uncertainties inherent in estimating the quantity of reserves and resources and in projecting future rates of production, including factors beyond the Company's control. Estimating the amount of hydrocarbon reserves and resources is an interpretive process and, in addition, results of drilling, testing and production subsequent to the date of an estimate may result in material revisions to original estimates.

The hydrocarbon resources data contained in this Document and in the Competent Person's Report are estimates only and should not be construed as representing exact quantities. The nature of reserve quantification studies means that there can be no guarantee that estimates of quantities and quality of the resources disclosed will be available for extraction. Therefore, actual production, revenues, cash flows and development and operating expenditures may vary from these estimates. Such variances may be material. Reserves estimates contained in this Document are based on production data, prices, costs, ownership, geophysical, geological and engineering data, and other information assembled by the Company (which it may not necessarily have produced). The estimates may prove to be incorrect and potential investors should not place reliance on the forward looking statements contained in this Document (including data included in the Competent Person's Report or taken from the Competent Person's Report and whether expressed to have been certified by the Competent Person or otherwise) concerning the Company's reserves and resources or production levels.

Hydrocarbon reserves and resources estimates are expressions of judgment based on knowledge, experience and industry practice. They are therefore imprecise and depend to some extent on interpretations, which may prove to be inaccurate. Estimates that were reasonable when made may change significantly when new information from additional analysis and drilling becomes available. This may result in alterations to development and production plans which may, in turn, adversely affect operations.

If the assumptions upon which the estimates of the Company's hydrocarbon resources have been based prove to be incorrect, the Company (or the operator of an asset in which the Company has an interest) may be unable to recover and produce the estimated levels or quality of hydrocarbons set out in this Document and the Company's business, prospects, financial condition or results of operations could be materially and adversely affected.

Failure to manage relationships with local communities, government and non-government organisations could adversely affect future growth potential of the Company

Natural resources businesses often face increasing public scrutiny of their activities. Operations located in or near communities that may regard oil and gas activities as detrimental to their environmental, economic or social circumstances. Negative community reaction to such operations could have a material adverse impact on the cost, profitability, ability to finance or even the viability of an operation. Such events could also lead to disputes with national or local governments or with local communities and give rise to material reputational damage. These disputes are not always predictable and may cause disruption to projects or operations. Oil and gas operations can also have an impact on local communities. Failure to manage relationships with local communities, government and non-government organisations may adversely affect the Company's reputation, as well as its ability to commence production projects, which could in turn affect the Company's revenues, results of operations and cash flows.

The Company, like other companies in the onshore oil and gas industry in the UK, has been subject to various protests from campaigners and activists who oppose the Company's business activities. Sometimes these protests have taken the form of unlawful activity which seeks to disrupt the Company's operations by activities such as trespass to land and other obstructive behaviour (including slow walking on the public highway, lorry surfing, intimidation of contractors or unlawful means conspiracy). The Company, as lead claimant, commenced proceedings in the High Court of Justice in London seeking various restraining orders against persons unknown who may fall into certain categories of prohibited behaviour (further details of which are set out in paragraph 17 of Part V of this Document). There is no assurance that the outcome of these proceedings will be favourable to the Company. Regardless of the outcome of these proceedings, the Company may be subject to further protests and related activities (both lawful and unlawful) which are beyond the control of the Company and which could result in damage or destruction of the Company's equipment, business interruption, monetary losses and possible adverse publicity for the Group.

RISKS RELATING TO ORDINARY SHARES

Fluctuations in the price of Ordinary Shares

The market price of Ordinary Shares may be subject to fluctuations in response to many factors, including variations in the operating results of the Company, divergence in financial results from analysts' expectations, changes in earnings estimates by stock market analysts and factors outside the Company's control including but not limited to general economic conditions, the performance of the overall stock market, other Shareholders buying or selling large numbers of Ordinary Shares and changes in legislation or regulations.

In addition, stock markets have from time to time experienced extreme price and volume fluctuations, which, as well as general economic and political conditions, could adversely affect the market price for Ordinary Shares.

The value of Ordinary Shares may go down as well as up. Investors may therefore realise less than, or lose all of, their original investment.

Realisation of investment

The market price of the Ordinary Shares may not reflect the underlying value of the Company's net assets. Potential investors should be aware that the value of Ordinary Shares can rise or fall and that there may not be proper information available for determining the market value of an investment in the Company at all times. Admission should not be taken as implying that there will be a liquid market in the Ordinary Shares. An investment in the Ordinary Shares may thus be difficult to realise.

In the event of a winding-up of the Company, the Ordinary Shares will rank behind any liabilities of the Company and therefore any return for Shareholders will depend on the Company's assets being sufficient to meet prior entitlements of creditors.

Liquidity of Ordinary Shares

Admission to AIM should not be taken as implying that there will be a liquid market for Ordinary Shares. It may be more difficult for an investor to realise their investment in the Company than in a company whose shares are quoted on the Official List.

Financing risks and requirements for further funds

Successful exploration for, or the development of, oil and gas on any project will require very significant capital investment. The major source of financing currently available to the Company (other than through the cash raised pursuant to the Placing) is through the issue of additional equity capital or through bringing in partners to fund exploration and development costs, or obtaining debt. The Company's ability to raise further funds will depend on the success of its strategy and operations. The Company may not be successful in procuring the requisite funds on terms which are acceptable to it (or at all) and, if such funding is unavailable, the Company may be required to reduce the scope of its investments or anticipated expansion, forfeit its interest in some or all of its assets, incur financial penalties, miss certain acquisition opportunities or reduce or terminate its operations.

If additional funds are raised through the issue of new equity or equity-linked securities of the Company other than on a pro rata basis to existing Shareholders, the percentage ownership of the existing Shareholders may be reduced. Shareholders may also experience subsequent dilution and/or such securities may have preferred rights, options and pre-emption rights senior to the Ordinary Shares. The Company may also issue Ordinary Shares as consideration for acquisitions or investments that would also dilute Shareholders' respective shareholdings. Share issues may be priced below the then market price of the Ordinary Shares, or below the price at which previous share issues have been made, and the issue of additional Ordinary Shares by the Company, or the possibility of such an issue, may cause the market price of the Ordinary Shares to decline. Such equity issues may result in a change of control of the Company.

Furthermore, any debt financing, if available, may include conditions that would restrict the Company's freedom to operate its business, such as conditions that:

- limit the Company's ability to pay dividends or require it to seek consent for the payment of dividends;
- increase the Company's vulnerability to general adverse economic and industry conditions;
- require the Company to dedicate a portion of any cash flow arising from future operations to payments on its debt, thereby reducing the availability of its cash flow to fund capital expenditures, working capital and other general corporate purposes; and
- limit the Company's flexibility in planning for, or reacting to, changes in its business and its industries, including the potential to take advantage of business opportunities as they arise.

There can be no guarantee or assurance that such debt funding or additional equity will be forthcoming when required, or as to the terms and price on which such funds would be available if at all. If the Company is unable to obtain additional financing as needed, or on terms which are acceptable, it may not be able to fulfil its strategy, which could have a material adverse effect on the Company's business, financial position and prospects.

Suitability of Ordinary Shares as an investment

Ordinary Shares may not be suitable for all the recipients of this Document. Before making any investment, prospective investors are advised to consult with an organisation or firm authorised or exempted pursuant to the FSMA and in the case of a resident in any other jurisdiction an appropriately authorised or exempted adviser for that jurisdiction, before making any investment decision. As the Directors believe the Company is unlikely to pay dividends in the foreseeable future, if ever, the Ordinary Shares are not suitable for investors requiring income. An investment in the Company is highly speculative, involves a considerable degree of risk and is suitable only for persons or entities which have substantial financial means and who can afford to hold their ownership interests for an indefinite amount of time.

Future sales of Ordinary Shares by Shareholders may depress the price of the Ordinary Shares.

Future sales or the availability for sale of substantial amounts of the Ordinary Shares in the public market could adversely affect the prevailing market price of the Ordinary Shares and could also impair the Company's ability to raise capital through future issues of Shares.

Dividend payments on the Ordinary Shares are not guaranteed

Payment of dividends by the Company to Shareholders will depend on a number of factors, including its financial condition and results of operations, contractual restrictions, and other factors considered relevant by the Board. Under English law, any payment of dividends would be subject to the Act. All final dividends to be distributed by the Company must be recommended by the Board and approved by Shareholders. Moreover, under English law, the Company may pay dividends on its Ordinary Shares only out of profits available for distribution in accordance with the Act and under its Articles.

Dilution of Shareholders' interests as a result of additional equity fundraising

The Company may need to raise additional funds in the future to finance, amongst other things, working capital, expansion of the business, new developments relating to existing operations or acquisitions. If additional funds are raised through the issuance of new equity or equity-linked securities of the Company other than on a pre-emptive basis to existing shareholders, the percentage ownership of the existing shareholders may be reduced. Shareholders may also experience subsequent dilution and/or such securities may have preferred rights, options and pre-emption rights senior to the Ordinary Shares.

Forward looking statements

This Document contains forward-looking statements that involve risks and uncertainties. The Company's results could differ materially from those anticipated in the forward-looking statements as a result of many factors, including the risks faced by the Company, which are described above and elsewhere in the Document. Additional risks and uncertainties not currently known to the Directors may also have an adverse effect on the Company's business.

PART III

COMPETENT PERSONS REPORT

2018 CPR

Competent Person's Report

UK Oil & Gas Investments PLC

Assignment Number: L400287-S00
Document Number: L-400287-S00-REPT-001

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Competent Person's Report

L400287-S00

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CONTENTS

The Directors

UK Oil & Gas Investments PLC ("UKOG")

8th Floor,

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WH Ireland

24 Martin Lane

London EC4R 0DR

11th July 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), 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. UKOG previously held an interest in Baxters Copse (PEDL233), this licence was allowed to lapse at the end of the initial term (30th June 2018) and is not included in this report.

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,

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

petrophysical, well logs and other data along with various technical reports. We have reviewed the information provided and modified assumptions where we considered this to be appropriate. No site visit has been undertaken

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating the volumes. These techniques rely on 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, notwithstanding the Horndean field for which we have not received any update to production volumes since 1st January. 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 July 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.

The licence in which Baxter Copse is located, PEDL233, was allowed to lapse at the end of the initial licence term on the 30th June 2018, Baxters Copse is not included in this updated report.

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.

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.

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").

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.

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
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		**11.5**	**18.8**	**30.9**	**7.3**	**12.0**	**19.6**		

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).

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)

[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.

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.

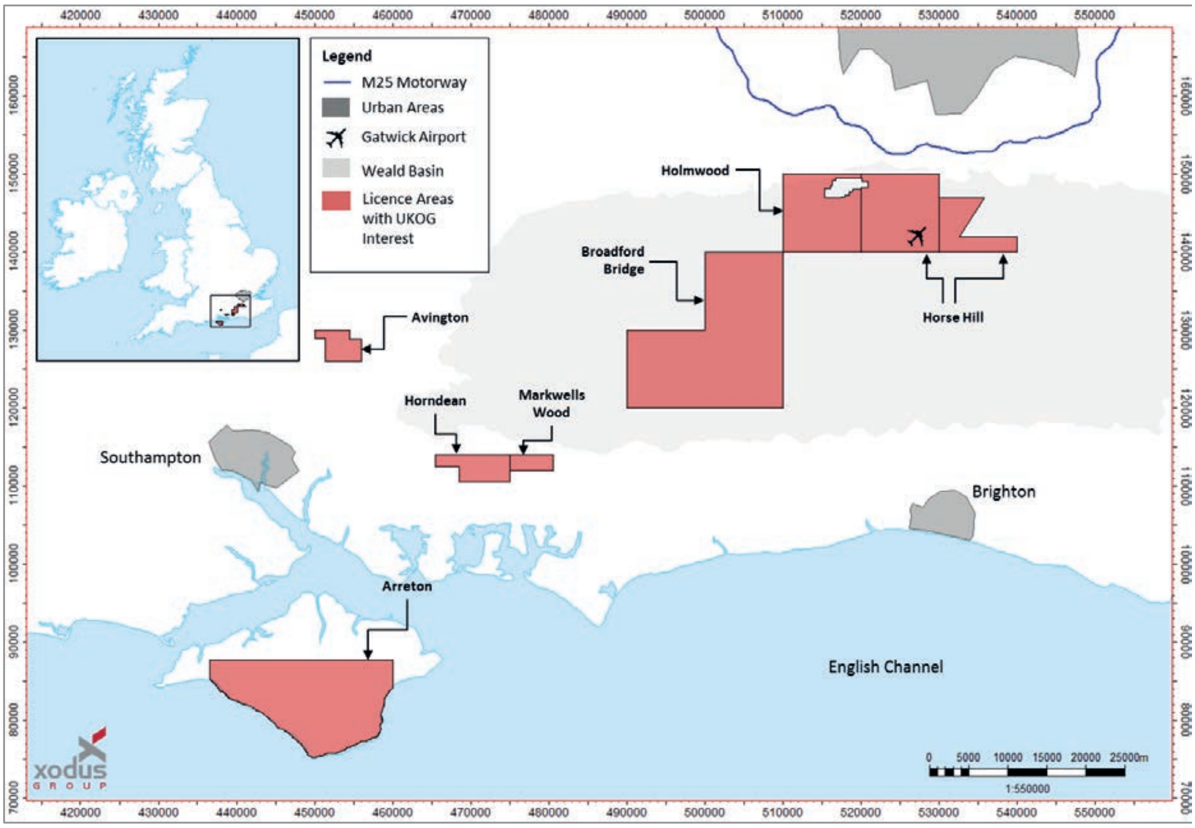


Figure 2.1 Map of UKOG licence interests in the south east England.

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
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 Holmwood (PEDL143) and Isle of Wight Onshore (PEDL331) licences are all in the Initial Term. 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.

[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

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, notwithstanding the Horndean field production forecasts, 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.

Horndean production forecasts date from 1st January 2018, no production volumes for the period 1st January to 30th June have been received by Xodus with which to update the forecast.

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.

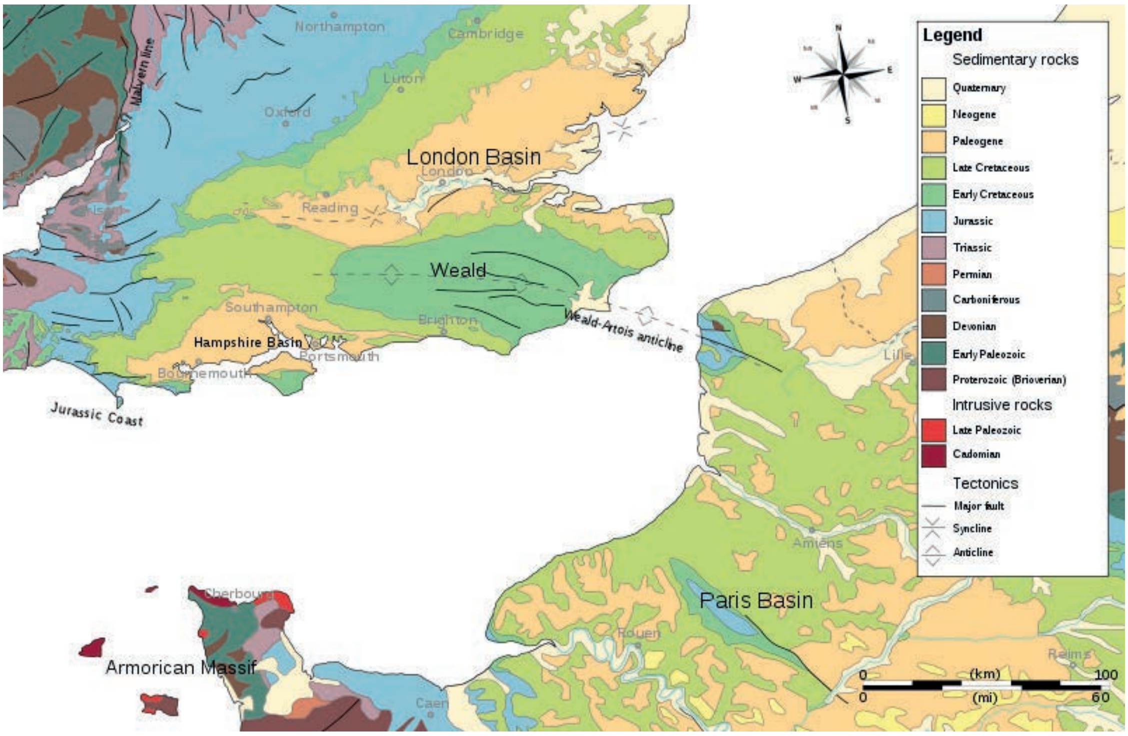


Figure 3.1: Geologic map of southeast England and the English Channel region

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.

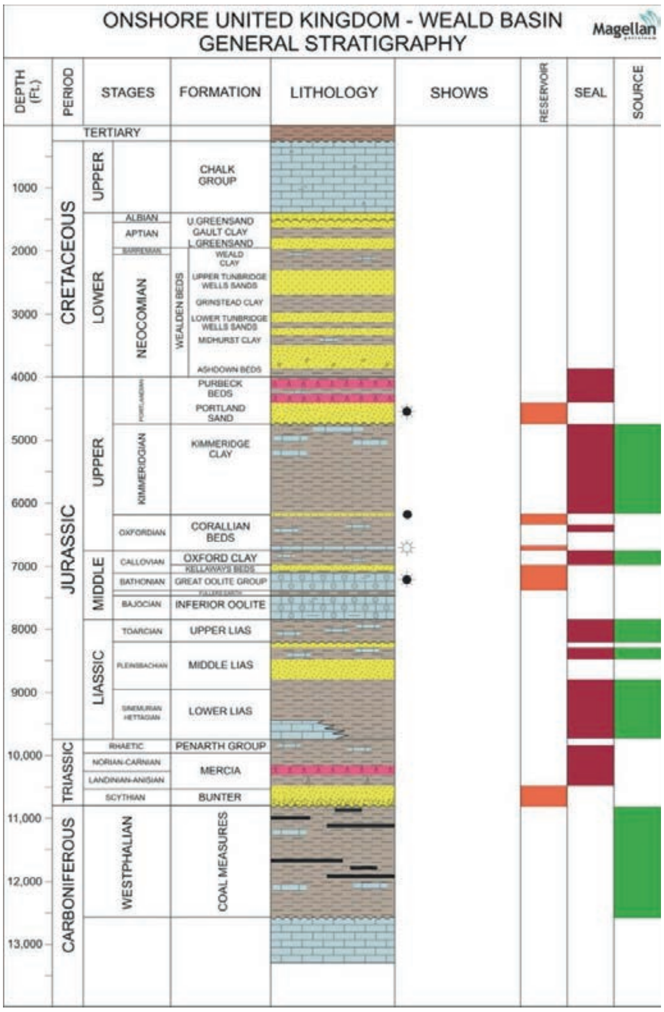


Figure 3.2: Primary Weald Proven Oil Play Details

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.

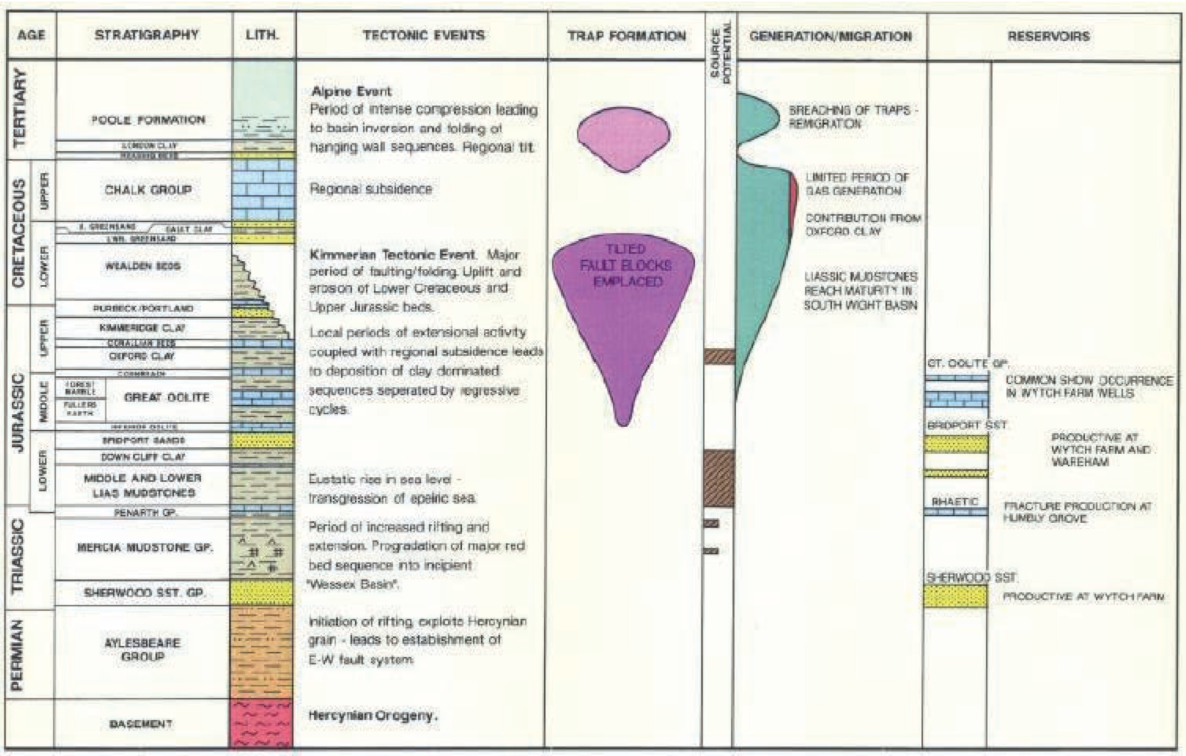


Figure 3.3: Stratigraphy and Petroleum Systems of the Wessex Basin

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).

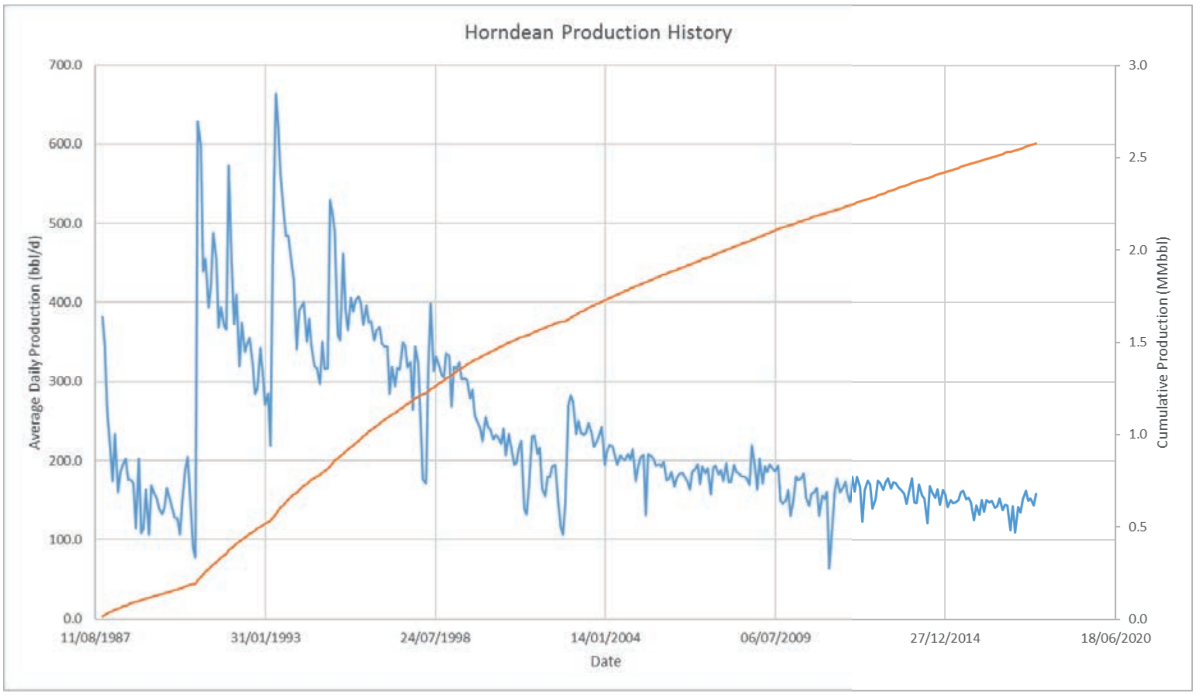


Figure 4.1 Horndean field production

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, with an effective date of 1st January 201, are given in Table 4.1.

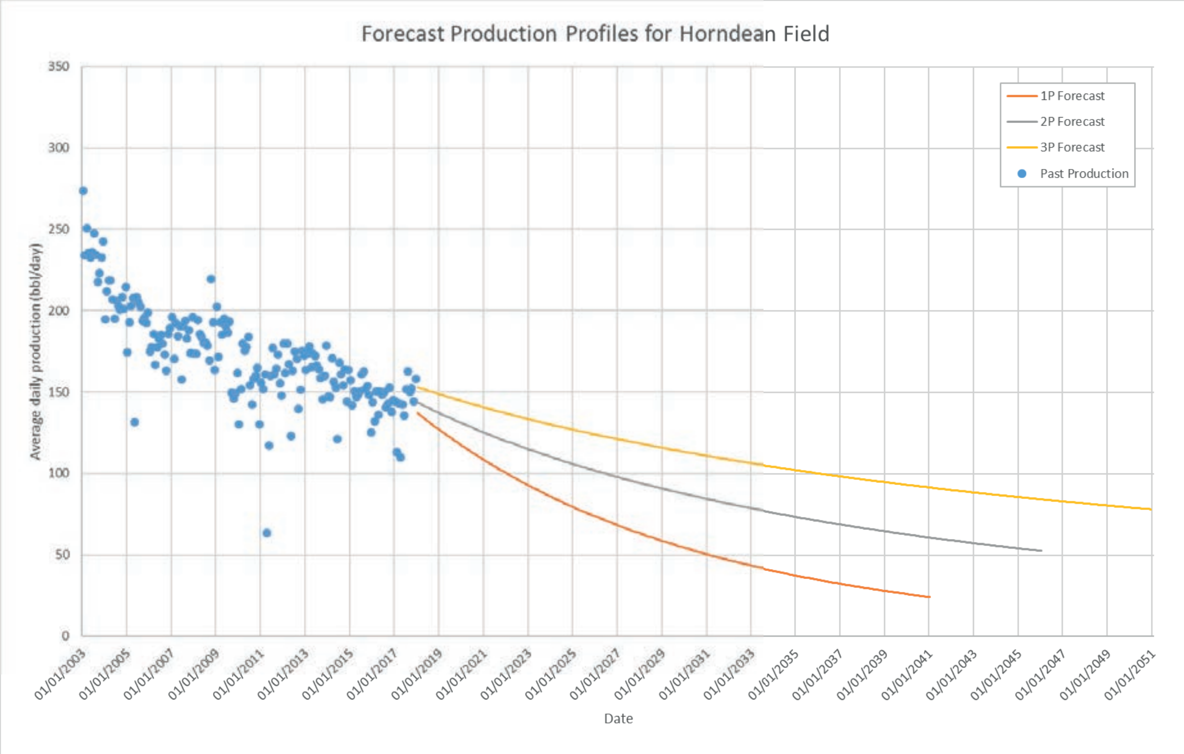


Figure 4.2 Production forecasts for the Horndean field

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 (effective 1st January 2018)

[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.

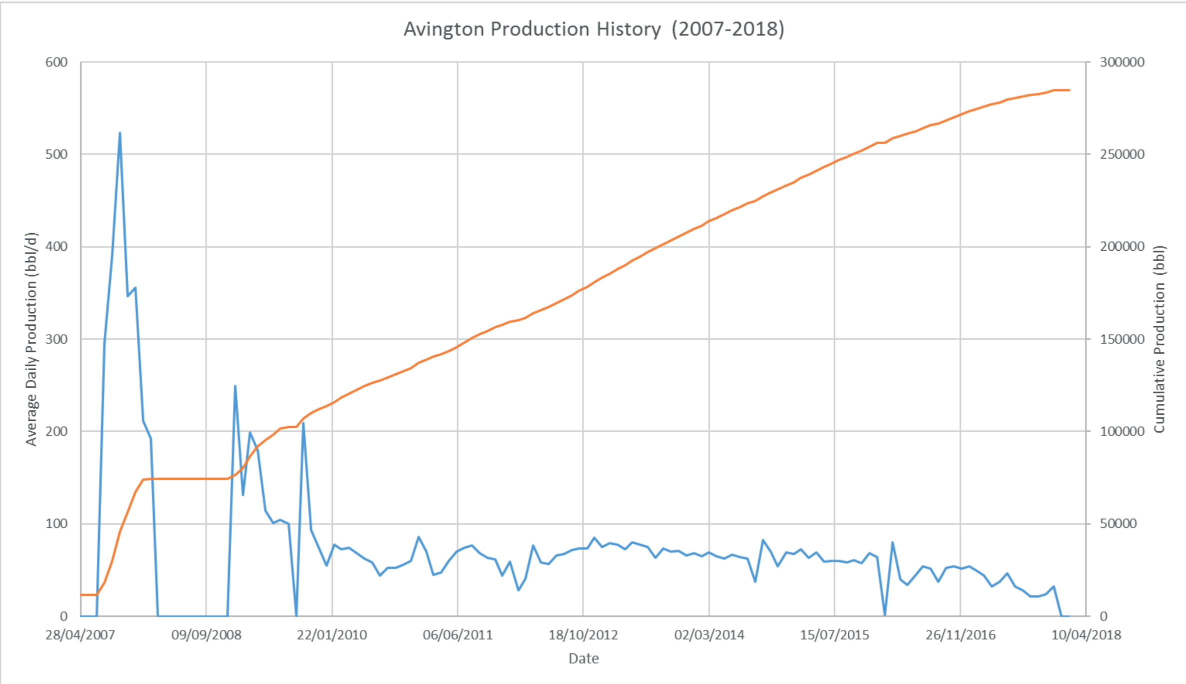


Figure 5.1 Avington Field production history since 2007

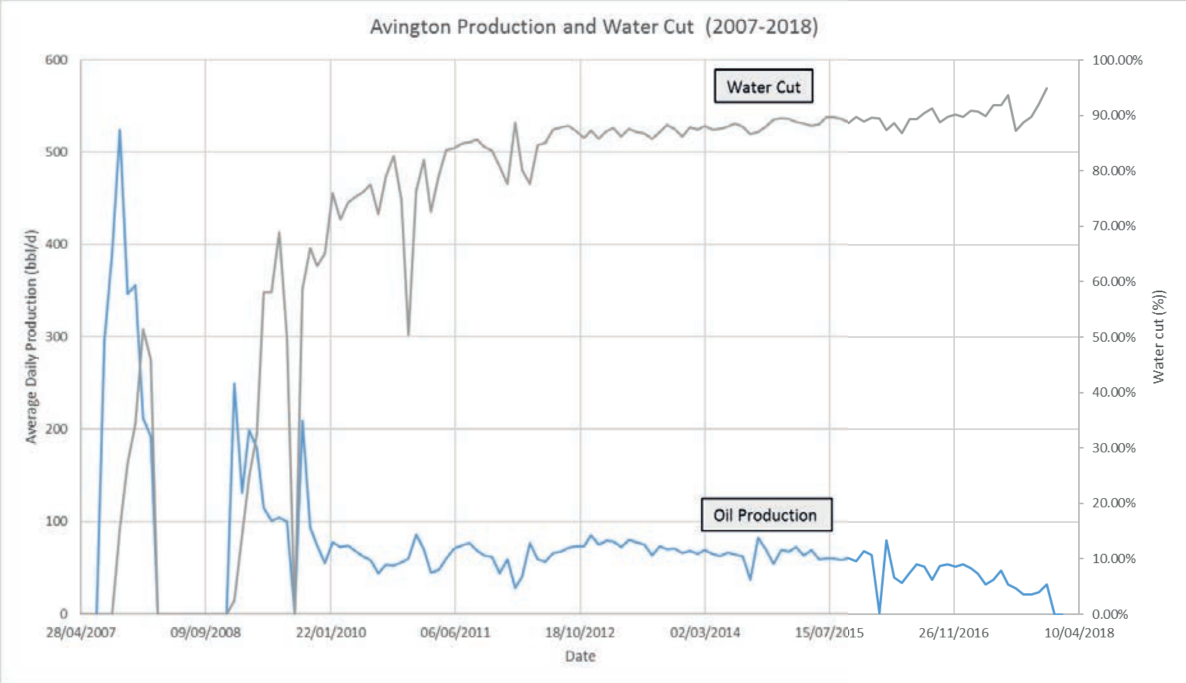


Figure 5.2 Avington field average daily production and water cut since 2007

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.

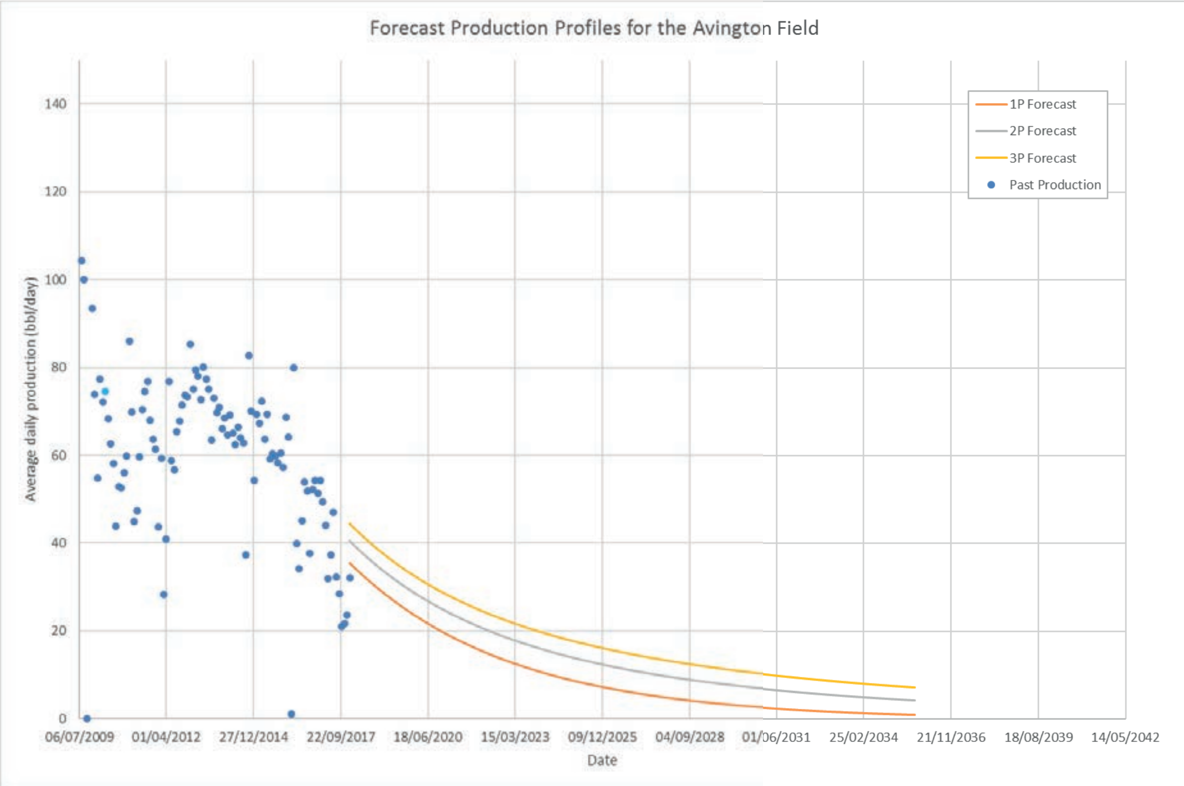


Figure 5.3 Avington forecast production profiles

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.

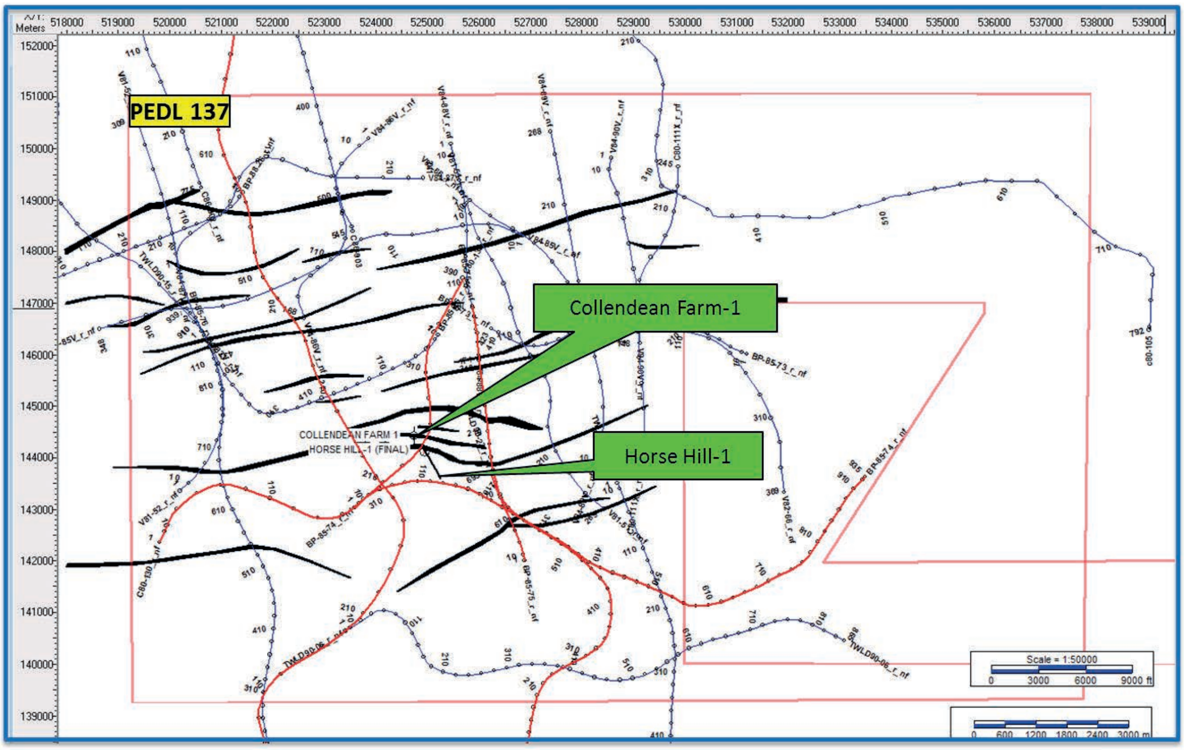


Figure 6.1 Seismic base map, with wells

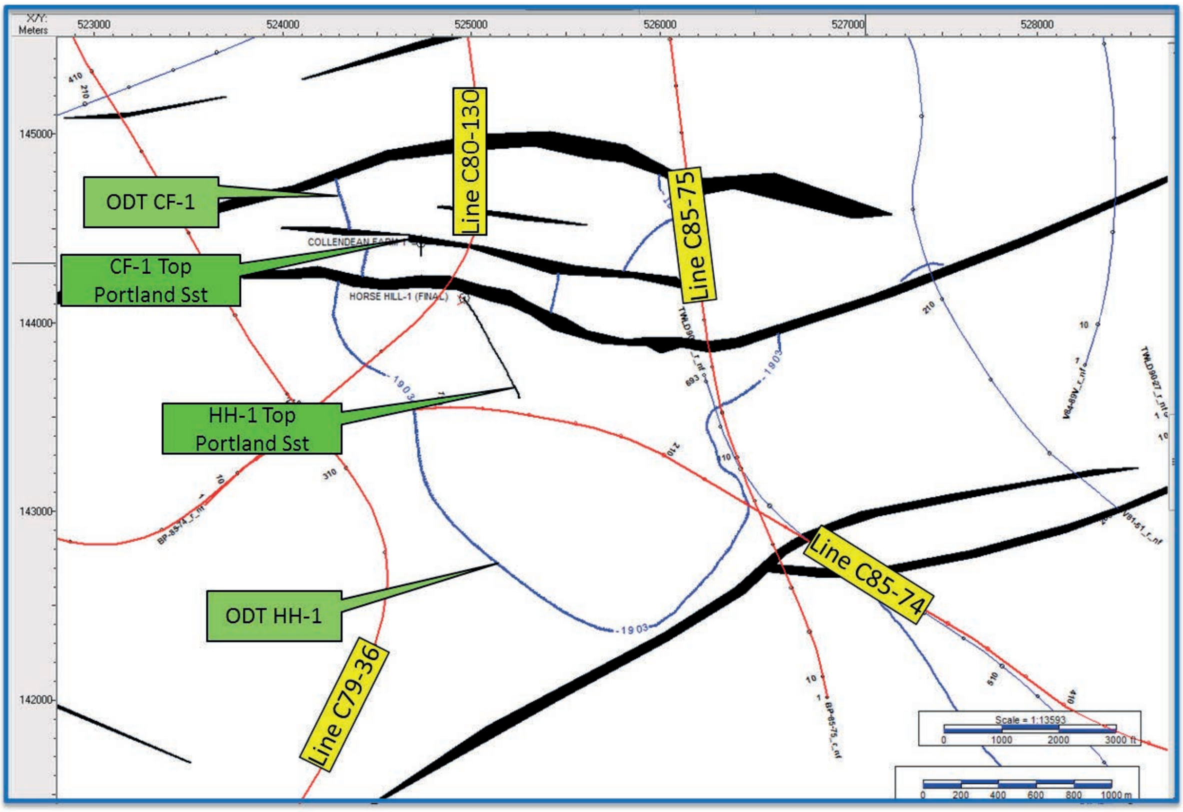


Figure 6.2 Key seismic lines across the Horse Hill discovery

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.

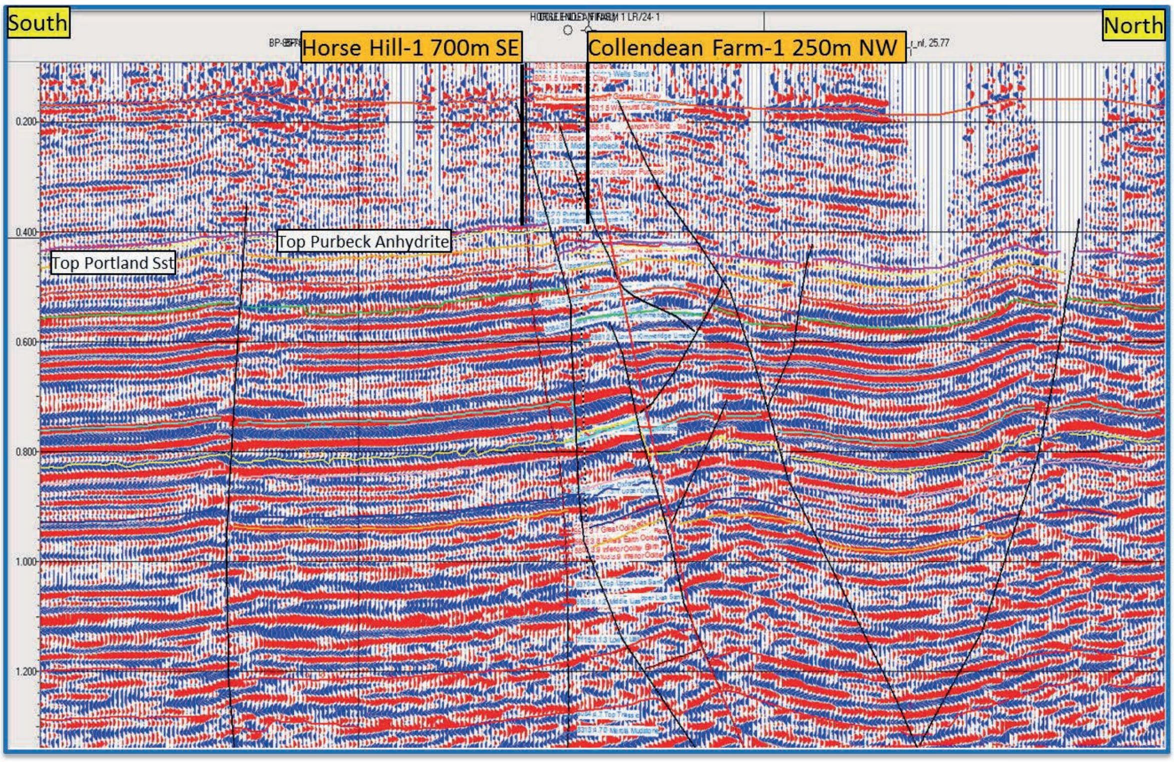


Figure 6.3 Example seismic section - Line C 80-130.

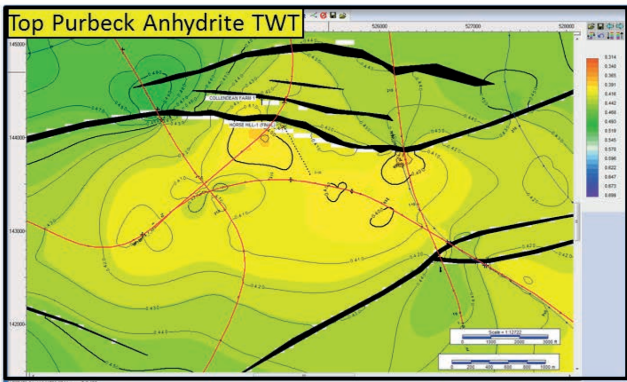
6.1.2 Interpretation and Mapping

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.

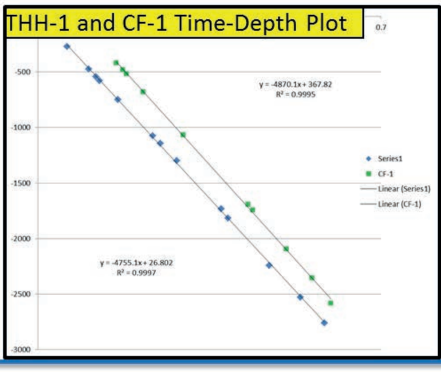
In general, reflection quality of the Top Purbeck Anhydrite is good, but on some critical lines (e.g. C79-36 and C80-130) continuity of the package sitting above the Kimmeridge is poor, probably due to lower impedance contrasts and reduced fold. This results in lower confidence in the key areas close 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 HH TVDSS	HH-1 HH TWT	CFm-1 CFm TVDSS	CFm-1 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		



Both well and seismic data suggest an anomaly in average velocity to Top Portland between Collendean Farm-1 and Horse Hill-1. The time map above (actually of Top Purbeck Anhydrite) indicates that the event is shallower in time at HH-1 than at CF-1. This is confirmed by time-depth data for the 2 wells also shown above. The same data demonstrates that the same event is deeper in depth at HH-1 than at CF-1, so there is a clear and significant variation in average velocity between the 2 wells. This is graphically illustrated on the plot. There may be several ways to distribute this variation, that adopted by the operator being just one.

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.

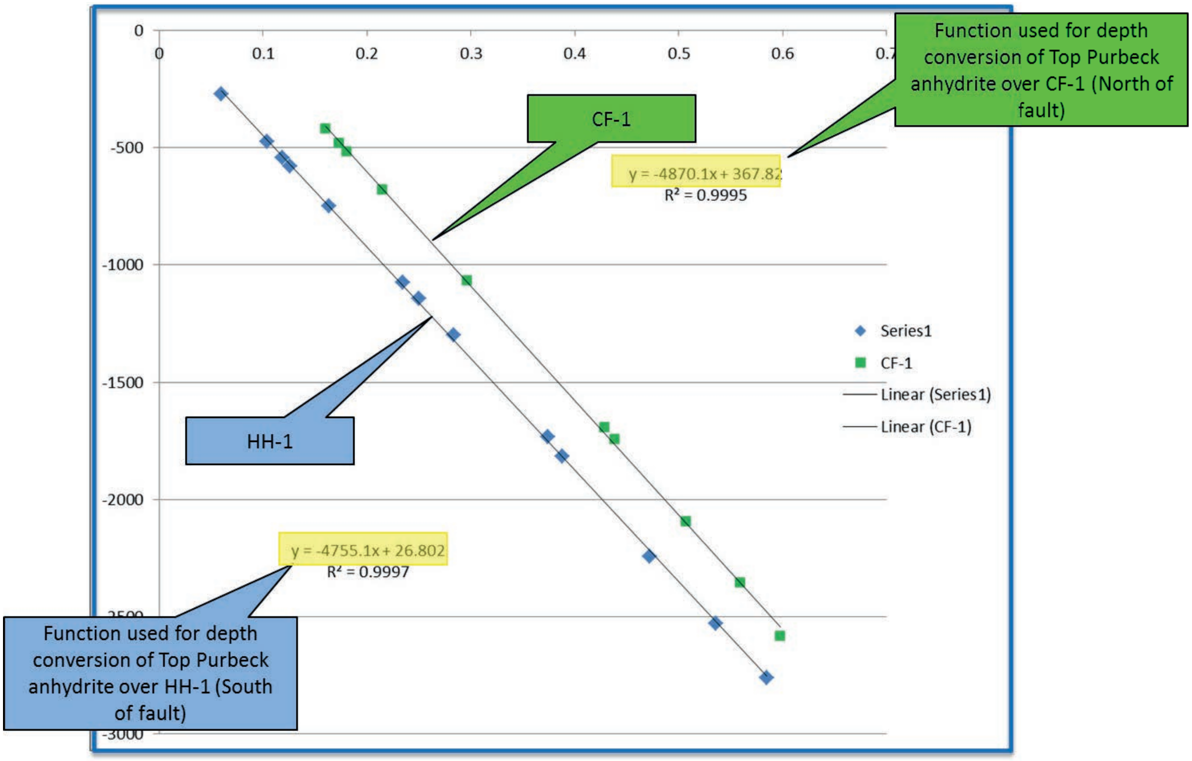


Figure 6.5 HH-1 and CF-1 time depth plot.

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.

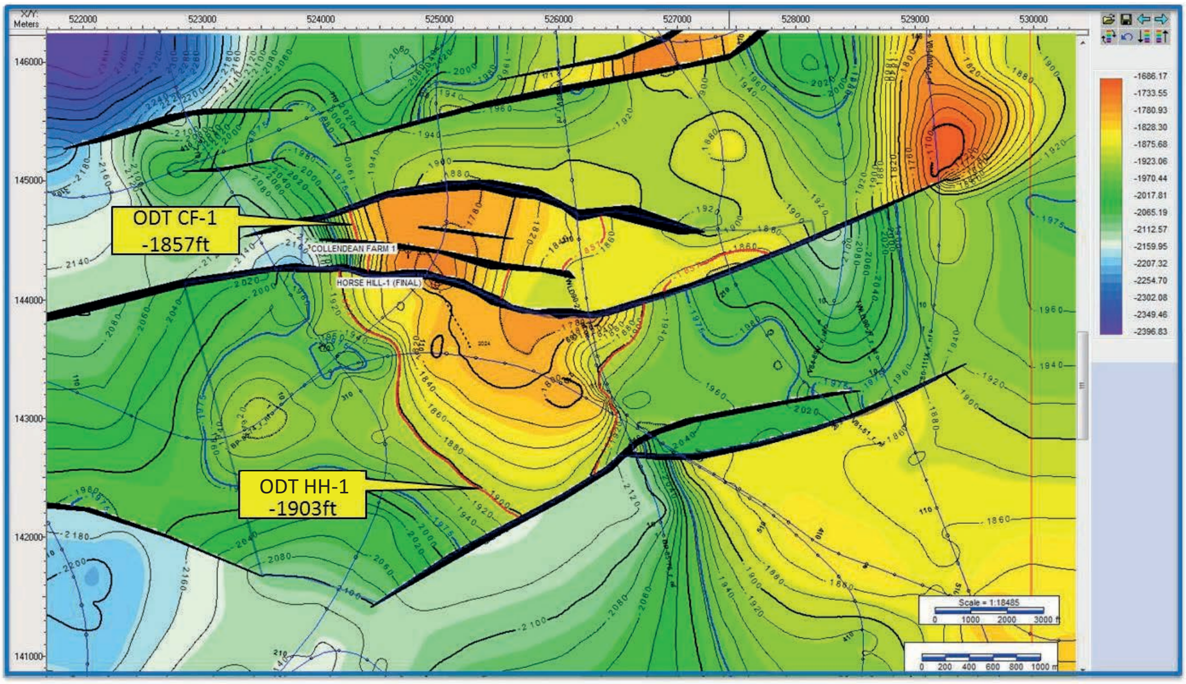


Figure 6.6 Top Portland Sandstone depth map, showing ODTs and LCCs.

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.

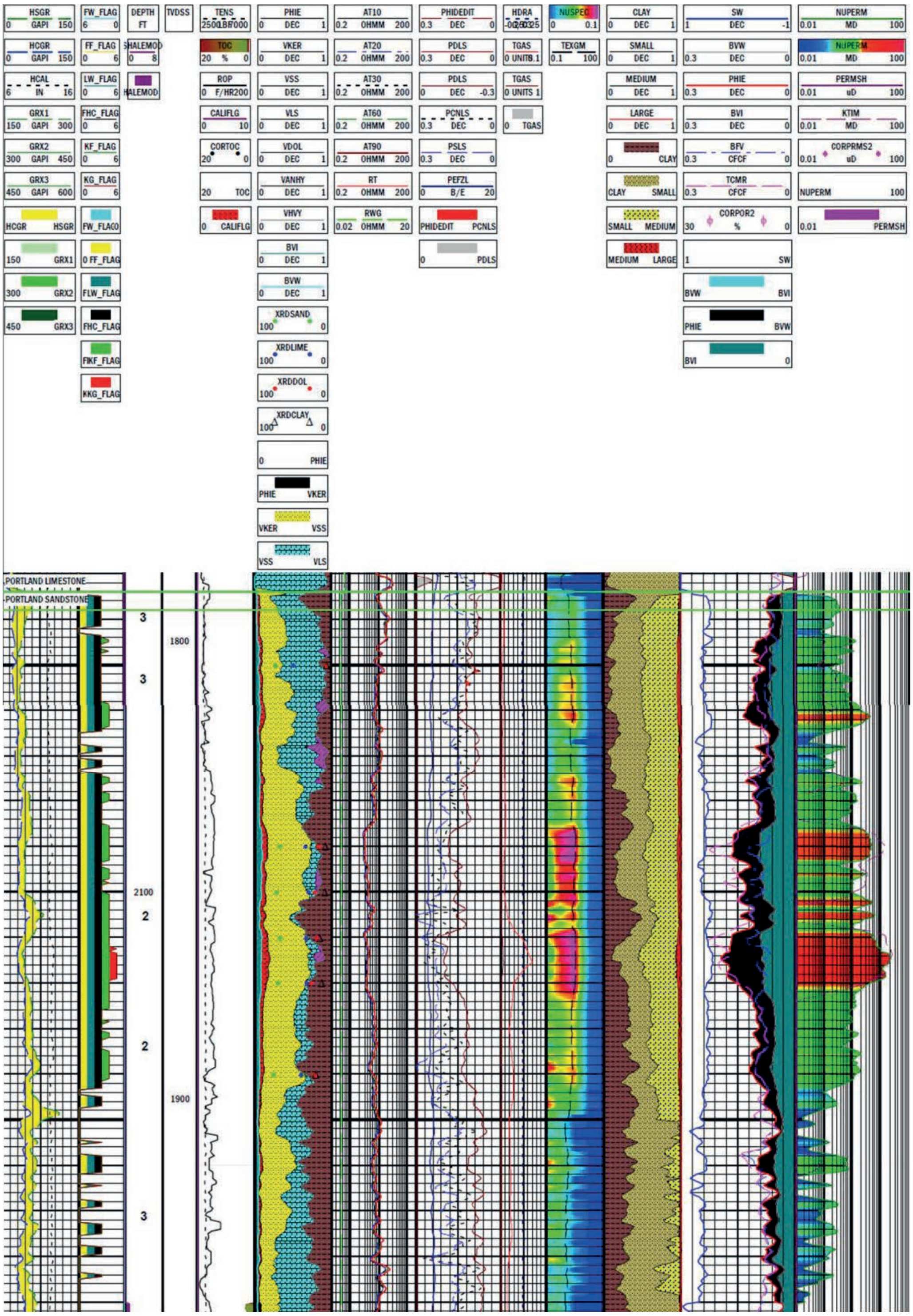


Figure 6.7 Nutech CPI of Portland Sandstone

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.

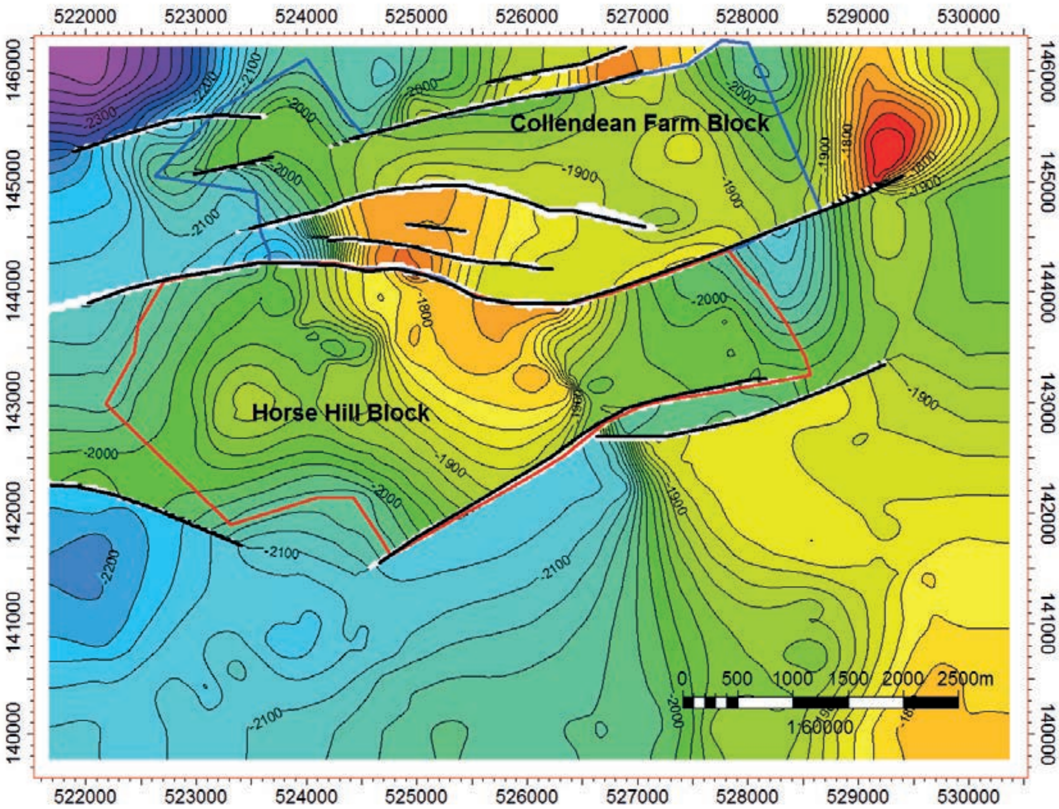


Figure 6.8 Map showing top Portland Sandstone surface and polygons

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.

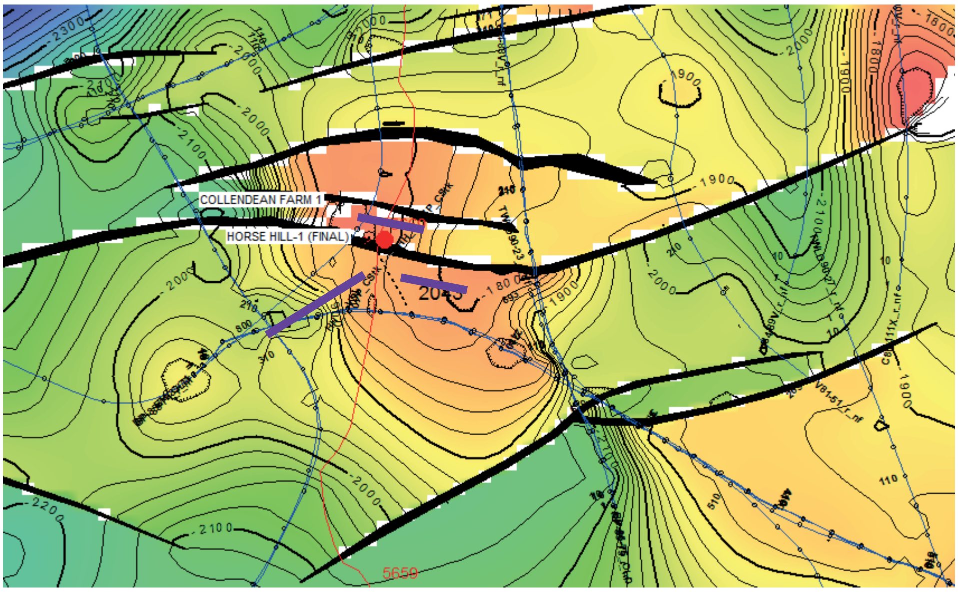


Figure 6.9 Indicative P_{50} Production Well Pattern for Horse Hill Portland

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.

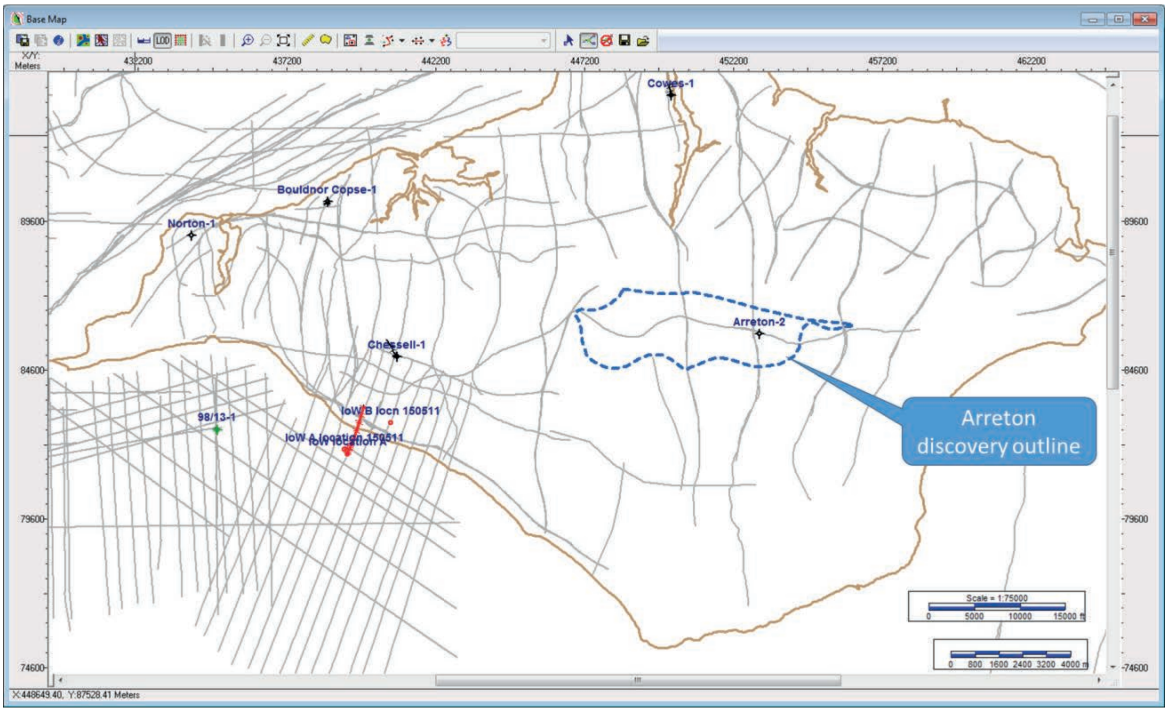


Figure 7.1: Seismic coverage and Arreton discovery outline

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.

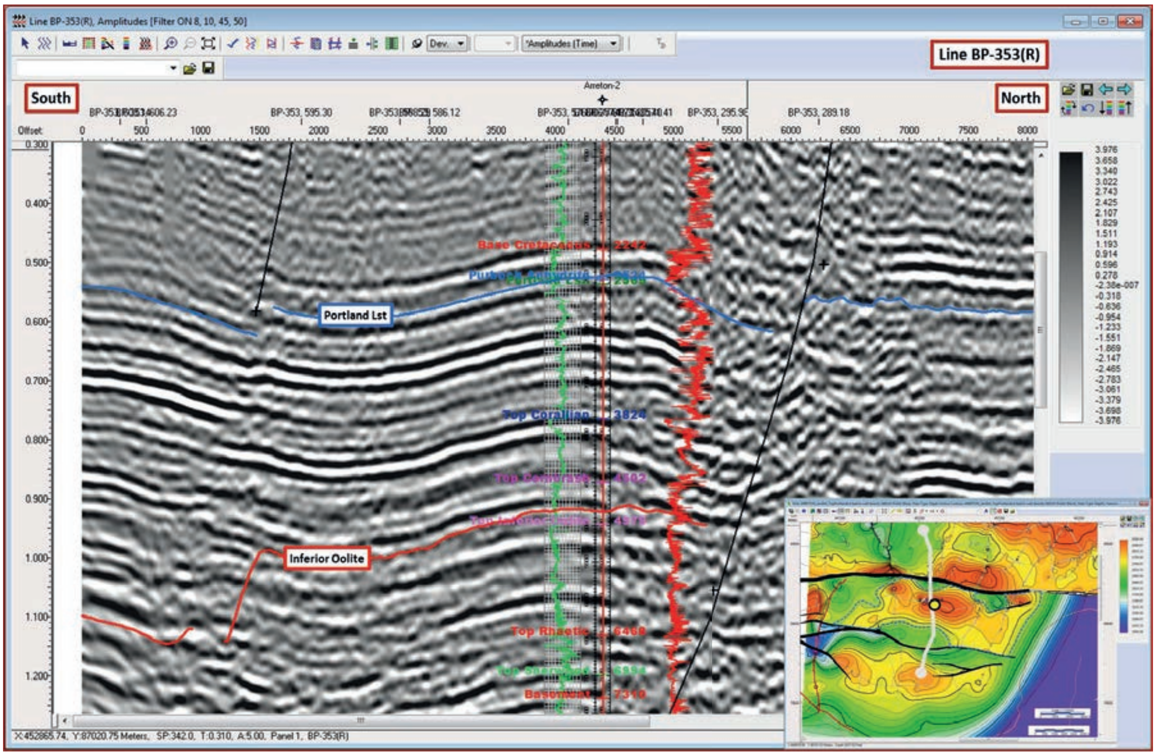


Figure 7.2: "Dip" line

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.

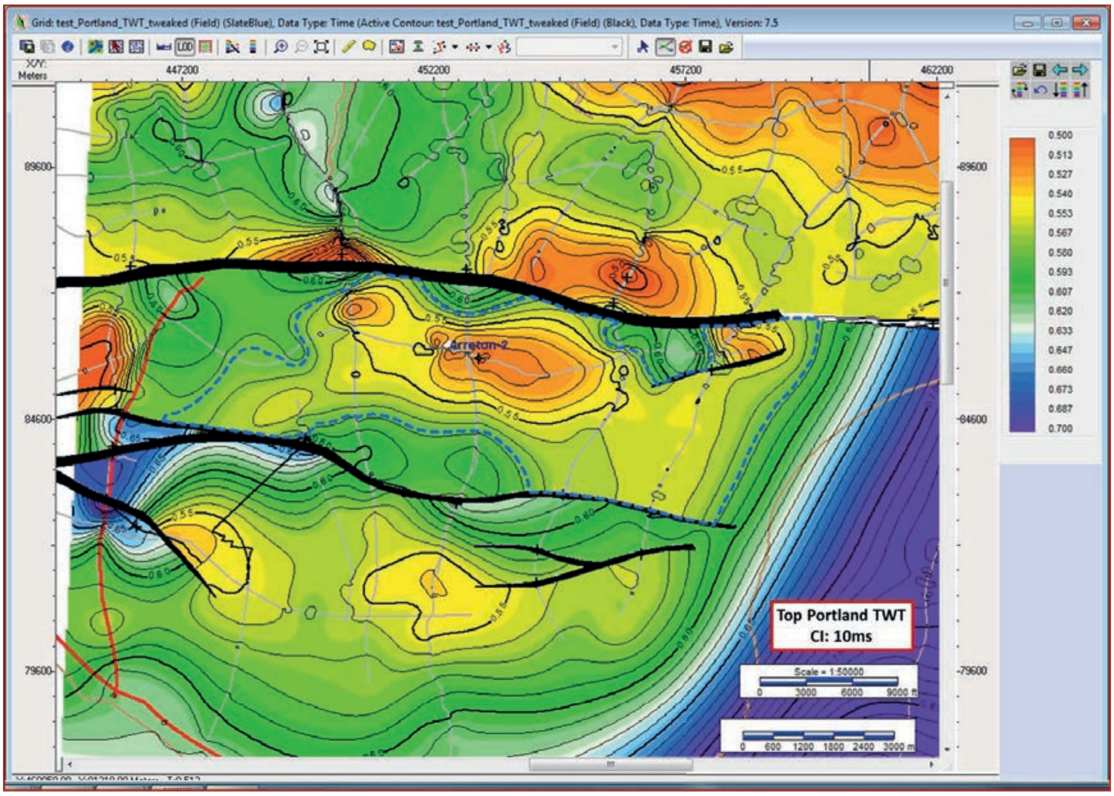


Figure 7.3: Top Portland Limestone TWT structure grid

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).

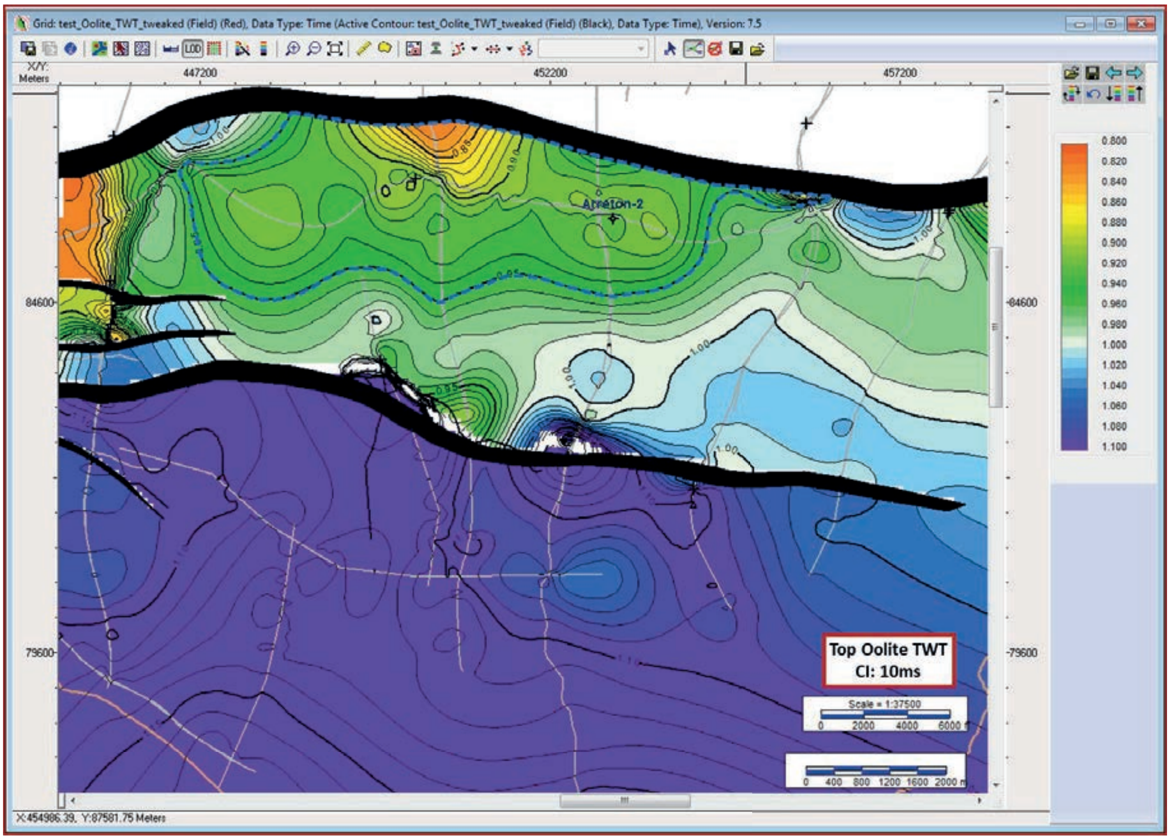


Figure 7.4: Top Inferior Oolite TWT structure grid

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.

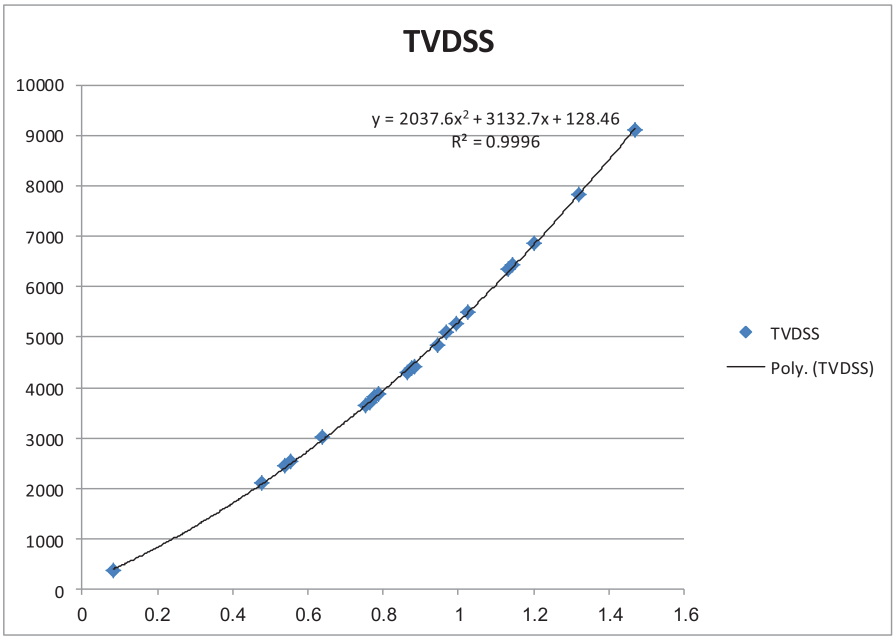


Figure 7.5: Velocity function used for depth conversion.

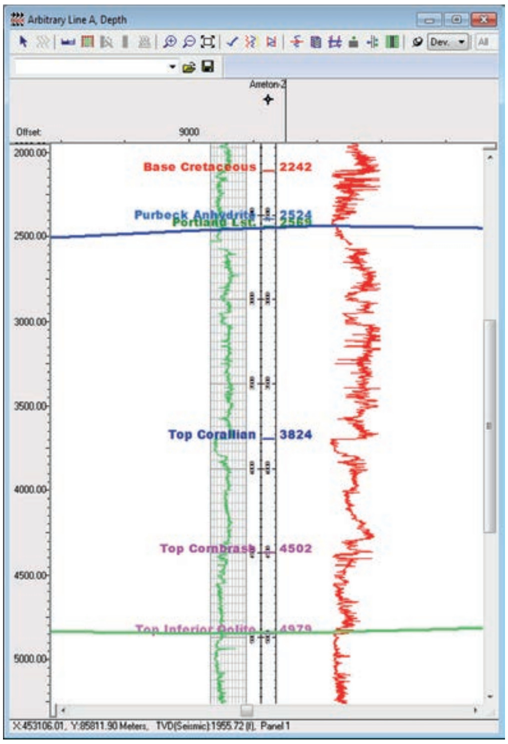


Figure 7.6: Top Portland and Inferior Oolite Depth Grids vs Arreton-2 well

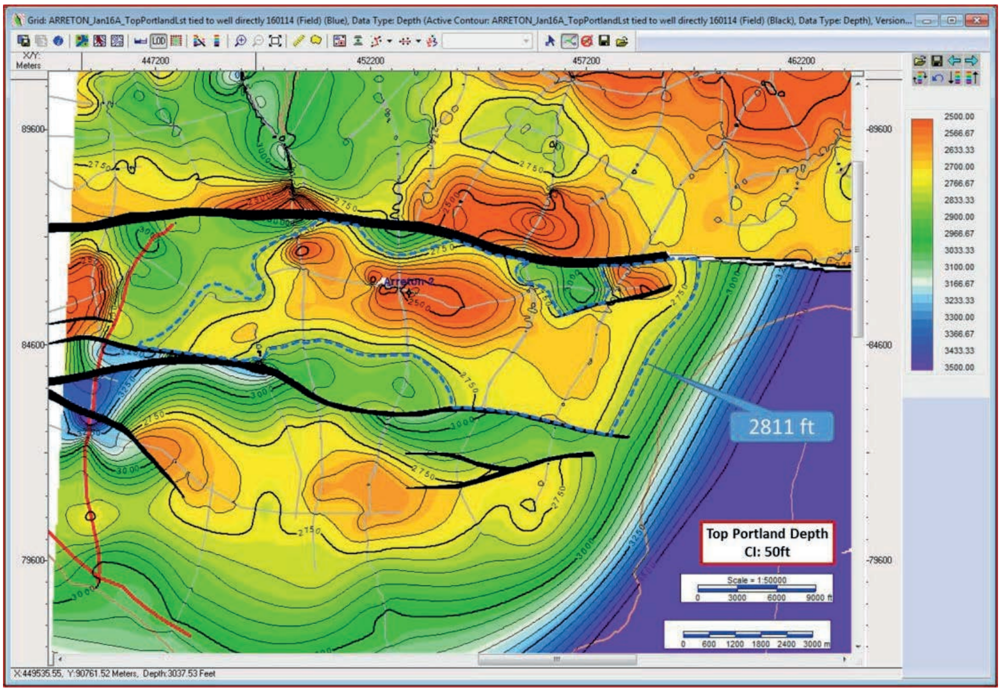


Figure 7.7: Top Portland Limestone Depth Grid

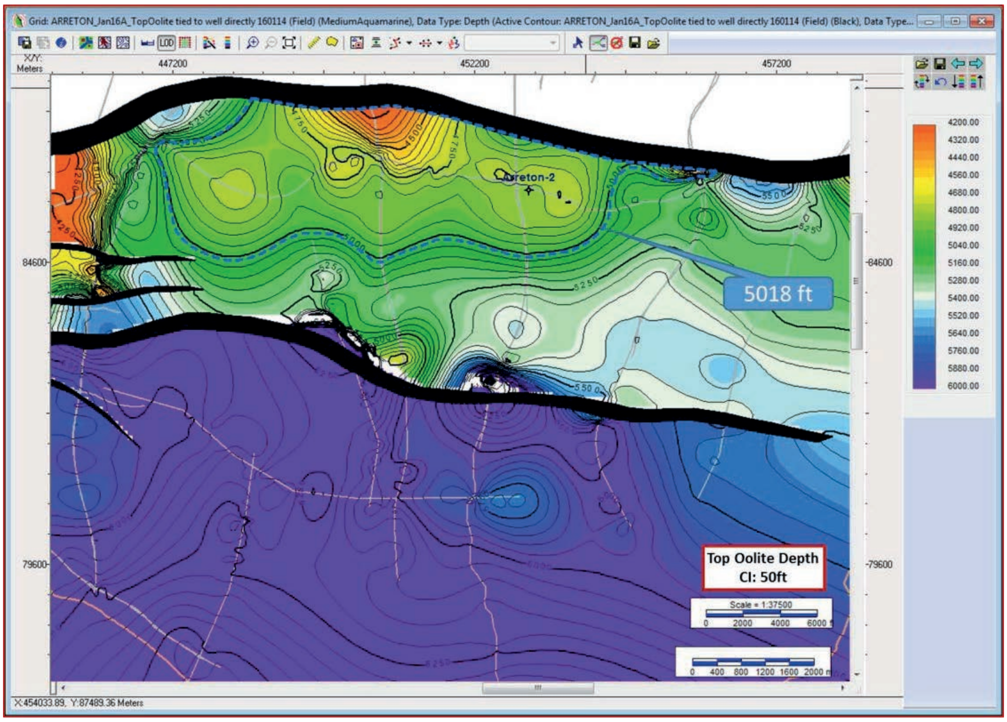


Figure 7.8: Top Inferior Oolite Depth Grid

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.

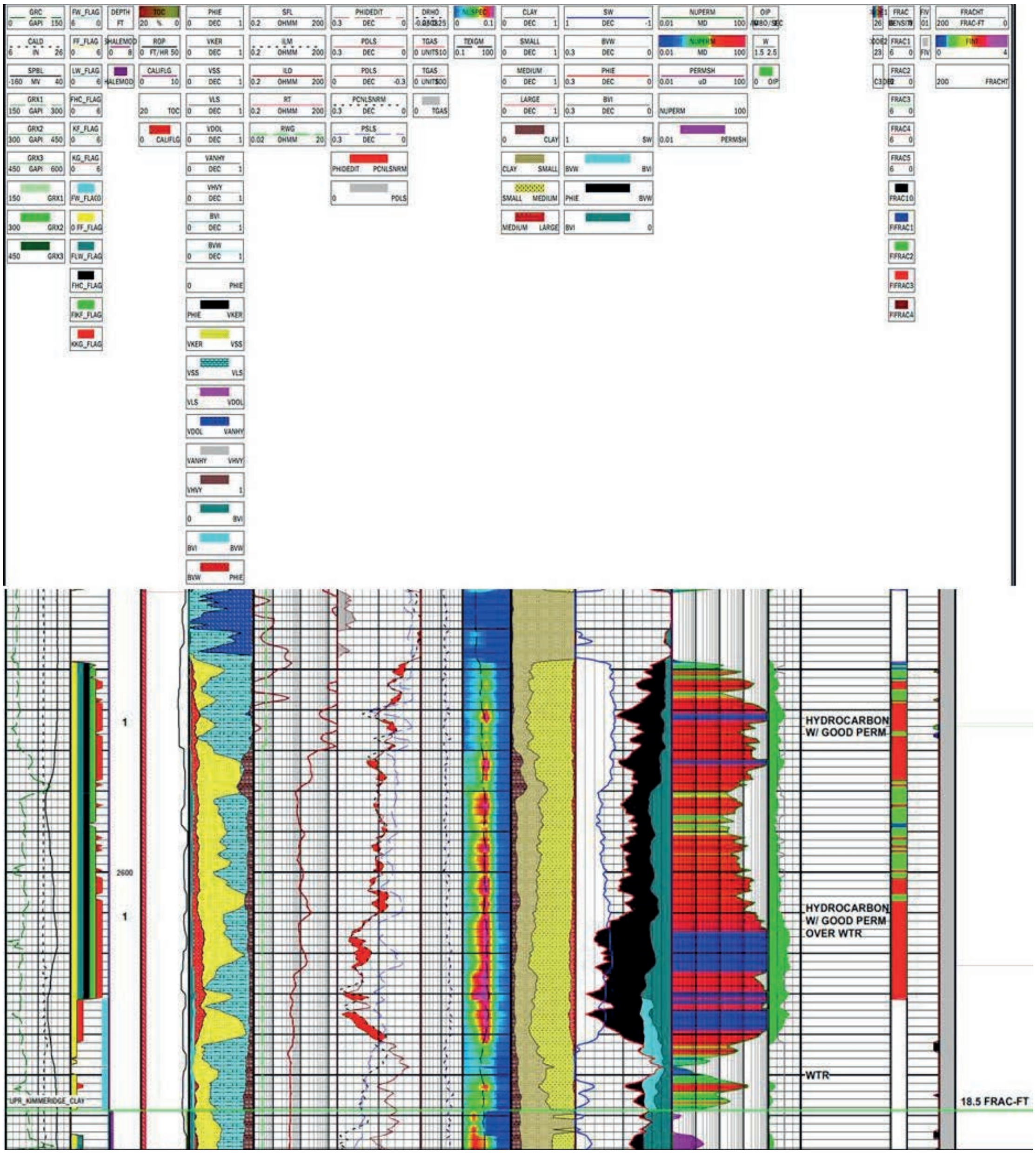


Figure 7.9: Portland Interval of the Arreton-2 well, Nutech interpretation.

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.

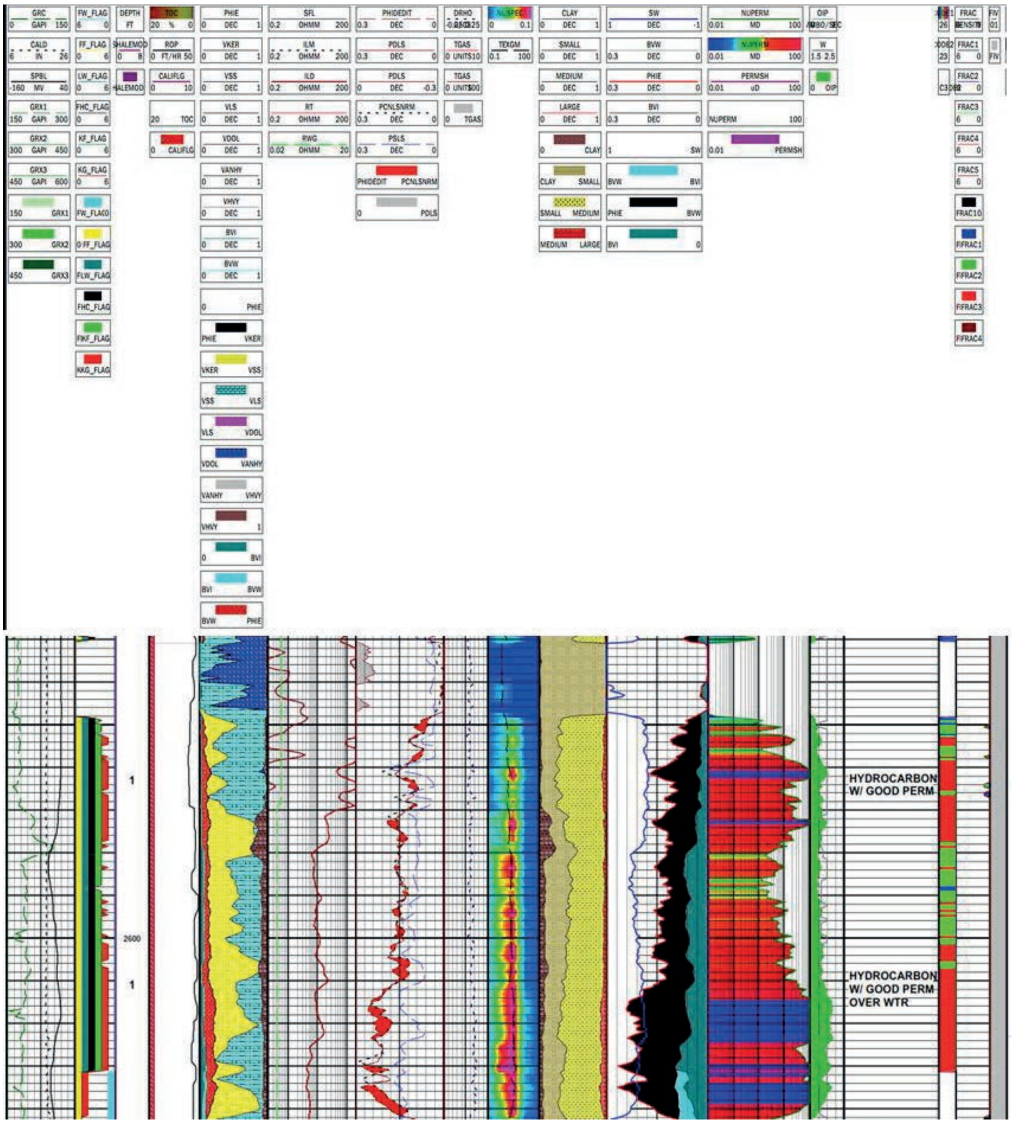


Figure 7.10 Nutech CPI through the Purbeck Limestone.

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.

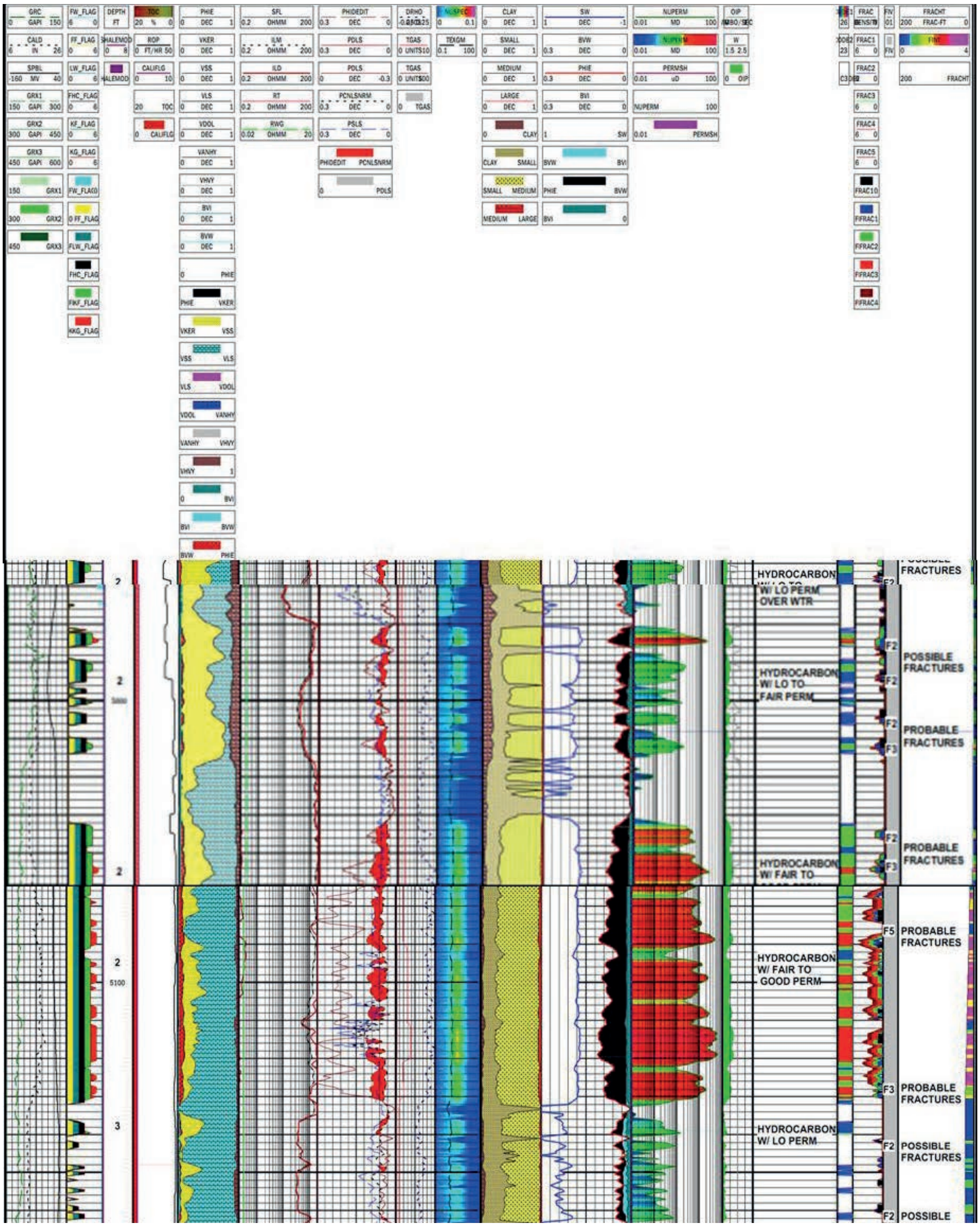


Figure 7.11: Inferior Oolite CPI from Nutech interpretation

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.

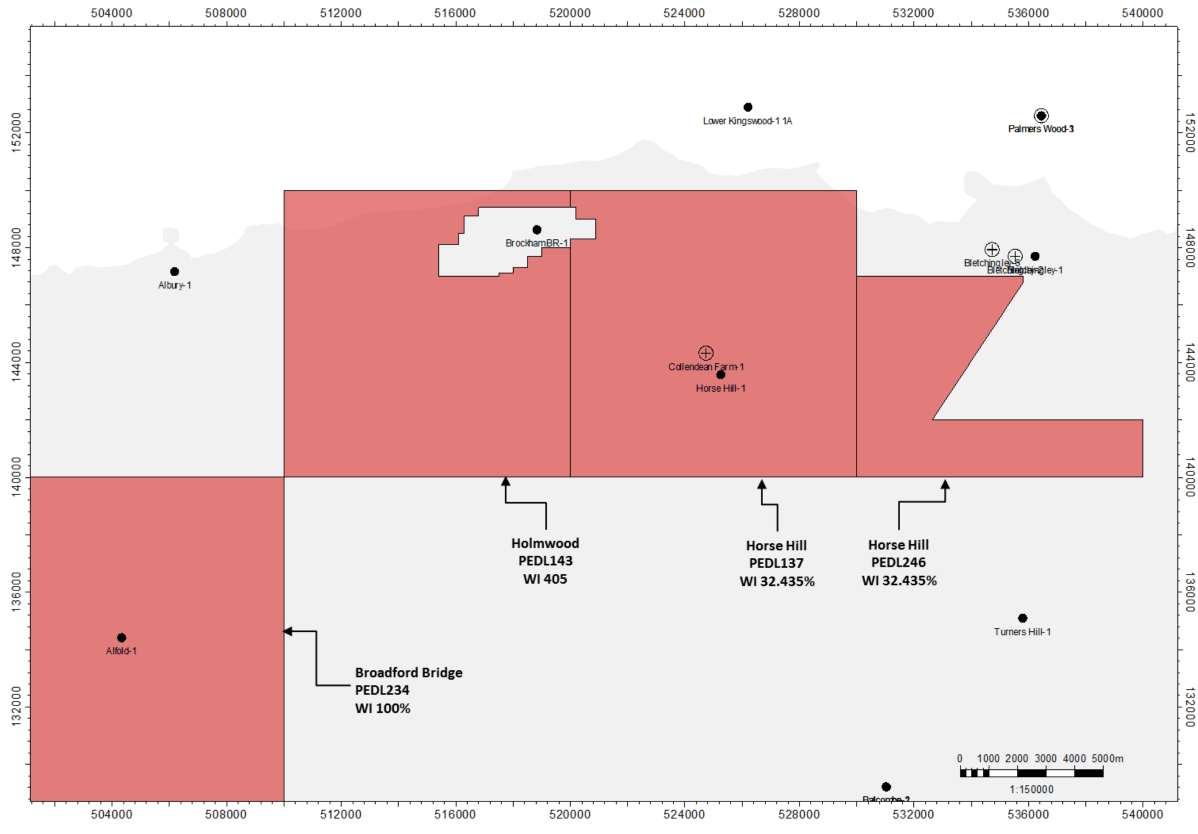


Figure 8.1 Map showing the Holmwood licence and nearby wells

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.

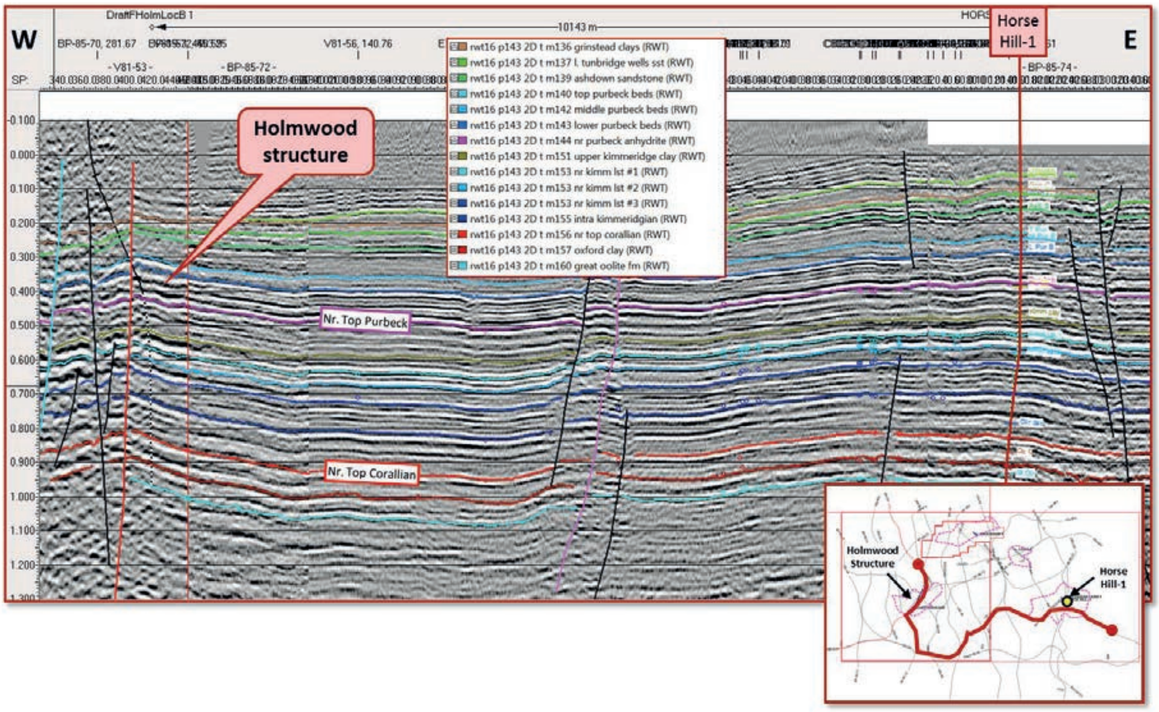


Figure 8.2 Arbitrary seismic traverse line across the Holmwood structure, extending eastwards towards the Horse Hill-1 well

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.

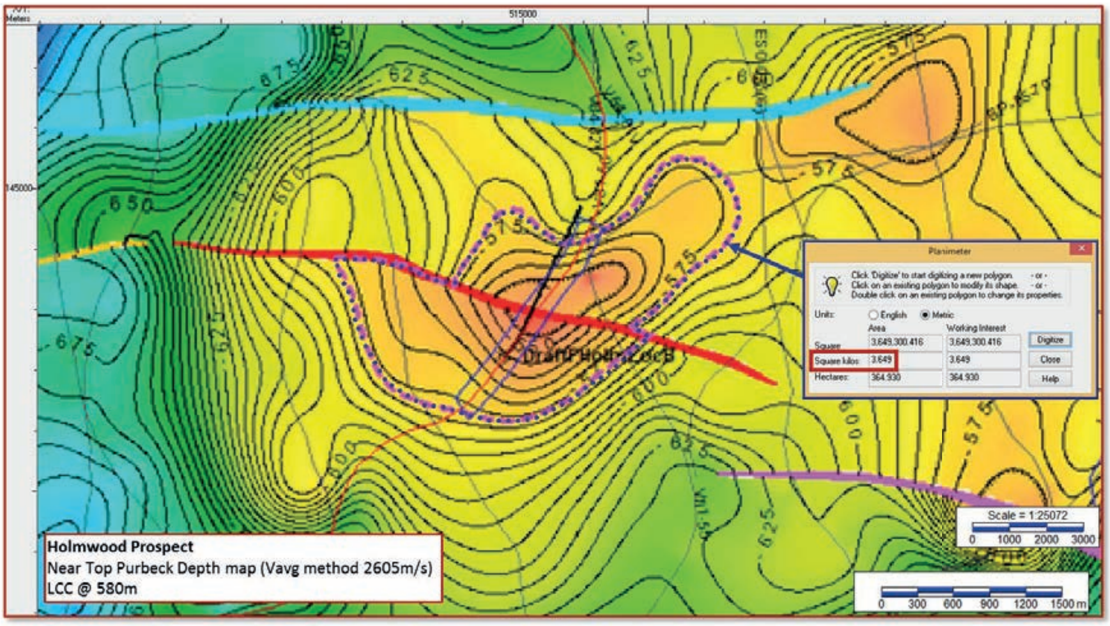


Figure 8.3 Near Top Purbeck (proxy for Top Portland) depth map (Contour Interval = 5m)
Lowest closing contour used for GRV calculation shown in blue. UKOG polygon shown in pink

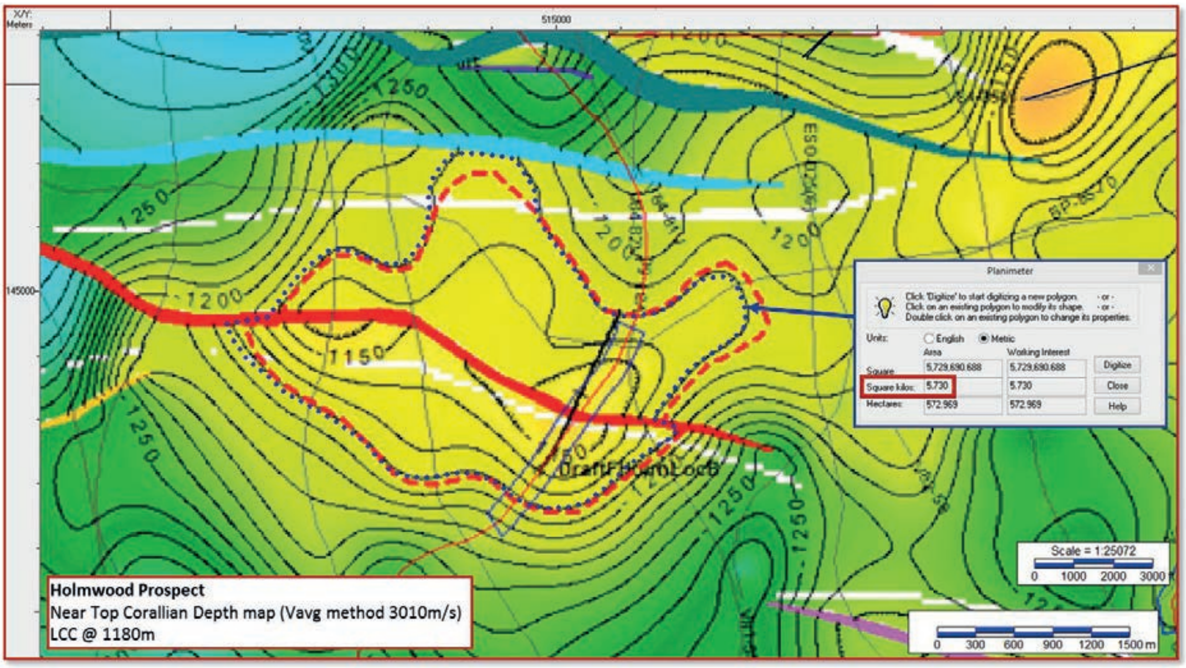


Figure 8.4 Near Top Corallian depth map (Contour Interval = 10m)
Lowest closing contour used for GRV calculation shown in blue. UKOG polygon shown in red

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

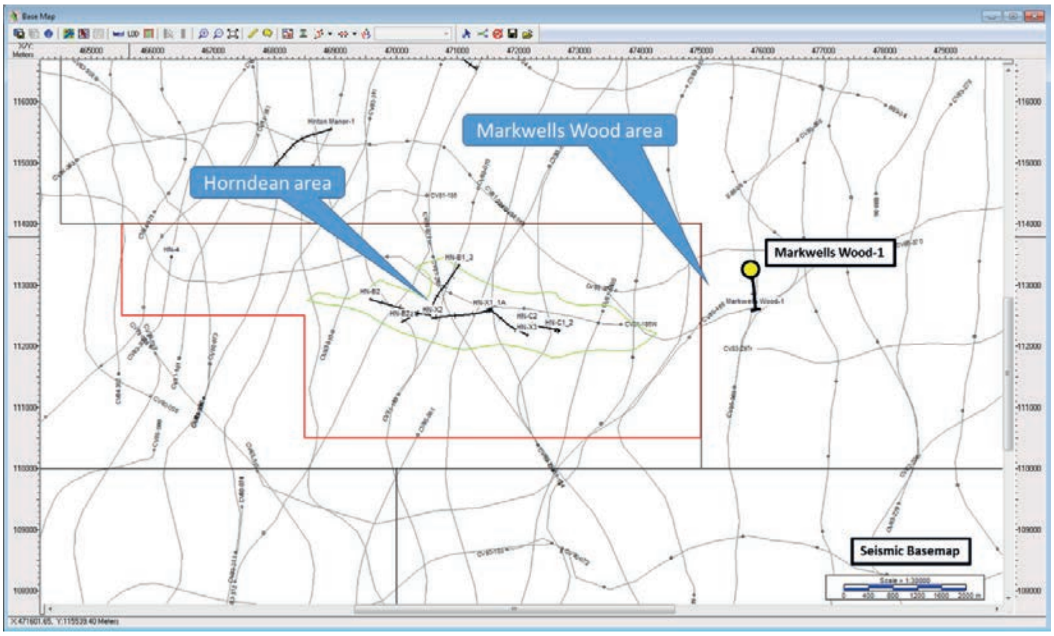


Figure 9.1 Markwells Wood license area seismic coverage

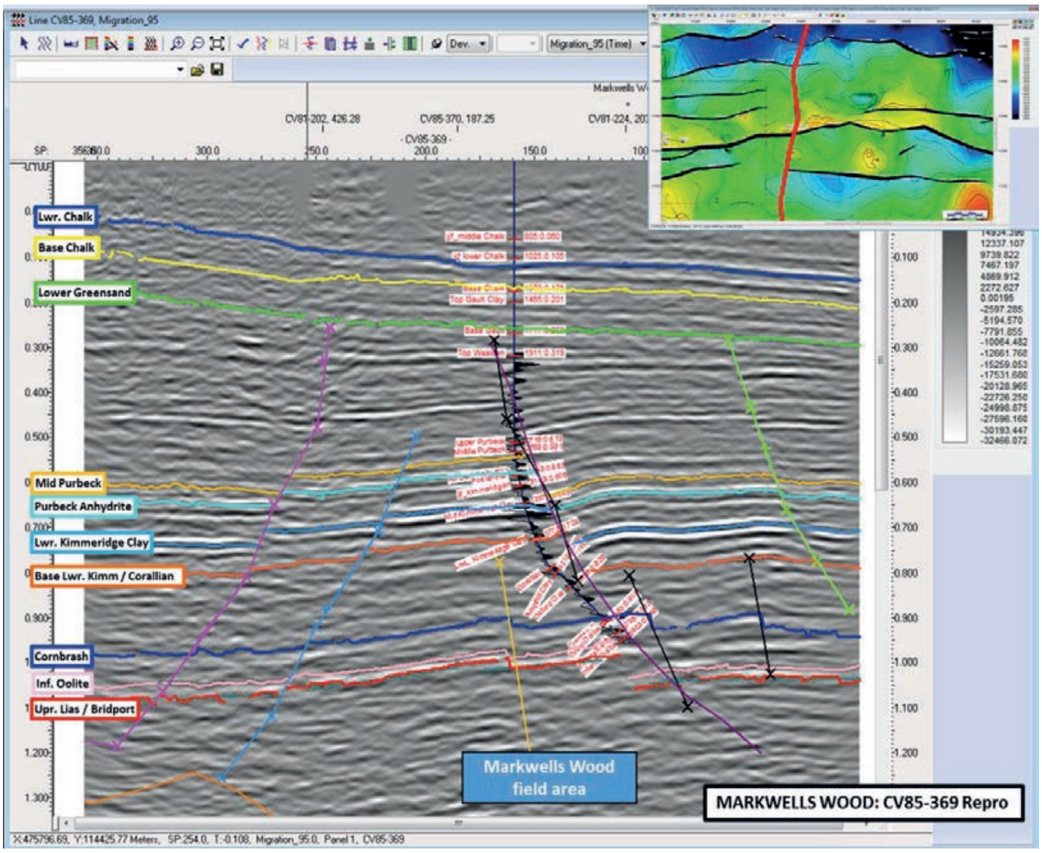


Figure 9.2 Line CV85-369 (Reprocessed)

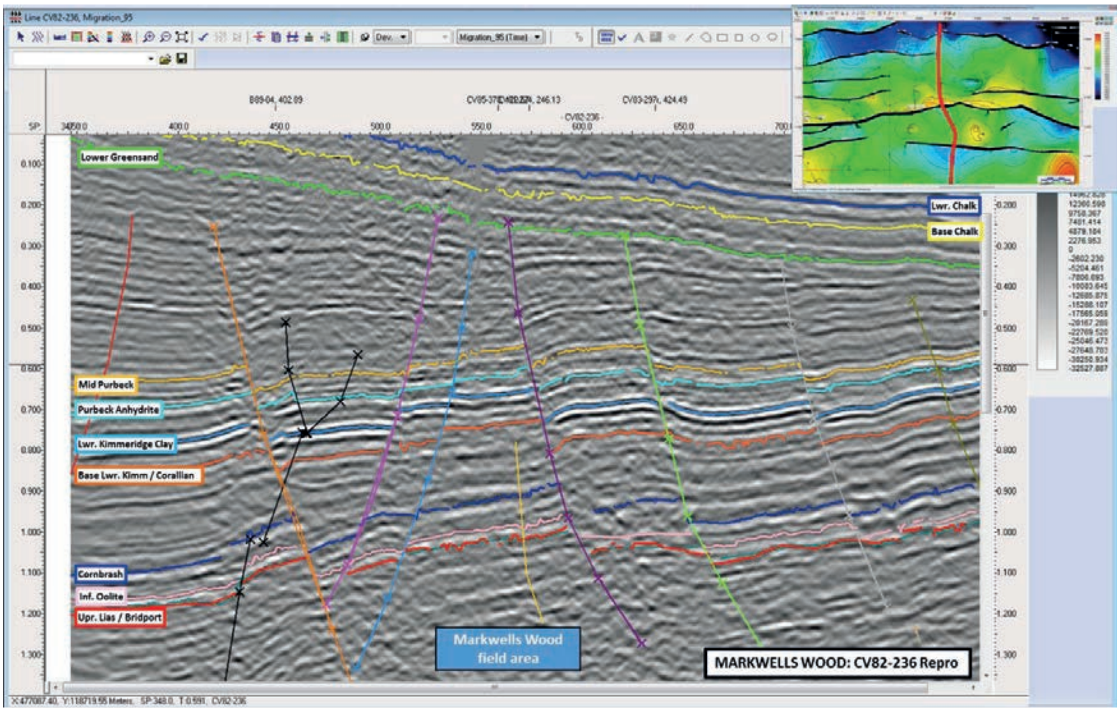


Figure 9.3 Line CV82-236 (Reprocessed)

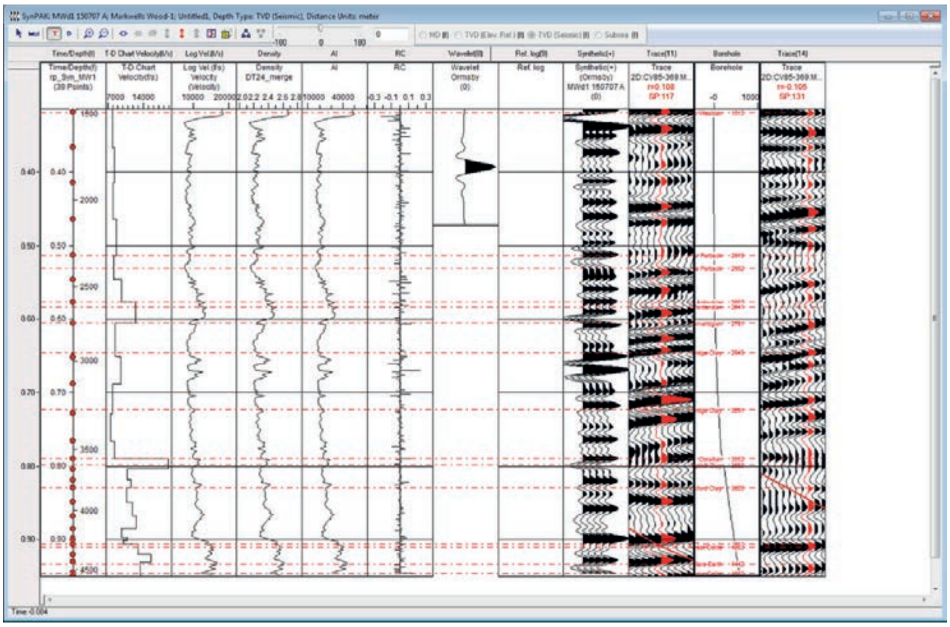


Figure 9.4 Markwells Wood-1 Well-to-seismic tie

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.

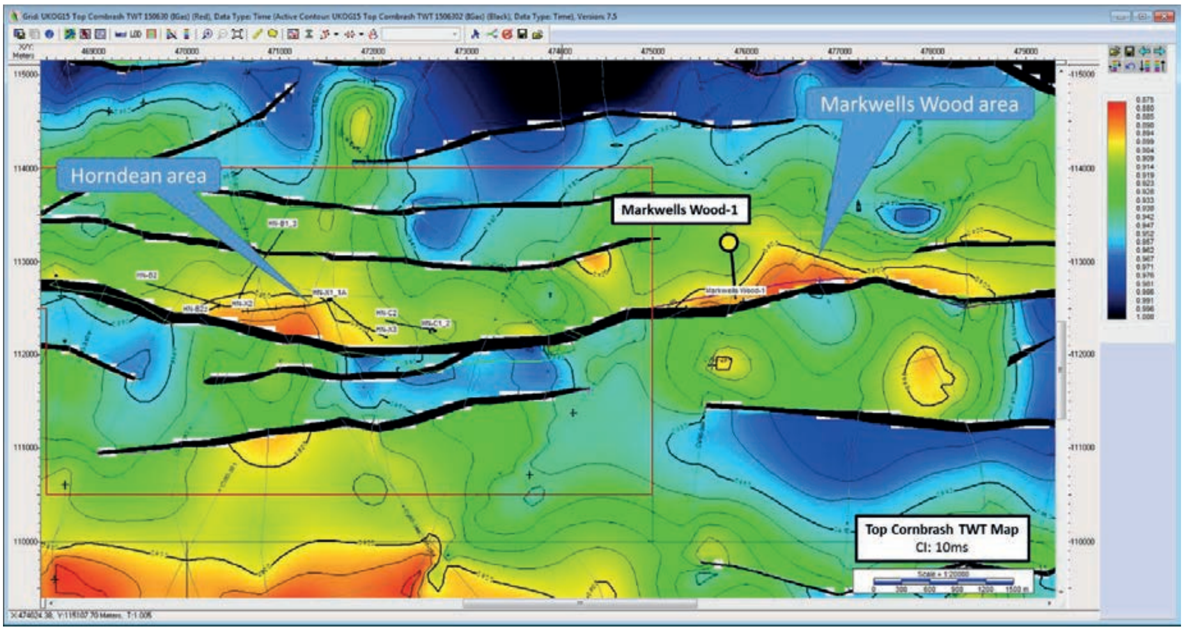


Figure 9.5 Top Cornbrash TWT structure grid (w/faults)

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).

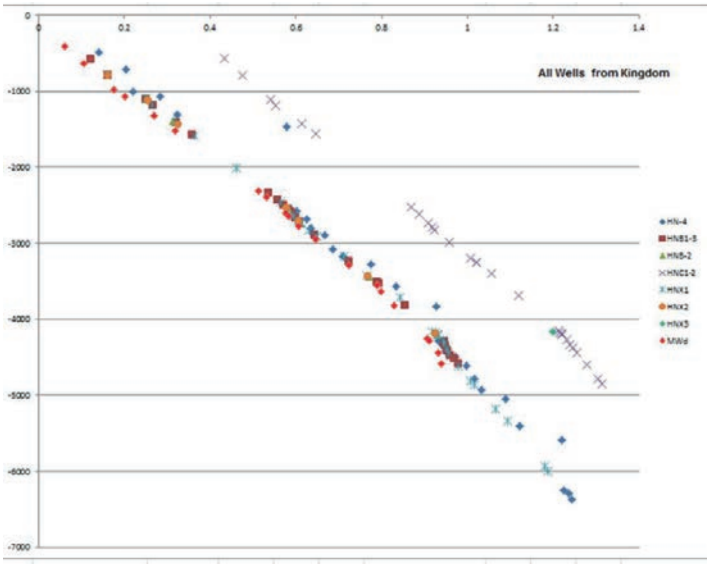


Figure 9.6 Velocity functions from nearby Horndean wells & Markwells Wood-1 (red diamonds). Note HNC1-2 lying anomalously off-trend to the other wells

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

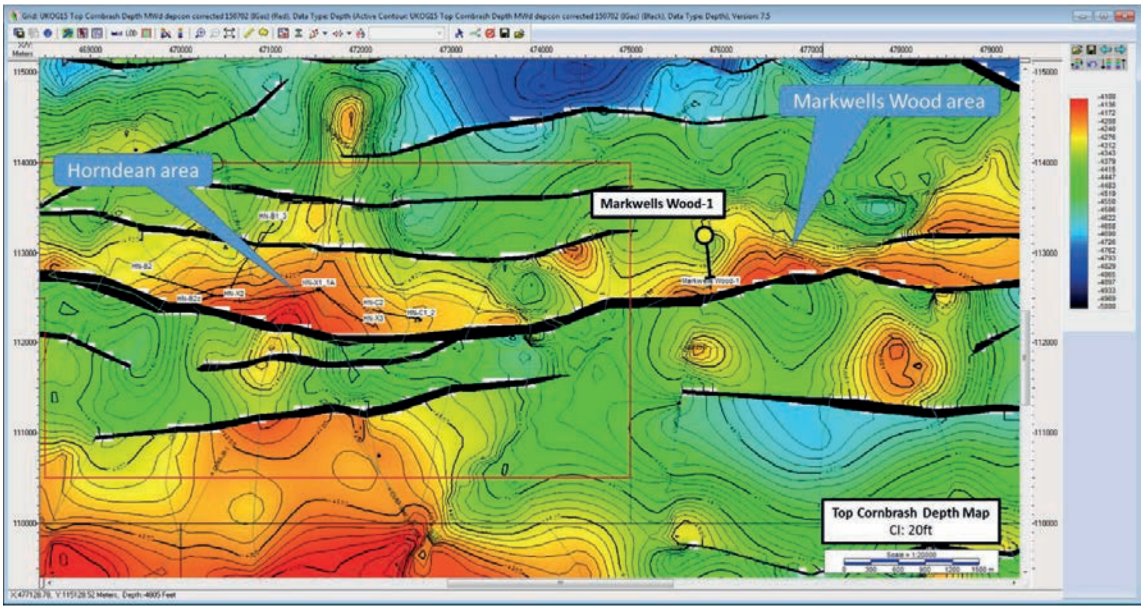


Figure 9.7 Top Cornbrash Depth Grid

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.

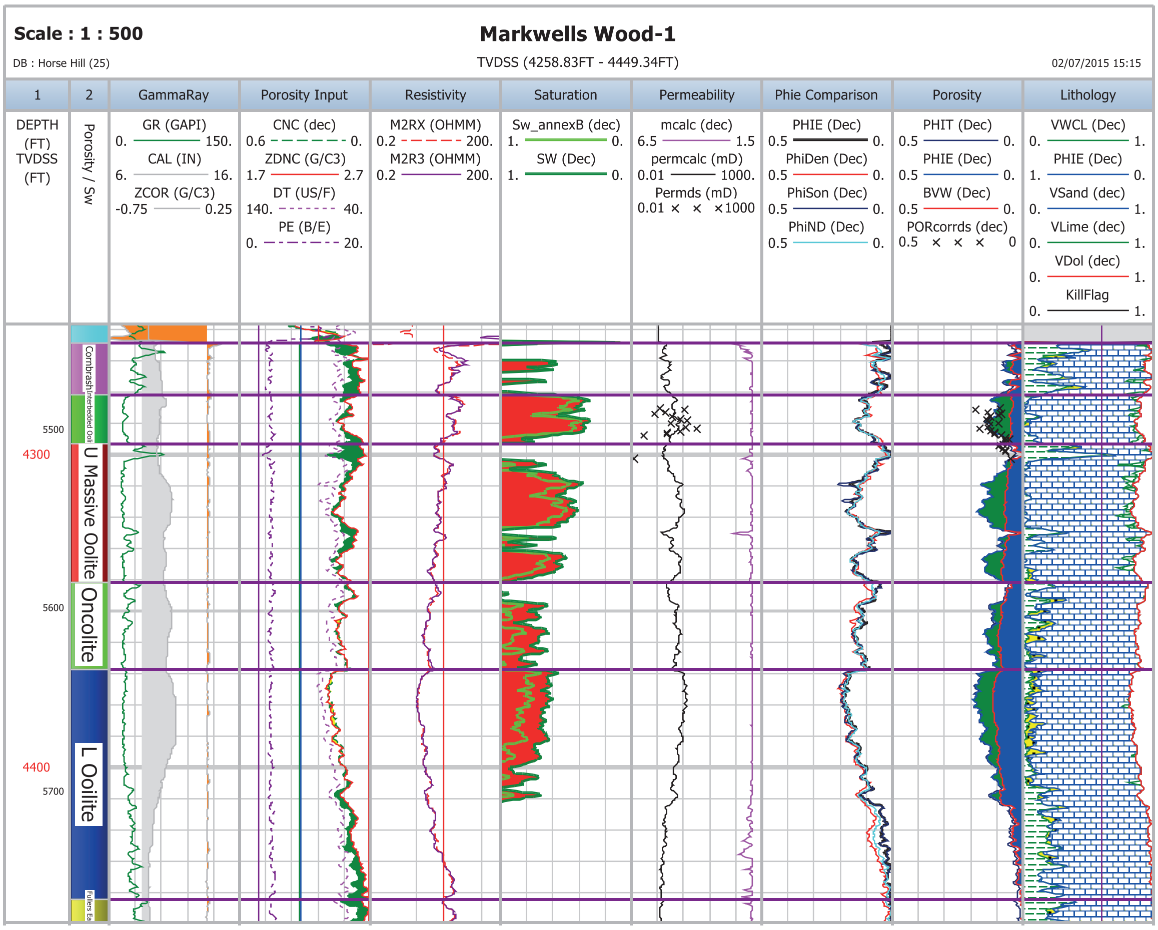


Figure 9.8 Markwells Wood-1 CPI across the Great Oolite formation.

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.

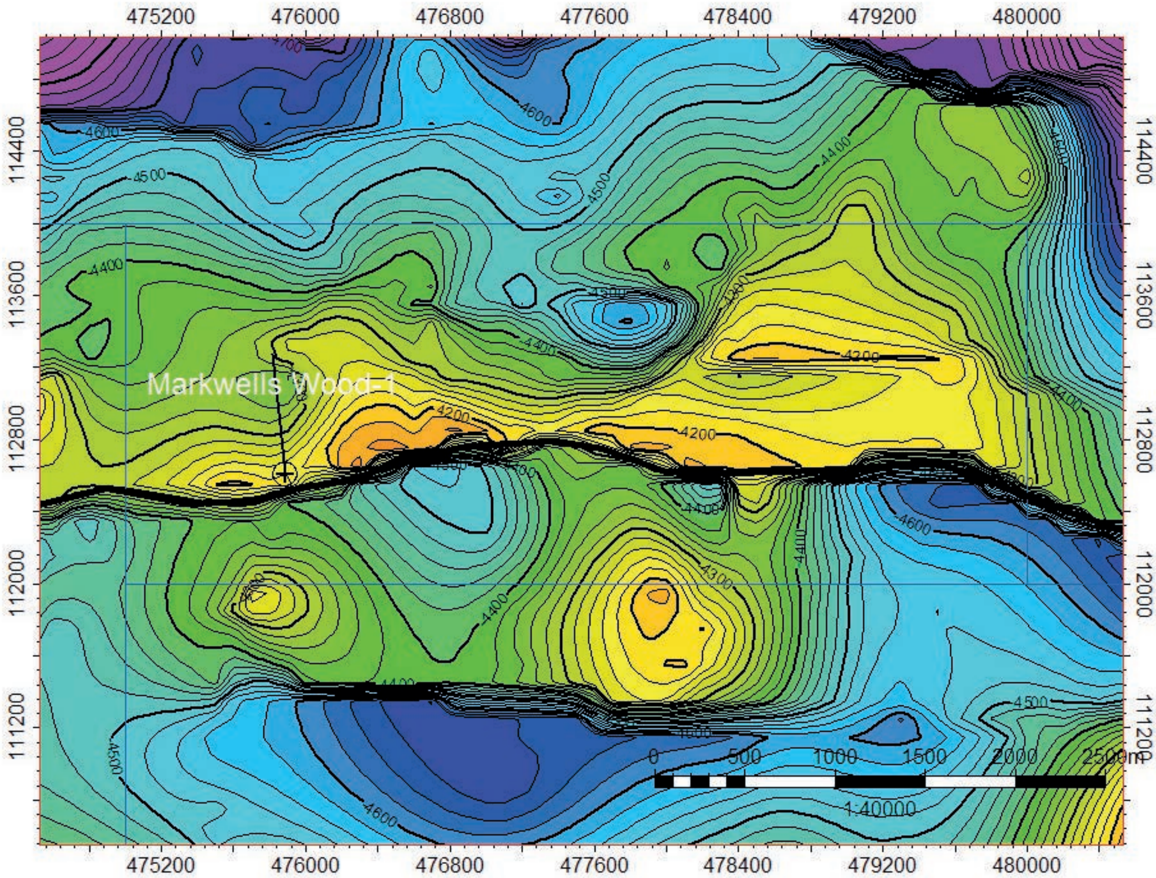


Figure 9.9 Map showing top Cornbrash which was used to generate area depth data for each reservoir.

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.

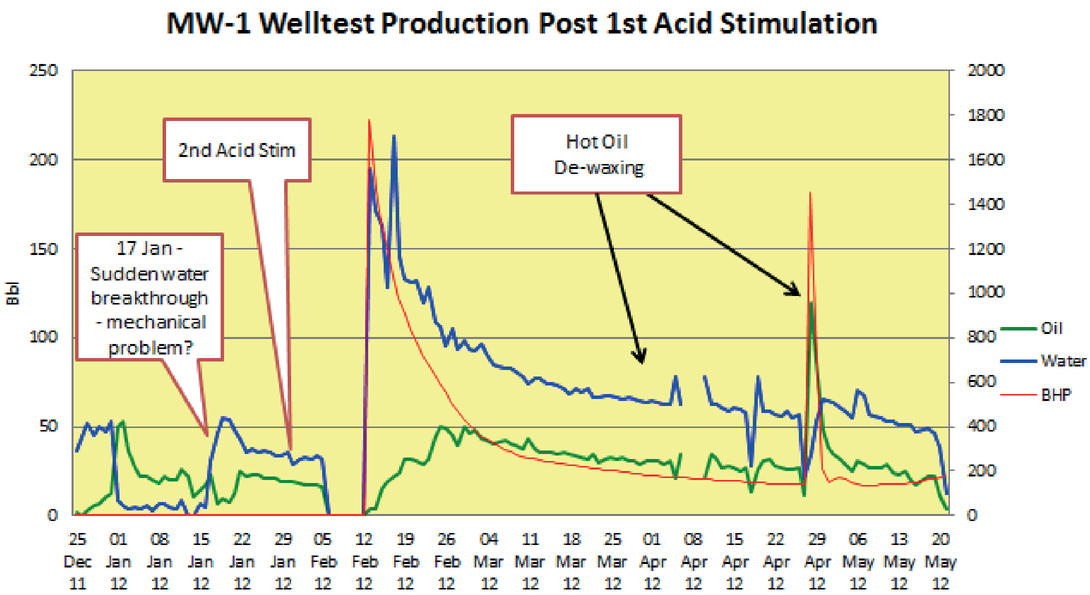


Figure 9.10 MW-1 extended well test

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.

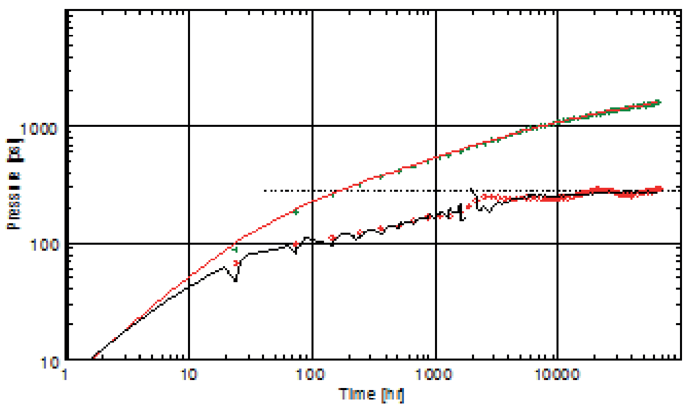


Figure 9.11 Log-log plot of MW-1 drawdown

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.

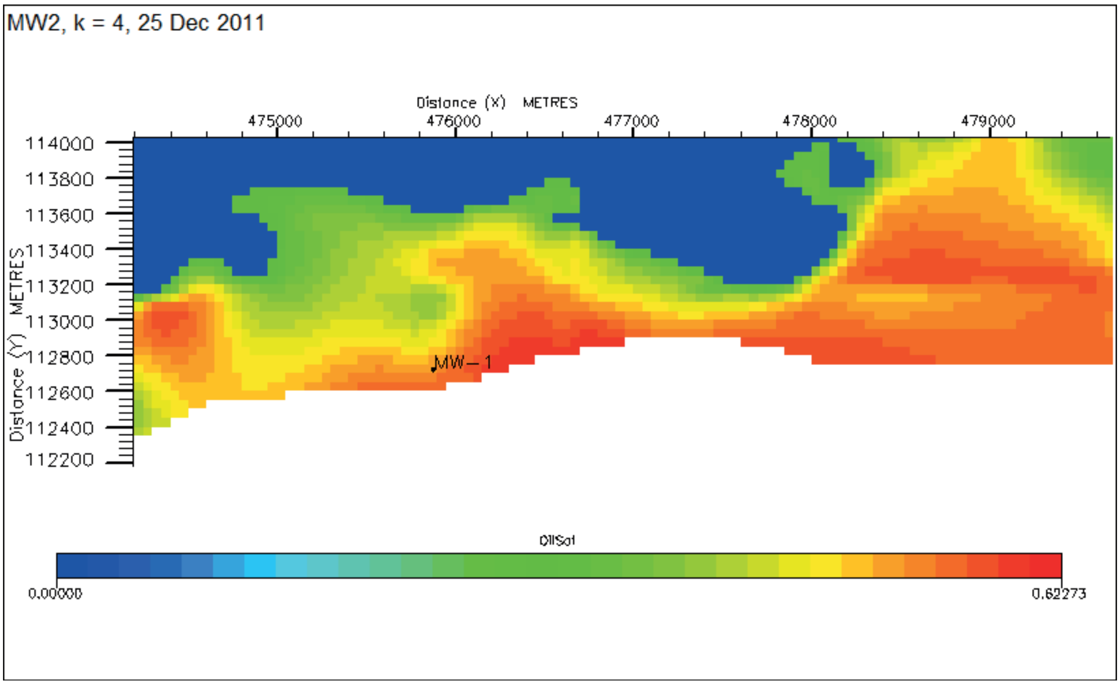


Figure 9.12 Oil saturation in the Markwells Wood model

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.

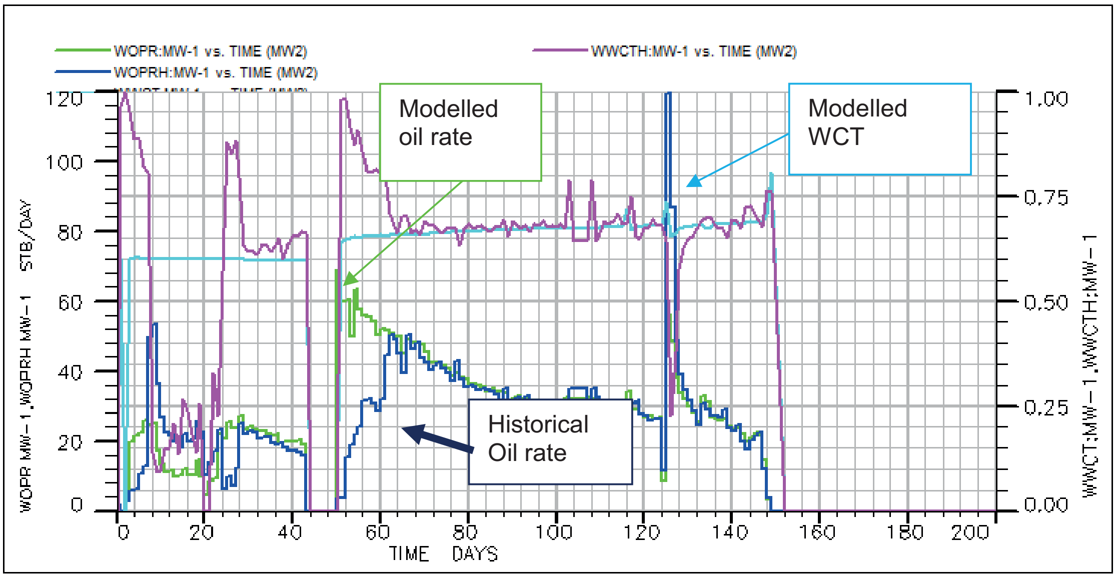


Figure 9.13 History match of MW-1 EWT

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.

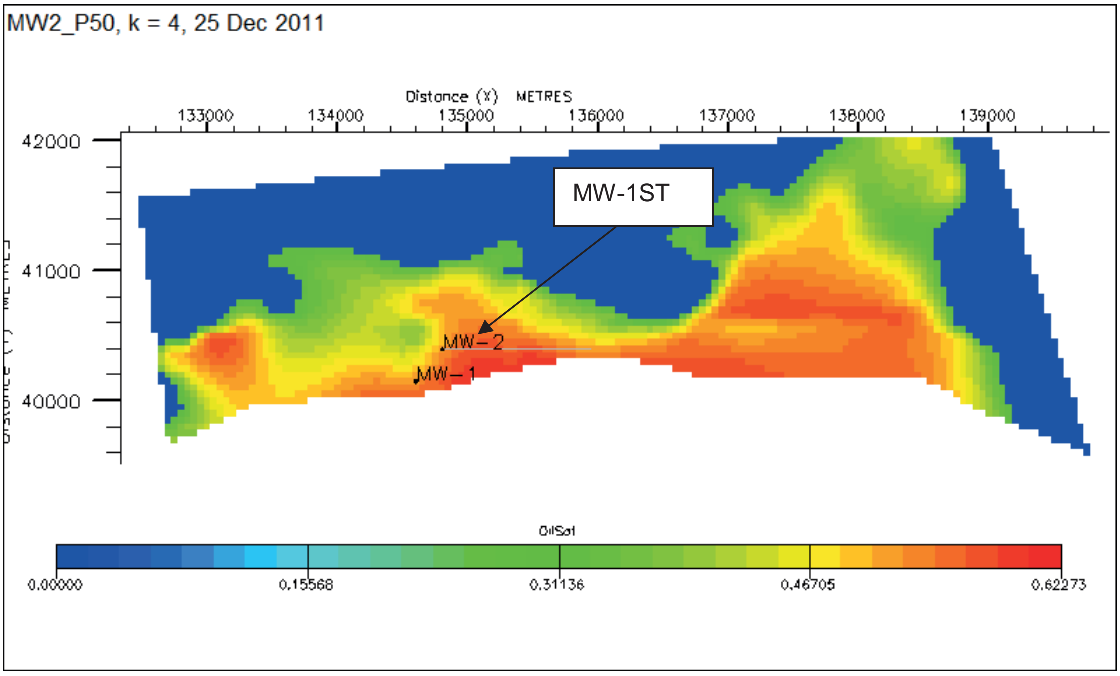


Figure 9.14 Initial oil saturation in the model showing the location of the MW-1ST well

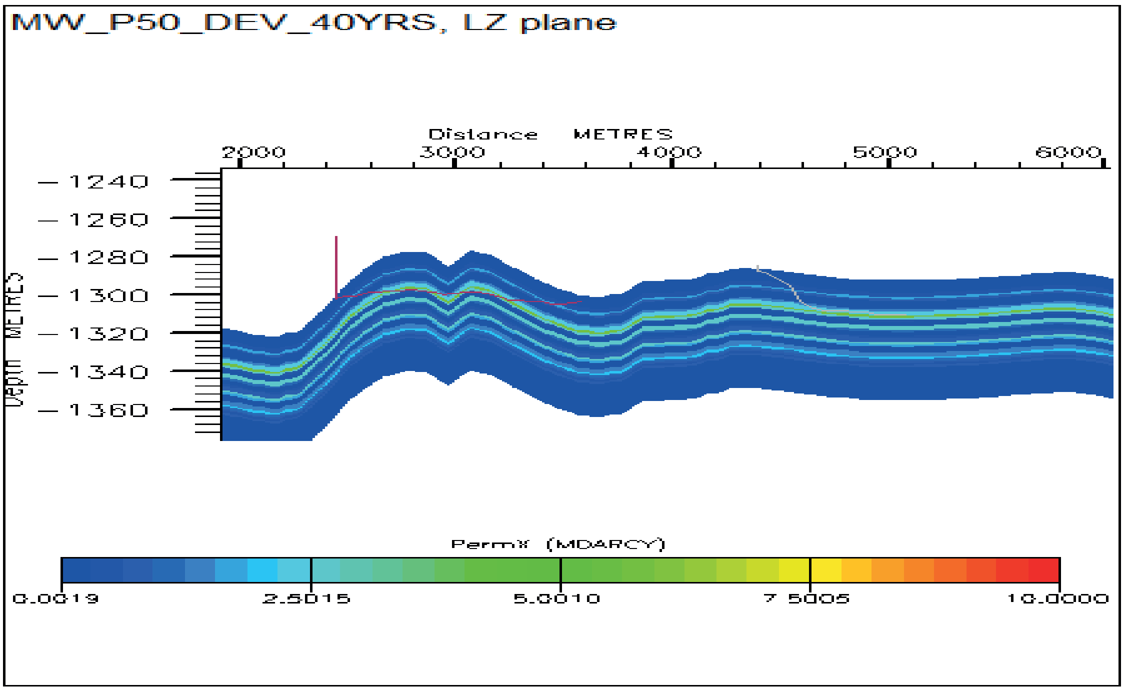


Figure 9.15 MW-1 ST cross section permeability

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.

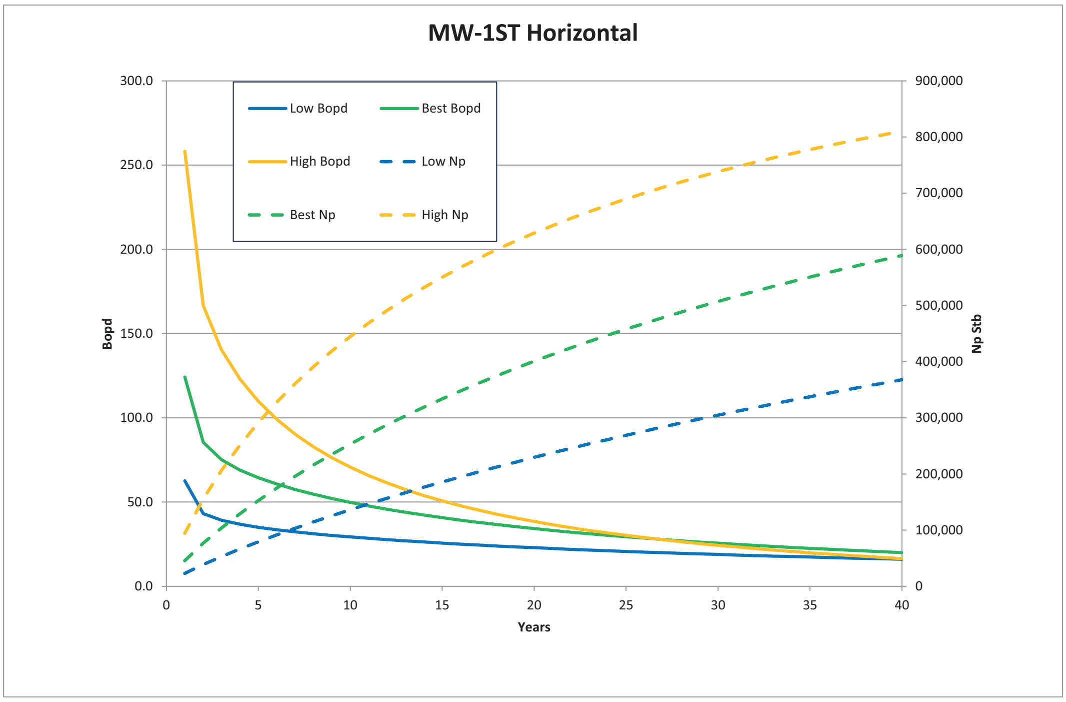


Figure 9.16 Production Forecasts MW-1ST cases

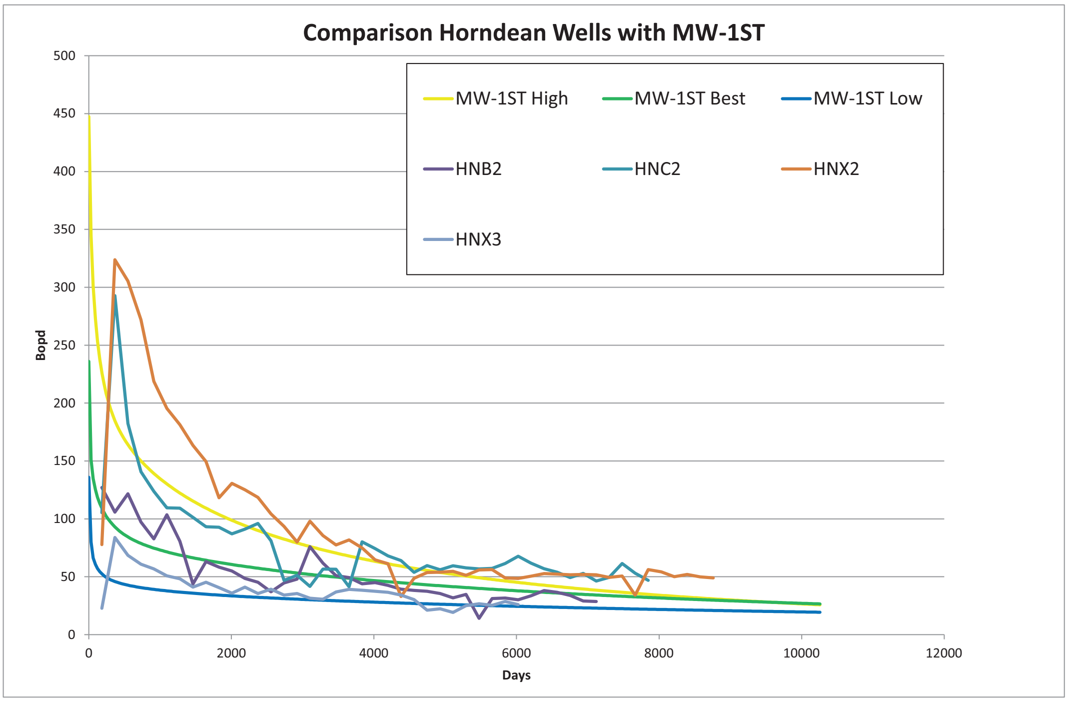


Figure 9.17 Comparison of oil rate for the MW-1ST cases with the Horndean wells

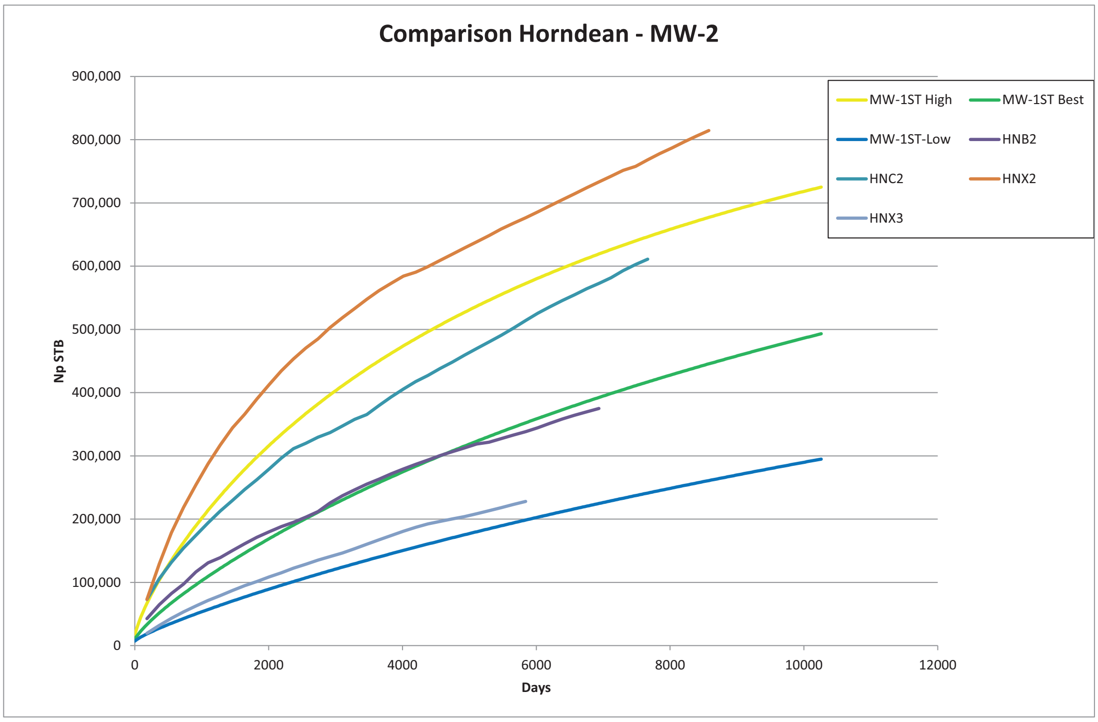


Figure 9.18 Comparison of cumulative production for the MW-1ST cases with the Horndean wells

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.

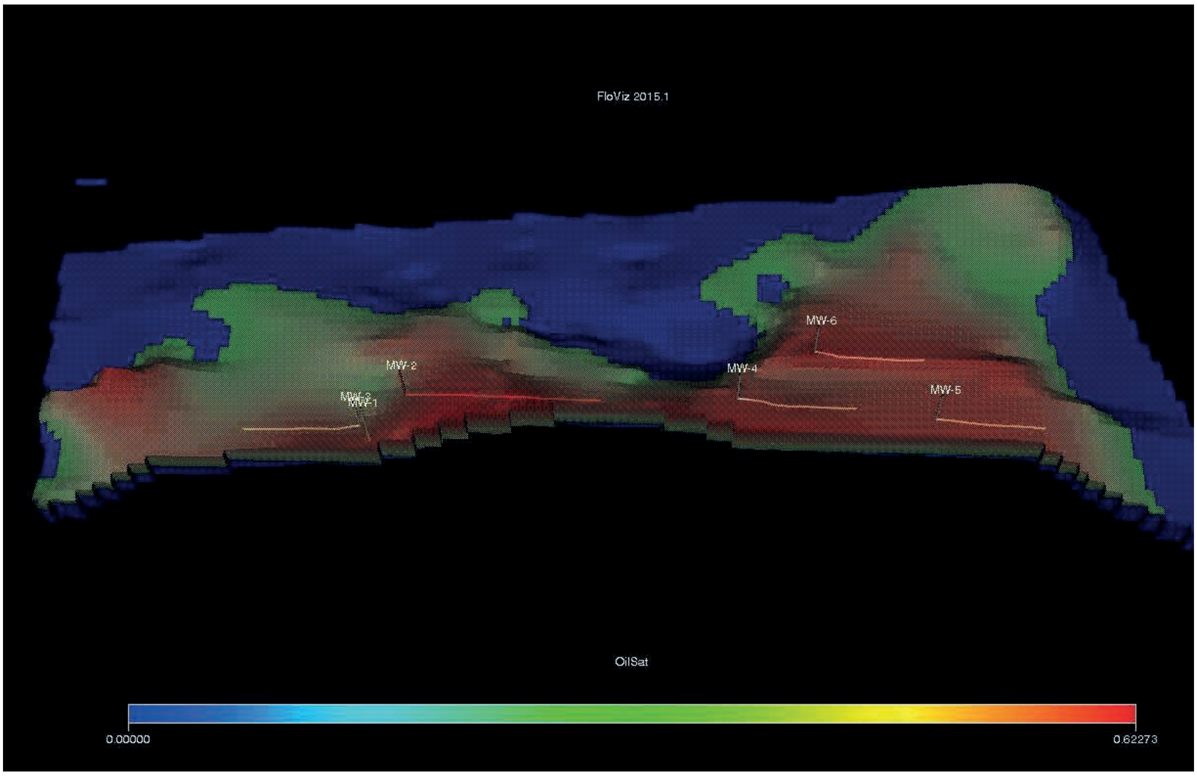


Figure 9.19 Location of Xodus notional development wells

[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

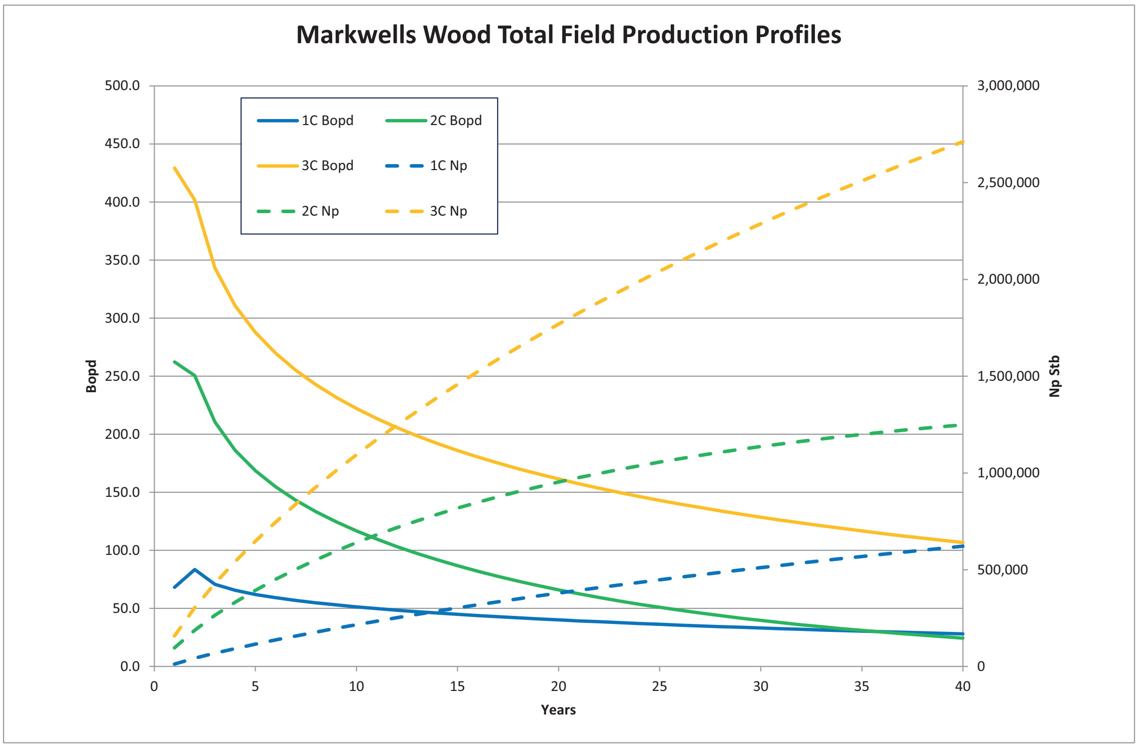


Figure 9.20 Xodus' total field production forecast - rates and cumulative production

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. A

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

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 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.

10.1 Broadford Bridge – Godley Bridge Discovery

The Broadford Bridge licence (PEDL234) is a 300 sq km block in the centre of the Weald Basin to the south west of adjacent to the Holmwood (PEDL143) licence. 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 10.1 is map showing the location of the licence and Godley Bridge discovery.

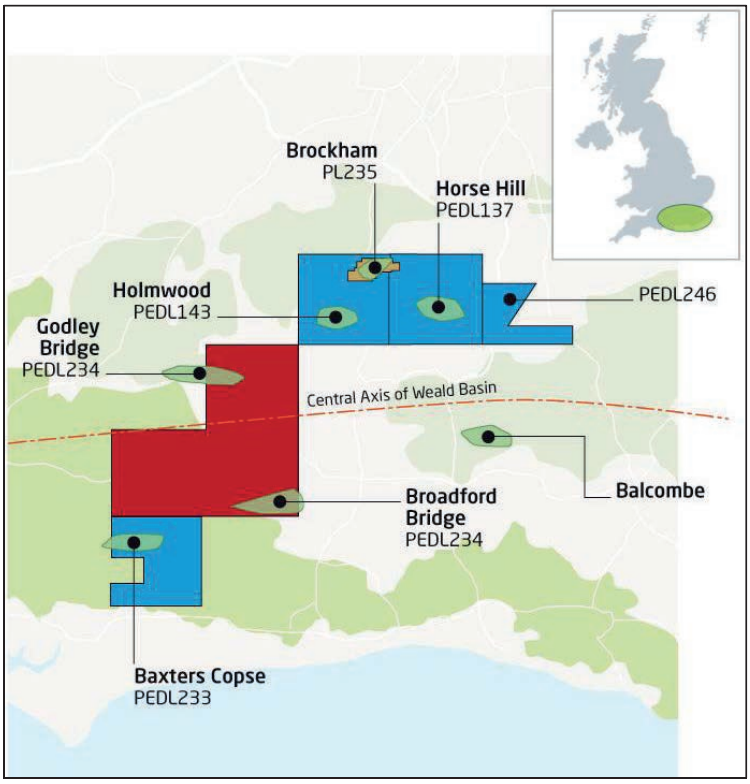


Figure 10.1 Map showing Broadford Bridge and surrounding licences (from UKOG)

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 10.2 shows a map of the top Purbeck Anhydrite marker bed showing the structure of the discovery.

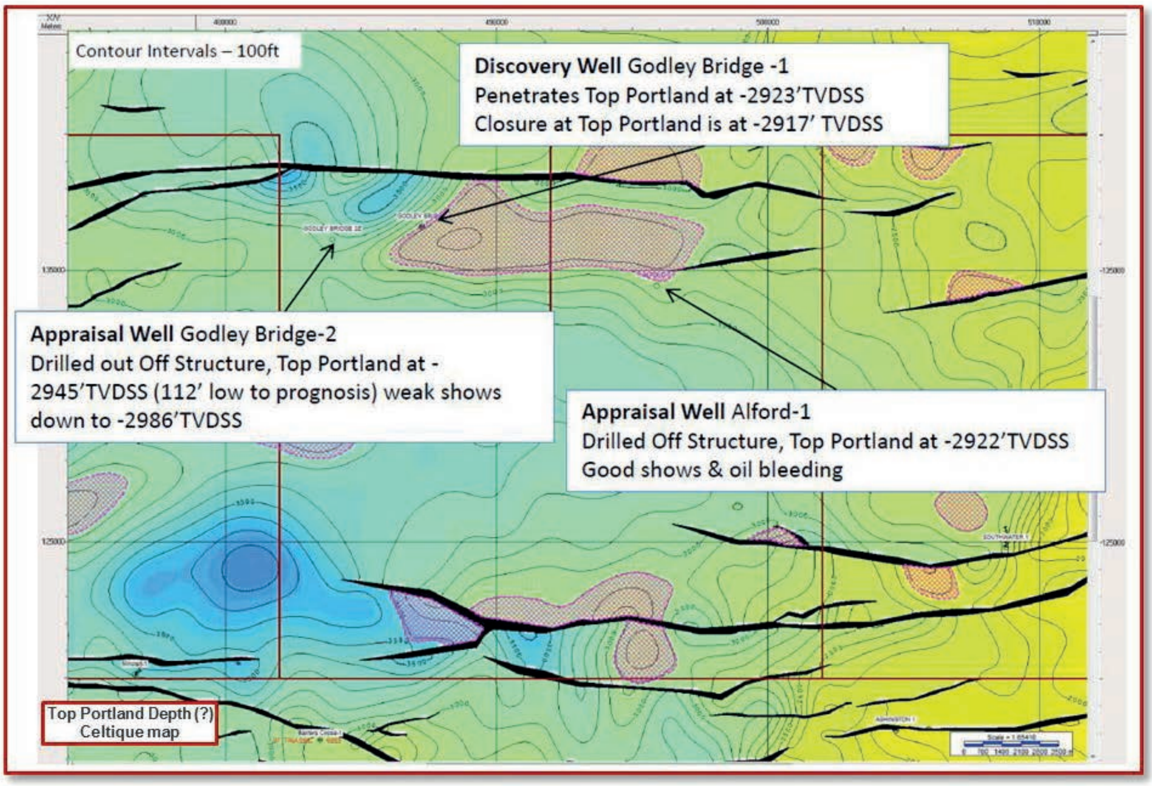


Figure 10.2 Top Purbeck Anhydrite (top seal) map, note the disconnect in the well depths between Godley Bridge-1 and Alfold-1: Godley Bridge-1 is deeper than Alfold (by 1ft) and encountered gas, while the shallower well Alfold-1 was water wet

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.

10.2 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.

10.2.1 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 10.3 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.

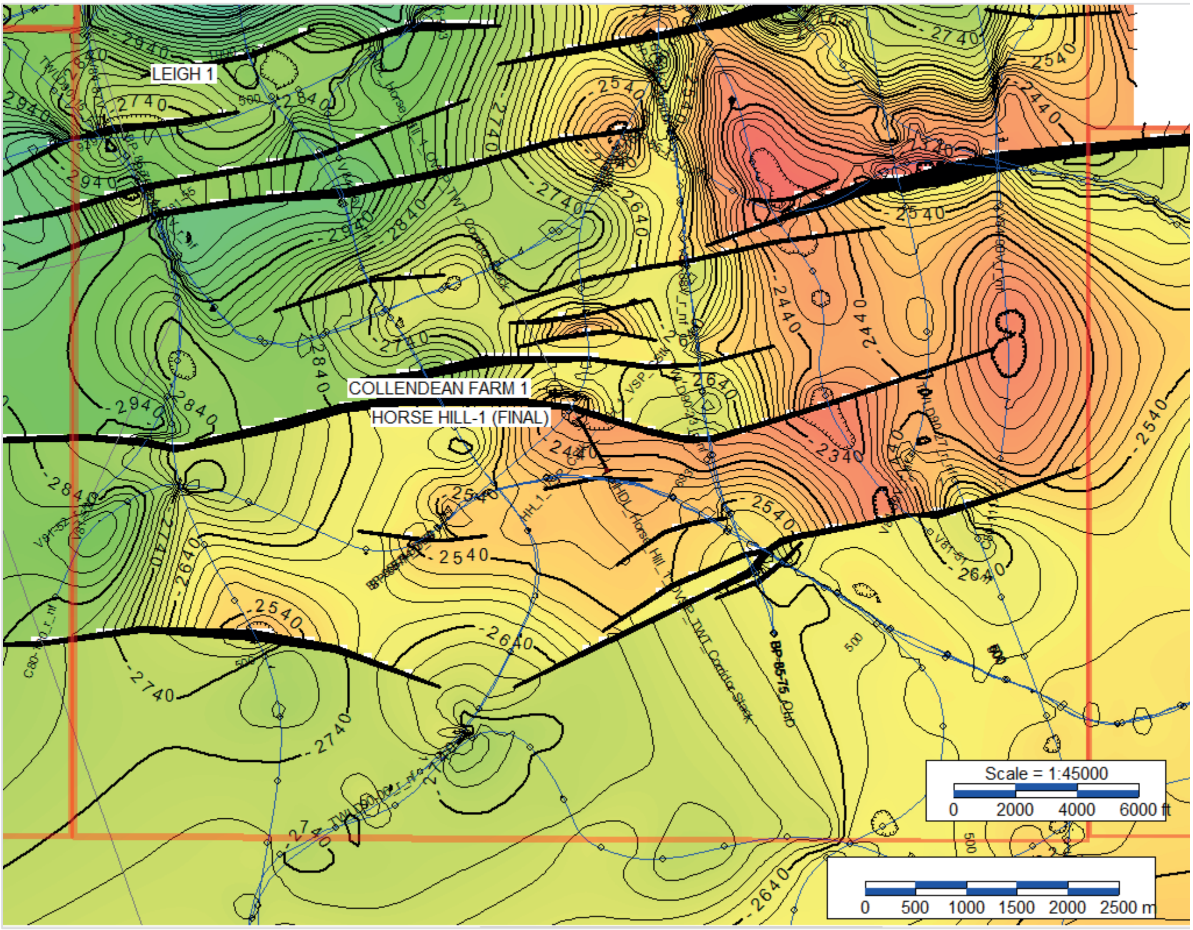


Figure 10.3 Top Kimmeridge Limestone 1 depth map, interpreted by UKOG

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.

10.2.2 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.

10.2.3 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.

11 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 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.

12 REFERENCES

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13 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	

14 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.

PART IV

SECTION A: ACCOUNTANT'S REPORT ON THE HISTORICAL FINANCIAL INFORMATION OF UKOG

UKOG's published financial information can be located on the Company's website under AIM Rule 26 at the following link: http://www.ukogplc.com/page.php?pID=82

The most recently published Annual Report and Accounts for the Year Ended 30 September 2017 is contained within the Appendix to this Document.

PART V

ADDITIONAL INFORMATION

1. RESPONSIBILITY

The Directors and the Proposed Director whose names appear on page 4 of this Document, and the Company, accept individual and collective responsibility for the information contained in this Document including individual and collective responsibility for compliance with the AIM Rules. To the best of the knowledge and belief of the Directors, the Proposed Director and the Company (who have taken all reasonable care to ensure that such is the case), the information contained in this Document is in accordance with the facts and does not omit anything likely to affect the import of such information.

2. INCORPORATION AND STATUS OF THE COMPANY

2.1 The Company was incorporated and registered in England and Wales under the Companies Act 1985 on 30 November 2004 with registered number 05299925 as a public company limited by shares with the name Pinco 2231 Plc. On 2 February 2005 the Company changed its name from Pinco 2231 to Sarantel Group Plc and on 4 December 2013 the Company changed its name from Sarantel Group Plc to UK Oil & Gas Investments Plc. The Company will change its name to UK Oil & Gas Plc with effect from Admission.

2.2 The principal legislation under which the Company operates and under which the Ordinary Shares are issued is the Companies Act and the regulations made under such legislation.

2.3 On 2 March 2005 the Company's Ordinary Shares were admitted to trading on AIM.

2.4 The registered office of the Company is at The Broadgate Tower, 8th Floor, 20 Primrose Street, London EC2A 2EW, United Kingdom.

2.5 The Company's telephone number is +44 (0) 1483 243 450.

2.6 The liability of the members of the Company is limited.

2.7 The address of the Company's website is www.ukogplc.com.

2.8 The ISIN number of the Ordinary Shares is GB00B9MRZS43.

3. THE GROUP

3.1 The Company has 6 wholly owned direct Subsidiaries and also holds a minority interest in one other company, details which are set out below:

Company name	Country of incorporation	Proportion of share capital held by the Company	Issued share capital
Kimmeridge Oil & Gas Limited	England and Wales	100%	7,552,554 ordinary shares of £1 each
Kimmeridge Energy Limited	England and Wales	100%	1 ordinary share of £1
UKOG (GB) Limited	England and Wales	100%	700,000 ordinary shares of £1 each
UKOG Weald Limited	England and Wales	100%	310,000 ordinary shares of £1 each
UKOG Solent Limited	England and Wales	100%	65,000 ordinary shares of £1 each
UK Oil & Gas Limited	England and Wales	100%	1 ordinary share of £1
Horse Hill Developments Ltd	England and Wales	49.9%	1,000 ordinary shares of £1 each

3.2 No third party has any rights over the unissued shares of any of the Subsidiaries.

4. SHARE CAPITAL OF THE COMPANY

4.1 On incorporation, the authorised share capital of the Company was divided into 50,000 ordinary shares of £1 each, 2 of which were issued credited as fully paid to the subscribers to the Company's Memorandum of Association.

4.2 The Company's entire issued share capital (then consisting of A ordinary and B ordinary Shares) were admitted to trading on AIM on 2 March 2005. By a resolution of the shareholders of the Company dated 25 November 2013 (1) the Articles were adopted; (2) each A ordinary Shares of 0.1 pence was divided into 1 A ordinary share of 0.001 pence and 99 deferred shares of 0.001 pence each and following such subdivision the A ordinary shares were consolidated on a 10 to basis; (3) and each B ordinary share was divided into 1 B ordinary share of 0.001 pence each 99 deferred shares of 0.001 pence each and following such sub-division the B ordinary shares were consolidated on a 10 to 1 basis. The B ordinary shares were re-designated as A ordinary shares following which all the A ordinary shares were re-designated into ordinary shares.

4.3 The following table shows the changes to the share capital of the Company that have taken place during the 3 years covered by the historical financial information:

Date of Issue/ Exercise	Description	No. of Shares allotted	Nominal value per share (£)	Subscription price paid per Share (£)	Total No. of Shares
08.10.2014	Allotment of Ordinary Shares	166,666,667	0.0001	0.12	1,589,730,116 Ordinary Shares 1,158,385,352,229 Deferred Shares
21.11.2014	Conversion of warrants	59,333,334	0.0001	0.0035	1,649,063,450 Ordinary Shares 1,158,385,352,229 Deferred Shares
23.12.2014	Allotment of Ordinary Shares	59	0.0001	0.0001	1,649,063,509 Ordinary Shares 1,158,385,352,229 Deferred Shares
12.03.2015	Allotment of Ordinary Shares	44,000,000	0.0001	0.008	1,693,063,509 Ordinary Shares 1,158,385,352,229 Deferred Shares
17.04.2015	Exercise of Warrants and Options	57,500,000	0.0001	0.004	1,750,563,509 Ordinary Shares 1,158,385,352,229 Deferred Shares
17.04.2015	Exercise of Warrants and Options	13,053,844	0.0001	0.0148	1,763,617,353 Ordinary Shares 1,158,385,352,229 Deferred Shares
15.06.2015	Allotment of Ordinary Shares	266,666,667	0.0001	0.0225	2,030,284,020 Ordinary Shares 1,158,385,352,229 Deferred Shares
01.03.2016	Exercise of options	10,666,666	0.0001	0.0225	2,040,950,686 Ordinary Shares 1,158,385,352,229 Deferred Shares
10.03.2016	Exercise of Warrants	2,500,000	0.0001	0.0225	2,043,450,686 Ordinary Shares 1,158,385,352,229 Deferred Shares

Date of Issue/ Exercise	Description	No. of Shares allotted	Nominal value per share (£)	Subscription price paid per Share (£)	Total No. of Shares
15.04.2016	Allotment of Ordinary Shares	43,886,116	0.0001	0.018229	2,087,336,802 Ordinary Shares 1,158,385,352,229 Deferred Shares
25.05.2016	Allotment of Ordinary Shares	266,666,667	0.0001	0.015	2,354,003,469 Ordinary Shares 1,158,385,352,229 Deferred Shares
11.08.2016	Allotment of Ordinary Shares	142,648,831	0.0001	0.0015773	2,496,652,300 Ordinary Shares 1,158,385,352,229 Deferred Shares
05.09.2016	Allotment of Ordinary Shares	50,981,799	0.0001	0.01667	2,547,634,099 Ordinary Shares 1,158,385,352,229 Deferred Shares
22.09.2016	Exercise of Options	30,000,000	0.0001	0.004	2,577,634,099 Ordinary Shares 1,158,385,352,229 Deferred Shares
07.12.2016	Exercise of options	20,000,000	0.0001	0.004	2,597,634,099 Ordinary Shares 1,158,385,352,229 Deferred Shares
24.05.2017	Allotment of Ordinary Shares	812,500,000	0.0001	0.008	3,410,134,099 Ordinary Shares 1,158,385,352,229 Deferred Shares
30.06.2017	Exercise of options	15,000,000	0.0001	0.004	3,425,134,099 Ordinary Shares 1,158,385,352,229 Deferred Shares
06.07.2017	Exercise of options	41,500,000	0.0001	0.004	3,466,634,099 Ordinary Shares 1,158,385,352,229 Deferred Shares
06.07.2017	Exercise of Warrants	13,500,001	0.0001	0.0255	3,480,134,100 Ordinary Shares 1,158,385,352,229 Deferred Shares
31.07.2017	Exercise of Warrants	40,625,000	0.0001	0.008	3,520,759,100 Ordinary Shares 1,158,385,352,229 Deferred Shares
30.08.2017	Allotment of Ordinary Shares	17,361,862	0.0001	0.0155	3,538,120,962 Ordinary Shares 1,158,385,352,229 Deferred Shares
11.09.2017	Exercise of options	2,000,000	0.0001	0.0115	3,540,120,962 Ordinary Shares 1,158,385,352,229 Deferred Shares

Date of Issue/ Exercise	Description	No. of Shares allotted	Nominal value per share (£)	Subscription price paid per Share (£)	Total No. of Shares
08.11.2017	Exercise of Options	8,000,000	0.0001	0.0115	3,548,120,962 Ordinary Shares 1,158,385,352,229 Deferred Shares
17.11.2017	Allotment of Ordinary Shares	12,229,633	0.0001	0.040884	3,560,350,595 Ordinary Shares 1,158,385,352,229 Deferred Shares
21.11.2017	Allotment of Ordinary Shares	13,308,137	0.0001	0.037571	3,573,658,732 Ordinary Shares 1,158,385,352,229 Deferred Shares
24.11.2017	Allotment of Ordinary Shares	14,159,092	0.0001	0.035313	3,587,817,824 Ordinary Shares 1,158,385,352,229 Deferred Shares
08.12.2017	Allotment of Ordinary Shares	9,382,271	0.0001	0.079938	3,597,200,095 Ordinary Shares 1,158,385,352,229 Deferred Shares
08.12.2017	Allotment of Ordinary Shares	16,753,225	0.0001	0.029845	3,613,953,320 Ordinary Shares 1,158,385,352,229 Deferred Shares
13.12.2017	Allotment of Ordinary Shares	16,753,225	0.0001	0.029845	3,630,706,545 Ordinary Shares 1,158,385,352,229 Deferred Shares
08.01.2018	Allotment of Ordinary Shares	18,581,144	0.0001	0.0269	3,649,287,689 Ordinary Shares 1,158,385,352,229 Deferred Shares
08.02.2018	Allotment of Ordinary Shares	18,779,343	0.0001	0.0266	3,668,067,032 Ordinary Shares 1,158,385,352,229 Deferred Shares
26.02.2018	Allotment of Ordinary Shares	18,754,689	0.0001	0.0133	3,686,821,721 Ordinary Shares 1,158,385,352,229 Deferred Shares
06.03.2018	Allotment of Ordinary Shares	16,831,617	0.0001	0.0149	3,703,653,338 Ordinary Shares 1,158,385,352,229 Deferred Shares
15.03.2018	Allotment of Ordinary Shares	17,603,154	0.0001	0.0142	3,721,256,492 Ordinary Shares 1,158,385,352,229 Deferred Shares
21.03.2018	Allotment of Ordinary Shares	20,650,917	0.0001	0.0121	3,741,907,409 Ordinary Shares 1,158,385,352,229 Deferred Shares

Date of Issue/ Exercise	Description	No. of Shares allotted	Nominal value per share (£)	Subscription price paid per Share (£)	Total No. of Shares
26.03.2018	Allotment of Ordinary Shares	24,297,794	0.0001	0.0103	3,766,205,203 Ordinary Shares 1,158,385,352,229 Deferred Shares
04.04.2018	Allotment of Ordinary Shares	24,297,794	0.0001	0.0103	3,790,502,997 Ordinary Shares 1,158,385,352,229 Deferred Shares
06.04.2018	Allotment of Ordinary Shares	21,981,887	0.0001	0.0114	3,812,484,884 Ordinary Shares 1,158,385,352,229 Deferred Shares
09.04.2018	Allotment of Ordinary Shares	21,981,887	0.0001	0.0114	3,834,466,771 Ordinary Shares 1,158,385,352,229 Deferred Shares
16.04.2018	Exercise of options	1,000,000	0.0001	0.004	3,835,466,771 Ordinary Shares 1,158,385,352,229 Deferred Shares
09.05.2018	Allotment of Ordinary Shares	18,701,376	0.0001	0.0134	3,854,168,147 Ordinary Shares 1,158,385,352,229 Deferred Shares
21.05.2018	Allotment of Ordinary Shares	19,658,725	0.0001	0.0127	3,873,826,872 Ordinary Shares 1,158,385,352,229 Deferred Shares
04.06.2018	Allotment of Ordinary Share	19,251,502	0.0001	0.0130	3,893,078,374 Ordinary Shares 1,158,385,352,229 Deferred Shares
14.06.2018	Allotment of Ordinary Shares	611,111,105	0.0001	0.009	4,504,189,479 Ordinary Shares 1,158,385,352,229 Deferred Shares
18.06.2018	Allotment of Ordinary Shares	53,384,583	0.0001	0.0094	4,557,574,062 Ordinary Shares 1,158,385,352,229 Deferred Shares
18.06.2018	Allotment of Ordinary Shares	26,692,291	0.0001	0.0094	4,584,266,353 Ordinary Shares 1,158,385,352,229 Deferred Shares
20/06/2018	Allotment of Ordinary Shares	52,865,299 Ordinary Shares	0.0001	0.0094	4,637,131,652 Ordinary Shares 1,158,385,352,229 Deferred Shares
27/06/2018	Allotment of Ordinary Shares	21,711,566	0.0001	0.0115	4,658,843,218 Ordinary Shares 1,158,385,352,229 Deferred Shares

Date of Issue/ Exercise	Description	No. of Shares allotted	Nominal value per share (£)	Subscription price paid per Share (£)	Total No. of Shares
28/06/2018	Allotment of Ordinary Shares	43,421,624 Ordinary Shares	0.0001	0.0115	4,702,264,842 Ordinary Shares 1,158,385,352,229 Deferred Shares
28/06/2018	Exercise of Warrants	3,000,000	0.0001	0.0115	4,705,264,842 Ordinary Shares 1,158,385,352,229 Deferred Shares
02/07/2018	Allotment of Ordinary Shares	151,975,684	0.0001	0.0115	4,857,240,526 Ordinary Shares 1,158,385,352,229 Deferred Shares
02/07/2018	Allotment of Ordinary Shares	250,000,000	0.0001	0.02	5,107,240,526 Ordinary Shares 1,158,385,352,229 Deferred Shares
04/07/2018	Allotment of Ordinary Shares	100,000,000	0.0001	0.02	5,207,240,526 Ordinary Shares 1,158,385,352,229 Deferred Shares

4.4 Each of the issued shares in the capital of the Company is fully paid.

4.5 The Company's issued share capital as at the date of this Document and as it is expected to be immediately following Admission is as set out below:

	At the date of this Document		Immediately Following Admission	
	Number	Aggregate Nominal Value (£)	Number	Aggregate Nominal Value (£)
Ordinary Shares	5,207,240,526	520,724.05	5,207,240,526	5,207,240,526
Deferred Shares	1,158,385,352,229	11,583,853.52229	1,158,385,352,229	11,583,853.52229

4.6 **Unissued shares in the Company**

4.6.1 As at the date of this Document, the Company has granted Options over a total number of 220,500,000 Shares, of which options over 115,000,000 Shares have been granted to the Directors. Details of the Directors' Options are set out at paragraph 7.2 of Part V of this Document.

4.6.2 In addition to the Options granted to the Directors (as set out at paragraph 4.6.1 above), senior management, consultants, key personnel and employees have been granted Options to subscribe for up to a total of 105,500,000 new Shares at prices ranging between 0.4p and 1.82 pence per Share, with vesting periods of between 3 and 7 years from the date of grant.

4.6.3 The Company has also granted a warrant over 30,555,555 new Shares to WH Ireland (or to such party as WH Ireland may direct), exercisable at a price of 0.9 pence per new Share for a period of 3 years following Admission.

4.6.4 Save as disclosed in this Document, no share or loan capital of the Company is proposed to be issued or is under option or is agreed conditionally or unconditionally to be under option.

5. ARTICLES OF ASSOCIATION

The Articles of Association of the Company include provisions to the following effect:

5.1 **Objects**

5.1.1 Section 31 of the Companies Act provides that the objects of a company are unrestricted unless any restrictions are set out in its Articles.

5.1.2 The Articles do not contain any restrictions on the objects of the Company.

5.2 **Share capital**

5.2.1 The Company has two classes of share, Ordinary Shares and Deferred Shares.

5.2.2 Subject to the Companies Act and subject to, and without prejudice to, any rights attached to any existing shares, any share in the Company may be issued with or have attached to it such rights or restrictions as to issuance as the Company may by ordinary resolution determine. Subject to the Companies Act, the Company may issue shares which are to be redeemed, or are liable to be redeemed, at the option of the Company or the holder of such redeemable shares and on such terms and in such manner as may be determined by ordinary resolution.

5.3 **Voting**

5.3.1 Subject to any special terms as to voting or to which any shares may have been issued or, no shares having been issued subject to any special terms, on a show of hands every Ordinary Shareholder who being an individual is present in person or, being a corporation is present by a duly authorised representative, has one vote, and on a poll every Ordinary Shareholder has one vote for every share of which he is the holder.

5.3.2 Unless the Directors determine otherwise, an Ordinary Shareholder of the Company is not entitled in respect of any shares held by him to vote at any general meeting of the Company if any amounts payable by him in respect of those shares have not been paid or if the member has a holding of at least 0.25% of any class of shares of the Company and has failed to comply with a notice under section 793 of the Companies Act.

5.3.3 The Deferred Shares shall not entitle the holders thereof to receive notice of or to attend of vote at any general meeting of the Company.

5.4 **Dividends**

5.4.1 In priority to any dividend or distribution which the Company determines to distribute and subject to the Company having profits available for distribution (within the meaning of Part 23 of the Act), the Company shall first distribute to the Deferred Shareholders £1 in aggregate (which shall be deemed satisfied by payment to any one holder of Deferred Shares) and the Deferred Shares shall not entitle the holders thereof to receive any further dividend or other distribution.

5.4.2 Subject to the provisions of the Companies Act and to any special rights attaching to any shares, following the payment of £1 in aggregate to the Deferred Shareholders, the Ordinary Shareholders are to distribute amongst themselves the profits of the Company according to the amounts paid up on the Ordinary Shareholders held by them, provided that no dividend will be declared in excess of the amount recommended by the Directors. Interim dividends may be paid if profits are available for distribution and if the Directors so resolve. The Directors may, with the sanction of an ordinary resolution of the Company, offer the holders of shares the right to elect to receive shares, credited as fully paid, instead of cash in respect of any dividend which the Company determines to distribute and subject to the Company having profits available for distribution (within the meaning of Part 23 of the Act.

5.5 **Return of capital (including on redemption and purchase)**

5.5.1 In priority to any return on capital, the Company shall first pay to the Deferred Shareholders £1 in aggregate (which shall be deemed satisfied by payment to any one holder of Deferred Shares) and the Deferred Shares shall not entitle the holders thereof to receive any further dividend or other distribution.

5.5.2 On a winding-up of the Company, the balance of the assets available for distribution will, subject to any sanction required by the Companies Act, be divided amongst the Ordinary Shareholders.

5.6 **Share transfers**

5.6.1 The instrument of transfer of a certificated share may be in any usual form or in any other form approved by the Board and shall be signed by or on behalf of the transferor and, unless the share is fully paid, by or on behalf of the transferee.

5.6.2 A member may transfer all or any of his uncertificated shares in accordance with the CREST Regulations, provided that legal title to such shares shall not pass until the transfer is entered in the register.

5.6.3 The Articles contain no restrictions on the free transferability of fully paid ordinary shares provided that the transfers are in favour of not more than four transferees, the transfers are in respect of only one class of share and the provisions in the Articles, if any, relating to registration of transfers have been complied with.

5.7 **Changes in share capital**

5.7.1 Subject to the provisions of the Companies Act any share may be issued with such rights or restrictions as the Company may by ordinary resolution determine, or in the absence of such determination, or so far as any such resolution does not make specific provision, as the Board may determine.

5.7.2 Subject to, and in accordance with the provisions of the Companies Act, and to any rights for the time being attached to any shares, the Company may purchase its own shares (including any redeemable shares), provided that the Company shall not purchase any of its shares unless such purchase has been sanctioned by an resolution passed at a separate meeting of the holders of any class of shares convertible into equity share capital of the Company.

5.8 **Pre-emption rights**

5.8.1 There are no rights of pre-emption under the Articles in respect of transfers of issued ordinary shares.

5.8.2 In certain circumstances, the Company's shareholders have statutory pre-emption rights under the Companies Act in respect of the allotment of new shares in capital of the Company. These statutory pre-emption rights require the Company to offer new shares for allotment by existing shareholders on a pro rata basis before allotment to other persons.

5.9 **Variation of class rights**

5.9.1 With regards to the Deferred Shares, any resolution for a reduction of capital involving the cancellation of the Deferred Shares without any repayment of capital in respect thereof, or a reduction of share premium account, or the obtaining by the Company or the making by the court of an order confirming any such reduction of capital or share premium account or the making effective of such order, nor the purchase by the Company in accordance with the provisions of the Companies Act of any of its own shares or securities or the passing of a resolution to permit any such purchase, shall constitute a variation or abrogation of the rights attaching to the Deferred Shares and as regards further issues, the rights conferred by the Deferred Shares shall not be varied or abrogated by the creation or issue of further shares ranking *pari passu* with or in priority to the Deferred Shares.

5.9.2 Subject to the provisions of the Companies Act and to any rights attached to existing shares (and except in the case where there is only one holder of the issued shares of a class of shares, in which case any and all rights attached to an existing class of shares may be varied only with the consent in writing of that holder), all or any of the rights attached to any class of shares may be varied either with the written consent of the holders of not less than 75% in number of the issued shares of that class or with the sanction of a special resolution passed at a separate general meeting of the holders of the issued shares of that class.

5.10 **Company name**

The name of the Company may be changed by a resolution of the board of Directors.

5.11 **General Meetings**

5.11.1 Annual general meetings are called on 21 days' notice in writing, exclusive of the day of which it is served or deemed to be served and of the day on which the meeting is to be held, and is to be given to all members on the register at the close of business on a day determined by the Company, such day being not more than 21 days before the day that the notice of meeting is sent.

5.11.2 An annual general meeting may be called on shorter notice providing all members entitled to attend and vote thereat agree. The Company must specify in the notice of meeting a time, not more than 48 hours before the time fixed for the meeting, by which a person must be entered into the register in order to have the right to attend or vote at the meeting. Notice of a general meeting may be validly given when sent in electronic form or made available on the Company's website.

5.11.3 All other general meetings may be called whenever the Directors think fit or when a meeting has been requisitioned in accordance with the Companies Act. General meetings are called on 14 days' notice in writing exclusive of the day on which it is served or deemed to be served and the day on which it is to be held. A general meeting can be called on shorter notice if a majority in number of the members having a right to attend and vote at the general meeting, being a majority together holding not less than 95% in nominal value of the shares giving that right, consent. Two members present in person or by proxy and entitled to vote shall be a quorum for all purposes.

5.11.4 Shareholders need not attend a meeting of the Company in person but can do so by way of a validly appointed proxy. Proxies are appointed in accordance with the Articles. In order to be validly appointed, details of the proxy must be lodged with the Company no later than 48 hours before the commencement of the relevant meeting (although a later time may be specified by notice of the meeting) or in the case of a poll which is not taken at or on the same day as the meeting, not less than 24 hours prior to the taking of the poll. Failure to lodge details of the appointed proxy in accordance with Articles will result in the proxy not being treated as valid.

5.12 **Disclosure notice**

5.12.1 The Company may by notice in writing require a person whom the Company knows or has reasonable cause to believe to be (either currently or at any point in the preceeding 3 years) interested in shares comprised in the Company's relevant share capital:

5.12.1.1 to confirm that fact or (as the case may be) to indicate whether or not it is the case; and

5.12.1.2 where he holds or has during that time held an interest in shares so comprised, to give such further information as may be required in the notice.

5.13 **Unclaimed dividends**

Any dividend unclaimed after a period of 12 years from the date of its declaration will be forfeited and will revert to the Company.

5.14 **Untraced Shareholders**

The Company may sell any share if, during a period of 12 years, at least three dividends in respect of such shares have been paid, no cheque or warrant in respect of any such dividend has been cashed and no communication has been received by the Company from the relevant member. The Company must advertise its intention to sell any such share in both a national daily newspaper and in a newspaper circulating in the area of the last known address to which cheques or warrants were sent. Notice of the intention to sell must also be given to the London Stock Exchange.

5.15 **Directors**

5.15.1 Unless otherwise determined by ordinary resolution of the Company, the number of Directors shall not be subject to any maximum, but shall not be less than two.

5.15.2 Subject to the Articles of Association and any special resolution of the shareholders of the Company, the Directors shall be entitled to exercise all the powers of the Company and may make such arrangements as the board thinks fit for the management and transaction of the Company's affairs.

5.15.3 The quorum for a meeting of the board of Directors shall unless otherwise so fixed, be two.

5.15.4 No shareholding qualification is required by a Director.

5.15.5 The Directors are entitled to remuneration at the rate decided by them, subject to an aggregate limit of £150,000 per annum or such additional sums as the Company may by ordinary resolution determine. If a Director serves on any committee of the Board or performs any special services or goes abroad on the Company's behalf, he may be paid such extra remuneration by way of salary, percentage of profits or otherwise as the board may determine. The Directors are also entitled to be repaid all travelling, hotel and other expenses incurred by them in connection with the business of the Company.

5.15.6 Each Director must retire from office at the third general meeting or annual general meeting at which he was appointed or last reappointed unless they were appointed by the other Directors since the last general meeting in which case such Director shall be required to retire at the first annual general meeting after they were appointed. A retiring Director is eligible for reappointment.

5.15.7 The Company may by special resolution remove any Director before the expiration of his period of office. Furthermore, the office of Director shall be vacated if the Director in question:

5.15.7.1 becomes bankrupt, or makes any arrangement or composition with his creditors generally;

5.15.7.2 he becomes incapable by reason of physical incapacity or mental disorder of discharging his duties as Director and the board resolves that his office be vacated;

5.15.7.3 he ceases to be a Director by virtue of any provisions of the Companies Act, is removed from office or becomes prohibited by law from being a Director;

5.15.7.4 he resigns from office by notice to the Company; or

5.15.7.5 he is removed from office by notice in writing signed by all the other Directors.

5.15.8 The Directors may from time to time appoint one or more of their body to be the holder of an executive office on such terms as they think fit. The emoluments and benefits of any executive Director shall be determined by the Board and may be of any description.

5.15.9 Questions arising at a meeting of the Directors shall be decided by a majority of votes. In the case of an equality of votes, the chairman of the meeting shall have a second or casting vote.

5.15.10 Except as provided in paragraph 5.15.11 below, a Director may not vote or be counted in the quorum present on any motion in regard to any contract, transaction, arrangement or any other proposal in which he has any material interest, which includes the interest of any person connected with him, otherwise than by virtue of his interests in shares or debentures or other securities of or otherwise in or through the Company. Subject to the Companies Act, the Company may by ordinary resolution suspend or relax this provision to any extent or ratify any transaction not duly authorised by reason of a contravention of it.

5.15.11 In the absence of some other material interest than is indicated below, a Director is entitled to vote and be counted in the quorum in respect of any resolution concerning any of the following matters:

5.15.11.1 the giving of any security, guarantee or indemnity to him in respect of money lent or obligations incurred by him or by any other person at the request of or for the benefit of the Company or any of its Subsidiaries;

5.15.11.2 the giving of any security, guarantee or indemnity to a third party in respect of a debt or obligation of the Company or any of its Subsidiaries for which he himself has assumed responsibility in whole or in part under a guarantee or indemnity or by the giving of security;

5.15.11.3 any proposal concerning an offer of shares or debentures or other securities of or by the Company or any of its Subsidiaries for subscription or purchase in which offer he is or is to be interested as a participant in its underwriting or sub-underwriting;

5.15.11.4 any contract, arrangement, transaction or other proposal concerning any other company in which he is interested, as defined in the Companies Act, provided that he is not the holder of or beneficially interested in 1% or more of any class of the equity share capital of such company, or of a third company through which his interest is derived, or of the voting rights available to members of the relevant company;

5.15.11.5 any arrangement in whole or in part for the benefit of the employees of the Company or any subsidiary undertakings which does not award him as such any privilege or advantage not generally awarded to the employees to whom such arrangement related; and

5.15.11.6 any contract, arrangement, transaction or proposal concerning insurance which the Company proposed to maintain or purchase for the benefit of Directors or for the benefit or persons including the Directors.

5.15.12 If any question arises at any meeting as to the materiality of a Director's interest or as to the entitlement of any Director to vote and such question is not resolved by his voluntarily agreeing to abstain from voting, such question must be referred to the chairman of the meeting and his ruling in relation to any other Director will be final and conclusive except in a case where the nature or extent of the interest of such Director has not been fully disclosed.

5.15.13 The Directors may provide or pay pensions, annuities, gratuities and superannuation or other allowances or benefits to any Director, ex-director, employee or ex-employee of the Company or any of its Subsidiaries or to the spouse, civil partner, children and dependants of any such Director, ex-director, employee or ex-employee.

5.16 Borrowing powers

The Directors shall restrict the borrowing of the Group, without the previous sanction of an ordinary resolution of the Company, to a sum equal to three times the share capital and reserves of the Group as adjusted to take into account any variation in the paid up share capital or any premium account or reserves thereof and any other matter which the Directors or the auditors consider relevant.

5.17 Communications by the Company

The Company may give any notice in writing, document or other communication to a member:

5.17.1 personally;

5.17.2 by sending it by post, in a prepaid envelope addressed to the member at his address in the Register;

5.17.3 by leaving it at that address;

5.17.4 by sending it in electronic form to such address (if any) as may for the time being be notified to the Company by or on behalf of the member for that purpose; or

5.17.5 by publishing it on a web site and notifying members, in accordance with the Companies Act, in such manner as the members may agree from time to time.

6. MANDATORY BIDS, SQUEEZE-OUT AND SELL-OUT RULES RELATING TO THE ORDINARY SHARES

Other than as provided under the Companies Act (as set out below) and the City Code there are no rules or provisions relating to mandatory takeover bids in relation to the Ordinary Shares and no rules or provisions relating to squeeze-out and/or sell-out rules relating to the Ordinary Shares.

6.1 Mandatory bids

The City Code applies to the Company. Under the City Code, if an acquisition of Ordinary Shares were to increase the aggregate holding of the acquirer and its concert parties to shares carrying 30% or more of the voting rights in the Company, the acquiror and, depending on the circumstances, its concert parties, would be required (except with the consent of the Panel on Takeovers and Mergers) to make a cash offer for the outstanding shares in the Company at a price not less than the highest price paid for the Ordinary Shares by the acquiror or its concert parties during the previous 12 months. This requirement would also be triggered by any acquisition of shares by a person holding (together with its concert parties) shares carrying between 30% and 50% of the voting rights in the Company if the effect of such acquisition were to increase that person's percentage of the voting rights.

6.2 Squeeze-out

Under section 979 of the Companies Act, if a person who has made a general offer to acquire shares in the Company were to acquire, by virtue of acceptances of the offer, 90% or more of the Ordinary Shares to which the offer relates then (within certain time periods prescribed in the Companies Act), it could compulsorily acquire the remaining 10%. It would do so by sending a notice to outstanding shareholders telling them that it will compulsorily acquire ordinary shares and then, 6 weeks later, executing a transfer of the outstanding ordinary shares in its favour and paying the consideration to the Company, which would hold the consideration on trust for outstanding shareholders. The consideration offered to the shareholders whose ordinary shares are compulsorily acquired under the Companies Act must, in general, be the same as the consideration that was available under the takeover offer.

6.3 Sell-out

Section 983 of the Companies Act gives minority shareholders a right to be bought out in certain circumstances by a person who has made a general offer as described in the paragraph immediately above this paragraph. If, at any time before the end of the period within which the offer can be accepted, the offeror holds, or has agreed to acquire not less than 90% of the Ordinary Shares, any holder of Ordinary Shares to which the offer relates who has not accepted the offer can, by a written communication to the offeror, require it to acquire those Ordinary Shares. The offeror is required to give each shareholder notice of this right to be bought out within 1 month of that right arising. The offeror may impose a time limit on the rights of minority shareholders to be brought out, but that period cannot end less than 3 months after the end of the acceptance period. If a shareholder exercises his rights, the offeror is entitled and bound to acquire those Ordinary Shares on the terms of the offer or on such other terms as may be agreed.

7. DIRECTORS' AND OTHER INTERESTS

7.1 The interests of the Directors and the Proposed Directors (all of which are beneficial) in the issued share capital of the Company as at the date of this Document, such interests being those which are required to be notified by each Director and Proposed Director to the Company or which are required to be entered in the register of interests required to be maintained pursuant to section 809 of the Companies Act or which are interests of persons connected with the Director or Proposed Director within the meaning of section 252 of the Companies Act, the existence of which is known or which could, with reasonable diligence, be ascertained by a Director or the Proposed Director are:

	Current	
Director	**Number of Ordinary Shares**	**% of Existing Share Capital**
Kiran Morzaria	4,508,178	0.1
Allen Howard II	–	–
Stephen Sanderson	–	–
Nicholas Mardon-Taylor	–	–

7.2 Following Admission, the following Directors and the Proposed Director will hold options over the following number of Ordinary Shares:

Optionholder	**Grant Date**	**Vesting Date**	**Expiry Date**	**Exercise Price (pence)**	**Number of Options**
Stephen Sanderson	21 January 2015	21 January 2015	31 December 2019	0.4	25,000,000
Stephen Sanderson	26 September 2016	26 September 2016	26 September 2019	1.82	35,000,000
Stephen Sanderson	25 May 2017	25 May 2017	24 May 2022	1.15	25,000,000
Kiran Morzaria	25 May 2017	25 May 2017	24 May 2022	1.15	20,000,000
Allen Howard	25 May 2015	25 May 2015	24 May 2022	1.15	10,000,000
Nicholas Mardon-Taylor	–	–	–	–	–
TOTAL					**115,000,000**

Other than as set out in this paragraph 7.2 of this Part V, at Admission there will be no options and/or warrants over Ordinary Shares held by the Directors.

7.3 Including the arrangements described in paragraph 7.2 above, options over 105,500,000 Ordinary Shares are held by employees which are exercisable.

7.4 In respect of each Director and the Proposed Director, there are no conflicts of interest between any duties they have to the Company and the private interests and/or other duties they may also have.

7.5 There are no outstanding loans granted by any member of the Group to the Directors or the Proposed Director or any guarantees provided by any member of the Group for the benefit of the Directors or the Proposed Director.

7.6 No Director, or the Proposed Director, has or has had any interest in any transaction which is or was unusual in its nature or conditions or which is or was significant to the business of the Group and which was effected by the Group during the current or immediately preceding financial year, or which was effected during an earlier financial year and remains in any respect outstanding or unperformed.

8. SUBSTANTIAL SHAREHOLDERS

8.1 Insofar as is known to the Company and in addition to the interests of the Directors and the Proposed Director disclosed in paragraph 7 above, the following persons are, at the date of this Document, and are expected, following Admission, to be interested directly or indirectly in 3% or more of the Enlarged Share Capital:

Shareholder	% Shareholding
Hargreaves Lansdown (Nominees) Limited	11.83%
Interactive Investor Services Nominees Limited	9.55%
Barclays Direct Investing Nominees Limited	8.64%
Hargreaves Lansdown (Nominees) Limited	7.14%
Interactive Investor Services Nominees Limited	6.71%
Hargreaves Lansdown (Nominees) Limited	6.09%
HSDL Nominees Limited	5.70%
HSDL Nominees Limited	5.69%
HSBC Client Holdings Nominee (UK) Limited	4.08%

None of the Company's major holders of Ordinary Shares listed above has voting rights different from the other holders of Ordinary Shares.

8.2 Save as disclosed in paragraph 8.1 above and in this paragraph 8.2, and insofar as the Company has the information, the Directors and the Proposed Director are not aware of any person or persons who either alone or, if connected jointly following the implementation of Admission, is or will be interested (within the meaning of the Companies Act) directly or indirectly in 3% or more of the issued Ordinary Share capital of the Company.

8.3 Save as disclosed in paragraph 8.1 above and in this paragraph 8.3, and insofar as the Company has the information, the Directors and the Proposed Director are not aware of any person or persons who either alone or, if connected jointly following the implementation of Admission, will (directly or indirectly) exercise or could exercise control over the Company.

9. ADDITIONAL INFORMATION ON THE DIRECTORS AND THE PROPOSED DIRECTOR

9.1 Other than directorships of Group companies, the Directors and the Proposed Director have held the following directorships or been partners in the following partnerships within the 5 years prior to the date of this Document:

Director	Current	Past
Kiran Caldas Morzaria	Academy Minerals Limited Built Intelligence Limited Cadence Minerals PLC European Metals Holding Limited Rare Earth Resources Limited REM Mexico Limited Tobin Bronze PLC HD Shelf Three plc	API Technology (UK) Limited Bacanora Minerals Limited Courthope Limited Panguma Diamond Ltd Green Park Finance PLC Horse Hill Developments Ltd Tubutama Limited Tubutama Borax Plc HD Shelf Two Limited Immersion Technology International Limited Immersion Technology Property Limited Immersion Technologies UK Limited Kimell Consulting Limited Kirst Services Limited Lonrho Limited Our Forgotten Children Limited River Diamonds UK Limited Solo Oil PLC Solo Oil (Argentina) Limited The World's Children Limited Travelwelcome Limited Zinnwald Lithium Limited Vatukoula Gold Mines PLC Vatukoula Australia Pty Limited

Director	Current	Past
Kiran Caldas Morzaria *(continued)*		Vatukoula Finance Pty Limited Vatukoula Gold Mines Limited Viso Gero International Inc
Allen Dee Howard II	None	None
Stephen Paul Sanderson	Horse Hill Developments Ltd UK Onshore Oil & Gas Limited	
Nicholas John Mardon-Taylor	None	Hurricane Energy plc Hurricane Petroleum Limited Hurricane Group Limited Hurricane Basement Limited Hurricane Exploration (UK) Limited Gold Island Limited

9.2 Mr Mardon-Taylor was a director of the following companies which were put into members voluntary liquidation: Bloomsbury Realisations (No.1) Limited, Bloomsbury Realisations (No. 2) Limited, C A Good & Co (Minerals) Limited, CA Good & Co, Catchstream Limited, Iridian Holdings Limited, JSG Nominees (No.2) Limited, JSG Nominees Limited, Habersen Ltd, S G Investment Management Limited and Soderan (UK) Limited. All of such companies were solvent at the time of liquidation.

In addition, Mr Mardon Taylor was a director of Petresearch International PLC ("Petresearch") and Whitehall Energy Limited ("Whitehall"). Such directorships were not held by Mr Mardon Taylor within a period of 5 years prior to the Last Practicable Date. Petresearch acquired Whitehall in March 1990 as part of a combined flotation and fundraising transaction proposed to take place in 1990. However, the fundraising failed and both companies became insolvent. Mr Mardon Taylor had been appointed on 9 March 1990 to the board of Petresearch in support of the fundraising. Petresearch was dissolved on 16 July 1994. Mr Mardon Taylor was appointed as a director of Whitehall on 27 April 1989. Whitehall was dissolved on 25 January 1994.

Mr Morzaria was a director of the following companies which were either put into members' voluntary liquidation or struck off from the register of Companies: API Technology (UK) Limited, Solo Oil (Argentina) Limited, Tubutama Borax Plc and Tubutama Limited. Arlington Resource Plc, of which Mr Morzaria was a director, was dissolved on December 2007 following a voluntary members' liquidation.

9.3 Save as disclosed in this Document, none of the Directors or the Proposed Director has:

9.3.1 any unspent convictions in relation to indictable offences;

9.3.2 had any bankruptcy order made against him or entered into any voluntary arrangements;

9.3.3 been a director of a company which has been placed in receivership, compulsory liquidation, administration, been subject to a voluntary arrangement or any composition or arrangement with its creditors generally or any class of its creditors, whilst he was a director of that company or within the 12 months after he had ceased to be a director of that company;

9.3.4 been a partner in any partnership which has been placed in compulsory liquidation, administration or been the subject of a partnership voluntary arrangement, whilst he was a partner in that partnership or within the 12 months after he ceased to be a partner in that partnership;

9.3.5 been the owner of any asset which has been placed in receivership or a partner in any partnership which has been placed in receivership whilst he was a partner in that partnership or within the 12 months after he ceased to be a partner in that partnership;

9.3.6 been officially publicly criticised incriminated or sanctioned by any statutory or regulatory authorities (including designated professional bodies); or

9.3.7 been disqualified by a court from acting as a member of the administrative, management or supervisory bodies of any company or from acting in the management or conduct of the affairs of a company in the 5 years preceding the date of this Document.

9.4 Save as disclosed in this Document, no Director or the Proposed Director has any interest, whether direct or indirect, in any transaction which is or was unusual in its nature or conditions or significant to the business of the Company taken as a whole and which was effected by the Company during the current or immediately preceding financial year, or during any earlier financial year and which remains in any respect outstanding or unperformed.

10. DIRECTORS' REMUNERATION AND SERVICE AGREEMENTS

10.1 A summary of the Directors' and the Proposed Director's service contracts and/or non-executive letters of appointment are as follows, as at Admission:

Directors	Commencement Date	Notice period from the Company (months)	Notice period to the Company (months)	Remuneration (£)	Benefits (£)	Bonus (£)	Pensions (£)
Stephen Sanderson	8 July 2015	6	6	310,000	N/A	N/A	Auto-enrolment scheme
Kiran Morzaria	23 October 2015	6	6	100,000	N/A	N/A	Auto-enrolment scheme
Allen Howard	1 March 2017	3	3	60,000	N/A	N/A	N/A
Nicholas Mardon-Taylor	Date of Admission	3	3	55,000	N/A	N/A	N/A

10.2 On 31 July 2018 the Company and Mr. Sanderson will enter into a service agreement pursuant to which Mr. Sanderson will continue as chief executive officer of the Company. Mr. Sanderson's employment commenced on 8 July 2015 and continues indefinitely unless and until terminated by either party giving the other not less than 6 months' written notice. As at the date of this Document, Mr. Sanderson is paid a salary at the rate of £310,000. As part of the terms of employment, Mr. Sanderson has also signed up to standard confidentiality and inventions provisions. The agreement also contains a number of standard restrictive covenants pursuant to which Mr Sanderson undertakes not to (without the written consent of the Board) compete with the Company.

10.3 On 31 July 2018 the Company and Mr. Morzaria will enter into a service agreement pursuant to which Mr. Morzaria will continue as finance director of the Company. Mr. Morzaria employment commenced on 23 October 2015 and continues indefinitely unless and until terminated by either party giving the other not less than 6 months' written notice. As at the date of this Document, Mr. Morzaria is paid a salary at the rate of £100,000. As part of the terms of employment, Mr. Morzaria has also signed up to standard confidentiality and inventions provisions. The agreement also contains a number of standard restrictive covenants pursuant to which Mr Morzaria undertakes not to (without the written consent of the Board) compete with the Company.

10.4 On 31 July 2018 the Company and Mr. Howard will enter into a letter of appointment pursuant to which Mr. Howard will continue as a non-executive director of the Company. Mr Howard's director's appointment commenced in March 2017 and continues unless terminated by either party giving the other at least 3 months' written notice. Mr. Howard is required to retire and seek re-election by the shareholders at the next annual general meeting of the Company and any subsequent annual general meeting. Mr Howard is paid fees of £60,000 in connection with his appointment and also in connection with his: (i) acting as chairman of the Company; (ii) sitting on the Company's audit committee; and (iii) sitting on the Company's remuneration committee.

10.5 On 31 July 2018 the Company and Mr. Mardon-Taylor will enter into a letter of appointment pursuant to which Mr. Mardon-Taylor will be appointed as a non-executive director of the Company on Admission. Mr Mardon-Taylor's appointment shall continue unless terminated by either party giving the other at least 3 months' written notice. Mr. Mardon-Taylor is required to retire and seek re-election by the shareholders at the next annual general meeting of the Company and any subsequent annual general meeting. Mr Mardon-Taylor is to be paid fees of

£55,000 in connection with his appointment and also in connection with his: (i) sitting on the Company's audit committee; and (iii) sitting on the Company's remuneration committee.

10.6 The Directors and the Proposed Director receive no Ordinary Shares or options over Ordinary Shares in lieu of remuneration or as any form of compensation. The share option grants disclosed in paragraph 7.2 of this Part V are made in addition to the remuneration packages disclosed above and many of them are conditional on the achievement of predetermined performance criteria.

10.7 The Company has established an auto-enrolment pension scheme through the National Employment Savings Trust. The Company makes a contribution equal to 2% of a qualifying employee's earnings (including the Directors). The minimum contribution payable by the Company will increase to 3% on or before April 2019.

10.8 There is no arrangement under which any Director or the Proposed Director has waived or agreed to waive future emoluments.

10.9 Save as disclosed in this paragraph 10 there are no existing or proposed service or consultancy agreements between any Director or the Proposed Director and any member of the Group.

10.10 In the year ended 30 September 2017 the total aggregate remuneration paid, and benefits-in-kind granted inclusive of share based payments, to the Directors was £670,000. The amounts payable to the Directors and the Proposed Director by the Company under the arrangements in force at the date of this Document in respect of the year ending 30 September 2018 are estimated to be £525,000 (excluding any discretionary payments which may be made under these arrangements).

10.11 Save as set out in this Document, no Director or the Proposed Director is currently party to an agreement with the Company and no member of any administrative, management or supervisory body of the Company has any service contracts with any Group company providing for benefits upon termination of employment.

11. EMPLOYEES

11.1 As at the date of this Document, the Group employed a total of 6 members of staff. The average number of persons employed by the Group in the financial period ended 30 September 2017 was 4.

11.2 The breakdown of persons employed by main category of activity was as follows:

2 Management, 1 Technical Services, 2 Finance and 1 Logistic Operations Support.

12. MATERIAL CONTRACTS

The following contracts: (i) (not being contracts entered into in the ordinary course of business), having been entered into by the Company or any member of the Group within the period of 2 years immediately preceding the date of this Document or which contain any provision under which any member of the Group has any obligation or entitlement which is, or may be, material to the Group at the date of this Document; or (ii) are subsisting agreements which are included within or which relate to the oil assets and liabilities of the Group (notwithstanding whether such agreements are within the ordinary course or were entered into outside of the 2 years immediately preceding the publication of this Document) and are, or may be material:

12.1 **Documents Relating to Admission**

12.1.1 ***Letter of Engagement between WH Ireland and the Company***

An engagement letter dated 31 January 2018 was signed by the Company with WH Ireland under which WH Ireland agreed to act as the Company's financial adviser in connection with the Admission and the Company's nominated adviser for purposes of the AIM Rules. In consideration for providing the services specified in the engagement letter, the Company agreed to pay WH Ireland a fee of £125,000 (plus any applicable VAT and disbursements).

12.1.2 ***Nominated Advisor Agreement between WH Ireland and the Company***

A nominated adviser agreement dated 19 November 2014 was entered into by the Company and WH Ireland under which WH Ireland agreed to act as nominated adviser to the Company for the purposes of the AIM Rules. The agreement can be terminated by either party giving 3 months' notice in writing to the other party. Pursuant to the agreement, as amended, the Company has agreed to pay to WH Ireland, an annual fee of £50,000 (excluding VAT). The agreement is governed by English law.

12.1.3 ***Introduction Agreement dated between WH Ireland and the Company***

An introduction agreement dated 13 July 2018 was entered into by the Company, the Directors and WH Ireland which provides for the responsibilities of the parties in respect of Admission. The Company has agreed to pay WH Ireland a fee of £125,000. In addition, the Company is required to pay all costs, charges and expenses reasonably agreed in respect of Admission (including WH Ireland's solicitors' fees). The agreement sets out warranties the Company and the Directors have given and will continue to give (until the time of Admission and with effect thereafter) to WH Ireland.

12.2 **Material Contracts relating to the Horse Hill Licences**

12.2.1 ***Petroleum Exploration and Development Licence 137 ("PEDL137")***

On 1 October 2004 PEDL137 was made between the OGA and Magellan. HHDL has since acquired a 65% participating interest in PEDL246 from Magellan. This licence incorporates the Model Clauses. PEDL137 had an initial term of 10 years from 1 October 2004 (up until 30 September 2014). PEDL137 was then renewed for a second term of 2 years from 20 September 2014 to 30 September 2016. On 30 September 2016 PEDL137 was renewed for a further 19 year production period which therefore provides for an anticipated expiration date of 30 September 2035. Where PEDL137 has continued in force for the period of the production period (up until 30 September 2035), the Minister, on application being made to him in writing by the licensees, may agree that this can be extended for such further period as the Minister may agree in order to secure the maximum economic recovery of petroleum from the licenced area.

12.2.2 ***Petroleum Exploration and Development Licence 246 ("PEDL246")***

On 1 July 2008 PEDL246 was made between the OGA and Magellan. HHDL has since acquired a 65% participating interest in PEDL246 from Magellan. This licence incorporates the Model Clauses. PEDL246 had an initial term of 8 years from 1 July 2008. PEDL246 was then renewed for a second term for a period of 3 years from 30 June 2016. The next renewal date will therefore be 30 June 2019 whereby the licensees may then apply for a further 20 year production period which would then provide for an anticipated expiration date of 30 June 2039. The Company intends to make this application upon expiry of the second term. Where PEDL246 has continued in force for the period of the production period (up until 30 September 2039), the Minister, on application being made to him in writing by the licensees, may agree that this can be extended for such further period as the Minister may agree in order to secure the maximum economic recovery of petroleum from the licenced area.

12.2.3 ***Binding term sheet between the Company and HHDL dated 19 December 2013***

On 19 December 2013, the Company and HHDL entered into a binding term sheet (the "First BTS"), pursuant to which the Company agreed to subscribe for a 7.5% shareholding in HHDL. It was agreed that the parties would enter into a formal investment agreement to reflect the terms of the First BTS. At the date of the First BTS, HHDL had entered into the Magellan Agreement, pursuant to which HHDL would farm in to a 65% participating interest in PEDL137.

The consideration payable by the Company for the 7.5% shareholding in HHDL was as follows:

(a) £10,000 payable within 7 days of the First BTS;

(b) £50,000 payable immediately on finalisation of a formal agreement setting out the rights and obligations of the parties under the First BTS which amount is to be used towards the cost of a 7,600 foot well (the "Well") in respect of PEDL137;

(c) following payment of the amount set out in paragraph (b), the Company shall bear a further £390,000 in cash calls which shall reflect the cash calls made under the Magellan Agreement for the drilling of the Well; and

(d) the Company will have an option to subscribe for a further 7.5% shareholding in HHDL (but this expired on 31 January 2014).

All payments made by the Company will be allocated to costs of the Well under the Magellan Agreement.

12.2.4 ***Binding term sheet dated 12 August 2014***

On 12 August 2014, the Company and HHDL entered into a binding term sheet (the "Second BTS"), pursuant to which the Company agreed to subscribe for a 12.5% shareholding in HHDL. It was agreed that the parties would enter into a formal investment agreement to reflect the terms of the Second BTS. At the date of the Second BTS, HHDL had entered into the Magellan Agreement.

The consideration payable by the Company for the 12.5% in HHDL was as follows:

(a) £10,000 payable within 7 days of the Second BTS;

(b) £50,000 payable immediately on finalisation of a formal agreement setting out the rights and obligations of the parties under the Second BTS which amount is to be used towards the Well in respect of PEDL137; and

(c) following payment of the amount set out in Paragraph (b) , the Company shall bear a further £690,000 in cash calls which shall reflect the cash calls made under the Magellan Agreement for the drilling of the Well.

All payments made by the Company will be allocated to costs of the Well under the Magellan Agreement.

12.2.5 ***Investment Agreement dated 15 September 2014***

On 15 September 2014, the Company entered into an investment agreement with HHDL and a number of investors (the "HHDL Investment Agreement") in respect of HHDL. This agreement set out the terms and conditions on which the parties operated HHDL, as holder of PEDL137 and PEDL246 (together the "Horse Hill Licences"). Under the terms of the HHDL Investment Agreement, the Company acquired a 20% interest in HHDL, with the other investors receiving the remaining 80% of shares between them.

Pursuant to the HHDL Investment Agreement, the Company agreed to subscribe for 200 ordinary shares in the capital of HHDL at a subscription price of £6,000 per share (£1,200,000 in aggregate), representing 20% of the entire issued share capital of HHDL. On completion of the HHDL Investment Agreement, the Company, together with the other HHDL Investors, were required to have paid up 10% of the subscription price in respect of the shares (being £120,000). The remainder of the subscription monies are to be paid by HHDL (and the other HHDL Investors) as are required pursuant to cash calls made against HHDL under the Magellan Agreement.

In the event that HHDL requires further working capital, such working capital is to be provided by all of the shareholders of HHDL by way of loan pro rata in proportion to their shareholdings. Unless determined otherwise, the loans made will accrue interest at a rate equal to the Bank of England base rate from time to time, be repayable on the date falling 30 business days' after HHDL's financial year end following such loan being made and all repayments are to be made on a pro rata basis between shareholders. If a shareholder does not provide finance as set out above, each other shareholder shall be issued new ordinary shares in the capital of HHDL based on the following formula:

Number of shares = shareholder loan contributed by the shareholder/£6,000.

The shares issued will be fully paid up out of the available reserves of HHDL save that if HHDL does not have sufficient available reserves, the relevant shareholders shall be entitled to subscribe for the anti-dilution shares at par value.

Customary (but non-extensive) warranties were given to the Company by HHDL and Angus Resources (the sole shareholder of HHDL prior to the HHDL Investment Agreement being entered into. The HHDL Investment Agreement can only be varied by HHDL Investors' holding at least 50% of the share capital between them. The HHDL Investment Agreement is governed by the laws of England and Wales.

12.2.6 ***Share Purchase Agreement dated 15 April 2016 in respect of HHDL***

On 15 April 2016, the Company entered into a share purchase agreement with Angus Energy Holdings UK Limited pursuant to which the Company purchased 120 ordinary shares in HHDL from Angus Energy Holdings UK Limited (the "Angus Energy SPA"). The consideration payable under the Angus Energy SPA was £1,800,000 (the "Angus Consideration"). Pursuant to the Angus Energy SPA, Angus also agreed to assign certain accrued loans made to HHDL to the Company. The Company agreed that it will be liable for all working capital contributions to HHDL attributable to the Angus Sale Shares arising on or after the date of the Angus Energy SPA.

10% of the Angus Consideration was payable on execution of the Angus Energy SPA. £820,000 was payable on completion of the Angus Energy SPA, of which £200,000 would be paid to HHDL as a company contribution. The balance of the Angus Consideration was satisfied by the allotment and issue of 43,886,116 ordinary shares in the Company at a price of 1.8229 pence per ordinary share, to Angus (the "Angus Consideration Shares").

Customary (non-extensive) warranties were given by Angus to the Company and vice versa. The Angus Energy SPA contains an indemnity given by the Company in favour of Angus and certain of its subsidiaries and related companies against any claims made by the Angus group of companies limited to an aggregate amount of £400,000. The Angus Energy SPA is governed by the laws of England and Wales.

12.2.7 ***Share Purchase Agreement dated 21 July 2016 in respect of HHDL***

On 21 July 2016, the Company entered into a share purchase agreement with Flowermay Limited ("Flowermay") relating to the purchase by the Company of 60 ordinary shares in HHDL from Flowermay (the "Flowermay SPA"). The consideration payable under the Flowermay SPA was £1,000,000 in cash. Flowermay agreed to apply £850,000 of the consideration received to subscribe for ordinary shares in the Company (the "Flowermay Subscription Shares"). The Flowermay Subscription Shares was issued and allotted to Flowermay on completion of the Flowermay SPA. The number of Flowermay Subscription Shares issued and allotted to Flowermay was calculated by applying the 10 day volume weighted average price for the Company's ordinary shares as at the date of completion of the Flowermay SPA.

Customary (but non-extensive) warranties were given to the Company by Flowermay. The Flowermay SPA was governed by the laws of England and Wales.

12.2.8 ***Share Purchase Agreement dated 7 July 2017 in respect of HHDL***

On 7 July 2017 the Company entered into a share purchase agreement with Regency Mines PLC ("Regency") relating to the purchase by the Company of 19 ordinary shares in HHDL from Regency (the "Regency SPA"). Regency also agreed to assign certain accrued loans made to HHDL (the "Regency Debt") to the Company.

The aggregate purchase price for the Regency Sale Shares and the Regency Debt is £323,000 payable in cash (the "Regency Purchase Price"). Regency agreed to apply £268,502 of the Regency Purchase Price to subscribe for ordinary shares in the Company (the "Regency Subscription Shares"). The Regency Subscription Shares were issued and allotted to Regency on completion of the Regency SPA. The number of Regency Subscription Shares issued and allotted to Regency was calculated by reference to the 30 day volume weighted average price for the Company's ordinary shares as at the date of completion of the Regency SPA.

In consideration for £1, Regency granted to the Company an irrevocable right of first refusal to acquire the .the remaining 31 ordinary shares in HHDL held by Regency and accrued loan made to HHDL by Regency at the same price per remaining ordinary share in HHDL as made by any *bona fide* third party on an arm's length basis ("Regency Qualifying Offer"). Regency provided and undertaking to promptly notify the Company should it receive a Regency Qualifying Offer.

Customary (but non-extensive) warranties were given to the Company by Regency. The Regency SPA was governed by the laws of England and Wales.

12.2.9 ***Deed of Assignment dated 22 August 2017 in respect of HHDL***

On 22 August 2017, the Company entered into a deed of assignment with Regency, pursuant to which Regency assigned certain accrued loans granted to HHDL to the Company ("Regency Assignment"). Regency unconditionally, irrevocably and absolutely assigned to the Company all of Regency's rights, title, interest and benefits in the Regency Debt from the date of the Regency Assignment. The Company provided an indemnity to Regency against any losses, damages or costs Regency suffers or incurs arising out of, relating to, or in connection with the Regency Debt. The Regency Assignment is governed by the laws of England and Wales.

12.2.10 ***Joint Operating Agreement in respect of PEDL137***

On an unspecified date in 2014 HHDL and Magellan entered into a joint operating agreement in relation to PEDL137 (the "PEDL137 JOA"). The PEDL137 JOA regulates operations over the PEDL137 licence area, comprising part of the Horse Hill oil field. The term of the PEDL137 JOA commenced on 1 October 2014 and shall run until such time as PEDL137 ceases to remain in place. The interests in the PEDL137 JOA are split 65% to HHDL and 35% to Magellan.

Under the PEDL137 JOA, HHDL is appointed as operator of the PEDL137. The operator shall have the right to resign at the end of any month by giving not less than 180 days' notice. Furthermore, the operator may be removed by the joint operating committee ("PEDL137 JOC") on 90 days' notice where the operator has been deemed to commit a material breach of the PEDL137 JOA. Furthermore, the operator may be removed immediately in the default events such as insolvency, cessation of business, the operator ceasing to hold a 15% interest in PEDL137 or the OGA withdrawing its approval of the operator. Furthermore, non-operators may remove the operator where at least 2 non-operator participants support such removal (where such non-operator participants hold 80% of the total interests held by non-operators) provided the operator holds at least a 35% participating interest.

The operator has the right and is obliged to conduct the operations under the PEDL137 under the supervision of the PEDL137 JOC. The operator is required to conduct the joint operations in a proper and workmanlike manner in accordance with customary prudent oil and gas practices. The operator shall not be liable for any loss or damage in connection with the operations unless such loss arises from its wilful misconduct or its failure to obtain or maintain insurance. The PEDL137 JOC is established in order to exercise overall supervision and control of joint operations. Each of the participants are entitled to appoint 1 representative to the PEDL137 JOC. The operator is entitled to appoint the chairman of the PEDL137 JOC. Meetings of the PEDL137 JOC are to be held at least once a year, but may also be held upon the request of either participant. Each participant's voting interest shall be equal to its participating interest. All decisions of the PEDL137 JOC shall be made by the affirmative vote of at least 2 participants having in aggregate a percentage interest of not less than 65%.

All risk, obligations, losses, damages, liabilities and associated expenses incurred in or arising out of the conduct under the joint operations shall be borne by the participants in proportion to their respective participating interests in PEDL137. The operator is required to obtain and maintain all necessary insurance regarding the PEDL137 operations. The cost of the insurance is borne equally by the participants.

Each of the participants has each provided warranties and an indemnity with respect to capacity and compliance with laws (including anti-bribery matters).

Any participant may undertake sole risk drilling or development once all working obligations have been completed and such sole risk drilling will not cause any conflict with any approved programme at the cost and expense of the participant carrying out such project. Where any other participant joints a sole risk programme, such cost and expense shall be shared proportionally to its participating interest under the PEDL137 JOA. Any participant operating a sole risk programme shall indemnify and hold harmless all other participants in respect of that programme. Data and information jointly owned by the Participants may be used for a sole risk programme. The PEDL137 JOA contains provisions setting out how non-participating parties may become participants in sole risk programmes. This provides that they must make a contribution of amounts that would have been required in the first instance together with interest thereon at a rate of 2%. In addition, such party will be required to pay an amount equal to 10 times the initial contribution that would have been required to the participating parties.

Default in paying any amounts due under the PEDL137 JOA shall result in the other non-defaulting participants covering the shortfall and all costs associated therewith shall be borne by the defaulting participant. A default may be remedied by the defaulting participant, but if not remedied within 6 working days, such defaulting participant shall cease to be entitled to its substance entitlement of petroleum which will be owned by the non-defaulting participants. Furthermore, they will cease to be entitled to representation at meetings of the PEDL137 JOC. If the default continues for more than 60 days, the non-defaulting participants shall be entitled to forfeit the defaulting participant's interest under the PEDL137 JOA on 30 days' notice (such notice being served after the 60 day default continuation period). This shall be subject to any necessary consent of the Minister. If this right of forfeiture is not exercised, the participants will be deemed to have abandoned the joint operations and each participant shall pay its share of costs associated with abandoning the joint operations.

Each party to the PEDL137 JOA is entitled to take in kind and separately dispose of, and will also be required to lift, its substance entitlement in the total quantities of petroleum available under the PEDL137 JOA. The operator is entitled to use as much petroleum as necessary in respect of continuing operations and such quantities shall be excluded from estimates provided.

Each participant may assign its interest with the consent of the OGA and provided that any proposed assignee can demonstrate its financial capability to perform its obligations under the PEDL137 JOA to the other participants. Each participant may withdraw from the PEDL137 JOA provided that all working obligations set out in the licence have been completed and that notice has been given at any time prior to 5 months before the expiry of the initial term set out above. If PEDL137 continues for a second term or is extended, a party may withdraw on 30 days' notice. No withdrawal may be made where a development programme authorised by the Minister remains incomplete. Where a withdrawal is made, unless the other participants agree, the liabilities and obligations of the withdrawing participant relating to programmes and budgets approved prior to the withdrawal shall remain the responsibility of such withdrawing participant.

The PEDL137 JOA is governed by the laws of England and Wales.

12.2.11 ***Joint Operating Agreement in respect of PEDL246***

On an unspecified date in 2014 HHDL and Magellan entered into a joint operating agreement in relation to PEDL246 (the "PEDL246 JOA"). The PEDL246 JOA regulates operations over the PEDL137 licence area, comprising part of the Horse Hill oil field. The term of the PEDL246 JOA commenced on 1 October 2014 and shall run until such time as PEDL246 ceases to remain in place. The interests in the PEDL246 JOA are split 65% to HHDL and 35% to Magellan.

Under the PEDL246 JOA, HHDL is appointed as operator of the PEDL246. The operator shall have the right to resign at the end of any month by giving not less than 180 days' notice. Furthermore, the operator may be removed by the joint operating committee ("PEDL246 JOC") on 90 days' notice where the operator has been deemed to commit a material breach of the PEDL246 JOA. Furthermore, the operator may be removed immediately in the default events such as insolvency, cessation of business, the operator ceasing to hold a 15% interest in PEDL246 or the OGA withdrawing its approval of the operator. Furthermore, non-operators may remove the operator where at least 2 non-operator participants support such removal (where such non-operator participants hold 80% of the total interests held by non-operators) provided the operator holds at least a 35% participating interest.

The operator has the right and is obliged to conduct the operations under the PEDL246 under the supervision of the PEDL246 JOC. The operator is required to conduct the joint operations in a proper and workmanlike manner in accordance with customary prudent oil and gas practices. The operator shall not be liable for any loss or damage in connection with the operations unless such loss arises from its wilful misconduct or its failure to obtain or maintain insurance. The PEDL246 JOC is established in order to exercise overall supervision and control of joint operations. Each of the participants are entitled to appoint 1 representative to the PEDL246 JOC. The operator is entitled to appoint the chairman of the PEDL1 37 JOC. Meetings of the PEDL246 JOC are to be held at least once a year, but may also be held upon the request of either participant. Each participant's voting interest shall be equal to its participating interest. All decisions of the PEDL246 JOC shall be made by the affirmative vote of at least 2 participants having in aggregate a percentage interest of not less than 65%.

All risk, obligations, losses, damages, liabilities and associated expenses incurred in or arising out of the conduct under the joint operations shall be borne by the participants in proportion to their respective participating interests in PEDL246. The operator is required to obtain and maintain all necessary insurance regarding the PEDL246 operations. The cost of the insurance is borne equally by the participants.

Each of the participants has each provided warranties and an indemnity with respect to capacity and compliance with laws (including anti-bribery matters).

Any participant may undertake sole risk drilling or development once all working obligations have been completed and such sole risk drilling will not cause any conflict with any approved programme at the cost and expense of the participant carrying out such project. Where any other participant joints a sole risk programme, such cost and expense shall be shared proportionally to its participating interest under the PEDL246 JOA. Any participant operating a sole risk programme shall indemnify and hold harmless all other participants in respect of that programme. Data and information jointly owned by the Participants may be used for a sole risk programme. The PEDL246 JOA contains provisions setting out how non-participating parties may become participants in sole risk programmes. This provides that they must make a contribution of amounts that would have been required in the first instance together with interest thereon at a rate of 2%. In addition, such party will be required to pay an amount equal to 10 times the initial contribution that would have been required to the participating parties.

Default in paying any amounts due under the PEDL246 JOA shall result in the other non-defaulting participants covering the shortfall and all costs associated therewith shall be borne by the defaulting participant. A default may be remedied by the defaulting participant, but if not remedied within 6 working days, such defaulting participant shall cease to be entitled to its substance entitlement of petroleum which will be owned by the non-defaulting participants. Furthermore, they will cease to be entitled to representation at meetings of the PEDL246 JOC. If the default continues for more than 60 days, the non-defaulting participants shall be entitled to forfeit the defaulting participant's interest under the PEDL246 JOA on 30 days' notice (such notice being served after the 60 day default continuation period). This shall be subject to any necessary consent of the Minister. If this right of forfeiture is not exercised, the participants will be deemed to have abandoned the joint operations and each participant shall pay its share of costs associated with abandoning the joint operations.

Each party to the PEDL246 JOA is entitled to take in kind and separately dispose of, and will also be required to lift, its substance entitlement in the total quantities of petroleum available under the PEDL246 JOA. The operator is entitled to use as much petroleum as necessary in respect of continuing operations and such quantities shall be excluded from estimates provided.

Each participant may assign its interest with the consent of the OGA and provided that any proposed assignee can demonstrate its financial capability to perform its obligations under the PEDL246 JOA to the other participants. Each participant may withdraw from the PEDL246 JOA provided that all working obligations set out in the licence have been completed and that notice has been given at any time prior to 5 months before the expiry of the initial term set out above. If PEDL246 continues for a second term or is extended, a party may withdraw on 30 days' notice. No withdrawal may be made where a development programme authorised by the Minister remains incomplete. Where a withdrawal is made, unless the other participants agree, the liabilities and obligations of the withdrawing participant relating to programmes and budgets approved prior to the withdrawal shall remain the responsibility of such withdrawing participant.

The PEDL246 JOA is governed by the laws of England and Wales.

12.3 **Material Contracts relating to Holmwood Licence**

12.3.1 ***Petroleum Exploration and Development Licence 143 ("PEDL143")***

On 1 October 2004 PEDL143 was made between the OGA and a number of parties. The Company has since acquired a 40% interest in PEDL143. This licence incorporates the Model Clauses. PEDL143 had originally provided for an initial term of 6 years from 1 October 2004 (up until 30 September 2010) with a second term of 5 years to 30 September 2015 and a further 20 year production period to expire on 30 September 2035. These periods have been altered and that the initial term of PEDL143 has been extended to 30 September 2018 and that the second term of PEDL143 shall be for 2 years to 30 September 2020. Following expiry of the second term, there may be a further 15 year production period to expire on 30 September 2035. Where PEDL143 has continued in force for the period of the production period (up until 30 September 2035), the OGA, on application being made to it in writing by the licensees, may agree that this can be extended for such further period as the OGA may agree in order to secure the maximum economic recovery of petroleum from the licenced area.

12.3.2 ***Farmout agreement dated 26 June 2015 in respect of PEDL143***

On 26 June 2015, the Company and Egdon Resources U.K. Limited ("Egdon") entered into a farmout agreement (the "Egdon Farmout Agreement") to farm out to the Company a 20% interest (the "Egdon Farmed Interest") in PEDL143 and the joint operating agreement dated 1 March 2006 ("PEDL143 JOA").

On signature of the Egdon Farmout Agreement, the Company agreed to pay to Egdon £50,000 (the "Egdon Initial Consideration"). In consideration for the transfer of the Egdon Farmed Interest, the Company agreed to:

(a) pay its percentage interest share of all costs pursuant to the PEDL143 JOA attributable to the Egdon Farmed Interest;

(b) pay an additional 20% of the costs charged to the joint account for the preparation for and drilling of the Holmwood-1 well up to and including the point when the well:

  a. either is suspended following the running of production casing and installation of the well completion; or

  b. has been plugged and abandoned, whether tested or not, and the well site has been vacated and restored as necessary; and

(c) the 20% payable will be limited to the applicable share of total costs of the Holmwood-1 well of £3 million and costs above that shall be borne in percentage interest under the PEDL143 JOA.

The Company indemnified Egdon against any costs, charges, expenses, liabilities and obligations relating to the Egdon Farmed Interest which were or are properly incurred by Egdon following completion of the Egdon Farmout Agreement (save for any subject matter in respect of which Egdon has been demonstrated by the Company to be in breach of a warranty). Egdon indemnified the Company against any costs, charges, expenses, liabilities and obligations relating to the Egdon Farmed Interest which were or are properly incurred by the Company which accrued in respect of any period prior to completion of the Egdon Farmout Agreement, provided that it is not an expense for which the Company is properly liable.

Customary (non-extensive) warranties were provided by Egdon and the Company. The Egdon Farmout Agreement is governed by the laws of England and Wales.

12.3.3 ***Farmout agreement dated 20 November 2015 in respect of PEDL143***

On 20 November 2015, the Company and Warwick Energy Exploration and Production Limited ("Warwick") entered into a farmout agreement (the "Warwick Farmout Agreement") to farm out to the Company a 10% interest (the "Farmed Interest") in PEDL143 and the PEDL143 JOA.

On signature of the Warwick Farmout Agreement, the Company paid to Warwick £25,000 (the "Warwick Initial Consideration"). In consideration for the transfer of the Farmed Interest, the Company agreed to:

(a) pay the percentage interest held in PEDL143 share of all costs pursuant to the JOA attributable to the Farmed Interest;

(b) pay an additional 10% of the costs charged to the joint account for the preparation for and drilling of the Holmwood-1 well and which would otherwise have been paid by Warwick, up to and including the point when such well:

a. either is suspended following the running of production casing and installation of the well completion; or

b. has been plugged and abandoned, whether tested or not, and the well site has been vacated and restored as necessary;

(c) the 10% payable will be limited to the applicable share of total costs of the Holmwood-1 well of £3 million and costs above that shall be borne in percentage interest under the PEDL143 JOA.

The Company indemnified Warwick against any costs, charges, expenses, liabilities and obligations relating to the Farmed Interest which are or were properly incurred by Warwick following completion of the Warwick Farmout Agreement (save for any subject matter in respect of which Warwick has been demonstrated by the Company to be in breach of a warranty). Warwick indemnified the Company against any costs, charges, expenses, liabilities and obligations relating to the Farmed Interest which are or were properly incurred by the Company which accrued in respect of any period prior to completion of the Warwick Farmout Agreement, provided that it is not an expense for which the Company is properly liable.

Customary (non-extensive) warranties are provided by Warwick and the Company. The Warwick Farmout Agreement is governed by the laws of England and Wales.

12.3.4 ***Sale and purchase agreement dated 22 September 2017 in respect of PEDL143***

Pursuant to a sale and purchase agreement dated 22 September 2017 entered into by the Company and Warwick the Company acquired a 10% beneficial interest in PEDL143 and the PEDL143 JOA (the "WEEP SPA"). Following completion of the WEEP SPA, the Company held a 40% beneficial interest in PEDL143 and the PEDL143 JOA, which it holds as at today's date.

The consideration payable by the Company to Warwick comprised of £750,000 which Warwick undertook to use to immediately subscribe for ordinary shares in the capital of the Company (the "WEEP Consideration Shares"). The number of ordinary shares issued was to be calculated by reference to the 10 day volume weighted average price of the Company's shares immediately prior to the date of the WEEP SPA. It was further agreed that the consideration shall be allocated to PEDL143. The consideration payable was to be adjusted for any deductions or increases pursuant to the WEEP SPA, such adjustments being notified by the Company to WEEP within 30 business days of the WEEP SPA, and such adjustments either being agreed or disputed within 5 business days thereafter.

The Company and Warwick agreed that all costs and benefits associated with PEDL143 would be apportioned as at the date of the WEEP SPA, save for any liabilities arising under the Warwick Farmout Agreement, the warranties contained in the WEEP SPA or for tax.

The Company indemnified Warwick for all environmental and abandonment liabilities arising before or after completion of the WEEP SPA. Customary (non-extensive) warranties are provided by Warwick and the Company. The maximum liability of Warwick is the capped at an amount equal to the consideration paid.

The WEEP SPA is governed by the laws of England and Wales.

12.3.5 ***Joint operating agreement dated 1 March 2006 in respect of PEDL143***

On 1 March 2006, Europa Oil & Gas Limited, Egdon Resources PLC, Warwick and Altwood Petroleum Limited entered into the PEDL143 JOA in respect of PEDL143. The PEDL143 JOA regulates operations over the PEDL143 licence area, comprising part of the Holmwood oil field. Upon acquiring its interest in PEDL143, the Company became a party to the PEDL143 JOA.

The term of the PEDL143 JOA is deemed to have commenced on 1 October 2004 and shall continue for so long as PEDL143 remains in force and until all joint property has been disposed of and final settlement has been made between the Participants in accordance with their rights and obligations.

Europa is appointed as operator of the PEDL143 for the purposes of exploration for and the production of petroleum within the PEDL143 licence area. The operator shall have the right to resign at the end of any month by giving not less than 270 days' notice to the Participants or such shorter period of notice as the joint operating committee may agree (the "PEDL143 JOC"). Furthermore, the operator may be removed at the end of any month by the PEDL143 JOC on 90 days' notice. The operator can be removed immediately in the default events such as insolvency, cessation of business, the operator ceasing to hold a 20% interest in PEDL143 or the Minister withdrawing its approval of the operator.

The operator has the right and is obliged to conduct the operations under the PEDL143 under the supervision of the PEDL143 JOC. The operator is required to conduct the joint operations in a proper and workmanlike manner in accordance with customary prudent oil and gas practices. The operator shall not be liable for any loss or damage in connection with the operations unless such loss arises from its wilful misconduct or its failure to obtain or maintain insurance.

The operator has the authority to obtain materials and/or services in respect of the joint operations pursuant to contracts or orders awarded or to be awarded to third parties. If the costs of such contract exceeds £20,000 per annum or is likely to exceed £30,000 over its expected duration the operator shall obtain the approval of the JOC prior to the award of such order. In the case of any proposed contract to be awarded to a third party where the commitment thereunder will exceed £500,000 in the case of development operations or £250,000 in the case of exploration, appraisal and production activities the contract shall be put out to competitive tender.

The PEDL143 JOC is established in order to exercise overall supervision and control of joint operations in respect of PEDL143. Each Participant is entitled to appoint 1 representative to the PEDL143 JOC. The operator is entitled to appoint the chairman of the PEDL143 JOC. Meetings of the PEDL143 JOC are to be held at least once a year. On request of any of the Participants the PEDL143 JOC shall hold a special meeting. The request must be made by notice to all other Participants and state the matters to be considered at that meeting. Each Participant's voting interest shall be equal to its participating interest. All decisions of the PEDL143 JOC shall be made by the affirmative vote of at least 2 participants having in aggregate a percentage interest of not less than 65%. All the Participants shall be bound by each decisions of the PEDL143 JOC made in accordance with the PEDL143 JOA.

All risk, obligations, losses, damages, liabilities and associated expenses incurred in or arising out of the conduct under the joint operations shall be borne by the Participants in proportion to their respective participating interests in PEDL143. The operator is required to obtain and maintain all necessary insurance regarding the PEDL143 operations. The cost of the insurance is borne equally by the Participants.

Any Participant may undertake sole risk drilling or development once all working obligations have been completed and such sole risk drilling will not cause any conflict with any approved programme at the cost and expense of the Participant carrying out such project. Any sole risk project shall be carried out at the sole risk, cost and expense of the Participant proposing such project and any other Participant electing to join such project. If a sole risk project is undertaken by more than one Participant the risk and cost thereof shall be shared in proportion to each Participant's participating interest under the PEDL143 JOA. A Participant to a sole risk project shall indemnify and hold harmless the other Participants not participating in the sole risk project against all actions, claims, demands and proceedings in arising out of the sole risk project. The PEDL143 JOA contains provisions setting out the approval process for sole risk drilling, payments to be made should a discovery of petroleum reserves be made in respect of a sole risk project and how Participants can elect to join a sole risk project once a discovery has been made in respect of that sole risk project has commenced. Should a Participant wish to join a sole risk project once a discovery is made in respect of that project the Participant shall pay the sole risk Participant (or in the case of more than one sole risk Participant, in proportion to their respective percentage interest in PEDL143) an amount equal to the amount it would have contributed to the joint account had such sole risk drilling been carried out as part of the joint operations.

Default by any Participant in paying any amounts due under the PEDL143 JOA shall result in the other non-defaulting Participants covering the shortfall and all costs associated therewith shall be borne by the defaulting Participant. A default may be remedied by the defaulting Participant, but if not remedied within 6 working days following notice by the operator of such default, such defaulting Participant shall lose its entitlement of its percentage interest share of petroleum which shall instead be owned by the non-defaulting Participants in proportion to their participating interest in the PEDL143 JOA. Furthermore, they will cease to be entitled to representation at meetings of the Warwick JOC. If the default continues for more than 60 days, the non-defaulting Participants shall have the right to have forfeited to it the defaulting Participant's interest in PEDL143 on 30 days' notice (such notice being served after the 60 day default continuation period). This shall be subject to any necessary consent of the Minister. If this right of forfeiture is not exercised, the participants will be deemed to have abandoned the joint operations and each participant shall pay its share of costs associated with abandoning the joint operations.

Each Participant is entitled to take in kind and separately dispose of, and will also be required to lift, its percentage interest share in the total quantities of petroleum available under the PEDL143 JOA. The operator is entitled to use as much petroleum as necessary in respect of continuing operations and such quantities shall be excluded from estimates provided.

Each Participant may assign its interest with the consent of the Minister and provided that any proposed assignee can demonstrate its financial capability to perform its obligations under the PEDL143 JOA to the other Participants. No transfer of any interest under PEDL143 or the PEDL143 JOA shall be made by any Participant which results in any new or continuing Participant having a percentage interest of less than 5%.

Each Participant may withdraw from the PEDL143 JOA provided that all working obligations set out in PEDL143 have been completed and that notice has been given at any time prior to 5 months before the expiry of the initial term set out above. Within 30 days of receipt of such notice, any other Participant may similarly give notice that it wishes to withdraw from PEDL143 and the PEDL143 JOA. If all Participants give notice the Participants shall be deemed to have abandoned the joint operations. A withdrawing Participant shall assign all of its interest to non-withdrawing Participants to be allocated to them in proportion to their percentage participating interest in the PEDL143 JOA. No withdrawal may be made where a development programme authorised by the Minister remains incomplete. Where a withdrawal is made, unless the other Participants agree, the liabilities and obligations of the withdrawing Participant relating to programmes and budgets approved prior to the withdrawal shall remain the responsibility of such withdrawing Participant.

The PEDL143 JOA is governed by the laws of England and Wales.

12.4 **Material Contracts relating to Markwells Wood**

12.4.1 ***Petroleum Exploration and Development Licence 126 ("PEDL126")***

On 1 July 2003 PEDL126 was made between the OGA and certain parties, including UKOG (GB) Limited which initially held a 50% participating interest in PEDL126. UKOG (GB) Limited has since acquired a further 50% participating interest in PEDL126. This licence incorporates the Model Clauses. The Licence had originally provided for an initial term of 6 years from 1 July 2003 (up until 30 June 2009) with a second term of 5 years to 30 June 2014 and a further 20 year production period to expire on 30 June 2034. A search of the OGA website shows that these periods have been altered and that the initial term of the Licence was extended to 30 June 2011 and that the second term of the Licence was revised to a period of 5 years to 30 June 2016. Following expiry of the second period, a further 18 year production period commenced which shall expire on 30 June 2034. Where the Licence has continued in force for the period of the production period (up until 30 June 2034), the OGA, on application being made to it in writing by the licensees, may agree that this can be extended for such further period as the OGA may agree in order to secure the maximum economic recovery of petroleum from the licenced area.

12.4.2 ***Sale and Purchase Agreement 2015 in respect of PEDL126***

On an unspecified date in 2015, Egdon entered into an agreement with UKOG (GB) to sell its 10% participating interest in PEDL126 (the "Egdon SPA"). The consideration payable to Egdon under the Egdon SPA was £9,999.

Customary (but non-extensive) warranties were given to the Company by Egdon. The Egdon SPA is governed by the laws of England and Wales.

12.4.3 ***Sale and Purchase Agreement dated 18 February 2015 in respect of PEDL126***

On 18 February 2015, Magellan entered into an agreement with UKOG (GB) to sell its 40% participating interest in PEDL126 (the "Magellan SPA"). The consideration payable to Magellan under the Magellan SPA was £1.

Customary (but non-extensive) warranties were given to the Company by Magellan. The Magellan SPA is governed by the laws of England and Wales.

12.5 **Material Contracts relating to Horndean Licence**

12.5.1 ***Petroleum Licence 211 ("PL211")***

On 5 April 1982 the OGA granted PL211. UKOG (GB) Limited has since acquired a 10% participating interest in PL211. This licence incorporates the Model Clauses. PL211 had an initial term of 4 years from 5 April 1982 (until 4 April 1986), which was extended for a period of 20 years until 4 April 2026 by notice given to the OGA. The anticipated expiration date is therefore 4 April 2026. The OGA has discretion to extend or renew PL211 for such further period it deems appropriate, but reserves the right to reconsider the provisions of PL211 before doing so, taking into consideration the acreage of PL211 and the rentals payable.

The Company acquired its indirect 10% interest in PL211 through the acquisition of the entire issued share capital of UKOG (GB) Limited pursuant to the NPetroleum SPA.

12.5.2 ***Joint Operating Agreement dated 14 March 1984 in respect of PL211***

On 14 March 1984, the participants entered into a joint operating agreement in respect of PL211 (the "PL211 JOA"). The PL211 JOA regulates operations over the PL211 licence area, comprising part of the Horndean oil field. The term of the PL211 JOA is deemed to have commenced on 1 January 1982 or on such later date as PL211 has been issued and shall continue for so long as PL211 remains in force and until all joint property has been disposed of and final settlement has been made between the participants in accordance with their rights and obligations.

Under the PL211 JOA, Carless Exploration Limited was appointed as operator of the PL211 for the purposes of exploration for and the production of petroleum within the PL211 licence area. Since entry into the PL211 JOA, Carless has ceased to act as operator and the current operator is Island Gas Limited. The operator shall have the right to resign at the end of any month by giving not less than 270 days' notice. The operator shall have the right to resign at the end of any month by giving not less than 270 days' notice to the participants or such shorter period of notice as the joint operating committee may agree (the "PL211 JOC"). Furthermore, the operator may be removed at the end of any month by the PL211 JOC on 90 days' notice. The operator can be removed immediately in the default events such as insolvency or cessation of its business.

The operator has the right and is obliged to conduct the operations under the PL211 under the supervision of the PL211 JOC. The operator is required to conduct the joint operations in a proper and workmanlike manner in accordance with methods and practices customarily used in good and prudent oil and gas field practice. The operator shall not be liable for any loss or damage in connection with the operations unless such loss arises from its wilful misconduct or its failure to obtain or maintain insurance. The operator has the authority to obtain materials and/or services in respect of the joint operations pursuant to contracts or orders awarded or to be awarded to third parties. If the costs of such contract exceeds £25,000 or such other amount as may be determined by the PL211 JOC. The operator shall obtain with respect to such contract a competitive sealed bid tender and the approval of the PL211 JOC for such tender.

The PL211 JOC is established in order to exercise overall supervision and control of joint operations in respect of PL211. Each participant is entitled to appoint 1 representative to the PL211 JOC. The operator is entitled to appoint the chairman of the PL211 JOC. Meetings of the PL211 JOC are to be held at least once a year. The PL211 JOC shall hold meetings once every year (or at such other regular intervals as may be agreed by the PL211 JOC). On request of any of the Participants, the PL211 JOC shall hold a special meeting. The request must be made by notice to all other participants and state the matters to be considered at that meeting. Each participant's voting interest shall be equal to its participating interest. All decisions of the PL211 JOC shall be made by the affirmative vote of at least 2 participants having in aggregate a percentage interest of not less than 60%. All the participants shall be bound by each decisions of the PL211 JOC made in accordance with the PL211 JOA.

All risk, obligations, losses, damages, liabilities and associated expenses incurred in or arising out of the conduct under the joint operations shall be borne by the participants in proportion to their respective participating interests in PL211. Island Gas Limited, in its capacity as operator, is required to obtain and maintain all necessary insurance regarding the PL211 operations. The cost of the insurance is borne equally by the participants.

Any participant may undertake sole risk drilling or development once all working obligations have been completed and such sole risk drilling will not cause any conflict with any approved programme at the cost and expense of the participant carrying out such project. Any sole risk project shall be carried out at the sole risk, cost and expense of the participant proposing such project and any other participant electing to join such project. If a sole risk project is undertaken by more than one participant the risk and cost thereof shall be shared in proportion to each participant's participating interest under the PL211 JOA. A participant to a sole risk project shall indemnify and hold harmless the other participants not participating in the sole risk project against all actions, claims, demands and proceedings in arising out of the sole risk project. The PL211 JOA contains provisions setting out the approval process for sole risk drilling, payments to be made should a discovery of petroleum reserves be made in respect of a sole risk project and how participants can elect to join a sole risk project once a discovery has been made in respect of that sole risk project has commenced.

All participants shall participate in any work or expenditure required by the terms of PL211 or any applicable laws to maintain or hold PL211 or part thereof and if any participant fails to participate , then in the event the default continues for more than 60 days after notice of such failure to participate, the participating participants shall be entitled to do the work and incur the expenditure at their sole cost and receive in proportion to their current percentage participating interest the non-participating participant's participating interest.

Default by any participant in paying any amounts due under a cash call the other non-defaulting participants covering the shortfall in proportion to their percentage interest and all costs associated therewith shall be borne by the defaulting participant. A default may be remedied by the defaulting participant, but if not remedied within 6 working days following notice by the operator of such default, such defaulting participant shall lose its entitlement of its percentage interest share of petroleum which shall instead be owned by the non-defaulting participants in proportion to their participating interest in the PL211 JOA. Furthermore, the defaulting participant will cease to be entitled to representation at meetings of the PL211 JOC. If the default continues for more than 60 days, the non-defaulting participants shall have the right to have forfeited to it the defaulting participant's interest in PL211 on 30 days' notice (such notice being served after the 60 day default continuation period). This shall be subject to any necessary consent of the Minister. If this right of forfeiture is not exercised, the participants will be deemed to have abandoned the joint operations and each participant shall pay its share of costs associated with abandoning the joint operations.

Each participant is entitled to take in kind and separately dispose of, and will also be required to lift, its percentage interest share in the total quantities of petroleum available under the PL211 JOA. The operator is entitled to use as much petroleum as necessary in respect of continuing operations and such quantities shall be excluded from estimates provided.

Each participant may assign its interest with the consent of the Minister and provided that any proposed assignee can demonstrate its financial capability to perform its obligations under the PL211 JOA to the other participants. No transfer of any interest under PL211 or the PL211 JOA shall be made by any participant which results in any new or continuing participant having a percentage interest of less than 5%.

Each participant may withdraw from the PL211 JOA provided that all working obligations set out in the licence have been completed and that notice has been given at any time prior to 5 months before the expiry of the initial term set out above. Within 30 days of receipt of such notice, any other participant may similarly give notice that it wishes to withdraw from PL211 and the PL211 JOA. If all participants give notice the participants shall be deemed to have abandoned the joint operations. A withdrawing participant shall assign all of its interest to non-withdrawing participants to be allocated to them in proportion to their percentage participating interest in the PL211 JOA. No withdrawal may be made where a development programme authorised by the Minister remains incomplete. Where a withdrawal is made, unless the other participants agree, the liabilities and obligations of the withdrawing participant relating to programmes and budgets approved prior to the withdrawal shall remain the responsibility of such withdrawing participant.

The PL211 JOA is governed by the laws of England and Wales.

12.6 Material Contracts relating to Avington Licence

12.6.1 *Petroleum Exploration and Development Licence 070 ("PEDL070")*

On 16 October 2000 PEDL070 was made between the OGA and a number of parties. The Company acquired its indirect 5% interest in PEDL070 pursuant to the its acquisition of UKOG (GB) Limited. This licence incorporates the Model Clauses. PEDL070 had an initial term of 6 years from 8 September 2000 (up until 7 September 2006). PEDL070 was then renewed for a second term of 5 years to 7 September 2011. PEDL070 has since been renewed for a further 20 year production period which therefore provides for an anticipated expiration date of 7 September 2031. Where PELD 070 has continued in force for the period of the production period (up until 7 September 2031), the OGA, on application being made to it in writing by the licensees, may agree that this can be extended for such further period as the OGA may agree in order to secure the maximum economic recovery of petroleum from the licenced area.

12.6.2 *Share purchase agreement dated 23 July 2014 in respect of UKOG (GB) Limited*

On 23 July 2014 the Company and Northern Petroleum plc entered into sale and purchase agreement, pursuant to which the Company agreed to purchase the entire issued share capital of UKOG (GB) Limited (the "NPetroleum SPA"). The consideration payable by the Company was the aggregate of: (a) £1,311,999.00; and (b) an amount equal to the aggregate value of the current assets of UKOG (GB) less the current liabilities of UKOG (GB) as at 00.00.01 BST on the date of the NPetroleum SPA, provided that such aggregate and the amount of net current asset value pursuant to each of the NPetroleum SPA and the Weald SPA shall not exceed £50,000. The completion payment was satisfied by the Company in cash although NPetroleum was entitled to have an amount of the completion payment equivalent to the £500,000.00 to be satisfied by the issue of 45,708,853 ordinary shares of the Company to NPetroleum.

Customary (but non-extensive) warranties and tax warranties were given to the Company by NPetroleum as at the date of the NPetroleum SPA. Customary (but non-extensive) warranties were given to NPetroleum by the Company as at the date of the NPetroleum SPA and the date of completion.

The Company gave an undertaking to NPetroleum and its affiliates that it shall procure that UKOG (GB) shall following completion comply with its obligations in respect of the licence interests, field property and facilities and to hold each of NPetroleum and its affiliates harmless from and against any losses caused by or arising out of or resulting from any breach of this undertaking.

NPetroleum shall have any liability for any claim unless it exceeds £50,000 and the aggregate amount of all material claims exceeds the cumulative threshold of £100,000. A claim is material if it exceeds the individual threshold of £50,000. The total liability of NPetroleum shall not in any circumstances exceed the purchase price.

The NPetroleum SPA is governed by the laws of England and Wales.

12.6.3 *Joint Operating Agreement dated 20 June 2001 in respect of PEDL070*

Operations in respect of PEDL070 are governed by a joint operating agreement dated 20 June 2001 (the "PEDL070 JOA") which the Company has acquired an interest pursuant to its acquisition of UKOG (GB) Limited. The PEDL070 JOA regulates operations over the PEDL070 licence area comprising the Avington oil field. The term of the PEDL070 JOA commenced on 20 June 2001 and shall run until such time as PEDL070 ceases to remain in place.

Under the PEDL070 JOA, Pentex was appointed as operator of the PEDL070. Since entry into the PEDL070, Pentex has ceased to act as operator and the current operator is IGas Energy Plc. The operator shall have the right to resign at the end of any month by giving not less than 270 days' notice. Furthermore, the operator may be removed by the joint operating committee ("070 JOC") on 90 days' notice where the Company has been deemed to commit a material breach of the PEDL070 JOA. The operator may be removed on 30 days' notice in default events such as insolvency, cessation of business, the operator ceasing to hold a 15% interest in PEDL070 (unless such interest is still not less than the largest participating interest), or the OGA withdrawing its approval of the operator. In the event that the operator resigns or is removed, it shall have no claim against the other 070 Participants. If resignation occurs prior to the completion of all work obligations, it shall not be entitled to any costs or expenses incurred in connection with the change of ownership. If resignation or removal occurs after the completion of work obligations, it shall be entitled to charge costs and expenses to the joint operating account (as may be approved by the 070 JOC). As soon as practicable after the operator transfers its obligations, the 070 JOC may order an audit of the joint account and an inventory of all joint property and joint petroleum. The operator shall not be entitled to vote on matters concerning its removal or resignation.

The operator has the right and is obliged to conduct the operations under PEDL070 under the supervision of the 070 JOC. The Company is required to conduct the joint operations in a proper and workmanlike manner in accordance with customary prudent oil and gas practices. The operator shall not be liable for any loss or damage in connection with the operations unless such loss arises from its wilful misconduct or its failure to obtain or maintain insurance by virtue of it being the operator. Liability is to be borne by the 070 Participants by reference to their participating interest in PEDL070. Where the operator proposes to supply materials or services at a cost in excess of £150,000 the consent of the 070 JOC will be required with competitive bid tenders being obtained. Where a contract exceeds £250,000, it must be put out to competitive tender and a formal bid process followed. Where a contract to be awarded is in excess of £750,000, the 070 JOC must approve the final contract.

The 070 JOC is established in order to exercise overall supervision and control of joint operations. Each 070 Participant is entitled to appoint 1 representative to the 070 JOC. The operator is entitled to appoint the chairman of the 070 JOC. Meetings of the 070 JOC are to be held at least once a quarter, but may also be held upon the request of either 070 Participant. Each 070 Participant's voting interest shall be equal to its participating interest. All decisions of the 070 JOC shall be made by the affirmative vote of not fewer than 50% of the 070 Participants having individually or in aggregate a percentage interest of at least 60%. The termination of the PEDL070, surrender of any part of the licence area and the use of joint property by third parties requires the consent of all 070 Participants.

All risk, obligations, losses, damages, liabilities and associated expenses incurred in or arising out of the conduct under the joint operations shall be borne by the 070 Participants in proportion to their respective participating interests in PEDL070. The operator is required to obtain and maintain all necessary insurance regarding the PEDL070 operations. The cost of the insurance is borne equally by the 070 Participants. In addition, all other 070 Participants are required to obtain insurances necessary in respect of their own participating interests. Incidents that could lead to litigious liability in excess of £50,000 must be notified to the 070 Participants by the operator and consents of the participants and 070 JOC will be required.

Any 070 Participant may undertake sole risk drilling or development provided such sole risk project does not jeopardise or conflict with any programme approved by the 070 JOC or if such works would satisfy an outstanding work obligation unless all of the 070 Participants agree. The sole risk project is undertaken at the risk of those participating. Any 070 Participant operating a sole risk programme shall indemnify and hold harmless all other participants in respect of that programme. Data and information jointly owned by the participants may be used for a sole risk programme. The operation of a sole risk project will be undertaken by the operator, but it may decline to carry out drilling. In respect of sole risk development, it will not carry out the works unless all other participants agree. Sole risk projects must have first been proposed to, and rejected by, the 070 JOC. The PEDL070 JOA contains provisions setting out how non-participating parties may become participants in sole risk programmes. This provides that they must make a contribution of that would have been required in the first instance with interest at the rate of 5% thereon. In addition, any participant opting in will be required to pay an additional amount to the sole risk participants in respect of each sole risk drilling operation in which it did not participate in an amount equal to 10 times the amount that would have been required to pay as a sole risk participant in the first instance.

Default in paying any amounts due under the PEDL070 JOA shall result in the other non-defaulting participants covering the shortfall and all costs associated therewith shall be borne by the defaulting participant. Finance provided by the Company (as operator) bears interest at the rate of 5% above the Bank of Scotland base rate. A default may be remedied by the defaulting participant, but if not remedied within 6 working days, such defaulting participant shall cease to be entitled to its substance entitlement of petroleum which will be owned by the non-defaulting participants. Furthermore, they will cease to be entitled to representation at meetings of the 070 JOC. If the default continues for more than 60 days, the non-defaulting participants shall be entitled to forfeit the defaulting participant's interest under the PEDL070 JOA on 30 days' notice (such notice being served after the 60 day default continuation period). This shall be subject to any necessary consent of the Minister. If this right of forfeiture is not exercised, the participants will be deemed to have abandoned the joint operations and each Participant shall pay its share of costs associated with abandoning the joint operations.

Each party to the PEDL070 JOA is entitled to take in kind and separately dispose of, and will also be required to lift, its substance entitlement in the total quantities of petroleum available under the PEDL070 JOA. The operator is entitled to use as much petroleum as necessary in respect of continuing operations and such quantities shall be excluded from estimates provided.

Each 070 Participant may assign its interest with the consent of the other participants (to be withheld only on grounds that financial and technical capability has not been adequately demonstrated). In the event that a 070 Participant proposes to assign or transfer its interests, the other 070 Participants shall have a right of pre-emption. Each 070 Participant may withdraw from the PEDL070 JOA at any time prior to 5 months before expiry of the initial term of the licence provided that all working obligations set out in the licence have been completed. No withdrawal may be made where a development programme authorised by the Minister remains incomplete. Where a withdrawal is made, unless the other participants agree, the liabilities and obligations of the withdrawing participant relating to programmes and budgets approved prior to the withdrawal shall remain the responsibility of such withdrawing participant.

The PEDL070 JOA is governed by the laws of England and Wales.

12.7 Material Contracts relating to Baxters Corpse Licence

12.7.1 *Petroleum Exploration and Development Licence 233 ("PEDL233")*

On 1 July 2008 PEDL233 was made between the OGA and other parties. The Company has since acquired an indirect 50% participating interest in PEDL233 by acquiring UKOG (Weald) Limited from NP Oil & Gas Holdings Limited ("NPOG"). This licence incorporates the Model Clauses. PEDL233 had originally provided for an initial term of 6 years from 1 July 2008 (up until 30 June 2014) with a second term of 5 years to 30 June 2019 and a further 20 year production period to expire on 30 June 2039. These periods have been altered and that the initial term of PEDL233 was extended to 30 June 2018 and that the second term of PEDL233 would be for 1 year to 30 June 2019. Following expiry of the second term, there may be a further 20 year production period to expire on 30 June 2039. Where PEDL233 has continued in force for the period of the production period (up until 30 June 2039), the OGA, on application being made to it in writing by the licensees, may agree that this can be extended for such further period as the OGA may agree in order to secure the maximum economic recovery of petroleum from the licenced area. The Company has not completed the exploration commitment set out below in respect of PEDL233, and has not sought to extend the initial term of the licence. On 5 July 2018, the Company received formal notice from the OGA with regards to relinquishing PEDL233. The Company will relinquish its in interests in PEDL233. IGas Energy Plc (as licence operator) now need to formalise the relinquishment of the licence and provide a relinquishment report to the OGA. This is due within 3 months of notification of the expiry of the licence. The Company expects to be responsible for its relevant proportion of the operator's costs associated in preparing the relinquishment report, but does not expect there to be any material costs associated with the relinquishment of the licence as no substantive works have been carried out.

12.7.2 ***Share Purchase Agreement dated 23 July 2014 in respect of UKOG (Weald) Limited***

On 23 July 2014 the Company and NP Oil & Gas Holdings Limited ("NPOG") entered into a sale and purchase agreement, pursuant to which the Company agreed to purchase the entire issued share capital of UKOG Weald Limited (the "Weald SPA"). UKOG Weald Limited was, and remains, the holder of a 50% participating interest in PEDL233. The consideration payable by the Company was the aggregate of: (a) £188,000.00; and (b) an amount equal to the aggregate value of the current assets of UKOG Weald less the current liabilities of NPW as at 00.00.01 BST on the date of the Weald SPA, provided that such aggregate and the amount of net current asset value pursuant to each of the NPetroleum SPA (as defined below) and the Weald SPA shall not exceed £50,000.

Customary (but non-extensive) warranties and tax warranties were given to the Company by NPOG as at the date of the Weald SPA. The Weald SPA is governed by the laws of England and Wales. The Company gave an undertaking to NPOG and its affiliates that it shall procure that UKOG Solent Limited shall following completion comply with its obligations in respect of the licence interests, field property and facilities and to hold each of NPOG and its affiliates harmless from and against any losses caused by or arising out of or resulting from any breach of this undertaking.

NPOG shall have any liability for any claim unless it exceeds £50,000 and the aggregate amount of all material claims exceeds the cumulative threshold of £100,000. A claim is material if it exceeds the individual threshold of £50,000. The total liability of NPOG shall not in any circumstances exceed the purchase price.

12.7.3 ***Joint Operating Agreement in respect of PEDL233***

On an unspecified date in 2014 UKOG Weald Limited entered into a joint operating agreement with Island Gas (Singleton) Limited in respect of PEDL233 (the "PEDL233 JOA"). The term of the PEDL233 JOA commenced on the date of the JOA and shall continue for so long as the PEDL233 remains in force.

Under the PEDL233 JOA, Island Gas (Singleton) Limited was appointed as operator of PEDL233. Since entry into the PEDL233 JOA, Island Gas (Singleton) Limited has ceased to act as operator and the current operator is IGas Energy Enterprise Limited. The operator shall have the right to resign at the end of any month by giving not less than 270 days' notice. The operator shall have the right to resign at the end of any month by giving not less than 180 days' notice to the participants or such shorter period of notice as the joint operating committee ("PEDL233 JOC") may decide. The operator may be removed at the end of any month with at least 90 days' notice if it is guilty of wilful misconduct and the operator has not remedied the wilful misconduct to the reasonable satisfaction of the PEDL233 JOC within 28 days of receipt of a notice requiring it to do so. Alternatively, the operator may be removed if its aggregate percentage interest (together with its affiliates) in PEDL233 falls to less than 25%.

The operator has the right and is obliged to conduct the operations under the PEDL233 under the overall supervision of the PEDL233 JOC. The operator is required to conduct the joint operations in a proper and workmanlike manner in accordance with good industry practices. The operator shall not be liable for any loss or damage in connection with the operations unless such loss arises from its wilful misconduct or its failure to obtain or maintain insurance. Where a contract for material and services is in excess of £500,000, the operator shall consult with the non-operating participants and the JOC prior to awarding the contract.

The operator is required to prepare and maintain separate books and records in respect of the operations carried out.

All risk, obligations, losses, damages, liabilities and associated expenses incurred in or arising out of the conduct under the joint operations shall be borne by the participants in proportion to their respective participating interests in PEDL233.

The PEDL233 JOC is established in order to exercise overall supervision and control of joint operations. Each of the participants is entitled to appoint 1 representative to the PEDL233 JOC. The operator is entitled to be represented in its capacity as operator, having no additional voting rights, and shall be the chairman of the PEDL233 JOC. Meetings of the PEDL233 JOC are to be held at least once a year, but may also be held upon the request of either Participant. Each participant's voting interest shall be equal to its participating interest. All decisions of the PEDL233 JOC shall require the affirmative vote of at least 2 participants with a total percentage interest of not less than 65%. If a participant is excluded from voting, then a percentage of not less than 65% of the percentage interests of the participants entitled to vote shall be required. If only 1 participant is entitled to vote, decisions shall be made by the affirmative vote of that participant.

Any participant may undertake sole risk drilling or development once all working obligations have been completed and so long as such drilling is not substantially similar to or causes any conflict with any approved programme at the cost and expense of the participant carrying out such project.

Where any other participant joints a sole risk programme, the risk, costs, rights and obligations shall be shared proportionally to its participating interest under the PEDL233 JOA. Any participant operating a sole risk programme shall indemnify and hold harmless all other participants in respect of that programme. The PEDL233 JOA contains provisions setting out how participants who are not participating in the sole risk project may become participants in sole risk programmes. These provide that they must give notice of their intention to participate within specific time frames and pay 10 times the amount it would have contributed to the joint account with interest at a rate of LIBOR plus 3%.

If a participant fails to pay, the operator shall give notice of this to all the participants. Default in paying any amounts due under the PEDL233 JOA shall result in the other non-defaulting participants covering the shortfall in proportion to their percentage interest and all costs associated therewith shall be borne by the defaulting participant. If the defaulting participant does not remedy the default within 6 working days, it may not dispose of its percentage interest share of petroleum. Instead, such interest will be taken in kind and disposed of on behalf of the defaulting participant. The proceeds of this sale will be used firstly to reimburse the non-defaulting participants, and then to discharge any other liabilities of the defaulting participant. Any proceeds remaining will be returned to the defaulting party. The defaulting participant will also cease to be entitled to representation or to vote at meetings of the JOC. If the default continues for more than 60 days, the non-defaulting participants shall be entitled to forfeit the defaulting participant's interest under the PEDL233 JOA within 30 days. This shall be subject to any necessary consent of the Minister. Until this right of forfeiture is exercised, the joint operations shall continue unless it is decided otherwise.

Each participant is entitled to take in kind and separately dispose of, and will also be required to lift, its percentage interest share in the total quantities of petroleum available under the PEDL233 JOA. The operator is entitled to use as much petroleum as necessary in respect of continuing operations and such quantities shall be excluded from estimates provided.

Each participant may assign its interest with the consent of the remaining non-transferring participants (as well as the Minister) in writing. Consent may only be withheld on the ground that the proposed transferee has not demonstrated its financial responsibility or technical capability. Each participant may withdraw from the PEDL233 JOA provided that all working obligations set out in the licence have been completed and that notice has been given to the other participants. Within 30 days of this notice, another participant may also give notice that it wishes to withdraw. If all the other participants give such notice, the licence shall be surrendered. Where a withdrawal is made, unless the other participants agree, the liabilities and obligations of the withdrawing participant relating to programmes and budgets approved prior to the withdrawal shall remain the responsibility of such withdrawing participant. A withdrawing participant shall remain liable for its percentage interest share of all obligations relating to the decommissioning of joint operation and all sole risk projects that it participated in decommissioned within 10 years of the withdrawal.

The PEDL233 JOA is governed by the laws of England and Wales.

12.8 **Material Contracts relating to Broadford Bridge Licence**

12.8.1 ***Petroleum Exploration and Development Licence 234 ("PEDL234")***

On 1 October 2004 PEDL234 was made between the OGA, Kimmeridge and Magellan. PEDL234 had originally provided for an initial term of 6 years from 1 July 2008 (up until 30 June 2014) with a second term of 5 years to 30 June 2019 and a further 20 year production period to expire on 30 June 2039. These periods have been altered and the initial term of PEDL234 was extended to 30 June 2018 and that the second term of the Licence shall be for 1 year to 30 June 2019. Following expiry of the second term, there may be a further 20 year production period to expire on 30 June 2039. Where PEDL234 has continued in force for the period of the production period (up until 30 June 2039), the OGA, on application being made to it in writing by the licensees, may agree that this can be extended for such further period as the OGA may agree in order to secure the maximum economic recovery of petroleum from the licenced area.

12.8.2 ***Deed of assignment dated 11 August 2016 in respect of PEDL234***

Pursuant to a deed of assignment dated 13 June 2016 entered into between Magellan, Kimmeridge and the OGA, Magellan assigned its 50% interest in PEDL234 to Kimmeridge. Kimmeridge covenanted in favour of the OGA and Magellan that it will perform and observe the terms and conditions contained in PEDL234.

12.8.3 ***Deed of novation dated 11 August 2016 in respect of PEDL234***

Pursuant to a deed of novation dated 13 June 2016 entered into between Kimmeridge, Magellan and the Company, Magellan assigned its interest in a joint operating agreement dated 1 December 2009 which regulated their interest in PEDL234 ("PEDL234 JOA") to Kimmeridge ("Magellan Deed of Novation"). With effect from the date of the Deed of Novation Magellan ceased to be a party to the PEDL234 JOA in respect of its percentage interest in PEDL234 ("Transferred Interest") and Kimmeridge replaced it as a party to the PEDL234 JOA in respect of the Transferred Interest and agreed to assume the liabilities, perform the obligations and be entitled to such rights and benefits in respect of the Transferred Interest as if Kimmeridge had at all times been a party to the PEDL234 JOA in the place of Magellan. With effect from the date of the Magellan Deed of Novation, Kimmeridge had a 100% interest in PEDL234 and the PEDL234 JOA.

Kimmeridge gave undertakings and covenants to Magellan to assume, observe, perform, discharge and be bound by all liabilities and obligations under the PEDL234 JOA. Kimmeridge released and discharged Magellan from the observance, performance and discharge of the liabilities and obligations assumed by Kimmeridge. Magellan is bound and continues to be bound to observe and perform such duties of confidentiality and nondisclosure owed to Kimmeridge.

The Magellan Deed of Novation is governed by the laws of England and Wales.

12.8.4 ***Share purchase agreement dated 13 June 2016 in respect of Kimmeridge Oil & Gas Limited***

Pursuant to a share purchase agreement dated 13 June 2016 entered into by the Company and Celtique Energie Petroleum Limited ("Celtique"), the Company acquired the entire issued share capital of Kimmeridge (the "Kimmeridge SPA"). The consideration payable by the Company to Celtique comprised of:

(a) £625,000 that was satisfied in cash on completion; and

(b) £1,125,000 that was satisfied by the issue to Celtique of 69,854,083 ordinary shares in the capital of the Company at a subscription price of £0.016105 on completion (the "Consideration Shares").

The Company and Celtique agreed that 31 March 2016 would be the "economic date" of the transaction and that all liabilities and benefits relating to the licences held by Kimmeridge would be apportioned as at this date accordingly (save as provided below). The Kimmeridge SPA provided a mutual indemnity in respect of such amounts and requires amounts received by either party that is due to the other pursuant to these provisions to be transferred to them. The Company indemnified Celtique for all environmental and decommissioning liabilities arising following economic date, save for those expressly agreed to be assumed by Celtique or which arise as a consequence of breach of warranty. Customary (but non-extensive) warranties were given to the Company by Celtique.

The Kimmeridge SPA is governed by the laws of England and Wales.

12.9 **Material contracts in respect of the Arreton Licence**

12.9.1 ***Petroleum Exploration and Development Licence 331 ("PEDL331")***

On 21 July 2016 PEDL331 was made between the OGA and a number of parties (including the Company). This licence incorporates the Model Clauses. PEDL331 has an initial term of 5 years from 21 July 2016. At any time not later than 1 month before the expiry of the initial term (20 July 2021) the holders of PEDL331 may give notice that they desire PEDL331 to continue in force for a further 5 year second term until 20 July 2026. The licensees may then apply for a further 20 year production period from the end of the second term which then provides for an anticipated expiration date of 20 July 2046. Where PEDL331 has continued in force for the period of the production period (up until 20 July 2046), the OGA, on application being made to it in writing by the licensees, may agree that PEDL331 can be extended for such further period as the OGA may agree in order to secure the maximum economic recovery of petroleum from the licenced area.

12.9.2 ***Joint Operating Agreement in respect of PEDL331***

On 28 November 2017 the Company entered into a joint operating agreement with Solo Oil Plc ("Solo") and Doriemus Plc ("Doriemus") in respect of PEDL331 ("PEDL331 JOA"). The term of the PEDL331 JOA commenced on 16 September 2016 and shall run until such time as PEDL331 terminates.

Under the PEDL331 JOA, the Company is appointed as operator of the PEDL331. The operator shall have the right to resign at the end of any month by giving not less than 180 days' notice, or in the event that the operator has agreed to assign its entire interest in PEDL331, at the end of any month by giving not less than 90 days' notice. Furthermore, the operator may be removed by the joint operating committee ("PEDL331 JOC") on 90 days' notice where the operator has been deemed to commit a material breach of the PEDL331 JOA. Furthermore, the operator may be removed immediately in default events such as insolvency, cessation of business, the operator ceasing to hold a 25% interest in PEDL331 (unless such interest is still not less than the largest participating interest), cessation of holding any participating interest in PEDL331, the committal of an act of wilful misconduct, or the OGA withdrawing its approval of the operator. In the event that the operator resigns or is removed as operator, it shall have no claim against the other participants. If resignation occurs prior to the completion of all work obligations, it shall not be entitled to any costs or expenses incurred in connection with the change of ownership. If resignation or removal occurs after the completion of work obligations, it shall be entitled to charge costs and expenses to the joint operating account (as may be approved by the PEDL331 JOC). In the event that the operator transfers its obligations as operator, the PEDL331 JOC may order an audit of the joint account and an inventory of all joint property and joint petroleum. The operator shall not be entitled to vote on matters concerning its removal or resignation.

The operator has the right and is obliged to conduct the operations under PEDL331 under the supervision of the PEDL331 JOC. The operator is required to conduct the joint operations in a proper and workmanlike manner in accordance with customary prudent oil and gas practices. The operator shall not be liable for any loss or damage in connection with the operations unless such loss arises from its wilful misconduct or its failure to obtain or maintain insurance by virtue of it being the operator. Liability is to be borne by the participants by reference to their participating interest in PEDL331.

The PEDL331 JOC is established in order to exercise overall supervision and control of joint operations. Each participant is entitled to appoint 1 representative to the PEDL331 JOC. The operator is entitled to appoint the chairman of the PEDL331 JOC. Meetings of the PEDL331 JOC are to be held at least once a quarter, but may also be held upon the request of either participant. Each participant's voting interest shall be equal to its participating interest. All decisions of the PEDL331 JOC shall be made by the affirmative vote of no fewer than 50% of the participants having individually or in aggregate a percentage interest of at least 60%. There are restricted matters requiring the consent of approval of all participants. This includes: (i) the prosecution or defence of litigation; (ii) waiver of a notice period for a meeting of the PEDL331 JOC; (iii) seeking relief from work obligations; (iv) approval for the creation of a new area; (v) satisfaction of a work obligation by a sole risk project (vi) carrying out a sole risk project by the operator; (vii) abandoning joint operations; (viii) approval of the disclosure of confidential information (ix) approval of trading data; and (x) amendment to the terms of the PEDL331 JOA. The PEDL331 JOC shall determine the location and time in respect of the exercise of work obligations. If no determination is made by a date 6 months prior to the expiration of the applicable period to carry out the work obligation, the operator shall propose a programme and timetable. If no programme is agreed within 1 month, the proposal of the operator shall be deemed to be agreed.

All risk, obligations, losses, damages, liabilities and associated expenses incurred in or arising out of the conduct under the joint operations shall be borne by the Participants in proportion to their respective participating interests in PEDL331.

Any participant may undertake sole risk drilling or development provided such sole risk project does not jeopardise or conflict with any programme approved by the PEDL331 JOC or if such works would satisfy an outstanding work obligation unless all of the participants agree. The sole risk project is undertaken at the risk of those participating. Any participant operating a sole risk programme shall indemnify and hold harmless all other participants in respect of that programme. Data and information jointly owned by the participants may be used for a sole risk programme. The operation of a sole risk project will be undertaken by the operator, but it may decline to carry out drilling. In respect of sole risk development, it will not carry out the works unless all other participants agree. Sole risk projects must have first been proposed to, and rejected by, the PEDL331 JOC. The PEDL331 JOA contains provisions setting out how non-participating parties may become participants in sole risk programmes. This provides that they must make a contribution of amounts equal to a 5x multiple of drilling and interim costs that would have been required in the first instance. In addition, any participant opting in will be required to pay an additional amount to the sole risk participants in respect of each sole risk drilling operation in which it did not participate based on the following formula:

$A = B \times C/D$ where:

A = amount to be paid;

B = amount paid in respect of sole risk drilling (based on the 5x multiple);

C = value of the index on the date on which the secretary authorised commencement of the development;

D = the value of the index on the date of termination of such sole risk drilling operation.

The "index" referred to is the index numbers of producer prices published by national statistics in the monthly digest of statistics.

Default in paying any amounts due under the PEDL331 JOA shall result in the other non-defaulting participants covering the shortfall and all costs associated therewith shall be borne by the defaulting participant. Finance provided by the operator bears interest at the rate of 4% above LIBOR. A default may be remedied by the defaulting participant, but if not remedied within 6 working days, such defaulting participant shall cease to be entitled to its substance entitlement of petroleum which will be owned by the non-defaulting participants. Furthermore, they will cease to be entitled to representation at meetings of the PEDL331 JOC. If the default continues for more than 60 days, the non-defaulting participants shall be entitled to forfeit the defaulting participant's interest under the PEDL331 JOA on 30 days' notice (such notice being served after the 60 day default continuation period). This shall be subject to any necessary consent of the OGA.

Each party to the PEDL331 JOA is entitled to take in kind and separately dispose of, and will also be required to lift, its substance entitlement in the total quantities of petroleum available under the PEDL331 JOA. The operator is entitled to use as much petroleum as necessary in respect of continuing operations and such quantities shall be excluded from estimates provided.

Each participant may assign its interest with the consent of the other participants (to be withheld only on grounds that financial and technical capability has not been adequately demonstrated). No assignment may occur if such assignment will lead to a participant's share falling below 5%. Each participant may withdraw from the PEDL331 JOA provided that all working obligations set out in the licence have been completed. No withdrawal may be made where a development programme authorised by the Minister remains incomplete. Where a withdrawal is made, unless the other participants agree, the liabilities and obligations of the withdrawing participant relating to programmes and budgets approved prior to the withdrawal shall remain the responsibility of such withdrawing participant.

The PEDL331 JOA is governed by the laws of England and Wales.

12.10 **Other Material Contracts**

12.10.1 ***Investment Agreement dated 14 November 2017***

On 14 November 2017, the Company, YA II PN Limited ("YA") and Cuart Investments PCC Limited ("Cuart") entered into an investment agreement pursuant to which YA and Cuart would invest up to £10,000,000 in the Company on the terms of the agreement (the "Yorkville Investment Agreement"). Pursuant to the Yorkville Investment Agreement, YA and Cuart (together the "Noteholders") agreed to advance to the Company an aggregate amount of £10,000,000 (the "Advance") in proportion to their respective applicable percentages being 86.66% in respect of YA and 13.34% in respect of Cuart ("Applicable Percentage"). The Advance would be paid in two tranches. The first tranche is £7,500,000 of the Advance ("Tranche 1") and the second tranche is £2,500,000 of the Advance ("Tranche 2").

No interest was payable by the Company to the Noteholders on the outstanding amount of the Advance. Default interest would have accrued at a rate of 15% per annum in respect of any amount that the Company failed to pay by the repayment date (being the date falling 24 months from the relevant advance date).

The Noteholders could, in their absolute discretion, elect to convert such portion of the principal amount of the Advance and/or any interest thereon in integral multiples of not less than £250,000 into ordinary shares in the Company ("Conversion Amount"). On notice to convert, the Company alloted and issued to the Noteholders the Applicable

Percentage of such number of ordinary shares in the Company as is equal to the Conversion Amount divided by the lower of: (i) a fixed conversion price (being 8 pence); or (ii) a variable conversion price (being 90% of the lowest variable weighted average price in respect of the Company's shares during the 5 trading days immediately preceding the date of the conversion notice).

Customary (but non-extensive) warranties and undertakings were given by the Company to the Noteholders. Customary (non-extensive) indemnities given by the Company to the Noteholders.

The Noteholders agreed that for so long as any amount is outstanding under the Yorkville Investment Agreement, it would not, and it would not cause its affiliates to hold any net short position in respect of the Company's shares.

The Noteholders were unable to assign or transfer its rights to any of its affiliates. It may not assign its rights, benefits or obligations to any other person without the written consent of the Company.

The Yorkville Investment Agreement is governed by the laws of England and Wales.

All advances made pursuant to this agreement have now been converted to Ordinary Shares and no amount is currently owing to YA or Cuart.

12.10.2 ***Placing Agreement dated 19 May 2017***

In 19 May 2017, the Company and Cenkos Securities PLC ("Cenkos") entered into a placing agreement pursuant to which Cenkos agreed to procure subscribers for the Company's shares (the "Cenkos Placing Agreement"). The Company agreed to appoint Cenkos to obtain subscribers for the placing of up to 812,500,000 new ordinary shares in the Company for 0.80 pence per share.

Customary warranties were provided by Cenkos and the Company. Customary indemnities are provided by the Company to Cenkos in respect of claims and liabilities etc. against an indemnified person (being Cenkos and any associate of Cenkos, any division of Cenkos, and the current and former directors, officers (other than auditors), employees and agents of each of such persons) in relation to their obligations under the Placing Agreement, unless it is as a result of gross negligence, wilful default or fraud of Cenkos or any indemnified person. The indemnities shall extend to include all costs and expenses including legal fees and expenses (plus VAT) suffered or incurred by any indemnified person or in connection with claiming and/or enforcing its or their rights under the indemnities.

Cenkos was paid a commission of 5% of the aggregate value at the placing price (0.80 pence per placing share) of the placing shares. The Company also agreed to issue to Cenkos warrants to subscribe for a maximum of Ordinary Shares equal in number to 5.0% of the placing shares issued.

The Cenkos Placing Agreement is governed by the laws of England and Wales.

12.10.3 ***Placing Agreement dated 14 June 2018***

On 14 June 2018, the Company and WH Ireland entered into a placing agreement pursuant to which WH Ireland agreed to procure subscribers for the Company's shares (the "WH Ireland First Placing Agreement"). The Company agreed to appoint WH Ireland to obtain subscribers for the placing of up to 611,111,105 new Ordinary Shares in the Company for 0.9 pence per Ordinary Share.

Customary warranties were provided by WH Ireland and the Company. Customary indemnities are provided by the Company to WH Ireland in respect of claims and liabilities etc. against an indemnified person (being WH Ireland and every entity which is a parent undertaking of WH Ireland or any subsidiary undertaking of, and every entity controlled by, WH Ireland or any such parent undertaking and every person who is a director, officer, consultant or agent of WH Ireland or the above mentioned entities) in relation to their obligations under the Placing Agreement, unless it is as a result of gross negligence, wilful default or finally judicially determined fraud of WH Ireland or any indemnified person.

WH Ireland was paid a commission of 5% of the aggregate value at the placing price being 0.90 pence per Ordinary Share of the placing shares. The Company also agreed to issue to WH Ireland warrants to subscribe for a maximum of Ordinary Shares equal in number to 0.5% of the placing shares issued.

The WH Ireland Placing Agreement is governed by the laws of England and Wales.

12.10.4 ***Warrant Instrument dated 15 June 2018***

On 15 June 2018, the Company granted to WH Ireland warrants to subscribe for up to 0.5% of the placing shares (as defined in the WH Ireland Placing Agreement) (the "WH Ireland Warrant Instrument"). Under the WH Ireland Warrant Instrument WH Ireland has been granted warrants to subscribe for 30,555,555 Ordinary Shares at an exercise price of 0.9 pence which warrants are exercisable from the date that the placing shares (under the WH Ireland Placing Agreement) are admitted to AIM until the earlier of the date that no further subscription rights are exercisable or a date falling three years from the date of Admission of the placing shares.

12.10.5 ***Letter of Engagement between Novum Securities Limited and the Company***

An engagement letter dated 02 July 2018 was signed by the Company with Novum Securities Limited ("Novum") under which Novum agreed to act as the Company's sole placing agent in respect of a fundraise of £5,000,000 by way of the issue of Shares at a placing price of 2p per Share. In consideration for providing the services specified in the engagement letter, the Company agreed to pay Novum a commission equal to 5% of the gross aggregate value of funds introduced by Novum.

12.10.6 ***Placing Agreement dated 04 July 2018***

On 04 July, the Company and WH Ireland entered into a placing agreement pursuant to which WH Ireland agreed to procure subscribers for the Company's shares (the "WH Ireland Second Placing Agreement"). The Company agreed to appoint WH Ireland to obtain subscribers for the placing of up to 100,000,000 new Ordinary Shares in the Company for 2 pence per Ordinary Share.

Customary warranties were provided by WH Ireland and the Company. Customary indemnities are provided by the Company to WH Ireland in respect of claims and liabilities etc. against an indemnified person (being WH Ireland and every entity which is a parent undertaking of WH Ireland or any subsidiary undertaking of, and every entity controlled by, WH Ireland or any such parent undertaking and every person who is a director, officer, consultant or agent of WH Ireland or the above mentioned entities) in relation to their obligations under the Placing Agreement, unless it is as a result of gross negligence, wilful default or finally judicially determined fraud of WH Ireland or any indemnified person.

WH Ireland was paid a commission of 5% of the aggregate value at the placing price being 2 pence per Ordinary Share of the placing shares.

The WH Ireland Placing Agreement is governed by the laws of England and Wales.

12.10.7 ***Consultancy Agreement with Matt Cartwright Consulting Limited***

On 12 July 2018, the Company entered into a consulting agreement with Matt Cartwright Consulting Limited ("MCCL") pursuant to which MCCL makes available the services of Matt Cartwright to the Company in order to provide technical and operating services which may be terminated on 4 weeks' notice. The Company pays to MCCL a consultancy fee of £13,750 per month in connection with the services provided pursuant to the consulting agreement. The consulting agreement also includes standard confidentiality provisions.

13. UNITED KINGDOM TAXATION

The following statements are intended only as a general guide to certain UK tax considerations relevant to prospective investors in the Shares. They do not purport to be a complete analysis of all potential UK tax consequences of acquiring, holding or disposing of Shares. They are based on current UK tax law and what is understood to be the current published practice

(which may not be binding) of HMRC as at the date of this Document, both of which are subject to change, possibly with retrospective effect. The following statements relate only to Shareholders who are resident (and, in the case of individuals, resident and domiciled or deemed domiciled) for tax purposes in (and only in) the UK (except in so far as express reference is made to the treatment of non-UK residents), who hold their Shares as an investment (other than in an individual savings account or pension arrangement) and who are the absolute beneficial owners of both the Shares and any dividends paid on them. The tax position of certain categories of Shareholders who are subject to special rules, such as persons who acquire (or are deemed to acquire) their Shares in connection with their (or another person's) office or employment, traders, brokers, dealers in securities, insurance companies, banks, financial institutions, investment companies, tax-exempt organisations, persons connected with the Company or the Group, persons holding Shares as part of hedging or conversion transactions, Shareholders who are not domiciled or not resident in the UK, collective investments schemes, trusts and those who hold 5% or more of the Shares, is not considered. Nor do the following statements consider the tax position of any person holding investments in any HMRC-approved arrangements or schemes, including the enterprise investment scheme or venture capital scheme, able to claim any inheritance tax relief or any non-UK resident Shareholder holding Shares in connection with a trade, profession or vocation carried on in the UK (whether through a branch or agency or, in the case of a corporate Shareholder, a permanent establishment or otherwise).

Prospective investors who are in any doubt as to their tax position or who may be subject to tax in a jurisdiction other than the UK are strongly recommended to consult their own professional advisers.

13.1 **UK taxation of dividends**

The Company is not required to withhold tax when paying a dividend. Liability to tax on dividends will depend upon the individual circumstances of a Shareholder.

UK resident individual shareholders

Under current UK tax rules, specific rates of tax apply to dividend income. As of 1 April 2016, the notional dividend tax credit system was abolished. Instead, there is a nil rate of tax (the "Nil Rate Amount") which from 6 April 2018, applies to the first £2,000 of dividend income received by an individual Shareholder who is resident for tax purposes in the UK for 2018/2019. Dividend income in excess of the Nil Rate Amount (taking account of any other dividend income received by the Shareholder in the same tax year) will be taxed at the following rates for 2018/2019: 7.5% (to the extent that it falls below the threshold for higher rate income tax); 32.5% (to the extent that it falls above the threshold for higher rate income tax and is within the higher rate band); and 38.1% (to the extent that it is within the additional rate). For the purposes of determining which of the taxable bands dividend income falls into, dividend income is treated as the highest part of a Shareholder's income. In addition, dividends within the Nil Rate Amount which would (if there was no Nil Rate Amount) have fallen within the basic or higher rate bands will use up those bands respectively for the purposes of determining whether the threshold for higher rate or additional rate income tax is exceeded.

UK resident corporate shareholders

Shareholders within the charge to UK corporation tax which are "small companies" for the purposes of Chapter 2 of Part 9A of the Corporation Tax Act 2009 will generally not be subject to UK corporation tax on any dividend received provided certain conditions are met (including an anti-avoidance condition).

A UK resident corporate Shareholder (which is not a "small company" for the purposes of the UK taxation of dividends legislation in Part 9A of the Corporation Tax Act 2009) will be liable to UK corporation tax (currently at a rate of 19% from 1 April 2017, and is expected to reduce to 17% from 1 April 2020) unless the dividend falls within one of the exempt classes set out in Part 9A. Examples of exempt classes (as defined in Chapter 3 of Part 9A of the Corporation Tax Act 2009) include dividends paid on shares that are "ordinary shares" (that is shares that do not carry any present or future preferential right to dividends or to the Company's assets on its winding up) and which are not "redeemable", and dividends paid to a person holding less than 10% of the issued share capital of the payer (or any class of that share capital in respect of which the distribution is made). However, the exemptions are not comprehensive and are subject to anti-avoidance rules.

Non-UK resident Shareholders

Non-UK resident Individual Shareholders who receive a dividend from the Company are treated as having paid UK income tax on their dividend income at the dividend ordinary rate (7.5%). Such income tax will not be repayable to a non-UK resident Individual Shareholder. A non-UK resident Shareholder is not generally subject to further UK tax on dividend receipts.

A non-UK resident Individual Shareholder may also be subject to taxation on dividend income under local law, in their country or jurisdiction of residence and/or citizenship. A shareholder who is not solely resident in the UK for tax purposes should consult his own tax advisers concerning his tax liabilities (in the UK and any other country) on dividends received from the Company in respect of liability to both UK taxation and taxation of any other country of residence or citizenship.

Taxation of chargeable gains

Individual and corporate Shareholders who are resident in the United Kingdom may, depending on their circumstances (including the availability of allowances, exemptions or reliefs), realise a chargeable gain or an allowable loss for the purposes of taxation of capital gains on a sale or other disposal (or deemed disposal) of Shares.

UK resident individual Shareholders

For an individual Shareholder within the charge to UK capital gains tax, a disposal (or deemed disposal) of Ordinary Shares may give rise to a chargeable gain or an allowable loss for the purposes of capital gains tax. The rate of capital gains tax on disposal of shares is 10% (2018/2019) for individuals who are subject to income tax at the basic rate and 20% (2018/2019) for individuals who are subject to income tax at the higher or additional rates. An individual Shareholder is entitled to realise an annual exempt amount of gains (currently £11,700) for the year to 5 April 2019 without being liable to UK capital gains tax.

UK resident corporate Shareholders

For a corporate Shareholder within the charge to UK corporation tax, a disposal (or deemed disposal) of Ordinary Shares may give rise to a chargeable gain at the rate of corporation tax applicable to that Shareholder (currently 19% with effect from 1 April 2017, and is expected to reduce to 17% from 1 April 2020) or an allowable loss for the purposes of UK corporation tax.

Non-UK tax resident Shareholders

An individual Shareholder who is only temporarily resident outside the United Kingdom may, under anti-avoidance legislation, still be liable to UK tax on any capital gain realised when they resume UK tax residence (subject to available allowances, exemptions or reliefs) upon a sale or other disposal (or deemed disposal) of Shares.

Shareholders who are not tax resident in the United Kingdom and, in the case of an individual Shareholder, not temporarily non-resident, will not generally be subject to UK taxation of capital gains on a sale or other disposal (or deemed disposal) of Shares unless such Shares are used, held or acquired for the purposes of a trade, profession or vocation carried on in the UK through a branch or agency or, in the case of a corporate Shareholder, through a permanent establishment. Shareholders who are not resident in the United Kingdom may be subject to non-UK taxation on any gain under local law, and should consult their own tax advisors concerning their tax liabilities upon a sale or other disposal (or deemed disposal) of shares.

13.2 **Stamp Duty and Stamp Duty Reserve Tax ("SDRT")**

No UK stamp duty or SDRT will be generally payable on the issue of Shares. AIM qualifies as a recognised growth market for the purposes of the UK stamp duty and SDRT legislation. Accordingly, for so long as the Shares are admitted to trading on AIM and are not listed on any other market no charge to UK stamp duty or SDRT should arise on their subsequent transfer. If the Shares cease to qualify for this exemption their transfer on sale will be subject to stamp duty and/or SDRT (generally at the rate of 0.5% of the consideration subject to a de minimis threshold), although special rules apply in respect of certain transfers including transfers to market intermediaries and transfers into clearance services or depositary receipt arrangements. The statements in this paragraph apply to any holders of Shares irrespective of their residence, and are a summary of the current position and are intended to be a general guide to the current stamp duty and SDRT position. Shareholders in any doubt about their position should seek appropriate tax advice.

13.3 **Inheritance tax**

The Shares will be assets situated in the United Kingdom for the purposes of UK inheritance tax. A gift of such assets during lifetime or on the death of, an individual holder of such assets may (subject to certain exemptions and reliefs) give rise to a liability to UK inheritance tax, even if the holder is or was neither domiciled in the United Kingdom nor deemed to be domiciled there, under certain rules relating to long residence or previous domicile. Generally, UK inheritance tax is not chargeable on gifts to individuals if the transfer is made more than seven complete years prior to the death of the donor. For inheritance tax purposes, a transfer of assets at less than full market value may be treated as a gift and particular rules apply to gifts where the donor reserves or retains some benefit following a gift of an asset. Special rules also apply to close companies and to trustees of settlements who hold Shares bringing them within the charge to inheritance tax. A change to inheritance tax may also arise if the shares are transferred to a trust during their lifetime or on death. Holders of Shares should consult an appropriate professional adviser if they make a gift of any kind or a transfer at less than market value, or if they intend to hold any Shares through a trust or similar indirect arrangements. They should also seek professional advice in a situation where there is potential for a double charge to UK inheritance tax and an equivalent tax in another country or if they are in any doubt about their UK inheritance tax position.

THE DISCUSSION ABOVE IS A GENERAL SUMMARY. IT DOES NOT COVER ALL TAX MATTERS THAT MAY BE OF IMPORTANCE TO A PROSPECTIVE INVESTOR. EACH PROSPECTIVE INVESTOR IS URGED TO CONSULT ITS OWN TAX ADVISOR ABOUT THE TAX CONSEQUENCES TO IT OF AN INVESTMENT IN THE SHARES IN LIGHT OF THE INVESTOR'S OWN CIRCUMSTANCES.

14. SHARE OPTIONS

14.1 The Directors and the Proposed Director believe that it is important that directors, employees of, and consultants to the Group are appropriately and properly motivated and rewarded and have issued the Options referred to in paragraph 22 of Part V for that purpose.

14.2 The Company has not adopted a formal share option scheme in order to issue options to directors, employees and consultants, but does so on the terms of a customary form option deed which is used for all options issued. The number of options, vesting date, exercise price and exercise period stated in options issued are determined by the Board as deemed appropriate in relation to each issue of options.

15. WORKING CAPITAL

The Directors and the Proposed Director are of the opinion, having made due and careful enquiry that, taking into account the existing facilities available to the Company the Company has sufficient working capital for its present requirements, that being at least 12 months from the date of this Document.

16. ENVIRONMENTAL ISSUES

The Company is not aware of any environmental issues or risks affecting the utilisation of the property, plant or machinery of the Company.

17. LITIGATION

On 1 March 2018, the Company, as lead claimant, commenced proceedings in the High Court of Justice (Business and Property Courts of England and Wales Property Trusts and Probate list (Ch)) in London seeking various restraining orders (the "Injunctions") against persons unknown who may fall into certain categories of prohibited behaviour.

The intention of the Injunctions is to protect the Company's interests at the operational sites for PEDL137, PEDL246 and PEDL234 from prohibited activities from persons unknown, such as trespass to land and other obstructive behaviour (including slow walking on the public highway, lorry surfing, intimidation of contractors or unlawful means conspiracy).

The target of the Injunctions are those who seek to protest against the Company's business activities outside of the parameters permitted by law and it follows other similar injunctions brought by companies within the oil and gas exploration industry.

The Injunction hearing was heard in the High Court in London between 2-5 July 2018 and judgement has been reserved for the time being and is not expected to be given until August 2018 at the earliest.

Other than as set out above, no member of the Group is or has been involved in any governmental, legal or arbitration proceedings which may have or have had since incorporation a significant effect on the Group's financial position or profitability and, so far as the Directors and the Proposed Director are aware, there are no such proceedings pending or threatened against the Group.

18. SIGNIFICANT CHANGES

There has been no significant change in the financial or trading position of the Group or Company since 30 September 2017, being the date on which the Group and Company's latest audited accounts were prepared.

No material changes have occurred since 11 July 2018, the date of the Competent Person's Report, the omission of which would make the Competent Person's Report misleading.

19. RELATED PARTY TRANSACTIONS

19.1 Save as set out below, there have been no related party transactions entered into by the Company prior to the date of this Document which are considered material either in the context of the Admission or in the context of the turnover of the Company in the relevant periods.

20. GENERAL

20.1 The auditors of the Company are Chapman Davis LLP, Chartered Accountants and Registered Auditors, of 2 Chapel Court, London SE1 1HH.

20.2 In accordance with Rule 28 of the Aim Rules, this Document does not contain historical financial information of the Company, which would otherwise be required under section 20 of Annex I of the Prospectus Rules. The Group's consolidated audited financial statements and annual reports for the years ended 30 September 2017, 30 September 2016 and 30 September 2015 are available from the Company's website at the following link: http://www.ukogplc.com/page.php?pID=82. The most recently published Annual Reports and Accounts for the year ended are also contained within the Appendix to this Document.

20.3 The financial information contained in this Document does not comprise statutory accounts for the purposes of section 434 of the Companies Act.

20.4 It is estimated that the total expenses payable by the Company in connection with the Admission will amount to £400,000 (including VAT).

20.5 WH Ireland Limited is authorised and regulated in the United Kingdom by the FCA. WH Ireland has given and not withdrawn its written consent to the issue of this Document with references to its name in the form and context in which they appear.

20.6 The Competent Person, Xodus Group Ltd has given and not withdrawn its written consent to the issue of this Document with the inclusion in it of its report and letter and references to it and to its name in the form and context in which they respectively appear.

20.7 The Competent Person has confirmed to each of the Company and WH Ireland Limited that: (i) they have reviewed the information which relates to information contained in the report on the Company in this Document, set out in Part III "Competent Person's Report", which is contained in a portion of this Document other than in such report; and (ii) such information contained in a portion of this Document other than such report is, to the best of the Competent Person's knowledge, correct on its facts, accurate, balanced, complete, not inconsistent with such report and contains no material omissions likely to affect its import.

20.8 The Competent Person has no material interests in the Company.

20.9 Where information which appears in this Document has been sourced from a third party, the information has been accurately reproduced. As far as the Directors, the Proposed Director and the Company are aware and able to ascertain from such information supplied or published by a third party, no facts have been omitted which would render any reproduced information false, inaccurate or misleading.

20.10 The accounting reference date of the Company is currently 30 September.

20.11 Save as set out in this Document, there are no patents or intellectual property rights, licences or particular contracts which are of fundamental importance to the Group's business.

20.12 This Document has been prepared in accordance with current UK tax legislation, practice and concession and interpretation thereof. Such legislation and practice may change and the current interpretation may therefore no longer apply.

20.13 Except as disclosed in the financial information which has been incorporated by reference in this Document, the Company has not been a party to any transaction with any related party required to be disclosed under International Financial Reporting Standards.

20.14 Save as set out in this Document, as at the date of this Document the Company has no principal investments in progress and there are no future principal investments on which the Company has made a firm commitment.

20.15 The Directors and the Proposed Director are not aware of any trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Company's prospects for at least the current financial year.

20.16 The Directors and the Proposed Director are not aware of any exceptional factors that have influenced the Company's activities.

20.17 Save as disclosed in this Document, no person (other than the professional advisers referred to in this Document) has received, directly or indirectly, from the Company or has entered into a contractual arrangement to receive, directly or indirectly, from the Company on or after the date of this Document, fees totalling £10,000 or more or securities in the Company with a value of £10,000 or more calculated by reference to the Current Share Price or any other benefit to the value of £10,000 or more in respect of services provided to the Company during the period between incorporation of the Company and the date of this Document.

20.18 Save as disclosed, there is no Director, Proposed Director or member of a Director or the Proposed Director's family who has a related financial product (as defined in the AIM Rules) referenced to the Ordinary Shares.

20.19 Save as set out in this Document and so far as the Directors are aware, there are no arrangements relating to the Company, the operation of which may at a subsequent date result in a change of control of the Company.

20.20 Save as disclosed in this Document, no person has made a public takeover bid for the Company's issued share capital since its incorporation or in the current financial period and the Company is not aware of the existence of any takeover pursuant to the rules of the City Code.

21. DOCUMENTS AVAILABLE FOR INSPECTION

Copies of the following Documents may be inspected at the registered office of the Company during usual business hours on any weekday (Saturdays, Sundays and public holidays excepted) from the date of this document until one month following Admission:

21.1 the Memorandum and Articles of Association of the Company;

21.2 the audited accounts of the Group for financial year ending 30 September 2017 as outlined in Section IV; and

21.3 this Document.

22. AVAILABILITY OF THIS DOCUMENT

Copies of this Document will be available free of charge from the date of this Document until 1 month following Admission, at the Company's and the Nomad & Broker's office as per page 4 of this Document. Additionally, an electronic version of this Document will be available on the Company's website, www.ukogplc.com.

Dated 13 July 2018

UK Oil & Gas Investments PLC

Annual Report and Accounts
For the year ended 30 September 2017

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Forward-looking Statement

This annual report contains 'forward-looking information', which may include, but is not limited to, statements with respect to the future financial and operating performance of UK Oil & Gas Investments PLC, its subsidiaries, investment assets and affiliated companies, the estimation of oil reserves or resources, the realisation of resource estimates, costs of production, capital and exploration expenditures, costs and timing of the development of new assets, requirements for additional capital, governmental regulation of operations and exploration operations, timing and receipt of approvals, licenses, environmental risks, title disputes or claims.

Often, but not always, forward-looking statements can be identified by the use of words such as 'plans', 'expects', 'is expected', 'budget', 'scheduled', 'estimates', 'forecasts', 'intends', 'anticipates' or 'believes', or variations (including negative variations) of such words and phrases, or state that certain actions, events or results 'may', 'could', 'would', 'might' or 'will' be taken, occur or be achieved. Forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of UK Oil & Gas Investments PLC and/or its subsidiaries, investment assets and/or its affiliated companies to be materially different from any future results, performance, or achievements expressed or implied by the forward-looking statements.

Such factors include, among others, general business, economic, competitive, political and social uncertainties; the actual results of current exploration activities; conclusions of economic evaluations and studies; fluctuations in the value of UK Pounds Sterling relative to the United States Dollar, and other foreign currencies; changes in project parameters as plans continue to be refined; future prices of products; possible variations recovery rates; failure of plant, equipment or processes to operate as anticipated; accidents, labour disputes and other risks of the oil and gas industry; political instability, adverse weather conditions, insurrection or war; delays in obtaining governmental approvals or financing or in the completion of development or construction activities.

Although UK Oil & Gas Investments PLC has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking statements, there may well be other factors that cause actions, events or results to differ from those currently anticipated, estimated or intended.

Forward-looking statements contained herein are made as of the date of this annual report and UK Oil & Gas Investments PLC disclaims any obligation to update any forward-looking statements, whether as a result of new information, future events or results or otherwise. There can be no assurance that forward-looking statements will prove to be accurate, as actual results and future events could differ materially from those anticipated in such statements. Accordingly, readers should not place undue reliance on forward-looking statements due to the inherent uncertainty therein. Nothing in this annual report should be construed as a profit forecast.

HIGHLIGHTS

- Broadford Bridge-1 step-out exploration well was spudded in May 2017 within UK Oil and Gas Investments PLC's ("UKOG's") 100% owned, 300 km^2 PEDL234 Weald Basin licence. A successful sidetrack BB-1z was drilled within 6 days.
- Oil flowed continuously on pump from the Kimmeridge Limestone ("KL") 5 test zone together with the recovery of oil and gas to surface from multiple flow tests. Most extensive testing ever of an onshore exploration well conducted over 1000 plus feet of perforations.
- The oil discovery provides "proof of concept" for the Kimmeridge continuous oil deposit and proves further evidence to support a regionally extensive natural-fracture network capable of delivering oil to surface from the KL without reservoir stimulation.
- This financial year's (2018) imminent long-term Portland and KL flow testing and appraisal drilling programme at Horse Hill (operated by Horse Hill Developments Ltd) will follow up on the successful flow test results of early 2016, where an aggregate stabilised natural flow rate of 1,688 barrels of oil per day was achieved from three Portland and KL zones.
- The Horse Hill testing and subsequent drilling programme is geared towards delivering both conventional Portland oil production and the KL's first commercially viable stable oil production in 2019.
- UKOG's total gross attributable P50 Kimmeridge Clay Formation ("KCF") oil in place ("OIP") increased by 72% to 17.1 billion barrels in Weald Basin licence interests.
- Total UKOG net attributable KL OIP increased by 348% to 2.4 billion barrels via the 100% Broadford Bridge (PEDL234) acquisition.
- PEDL234 KCF P50 OIP was calculated by Nutech as 7.1 billion barrels, of which 1.7 billion barrels lie within the KL.
- HH-1 Portland oil discovery's OIP increased by 53% to 32 million barrels. Gross 2C contingent resources were estimated as 1.5 million barrels with further significant recoverable resource upside via early water re-injection.

STATEMENT FROM THE CHAIRMAN

2017 has been a transformational year for UKOG. We have continued to build a spread of investments, focused on UK onshore oil assets centred upon our exciting and industry-leading position in the Weald Basin's Kimmeridge Limestone ("KL") oil play. These investments are underpinned by further discovered oil resources outside the KL play contained within five low-risk undeveloped oil and gas discoveries, which alone contain recoverable resources of over 14 million barrels net to the Company.

Our investment portfolio delivers a good balance of risk-reward between the KL's higher risk-higher reward growth potential and the lower risk-moderate reward of proven conventional oil discoveries.

PEDL234 - Broadford Bridge

The potential and further understanding of the KL oil play has been our prime focus over the past year. The Broadford Bridge-1 and 1z ("BB-1/1z") oil discovery, located in the Weald's largest single licence, the 300 km^2 PEDL234, 100% UKOG owned and operated by Kimmeridge Oil and Gas Limited ("KOGL"), delivered on its technical objectives, namely: "proof of concept" for the existence of a continuous oil deposit within the Kimmeridge section, the determination of the deposit's lateral extent and supporting evidence for a regionally extensive natural fracture system within Kimmeridge Limestones. Importantly, the fracture system was shown to deliver oil to surface without the need for reservoir stimulation utilising massive hydraulic fracturing ("fracking").

The BB-1/1z exploration well, for which operations ceased in March 2018, was a bold 27 km step-out from HH-1, designed to provide proof of our geological concept that oil within the KL, as demonstrated at the Company's Horse Hill-1 discovery ("HH-1"), was part of a regionally extensive continuous oil deposit. Since the two prior Weald Basin wells which tested and recovered Kimmeridge oil to surface, HH-1 and Balcombe-1, were drilled within well-defined mapped conventional structural features, it was necessary to demonstrate that the BB-1/1z location, without any discernible conventional hydrocarbon trapping configuration (i.e. no structural or stratigraphic closure) contained moveable oil within the Kimmeridge.

Consequently, the multiple live, mobile oil shows seen in cuttings and drilling fluids, light oil seen in open fractures in cores, the recovery of oil and gas to surface from KL1 to KL4 flow tests, together with the light oil flowed continuously to surface from the KL5 test zone, presents further compelling evidence that the Upper Jurassic Kimmeridge of the central Weald Basin contains an extensive continuous oil accumulation. We believe that the data provided from BB-1/1z and analysed to date provides us proof of geological concept.

These live, mobile oil occurrences, together with corresponding rock and electric log data likely demonstrate a KL oil deposit of up to 1400 ft vertical extent exists at BB-1z. Geochemical analyses further support this proof of concept, as all oil samples from both BB-1z and HH-1 analysed to date are determined by Geomark Research to come from the same Upper Jurassic shale source, i.e. the oil lies within or immediately adjacent to the Upper Jurassic rocks where it was generated, one of the fundamental characteristics of a continuous oil accumulation.

The flow test campaign also contributed significantly to our understanding of the Kimmeridge play. Flow test inflows and pressure data, together with the specialist analysis of formation image log and core fractures, also demonstrated that the Kimmeridge contains both a local and regionally developed natural-fracture system, key to the future commercial viability of the KL deposit. These fractures are present in both limestones and shales.

Significantly, prior to the testing campaign these fracture-related data showed the key fracture sets to be open, i.e. likely able to transmit fluids under reservoir conditions. Consequently, neither the drilling fluid nor drilling and coring methodology appears to have "damaged" the reservoir (i.e. blocked or plugged fractures surrounding the well bore). As to whether these fractures remained fully or partly open during the necessary pressure draw-downs following acidisation used during testing is currently under investigation.

The ability of these fractures to deliver hydrocarbons to surface at BB-1z without stimulation (i.e. without "fracking") was demonstrated by both the KL5 test and by high initial instantaneous flow-back rates from the KL4 and KL3 test zones of 466 and 719 barrels of fluid per day respectively.

The finding of near identical reservoir geology and geochemistry between HH-1 and BB-1/1z also provided a valuable understanding that the Kimmeridge oil deposit stretches around 30 km across the Weald basin from the north-east at Horse Hill to the southern edge of our 100% PEDL234 Licence, with BB-1/1z likely lying on the deposit's southernmost boundary.

It is worth noting that since BB-1 lies in the extreme south of PEDL234, the well also demonstrates that most of the licence lies within the deposit's most prospective sweet spot. It is in this area where the Upper Jurassic shales are thickest, most deeply buried and have likely generated the most significant volumes of in-situ hydrocarbons.

Consequently, in the light of significant positive technical learnings and understanding of the wider KL deposit gained from BB-1/1z, the Company has accelerated its PEDL 234 drilling plans. We have now selected two further drilling sites in the central area of the licence, the first of which, subject to regulatory approval, should commence drilling in 2019. The required necessary planning application and Environment Agency ("EA") application are currently in preparation and are scheduled to be submitted by the summer.

Whilst the KL flow rates observed to date are likely sub-commercial, we are encouraged by the multiple occurrences of mobile oil observed in the well and their correlation with good calculated oil saturations in electric logs and core analyses. Consequently we are currently exploring new methods and technologies that might enable us to achieve higher sustainable oil rates and commercial viability from the 1400 vertical feet of oil-saturated KL reservoir rock interpreted at BB-1z.

With this in mind, serious consideration is being given to a possible future short sidetrack, BB-1y. The sidetrack's objective would include a selective re-test of the main KL units, likely utilising an alternate completion methodology, new completion fluids, the possible use of small-bore radial drilling and other reservoir stimulation techniques. Any future work at BB-1/1z would likely take place after a successful trial of such alternate methods and technologies in the next planned PEDL234 exploration well. Such future operations will require further in-depth study of the vast amount of data collected during drilling, coring, electric logging and testing before any conclusions can be finalised.

It is worth reflecting that, to date, the first two wells of UKOG's KL exploration programme, HH-1 and this year's BB-1/1z have produced Kimmeridge oil to the surface. This is no mean feat for a new play, particularly one involving both the first large-scale potential continuous oil deposit identified in the UK and one reliant on flowing oil to surface via naturally fractured reservoir rocks. Prior to these two wells, only one well (the 1986 Balcombe-1 well) within the Weald Basin's central thousand square mile area had tested the Kimmeridge reservoir, returning Kimmeridge oil to the surface.

PEDL137 – Horse Hill

This financial year's imminent long-term KL flow testing and appraisal drilling programme at Horse Hill (operated by Horse Hill Developments Ltd) will follow up on the successful flow test results of early 2016, where an aggregate stabilised natural flow rate of 1,688 barrels of oil per day was achieved from the Portland and two KL reservoir zones, KL3 and KL4.

The Horse Hill testing programme is solely geared towards determining the commerciality of both the conventional Portland oil accumulation and the continuous oil deposit within KL3 and KL4. The subsequent drilling phase, contingent upon a successful testing outcome will prepare the way for full time production at Horse Hill. If the programme is successful it is planned that Horse Hill will deliver stable oil production in 2019, subject to obtaining the necessary regulatory consents. Although the HH-1 well is not intended to be an immediate producer, any oil produced from the tests will, of course, be sold. Sales volumes are not incorporated into budgetary planning, but a successful testing outcome would generate further oil sales revenues for the Company.

Other Weald Basin and SE England Investments

The significant growth potential of the overall KL play in our portfolio is also solidly underpinned by oil within five other low-risk undeveloped oil discoveries. These discoveries contain third-party audited recoverable resources of over 14 million barrels net to UKOG (excludes discovered oil in the KL play and Godley Bridge Portland gas). Of these recoverable resources over half lie within the Horse Hill and Arreton (Isle of Wight) conventional Portland discoveries, both the subject of ongoing operational activities and investment. As stated above, first-oil from the Horse Hill Portland discovery is planned in 2019.

In the light of the "KL proof of concept" by BB-1/1z, UKOG's planned forward KL programme will now see a doubling of the Weald's drilled and tested Kimmeridge wells, with three more planned exploration step-out wells over the next 18 months, at Horse Hill, in PEDL234 (subject to regulatory approvals) and the Holmwood prospect (operated by Europa Oil & Gas).

Outlook

The key to maximising UKOG's growth remains a combination of the KL oil exploration play, which will continue to be our flagship for the foreseeable future, balanced by low-risk appraisal and development projects such as the Horse Hill Portland and Arreton Portland discoveries. The importance of our conventional assets should not be underestimated. Whilst the KL offers the potential of around 1,000 barrels per day per well if Horse Hill can be widely replicated, both Arreton and Horse Hill Portland potentially offer low-risk gross flow rates of several hundred barrels per day per well in the first year of production.

Our industry leading flagship KL programme's goal is to demonstrate that the play can generate economic returns and is repeatable over most of UKOG's 672 gross km² licence holding in the basin's "sweet spot". This is the largest KL licence holding of any company. Whilst the play is still developing, the goals of our investee companies are simple:

- Demonstrate commercial viability from one, possibly two, wells at Horse Hill in 2018. If this is successful and funding is forthcoming, move Horse Hill into long-term commercial production in 2019.
- Demonstrate that the KL sequence is commercially viable across three other locations in the Weald basin: Holmwood and two further wells in PEDL234. All of these will be subject to the relevant regulatory approvals and sufficient funding.
- Define and secure a batch of new drill sites, submit 'batch' planning consent applications to ensure a "hopper" of ready to drill locations.
- Consider submitting production planning applications immediately post-discovery and prior to commercial declaration. This will help deliver production from each well as early as regulatory permitting allows.
- Further consolidate our holdings in discoveries and developments, where possible, and acquire further prospective acreage and opportunities.

Planning permissions are in place for the full Horse Hill long-term testing and appraisal programme and Holmwood well. At the time of writing our investee companies are forecast to be able to asses commerciality in Q2 of 2018 and 2019 respectively.

For our non-KL discoveries, our focus will be firmly upon Horse Hill Portland and Arreton on the Isle of Wight. In a similar fashion to the KL strategy, we already have Horse Hill planning permission and EA permits in place to enable us to test the Portland in HH-1 and drill the necessary HH-2 well. At Arreton, a well site is being secured, and planning/permit application prepared. In the success case, production will be achieved as soon as the regulatory system allows, but it is envisaged that Arreton will be drilled in 2019.

We will continue to review, rank, prune and add to our investment portfolio to ensure our resources are employed only on the most technically and economically viable projects. This process was recently evidenced by the removal of the offshore Isle of Wight P1916 from the portfolio due to low technical prospectivity and the selected drill site's environmental sensitivity.

Corporate

During the financial year, UKOG raised gross proceeds of £7.46 million via the issue of equity which in addition to the £2.44 million in cash was used to fund £8.7 2 million of investment in exploration and evaluation assets, at the end of the year the Company had £1.74 million in cash and cash equivalents.

Cenkos Securities plc were appointed as UKOG's joint broker, and they were instrumental in the equity fund raise from a mix of institutional and retail investors which has partly funded Broadford Bridge. Subsequent to the year-end UKOG raised £10 million in convertible debt of which £5.25 million was outstanding at the date of the publication of this report.

Sadly, in November 2016, Jason Berry a director of the Company died suddenly following a short illness, Jason joined the Board in August 2014 and was instrumental in providing a firm financial footing for the early growth of the Company.

In March 2017, Allen Howard was appointed as Non-Executive Director of the Company. Allen has brought a wealth of technical expertise in well analysis and completions, huge experience and knowledge from the US onshore sector, plus a global network of industry and finance contacts. He is a hugely valuable addition to our team to help move our KL exploration and conventional assets into production.

The social licence obtained via our positive engagement process and good practices led to swift and unopposed grants of planning consent for BB-1/1z's flow testing extension and the extensive flow testing and appraisal programme at Horse Hill. My congratulations go to our entire team for the open, honest and professional way they have communicated with our neighbours and stakeholders.

Our operations and related technical analyses have also further demonstrated our commitment to fully understanding our assets. The extensive data acquisition programme of BB-1/1z has provided us with invaluable new insights into the key controls on the play and, consequently, represents a sound investment fundamental to our future success. We have continued to work with global experts, such as Chemostrat Inc., Geomark Research, Halliburton, Nutech, Premier Oil Field Laboratories, Schlumberger and Xodus Group, together with internationally recognised academic institutions such as Imperial College, London and the University of Utah's Exploration Geoscience International, to provide us with the best advice to help turn our ideas and oil discoveries into economic reality.

The progress made during 2017 would not have been possible without the efforts of UKOG's management team, consultants, supportive shareholders and other stakeholders. We would like to take this opportunity to thank all of them as we continue to deliver our strategy.

The Strategic Report was approved by the Board on 28 March 2018 and signed on its behalf by:

Stephen Sanderson
Executive Chairman & Chief Executive Officer
28 March 2018

STRATEGY & BUSINESS MODEL

UKOG is an oil and gas investment company which specialises in investing in new geological ideas, concepts and methodologies to find and produce oil from previously unexplored rock formations within established oil-producing basins. Since relisting on London's AIM market ("AIM") at end-2013, driven initially by the successful Horse Hill Portland and Kimmeridge oil discoveries in 2014, our UK-focused asset acquisitions and successful investee drilling programme has made UKOG one of the most recognised and stand-out players in the entire UK onshore sector.

UKOG has a portfolio of direct and indirect interests in nine UK onshore exploration, appraisal, development and production assets, all situated within the Weald and Purbeck-Wight Basins of southern England. We are by far the largest acreage holder in the south of England, and the fourth largest in the overall UK onshore, with assets covering 942 gross km².

UKOG's portfolio includes five non-KL conventional oil discoveries together with a significant industry-leading position in the new flagship KL oil deposit or "play". This exciting new play has the potential for exceptional growth in the near and foreseeable future. UKOG, as the creator of the KL play, holds by far the largest acreage position within the play's most prospective area or "sweet spot", covering 672 gross km². Our sweet spot licences are independently calculated to contain a significant 21% of the play's total resource with a mean or average Kimmeridge oil in the ground within UKOG licences of 17 billion barrels.

We have built a portfolio that has the potential to generate significant returns for the Company and its shareholders. It includes a balanced portfolio of low-risk oil & gas production, appraisal and development assets as well as high upside exploration assets.

PRINCIPAL RISKS AND UNCERTAINTIES

UKOG continuously monitors its risk exposures and reports to the board of directors ("The Board") on a regular basis. The Board reviews these risks and focuses on ensuring effective systems of internal financial and non-financial controls are in place and maintained.

Risk	Mitigation	Magnitude & Likelihood
Exploration Risk, UKOG's Investee companies, fail to locate and explore hydrocarbon bearing prospects that have the potential to deliver commercially, e.g. key wells are dry or less successful than anticipated	Analysis of available technical information to determine work programme. Risk sharing arrangements entered into to reduce downside risk	Magnitude- High Likelihood - High
Permitting Risk, planning, environmental, licensing and other permitting risks associated with our investees operations particularly with exploration drilling operations.	UKOG's investee companies have to date been successful in obtaining the required permits to operate. Therefore, UKOG considers that such risks are partially mitigated through compliance with regulations, proactive engagement with regulators, communities and the expertise and experience of the management teams.	Magnitude- High Likelihood - Medium
Liquidity Risk, because of its investee's exploration and development activities	The Board regularly reviews UKOG's cashflow forecast and the availability or adequacy of its current facilities to meet UKOG's cash flow requirements	Magnitude- High Likelihood - Medium

For UKOG and its investments, it was a busy financial year and continued to be so post period end. Although during the year our investees were primarily focused on the Broadford Bridge exploratory well and associated flow testing, they were also preparing for a busy 2018.

In particular, it was important to secure the relevant regulatory approvals for the extended well or flow tests and, if successful, the drilling of two further wells at the Horse Hill oil discovery. These well tests are geared towards enabling the determination of commerciality to be made in Q2 of 2018, and subject to the necessary regulatory consents, stable long-term production from at least one well in 2019.

UKOG has been actively exploring other new opportunities and is acquiring further well sites, together with preparing planning applications for further exploration and appraisal drilling, notably in PEDL234 and onshore Isle of Wight (PEDL331).

The Company also made important decisions for two of our other investments: Markwells Wood and offshore Isle of Wight.

In the post reporting period, UKOG announced the decision that to focus upon appraising the onshore PEDL331 Arreton oil discovery and satellite exploration prospects, it had informed the Oil and Gas Authority ("OGA") that it will not seek any further extension to UKOG's only offshore licence P1916, which has now been relinquished.

In order to progress the acquisition of new site-specific hydrogeological data over and around the Markwells Wood well pad our investees temporarily withdrew their planning application to the South Downs National Park Authority ("SDNPA"). UKOG is considering whether to resubmit a revised planning application in 2018 after the completion of the planned data acquisition and upon the conclusions of ongoing technical conversations with EA. The Company acted in good faith that this position was understood and agreed by SDNPA and EA.

Subsequent to the year-end, UKOG received a breach of condition notice from SDNPA. UKOG and its investees do not consider the notice to be valid, and UKOG is considering its position on Markwells Wood in discussion with SDNPA and EA.

A more detailed review of each of UKOG's investments and the activities during the year is included below

PEDL234 - Broadford Bridge

During the previous financial year, UKOG acquired PEDL234 (300 km², net interest 100%), significantly increasing its acreage holding within the KL play's prime prospective area and making UKOG the largest player within both the Weald Basin and the KL play. The licence is operated by Kimmeridge Oil & Gas Limited ("KOGL"), a wholly-owned subsidiary of UKOG.

Onshore licence PEDL234 is one of the UK's largest, covering 300 km², three times the size of our Horse Hill licence PEDL137. The licence contains multiple look-alike geological features to the Horse Hill KL oil discoveries and an eastern extension of the Godley Bridge-1 conventional Portland gas discovery.

The licence straddles both the northern and southern flanks of the Weald Basin and, more crucially, the basin centre, where the Kimmeridge is thickest, most thermally mature and is consequently interpreted to contain the most significant volumes of in-situ generated KL oil. The results of the BB-1z and HH-1 wells now firmly puts the prime prospective are of the KL play, or sweet spot, firmly over the central and northern areas of the Nutech's calculated Kimmeridge P50 OIP figures of 7.1 billion barrels within PEDL234, of which 1.7 billion barrels lie within the limestones, gives comfort to this viewpoint.

Importantly, the licence acquisition included the existing Broadford Bridge well pad, planning permission and EA consent to drill the Broadford Bridge-1 ("BB-1") exploratory well.

The intent of the BB-1 exploratory well and flow tests was to demonstrate that moveable light oil in commercial quantities exists within the KL on the southern side of the Weald Basin, 27 km to the south-west of the Horse Hill Kimmeridge oil discovery. The BB-1 technical objectives were as follows; confirm that KL oil is contained within a resource or continuous oil deposit, determine the southerly extent of the deposit and provide supporting evidence for a regionally extensive natural fracture system within the KL.

To achieve these goals, the well was planned to acquire the most comprehensive data set gathered to date over the KL sequence. Data acquisition included an extensive conventional coring and electric logging programme aimed at characterising natural fracturing and other key reservoir and engineering parameters. Once drilled, cored and logged, the well would be completed to allow for flow testing of four KL zones.

We currently conclude that the most important technical goals of the drilling, coring and flow testing programme were achieved, namely: further proof of the KL "geological concept", the determination of the deposit's lateral extent and the presence of a regional scale open natural-fracture network capable of flowing oil to surface from the KL without reservoir stimulation.

The BB-1 well was deliberately designed as a deviated or "slant" well with a steady angle throughout the Kimmeridge so that it would penetrate an optimal number of near vertical natural fractures within the five naturally-fractured KL's (KL1-KL5). Drilling commenced on the BB-1 exploration well in May 2017 and was successfully drilled at an inclination of around 50 degrees to vertical to a depth of around 6,000 ft or 1,900 metres, terminating within the Jurassic Corallian sandstone.

The well's orientation was deliberately chosen to intersect the maximum number of potentially open fractures by drilling at approximately 90 degrees to the predicted open natural fracture orientation within the KL. The open natural fracture orientation was derived from analysis of the Weald's regional stress field and available wells with image logs. Drilling and coring of the BB-1 exploration well was completed in July 2017.

It should be noted that the KL's open natural fracture orientation recorded at the well was as predicted (within 5 degrees). Consequently the well's original design was validated. Subsequent specialist analysis of formation image log and core fractures, also demonstrated that the Kimmeridge contains both a local and regionally developed natural-fracture system, key to the future commercial viability of the KL deposit. These fractures were found to be present in both the Kimmeridge's limestones and shales and vertically throughout the entire Kimmeridge section.

An extensive coring programme was succesfully completed acquiring some 550 feet of 4-inch core. A continuous core totalling 520 feet was cut within the KL3 to KL5 section and a single 30 ft core within the deeper KL2 limestone. Specialist core analysis was undertaken on the cores by COREX in Aberdeen and Premier Oilfield Laboratories in Houston, Texas, a specialist in the analysis of the shale and unconventional reservoirs of the USA. These cores represent the first significant coring of both Kimmeridge limestones and shales in the UK and provide the essential calibration for subsequent electric log analyses.

The coring programme provided the first evidence for the technical proof of KL geological concept. The cores retrieved from the KL5 section saw mobile, light oil recovered to surface. Oil in fact was seen at the site seeping from open natural fractures. The oil was sampled and analysed and was confirmed to have been generated by an Upper Jurassic shale source and of nearly identical geochemical composition and origin to the Horse Hill KL 3 and KL4 oils. Subsequent analysis of the KL5 limestone core also revealed that the matrix of the limestone itself was also oil saturated, occupying a significant 6% by weight of the actual rock. Further live oil traces were seen in cores throughout the coring process.

Following coring, the well was drilled ahead to total depth. Good mobile oil shows were seen in cuttings, and in the mud retort samples throughout the KL sequence together with elevated wet gas readings. Oil shows and elevated gas readings were found to coincide with fractures interpreted from image logs and appeared to be connected to several lost circulation zones (i.e. drilling fluid entering open fractures connected to the wellbore). Indirectly therefore, it appears that the lost circulation zones indicate that fractures were open and apparently well-connected and likely the source of the oil shows.

Significantly, prior to the testing campaign fracture-related data showed the key fracture sets to be open i.e. likely able to transmit fluids under reservoir conditions. Consequently, neither the drilling fluid nor drilling and coring methodology appears to have “damaged” the reservoir (i.e. blocked or plugged fractures surrounding the well bore). As to whether these fractures remained fully or partly open during the necessary pressure draw-downs following acidisation used during testing is currently under investigation.

After completion of the BB-1 exploration well it became apparent that the duration and difficulty of coring such highly-fractured rocks in an inclined well within the overall compressional stress regime of the Weald, together with the multiple pipe trips and significant electric logging runs likely exacerbated potential borehole breakouts creating ledges protruding into the borehole. These ledges prevented the final 7 inch casing from reaching the necessary depth in the inclined well. Caliper log data clarly showed that the well maintained an acceptable degree of rugosity with absolutely no evidence of any collapse.

The inability to case the well in the main reservoir section combined with potential plugging of near wellbore fractures with lost circulation material likely meant that future testing would be compromised. Therefore the decision was made to drill, log and case a mechanical sidetrack exploration well, BB-1z. This was drilled over a 6 day period in August 2017.

The BB-1z sidetrack was drilled from below the Purbeck Limestones and replicated the BB-1 exploration well some 200 ft to the south. The sidetrack delivered a fresh, near identical section of the KL, with minimal formation damage designed to be optimal for well completion and flow testing. Mobile oil traces were recovered from the drilling fluid throughout the Kimmeridge section and both oil and wet gas shows were at approximately the same level as that seen in the original BB-1 borehole.

In September 2017 the BB-1z exploration sidetrack was completed with an aggregate total of 1,064 ft of perforations over eight naturally fractured zones, including within the new uppermost reservoir zone, KL5 and within a 500 ft section of the deepest KL0 section. Over the next six months, the Company embarked on an extended well test across the identified KL zones (KL0-KL5).

The first four tests were conducted over the original 4-zone production completion. Each test covered multiple peforated sections which included significant sections of interbeddedd fractured KL shales. Acidisation was therefore not selectively administered to any specific limestone horizon. Whilst the results of the tests showed inflows indicating some initial permeabilty together with natural gas blows, the results were disappointing. it was concluded that during the significant pressure draw-downs associated with the test’s coiled tubing lifting methodology, the fractures within the predominantly shale test sections closed-up, reducing permeability effectively to zero. Consequently, any possibility of sustained flow rates from such shale dominated sections could likely only be obtained via reservoir stimulation beyond the scope of BB-1z’s existing regulatory permissions.

It should also be noted that the KL0 section, comprising 500 ft thick fractured shale and interbedded thin limestones was tested within an uncemented section below a cement plug at the base of KL1, possibly further reducing the efectiveness of the acid wash. However some inflow and gas blow was recorded indicating at least an initial inflow of methane from the Kimmeridge. The KL0 zone was not subsequently selectively tested.

Given that traces of oil had been recovered to surface from each of the four tests, it was decided to abandon nitrogen lifting, open all four test zones and lift the well with a linear rod pump. This lift achieved oil to surface in measureable quantities but with no definition as to which zone or zones may have contributed to flow. It is, however, interesting that the KL5 zone, which subsequently flowed oil to surface during the latter selective test campaign was not perforated, suggesting oil flow came from a deeper zone in the well. The recovered oil was sampled and analysed, showing it was geochemically identical to that found in the KL5 cores and HH-1 crudes.

In October 2017 management made the decision to proceed with a workover of the well and implement a revised selective testing programme. The revised testing methodology was similar to that undertaken at the Horse Hill oil discovery, utilisng a rod pump and nitrogen cylinders to provide initial lift to the well.

The decision to workover the BB1-z exploration well also followed an assessment by two independent consultants and the Company that the quality of the cement-bond between the well casing and the surrounding rock was not optimal, particularly over some of the secondary interbedded limestone and shale units in KL1, KL2 and KL5. As a result the completion programme had in some places not effectively connected the BB-1z well to the best open natural fractures, therefore the testing up to that point had been unable to accurately assess the flow potential from the KL sequences.

The revised testing programme consisted of nine individual selective test zones throughout the KL each of around 50-100 ft of vertical extent. In November 2017 UKOG reported the results from KL1. Two short initial tests over secondary shale-dominated fractured secondary reservoir objectives within the KL1 were performed. The interbedded shale and limestone stringers returned gas to the flare and traces of oil to surface. The second KL1 test, recorded an inflow were returned to the well at an initial natural flow rate of over 370 barrels per day, accompanied by a wet gas blow and traces of oil to surface. The KL2 test, again in a secondary section of shales and interbedded limestones, showed an initial inflow of returned completion fluids of 99 barrels per day.

Although these KL1 and KL2 zones are interpreted on electric logs to be hydrocarbon bearing corresponding to the oil recovered to surface, the Company concluded that sustained commercial flow rates from the shale dominated KL1 could likely only be obtained via reservoir stimulation beyond the scope of its existing regulatory permissions. As with the original 4-zone test programme we believe that the acid wash likely entered the highly fractured shales, not the thinner, lesser fractured limestones and under the pressure draw-downs exterted by both nitrogen lifting and pummping closed up during testing.

Oil and associated gas were recovered to surface from within three tests in the uppermost KL3 and KL4. High initial instantaneous flow-back rates were obtained from the KL4 and KL3 test zones of between 466 and 719 barrels of fluid per day respectively, but with no sustained flow. Due to the limited time remaining on the planning consent and the ongoing costs of testing, the decision was made to spend no further time on these zones and proceed ahead to the KL5 zone.

In February 2018 the Company reported that oil had flowed to surface from the naturally fractured KL5 reservoir. Fluid returns to the surface, measured as half-hourly instantaneous pumped flow-rates over a 96-hour near-continuous period, ranged between 10 to 72 barrels per day. The fluid returns through the test equipment consisted of a mixture of oil plus returned spent-acid from an acid wash treatment, with no observed obvious formation water component. Associated oil-cut steadily increased to over 30%, with intermittent periods exceeding 50% by volume. The test continued to flow oil to surface at similar rates and oil-cuts as reported on 20 February. Although the continuous flow showed evidence of gradual cleaning and stabilisation over further days, due to planning permission time-constraints, the test was halted to test the deeper KL1 zone.

The KL1 test, over a newly perforated 40 ft naturally-fractured limestone section, showed encouraging initial fluid inflow rates of between 40-50 barrels per day post acidisation. However, no fluids were able to flow to surface due to a series of significant mechanical problems that could not be rectified within the remaining planning consent window. However, after the test halt, upon retrieving the uppermost packer and tubing, live mobile light oil was seen mixed with completion fluids.

Well test operations were completed in late March 2018 and the well was suspended for possible future re-entry and interventions.

As previously reported on 20 February, the presence of KL5 oil flowing to surface, oil returned to surface from KL1-KL4 flow tests, together with mobile oil in cores and drilling fluids, presents further compelling evidence that the Upper Jurassic Kimmeridge of the central Weald Basin contains an extensive continuous oil accumulation. These live, mobile oil occurrences, together with corresponding rock and electric log data likely demonstrate a deposit of up to 1400 ft vertical extent at BB-1/1z.

Geochemical analyses further support this conclusion, as all oil samples from both BB-1z and HH-1 analysed to date are determined by Geomark Research to come from the same Upper Jurassic shale source, i.e. the oil lies within or immediately adjacent to the Upper Jurassic rocks where it was generated, one of the key aspects of a continuous oil accumulation.

The near identical reservoir geology and geochemistry between HH-1 and BB-1/1z demonstrates that this continuous oil deposit has around a 30 km north-south extent, with BB-1/1z likely lying on the deposit's southernmost boundary. UKOG is the largest licence holder within the deposit's most prospective area or "sweet-spot", much of which resides in PEDL234.

Flow test inflows and pressure data, together with electric image log analyses, also demonstrate that the Kimmeridge contains both a local and regionally developed natural-fracture system, key to the future commercial viability of the KL deposit.

Whilst the KL flow rates observed are likely sub-commercial, given the multiple occurrences of mobile oil observed in the well and their correlation with good calculated oil saturations in electric logs and core analyses, we are exploring new methods and technologies that might enable us to achieve higher sustainable oil rates and commercial viability from the 1400 vertical feet of oil-saturated KL reservoir rock interpreted at BB-1z.

With this in mind, serious consideration is being given to a possible future short sidetrack, BB-1y. The sidetrack's objective would include a selective re-test of the main KL units, likely utilising an alternate completion methodology, new completion fluids, the possible use of small-bore radial drilling and other reservoir stimulation techniques. Any future work at BB-1/1z would likely take place after a successful trial of such alternate methods and technologies in the next PEDL234 exploration well.

PEDL234 – Future KL Exploration Plans

Due to the significant positive technical learnings and understanding of the wider KL play gained from BB-1/1z, the Company has accelerated its plans, to drill further wells within the PEDL234 licence. Two drilling sites have now been finalised, both located firmly within what the Company interprets to be the KL oil deposit's most prospective sweet-spot.

Both new locations lie within geological features in the central area of the 300 km² licence where the thickest, deepest buried and the most thermally mature (i.e. oil generative) KL section resides.

Lease terms on the first location have been agreed and a preliminary meeting with the Local Planning Authority is scheduled for this week. It is expected that a formal planning application will be submitted in Q3 2018, with drilling and testing in 2019 subject to obtaining necessary regulatory consents and funding.

PEDL234 - Godley Bridge

Godley Bridge also lies within onshore licence PEDL234. Godley Bridge-1 (“GB-1”) was drilled in 1982/83 to a depth of 8,473 ft in the Lower Jurassic. Gas was discovered in the Upper Portland Sandstone and tested 1-1.5 mmscfd on test. In 1986 an appraisal well (GB-2) was drilled which came in very low to prognosis and well below any gas water contact seen in the first well. Subsequent investigations showed a major problem with the seismic static corrections in the area which had led to the appraisal well being badly positioned. Since the mid-1990’s more modern processing has solved this problem and there is a high degree of confidence that a new well can be drilled up-dip of the original discovery to test a thicker section.

Although only the Portland D Sand Unit was proven to be gas bearing in the GB-1 well, it is possible that in a more crestal position the gas column extends down into the E1 Sand Unit below. Both of these reservoir units are well developed along the Godley Bridge anticlinal axis, the thick, clean sandstones with good reservoir properties extending to the east and west along the northern edge of the Weald Basin.

The Portland F Sand Unit, occurring at the base of the Portland interval in the Leigh-1 and Collingdean Farm-1 wells, could be a useful additional reservoir objective on the eastern extension of the anticlinal axis.

Technical studies by Xodus and UKOG show that the GB-1 Portland gas discovery likely extends into the north of PEDL234. More importantly, Nutech’s petrophysical analysis of the GB-1 well also indicates that significant oil potential lies within the Kimmeridge underlying the Portland gas accumulation.

The Kimmeridge section encountered by the GB-1 well is thicker and more deeply buried than at Horse Hill, indicating the possibility for greater oil generation per unit volume of Kimmeridge shale than at Horse Hill. The Godley Bridge discovery also lies along a pronounced east-west faulted structural flexure, some 15 km in extent, and which is a prime candidate for the development of an associated significant fracture-network within both limestones and shales. Wet gas and oil shows were recorded throughout the Kimmeridge in GB-1 as is the case at the HH-1 discovery.

KOGL is finalising the selection of a well site and associated planning/permit applications. The well, subject to funding and the necessary planning consents, would both further appraise the Portland gas discovery and test the deeper KL in an optimised location.

PEDL 137 & PEDL 246 - Horse Hill

Onshore licences PEDL137 (99.3 km², net interest 32.435%) and PEDL246 (43.6 km², net interest 32.435%) contain the HH-1 conventional Portland oil discovery and the KL3 and KL4 discoveries within the KL continuous oil accumulation. These discoveries were flow tested in 2016 resulting in a combined aggregate initial flow rate of 1688 barrels of oil per day.

Planning permission for the forthcoming Horse Hill extended well or flow test and appraisal programme was received on 1 November 2017, and on 23 March 2018, all pre-commencement planning conditions were discharged by Surrey County Council. As at the date of the publication of this document licence operator Horse Hill Developments Ltd (“HHDL”) has received the necessary permission to begin testing and drilling from EA and is now awaiting final approval from OGA. A programme of civil construction works in preparation for this programme is currently underway at the site. Long-term production testing is anticipated to commence in Q2 of 2018.

The planned production tests are specifically designed to prove that commercial volume of OIP. Consequently, we expect that HHDL will be to be able to make a determination of the commerciality for the Kimmeridge and Portland following these test results from Q2 of 2018.

HHDL has informed us that, subject to a successful test they plan to drill a new Portland appraisal well, HH-2, plus a further deviated KL wellbore, HH-1z, from the existing HH-1 wellbore. These wells are designed to be completed as future permanent oil producers, with first oil planned in 2019, subject to the necessary regulatory approvals and field development consent.

The HH-1 Portland oil discovery's importance was further boosted by Xodus' report in February 2017, which determined that the P50 OIP had increased to 32 million barrels, an increase of 53% from the 21 million barrels reported prior to 2016 flow testing. Gross Contingent Resources rose to 1.5 million barrels (0.5 million barrels net to UKOG) with a further 1.7-6.6 million barrels gross recoverable (0.5-2.1 million barrels net to UKOG) being possible via implementation of a water re-injection scheme.

Other Horse Hill-related Activity Highlights

- "Retention Areas" and related work programmes over the entirety of PEDL137 and PEDL246 were agreed with OGA, which extend both licences to 2021.

- UKOG acquired a further 1.9% interest in HHDL from Regency Mines plc.

Holmwood

Onshore licence PEDL143 (91.8 km², net interest 40%, operator Europa Oil & Gas (Holdings) plc) contains the Holmwood prospect, which is a look-alike feature to the HH-1 Portland and Kimmeridge oil discoveries, 8 km to the east. Planning permission is in place to drill the Holmwood-1 well to test the Portland and the Kimmeridge in 2018.

In September 2017 UKOG further increased its interest in the Holmwood PEDL143 licence and now holds a 40% stake, being the largest single participant in the joint venture.

The Holmwood-1 well is an important part of our Kimmeridge oil development strategy, designed to demonstrate that the results of Horse Hill can be replicated across the Weald and that the Kimmeridge contains a continuous oil deposit. The planned deviated well will also test a shallower Portland sandstone objective in a look-alike geological setting to the Horse Hill and Collendean Farm Portland discovery.

Isle of Wight

Onshore licence PEDL331 (200 km², net interest 65%) contains the Arreton-1 and Arreton-2 Portland oil discovery. The Isle of Wight onshore is an important element of our growth portfolio, with a focus upon fracture-enhanced conventional limestone and sandstone oil discoveries and look-alike explortaion prospects that have been missed by previous operators.

The PEDL331 licence was formally granted to UKOG by OGA in September 2016. Angus Energy assigned its 5% licence interest to Doriemus Plc and UKOG was formally appointed by OGA as the licence operator. The Joint Operating Agreement was executed with Doriemus and 30% partner Solo Oil Plc. UKOG is finalising the selection of the well site and preparing a planning application to drill the Arreton-3 appraisal well, again with a view to achieving early oil production in the event of success.

A volumetric and resource analysis by Xodus Group Ltd ("Xodus") of the Arreton-2 oil discovery ("Arreton Main") and the adjacent low-risk Arreton North and South Prospects ("Arreton Prospects") calculated a significant aggregate gross P50 OIP of 219 million barrels, with corresponsing net Company P50 Contingent Resources of 10.2 million barrels and 6.8 million barrels for the Arreton Main discovery and the Arreton South exploration prospect respectively.

Sites for the Arreton-3 appraisal well together with an Arreton-South exploration well have now been finalised. The Arreton-3 site is currently under negotiation and the plan is to submit a planning application by end of Summer 2018 for possible drilling towards the end of 2019.

Offshore licence P1916 (UKOG 100%) was relinquished due to low technical prospectivity, environmental sensitivity of the site and to focus upon the higher reward, technically robust, lower risk discovered oil of the onshore Isle of Wight.

Markwells Wood

Onshore licence PEDL126 (11.2 km², net interest 100%) contains the Markwells Wood-1 oil discovery.

In September 2016 UKOG submitted a planning application to the South Downs National Park Authority ("SDNPA") to further appraise and develop the Markwells Wood-1 oil discovery. The planned two-phase programme would see four horizontal wells drilled within the conventional Great Oolite limestone reservoir. The discovery is a geological look-alike to the neighbouring Horndean producing oil field (UKOG net interest 10%). However, this planning application was withdrawn in May 2017 to allow for further discussions with EA and to allow the gathering of site-specific information relating to groundwater and hydrogeology.

Subsequent to the year-end UKOG received a breach of condition notice from SDNPA. UKOG does not consider the Notice to be valid. Moreover, UKOG is of the opinion that the notice was misleading as it failed to recognise UKOG's extensive good faith discussions with the various regulatory authorities. Critically, the notice fails to mention that UKOG submitted a new Markwells Wood planning application to SDNPA dated 16 September 2016; the condition to rehabilitate within the specified timeframe was effectively suspended while SDNPA considered this new application.

UKOG, therefore, does not consider the Notice to be valid and is considering its position on Markwells Wood in discussion with SDNPA.

Baxters Copse

Onshore licence PEDL233 (89.6 km², net interest 50%, Operator IGas Energy plc) contains the Baxters Copse-1 oil discovery.

Horndean

Onshore licence PL211 (27.3 km², net interest 10%, operator IGas Energy plc). Horndean continued stable oil production throughout the period averaging around 140 gross bopd in 2017.

Avington

Onshore licence PL070 (18.3 km², net interest 5%, operator IGas Energy plc). Average Avington production in 2017 was around 35 bopd. Due to high operating costs and issues with one of the production wells, Avington production was temporarily shut down in early 2018.

Brockham and Lidsey

During the period, UKOG completed the sale of its shares in Angus Energy. Therefore, UKOG no longer has an indirect interest in the Brockham and Lidsey oil fields.

Matt Cartwright
Chief Operating Officer
28 March 2018

Income Statement
In 2017, production continued from Horndean and Avington generating revenues of £0.21 million. The operating loss decreased in 2017 to £2.39 million from £2.89 million loss in 2016. This decrease is due to lower consultant and administrative cost. Loss for the year was £2.27 million an increase from the £1.97 million loss in 2016. This variance was due to the £1.03 million credit to the Income statement as a result of the negative goodwill associated with the acquisition of PEDL234.

Cash Flow / Financing
The group raised £7.12 million (net of costs) during the year, which along the cash and cash equivalents at the beginning of the period of £2.44 million was utilised to further our investees exploration and evaluation of the Weald basin (£8.72 million). We also disposed of our stake in Angus Energy which netted £0.57 million in cash.

Balance Sheet
During 2017, non-current assets increased by £8.53 million primarily as a result of the increased expenditure on exploration and evaluation assets, in particular, the drilling and coring of BB-1/1z which increased the exploration and evaluation assets from £6.19 million in 2016 to £15.11 million in 2017. The increase in expenditure on exploration and evaluation assets was also the primary driver for the increase in total assets to £27.25 million (2016: £18.52 million).

At the end of the period, the Group had £1.78 million (2016: £2.44 million) in cash and cash equivalents.

UKOG ‘s total liabilities increased to £4.08 million (2016: 0.59 million). This was driven by the increase in trade and other payables, associated with the increased operational activities at the Broadford Bridge.

Subsequent to the year-end UKOG) entered into a £10 million loan agreement ("Loan") with Cuart Investments PCC Ltd and YA II PN Ltd, an investment consortium arranged by Riverfort Global Capital Ltd. The first tranche of £7.5 million was drawn down by the Company in November, with the second tranche of £2.5 drawn down on 31 December 2017. The first and second tranches are repayable on 13 November 2019 and 31 December 2019, respectively.

The Loan attracts 0% interest and may, at the sole discretion of the Investors, be converted into new ordinary shares in the Company. The conversion price is the lower of either a share price of 8 pence, or 90% of the Company's lowest daily volume weighted average price during the five days prior to the conversion date. The Loan is convertible in tranches of not less than £250,000, with a limit of £3 million per quarter, unless otherwise agreed by the Company.

UKOG can repay the principal amount of the Loan at any time for cash, provided that the 5-day VWAP of the Company's equity is less than 8 pence and a prepayment fee equal to 10 percent of the principal amount of the Loan then outstanding is paid by the Company to the Investors.

At the date of the publication of this document, the outstanding amount due on this loan is £5.25 million.

Kiran Morzaria
Finance Director
28 March 2018

RESERVES, RESOURCES AND OIL IN PLACE

In the past year, there has been a 72% increase in UKOG's total gross attributable P50 Kimmeridge oil in place ("OIP") to 17.1 billion barrels in its Weald Basin licence interests. There has been a 348% increase in total UKOG net attributable KL OIP to 2.4 billion barrels via the PEDL234 (Broadford Bridge) acquisition.

Nutech calculated PEDL234 Kimmeridge P50 OIP of 7.1 billion barrels, of which 1.7 billion barrels lie within the KL. The HH-1 Portland oil discovery's OIP increased by 53% to 32 million barrels.

UKOG has estimated net attributable P50 reserves of 98,200 barrels of oil (effective 31 December 2017, see Table 1 below). This figure is 19% lower than last year, due continuing production and the sale of UKOG's shares in Angus Energy, together with UKOG's net attributable interests in Brockham and Lidsey.

At the time of writing, UKOG also has 22.6 million barrels ("MMbbl") of net attributable P50 Contingent and Prospective Resources, 14.4 million barrels of this is in four non-KL discoveries (see Table 2 below). Table 2 includes net Contingent Resources for the Horse Hill Portland reservoir. However, Table 2 does not include net Contingent Resources for the PEDL234 Godley Bridge Portland gas discovery.

Gross unrisked oil in place ("OIP") for UKOG's licence interests are shown in Table 3. These OIP volumes are dominated by the Kimmeridge OIP estimated for the Horse Hill and Broadford Bridge/Godley Bridge licences.

Table 1: UKOG's Producing Fields, Gross and Net Reserves (at 31 December 2017)

Asset	UKOG Interest	Gross Reserves (barrels)			Net Reserves (barrels)			Source, Date
		P90	P50	P10	P90	P50	P10	
Horndean[1]	10%	713,000	982,000	1,219,000	71,300	98,200	121,900	IGas, Dec 2017
Avington[1]	5%	-	-	-	-	-	-	IGas, Dec 2017
TOTALS					**71,300**	**98,200**	**121,900**	

Note:

IGas's internal reserves estimates for Horndean and Avington: proven ("1P"), proven + probable ("2P"), proven + probable + possible ("3P") are deterministic, not probabilistic.

Table 2: UKOG's Unrisked Gross and Net Resources

Asset	Licence	UKOG's Interest	Gross Resources (MMbbl)			Net Resources (MMbbl) [1]			Source, Date
			P90	P50	P10	P90	P50	P10	
Horndean [2,5]	PEDL126	10%	N/A	0.82	N/A	N/A	0.08	N/A	IGas, Dec 2017
Avington [2,5]	PEDL070	5%	N/A	0.74	N/A	N/A	0.04	N/A	IGas, Dec 2017
Markwells Wood [2]	PEDL126	100%	0.6	1.3	2.7	0.6	1.3	2.7	Xodus, September 2015
Holmwood [3]	PEDL143	40%	0.8	3.4	12.5	0.3	1.4	5.0	Europa/ERCE, June 2012
Baxters Copse [2,4]	PEDL233	50%	2.7	4.6	6.7	1.3	2.3	3.4	IGas/DeGMcN, July 2016
Horse Hill Portland [2]	PEDL137	32.4%	0.6	1.5	3.6	0.2	0.5	1.2	Xodus, January 2017
Arreton Main [2]	PEDL331	65%	9.9	15.7	24.1	6.4	10.2	15.7	Xodus, January 2016
Arreton Prospects [3]	PEDL331	65%	4.0	10.5	21.6	2.6	6.8	14.0	Xodus, January 2016
TOTALS						**11.4**	**22.6**	**42.0**	

Notes:

1. UKOG net share.
2. Contingent Resources.
3. Prospective Resources.
4. Contingent Resources are in barrels of oil equivalent, as they include gas.
5. IGas's internal reserves estimates for Horndean and Avington: proven ("1P"), proven + probable ("2P"), proven + probable + possible ("3P") are deterministic, not probabilistic.

Table 3: UKOG Unrisked Gross OIP

Asset	Licence	UKOG's Interest	OIP (MMbbl) or GIIP (bcf)			Source & Date
			Low P90	Best P50	High P10	
Onshore Isle of Wight	PEDL331	65%	144	219	322	Xodus, January 2016
Markwells Wood	PEDL126	100%	34	47	63	Xodus, September 2015
Holmwood	PEDL143	30%	4	15	55	Europa/ERCE, June 2012
Horndean	PL211	10%	27	56	110	Northern/RPS, Feb 2010
Avington	PEDL070	5%	25	59	110	IGas/Senergy, July 2014
Baxters Copse	PEDL233	50%	N/A	52	N/A	IGas/Senergy, July 2014
Horse Hill Portland	PEDL137	31.2%	22	32	47	Xodus, January 2017
Horse Hill Oil	PEDL137/246	31.2%	3,131	9,245	17,519	Nutech, June 2015
Horse Hill Oil	PEDL137/246	31.2%	N/A	10,993	N/A	Schlumberger, August 2015
Broadford Bridge/ Godley Bridge Oil	PEDL234	100.0%	3,158	7,120	13,717	Nutech, December 2016

SAFETY AND THE ENVIRONMENT

The United Kingdom has one of the most stringent regulatory regimes in the world. There are multiple standards and guidelines that our investee companies are required to conform to prior to and during operations.

Prior to the start of drilling the wells our investee companies must have multiple permits and consents. These include a license from the Oil and Gas Authority to commence operations, planning permissions from the local planning agencies, local landowner consents, environmental permits for the EA and permits from the Health and Safety Executive. Our Investee's operations are also subject to regular inspections to ensure that they are always fully compliant.

Environmental Initiatives

To further enhance the environmental credentials of our investee companies, they agreed on a long-term alliance with a British-based company to use its natural, biodegradable drilling fluid. UKOG will insist that this zero-hazard drilling fluid (or "mud") will be used in all of UKOG's investee oil exploration and development drilling activities across the Weald Basin. The use of this mud will ensure that there can be zero contamination of any groundwater via the drilling process.

The drilling fluid, also used by water well drilling companies in the UK, is registered with the Centre for Environment, Fisheries and Aquaculture Science (Cefas). It is also the only drilling fluid to be formally approved by the Department for the Environment, Food and Rural Affairs for use in the public water supply.

HHDL is also commissioning a company to construct and operate an enclosed flare for its upcoming appraisal and well testing programme. The enclosed flare, commonly used at landfill sites, is clean burning, without odour and produces low emissions. The enclosed flare will be a first in the UK onshore industry.

Community Engagement

As part and parcel of any of our investee's exploration and development, there runs alongside this a comprehensive community engagement plan.

It is vital that our investee companies engage, listen and communicate effectively with local communities, particularly when they begin the process of planning new developments.

Throughout this year's operations, UKOG is proud that its investee companies have embarked on a proactive community engagement campaign. For the first time in the onshore industry in the UK, a viewing platform was built at Broadford Bridge to accommodate residents, local politicians, media and investors to observe the working of the well pad and engage with the management and operators. Up to 300 people visited the BB-1 site, and it is our goal that this feature should be part of all our investee community engagement programmes going forward.

The Company actively engaged and had meetings with the two Members of Parliament in the area, Nick Herbert (Arundel & South Downs) and Jeremy Quin (Horsham). Both were given access to the site.

Elsewhere, our investees kept in contact with community group representatives in both the Horse Hill and Markwells Wood areas, holding occasional Community Engagement Group meetings. At the time of writing, over 200 letters are being delivered to residents of Horse Hill and they will be invited to visit the site as soon as the viewing platform has been erected. This follows various meetings with the local group Norwood Hill Residents, together with representatives from the parish councils of Charlwood and Salford & Sidlow.

OIL PRICE ENVIRONMENT

Brent crude oil price ended 2017 at $65/barrel (“b”), the highest end-of-year price since 2013. West Texas Intermediate (WTI) crude oil prices averaged $51/b in 2017, up $7/b from the 2016 average, and ended the year $6/b higher than at the end of 2016. Brent prices have moved up $10/b since the end of 2016 and ended the year at $65/b, widening the Brent-WTI spread to $5/b at the end of the year, the largest difference since 2013.

Despite relatively high U.S. crude oil production, curtailments in production by members of the Organization of the Petroleum Exporting Countries (OPEC) and robust global demand supported crude oil price increases in 2017. The OPEC agreement to curtail crude oil production in 2017 and subsequent extension of that agreement through 2018 tightened crude oil supplies, which put upward pressure on crude oil prices.

The price spread between Brent and WTI was significantly greater in 2017 than in 2016. Lower domestic crude oil prices made U.S. crude oil more competitive in international markets and supported record U.S. crude oil exports. Domestic demand was also higher: U.S. product supplied for crude oil and petroleum products was the highest level since 2007.

DIRECTORS

Stephen Sanderson, Executive Chairman and Chief Executive Officer
Stephen Sanderson joined UK Oil & Gas Investments PLC in September 2014 and was appointed Executive Chairman and Chief Executive in July 2015. A highly-experienced petroleum geologist, oil industry veteran and upstream energy business leader, with over 30 years operating experience, Stephen is a proven oil finder and has been instrumental in the discovery of more than 12 commercial conventional fields, including the Norwegian Smorbuk-Midgaard field complex. Stephen held a variety of senior management roles for ARCO (which was acquired by BP in 2000), Wintershall AG (a subsidiary of German chemical giant BASF) and three junior start-ups. He created and ran successful new exploration businesses in Africa, Europe and South America. He has significant technical and commercial expertise in the petroleum systems of Africa, the North Sea, Norway, onshore UK & Europe, South America, the South Atlantic, Middle East, Asia, India, Australia and the USA. He is a graduate and Associate of the Royal School of Mines, Imperial College, London, a Fellow of the Geological Society of London and a member of the American Association of Petroleum Geologists. He served for four years in the British Army and TAVR as a platoon commander, serving in the UK and Berlin.

Kiran Morzaria, Finance Director (appointed 23 October 2015)
Mr Morzaria holds a Bachelor of Engineering (Industrial Geology) from the Camborne School of Mines and an MBA (Finance) from CASS Business School. He has extensive experience in the mineral resource industry working in both operational and management roles. Mr Morzaria spent the first four years of his career in exploration, mining and civil engineering. He then obtained his MBA and became the Finance Director of Vatukoula Gold Mines Plc for seven years. He has served as a director of a number of public companies in both an executive and non-executive capacity; he is a non-executive director of European Metals Holdings Ltd and the Chief Executive Officer for Rare Earth Minerals Plc.

Allen D Howard, Non-Executive Director (appointed 1 March 2017)
Mr Howard was Senior Vice President of Houston-based Premier Oilfield Laboratories, having been Chief Operating Officer of well analysis experts Nutech. Allen also held senior positions with Schlumberger. He holds a degree in Chemical Engineering from Texas Tech University and an MBA from Mays Business School in Texas.

REPORT OF THE DIRECTORS

The Directors present their annual report together with the audited consolidated financial statements of the Group for the Year Ended 30 September 2017.

Principal Activity and Business Review
The principal activity of the Group and the Company is that of an investment holding company to acquire a diverse portfolio of direct and indirect interests in exploration, development and production oil and gas assets which are based in the UK.

Results and Dividends
Loss on ordinary activities of the Group after taxation amounted to £2,268,000 (2016: Loss £1,972,000). The Directors do not recommend the payment of a dividend (2016: £nil). The Company has no plans to adopt a dividend policy in the immediate future.

Principal Risks and Uncertainties
The principal risks and uncertainties facing the Group involve the ability to secure funding in order to finance the acquisition and exploitation of oil and gas assets and fluctuating commodity prices.

In addition, the amount and quality of the Group's oil and gas resources and the related costs of extraction and production represent a significant risk to the Group.

Financial Risk Management Objectives and Policies
The Group's principal financial instruments are available for sale assets, trade receivables, trade payables and cash at bank, and borrowings. The main purpose of these financial instruments is to fund the Group's operations.

It is, and has been throughout the period under review, the Group's policy that no trading in financial instruments shall be undertaken. The main risk arising from the Group's financial instruments is liquidity risk. The Board reviews and agrees policies for managing this risk and this is summarised below.

Liquidity Risk
The Group's objective is to maintain a balance between continuity of funding and flexibility through the use of equity and its cash resources. Further details of this are provided in the principal accounting policies, headed 'going concern'.

Key Performance Indicators
Due to the current status of the Group, the Board has not identified any performance indicators as key.

Future Developments
Future developments are outlined in the Chairman's Statement and Strategic Report.

Going Concern
The Directors note the substantial losses that the Group has made for the year ended 30 September 2017. The Directors have prepared cash flow forecasts for the period ending 31 March 2019 which take account of the current cost and operational structure of the Group.

The cost structure of the Group comprises a high proportion of discretionary spend and therefore in the event that cash flows become constrained, costs can be quickly reduced to enable the Group to operate within its available funding.

These forecasts demonstrate that the Group has sufficient cash funds available to allow it to continue in business for a period of at least twelve months from the date of approval of these financial statements. Accordingly, the financial statements have been prepared on a going concern basis.

Events After the Reporting Period
Events after the Reporting Period are outlined in Note 23 to the Financial Statements.

Corporate Governance

Audit and Remuneration Committees have been established and, in each case, comprises Directors Allen D Howard and Kiran Morzaria, with Allen D Howard as Chairman.

The role of the Remuneration Committee is to review the performance of the executive Directors and to set the scale and structure of their remuneration, including bonus arrangements. The Remuneration Committee also administers and establishes performance targets for the Group's employee share schemes and executive incentive schemes for key management. In exercising this role, the terms of reference of the Remuneration Committee require it to comply with the Code of Best Practice published in the Combined Code.

The Audit Committee is responsible for making recommendations to the Board on the appointment of the auditors and the audit fee and receives and reviews reports from management and the Company's auditors on the internal control systems in use throughout the Group and its accounting policies.

Suppliers' Payment Policy

The Group's policy is to agree terms and conditions with suppliers in advance; payment is then made in accordance with the agreement provided the supplier has met the terms and conditions. Suppliers are typically paid within 30 days of issue of invoice.

Charitable Contributions

During the year the Group made charitable donations amounting to £Nil (2016 - £Nil).

Substantial Shareholdings

As at 23 March 2017, the Company had been notified of the following substantial shareholdings in the ordinary share capital:

Shareholder	Number of Ordinary Shares	Holding %
Interactive Investor Services Nominees Limited	421,839,126	11.27%
Hargreaves Lansdown (Nominees) Limited	410,897,345	10.98%
Barclays Direct Investing Nominees Limited	335,123,598	8.96%
Hargreaves Lansdown (Nominees) Limited	265,625,006	7.10%
Hargreaves Lansdown (Nominees) Limited	250,827,819	6.70%
Interactive Investor Services Nominees Limited	222,659,495	5.95%
HSDL Nominees Limited	215,696,083	5.76%
HSDL Nominees Limited	183,730,054	4.91%
HSBC Client Holdings Nominee (UK) Limited	145,213,074	3.88%

Directors
The Directors who held office during the year and up to the date of this report are given below:

Current Board
Stephen Sanderson (Executive Chairman & CEO)
Kiran Morzaria (Finance Director)
Allen D Howard (Non-Executive Director) (appointed 1 March 2017)

Previous Directors
Jason Berry (ceased 16 November 2016)

The total options held by directors is 115,000,000. Stephen Sanderson holds fully vested options over 85,000,000 which are exercisable at 0.4p, 1.15p and 1.82p each up until 31 December 2017, 28 September 2019 and 24 May 2022 respectively (The 0.4p options that were due to expire on the 31 December 2017, were extended in December 2017, until Stephen Sanderson entered into a open period, as permitted under the option agreement). Kiran Morzaria holds 20,000,000 options and Allen Howard holds 10,000,000 options all exercisable at 1.15p up until 24 May 2022.

Auditor
A resolution to reappoint Chapman Davis LLP as auditor will be proposed at the forthcoming Annual General Meeting ("AGM").

Annual General Meeting
Notice of the forthcoming Annual General Meeting will be enclosed separately.

Statement of Directors' Responsibilities
The Directors are responsible for preparing the annual report and financial statements in accordance with applicable law and regulations.

Company law requires the directors to prepare consolidated financial statements for each financial year. The Directors have prepared the consolidated accounts in accordance with International Financial Reporting Standards as adopted by the EU ("adopted IFRS"). The consolidated financial statements are required by law to give a true and fair view of the state of affairs of the Group and Company and of the profit or loss for that period. In preparing these financial statements, the Directors are required to:

- Select suitable accounting policies and then apply them consistently;
- Make judgements and estimates that are reasonable and prudent;
- State whether applicable IFRS's have been followed, subject to any material departures disclosed and explained in the financial statements; and
- Prepare the consolidated financial statements on the going concern basis unless it is inappropriate to presume that the Group will continue in business.

The Directors are responsible for keeping adequate accounting records, which disclose with reasonable accuracy at any time the financial position of the Group and to enable them to ensure that the consolidated financial statements comply with the Companies Act 2006. They are also responsible for safeguarding the assets of the Group and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

The Directors are responsible for the maintenance and integrity of the corporate and financial information included on the Company's website. The Company's website is maintained in accordance with AIM Rule 26.

Legislation in the United Kingdom governing the preparation and dissemination of consolidated financial statements may differ from legislation in other jurisdictions.

Statement as to Disclosure of Information to the Auditor
As at the date of this report the serving directors confirm that:

- So far as each director is aware, there is no relevant audit information of which the Group's auditors are unaware, and
- they have taken all the steps that they ought to have taken as directors' in order to make themselves aware of any relevant audit information and to establish that the Group's auditor are aware of that information.

ON BEHALF OF THE BOARD

Stephen Sanderson
Director
28 March 2018

OPINION

We have audited the financial statements of UK Oil & Gas Investments Plc (the 'Parent Company') and its subsidiaries (the 'Group') for the year ended 30 September 2017 which comprise the consolidated statement of comprehensive income, the consolidated and company statements of financial position, the consolidated and company's statements of changes in equity, the consolidated and company's statements of cash flows and notes to the financial statements, including a summary of significant accounting policies.

The financial reporting framework that has been applied in the preparation of the group and parent company financial statements is applicable law and International Financial Reporting Standards (IFRSs) as adopted by the European Union.

In our opinion:

• the financial statements give a true and fair view of the state of the Group's and of the Parent Company's affairs as at 30 September 2017 and of the Group's losses for the year then ended;

• the Group and Parent Company financial statements have been properly prepared in accordance with IFRSs as adopted by the European Union;

• the Parent Company financial statements have been properly prepared in accordance with IFRS as adopted by the European Union and as applied in accordance with the provisions of the Companies Act 2006; and

• the financial statements have been prepared in accordance with the requirements of the Companies Act 2006.

SEPARATE OPINION IN RELATION TO IFRSS AS ISSUED BY THE IASB

As explained in note 1 to the Group financial statements, the Group in addition applying IFRSs as adopted by the European Union, has also applied IFRSs as issued by the International Accounting Standards Board (IASB). Our opinion is extended to this financial framework.

BASIS FOR OPINION

We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)) and applicable law. Our responsibilities under those standards are further described in the Auditor's responsibilities for the audit of the financial statements section of our report. We are independent of the Group in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the FRC's Ethical Standard as applied to listed entities, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

CONCLUSIONS RELATING TO GOING CONCERN

We have nothing to report in respect of the following matters in relation to which the ISAs (UK) require us to report to you where:

- the directors' use of the going concern basis of accounting in the preparation of the financial statements is not appropriate; or
- the directors have not disclosed in the financial statements any identified material uncertainties that may cast significant doubt about the company's ability to continue to adopt the going concern basis of accounting for a period of at least twelve months from the date when the financial statements are authorised for issue.

KEY AUDIT MATTERS

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report of the current period. These matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. We have determined the matters described below to be the key audit matters to be communicated in our report.

CARRYING VALUE OF INTANGIBLE EXPLORATION AND EVALUATION ASSETS

The Group's intangible exploration and evaluation assets ('E&E assets') represent the most significant asset on its statement of financial position totalling £15.1m as at 30 September 2017.

Management and the Board are required to ensure that only costs which meet the IFRS criteria of an asset and accord with the Group's accounting policy are capitalised within the E&E asset. In addition in accordance with the requirements of IFRS 6 'Exploration for and Evaluation of Mineral Resources' ('IFRS 6') Management and the Board are required to assess whether there is any indication whether there are any indicators of impairment of the E&E assets.

Given the significance of the E&E assets on the Group's statement of financial position and the significant management judgement involved in the determination of the capitalisation of costs and the assessment of the carrying values of the E&E asset there is an increased risk of material misstatement.

How the Matter was addressed in the Audit

The procedures included, but were not limited to, assessing and evaluating management's assessment of whether any impairment indicators in accordance with IFRS 6 have been identified across the Group's exploration projects, the indicators being:

• Expiring, or imminently expiring, licence and/or exploration rights

• A lack of budgeted or planned exploration and evaluation spend on the licence areas

• Discontinuation of, or a plan to discontinue, exploration activities in the licence areas

• Sufficient data exists to suggest carrying value of exploration and evaluation assets is unlikely be recovered in full through successful development or sale.

In addition, we obtained the expenditure budget for the 2018/19 year(s) and assessed that there is reasonable forecasted expenditure to confirm continued exploration spend into the projects indicating that Management are committed to the projects. We also reviewed AIM announcements and Board meeting minutes for the year and subsequent to year end for exploration activity to identify any indicators of impairment.

We also assessed the disclosures included in the financial statements.

OTHER INFORMATION

The Directors are responsible for the other information. The other information comprises the information included in the annual report, other than the financial statements and our auditor's report thereon. Our opinion on the financial statements does not cover the other information and, except to the extent otherwise explicitly stated in our report, we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated. If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether there is a material misstatement in the financial statements or a material misstatement of the other information. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

OPINIONS ON OTHER MATTERS PRESCRIBED BY THE COMPANIES ACT 2006

In our opinion, based on the work undertaken in the course of the audit:

• the information given in the Strategic Report and the Directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements; and

• the Strategic Report and the Directors' report have been prepared in accordance with applicable legal requirements.

MATTERS ON WHICH WE ARE REQUIRED TO REPORT BY EXCEPTION

In the light of the knowledge and understanding of the Group and the Parent Company and its environment obtained in the course of the audit, we have not identified material misstatements in the Strategic report or the Directors' report.

We have nothing to report in respect of the following matters in relation to which the Companies Act 2006 requires us to report to you if, in our opinion:

• adequate accounting records have not been kept by the Parent Company, or returns adequate for our audit have not been received from branches not visited by us; or

• the Parent Company financial statements are not in agreement with the accounting records and returns; or

• certain disclosures of Directors' remuneration specified by law are not made; or

• we have not received all the information and explanations we require for our audit.

RESPONSIBILITIES OF DIRECTORS

As explained more fully in the Directors' responsibilities statement, the Directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view, and for such internal control as the Directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the Directors are responsible for assessing the Group's and the Parent Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors either intend to liquidate the Group or the Parent Company or to cease operations, or have no realistic alternative but to do so.

AUDITOR'S RESPONSIBILITIES FOR THE AUDIT OF THE FINANCIAL STATEMENTS

This report is made solely to the Company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the Company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the Company and the Company's members as a body, for our audit work, for this report, or for the opinions we have formed.

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs (UK) or ISA IAASB will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

A further description of our responsibilities for the audit of the financial statements is located on the Financial Reporting Council's website at: www.frc.org.uk/auditorsresponsibilities. This description forms part of our auditor's report.

Keith Fulton
(Senior Statutory Auditor)
For and on behalf of Chapman Davis LLP, Statutory Auditor
London
Chapman Davis LLP is a limited liability partnership registered in England and Wales (with registered number OC306037).

Date: 28 March 2018

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
FOR YEAR ENDED 30 SEPTEMBER 2017

	Notes	30 Sep 2017 £'000	30 Sep 2016 £'000
Revenue	3	207	151
Cost of sales		(254)	(204)
Gross (loss)		**(47)**	**(53)**
Operating expenses			
Administrative expenses		(1,785)	(2,062)
Foreign exchange losses		(15)	(20)
Depletion & impairment expense	9	(74)	(78)
Share based payments expense	19	(474)	(682)
Operating (loss)		**(2,395)**	**(2,895)**
Gain on settlements of financial instruments		204	-
Share of associate loss	11	(77)	(106)
Negative Goodwill	2	-	1,029
(Loss) before taxation	4	**(2,268)**	**(1,972)**
Taxation	6	-	-
(Loss) for the year attributable to equity holders of the parent		**(2,268)**	**(1,972)**
Other comprehensive income			
Transfer to income statement		-	-
Other comprehensive income net of taxation		**-**	**-**
Total comprehensive loss attributable to equity holders of the Parent		**(2,268)**	**(1,972)**
(Loss) per share			
		Pence	**Pence**
Basic and diluted	7	(0.08)	(0.09)

The accompanying accounting policies and notes form an integral part of these financial statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION
AS AT 30 SEPTEMBER 2017

	Notes	2017 £'000	2016 £'000
Assets			
Non-current assets			
Exploration & evaluation assets	8	15,110	6,187
Oil & Gas properties	9	1,428	1,500
Property, Plant & Equipment	9	170	370
Investment in associate	11	5,003	4,757
Available for sale investments	12	-	368
Total non-current assets		**21,711**	**13,182**
Current assets			
Inventory	13	4	3
Trade and other receivables	14	3,787	2,890
Cash and cash equivalents	15	1,748	2,444
Total current assets		5,539	5,337
Total Assets		**27,250**	**18,519**
Current liabilities			
Trade and other payables	16	(3,725)	(591)
Total current liabilities		**(3,725)**	**(591)**
Non-current Liabilities			
Provisions	17	(359)	(359)
Total non-current liabilities		**(359)**	**(359)**
Total liabilities		**(4,084)**	**(950)**
Net Assets		**23,166**	**17,569**
Shareholders' Equity			
Share capital	18	11,938	11,842
Share premium account		46,939	39,644
Share based payment reserve		1,172	1,224
Accumulated losses		(36,883)	(35,141)
Total shareholders' equity		**23,166**	**17,569**

These financial statements were approved by the Board of Directors on 28 March 2018 and are signed on its behalf by:

Stephen Sanderson
Director

Kiran Morzaria
Director

The accompanying accounting policies and notes form an integral part of these financial statements.

COMPANY STATEMENT OF FINANCIAL POSITION
AS AT 30 SEPTEMBER 2017

	Notes	2017 £'000	2016 £'000
Assets			
Non-current assets			
Exploration & evaluation assets	8	1,318	742
Investment in subsidiary companies	10	5,019	5,019
Investment in associate	11	5,003	4,757
Available for sale investments	12	-	368
Total non-current assets		**11,340**	**10,886**
Current assets			
Trade and other receivables	14	9,735	3,672
Cash and cash equivalents	15	1,714	2,371
Total current assets		**11,449**	**6,043**
Total Assets		**22,789**	**16,929**
Current liabilities			
Trade and other payables	16	(364)	(299)
Total Current Liabilities		**(364)**	**(299)**
Total liabilities		**(364)**	**(299)**
Net Assets	-	**22,425**	**16,630**
Shareholders' Equity			
Share capital	18	11,938	11,842
Share premium account		46,939	39,644
Share Based Payment Reserve		1,172	1,224
Accumulated losses		(37,624)	(36,080)
Total shareholders' equity		**22,425**	**16,630**

These financial statements were approved by the Board of Directors on 28 March 2018 and are signed on its behalf by:

Stephen Sanderson
Director

Kiran Morzaria
Director

The accompanying accounting policies and notes form an integral part of these financial statements.

CONSOLDATED STATEMENT OF CHANGES IN EQUITY
FOR THE YEAR ENDED 30 SEPTEMBER 2017

	Share capital	Share premium	Share based payment reserve	Accumulated losses	Total
	£'000	**£'000**	**£'000**	**£'000**	**£'000**
Balance at 1 October 2015	**11,787**	**31,622**	**659**	**(33,286)**	**10,782**
Loss for the year	-	-	-	(1,972)	(1,972)
Total comprehensive income	-	-	-	(1,972)	(1,972)
Issue of shares	55	8,262	-	-	8,317
Cost of share issue	-	(240)	-	-	(240)
Share option expired	-	-	(117)	117	-
Share based payments	-	-	682	-	682
Balance at 30 September 2016	**11,842**	**39,644**	**1,224**	**(35,141)**	**17,569**
Loss for the year	-	-	-	(2,268)	(2,268)
Total comprehensive income	-	-	-	(2,268)	(2,268)
Issue of shares	96	7,631	-	-	7,727
Cost of share issue	-	(336)	-	-	(336)
Share option exercised	-	-	(316)	316	-
Share option expired			(210)	210	-
Share based payments	-	-	474	-	474
Balance at 30 September 2017	**11,938**	**46,939**	**1,172**	**(36,883)**	**23,166**

COMPANY STATEMENT OF CHANGES IN EQUITY
FOR THE YEAR ENDED 30 SEPTEMBER 2017

	Share capital	Share premium	Share based payment reserve	Accumulated losses	Total
	£'000	**£'000**	**£'000**	**£'000**	**£'000**
Balance at 1 October 2015	**11,787**	**31,622**	**659**	**(33,286)**	**10,782**
Loss for the year	-	-	-	(2,911)	(2,911)
Total comprehensive income	-	-	-	(2,911)	(2,911)
Issue of shares	55	8,262	-	-	8,317
Cost of share issue	-	(240)	-	-	(240)
Share option exercised	-	-	(117)	117	-
Share based payments	-	-	682	-	682
Balance at 30 September 2016	**11,842**	**39,644**	**1,224**	**(36,080)**	**16,630**
Loss for the year	-	-	-	(2,070)	(2,070)
Total comprehensive income	-	-	-	(2,070)	(2,070)
Issue of shares	96	7,631	-	-	7,727
Cost of share issue	-	(336)	-	-	(336)
Share option exercised	-	-	(316)	316	-
Share option expired	-	-	(210)	210	-
Share based payments	-	-	474	-	474
Balance at 30 September 2017	**11,938**	**46,939**	**1,172**	**(37,624)**	**22,425**

CONSOLIDATED STATEMENT OF CASH FLOW
FOR THE YEAR ENDED 30 SEPTEMBER 2017

	2017 £'000	2016 £'000
Cash flows from operating activities		
Loss from operations	(2,395)	(2,895)
Foreign currency losses	-	20
Other non-cash income & expenses	-	(19)
Depletion & impairment	74	78
Share based payment charge	474	682
Increase in inventories	(1)	(1)
(Increase) / decrease in trade & other receivables	(897)	9
Increase in trade & other payables	3,134	262
Net cash (outflow) from operating activities	**389**	**(1,864)**
Cash flows from investing activities		
Expenditures on exploration & evaluation assets	(8,723)	(458)
Expenditures on oil & gas properties	(2)	(266)
Payments for acquisition of associate	(55)	(1,150)
Loans advanced to investee companies	-	(1,216)
Proceeds from sale of Available for Sale Financial Assets	572	-
Acquisition of subsidiaries, net of cash acquired	-	(1,257)
Net cash (outflow) from investing activities	(8,208)	**(4,347)**
Cash flows from financing activities		
Proceeds from issue of share capital	7,459	4,416
Share issue costs	(336)	(240)
Repayments of loan & borrowings	-	(111)
Net cash inflow from financing activities	**7,123**	**4,065**
Net change in cash and cash equivalents	**(696)**	**(2,146)**
Cash and cash equivalents at beginning of the period	2,444	4,590
Cash and cash equivalents at end of the period	**1,748**	**2,444**

COMPANY STATEMENT OF CASH FLOW
FOR THE YEAR ENDED 30 SEPTEMBER 2017

	2017 £'000	2016 £'000
Cash flows from operating activities		
(Loss) from operations	(2,197)	(2,785)
Foreign currency losses	-	1
Share based payment charge	474	682
Gain/(loss) on settlements of financial instruments	-	
Decrease in trade & other receivables	128	76
Increase / (decrease) in trade & other payables	65	(14)
Net cash (outflow) from operating activities	**(1,530)**	**(2,040)**
Cash flows from investing activities		
Expenditures on exploration & evaluation assets	(576)	(80)
Loan advanced to subsidiary	(6,191)	(412)
Payments for acquisition of associate	(55)	(1,150)
Loans advanced to investee companies	-	(1,216)
Proceeds from sale of Available for Sale Financial Instrument	572	-
Acquisition of subsidiaries, net of cash acquired	-	(1,257)
Net cash (outflow) from investing activities	(6,250)	**(4,115)**
Cash flows from financing activities		
Proceeds from issue of share capital	7,459	4,416
Share issue costs	(336)	(240)
Repayments of loan & borrowings	-	(111)
Finance costs paid	-	-
Net cash inflow from financing activities	**7,123**	**4,065**
Net change in cash and cash equivalents	**(657)**	**(2,090)**
Cash and cash equivalents at beginning of the period	2,371	4,461
Cash and cash equivalents at end of the period	**1,714**	**2,371**

NOTES TO THE FINANCIAL STATEMENTS

1. Principal Accounting Policies

Basis of Preparation
UK Oil and Gas Investments PLC is a company incorporated in the United Kingdom. The Company's shares are listed on the AIM market of the London Stock Exchange.

The Consolidated Financial Statements are for the year ended 30 September 2017 and have been prepared under the historical cost convention and in accordance with International Financial Reporting Standards as adopted by the EU ("adopted IFRS"). These Consolidated Financial Statements (the "Financial Statements") have been prepared and approved by the Directors on 28 March 2018 and signed on their behalf by Stephen Sanderson and Kiran Morzaria.

The accounting policies have been applied consistently throughout the preparation of these Financial Statements, and the financial report is presented in Pound Sterling (£) and all values are rounded to the nearest thousand pounds (£ '000) unless otherwise stated.

New standards, amendments and interpretations adopted by the Company
No new and/or revised Standards and Interpretations have been required to be adopted, and/or are applicable in the current year by/to the Group and/or Company, as standards, amendments and interpretations which are effective for the financial year beginning on 1 October 2016 are not material to the Company.

New standards, amendments and interpretations not yet adopted
At the date of authorisation of these financial statements, the following IFRSs, IASs and Interpretations were in issue but not yet effective. Their adoption is not expected to have a material effect on the financial statements unless otherwise indicated:

- IFRS 9 Financial Instruments (effective date 1 January 2018);
- IFRS 15 Revenue from Contracts with Customers (effective date 1 January 2018);
- IFRS 16 Leases (effective date 1 January 2019);
- IFRS 17 Insurance Contracts (effective date 1 January 2021).

1. Principal Accounting Policies (continued)

Basis of consolidation
The consolidated financial information incorporates the financial statements of the Company and its subsidiaries (the "Group"). Control is achieved where the Group is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee.

Inter-company transactions, balances and unrealised gains on transactions between Group companies are eliminated; unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

Where necessary, adjustments are made to the financial statements of subsidiaries to bring the accounting policies used in line with those used by the Group.

Business combinations
Business combinations are accounted for using the acquisition method. The consideration for acquisition is measured at the fair values of assets given, liabilities incurred or assumed, and equity instruments issued by the Company in order to obtain control of the acquiree (at the date of exchange). Costs incurred in connection with the acquisition are recognised in profit or loss as incurred. Where a business combination is achieved in stages, previously held interests in the acquiree are re-measured to fair value at the acquisition date (date the Group obtains control) and the resulting gain or loss, is recognised in profit or loss. Adjustments are made to fair values to bring the accounting policies of acquired businesses into alignment with those of the group. The costs of integrating and reorganising acquired businesses are charged to the post acquisition profit or loss where applicable.

Revenue
Revenue is measured by reference to the fair value of consideration received or receivable by the Group for services provided, excluding VAT and trade discounts. Revenue is credited to the Income Statement in the period it is deemed to be earned.

Revenue from the sale of oil and petroleum products is recognised when the significant risks and rewards of ownership have been transferred, which is considered to occur when title passes to the customer. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism.

Revenue from the production of oil, in which the Group has an interest with other producers, is recognised based on the Group's working interest and the terms of the relevant production sharing contracts. Differences between oil lifted and sold and the Group's share of production are not significant.

1. Principal Accounting Policies (continued)

Finance Income and Costs
Finance income and costs are reported on an accruals basis.

Oil & Gas properties ("OGP"), Exploration & Evaluation assets
Oil and natural gas exploration, evaluation and development expenditure is accounted for using the successful efforts method of accounting.

(i) Pre-licence costs
Pre-licence costs are expensed in the period in which they are incurred.

(ii) Licence and property acquisition costs
Exploration licence and leasehold property acquisition costs are capitalised in intangible assets. Licence costs paid in connection with a right to explore in an existing exploration area are capitalised and amortised over the term of the permit.

Licence and property acquisition costs are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned, or that it has been determined, or work is under way to determine that the discovery is economically viable based on a range of technical and commercial considerations and that sufficient progress is being made on establishing development plans and timing.

If no future activity is planned or the licence has been relinquished or has expired, the carrying value of the licence and property acquisition costs are written off through the statement of profit or loss and other comprehensive income. Upon recognition of proved reserves and internal approval for development, the relevant expenditure is transferred to oil and gas properties.

(iii) Exploration and evaluation costs
Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource.

Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalised as exploration and evaluation intangible assets until the drilling of the well is complete and the results have been evaluated. These costs include directly attributable employee remuneration, materials and fuel used, rig costs and payments made to contractors.

If no potentially commercial hydrocarbons are discovered, the exploration asset is written off through the statement of profit or loss and other comprehensive income as a dry hole. If extractable hydrocarbons are found and, subject to further appraisal activity (e.g., the drilling of additional wells), it is probable that they can be commercially developed, the costs continue to be carried as an intangible asset while sufficient/continued progress is made in assessing the commerciality of the hydrocarbons. Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalised as an intangible asset.

All such capitalised costs are subject to technical, commercial and management review, as well as review for indicators of impairment at least once a year. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off through the statement of profit or loss and other comprehensive income.

When proved reserves of oil and natural gas are identified and development is sanctioned by management, the relevant capitalised expenditure is first assessed for impairment and (if required) any impairment loss is recognised, then the remaining balance is transferred to oil and gas properties. Other than licence costs, no amortisation is charged during the exploration and evaluation phase.

1. Principal Accounting Policies (continued)

(iv) Development costs
Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, is capitalised within oil and gas properties.

Oil and gas properties and other property, plant and equipment

(i) Initial recognition
Oil and gas properties and other property, plant and equipment are stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation and, for qualifying assets (where relevant), borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalised value of a finance lease is also included within property, plant and equipment.

When a development project moves into the production stage, the capitalisation of certain construction/development costs ceases, and costs are either regarded as part of the cost of inventory or expensed, except for costs which qualify for capitalisation relating to oil and gas property asset additions, improvements or new developments.

(ii) Depreciation/amortisation
Oil and gas properties are depreciated/amortised on a unit-of-production basis over the total proved developed and undeveloped reserves of the field concerned, except in the case of assets whose useful life is shorter than the lifetime of the field, in which case the straight-line method is applied. Rights and concessions are depleted on the unit-of-production basis over the total proved developed and undeveloped reserves of the relevant area. The unit-of-production rate calculation for the depreciation/amortisation of field development costs takes into account expenditures incurred to date, together with sanctioned future development expenditure. Other property, plant and equipment are generally depreciated on a straight-line basis over their estimated useful lives, which is generally 20 years for refineries, and major inspection costs are amortised over three to five years, which represents the estimated period before the next planned major inspection. Property, plant and equipment held under finance leases are depreciated over the shorter of lease term and estimated useful life. An item of property, plant and equipment and any significant part initially recognised is derecognised upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in the statement of profit or loss and other comprehensive income when the asset is derecognised. The asset's residual values, useful lives and methods of depreciation/amortisation are reviewed at each reporting period and adjusted prospectively, if appropriate.

(ii) Major maintenance, inspection and repairs
Expenditure on major maintenance refits, inspections or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset, or part of an asset that was separately depreciated and is now written off is replaced and it is probable that future economic benefits associated with the item will flow to the Group, the expenditure is capitalised. Where part of the asset replaced was not separately considered as a component and therefore not depreciated separately, the replacement value is used to estimate the carrying amount of the replaced asset(s) and is immediately written off. Inspection costs associated with major maintenance programmes are capitalised and amortised over the period to the next inspection. All other day-to-day repairs and maintenance costs are expensed as incurred.

Provision for rehabilitation / Decommissioning Liability
The Group recognises a decommissioning liability where it has a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made.

1. Principal Accounting Policies (continued)

Provision for rehabilitation / Decommissioning Liability (continued)

The obligation generally arises when the asset is installed, or the ground/environment is disturbed at the field location. When the liability is initially recognised, the present value of the estimated costs is capitalised by increasing the carrying amount of the related oil and gas assets to the extent that it was incurred by the development/construction of the field. Any decommissioning obligations that arise through the production of inventory are expensed when the inventory item is recognised in cost of goods sold.

Changes in the estimated timing or cost of decommissioning are dealt with prospectively by recording an adjustment to the provision and a corresponding adjustment to oil and gas assets.

Any reduction in the decommissioning liability and, therefore, any deduction from the asset to which it relates, may not exceed the carrying amount of that asset. If it does, any excess over the carrying value is taken immediately to the statement of profit or loss and other comprehensive income.

If the change in estimate results in an increase in the decommissioning liability and, therefore, an addition to the carrying value of the asset, the Group considers whether this is an indication of impairment of the asset as a whole, and if so, tests for impairment. If, for mature fields, the estimate for the revised value of oil and gas assets net of decommissioning provisions exceeds the recoverable value, that portion of the increase is charged directly to expense. Over time, the discounted liability is increased for the change in present value based on the discount rate that reflects current market assessments and the risks specific to the liability. The periodic unwinding of the discount is recognised in the statement of profit or loss and other comprehensive income as a finance cost. The Company recognises neither the deferred tax asset in respect of the temporary difference on the decommissioning liability nor the corresponding deferred tax liability in respect of the temporary difference on a decommissioning asset.

Taxation

Current tax is the tax currently payable based on taxable profit for the year.

Deferred income taxes are calculated using the liability method on temporary differences. Deferred tax is generally provided on the difference between the carrying amounts of assets and liabilities and their tax bases. However, deferred tax is not provided on the initial recognition of goodwill, nor on the initial recognition of an asset or liability unless the related transaction is a business combination or affects tax or accounting profit. Deferred tax on temporary differences associated with shares in subsidiaries and joint ventures is not provided if reversal of these temporary differences can be controlled by the Company and it is probable that reversal will not occur in the foreseeable future. In addition, tax losses available to be carried forward as well as other income tax credits to the Company are assessed for recognition as deferred tax assets.

Deferred tax liabilities are provided in full, with no discounting. Deferred tax assets are recognised to the extent that it is probable that the underlying deductible temporary differences will be able to be offset against future taxable income. Current and deferred tax assets and liabilities are calculated at tax rates that are expected to apply to their respective period of realisation, provided they are enacted or substantively enacted at the balance sheet date.

Changes in deferred tax assets or liabilities are recognised as a component of tax expense in the income statement, except where they relate to items that are charged or credited directly to equity in which case the related deferred tax is also charged or credited directly to equity.

1. Principal Accounting Policies (continued)

Financial Assets
Financial assets are divided into the following categories: loans and receivables and available-for-sale financial assets. Financial assets are assigned to the different categories by management on initial recognition, depending on the purpose for which they were acquired, and are recognised when the Group becomes party to contractual arrangements. Both loans and receivables and available for sale financial assets are initially recorded at fair value.

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Trade, most other receivables and cash and cash equivalents fall into this category of financial assets. Loans and receivables are measured subsequent to initial recognition at amortised cost using the effective interest method, less provision for impairment. Any change in their value through impairment or reversal of impairment is recognised in the income statement.

Provision against trade receivables is made when there is objective evidence that the Group will not be able to collect all amounts due to it in accordance with the original terms of those receivables. The amount of the write-down is determined as the difference between the asset's carrying amount and the present value of estimated future cash flows.

A financial asset is derecognised only where the contractual rights to the cash flows from the asset expire or the financial asset is transferred, and that transfer qualifies for derecognition. A financial asset is transferred if the contractual rights to receive the cash flows of the asset have been transferred or the Group retains the contractual rights to receive the cash flows of the asset but assumes a contractual obligation to pay the cash flows to one or more recipients. A financial asset that is transferred qualifies for derecognition if the Group transfers substantially all the risks and rewards of ownership of the asset, or if the Group neither retains nor transfers substantially all the risks and rewards of ownership but does transfer control of that asset.

Derivative instruments are recorded at cost and adjust for their market value as applicable. They are assessed for any equity and debt component which is subsequently accounted for in accordance with IFRS's.

Financial Liabilities
Financial liabilities are obligations to pay cash or other financial assets and are recognised when the Group becomes a party to the contractual provisions of the instrument.

All financial liabilities initially recognised at fair value less transaction costs and thereafter carried at amortised cost using the effective interest method, with interest-related charges recognised as an expense in finance cost in the income statement. A financial liability is derecognised only when the obligation is extinguished, that is, when the obligation is discharged or cancelled or expires.

1. Principal Accounting Policies (continued)

Inventories
Inventories are stated at the lower of cost and net realisable value. The cost of materials is the purchase cost, determined on first-in, first-out basis. The cost of crude oil and refined products is the purchase cost, the cost of refining, including the appropriate proportion of depreciation, depletion and amortisation and overheads based on normal operating capacity, determined on a weighted average basis. The net realisable value of crude oil and refined products is based on the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale.

Cash and Cash Equivalents
Cash and cash equivalents comprise cash on hand and demand deposits, together with other short-term, highly liquid investments that are readily convertible into known amounts of cash and which are subject to an insignificant risk of changes in value.

Share-Based Payments
The Group operates a number of equity-settled, share-based compensation plans, under which the entity receives services from employees as consideration for equity instruments (options) of the Company. The fair value of the employee services received in exchange for the grant of the options is recognised as an expense. The total amount to be expensed is determined by reference to the fair value of the options granted:

- Including any market performance conditions;
- Excluding the impact of any service and non-market performance vesting conditions (for example, profitability or sales growth targets, or remaining an employee of the entity over a specified time period; and
- Including the impact of any non-vesting conditions (for example, the requirement for employees to save).

Non-market vesting conditions are included in assumptions about the number of options that are expected to vest. The total expense is recognised over the vesting period, which is the period over which all of the specified vesting conditions are to be satisfied.

In addition, in some circumstances, employees may provide services in advance of the grant date, and therefore the grant-date fair value is estimated for the purposes of recognising the expense during the period between service commencement period and grant date.

At the end of each reporting period, the entity revises its estimates of the number of options that are expected to vest based on the non-market vesting conditions. It recognises the impact of the revision to original estimates, if any, in profit or loss, with a corresponding adjustment to equity.

When the options are exercised, the Company issues new shares. The proceeds received, net of any directly attributable transaction costs, are credited to share capital (nominal value) and share premium.

Equity
Equity comprises the following:

"Share capital" representing the nominal value of equity shares.
"Share premium" representing the excess over nominal value of the fair value of consideration received for equity shares, net of expenses of the share issue.
“Share based payment reserve” represents the value of equity benefits provided to employees and directors as part of their remuneration and provided to consultants and advisors hired by the Group from time to time as part of the consideration paid.
"Retained earnings" represents retained profits and (losses).

1. Principal Accounting Policies (continued)

Foreign Currencies

Transactions in foreign currencies are translated at the exchange rate ruling at the date of the transaction. Monetary assets and liabilities in foreign currencies are translated at the rates of exchange ruling at the balance sheet date. Non-monetary items that are measured at historical cost in a foreign currency are translated at the exchange rate at the date of the transaction. Non-monetary items that are measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was determined. Any exchange differences arising on the settlement of monetary items or on translating monetary items at rates different from those at which they were initially recorded are recognised in the profit or loss in the period in which they arise. Exchange differences on non-monetary items are recognised in other comprehensive income to the extent that they relate to a gain or loss on that non-monetary item taken to other comprehensive income, otherwise such gains and losses are recognised in the income statement.

The Group and Company's functional currency and presentational currency is Sterling.

Significant accounting judgements, estimates and assumptions

The preparation of the Group’s consolidated financial statements requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the accompanying disclosures, and the disclosure of contingent liabilities at the date of the consolidated financial statements. Estimates and assumptions are continuously evaluated and are based on management’s experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

In particular, the Group has identified the following areas where significant judgements, estimates and assumptions are required. Further information on each of these areas and how they impact the various accounting policies are described below and also in the relevant notes to the financial statements.
Changes in estimates are accounted for prospectively.

(i) Judgements

In the process of applying the Group’s accounting policies, management has made the following judgements, which have the most significant effect on the amounts recognised in the consolidated financial statements:

(a) Contingencies

Contingent liabilities may arise from the ordinary course of business in relation to claims against the Group, including legal, contractor, land access and other claims. By their nature, contingencies will be resolved only when one or more uncertain future events occur or fail to occur. The assessment of the existence, and potential quantum, of contingencies inherently involves the exercise of significant judgement and the use of estimates regarding the outcome of future events.

(ii) Estimates and assumptions

The key assumptions concerning the future and other key sources of estimation uncertainty at the reporting date that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year, are described below. The Group based its assumptions and estimates on parameters available when the consolidated financial statements were prepared. Existing circumstances and assumptions about future developments, however, may change due to market change or circumstances arising beyond the control of the Group. Such changes are reflected in the assumptions when they occur.

1. Principal Accounting Policies (continued)

Significant accounting judgements, estimates and assumptions (continued)

(a) Hydrocarbon reserve and resource estimates

Hydrocarbon reserves are estimates of the amount of hydrocarbons that can be economically and legally extracted from the Group's oil and gas properties. The Group estimates its commercial reserves and resources based on information compiled by appropriately qualified persons relating to the geological and technical data on the size, depth, shape and grade of the hydrocarbon body and suitable production techniques and recovery rates. Commercial reserves are determined using estimates of oil and gas in place, recovery factors and future commodity prices, the latter having an impact on the total amount of recoverable reserves and the proportion of the gross reserves which are attributable to the host government under the terms of the Production-Sharing Agreements. Future development costs are estimated using assumptions as to the number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities, and other capital costs. The current long-term Brent oil price assumption used in the estimation of commercial reserves is US$80/bbl. The carrying amount of oil and gas development and production assets at 30 September 2017 is shown in Note 9.

The Group estimates and reports hydrocarbon reserves in line with the principles contained in the SPE Petroleum Resources Management Reporting System (PRMS) framework. As the economic assumptions used may change and as additional geological information is obtained during the operation of a field, estimates of recoverable reserves may change. Such changes may impact the Group's reported financial position and results, which include:

- The carrying value of exploration and evaluation assets; oil and gas properties; property, plant and equipment; and goodwill may be affected due to changes in estimated future cash flows
- Depreciation and amortisation charges in the statement of profit or loss and other comprehensive income may change where such charges are determined using the Units of Production (UOP) method, or where the useful life of the related assets change
- Provisions for decommissioning may require revision — where changes to the reserve estimates affect expectations about when such activities will occur and the associated cost of these activities
- The recognition and carrying value of deferred tax assets may change due to changes in the judgements regarding the existence of such assets and in estimates of the likely recovery of such assets

(b) Exploration and evaluation expenditures

The application of the Group's accounting policy for exploration and evaluation expenditure requires judgement to determine whether future economic benefits are likely, from future either exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves. The determination of reserves and resources is itself an estimation process that involves varying degrees of uncertainty depending on how the resources are classified. These estimates directly impact when the Group defers exploration and evaluation expenditure. The deferral policy requires management to make certain estimates and assumptions about future events and circumstances, in particular, whether an economically viable extraction operation can be established. Any such estimates and assumptions may change as new information becomes available. If, after expenditure is capitalised, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalised amount is written off in the statement of profit or loss and other comprehensive income in the period when the new information becomes available.

(c) Units of production (UOP) depreciation of oil and gas assets

Oil and gas properties are depreciated using the UOP method over total proved developed and undeveloped hydrocarbon reserves. This results in a depreciation/amortisation charge proportional to the depletion of the anticipated remaining production from the field.

1. Principal Accounting Policies (continued)

Significant accounting judgements, estimates and assumptions (continued)

(c) Units of production (UOP) depreciation of oil and gas assets

The life of each item, which is assessed at least annually, has regard to both its physical life limitations and present assessments of economically recoverable reserves of the field at which the asset is located. These calculations require the use of estimates and assumptions, including the amount of recoverable reserves and estimates of future capital expenditure. The calculation of the UOP rate of depreciation/amortisation will be impacted to the extent that actual production in the future is different from current forecast production based on total proved reserves, or future capital expenditure estimates change. Changes to proved reserves could arise due to changes in the factors or assumptions used in estimating reserves, including:

- The effect on proved reserves of differences between actual commodity prices and commodity price assumptions
- Unforeseen operational issues

(d) Recoverability of oil and gas assets

The Group assesses each asset or cash generating unit (CGU) (excluding goodwill, which is assessed annually regardless of indicators) each reporting period to determine whether any indication of impairment exists. Where an indicator of impairment exists, a formal estimate of the recoverable amount is made, which is considered to be the higher of the fair value less costs of disposal (FVLCD) and value in use (VIU). The assessments require the use of estimates and assumptions such as long-term oil prices (considering current and historical prices, price trends and related factors), discount rates, operating costs, future capital requirements, decommissioning costs, exploration potential, reserves (see (a) *Hydrocarbon reserves and resource estimates* above) and operating performance (which includes production and sales volumes). These estimates and assumptions are subject to risk and uncertainty. Therefore, there is a possibility that changes in circumstances will impact these projections, which may impact the recoverable amount of assets and/or CGUs. Information on how fair value is determined by the Group follows.

(e) Decommissioning costs

Decommissioning costs will be incurred by the Group at the end of the operating life of some of the Group's facilities and properties. The Group assesses its decommissioning provision at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing, extent and amount of expenditure may also change — for example, in response to changes in reserves or changes in laws and regulations or their interpretation.

Therefore, significant estimates and assumptions are made in determining the provision for decommissioning.
As a result, there could be significant adjustments to the provisions established which would affect future financial results.

External valuers may be used to assist with the assessment of future decommissioning costs. The involvement of external valuers is determined on a case by case basis, taking into account factors such as the expected gross cost or timing of abandonment, and is approved by the Company's Audit Committee. Selection criteria include market knowledge, reputation, independence and whether professional standards are maintained. The provision at reporting date represents management's best estimate of the present value of the future decommissioning costs required

1. Principal Accounting Policies (continued)

Significant accounting judgements, estimates and assumptions (continued)

(f) Fair value measurement

The Group measures financial instruments, such as derivatives, at fair value at each balance sheet date. From time to time, the fair values of non-financial assets and liabilities are required to be determined, e.g., when the entity acquires a business, or where an entity measures the recoverable amount of an asset or cash-generating unit (CGU) at FVLCD.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest.

A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.

The Group uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs. From time to time external valuers are used to assess FVLCD of the groups non-financial assets. Involvement of external valuers is decided upon by the valuation committee after discussion with and approval by the Company's Audit Committee. Selection criteria include market knowledge, reputation, independence and whether professional standards are maintained. Valuers are normally rotated every three years. The valuation committee decides, after discussions with the Group's external valuers, which valuation techniques and inputs to use for each case.

Changes in estimates and assumptions about these inputs could affect the reported fair value.

Going Concern

The Directors noted the losses that the Group has made for the Year Ended 30 September 2017. The Directors have prepared cash flow forecasts for the period ending 31 March 2019 which take account of the current cost and operational structure of the Group.

The cost structure of the Group comprises a high proportion of discretionary spend and therefore in the event that cash flows become constrained, costs can be quickly reduced to enable the Group to operate within its available funding.

These forecasts demonstrate that the Group has sufficient cash funds available to allow it to continue in business for a period of at least twelve months from the date of approval of these financial statements. Accordingly, the financial statements have been prepared on a going concern basis.

It is the prime responsibility of the Board to ensure the Group remains a going concern. At 30 September 2017 the Company had cash and cash equivalents of £1,748,000 and borrowings of £nil. The Company has minimal contractual expenditure commitments and the Board considers the present funds sufficient to maintain the working capital of the Company for a period of at least 12 months from the date of signing the Annual Report and Financial Statements. For these reasons the Directors adopt the going concern basis in the preparation of the Financial Statements.

2. Business Combinations

Acquisition of Celtique Energie Weald Limited

On 13 June 2016 through UK Oil and Gas Investments Plc, the Group announced the acquisition of 100 per cent of the entire issued share capital of Celtique Energie Weald Limited. The company was re-named Kimmeridge Oil & Gas Limited.

The total consideration of £3.5million, comprised £1.25million in cash and £2.5million in the form of 142,648,831 UKOG ordinary shares. The acquisition was completed, and shares issued on 5 August 2016.

Through the business combination the Group acquired the following assets:

- Weald Basin licence, PEDL234, a 300 sq. km area, more than doubling the Group's net acreage holdings in the prime Kimmeridge Limestone Oil province.

The assets and liabilities arising on the day of the acquisition are as follows:

	Celtique Energie Weald Limited Fair Value	**Fair Value Adjustments**	**Total Fair Value**
	£'000	**£'000**	**£'000**
Intangible Assets: Exploration Costs	4,536	-	4,536
Net identifiable assets acquired at fair value	4,536	-	4,536
	-	-	-
Total consideration	3,507	-	3,507
Negative goodwill on purchase			1,029

Total cash outflow on the acquisition is as follows:	
Cash paid	1,257
Net cash acquired with the subsidiaries	-
Net consolidated cash flow	**1,257**

3. Segment Reporting

All of the Group's assets and operations are located in the United Kingdom. For management purposes, the Group is organised into business units based on the main types of activities and has three reportable segments, as follows:

- Oil exploration and production segment: includes producing business activities
- Oil exploration and evaluation: includes non-producing activities.
- Head Office, corporate and administrative, including parent company activities.

The Board of Directors monitors the operating results of its business units separately for the purpose of making decisions about resource allocation and performance assessment. Segment performance is evaluated based on operating profit or loss and is measured consistently with operating profit or loss in the consolidated financial statements. However, the Group's financing (including finance costs and finance income) and income taxes are managed on a group basis and are not allocated to operating segments.
The accounting policies used by the Group in reporting segments internally are the same as those used in the financial statements.

Subject to further acquisitions and/or disposals, the Group expects to further review its segmental information during the forthcoming financial year, as it begins to see the full impact of its acquisitions and/or disposals.

Group **Year ended 30 September 2017**	**Oil production & exploration £'000**	**Oil exploration & evaluation £'000**	**Corporate & Administrative £'000**	**Consolidated £'000**
Revenue				
External Customers	207	-	-	207
Total revenue	**207**	-	-	**207**
Results				
Depletion & impairment	(74)	-	-	(74)
Share of associates loss	-	(77)	-	(77)
Profit/(loss) before& after taxation	**(66)**	**(209)**	**(1,993)**	**(2,268)**
Segment assets	**2,162**	**21,193**	**4,395**	**27,750**
Segment liabilities	**(306)**	**(3,415)**	**(363)**	**(4,084)**
Other disclosures:				
Investment in associate	-	323	-	323
Capital expenditure (1)	2	8,723	-	8,725

(1) Capital expenditure consists of capitalised exploration expenditure, development expenditure, additions to oil & gas properties and to other intangible assets including expenditure on assets from the acquisition of subsidiaries.

3. Segment Reporting (continued)

Group Year ended 30 September 2016	Oil production & exploration £'000	Oil exploration & evaluation £'000	Corporate & Administrative £'000	Consolidated £'000
Revenue				
External Customers	151	-	-	151
Total revenue	**151**	-	-	**151**
Results				
Depletion & impairment	(78)	-	-	(78)
Share of associates loss	-	(106)	-	(106)
(Loss) before & after taxation	**(53)**	**(106)**	**(1,831)**	**(1,972)**
Segment assets	**2,162**	**10,052**	**6,305**	**18,519**
Segment liabilities	**(310)**	**(341)**	**(299)**	**(950)**
Other disclosures:				
Investment in associate	-	2,800	-	2,800
Capital expenditure (1)	320	4,940	-	5,260

(1) Capital expenditure consists of capitalised exploration expenditure, development expenditure, additions to oil & gas properties and to other intangible assets including expenditure on assets from the acquisition of subsidiaries.

4. Operating Loss

Group	2017 £'000	2016 £'000
Operating (loss) is stated after charging:		
– Directors remuneration – fees & salaries	428	489
– Employee Benefit Trust charge	5	-
– Auditors' remuneration		
Audit-related assurance services	32	20
Other compliance services	-	-
Tax compliance	-	-
– Depletion & impairment of oil & gas properties	74	78

5. Directors and Employees

The Company employed the services of 4 Employees (2016: 3). Remuneration in respect of these employees of which 3 were executive and non-executive Directors was:

Group	2017 £'000	2016 £'000
Employment costs, including Directors, during the year:		
Wages and salaries	453	413
Consultancy fees	-	76
Share based payments	217	577
	670	1,066
Average number of persons, including executive Directors employed	**No.**	**No.**
Administration	4	3
	4	3
Directors' remuneration	**£'000**	**£'000**
Emoluments	645	1,066

The amounts set out above include remuneration in respect of the directors' are as follows:

	2017 £'000	2016 £'000
Donald Strang	-	1
Jason Berry (resigned 16 November 2016)	65	366
Stephen Sanderson	339	607
Kiran Morzaria	179	92
Allen Howard (appointed 1 March 2017)	62	-
Total Directors Emoluments	645	1,066

2017	Fees and salaries £'000	Share based payments (****) £'000	Total £'000
S Sanderson	240	99	339
K Morzaria	100	79	179
A Howard (*)	23	39	62
J Berry (**)	65	-	65
	428	217	645

2016	Fees and salaries £'000	Share based payments (****) £'000	Total £'000
S Sanderson	240	367	607
K Morzaria	92	-	92
J Berry	156	210	366
D Strang (***)	1	-	1
	489	577	1,066

* Appointed 1 March 2017.
** Resigned 16 November 2016.
*** Resigned 23 October 2015.
**** Share based payments are non-cash remuneration by way of the issue of share options in the company.
No pension contributions were made on behalf of Directors during the year.

6. Income Tax

There is no tax credit on the loss for the current or prior year. The tax assessed for the year differs from the standard rate of corporation tax in the UK as follows:

	2017 £'000	2016 £'000
Loss for the year before tax	(2,268)	(1,972)
Tax rate	19/20%	20%
Expected tax credit	(442)	(394)
Differences between capital allowances and depreciation	-	-
Expenses not deductible for tax purposes	107	136
Future income tax benefit not brought to account	335	258
Actual tax expense	-	-

No deferred tax asset has been recognised because there is uncertainty of the timing of suitable future profits against which they can be recovered.

7. Loss per Share

The calculation of the basic loss per share is calculated by dividing the consolidated loss attributable to the equity holders of the Company by the weighted average number of ordinary shares in issue during the year.

Group	**2017** **£'000**	**2016** **£'000**
(Loss) attributable to ordinary shareholders	(2,268)	(1,972)
	Number	**Number**
Weighted average number of ordinary shares for calculating basic loss per share	2,905,392,699	2,177,913,909
	Pence	**Pence**
Basic and diluted loss per share	(0.08)	(0.09)

As inclusion of the potential ordinary shares would result in a decrease in the earnings per share they are considered to be anti-dilutive, as such, a diluted earnings per share is not included.

8. Exploration & evaluation assets

	Group £'000	Company £'000
Cost & Net Book Value		
As at 1 October 2015	1,309	662
Acquired through Business Combinations	4,420	-
Additions	458	80
As at 30 September 2016	**6,187**	**742**
Acquired through Business Combinations	-	-
Reclassifications	200	-
Additions	8,723	576
As at 30 September 2017	15,110	1,318

During the year, there has been no impairment charged, or considered there required to be. The Directors have assessed the fair value of the exploration & evaluation assets as at 30 September 2017 and have concluded at this time there is no requirement to impair and reduce the carrying value whilst they continue to explore and assess these licence areas, further to the detail below.

Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource. The additions during the year reflect the associated exploration and evaluation activities. As this point the Company is still assessing the potential of these assets and will continue to develop and evaluate these assets in the coming year. Since the acquisition date there has been no material changes to the Licence areas. The directors therefore consider that no impairment is required at 30 September 2017.

9. Oil & gas properties

Group	Oil & gas properties 2017 £'000	Property, plant & equipment 2017 £'000	Total 2017 £'000	Oil & gas Properties Total 2016 £'000
Cost				
As at 1 October	1,660	370	2,030	1,648
Acquired through Business Combinations	-	-	-	116
Reclassifications	-	(200)	(200)	-
Additions	2	-	2	266
As at 30 September	1,662	170	1,832	2,030
Depletion & impairment				
As at 1 October	(160)	-	(160)	(82)
Depletion charge	(74)	-	(74)	(78)
As at 30 September	(234)	-	(234)	(160)
Carrying value				
As at 30 September	**1,428**	**170**	**1,598**	**1,870**

Impairment review

The Directors have carried out an impairment review as at 30 September 2017 and determined that an impairment charge is not currently required. The Directors based this assessment ongoing production from Hordean and in the case of Avingdon the operational optimisation that is ongoing to improve operational efficiencies.

10. Investment in Subsidiaries

Company	2017 £'000	2016 £'000
Cost and net book amount		
At 1 October	5,019	1,512
Additions in the year	-	3,507
At 30 September	**5,019**	**5,019**

The Company holds more than 50 per cent of the share capital of the following companies as at 30 September 2017:

Company	Country of Registration	Proportion held	Functional Currency	Nature of business
UKOG (GB) Limited	UK	100%	GB£	Oil production
UKOG Solent Limited	UK	100%	GB£	Oil exploration
UKOG Weald Limited	UK	100%	GB£	Oil exploration
Kimmeridge Oil & Gas Limited	UK	100%	GB£	Oil exploration

All subsidiary undertakings are included in the consolidation. The proportion of the voting rights in the subsidiary undertaking held directly by the parent company do not differ from the proportion of the ordinary shares held. The following companies are taking an exception from the audit of the financial statements as per S479A of the Companies Act; UKOG (GB) Ltd (04050227), UKOG Solent Ltd (05000092), UKOG Weald Ltd (04991234), Kimmeridge Oil & Gas Ltd (07055133).

11. Investment in Associate

Group & Company	2017 £'000	2016 £'000
Carrying Value as at 1 October	4,757	2,063
Re-classification from available for sale investments	-	-
Equity additions at cost	323	2,800
Share of associates loss for the year	(77)	(106)
Carrying Value as at 30 September	5,003	4,757

On 6 March 2015, the Company acquired a further 8% interest in Horse Hill Development Ltd. ("Horse Hill") for a cash consideration of £580,000, thus increasing the Company's holding to 28%. At this point the interest was deemed to qualify as that of an associate company and the investment re-classified from this date. A further 2% holding was acquired on 12 March 2016, for £352,000 payable by the issue of 44million Ordinary Shares in UK Oil & Gas Investments Plc, at a price of 0.8pence per share. This acquisition took the Company's interest in Horse Hill to a 30% shareholding.

On 15 April 2016, the Company acquired a further 12% interest in Horse Hill for a total consideration of £1,800,000, payable as £1,000,000 in cash and £800,000 by the issue of 43,886,116 Ordinary Shares in UK Oil & Gas Investments Plc, at a price of 1.82p per share. A further 8% interest was acquired on 21 July 2016, for total consideration of £1,000,000, payable as £150,000 in cash and £850,000 by the issue of 50,981,799 Ordinary Shares in UK Oil & Gas Investments Plc at a price of 1.57pence per share. These acquisitions to the Company's interest in Horse Hill to a 48% shareholding at 30 September 2017.

On 24 August 2017 the Company acquired a further 1.9% shareholding in Horse Hill total consideration of £323,000, payable as £54,498 in cash and £268,502 by the issue of 17,361,862 Ordinary Shares in UK Oil & Gas Investments Plc, at a price of 1.55p per share, thus increasing the Company's holding to 49.9%.

11. Investment in Associate (continued)

Details of the Group & Company's associate at 30 September 2017 are as follows:

Name	Place of Incorporation	Proportion held	Date associate interest acquired	Reporting Date of associate	Principal activities
Horse Hill Developments Ltd	UK	49.9%	06/03/15	31/12/16	Oil exploration

Summarised financial information for the Group & Company's associate, where made publicly available, as at 30 September 2017 is given below:

	For the 9 months ended 30 September 2017			As at 30 September 2017	
	Revenue £'000	(Loss) £'000	Total other comprehensive income £'000	Assets £'000	Liabilities £'000
Horse Hill Developments Ltd	-	(123)	-	9,598	(6,963)

12. Available for Sale Investments

Group & Company	2017 £'000	2016 £'000
Investment in unlisted securities		
Valuation at 1 October	368	368
Additions at cost	-	-
Disposals	(368)	-
Valuation at 30 September	-	368

On 16 May 2014, the Company completed the acquisition of a strategic 6% shareholding in Angus Energy Plc, a company incorporated in Scotland and resident in the UK, for a consideration of £368,000, payable by the issue of 46million shares in the Company.

Angus Energy Plc completed a listing on the AIM Market on 14 November 2016. The Company disposed of its entire shareholding in Angus Energy Plc for £572,000 in early 2017 resulting in a gain on disposal of £204,000.

13. Inventory

Group	2017 £'000	2016 £'000
Inventories - Crude Oil	4	3
Total	4	3

14. Trade and Other Receivables

	Group		Company	
	2017 £'000	2016 £'000	2017 £'000	2016 £'000
Trade debtors	164	160	145	145
Other debtors	1,488	594	418	546
Loans to related parties (see Note 24)	2,117	2,117	2,117	2,117
Loans to subsidiary companies	-	-	7,055	864
Prepayments and accrued income	16	19	-	-
Total	**3,785**	**2,890**	**9,735**	**3,672**

The directors consider that the carrying amount of trade and other receivables approximates to their fair value.

15. Cash and Cash Equivalents

	Group		Company	
	2017	2016	2017	2016
	£'000	£'000	£'000	£'000
Cash at bank and in hand	1,748	2,444	1,714	2,371
Total	**1,748**	**2,444**	**1,714**	**2,371**

16. Trade and Other Payables

	Group		Company	
	2017	2016	2017	2016
Current trade and other payables	£'000	£'000	£'000	£'000
Trade creditors	2,656	536	283	244
Accruals and deferred income	1,069	55	81	55
Total	**3,725**	**591**	**364**	**299**

The directors consider that the carrying amount of trade and other payables approximates to their fair value.

17. Provisions - Decommissioning

	2017	2016
Group	**£'000**	**£'000**
As at 1 October	359	359
Acquired on acquisition of subsidiaries	-	-
Additions	-	-
As at 30 September	**359**	**359**

The amount provided at 30 September 2017 represents the Group's share of decommissioning liabilities in respect of the producing Horndean and Avington fields, and the Markwell's Wood and Havant drilling sites.

The Company makes full provision for the future cost of decommissioning oil production facilities and pipelines on a discounted basis on the installation of those facilities. The decommissioning provision represents the present value of decommissioning costs relating to oil and gas properties. At this point in time it is uncertain as to when some of these decommissioning costs will occur given current plans by the Company which may change when operations cease. Therefore, the Directors have taken a conservative approach and not discounted these values. These provisions have been created based on the Company's internal estimates. Assumptions based on the current economic environment have been made, which management believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required that will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning is likely to depend on when the fields cease to produce at economically viable rates. This, in turn, will depend upon future oil and gas prices, which are inherently uncertain.

18. Share Capital

Ordinary Shares	Number of ordinary shares	Nominal Value £	Total Value £'000
Issued at 30 September 2015	**2,030,284,020**	**0.0001**	**203**
On 01 March 16, for warrants exercised at 2.25p per share	10,666,666	0.0001	1
On 10 March 16, for warrants exercised at 2.25p per share	2,500,000	0.0001	-
On 15 April 16, for acquisition at 1.82p per share	43,886,116	0.0001	5
On 25 May 16, placing for cash at 1.5p per share	266,666,667	0.0001	27
On 05 August 16, for acquisition at 1.58p per share	142,648,831	0.0001	14
On 11 September 16, for acquisition at 1.67p per share	50,981,799	0.0001	5
On 22 September 16, for options exercised at 0.4p per share	30,000,000	0.0001	3
Issued at 30 September 2016	**2,577,634,099**	**0.0001**	**258**
On 08 December 16, for options exercised at 0.4p per share	20,000,000	0.0001	2
On 24 May 17, placing for cash at 0.8p per share	812,500,000	0.0001	81
On 16 June 17, for warrants exercised at 0.4p per share	15,000,000	0.0001	1
On 19 July 17, for options/warrants exercised at 0.4p/2.25p per share	55,000,001	0.0001	6
On 28 July 17, for warrants exercised at 0.8p per share	40,625,000	0.0001	4
On 24 August 17, for acquisition at 1.55p per share	17,361,862	0.0001	2
On 04 September 17, for options exercised at 0.4p per share	2,000,000	0.0001	-
Issued at 30 September 2017	**3,540,120,962**	**0.0001**	**354**

Deferred shares

The Company has in existence at 30 September 2016 and at 30 September 2017, 1,158,385,229 deferred shares of 0.001p. These deferred shares do not carry voting rights.

Total Ordinary and Deferred Shares

The issued share capital as at 30 September 2017 is as follows:

	Number of shares	Nominal Value £	Total Value £'000
Ordinary shares	3,540,120,962	0.0001	354
Deferred shares	1,158,385,352,229	0.00001	11,584
			11,938

18. Share Capital (continued)

Share Options
During the year 120 million options were granted (2016: 65 million).

As at 30 September 2017 the options in issue were:

Exercise price	Expiry date	Options in issue 30 September 2016
0.4p	31 December 2017	44,000,000
1.15p	24 May 2022	120,000,000
1.82p	26 September 2019	45,000,000
		209,000,000

78.5 million options were exercised, and no options were cancelled during the year (2016: 30 million exercised).
20 million options lapsed during the year (2016: nil).

Warrants

As at 30 September 2017, no warrants were in issue (2016: 13,500,001).

40,625,000 warrants were issued during the year (2016: 13,500,001). No warrants lapsed during the year (2016: nil). 54,125,001 warrants were exercised during the year (2016: 13,166,666 exercised).

Employee Benefit Trust
The Company established on 29 September 2014, an employee benefit trust called the UK Oil & Gas Employee Benefit Trust ("EBT") to implement the use of the Company's existing share incentive plan over 10% of the Company's issued share capital from time to time in as efficient a manner as possible for the beneficiaries of that plan. The EBT is a discretionary trust for the benefit of directors, employees and consultants of the Company.

Accordingly, the trustees of the EBT subscribed for 129,000,000 new ordinary shares of 0.01p each in the Company, at par value per share at an aggregate cost to the Company of £12,900, such shares representing 9.07% of the existing issued share capital of the Company (at that date). The shares held in the EBT are intended to be used to satisfy future awards made by the Company's Remuneration Committee under the share incentive scheme.

No further issue of ordinary shares was made to the EBT during the year ended 30 September 2017.

19. Share-Based Payments

Details of share options and warrants granted during the year to Directors & consultants over the ordinary shares are as follows:

Share options	At 1 October 2016 No. millions	Issued during the year No. million	lapsed /exercised during the year No. millions	At 30 September 2017 No. millions	Exercise price £	Date from which exercisable	Expiry date
Allen Howard	-	10	-	10	0.0115	25/05/2017	24/05/2022
Donald Strang	10	-	(10)	-	0.0040	28/11/2013	28/11/2020
David Lenigas	10	-	(10)	-	0.0040	28/11/2013	28/11/2020
Jason Berry	10	-	(2)	8	0.0115	22/08/2014	22/08/2019
Jason Berry	20	-	(20)	-	0.0182	28/09/2016	28/09/2016
Kiran Morzaria	-	20	-	20	0.0115	25/05/2017	24/05/2022
Stephen Sanderson	25	-	-	25	0.0040	21/01/2015	31/12/2017
Stephen Sanderson	35	-	-	35	0.0182	28/09/2016	28/09/2016
Stephen Sanderson	-	25	-	25	0.0115	25/05/2017	24/05/2022
	110	55	(42)	123			
Consultants	2.5	-	(2.5)	-	0.0040	28/11/2013	28/11/2020
Consultants	65	-	(54)	11	0.0040	21/01/2015	31/12/2017
Consultants	10	-	-	10	0.0182	28/09/2016	28/09/2019
Consultants	-	65	-	65	0.0115	25/05/2017	24/05/2022
	187.5	120	(98.5)	209.0			

The share price range during the year was £0.0088 to £0.0898 (2016 - £0.0088 to £0.0298).

The disclosure of Weighted Average Exercise Prices, and Weighted Average Contractual Life analysis is not viewed as informative because of the minimal variation of options currently in issue, and therefore has accordingly not been disclosed.

For those options granted where IFRS 2 "Share-Based Payment" is applicable, the fair values were calculated using the Black-Scholes model. The inputs into the model were as follows:

	Risk free rate	Share price volatility	Expected life	Share price at date of grant
28 September 2016	2.5%	90.1%	3 years	£0.0180
25 May 2017	0.5%	56.7%	5 years	£0.093

Expected volatility was determined by calculating the historical volatility of the Company's share price for 12 months prior to the date of grant. The expected life used in the model has been adjusted, based on management's best estimate, for the effects of non-transferability, exercise restrictions and behavioural considerations.

The Company recognised total expenses of £474,000 (2016: £682,000) relating to equity-settled share-based payment transactions during the year, and £526,000 (2016: £117,000) was transferred via equity to retained earnings on the exercising or lapse of options during the year.

20. Financial Instruments and Risk Analysis

Financial Assets by Category

The categories of financial asset included in the balance sheet and the headings in which they are included are as follows:

Current assets - Group	2017 £'000	2016 £'000
Inventory	4	3
Loans and receivables	3,787	2,890
Cash and cash equivalents	1,748	2,444
	5,539	5,337

Financial Liabilities by Category

The categories of financial liability included in the balance sheet and the headings in which they are included are as follows:

Current liabilities - Group		
Financial liabilities measured at amortised cost	3,725	591

The group is exposed to market risk through its use of financial instruments and specifically to credit risk, and liquidity risk which result from both its operating and investing activities. The group's risk management is coordinated at its head office, in close co-operation with the board of Directors, and focuses on actively securing the group's short to medium term cash flows by minimising the exposure to financial markets. Long term financial investments are managed to generate lasting returns. The group does not actively engage in the trading of financial assets for speculative purposes nor does it write options. The most significant financial risks to which the group is exposed to are described below.

Interest Rate Sensitivity

The group is not substantially exposed to interest rate sensitivity, other than in relation to interest bearing bank accounts.

Credit Risk Analysis

The group's exposure to credit risk is limited to the carrying amount of trade receivables. The group continuously monitors defaults of customers and other counterparties, identified either individually or by Company, and incorporates this information into its credit risk controls. Where available at reasonable cost, external credit ratings and/or reports on customers and other counterparties are obtained and used. Group's policy is to deal only with creditworthy counterparties. Group management considers that trade receivables that are not impaired for each of the reporting dates under review are of good credit quality, including those that are past due. None of the group's financial assets are secured by collateral or other credit enhancements. The credit risk for liquid funds and other short-term financial assets is considered negligible since the counterparties are reputable banks with high quality external credit ratings.

Liquidity risk analysis

The group's continued future operations depend on the ability to raise sufficient working capital through the issue of equity share capital. The Directors are confident that adequate funding will be forthcoming with which to finance operations. Controls over expenditure are carefully managed.

21. Financial Instruments and Risk Analysis (continued)

Capital Management Policies
The group's capital management objectives are to:

- Ensure the group's ability to continue as a going concern; and
- Provide a return to shareholders

The group monitors capital on the basis of the carrying amount of equity less cash and cash equivalents.

Commodity price risk
The Group is exposed to the risk of fluctuations in prevailing market commodity prices on the mix of oil and gas products it produces. The Group's policy is to manage these risks through the use of contract-based prices with customers.

Commodity price sensitivity
The table below summarises the impact on profit before tax for changes in commodity prices. The analysis is based on the assumption that the crude oil price moves 10% resulting in a change of US$5.43/bbl (2016: US$4.35/bbl), with all other variables held constant. Reasonably possible movements in commodity prices were determined based on a review of the last two years' historical prices and economic forecasters' expectations.

Increase/decrease in crude oil prices	**Effect on profit before tax for the year ended 30 September 2017 Increase/(Decrease)**	**Effect on profit before tax for the year ended 30 September 2016 Increase/(Decrease)**
	£'000	**£'000**
Increase US$5.43/bbl (2016: US$4.35/bbl)	25	16
Decrease US$5.43/bbl (2016: US$4.35/bbl)	(25)	(16)

22. Commitments & Contingent Liabilities

As at 30 September 2017, the Group had the following material commitments;

Ongoing exploration expenditure is required to maintain title to the Group's exploration permits. No provision has been made in the financial statements for these amounts as the expenditure is expected to be fulfilled in the normal course of the operations of the Group.

There were no contingent liabilities at 30 September 2017.

23. Events after the Reporting Date

On 9 November 2017, 8,000,000 options were exercised at 1.15p per share, for £92,000.

On 15 November 2017, the Company announced that it had entered into £10 million convertible loan agreement. As at the date of signing the annual report, £4.75 million of the loan has been converted into 211,943,189 shares at an average price of £0.022 per share.

24. Related Party Transactions

The company had the following amounts outstanding from its investee companies at 30 September:

	2017 £'000	2016 £'000
Horse Hill Development Ltd ("Horse Hill")	2,117	2117
	2,117	2117

The above loans outstanding are included within trade and other receivables, Note 14. The loan to Horse Hill has been made in accordance with the terms of the investment agreement whereby it accrues interest daily at the Bank of England base rate and is repayable out of future cashflows.
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Remuneration of Key Management Personnel
The remuneration of the directors, and other key management personnel of the Company, is set out below in aggregate for each of the categories specified in IAS24 Related Party Disclosures

	2017 £'000	2016 £'000
Short-term employee benefits	599	678
Share-based payments	474	682
	1,073	**1,360**

25. Ultimate Controlling Party

In the opinion of the directors there is no controlling party.

26. Profit and loss account of the parent company

As permitted by section 408 of the Companies Act 2006, the profit and loss account of the parent company has not been separately presented in these accounts. The parent company loss for the year was £2,070,000 (2016: loss £2,911,000).

COMPANY INFORMATION

Company registration number	05299925
Registered office	The Broadgate Tower 8th Floor 20 Primrose Street London EC2A 2EW
Directors	Stephen Sanderson Kiran Morzaria Allen Howard
Secretary	Kiran Morzaria
Auditors	Chapman Davis LLP Chartered Accountants Registered Auditor 2 Chapel Court London, SE1 1HH
Nominated Adviser	WH Ireland Limited 24 Martin Lane London, EC4R 0DR
Solicitors	Kerman and Co. LLP 200 Strand, London, WC2R 1DJ
Registrars	Share Registrars Limited Suite E, First Floor, 9 Lion and Lamb Yard, Farnham, Surrey, GU9 7LL

UK OIL & GAS INVESTMENTS PLC

(incorporated and registered in England and Wales under number 5299925)

NOTICE OF GENERAL MEETING

NOTICE is hereby given that the General Meeting of UK Oil & Gas Investments Plc ("Company") will be held at 8th Floor, The Broadgate Tower, 20 Primrose Street, London EC2A 2EW at 10.00 a.m. on 31 July 2018 for the purpose of considering and if thought fit passing the following Resolutions, of which resolutions 1 and 2 will be proposed as ordinary resolutions and resolution 3 as a special resolution:

Resolution 1: THAT the proposed readmission of the Company's Shares to trading on the AIM Market of London Stock Exchange plc as an operating company (the "Readmission"), on the terms and as set out in the readmission document sent to shareholders of the Company dated 13 July 2018, be and is hereby approved and that the directors of the Company be and are hereby authorised to do all such things as any of them may consider necessary or desirable to complete the Readmission, or otherwise in connection with the same.

Resolution 2: That, pursuant to section 551 of the Companies Act 2006 (the "Act") the Directors be and are hereby generally and unconditionally authorised to exercise all powers of the Company to allot equity securities (as defined by section 560 of the Act) up to the maximum aggregate nominal amount of £170,000 PROVIDED that the authority granted under this resolution shall lapse at the end of the next annual general meeting of the Company to be held after the date of the passing of this resolution save that the Company shall be entitled to make offers or agreements before the expiry of this authority which would or might require shares to be allotted or equity securities to be granted after such expiry and the Directors shall be entitled to allot shares and grant equity securities pursuant to such offers or agreements as if this authority had not expired; and all unexercised authorities previously granted to the Directors to allot shares and grant equity securities be and are hereby revoked.

Resolution 3: That, subject to the passing of Resolution 2 above, and in accordance with section 570 of the Act, the Directors be generally empowered to allot equity securities (as defined in section 560 of the Act) for cash pursuant to the authority conferred by Resolution 2 or by way of a sale of treasury shares, as if section 561(1) of the Act did not apply to any such allotment, provided that this power shall be limited to the allotment of equity securities:

(a) in connection with an offer of equity securities to the holders of Ordinary Shares in proportion (as nearly as may be practicable) to their respective holdings; and to holders of other equity securities as required by the rights of those securities or as the Directors otherwise consider necessary, but subject to such exclusions or arrangements as the Directors may deem necessary or expedient in relation to the treasury shares, fractional entitlements, record dates, arising out of any legal or practical problems under the laws of any overseas territory or the requirements of any regulatory body or stock exchange; and

(b) (otherwise than pursuant to sub paragraph (a) above) up to an aggregate nominal amount of £170,000; and provided that this power shall expire on the conclusion of the next annual general meeting of the Company (unless renewed, varied or revoked by the Company prior to or on that date) save that the Company may, before such expiry, make offer(s) or agreement(s) which would or might require equity securities to be allotted after such expiry and the Directors may allot equity securities in pursuance of any such offers or agreements notwithstanding that the power conferred by this resolution has expired.

BY ORDER OF THE BOARD

Kiran Morzaria
Company Secretary

13 July 2018

Registered office:

The Broadgate Tower 8th Floor
20 Primrose Street, London, United Kingdom, EC2A 2EW

Notes:

Appointment of proxies

1 As a member of the Company, you are entitled to appoint a proxy to exercise all or any of your rights to attend, speak and vote at the meeting and you should have received a proxy form with this notice of meeting. You can only appoint a proxy using the procedures set out in these notes and the notes to the proxy form.

2 A proxy does not need to be a member of the Company but must attend the meeting to represent you. Details of how to appoint the chairman of the meeting or another person as your proxy using the proxy form are set out in the notes to the proxy form. If you wish your proxy to speak on your behalf at the meeting you must appoint your own choice of proxy (not the chairman) and give your instructions directly to the relevant person.

3 You may appoint more than one proxy provided each proxy is appointed to exercise rights attached to different shares. You may not appoint more than one proxy to exercise rights attached to any one share. To appoint more than one proxy, you must complete a separate proxy form for each proxy and specify against the proxy's name the number of shares over which the proxy has rights. If you are in any doubt as to the procedure to be followed for the purpose of appointing more than one proxy you must contact the Company at Suite 3B, Princes House, 38 Jermyn Street, London SW1Y 6DN. If you fail to specify the number of shares to which each proxy relates, or specify a number of shares greater than that held by you on the record date, proxy appointments will be invalid.

4 If you do not indicate to your proxy how to vote on any resolution, your proxy will vote or abstain from voting at his discretion. Your proxy will vote (or abstain from voting) as he thinks fit in relation to any other matter which is put before the meeting. Appointment of proxy using the hard copy proxy form.

5 The notes to the proxy form explain how to direct your proxy how to vote on each resolution or withhold his vote.

6 To appoint a proxy using the proxy form, it must be:

6.1 completed and signed;

6.2 sent or delivered to Share Registrars Limited at The Courtyard, 17 West Street, Farnham, Surrey GU9 7DR or sent by email to voting@shareregistrars.uk.com; and

6.3 received by Share Registrars Limited no later than 10 a.m. on 27 July 2018.

7 In the case of a member which is a company, the proxy form must be executed under its common seal or signed on its behalf by an officer of the company or an attorney for the company.

8 Any power of attorney or any other authority under which the proxy form is signed (or a duly certified copy of such power or authority) must be included with the proxy form.

9 The Company, pursuant to regulation 41 of The Uncertificated Securities Regulations 2001, specifies that only those ordinary shareholders registered in the register of members of the Company 48 hours before the meeting shall be entitled to attend or vote at the meeting in respect of the number of Ordinary Shares registered in their name at that time. Changes to entries on the relevant register of securities after that time will be disregarded in determining the rights of any person to attend or vote at the meeting.

Appointment of proxy by joint members

10 In the case of joint holders of shares, where more than one of the joint holders purports to appoint a proxy, only the appointment submitted by the most senior holder (being the first named holder in respect of the shares in the Company's register of members) will be accepted.

Changing proxy instructions

11 To change your proxy instructions simply submit a new proxy appointment using the method set out in paragraph 6 above. Note that the cut off time for receipt of proxy appointments specified in that paragraph also applies in relation to amended instructions. Any amended proxy appointment received after the specified cut off time will be disregarded.

12 Where you have appointed a proxy using the hard copy proxy form and would like to change the instructions using another hard copy proxy form, please contact the Company as indicated in paragraph 3 above.

13 If you submit more than one valid proxy appointment, the appointment received last before the latest time for the receipt of proxies will take precedence.

Termination of proxy appointments

14 In order to revoke a proxy instruction you will need to inform the Company by sending a signed hard copy notice clearly stating your intention to revoke your proxy appointment to the Company as indicated in paragraph 3 above. In the case of a member which is a company, the revocation notice must be executed under its common seal or signed on its behalf by an officer of the company or an attorney for the company. Any power of attorney or any other authority under which the revocation notice is signed (or a duly certified copy of such power or authority) must be included with the revocation notice.

15 The revocation notice must be received by the Company no later than 10 a.m on 27 July 2018.

16 If you attempt to revoke your proxy appointment but the revocation is received after the time specified then, subject to paragraph 17 below, your proxy appointment will remain valid.

17 Appointment of a proxy does not preclude you from attending the meeting and voting in person. If you have appointed a proxy and attend the meeting in person, your proxy appointment will automatically be terminated.

Total voting rights

18 As at 12 July 2018, being the last practicable date before dispatch of this notice, the Company's issued share capital comprised 5,207,240,526 ordinary shares of £0.0001 each. Each ordinary share carries the right to one vote at a general meeting of the Company and, therefore, the total number of voting rights in the Company as at 12 July 2018 is 5,207,240,526.

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